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THE AUTOMATION OF NEW AND EXISTING SUBSTATIONS: WHY AND HOW?

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The automation of new and existing substations: why and how

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1 Introduction

Today new substations are built with state of the art secondary equipment. It is of great importance to know what their overall purpose is during the whole lifetime of the substation. This can influence the chosen concept, architecture and equipment. Today a lot of expertise exists on an international scale and its related subjects.

Today's existing substations are built with equipment and materials, which have different life times. Primary equipment has an average lifetime of approximately 40 years and secondary equipment such as protection, control or communication equipment approximately 20 years. Consequently, the secondary equipment has to be refurbished once during the lifetime of the substation.

Many different ways exist to do this. There are a variety of different approaches to refurbish a substation. The following two approaches show the boundaries:

- Refurbishment of individual components (e.g. protection relays) – one per one and possibly over a long time span.
- Refurbishment of the entire secondary equipment – all at once.

1.1 Purpose

This report discusses the impact of modern secondary equipment in substations to utilities. Discussed are not individual functions of modern intelligent electronic devices but the overall aspects. It applies for new substations as well as for refurbishment of secondary equipment in existing substations.

The purpose is to assist engineers who have not yet had experience with modern secondary equipment. It provides useful information gained by utilities, manufacturers, and system integrators.

1.2 Scope

Chapter 2: Why should existing substations be automated? What are the economical and technical expectations of today's utilities?

Chapter 3: What are typical functions of a modern substation automation (SA) system regarding control, protection, supervision, and what is the basic structure and architecture of these systems?

Chapter 4: A few hundred substations are already equipped with modern SA systems and international experience has been gained. An example from a Spanish utility is given.

Chapter 5: The basic architectures of modern SA Systems are discussed, differences between them and their impacts for the functionality and the utility in general.

Chapter 6: Today distribution of the energy and transmission of the energy are allocated to different departments or even to different companies. Are there also differences in requirements for modern SA systems? What is common in distribution SA Systems and high voltage SA Systems?

Chapter 7: Wide Area Functions are functions that require data from other substations or the grid in general, and can be implemented in modern SA Systems. Examples for wide area functions are regional interlocking or regional load shedding schemes. There are requirements for these new functions but they are rarely used today. Why?

Chapter 8: Communication within the substation and communication between the substation and the network control centre (NCC) is one of the most discussed subjects in modern SA

Systems. The communication has an impact on the interoperability and flexibility of the SA System. A summary of today's existing communication standards and applications is given and an outlook to the near and far future.

Chapter 9: The cost of a modern SA Systems life cycle is of great interest. Many parameters influence life cycle cost. Theoretical models to calculate Life Cycle Cost exist. However, many of the parameters and data required to calculate the cost are difficult to obtain, or even not available today. Using EDF data, an example is described.

Chapter 10: It is crucial to have a clear defined vision for the SA System before introducing it in a utility. The most important reasons for this are: Influence of the utilities operating principles, its maintenance and even procurement concept. How can the dependability of the vendor be limited, how does the staff have to be trained and what is the required interoperability of the equipment? These questions are discussed among others, which should be answered. The so-called "System Integrator" should guide this learning process in a utility company.

Chapter 11: Modern intelligent electronic devices (IED) with communication capabilities can provide useful information about their own operating status as well as the status of associated equipment (e.g. breakers). Consequently, an improvement in the whole monitoring and supervision of a substation is expected from modern SA Systems. Examples are discussed.

1.3 How to use this report

The titles of the different chapters clearly indicate the subjects discussed. The intention of WG B5.07 is to provide useful information to the many different subjects, and being able to understand them without having to read the report as a whole. It is, for example, not a prerequisite to read the whole book in order to understand the chapter "Current state of communication standards and applications".

2 Why do existing substations need to be automated

The power system industry is in fast competition to have optimal management of the power system network in all system levels. The privatisation of the power system industry creates the opening of new electricity markets that differs in all aspects from the traditional market. A situation in where the consumers become customers due to which new energy supply and traders are appearing in the market. In fact, in the very near future, power system industry all-round the word will see more and more of power producer, retailers and network companies.

Therefore the need to automate existing substations should be evaluated by each utility in order to meet the expected challenges of the future market, and the reliability of the existing equipment.

Utilities all over the world are preparing themselves for a coming future challenge for their network substations for all levels of transmission and distribution. To do this the utility must acquire full knowledge of its needs for automation and its benefits. Each utility, in their effort to automate existing substations, should focus on two aspects that influence the optimum control of its power system management business. These two aspects are economical and technical.

2.1 Economical

Economics plays a major role in justifying existing substation automation (SA). Information about the power system gives the utility the strength to be more successful and competitive in a free market where there is competition between utilities caused by deregulation of the power system industry. In this environment information becomes a strategic requirement when fast decisions are required. Without this information, which can’t be obtained from existing conventional substation, the utility cannot be responsive.

Changes currently occurring, and those expected in the near future, are discussed.

2.1.1 Changes in the power system market

Major changes are taking place in the power system market, and more changes are expected in the future. In a traditional market, where Nation/Area-wise power control centres control and market the energy, there were no other suppliers of electricity to customers. In a deregulated market, this situation is disappearing gradually, and the trend will continue at a faster rate in the near future. Energy service companies are replacing power system companies, and new retailers of energy are being introduced in the market. Also, privatisation/deregulation of the nation’s electrical networks has introduced non-national companies in their market giving new power producers and retailers.

In this open market the consumer is becoming a customer who can choose his supply contractor. This should increase the competition between suppliers, and lead to a market with variable electricity price. New power supply agreements are introduced to account for power supply and price and different suppliers. This is called a “free market price and place”.

Suppliers provide daily information of the power transfer capabilities and retailers receive consumption information. This requires rapid exchange of accurate power supply and price information. Moreover, the customers also need to know their daily operational cost in order to properly plan production to minimise cost and increase their profit.

Transmission and distribution utilities have to separate regulated (transmission and distribution) and non-regulated (energy market) businesses to participate in an open market. In the energy market business there are new functions required for running this business. While in the regulated business there are no major changes required, there is only the need to provide the information necessary to support the energy market decisions.

To support the energy market decision process existing substation may have to be upgraded to provide the necessary information in a timely manner.

2.1.2 Cost reduction in operation

Operational costs have major influence on the overall economic performance of the utility. Accurate information is essential to reduce the operational cost. The following savings can be achieved:

- Personal reduction by implementing the capability to remotely controls the substations. This includes dispatching personal, and field and maintenance crews, which can be better co-ordinated and guided with current situation information received remotely from the substations and the network.
- Faster fault location and clearance, which results in shorter supply interruption time. Shorter supply interruption time is directly related to cost. This is also valid for failures of control and protection equipment.
- Sequential switching and expert systems, which perform sophisticated functions faster and more precisely than human operator.
- Better and more co-ordinated network control functions as voltage/VAR control, network reconfiguration, supply reestablishment after faults.

2.1.3 Cost reduction in maintenance

Utilities operating in a competitive market must contain maintenance cost in three categories.

2.1.3.1 Reduction of troubleshooting and fixing

Troubleshooting in existing substations is tedious and time consuming due to the complex wiring that interconnects different panels for control and protection equipment. In automated substations troubleshooting can be minimised because wiring is less complex and restricted to limited distance. Most troubleshooting will now be in the software where manpower and equipment testing is limited.

2.1.3.2 Reduction in maintenance cost of primary equipment

Material, spare parts, and man-hours spent maintaining regular schedules for primary equipment is reduced by receiving accurate and timely data about the operation of the equipment. For example new distribution feeder protective relays may have features that provide information about how many times the feeder breaker operated on fault conditions rather than simple counters that count the number of total operation of the breaker. Knowing the number of times the feeder breaker operated on fault conditions will be used to determine when to maintain the breaker based on actual fault operation of the breaker. This data can't be obtained from conventional type of substation.

2.1.3.3 Reduction cost in maintenance and operation of control and protection equipment

The revolution of the digital communication, new software technology, numerical relays, and digital control equipment should significantly reduce the man-hours spent in operation, routine testing, and maintenance of conventional solid-state relays and control devices.

A substation automation system provides the capability to continuously supervise various signals and components. Continuous monitoring and diagnostics of the entire installation during operation allows maintenance to be planned on need rather than on a regular basis.

2.1.4 Substation installation cost reduction

It is expected that with the new modern equipment the cost reduction can be achieved. Specifically cost reduction will realise in consolidating individual equipment into one unit. However, this depends on the size and function requirement of the substation.

Utilities as well industrial customers need to see a clear cost reduction comparison between conventional and the new systems. Such a comparison will encourage retrofitting old substations with new modern equipment. Until now the real data required for this study is difficult to obtain. Annex C shows a practical example of where cost recover is achieved.

The following equipment arrangements are considered the major cost reduction.

2.1.4.1 Reduction in cabling and space for control and protection in conventional control technology

Extensive cabling is required between bays in a substation and control room in existing conventional types of substation. This cabling suffers from environmental factors as well as deterioration, induction, loss of signal, cable failure. Cable failures require onsite attendance and time to troubleshoot and replace or repair the cable.

Substation automation using digital signal processing does not require extensive cabling. Only cabling is needed for communication between primary equipment and it's local bay control cubical, either directly or through a process bus.

In addition to the cost savings that can be achieved by reducing the cabling, space required for construction of new substations can also be reduced.

2.1.4.2 Reduction in dedicated equipment for each function

In modern substation automation, there should be major cost reduction with the new technology. This cost reduction will provide major savings in upgrading, installing, and maintaining equipment like SCADA RTUs, digital transient fault recorder (TFR), sequence of event recorders (SOE), interface cubicles, metering panels, and control panels if they are replaced with new modern equipment. This should have major impact in cost reduction without affecting the reliability of the either substation or equipment redundancy.

2.1.4.3 Additional requirement in substation

Existing substations with conventional systems require extensive cabling, space and panel changes whenever a new requirement or a function is needed. Cabling, space for new panels need to be evaluated on case-to-case basis. In some cases, new modern substation automation systems do not require these changes.

2.2 Technical

New business needs, which require more information, will require that a utility upgrade its existing substations. Information is needed about the industrial as well as other customers; e.g., computerised load forecast and complex metering for bulk trading and energy management.

Accurate, timely and trusted information must be provided to the utilities and traders. This information gives the utility an opportunity to enhance its competitive position in a very competitive field. Following are the major technical issues that require upgrading existing conventional substation.

2.2.1 Data requirement

Information, based on substation data, plays an essential role in the optimal management of a power system. A utility will not be able to compete if it doesn't have accurate and timely information about all the power system components. Data to the master control stations from automated substations is needed continuously. Energy management programs to provide information regarding power availability and energy metering use data, such as alarms, breaker status, real time sampling of watts, Var., volts, Amps.

These data are needed in the modern power system industry. Future power control centres will then become information technology centres. This requires that the existing substation be upgraded to an automated substation able to supply accurate and timely data.

2.2.2 Documentation

Today, utilities face difficulties in documenting all changes and upgrades to the network. In other words, there is no "As Built" document that reflects the actual site conditions of the secondary equipment. Significant time is wasted in verifying the existing installation before starting to upgrade or modify an existing installation.

New numerical systems provide the capability to automatically document the system configuration during installation. Software is updated with each modification before putting the new system in operation. Therefore, an "As Built" document is updated continuously. This makes system modification of all the secondary equipment more simple and less time consuming.

2.2.3 Functionality

Unlike the conventional existing system that requires a lot of changes in the secondary equipment to add additional functions, a new modern system provides the capability to add functions to the existing modern equipment. In turn, this provides the ability to select a function from different hardware units and provide via communication the data needed by the master station software.

2.2.4 Reliability

The ability to diagnose in real time problems in the system, and provide accurate information about the power system shortens the time required for diagnosis and increases the reliability of the substation. This resulted in a faster restoration of the substations.

2.3 Conclusions

The utilities in their effort to automate the existing substations should focus on two aspects that shall influence the optimum control of its power system management business. These two aspects are economical and technical.

3 What functions can be designed into automated substations

All equipment for protection, control, monitoring, metering and communication in a substation (S/S) make up the secondary equipment. Secondary equipment can be linked together with serial communication. A substation with such technologies is called an automated substation. An overview of the functions that can be performed by an automated substation is given in this chapter as well as a basic structure of such a system. An example of how an automated system may look in the future, and a comparison table with today and tomorrows functionality is also discussed.

3.1 Typical structure of an automated system

Figure 3-1 shows a typical modern automated substation. Included in this example are intelligent electronic devices (IEDs) for all functions, parallel connection of the IEDs to the primary equipment, serial communication of the IEDs with the station unit and station HMI, and serial communication via a communications unit (ComU) with the network control centre (NCC). IEDs include protection units (PUs), control units (CUs), combined protection and control units (C/Ps), and station units (SUs).

Figure 3-1 Typical structure of today's automated substation

Functions are typically allocated to feeder level equipment for protection, feeder control, disturbance recording, general data acquisition, and time synchronisation.. Functions are typically allocated to station level equipment for communications to remote NCC, communication to feeder equipment, station level HMI, event and alarm handling, monitoring, data evaluation and archiving, and status supervision.

3.2 Protection

All protection functions required (Line, Transformer, Generator, Busbar) are performed in protection units (PU). Examples for protections are:

- Distance protection
- Overcurrent (O/C) protection
- Differential protection
- Thermal overload protection
- Busbar protection
- Breaker failure protection

3.3 Control

These functions are performed in control units (CUs), combined protection and control units (C/P's), and/or in a station unit (SU).

3.3.1 Basic control functions

Typical basic control functions are:

- Control of circuit breaker (CB)
- Control of isolator
- Control of earthing switch
- Control of transformer tap changer
- Interlocking
- Synchrocheck (SC) before closing CB
- Communication to NCC

3.3.2 Enhanced control functions

Typical enhanced control functions are:

- Switching sequences
- Automatic isolating of faulty sections
- Automatic changes of busbars
- Intelligent auto reclose
- Shifting of loads between lines
- Intelligent load shedding
- Intelligent power restoration

3.3.3 Station level control functions

Typical station level control functions are:

- Stationwide interlocking
- Stationwide time synchronising
- Stationwide storage of data

- Collection of disturbance record files
- Analysis and diagnostics

3.4 Metering

The data used for billing purposes are the metering data.

CT's and VT's for protection and control do not have sufficient accuracy for billing purposes. Thus the metering system is usually separate, connected to separate CT and VT metering cores, maintained by different people than those for the substation automation system.

The data from the metering system is transmitted to the billing department.

Metering is therefore not discussed in this report.

3.5 Monitoring

The monitoring functions can be classified in "basic" and "enhanced" functions

Examples for basic monitoring functions are:

- Switchgear status indication
- Measurements
- Event list
- Alarm list

Examples for enhanced monitoring functions are:

- Fault records
- Disturbance records
- Trend curves
- Measurement calculations

3.6 Analysis and Diagnostics

One of the main advantages of an automated system is its ability to generate "intelligent information", e.g. information to support the analysis or diagnosis of the substation equipment.

Examples for analysis and diagnostic functions are:

- Suppression of not relevant alarms
- Failure analysis
- Automatically generated fault reports
- Sequence of event analysis
- Alarm statistics (e.g. of a feeder)
- Automatic disturbance evaluation
- Condition monitoring

More information regarding condition monitoring of primary equipment is given in Appendix C "Use of information for condition monitoring."

3.7 Support intelligence for operation and restoration

The station unit has all relevant date of the substation. These data are quickly available and can be used for intelligent (automated) operation and restoration of the substation.

Typical improvements achieved with automated systems are:

- Clear indication of substation status (substation is ok, incipient failure, fault occurred, etc)
- System can be worked harder to the limits
- Tracking of events, alarms, faults
- Detection of incipient failures
- Earlier preventive measures
- Maintenance prediction on request
- Performance based maintenance
- Reduced down time for repairs
- Reduced repair cost

3.7.1 Example support functions for intelligent operation

Example support functions for intelligent operation are:

- Integrated substation diagnostics
- Integrated condition monitoring
- Plausibility checks
- (Value) limit supervision
- Alarm categorisation (class 1, class 2, class 3)
- Automated notification of problems
- Maintenance prediction (immediately, next week)
- Automatic load shedding

3.7.2 Example support functions for intelligent restoration

Example support functions for intelligent restoration are:

- Clear indication of faulty device, section
- Reliable evaluation of fault history
- Operating instruction
- Automatic change of feeder from faulty to healthy busbar
- Automatic power restoration programs

3.8 Automatic documentation

Automatic documentation is required for substation changes, upgrades and modifications, and actions resulting from all operations.

3.8.1 Substation changes, upgrades, and modifications

Automated systems also need changes, modifications, upgrades or extensions. Such actions are made at station level in modern systems. Data is downloaded from here to the IEDS. All changes made at station level can therefore be automatically documented.

3.8.2 Substation actions

Modern automated systems record all operating activities, switching, and changes made in a substation.

Example actions automatically monitored, controlled, supervised or stored are:

- Status
- Events, alarms, limit values
- Plausibility checks
- All switching (breakers, isolators, tap controller, interlocking, blockings)
- Operating values (15 min average, trends)
- Switching sequences
- Auto reclosures
- Fault / disturbance recordings
- Selected events
- Performance values (e.g. breaker times, running times of isolators)

3.9 Safe and secure operation

One of the most outstanding qualities of modern automated systems fulfilling the requirement for such systems is their safe and secure operation. The probability of a wrongly executed command is extremely small.

All actions, Interlocking, plausibility checks, for example are performed as close to the process as possible. The station unit records all activities.

A failure in the station unit or in the communication path of a system that fulfils the requirements for such systems should therefore not result in any faulty operation.

3.10 Multiple use of data

All data available in an automated system is stored and generally made available for further processing by any device

Example: The currents and the voltages are digitised in the A/D converter. The digitised values are used for:

- Protection
- Load monitoring
- Display of the operational value
- Disturbance recording
- Reports
- Evaluation
- Limit value supervision

Multiple uses of data can simplify the wiring in a substation considerably.

3.11 Typical structure of tomorrow's automated system

The typical structure of tomorrow's automated substation shown in Figure 3-2 is:

- Intelligent electronic devices (IEDs) for all functions
- LAN communication between the IEDs and the primary equipment (sensors and actuators) or hard wired (CT's and PT's, breakers, isolators etc)
- LAN communications between IEDs and to the station unit and station HMI
- Serial or LAN communication via ComU with the network control centre (NCC)

3.11.1 Feeder level equipment

Feeder level equipment includes:

- Protection
- Control
- Disturbance recorders
- Data acquisition in general

3.11.2 Station level equipment

Station level equipment includes:

- Communication to remote NCC
- Communication to feeder level
- Station level HMI
- Event and alarm handling
- Monitoring
- Data evaluation and archiving
- Status supervision
- Time synchronisation

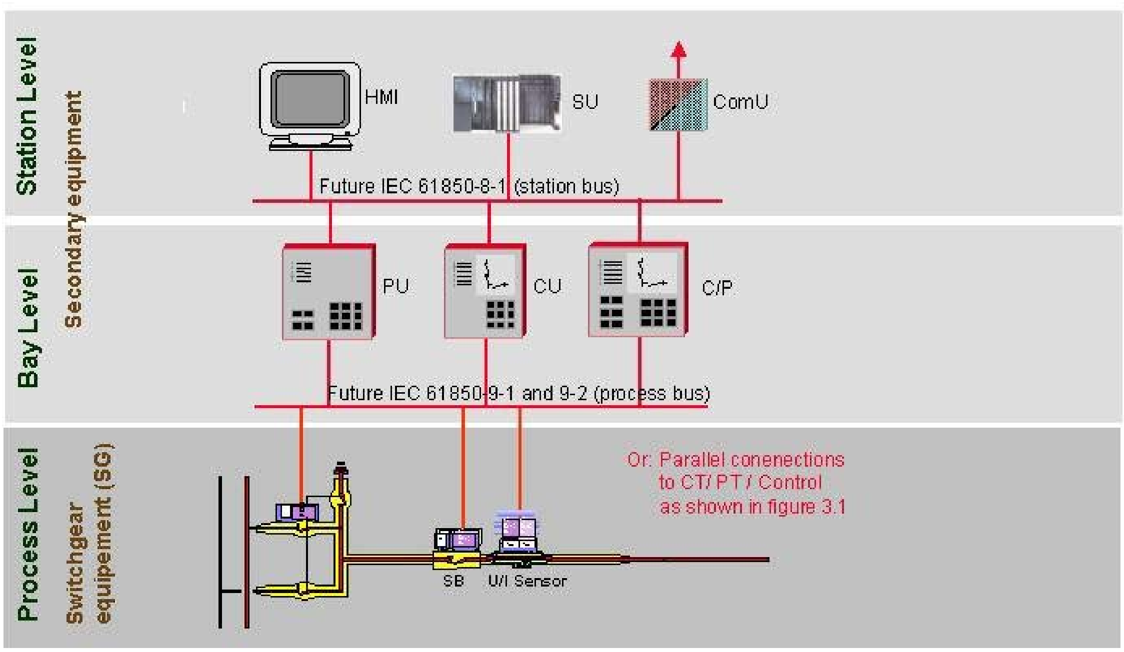

Figure 3-2 Typical structure of tomorrow's automated substation

3.12 *Functional comparison of the different generations of technology*

Table 3-1 shows an overview of today's available functionality and the expected functionality in the future with the IEC 61850 bus.

Explanation of symbols in **Erreur ! Source du renvoi introuvable.**:

"-" Function not fulfilled

"(x)" Function fulfilled with limitations / manufacturer specific solutions

"X" Function fulfilled

Column A: Conventional Technology (today's existing substations)

- Parallel wiring between all equipment (primary and secondary)
- With RTUs for remote control (with the existing NCC protocol)

Column B: Today's Technology

- Parallel wiring between primary equipment and IEDs
- Serial connection of secondary equipment to station unit with proprietary protocols for control with IEC60870-5-103 or DNP3 (mainly USA) protocol for protection equipment
- Serial communication to NCC (with the existing NCC protocol)

Column C: Tomorrow's Technology with 61850

- Parallel wiring between primary equipment and IED or LAN communication between IED's and non conventional U/I sensors and actuators
- LAN communication of secondary equipment to station unit; e.g., IEC 61850 station bus for protection and control
- Serial communication to NCC (with the existing NCC protocol)

Table 3-1 Functional Comparison of different generations of technology

Function	Functionality	A	B	C	Comment (Why is this important)
Protection (see 3.2)	Fundamental protection functions	X	X	X	
	Upload disturbance record files from protection units	-	X	X	
	Interoperability control and protection units	-	X	X	
	Enhanced interoperability between protection units	-	-	X	For example, multicast state change messages so that all devices know the status of the other devices.
	Remote configuration			X	
Control (see 3.3)	Basic control functions	X	X	X	
	Enhanced control functions	-	X	X	
	Station level control functions	-	X	X	

Function	Functionality	A	B	C	Comment (Why is this important)
	Interoperability between control and protection units Interoperability of control units	-	-	X	Permits multi-vendor interoperability, and allows distributed functionality.
	Interchangeability of station units	-	-	(x)	To be verified and further discussed (not in this report).
Metering	Integration of metering data equipment and data into SA system for billing purposes	-			Metering is a completely separate system.
	Connect kWh meter to non-conventional U/I sensors	-	-	X	Permits use of single instrument transformer.
Monitoring protection and control equipment	Basic monitoring functions	-	X	X	
	Enhanced monitoring functions	-	(x)	X	
Monitoring switchgear equipment	Monitoring of equipment	-	(x)	X	
Analysis and Diagnostics	Provide meaningful information of secondary equipment	-	(x)	X	
	Automatic disturbance record upload and analysis	-	(x)	X	
Support for maintenance, operation, and restoration	Automatically generate maintenance alarms		(x)	X	
	Automatic switching programs	-	(x)	X	
	Automatic power restoration programs	-	(x)	X	
	Integration of nonconventional sensors (e.g., CT, VT)	-	(x)	X	
	Integration of nonconventional actuators (e.g., for breakers, isolators)	-	(x)	X	

3.13 Conclusions

All the equipment and functions required for a safe and secure operation of substations are available today.

More sophisticated functions will become available in the future and especially interoperability of IED’s from different manufacturers will become reality.

4 Experiences to date with the application of automation

4.1 The experience of Iberdrola (Spain)

The following is the experience of Iberdrola, an electric utility in Spain, with a total of more than 1900 protection and control digital units installed, taking into account bay and substation level units, whose installation began in 1996.

4.1.1 Brief description of the system

Iberdrola's system is based on substation and bay level units. At bay level there is total integration of protection and control in one unit less than 100 kV, while above this, there is no integration for distance protection and control equipment (communication between them is done through conventional cabling of signals, or by means of Procome protocol for uploading protection signals). However, from Iberdrola's experience, there is no significant difference between both situations as regards commissioning, maintenance, organisation, etc.

Iberdrola has two Spanish manufacturers of all equipment, with full compatibility between them. The typical situation, however, is that substation level equipment is from one supplier and bay level units from the other, although more complex configurations are also possible. Compatibility is reached by the Procome protocol that is being used in Spain.

The Procome protocol is a Spanish protocol, fully compatible with IEC 60870-5, which uses the private area in order to define additional functions.

4.1.2 General assessment

The overall experience of these systems is good and the new technology is seen as an opportunity to improve performance, reliability and to reduce total life costs of substations.

Since the first substation was installed in 1996, no major operational problems have occurred. The systems have behaved as they were designed to do, with few exceptions.

In fact, Iberdrola is stepping ahead to take advantage of this new technology:

- In the year 2000, Iberdrola launched a project whose main objective is to use this new technology also in the upgrading of one bay in an entire substation with conventional P&C, or in extensions of existing substations with conventional control.
- Also, some functions, such as, for instance, interlocking, that in the beginning were not included in the digital equipment due to reliability and security reasons, are now being introduced in the digital equipment.
- Moreover, the system is evolving to a higher degree of integration: for instance, at 220 kV, the synchronism checking relays and circuit breaker tripping coils supervisory relays are going to be introduced in the digital equipment, so that two distance digital relays and one bay control digital unit are the main equipment items in the cubicle.

The advantages that are foreseen in the new technology are:

1. Total life costs are reduced, not only considering investment costs, but also maintenance costs, due to the self-checking function of new equipment.
2. Integration highly improves reliability as, on the one hand, cables and auxiliary relays, etc. are reduced (they are responsible for a large number of failures), and on the other hand, integration of several functions in one unit reduces the probability of failure.

3. It is a good opportunity to achieve standard protection and control logics as the logic now is programmed by the only two manufacturers and not determined by a lot of different engineering suppliers as before.
4. More functionality can be implemented by this technology than by previous ones. Important modifications of functionality during the life of the equipment are much easier.
5. A large amount of information for analysis and maintenance is available remotely.

4.1.3 Issues related to corrective maintenance

Figure 4-1 shows the rate of failure of bay equipment experienced from 1996 through 2002.

Figure 4-1 Total number of failures and units installed per year

The typical failures of bay units are: failure of input/output boards, supply boards, communication interfaces. Typical failures of substation level units are: CPU failures, supply failures, HMI PC blocking, CPU failure avoiding reconfiguration, and communication errors with remote control centres, with the number of failures of substation level units being three times the number of those of bay units.

The most important failures occurred are related to hidden software bugs that were not detected in factory reception tests. The first one came to light when a new substation level version of software was put under service in some substations, and this caused the software of one bay unit to crash, due to a software error. The second one was also a hidden error that appeared only several months after commissioning, in one especial bay, in which the probability of happening was very high, because of especial conditions.

These problems show the importance of doing very thorough type-tests of software versions, so that the probability that these bugs may finally cause errors is highly decreased.

Of the two manufacturers, one is a traditional relaying manufacturer and the other is a traditional manufacturer of Remote Telecontrol Equipment. The former has had more trouble with substation level units while the latter has had more with bay units.

As can be seen, the failure rate of this equipment is quite good, and it has not increased with the number of units.

4.1.4 Questions and challenges

However, as with any new technology, in the early days, several problems have begun to arise:

1. The commissioning of the substations has become more complicated because new organisations have appeared: the manufacturer of protection and control equipment, digital control engineer, and also because the changes that were previously done on site are now prepared in the office by more skilled personnel, causing a delay between detection of a problem and its solution.
2. Maintenance: at the moment, this is the major problem, for the following reasons:
    - The digital equipment evolves very fast and therefore it is costly to maintain a spares policy.
    - At this moment, there is a strong dependence on the manufacturer when a unit fails and has to be put in service. The maintenance departments are still not prepared to do the work without the help of the manufacturer.
3. As different functions are integrated into the same equipment, it is more difficult to determine the commissioning and maintenance responsibility of each traditional department.
4. New versions of software implemented during commissioning may reproduce errors solved in previous versions.

Therefore, the new challenges that utilities face is:

1. The number of software versions that are used during the commissioning process must be reduced and a procedure that determines how a new version must be tested has to be developed, in order to reduce the risk mentioned in point number 4.
2. The maintenance of new equipment has to be organised, taking into account that utilities cannot depend on manufacturers. The documentation that has to be delivered with the system also has to be determined.
3. A new commissioning procedure has to be developed in order to take advantage of the new technology and to solve the problems that appear.
4. One single organisation has to be responsible for the whole system.

4.1.5 Issues related to commissioning

Up to now, Iberdrola has mainly faced the commissioning step, and the following actions have been taken, with the result that commissioning times have been reduced.

- Factory tests have been established, in order to test software thoroughly before being installed on site. These tests include simulation with remote telecontrol databases. The goal of these tests is to reduce the number of software versions, and to decrease the number of errors detected on site, so that they can be solved in “real time”, i.e. as they are detected.

- The number of organisations participating in commissioning tasks has been reduced, and protection personnel have taken the responsibility for on site final tests.
- Complex automatisms are thoroughly laboratory tested. These tests are type-tests, so that only simple final functional tests are carried out on site each time.

A comparison between conventional and the new integrated control technology is shown in Table 4-1.

Table 4-1 Comparison of conventional and integrated control

Conventional control	Integrated control
On site modifications during commissioning are performed by erection personnel	On site modifications during commissioning are performed by erection personnel or by digital equipment manufacturer
These personnel are permanently on site during commissioning. Their qualification is low.	Digital equipment manufacturer personnel are not on site permanently. Modifications are made in the office and afterwards sent to the substation. Their qualification is medium.
Control equipment is similar in all substations and easily interchanged => It is quite easy to have spares with a minimum stock	Digital equipment develops very fast and is not easily interchanged. Therefore, a large inventory stock is needed in order to have spares.
Control/protection/telecontrol functions are done by different equipment => maintenance responsibilities are perfectly defined and limited	The same equipment does control, protection, and telecontrol functions. Therefore, it is difficult to define the limits of maintenance responsibilities of each organisation.
Maintenance and simple control modification is simple and the risk of errors is low	Maintenance and simple control modification is complex and the risk of errors is high, due to the complexity of software, firmware, and hardware version and configuration.
Commissioning can be done unit by unit, with final functional tests	Final functional tests are the only way to do commissioning tasks, due the high level of integration
High reliability	Very high reliability
High necessity of space	Low necessity of space
Medium cost of equipment and high cost of installation	Medium cost of equipment and low cost of installation
Low information for analysis and maintenance and locally available	Extensive information for analysis and maintenance and remotely available
Limited functionality	High functionality
Long life	Life unknown but probably medium
Introduction of important modifications is complex and expensive	Introduction of important modifications is simpler and less expensive

4.1.6 Conclusions

Iberdrola has used automation systems since 1996, with more than 100 automated substations at the moment. The overall experience is remarkable.

The major drawback of these systems is maintenance. Thorough software tests are considered a critical issue for this technology.

4.2 The experience of NV Remu (The Netherlands)

In 1987 NV Remu began to equip transmission stations with station automation rather than traditional relay technology. 30% of NV Remu's transmission stations are currently equipped with station automation. The use of station automation has far-reaching consequences from both a technical and an organisational point of view. On the basis of implemented projects the trend of the past ten years is analysed.

4.2.1 Initial experiences with station automation

In 1987 two 150 kV transmission stations were simultaneously equipped with station automation. The order was preceded by an extensive preliminary study. Opinions within the company were sharply divided. At the time the advantages and disadvantages were difficult to quantify. Inexperience, uncertainty about reliability and the absence of actual figures made the discussion a complex one. In addition, a number of staff wondered why a relatively static process had to be automated.

A universal automation system from the process industry was selected. The system consists of several Program Logic Controllers (PLCs) that communicate with each other over a redundant network. Because industrial PLCs were selected, which are sensitive to electromagnetic disturbances, additional electromagnetic capability (EMC) measures had to be taken. The protection room was shielded (a Faraday cage was created), the station earthing was extended further and the secondary cables were provided with an earth shield.

Programming the automatic functions (interlocking, voltage control, busbar changeover) took a long time. The programming freedom with systems like this is enormous. NV Remu's ideas on how systems and functions ought to be built up were implemented relatively easily. A great deal of energy went into making the entire system robust. To eliminate any risk, switch-error locking devices were created in the software and by means of auxiliary relays ("hard" contacts). The implementation of the initial systems represented a new trend for NV Remu.

Over the years several changes have been made to the initial systems. The main ones are: locks and switch back-up protection were placed only in the software, the automatic clearing of rail systems was further extended, remote I/O was applied and it became possible to read out protective relays. For the most recent projects, a combined protective control unit was used for the 10 kV fields.

4.2.2 Analysis of NV Remu's experience over the past 10 years

For the analysis the following criteria was used: the average number of I/O points, the development of the number of different functions, the number of systems and the average field price. The trend is analysed using the four criteria; however, the number of transmission stations on which the analysis is based is relatively small. Therefore, the figures presented should not be taken as absolute. To enable different systems to be compared, weighting factors were used for 150, 50 and 10 kV fields. The following graphs show the development of the past years as percentages, with the current method having the value 100%.

4.2.2.1 Average number of I/O points

Figure 4-2 shows the average hardware data points per field. By comparison, after the introduction of station automation the number of reports increased by 60%. The graph shows appreciable growth between 1990 and 1995. This growth is a consequence of increasing confidence in the technology used (an increasing need to report everything develops). After 1995 a sharp drop can be seen. This fall was due to the fact that people started to wonder whether everything really had to be reported. A second cause was that in 1998 an integrated unit for protection and operation was selected for the first time. Within the sector, protection and station automation was two separate worlds. The only form of integration was the exchange of adjustment and switch-off data. For protection specialists in particular, the idea of combining protection with station automation was not a subject for discussion. As a result, suppliers could hardly supply products in which protection and control were combined together. In the recent projects, a combined relay/field unit was used for the 10 kV fields. As a result of this development, the number of hardware connections has decreased by a factor of five.

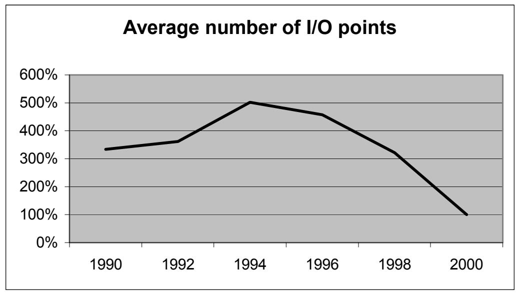

Figure 4-2 Average number of I/O points

4.2.2.2 Number of different systems

Figure 4-3 shows the number of different systems. In this overview a different system is defined; i.e., one in which the hardware or software is substantially different. In the period 1990 to 1996, the number of systems increased constantly. There are currently six different systems operational in NV Remu's organisation. This increase is caused by developments at the supplier. For a number of reasons, until 1996 NV Remu opted for a single supplier. After 1998 the slope of the graph increases slightly. One of the factors contributing to this increase is the introduction of a second supplier. The reason why a new supplier was introduced, apart from considerations of competition, was the fact that 50/10 kV transmission stations became considerably simpler. The functionality (and therefore the required investment) of powerful industrial systems is no longer proportional to the simplified primary installation.

Figure 4-3 Number of different systems

4.2.2.3 Average cost for station automation

Figure 4-4 shows the average investment for a field equipped with station automation. Investments from previous years have been adjusted to 2000 prices. The average field price was determined using weighting factors for 150, 50 and 10 kV. In the period 1990 to 1995, the average investment hardly increased. If on the other hand one takes into account an increase in the number of I/O points of over 30% (see Figure 4-1), the average investment per data point has decreased. The average field price approximately halved between 1996 and 2000. This fall is attributable both to different technology (see number of different systems) and competition between suppliers. It can be stated that the average costs for station automation have approximately halved in the past ten years.

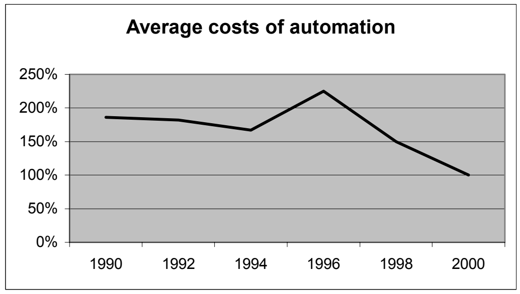

Figure 4-4 Average cost of automation

4.2.2.4 Station automation systems management

The introduction of station automation has brought about a change in the management of secondary installation. For the management a distinction must be made between preventive and corrective maintenance. As regards corrective maintenance, NV Remu's experience is that the systems require very little maintenance.

NV Remu performs the following activities periodically:

- Making a back-up of the software: after every major change or once a year
- Visually inspecting the printed circuit boards and rendering them dust-free: every two years
- Periodically replacing dust filters (after system warning)
- Checking analogue inputs and replacing batteries: every five years

As regards corrective maintenance, a distinction is made between faults in the remaining secondary installation and faults in the station automation. Because generally speaking much more reporting is done and also the time sequence is fixed, faults in the remaining secondary installations are relatively simple to solve. Solving faults in station automation systems is often a complex process. In conventional stations faults can be traced by means of a multimeter, whereas with automated stations a specialist often has to come with his laptop (signals disappear into a "black box"). Another aspect is that faults often remain unexplained: they come and go spontaneously. The unpredictability is caused by the complexity, the impossibility of testing everything and the high degree of component integration.

Besides having to find solutions to more complex faults, NV Remu is increasingly faced with rising hardware costs. NV Remu's experience is that hardware stays in production for an average of five years, after which the supplier switches to a different technology. While it is true that suppliers guarantee delivery periods of up to 15 years, replacement system components are expensive. Generally speaking, the maintenance costs of stations with station automation are not much different from those of conventional stations.

4.2.2.5 Personnel

The introduction of station automation has had not only a technological impact, but also consequences for personnel. A shift has taken place in employees' tasks, procedures and level of knowledge. Instead of designing and drawing circuit diagrams, the engineering department now has to write functional specifications. The supplier often does the detailed engineering and the programming.

The number of assembly hours performed by the implementation/management department has fallen sharply. As the number of hours has declined, however, the training level of the technicians concerned has increased.

As indicated, NV Remu made a conscious decision to build up the initial systems with industrial PLCs. The initial systems were programmed in close collaboration with the supplier. At that time the programming tools were less intelligent than today's tools. The great advantage of having extensive co-operation and a relatively low level of intelligence is that this enables NV Remu technicians to acquire a great deal of system knowledge. In the ensuing years, the application software has increasingly taken over tasks that used to be done by the technicians. Windows technology more broadly applied, terms like cut and paste, what you see is what you get, are increasingly common in application software. Suppliers are more and more developing universally applicable function blocks. These function blocks are designed in such a way that they can be used in different projects for different customers. The use of these function blocks shortens the time needed to write the application. However, the actual knowledge required by the technician is reduced. A consequence of the more complex software and decreasing system knowledge is that faults are more and more difficult to remedy.

Besides the problem of declining system knowledge as described above, the number of different systems is constantly increasing. NV Remu technicians are therefore increasingly involved with different programming methods. Know-how and experience can be secured by taking out maintenance contracts. Such maintenance contracts are generally very expensive, however. NV Remu policy is to ensure that their own personnel can perform the first-line maintenance, including correcting faults. Whether NV Remu can continue to maintain this point of view in the future is a matter that will have to resolve in the near future.

4.2.2.6 Conclusion

NV Remu experience is that station automation systems have made a major contribution in the past few years. Transmission stations still do the same thing, the amount of I/O points has been dramatically reduced and the investment has halved.

A shift has taken place, especially for the employees where know how and expertise on different skills are called upon.

5 Possible architecture of HV substation automated systems

Today, most substation automation systems (or SAS) developed by manufacturers and used by utilities have a similar material architecture, except for a few differences. However, from the utilities point of view, the requirements in terms of functions, safety, operation, and maintenance procedures may be extremely different, and strongly influence the chosen design of the substation automation systems.

The aim of this chapter is to identify several typical *architectures* for transmission SAS, in accordance with both the today's standard manufacturers' offer, and the more or less "specific" utilities' requirements.

5.1 Main features of SAS in a standard industrial offer

All components with metallic connections to the substation - dc power supplies, I/O circuits, and metallic communications circuits - must be designed to meet environmental requirements.

This Section gives a brief overview of this convergent offer: various basic components of the system architecture: computers and their operating systems, communication networks, supervision software, synchronisation and remote interface are described.

5.1.1 Control processor units and I/O boards

At present, most manufacturers offer substation automation systems for which the control processor unit (CPU) is a dedicated one. In order for the CPU and I/O boards to meet the electrical transients constraints that occur on substation wiring, use of non adapted off-the shelf components is not recommended.

Indeed, to deal with this type of problem, there are two solutions facing the SAS supplier:

- To develop (design and manufacture) specific boards (CPU and I/O) in-house. This solution can be beneficial in the sense that the manufacturer is in total control of the technology used and can implement specific functionality on-board.
- To adapt the boards available off-the-shelf. This second solution can be interesting for the following reasons: microprocessor equipment and the associated material are changing quickly, and all board suppliers who are committed to the profession have fast enough reactions and the knowledge needed to fully address these changes. The compatibility between I/O board and control processing unit is hence delegated and not under the control of the SAS supplier.

5.1.2 Operating systems

In addition to proprietary solutions now less widely used than previously, two families of operating systems (OS) are now available on the market:

- GPOS (General Purpose Operating System): Windows, Unix, Linux,
- RTOS (Real Time Operating System): pSOS, QNX, VxWorks, RTX, Lynx, CMS, and all other vendors of specific operating systems.

The former are widespread for the following uses: Unix for master stations in control centers, Windows NT for HMI. The latter are more generally used when real-time constraints are particularly demanding i.e. for protection and logic control functions.

To add additional functionality to their operating systems, which makes a GPOS into a dedicated solution, GPOS manufacturers are attempting to upgrade them and equip them with some real-time characteristics; however, the corresponding performance is still particularly remote from the performance offered by genuine real-time systems. The best approach consists in upgrading them in greater depth. Products like RTX 4.1 from VenturCom or INTime 1.20 from Radisys or Hyperkernel 4.3 from Imagination System mean that the same processor can offer a particularly widespread operating system, Windows NT, with the same real-time characteristics as an RTOS. In parallel, other upgrades will allow developments based on Unix systems.

5.1.3 Communication networks

This point is, strictly speaking, on the sidelines of the system architecture but it is worth mentioning that the HMI is usually a part of the system, even if in practice it is often linked to the SAS through a laptop.

The software available on the market like iFix from GE Intellution or InTouch from Wonderware, come from other application areas, and are not entirely tailored to be used in electrical substation control and monitoring systems. That is why several manufacturers are developing their own supervision software independently of the market supply. Nevertheless, a new trend towards browseable user interfaces seems to appear.

In the future, a standard such as IEC 61850 will allow making HMI an independent subsystem connected to the SAS structure through a standard communication interface.

5.1.4 Time synchronisation

The manufacturers are using two approaches:

- Synchronisation at the central computer, which then dispatches the information to the other computers via the communication network. This simplifies clock connection but causes problems of synchronisation between various system components. In today's common practice, this method doesn't allow high performance (namely down to 5 ms). New (IEEE 1588 or IEC 61850) and future standards can improve accuracy.
- The central computer, the decentralised computers and the IEDs receive time information directly from the sync clock. In this case, synchronisation is better but implementation is more difficult (requirement to equip each component with a suitable input and have an associated timing bus).

5.1.5 Communications external to the substation

The analyse leads to state there are two main types of communication depending on the security and on the kind of traffic.

- The conventional “real time” SCADA requiring high availability, for control and supervision data: commands, cyclic measurements, system, protection and process events. Standard protocols are used: DNP.3, IEC 60870-5-101 or IEC 60870-5-104 (see Chapter 8 and Appendix D for further details). Sometimes, manufacturers must develop specific protocols to adapt to the utility's legacy telecontrol infrastructure.
- The other one allowing data exchanges for remote setting of protection equipment and remote maintenance, or other various operation and engineering tasks. It is not mandatory to establish a permanent connection and there is no real time requirement. These functions may be activated remotely over a Wide Area Network (or WAN).
- The connection is in general not permanent (dial-up connection on RTC network) but the development of web-based communication for telesupervision, fault analysis or asset management can require a WAN permanent link.

Some security functions may be requested especially when remote parameter settings and file downloading are used.

5.2 Main functional requirements for SAS

5.2.1 Common functions

For most utilities (in European countries), SAS are configured in a bay oriented structure, where a bay corresponds:

- A feeder
- A transformer
- A busbar coupler

The bay equipment assembly is physically located either in bay kiosks in the switchyard, or in bay cubicles inside the substation building.

Functions performed at the bay level are control, protection, and data acquisition related to the power line. Although integration levels between protection and control functions vary, the supported functions are the same. Hereafter is a list of the most standard functions:

- Interlocking
- Synchronism
- Energising check
- Automatic reclosing
- Breaker failure protection
- Zero voltage supervision
- Disturbance recording

An important point is the integration level between protection and control functions: high integration level may be allowed. But protection functions may also remain segregated in dedicated devices. In that case, the trip commands are linked directly to the switchgear and are independent of the control system to achieve high reliability.

Because of refurbishment constraints, existing protection equipment are not always systematically replaced by digital IED. Therefore, they are interfaced to the digital system. The aim is to reduce investment costs and to avoid "early write off" of existing protection equipment before their end of life. Protections may come from different manufacturers and communication possible choice consists in or parallels wiring or standard protocol (IEC 60870-5-103).

In Europe, a common practice for SAS is that all digital bays come from the same manufacturer; it is difficult at the moment to achieve interoperability between heterogeneous digital bay devices as above mentioned in Section 5.1.3.

Alternatively, it is worth mentioning that all systems offer the possibility to interface "conventional" bay equipment thanks to interface digital Input-output units located at bay level or grouping the control of several bays at substation level.

5.2.2 Factors that differentiate architectural features

Although there is a common functional basis, there are still different requirements to implement them, which strongly influence the global design of the SAS. Main differentiation comes from the factors described in Table 5-1.

Table 5-1 Impact on system architecture

Influence factor	Impact on system architecture
Size of the substation: • Number of voltage levels • Number of bays • Number of busbars	Number of LAN's: a single Ethernet segment for both substation and bay level, or several segments, one for substation level and others for bay level.
Reliability and availability requirements depending on: • The voltage level, • The substation criticality in the power system	• Redundancy or not of LANs • Redundancy of bay level and/or station level controllers and HMI • Integration or not between control and protection • Redundancy of protections
Utility's industrial strategy: • Bay per bay Refurbishment • New substations	• Choice of modular and flexible architectures • Interfaces with existing conventional devices • Choice of configuration tools easy to manage
Cost over the system life cycle	• Number of devices • Redundancy
Operating procedures of the country or the utility.	• Remote control interface using proprietary communications • Integration of protection from other manufacturers
Topology of the substation: • Transfer busbars • 1 or 1 $^{1/2}$ Circuit breaker arrangement	• Number of cubicles • Number of bay computers • Functions of automation at bay and substation level

5.2.3 *Main criteria of the utility's architectural choice*

Three identified criteria of architecture choice, given here after, can be used by the utilities - the importance of each criterion depends on the utility strategy:

- Cost of the SAS: system life cost – linked with the MTBF of the System – and investment costs, depending on the utility's industrial policy
- Functional flexibility and user friendliness of the SAS, interoperability with equipment of other manufacturers, adaptability of the manufacturer in the bid set up
- Associated services: from engineering (installation, tests) to maintenance (supervision, fault analysis)

5.3 *Identification of typical SAS architectures*

According to Sections 5.2.2 and 5.2.3 the material configuration of SAS is relatively convergent in the industrial offer, whereas utilities needs, sometimes due to utility's history, are much more heterogeneous.

The question is therefore the design of several typical architectures based on the industrial offer but able to adapt to these "specific" needs, which hence can decrease interoperability, and to give comparison criteria between them.

It can be said that most systems have a sufficient scalability and flexibility to meet specific requirements if needed. Each manufacturer is therefore able to adapt its generic[1] architecture to different configurations.

Architectural alternatives may be identified that correspond to the above-mentioned elements that influence the architecture of substation automation systems. The basic difference between these alternatives is segregated protection and control architecture per bay, a multifunction box approach, and a separated maintenance and control architecture.

5.3.1 Segregated protection and control per bay

In North American and in many other areas, it is common for protection and control to be supplied in one IED, which has a serial interface to the substation computer. This architecture (see Figure 5-2) is used at all voltage levels, including EHV.

In the segregated protection and control architecture per bay, the system exchanges information with relays, remaining segregated from the core automation system. Reasons for this choice are:

Dependability requirements: It is important to avoid common mode failure of the protection system. The choice of separate protection devices corresponds to being able to continue to protect a line, when the bay controller gets corrupted.

Protection needs: the algorithms may be sophisticated (distance, differential) thus the approval of the protection devices by the utility may represent a long process. Reciprocally, once a customer has approved a product, he wants to keep the same product. Therefore, the digital bay may have to interface with existing protections.

Substation needs: There are relatively few new substations, but there are many partial refurbishments of existing substations. Therefore, the new digital bays must be compatible with the rest of the substation. Inter-bay communication and communication with existing static relays remain “conventional”. A common case is retrofit projects where the existing busbar protections are kept and where some bays remain unchanged.

In this approach, legacy relays are interfaced to a digital bay with parallel wiring. For digital protection, a standard communication link may be adopted. There is currently a single protocol available: IEC 60870-5-103 (master slave based, using conventional UART serial port, with a maximum speed of 19.2 kbps). It is not well-adapted (too large provision for private extensions, limited range of public information, low speed) and must be complemented by conventional parallel wiring between devices. The future IEC 61850 standard is likely to replace it.

Figure 5-1 shows the main features of this approach.

In Europe, segregated protection and control architecture per bay is usually used for HV substations. Although for MV substations, this architecture can be used, or the architecture substations, without changing the concept described in the next section.

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[1] A generic substation automation system means that the architecture may be configured to match all kind of substations, without changing the concept.

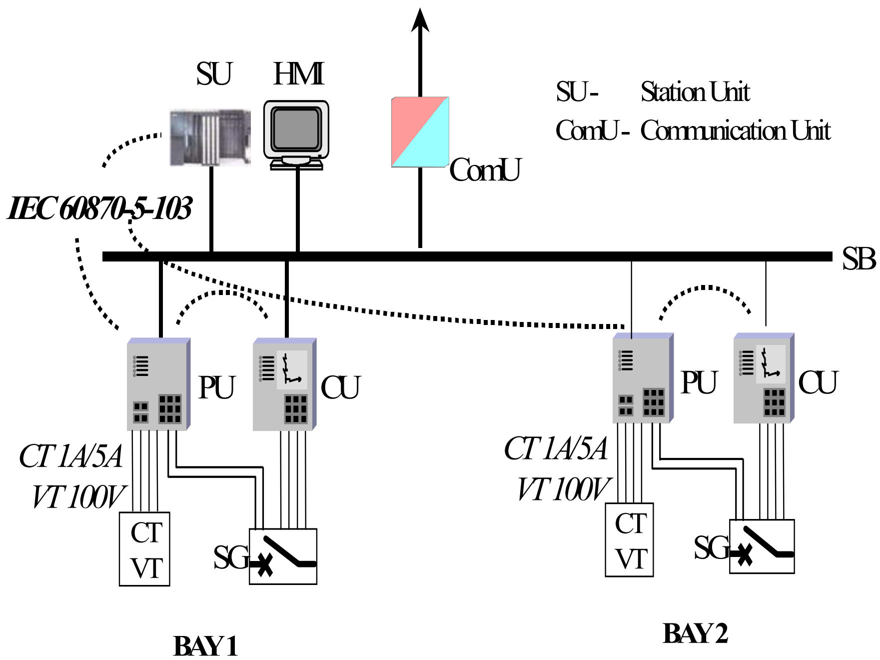

Figure 5-1 Segregated protection and control per bay architecture

5.3.2 Multifunction box approach

In the multifunction box approach, which allows optimising cost and place, the protection relays are part of the substation automation system. Feeder relays perform protection functions, but are also providing autoreclosing, measurements, disturbance recording facilities, communication capabilities, and even possibly maintenance and operation services. Figure 5-2 shows the main features of this approach.

In Western hemisphere, it is common for protection and control to be supplied in one IED which has a serial interface to the substation computer at all voltage levels, including EHV. Either the architecture shown in Figure 5-2 or Figure 5-1 is used.

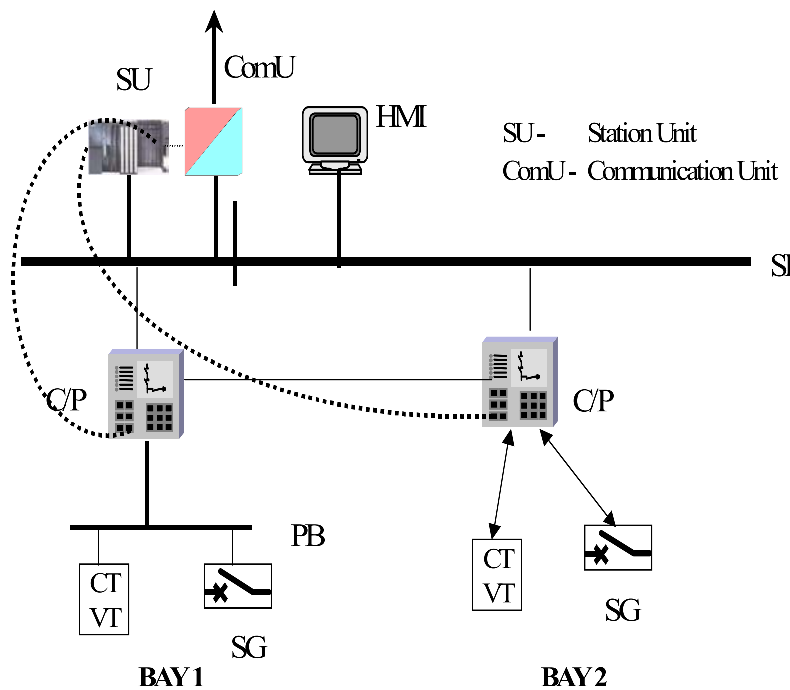

Figure 5-2 Multifunction box per bay architecture

5.3.3 Separated maintenance and control architecture

Concerning the previous alternatives, it is not only possible to combine them into the same system architecture, but also to add a separated maintenance and operation architecture on a dedicated LAN. Figure 5-3 shows the main features of this approach, which is used in Japan.

At the bay level, protection and control functions may be either fully "integrated" or fully "segregated". Regardless of this choice, substation communications are in general "co-ordinated" that is to say divided into separate flows, according to the final application and users because of the nature of information.

SCADA real-time information: cyclic measurements, event driven data points with timestamps, commands are retried from / sent to bay level devices. LAN 1 (see Figure 5-3) concerns these exchanges (master slave serial link - IEC 60870-5-103, or peer to peer communication bus like LON, Modbus, Profibus).

Operation support information without real time requirements: disturbance-recording files, dump files at administration purposes, configuration files parameter settings; LAN 3, using a proprietary protocol, (see Figure 5-3) is dedicated to these operation support functions including:

- Protection oriented functions (parameter settings and supervision of protection equipment, disturbance recording analysis).

Figure 5-3 Separated maintenance and control architecture

- System maintenance and administration oriented functions (restoration support for device failure, system diagnostics, failure identification location, automatic restoration procedures, and self-supervision messages).
- HV equipment maintenance
- Test mode simulation, training simulation
- Various engineering tasks, configuration files downloading, and software versions handling

At substation level, LAN 2 (see Figure 5-3) is generally an Ethernet proprietary network, as real time requirements are not as high as bay level communication. LAN 2 provides communications for both operation applications, and SCADA substation control and supervision functions.

5.3.4 Distributed and hierarchical system architectures

A distributed architecture and a hierarchical architecture are described.

5.3.4.1 Distributed architecture

A major trend seems to be toward the distributed architecture, hence reaching better availability and modularity. In the distributed choice, there is not a substation "master" controller, but only bay level control and protection units. Peer-to-peer communications is required between bays, and to the substation level/bay level digital interfaces. This choice achieves good availability performances.

Figure 5-2 and Figure 5-3 are distributed architectures with a different threshold of integration in terms of protection and control. At the bay level the functions are integrated in both bay controllers and digital protection equipment. The integration level depends on the utility's requirements[2].

The trend, in accordance with manufacturers offer, is to distribute intelligence at bay level. This trend is further enhanced by the emergence of a process level high-speed field bus for direct exchanges with intelligent CTs and VTs and high voltage switchgear equipment.

5.3.4.2 Hierarchical architecture

Hierarchical architectures still exists on the SAS market. The system architecture can be hierarchical or centralised. The hierarchical substation unit or sub-master controller may perform several functions: data and communication concentrator, substation-level automation like station wide bay interlocking, voltage regulation, and data storage. Figure 5-4 shows the main features of this approach.

Sometimes, the communication unit function can be included in the substation controller.

The evolution of the technology, together with further cost and operation optimisation goals, lead to the definition of a new generation of architecture for the SAS that offers more technological and functional choices. However, from a customer's point of view, the SAS architecture is constrained by various factors such as dependability, substation progressive refurbishment, use of different suppliers, etc.

Therefore the main choices concern the integration threshold between protection and control, the distribution or centralisation choices of various functions and the existence of redundancies due to specific customer's reliability and availability requirements. The general trend is towards a growing distribution (better availability, modularity), and towards a growing integration (cost and space optimisation). It is expected that future communication standards, such as IEC 61850, will enable the development of new architecture that will be more performance and more cost effective.

Because IEC 61850 is standards-based, communication between IEDs supplied by different vendors can be achieved. Replacing parallel wiring between protection and high voltage equipment (e.g., CTs, VTs, and switchgear) by a digital process bus will provide additional future benefits.

The development of an efficient cost estimation methodology based on utility's data (see Chapter 9) is another benefit. Compiling these data will provide a relatively precise measure of the cost and reliability of a distributed open-architecture implementation.

[2] In Japan for example, the transmission network is still in expanding phase, therefore, as new substations are planned, a more innovative approach is allowed, with higher integration level between protection and control.

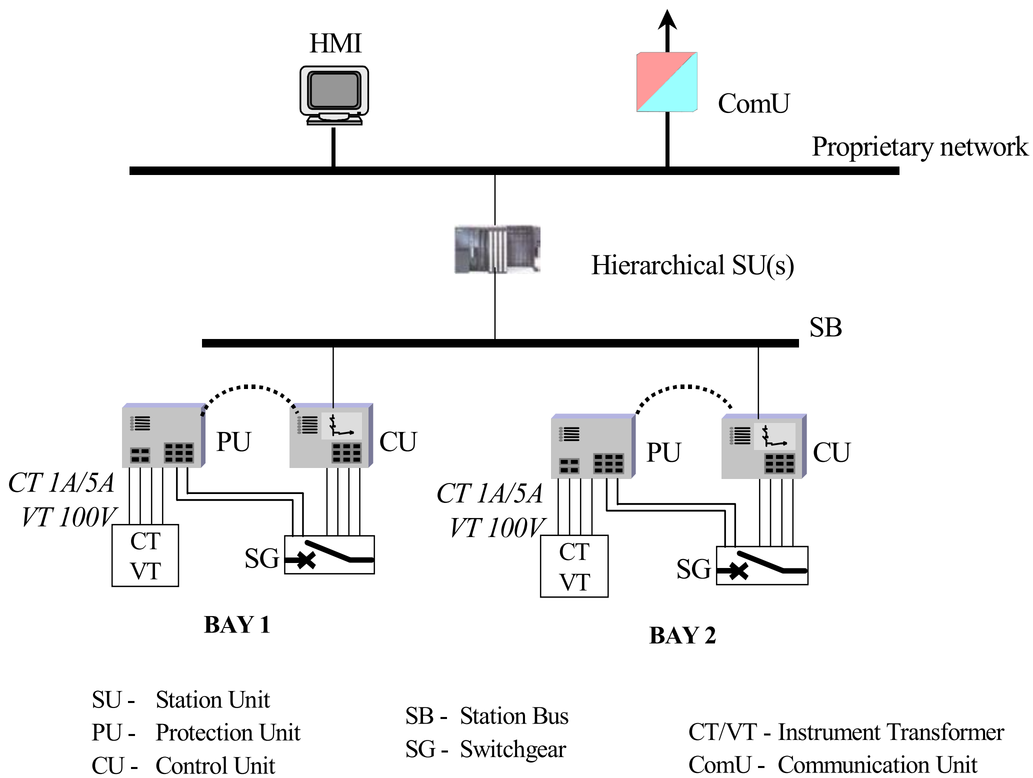

Figure 5-4 Hierarchical architecture

5.4 Conclusion

The major trend in terms of architecture seems to be the distributed one, hence reaching better availability and modularity. However, the hierarchical architecture still exists on the SAS market. Moreover, another important alternative consists in integrating more or less the protection and control units. The trend towards a growing integration allows optimising cost and space. In a functional point of view, differences all over the world may consist in adding:

- A separated maintenance and operation architecture.
- Redundancies in terms of control units and/or protection units, according to the customer requirements.

Finally, an important notion, which will be all the more important in the future with the availability of a communication standard such as IEC 61850, is the number of open points of the SAS in order to make several manufacturers equipment interoperate. The trend in terms of architecture should be re-evaluated in the future, with a wider and richer experience feedback on SAS.

6 Tie into medium voltage automation schemes

6.1 Physical dimensions and configuration

6.1.1 Switchgear dimensions

MV switchgear requires because of smaller isolation distances less space, than conventional HV switchgear. MV switchgear normally consists of cubicles, where different bays are located. All primary equipment including circuit breakers (CBs) and CTs VTs is housed in such a cubicle. The width of such cubicle does not exceed 2 m, often even less than 1 m. Therefore the whole MV switchgear is very compact.

There are also MV Gas Insulated Switchgears (GIS) available on the market, but from the point of view of the space needed, they don't bring many advantages. Their advantages are supposed more in total life-cycle costs and easier maintenance, especially in heavier operation conditions.

6.1.2 Number of bays

Since MV substations (substations) are used for power distribution, high number of bays in one substation is very often. Number of MV bays can be easily up to 40. Even in that case, switchgear dimension will be from 40 to 80 m long.

6.1.3 Secondary equipment integration

Secondary equipment can be located directly in switchgear cubicles. Sometimes, there are additional protection panels located in the other (protection) room. Because of less wiring integration of secondary equipment into cubicles is better.

There are local control equipment, protection relays, interlocking, synchro-check, energy metering, power quality metering, logical function relays, all located in cubicles. If distributed control system is applied for telecontrol, also bay control units are integrated into cubicles. Modern bay units already cover most of mentioned functions therefore only one device per cubicle is needed. Since the secondary equipment is mounted very close to the primary equipment, it is more exposed to electromagnetic (EM) disturbances, especially in older substation, where primary equipment remains the same in the phase of station automation and is not adapted to the modern EMC standards.

Smaller dimensions of the switchgear and less important position in overall power system network have influence on substation automation system functionality and economical criteria for different solutions. There is not always newest technology or distributed automation system the correct and most economical solution. There are much more MV substation in the system and therefore costs are much more important criteria for substation automation system configuration and installation. Since dimensions are smaller, hard-wired connections can be often used instead of powerful communication networks especially at process bus level and serial communication links instead of network do just good on station level. In such case, little more is spent on installation works, but on the other hand cheaper equipment can be chosen and multi-vendor solutions can be applied, which give the utility wider choice of secondary equipment to be installed.

6.1.4 Bay equipment

It is very common that MV CBs are mounted on trolleys and can be drawn out from the cubicle. This has many advantages regarding maintenance and operation. CBs can be replaced in a minute. Contacts on the trolley are than used as disconnectors. For this reason, signal lists and commands at this point are different from these for HV switchgear and also operation is different. Position of trolley can't be controlled remotely. CBs are capable only of 3-pole operation, since all three poles are driven by the same mechanism. No single pole operation is possible normally. In outdoor air insulated substations, CBs are independent of the disconnectors or isolators. Protection and control may be located in the circuit breaker control cabinets or in a control house.

6.1.5 Network objects to be automated

Such objects are MV/LV Transformer Stations for transformation from MV to LV, pole-tops with reclosers using CB-s or with remotely controlled disconnectors and switching stations (small MV substations without voltage level transformation). These objects can be connected into the substation control system. They are remotely or locally controlled. Since switching stations can be remotely controlled from control centre, or locally from substation Human Machine Interface (HMI), attention should be paid to the control authorisation. If substation is controlled locally, switching station can still be controlled by control centre even in the case when it is connected directly into the substation control system. Therefore, substation control system has to be able, to control part of equipment locally and part of equipment remotely.

6.2 Position and importance in the power system

MV substations are less important for the integrity of the entire power system. They are used only for distribution purposes and affect only limited area of the MV network. Configuration of the network normally doesn't change during operation. Since there are not many activities, those personnel have to do during operation, automation and remote control of these substations is logical.

Generally, there is more MV substation (Distribution – HV/MV) than HV substation (Transmission – EHV and HV) in the power system. Ratio in Slovenia for example is 3.5 to 1 and similar in the other members of the UCTE. Since there are so many MV substations in the network and they are less important for the power system as a whole, price optimisation in the process of automation is necessary. This is done in less redundancy used and less functionality applied.

6.3 Operation

It is typical for MV network that it operates in radial configuration. Network is built in meshed configuration, but is than configured by switching states of disconnect, load switches and CBs into a radial network.

Generally, in MV substation different protection functions are applied, than in HV substation. There are normally no backup relays used in bays. Backup is located one level higher, since MV network is supplied in radial configuration. The time co-ordination in settings is applied to achieve selectivity. Because of economical reasons, integrated solutions of so-called feeder terminals are used with integrated protection and control functions. Main protection is over-current (O/C) – earth-fault (E/F) protection for short circuit and earth fault clearing.

In the case of meshed network configuration, ring lines or power supply located on MV feeders, directional overcurrent protection or even simple distance protection must be used. If the MV feeder is not one of these configurations, but is just point to point supply feeder, other protection schemes are used, as pilot-wire protection for example.

There are generally four different ways of neutral point grounding in MV network. For some smaller networks, isolated neutral point is often used. When the networks are of bigger size, capacitive current is larger and operation with isolated neutral point is not acceptable. In that case, compensated or low resistance earthed neutral point is applied. The most common North

American practice is to solidly ground the neutral point, and carry the neutral conductor out on the distribution system. This allows single phase loads to be connected phase to neutral. All the details about neutral point treatment depend additionally on earthing systems of transformer stations and substation ground characteristics and operational practise in the utility. Protection schemes and control functionality are closely related to the method of neutral point grounding.

The operational switching state of the MV network remains unchanged during the year. The only interventions are necessary because of faults or maintenance. A few times a year, network configuration might be changed for optimisation or load balancing. The new state is adapted to the new season loading conditions in order to minimise losses and to optimise the voltage profile.

The substation voltage level is set by the tap positions on transformer windings. Taps of MV/LV transformer stations are set manually and remain in a position for years. These tap changers are not able to change during operation. They are set based on the seasonal measurements of loads and voltages. Dynamic voltage control is performed in substation power transformers equipped with LTCs (Load Tap Changers). There are often also capacitor banks or shunt reactors in the substation and out on the distribution network to additionally compensate the reactive power and so co-operate in voltage control. On transformers, two kinds of automatic voltage/VAR control are applied. The first one keeps voltage constant on MV busbar and actually compensates only HV network and substation transformer voltage drops. The second one actively controls voltage in MV network using line drop compensation based on active or complex power and network parameters.

6.4 Control system

6.4.1 Facts important for the control system

There are some facts that cause differences in control system configuration of MV substation in comparison with HV substation.

- MV substation is not so important for the HV transmission power system operation.
- There are more MV substations, than HV substations, what influence costs reduction.
- There is less and different functionality of control system required in MV substation.
- Physical dimensions of the MV substation, especially MV switchgear, are smaller.

Therefore, generally no redundancy of equipment on bay level is required in the control system of MV substation. Since there are many MV substation, cost reduction and optimisation is much more important by purchasing of the substation control system.

6.4.2 Deviations from the HV substation control system

In metalclad switchgear, there is generally no need for a process bus, since all the elements of the bay, as CTs and VTs, breakers and disconnectors are physically very close together in the cubicle. They can easily be hardwired to the integrated protection/control unit in pre-fabricated MV cubicles. However, outdoor air insulated MV stations are more similar in physical configuration to HV stations, so a process bus may be applicable.

For control of MV network objects outside the substations, whatever communication facilities available are used. (CTV, cellular telephones and others) Economical reasons dominate the decision. These facilities can be initially meant for other purposes therefore the possibility exists that the communication facility is not suited for communication protocols used for HV substations.

It is reasonable therefore to concentrate information into the substation control system and then route it to the CC. The influence of MV network objects on the substation automation system is in the first place that integration of information from these objects into substation automation system may occur. Therefore additional information interfaces have to be added to the control these systems using different communication facilities. Pole tops are connected into the system via radio links, leased lines, CTV, PSTN, DLC or any other available communication media.

Another change is, that also these objects have to be considered in substation structure, especially in functions of interlocking, sequential switching orders and of course in faulted network segment isolation process and network reconfiguration. These functions are becoming automated. This helps the personnel to locate the fault in the network faster and reduce the supply interruption time; one of the basic tasks of MV network automation.

It is very important in such cases, that control can be switched from local (substation HMI) to remote (Control Centre HMI) for these objects separately from the substation itself.

6.4.3 Basic configurations

Basically, there are two configurations of the control system: a decentralised control system and a centralised control system.

There are also numerous configurations available on the market, where a combination of both approaches is applied. Only distributed I/O units can be connected to the main processing unit or some distributed intelligent units can be connected to the central unit, which acts also as communication/station computer.

All mentioned configurations can very well serve MV substation automation functionality and each of them can be good choice in particular substation configurations and particular criteria combinations.

6.4.3.1 Decentralised control system

Figure 6-1 shows a decentralised system with smaller intelligent decentralised bay units interconnected with communication links (station bus) to the station level. Processing power is located in every bay.

6.4.3.2 Centralised control system

Figure 6-2 centralised system with one centrally located unit at the station level. The amount of needed wiring is not so critical in MV metalclad switchgear as distances are short and it is small in physical dimension.

6.5 Conclusion

MV substations are less important, price optimisation in the process of automation is necessary and less functionality is normally applied. In MV substations it is accepted to use multifunctional IED's, therefore protection and control functions may be integrated into one box. In general the architecture is the distributed one, where IEDs are interconnected via the station bus. When HV and MV levels are combined in one station all IED's can be connected to the same station bus.

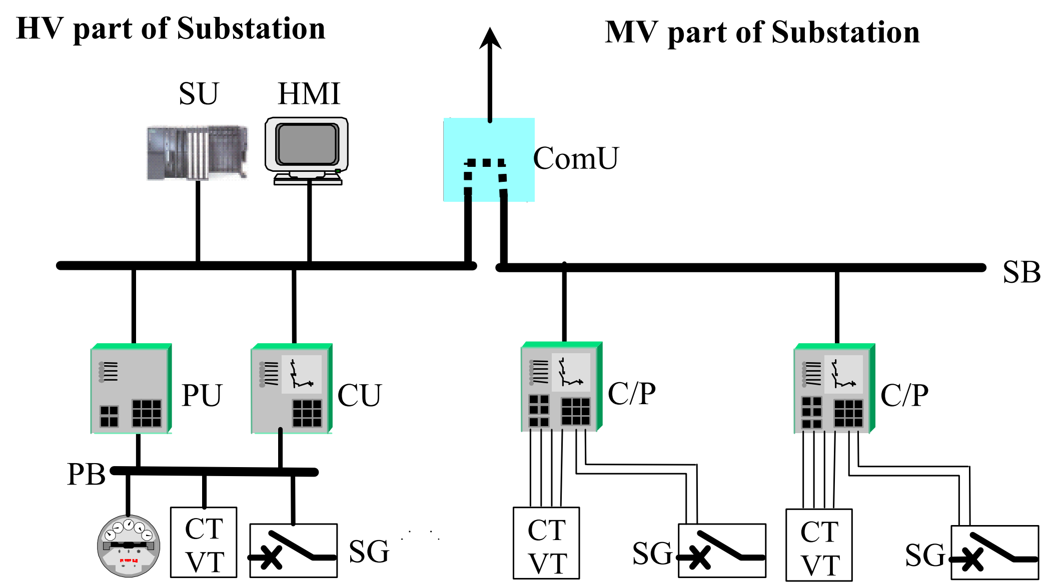

Figure 6-1 Decentralised control system

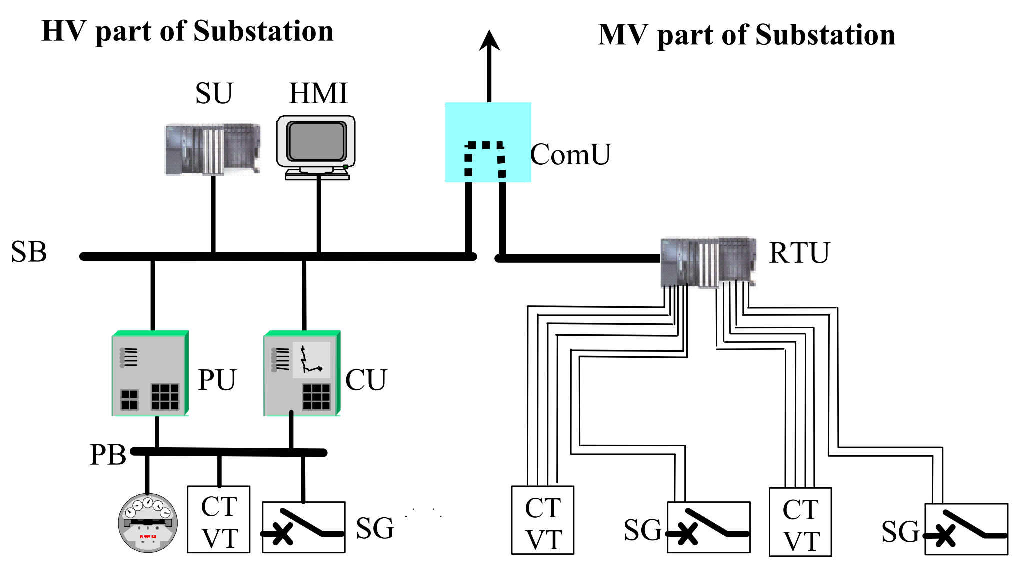

Figure 6-2 Centralised control system

7 Incorporation of wide area functions requiring exchange of data for control and protection

There are plenty of protection and/or control functions in a substation, that need to use information, coming from other sites or a more extensive area than is covered by the substation itself, to be performed correctly.

In most applications today, the information needed originates from directly interconnected devices in remote substations, but it can also be information coming from an even wider area of connected networks; e.g., from different voltage levels.

Possible applications in the future range from regional interlocking and synchronisation schemes, regional voltage control schemes, load shedding schemes up to inter-tripping and teleprotection protection schemes.

Over the last years the incorporation of LAN and WAN communication technologies for automation and control in electrical power networks has become more and more common practice. Thus, suggesting that the use of WAN communication between substations and between substations and control centers is now enabling the utility to perform control and protection functions in a substation, using data from other sites. This is true for certain categories of functions. In determining whether the implementation of a specific function is feasible, several restrictions that still exist today must be taken into account.

7.1 Incorporation of wide area network structures in substation automation

Both inside and outside the substation environment, devices and communication protocols have been or are being adapted to the use of local and wide area networks (see chapter 8). The use of computer network communication like Ethernet for communication between intelligent electronic devices (IEDs) offers speed, transfer capacity and versatility. The incorporation of high speed Ethernet as a future communication backbone both inside a substation and between substations and control centers appears to be an accepted fact. More and more examples and pilot projects are covered and described in CIGRE and IEEE working group papers.

LANs and WANs being accepted as the fast communication backbone to transfer data from one device to another opens the possibility to use the data in any device connected to the communication network. There is however several considerations that still form a restriction for the practical implementation of such schemes. Factors that have to be taken into account very seriously are, among others data security, data availability, communication speed, and response time.

Important to the performance required is the data load imposed upon the communication network, the limitations that protocols impose on the speed and functionality of communication, and the suitability of the software applications in the devices to make full use of the communication speed capability.

Several examples of applications requiring communication between IEDs are covered in the paper of IEEE PSRC Working Group H5. Many applications in these examples require on-line information at a speed that is currently only feasible within very strict limitations and conditions of the communication network. Currently, there are several pilots in progress to determine the network conditions to be able to guarantee the data transfer rates required for these applications.

Taking these conditions into account, the incorporation of computer networks in power network automation, control and protection represents a huge potential for the development of new and more efficient methods to be implemented, and with it a real potential for cost reduction and increase of efficiency in the use of the power network.

7.2 Applications requiring exchange of data from other sites

Modern SA systems are fully capable to automatically perform fixed pre-programmed schemes, regardless of where the data is originated. Typically, the realisation of automated schemes includes the requirement of information to be made available, a data model to enable the processing of these data in the desired applications, and the timely availability of the data required.

The need to incorporate remote information for applications in automation, protection and control can originate from two possible sources:

- Network control functions, that can be performed more efficiently or with a better quality in a substation instead of in a control center
- Device functions that can be performed more efficiently or with a better quality in a substation by sharing information generated by other devices on the network

Most applications requiring data from other sites are performed on a network control level instead of on a substation level. Although there are applications that are performed automatically on a SCADA level, most of these applications require human evaluation, human judgment and human action by an operator.

7.2.1 Network control functions

Network control functions, in the sense of functions normally executed on a supervisory (control center) level, will usually need an overview of the network or at least the network part in direct conjunction to the controlled substation to be performed correctly. Until now, the need for interactive and adaptive operator know-how on a network overview level limits the amount of functions that can be performed in a substation. To be able to perform network control oriented functions in an unmanned substation; these functions must generally be executable in a pre-programmed automated manner, eliminating human action. Typically, these functions will require information coming from other interconnected substations, but they either do not require exceptional performances or use dedicated peer-to-peer communication. Examples are interlocking and automated sequential functions like automatic change over, and distance and differential protection schemes, and in the US fault detection, isolation and system restoration.

7.2.2 Device functions

Device functions are mainly aimed at sharing functionality for the purpose of efficiency and cost reduction. These functions can require high-speed data exchange (sub-millisecond applications) for the purpose of measurement, protection and automation, mostly inside the substation. Although most applications are aimed at functions sharing information within a substation, devices sharing functionality can be useful for applications on the network level as well.

7.3 Incorporation of data from other devices and other sites

In classical power network control, SCADA/ Telecontrol systems use point-list models in their databases. At best, the network model incorporates a bottom-up hierarchical structure with the substation automation system incorporating a partial model, and the SCADA system incorporating the complete model. Thus in the classical system, the data models starts at the substation level (RTU); in the more recent implementations of substation automation systems in Europe the data model starts on the bay level. In the US it is common to implement multiple functions in a single IED. The concept however, is the same. It is usually sufficient for these IEDs to communicate with a hierarchically higher-level device in a master-slave communication structure.

The database of these devices is usually limited to process the information hard-wired to the device itself, thus necessitating multiple wiring when the information is required or is to be processed in another functional device.

The current developments on the communication protocol level enable RTUs, bay controllers, and IEDs to communicate to any other subsystem connected and addressable on the communication link (see Chapter 8).

Although modern LAN/WAN communication protocols use a physical LAN to communicate, the models and structures used are still the classic SCADA/ Telecontrol systems. These systems can incorporate remote data to perform certain automation and control functions by linking the devices together, and by expanding the local databases with the remote data it needs to process. This implicitly means expanding the database of individual devices with the desired remote data, thus generating larger individual databases that require more time and effort to maintain.

Recent developments aim at the use of IEDs on a much broader level, such as measurement devices (current and voltage transformers), primary equipment (switchgear, power transformers), and control devices (regulators, protective relays). By linking these IEDs together using a LAN or WAN, the IEDs can exchange information freely among each other, thus omitting the necessity of multiple wiring.

Recent and emerging protocols are using object modeling instead of point-list modeling of connected data. Within this concept all IEDs should be able to communicate to one another in common software environment involving standardized protocols and standardized object models for each IED (peer-to-peer communication), thus reducing the need for individual database maintenance.

Studies involved in investigating the feasibility of wide-area applications mostly rely on the use of proprietary protocols. The feasibility of these applications within a multi-vendor environment will depend heavily on the realization of standardized communication and standardized data modeling of IEDs.

These functions usually require at least the object modeling and protocol speed found in new standards. The intention to expand the use of these functions outside a substation will necessitate the incorporation of the object modeling and features used in above-mentioned standards on the inter-substation or substation SCADA level systems. Timing and performance, without neglecting the data security and availability factors, are in any case important aspect, which will determine the feasibility of wide area automation, control and protection functions.

The UCA® 2.0 initiatives in the USA are an initiative to meet these requirements. IEC 61850 takes these efforts one-step further, incorporating the UCA® 2.0 work and extending it towards the process level. The harmonization between UCA® 2.0 and IEC 61850 will eventually be an important step towards a worldwide-accepted standard. There is still substantial work to be done to incorporate these types of protocols on a SCADA level. IEC TC57 has formed a Task Force to rationalise the work of the various Working Groups using the 61850 modelling.

7.4 Speed requirements over the network

High speed Ethernet (100 Mbps – 1 Gbps) is now used as a basis to realise communication networks both inside and outside the substation. The still increasing speed of the Ethernet network is more and more facilitating the use of this type of network for power applications.

Taking into account that Ethernet is a non-deterministic (collision-based) protocol, proper measures must be taken to ensure that during operation, the network is not forced into situations where the load of the network is exceeding the collision-free operational limits. The use of Ethernet must be complemented by the use of suitable protocol stacks and software/ firmware applications to facilitate high-speed sharing of data between IEDs.

The highest speed requirements are imposed by device-oriented functions aimed at sharing data:

- Applications such as a decentralised synch-check require transfer of data over the network in tenths of milliseconds
- Decentralised protection schemes require transfer of data over the network in milliseconds.
- Applications involving interlocking can usually tolerate transfer times in the 10 to 100 msec range
- Applications such as remote measurement for instance tap-change control can tolerate transfer times of 250 msec

7.5 *IED availability*

Devices incorporating IEC 60870-5, Modbus, and DNP 3.0 protocols are widely available from many manufacturers.

Digital protection relays are adapting IEC 60870-5-103 almost as a standard communication interface, whilst on the RTU and SAS level; the IEC 60870-5-101/104 protocols are widely adapted and available.

Since IEC 61850 is still in the process of becoming an official standard, the incorporation in commercial products is still on a pilot base.

UCA® 2.0 (utility initiative) is supported by some manufacturers, which have introduced prototypes and pilot devices incorporating UCA®2.0. Work has been done to harmonize UCA® 2.0 and IEC 61850, the latter having the potential for future acceptance as a worldwide standard.

7.6 *Conclusions*

When LANs and WANs are available as fast communication backbone to transfer data from one device to another, it opens the possibility to use the data in whatever device interconnected to the communication network. To use this data in specific functions, data security, data availability, communication speed, response time and others have to be taken into account.

Emerging standards like IEC 61850 take more consideration of these conditions and factors than the current standards, in particular in multi-vendor environments. However, at present IEC 61850 is restricted to applications inside a substation LAN. The work to harmonize this standard to a level beyond the substation (SCADA level) has not even started yet.

The incorporation of LAN and WAN networks in power network automation, control and protection represents a huge potential for the development of new and more efficient schemes and functions.

8 Current state of communication standards and applications

8.1 General

Flexible, modular technical solutions for the energy supply are important factors for long-term success in the energy market. A major contribution in this competition is provided by the substation control system. The technical requirements for this system are constantly increasing the demands on its communication capacity. This communication, which spreads out from substation control systems to control centre systems to communication on both at enterprise and office level, is one of the integral components of modern control systems.

The possibility of substation automation systems rests on the strong technological development of large-scale integrated circuits, leading to the present availability of advanced, fast and powerful microprocessors. This resulted in an evolution of substation secondary equipment, from electromechanical devices to digital. This in turn provides the possibility to implement decentralised substation automation systems, using several IEDs to perform the required functions (protection, local and remote monitoring and control, etc.). As a consequence, the need arose for efficient communication among the IEDs, especially for a standard protocol.

8.2 The need for interoperability

The market is now characterised by vendor specific and hardware oriented solutions. As a consequence there are a large number of protocols for communication, which generally lead to the problem that devices from different manufacturers and even devices from different generations from the same manufacturer cannot communicate with each other or only with disproportionate expenditure. Due to the increasing number of modern information systems, the increasing of data and the fact that the innovation cycles of hard- and software are constantly becoming shorter the number of incompatible protocols is expected to rise. A reduction of variety in a relatively small market is extremely beneficial for both vendors and users. Thus standardisation is the key for the advancement of the connectivity and interoperability of systems. Through standardisation both users and suppliers arrive at economically suitable, reliable solutions.

Today in Europe substation control is organised on several hierarchical levels, i.e. the station level, the bay level, the actuator/sensor level and the process level. The communication between station level and bay level is done by different incompatible station busses like Ethernet, Profibus, MVB, LON, RS 485, Modbus, etc. and protocols like DNP.3, FMS, SPA, AMI, FTAM, ROSE, ACSE, etc. with the exception of the protocol IEC 60870-5-103 (see D.1.1.2). Parallel wiring, i.e. no serial link over process bus, does the communication between bay level and process level. In some countries outside Europe, e.g. the North America, they use only two levels, the station level and process level, i.e. they do not use a bay level. In this case the components of a substation control system are connected via a station bus and the process is connected to the components via parallel wiring.

Worldwide the substation control systems are fundamentally affected by the developments in Europe and North America. The European countries have provided considerable input to the standardisation in IEC based on their experience with digital substation automation systems. The American activities in this area are represented by the work of the IEEE. A considerable input to the IEC standardisation has been provided by UCA®, too. Without the harmonisation of IEC and IEEE activities to reach only one worldwide-accepted standard, two definitions of substation communication (IEEE-SA TR 1550 known under UCA™. 2 and IEC 61850) would compete with each other on the world market. Therefore international manufacturers would be forced to implement the communication and data models twice.

Figure 8-1 shows the standards applicable to communication between IEDs within the substation, and shows that there are options for implementing different parts of the communication architecture that is determined by the local requirements and operational constraints. In Figure 8-1 three bays are connected via an abstract communication structure; i.e., the station bus and process bus do not show the physical structure like point-to-point link, bus, or local area network. On the left-hand bay the traditional structure is given, where the process (switchgear, instrument transformers) is connected via parallel wiring. The right bay connects instrument transformers via a digital point-to-point link and communicates to the switchgear via a station bus. The middle bay uses a process bus, which can be connected to the station bus via a filter to prevent that sampled measured values are overcrowd the station bus.

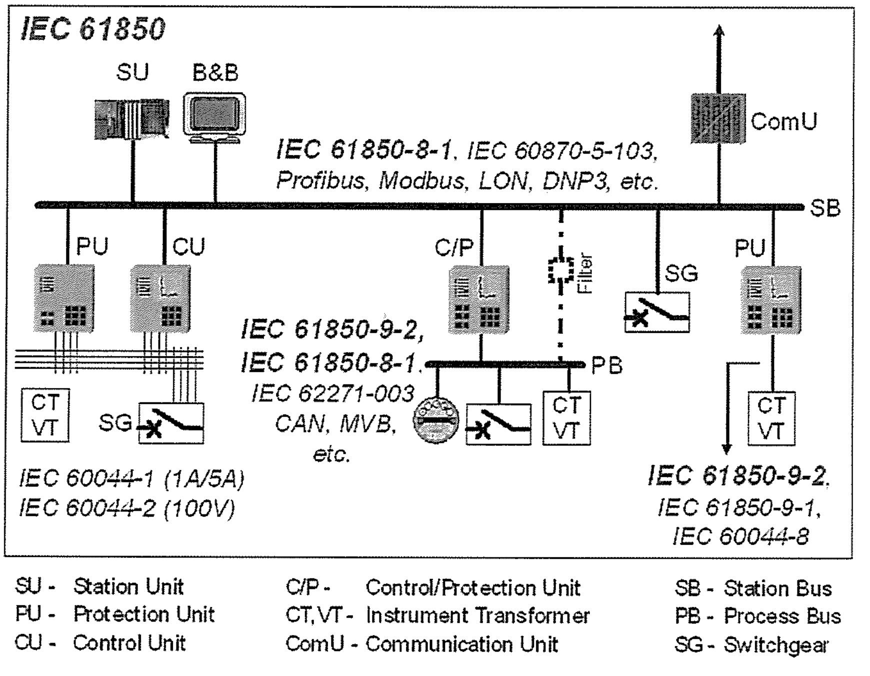

Figure 8-1 Inside substations a variety of communication standards are used

Figure 8-2 shows those standards that are applicable between a substation and IEDs external to the substation, again with different options on the standards that may be used.

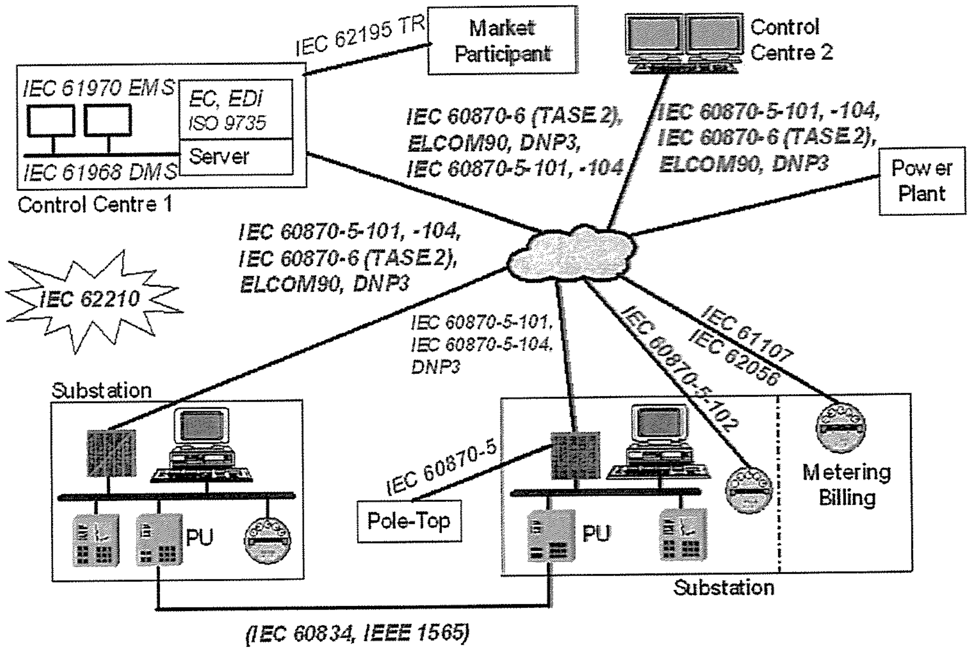

Figure 8-2 Outside substations a variety of communication standards are used

There is a tremendous amount of standardisation activity going on in substation communications (see Figure 8-1 and Figure 8-2. Fortunately, there are harmonisation meetings and work efforts ongoing between the IEC, IEEE and UCA® prototype demonstration initiatives. The support of major electric utilities and their collective purchasing power has forced the vendors to redesign their products to embrace the new communication standards. With this amount of industry support and harmonisation, substation communications standardisation is real and will take place.

In the following sections there is a short introduction of today's and future standards, de-facto standards, projects and users groups, which try to standardise the communication in the area of energy supply. The figures above should support the understanding of the amount of standards described below. The cloud in the figures represents every kind of communication connection or association like point-to-point or router network, etc. The standards described in this report are non-proprietary (open) standards; proprietary standards are not included.

8.3 *Conclusion*

Beside a lot of vendor specific standards the international standardisation committees like IEC and ANSI, provide the market with additional standards. But in a more and more global world it doesn't help to have different standards in each country and standards, which covers only a part of communication issues for the power supply automation. IEC is working on reference architecture to reach a seamless communication between the different levels of a power supply automation system. A seamless communication architecture can be reached by coordinating and harmonising the multiple independent standards initiatives to minimise the need for data transformation to exchange data between systems using these various standards. In the following possible advantages and features of the new seamless communication architecture are listed:

- Elimination of gateways for conversion of protocols and formats because the communication platform for local communication within the substation (substation bus) and telecontrol is the same.
- Instead of a gateway a proxy is used within the substation to present the information objects to the control centre.
- Control centres have individual access rights to the information objects of the substation and can subscribe for information objects published by the directly from the information object or from a proxy.
- Transport and routing between substation and control centres can be done by TCP/IP over a router network using logical paths. Compared with dedicated fixed lines redundant logical paths eliminate the need for a physical switch over from a failed link to a reserve link.
- The IP router network can also be used for engineering stations providing direct access over logical paths to IEDs (Intelligent Electronic Devices) in the substation for remote configuration and setting of parameters without the need of separate physical links.
- The information objects are identified with self-describing names instead with numerical addresses (for crucial reports an optimised addressing is defined).
- The device-oriented names of information objects can be mapped in the proxy to process-oriented technological names because the control centre application is process oriented and logical devices of the substation are therefore hidden.
- Essential parts of the metadata can be exchanged, e.g., technological name, information type, dimension, unit, range of values, and dead band value for reporting (self-describing objects) are inherent part of the communication.
- In general a seamless architecture leads to potential less cost for design, configuration, installation, operation, and maintenance combined with higher performance compared with current solutions.

Figure 8-3 shows those standards that could dominate the communication architecture in the near future.

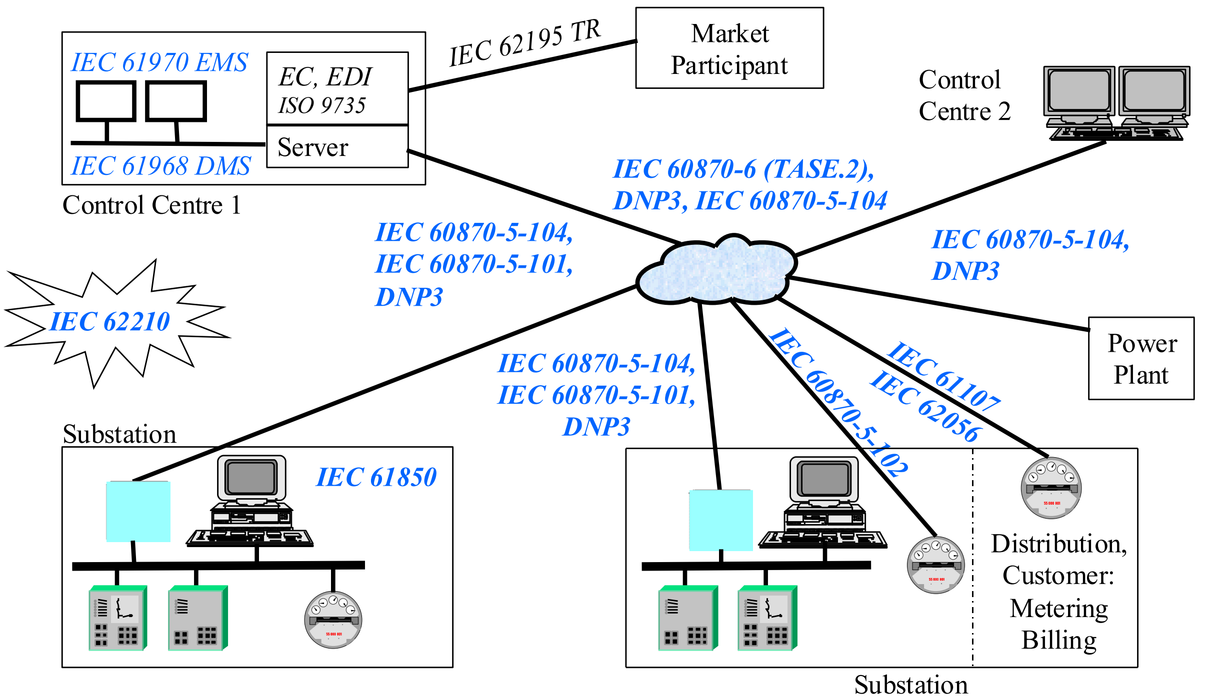

Figure 8-3 Possible trend in the near future

Figure 8-4 shows those standards that could dominate the communication architecture in the far future. The possible trend could be that the manufacturer and customer are concentrating mostly on the following standards.

- the upcoming standard IEC 61850 for communication
  - in substations
  - between substations
  - between substations and control centres
  - between power plants and substations
- TASE.2 for communication
  - between control centres
- IEC 62056 to communicate billing data
  - between meter and accounting centre

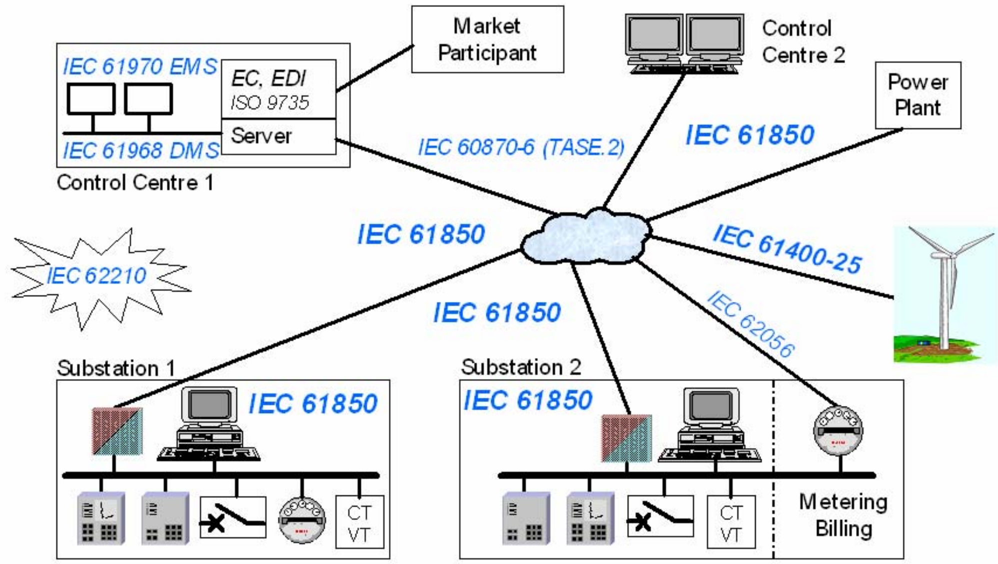

Figure 8-4 Possible trend in the far future

In appendix D "Overview of communication standards for electric power systems" the protocols and standards mentioned are presented in more detail.

9 Life cycle cost model

9.1 Theoretical model

Substation life cycle costs must be estimated to support the selection of architectural options and purchase decisions for substation automation. Modern cost analysis techniques using personal computer spreadsheet analysis tools are available to facilitate the cost analysis by providing algorithms to calculate both non-recurring and recurring costs. The selected software tool should include the capability for an analyst to completely customise the Cost Breakdown Structure (CBS), and enter any type of cost equation. It should support calculations over time using an appropriate inflation rate, provide sensitivity analysis, and Net Present Value (NPV) calculations.

Non-recurring costs should include initial facility development and component costs using a purchasing strategy that considers when costs are paid during the life cycle. Uncertainty in non-recurring cost due to economic factors and technology changes must be estimated and included in the cost function.

Recurring costs should include all training and facility/component maintenance and support costs. These cost tend to ramp-up sharply during the initial build-out or modernisation phase; but after the substation is commissioned for operation, the sustaining cost for operation tends to become quite stable

Cost model breakdown structure, parameters, and estimating methods are discussed further in Appendix E.

9.1.1 Basic objectives

The basic objective is to compute the cost of substation automation over its entire lifetime. Estimating tools must provide the ability to define cost elements included in the lifetime of the system, and then allow the analyst to assign cost equations to each element. These equations represent the calculation of the cost of that particular substation element.

Several features are needed to implement the cost methodology.

- Define time intervals with associated inflation rates to compute NPV (net present value) to assess today's cost versus future cost.
- Define alternatives to analyse one design alternative versus another, such as comparing the life cycle cost of a new design as compared to a potential retrofit.
- Define the coupling between the potential failure modes of a substation automation system and the resulting effects of those failures, which can be translated into cost.

9.1.2 Methodology

Figure 9-1 illustrates the basic methodology[3] for developing a forecast of substation automation cost. Before this methodology begins, other analysis should be completed to establish the basic requirements for substation automation including a technology baseline. A risk assessment should also be completed to establish risk management constraints. Based on agreed-to substation automation requirements, a selected technology baseline, and applying the risk management constraints, the project team should be able to define initial substation automation target architecture.

[3] Life cycle cost modelling and analysis methodology is based on the principles in [B.13.]. The model parameters have been tailored for substation automation.

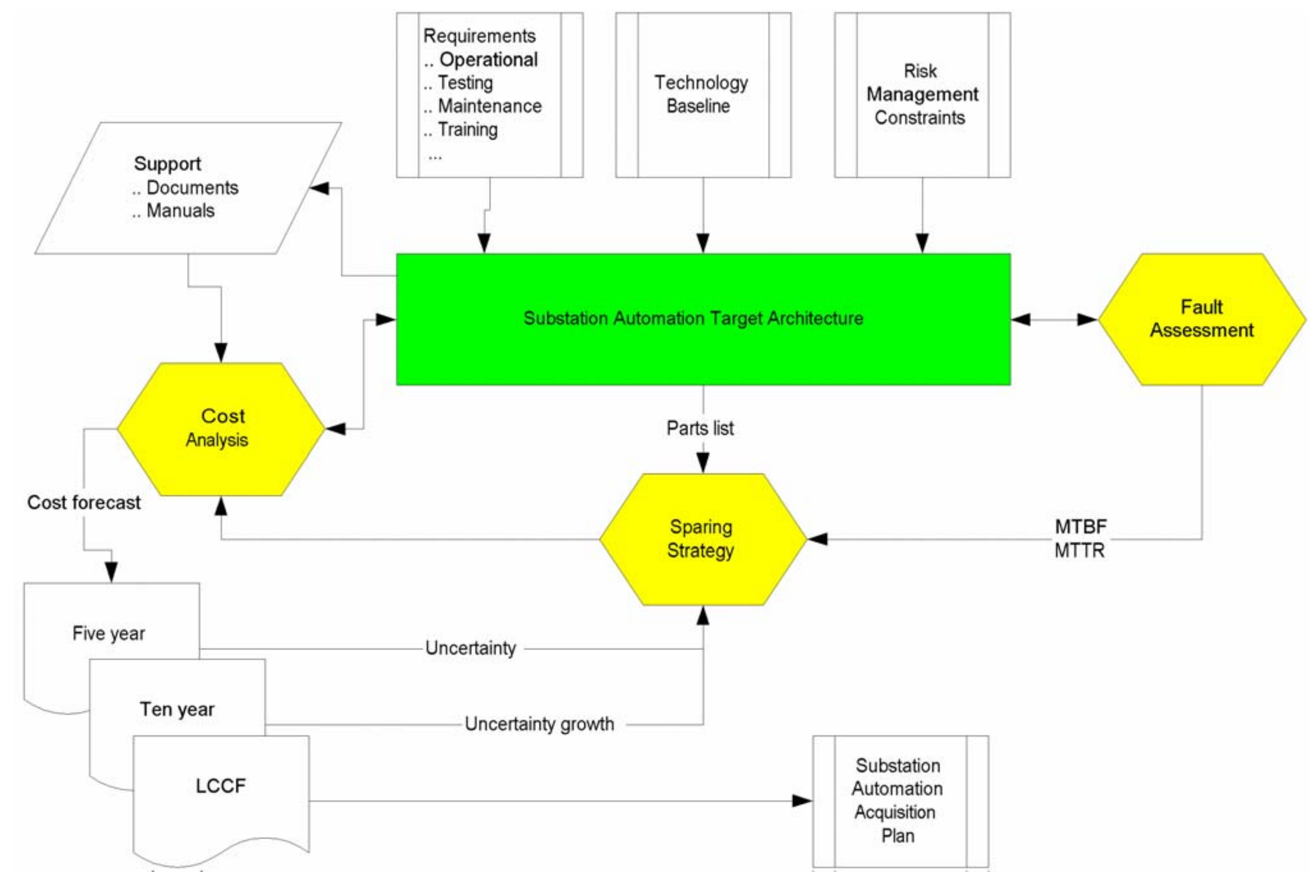

Figure 9-1 Life cycle cost development methodology

Three specifications are needed to initialise the methodology shown in Figure 9-1. It is therefore beneficial to expand the discussion of their influence on designing the target architecture.

> **Requirements:** First and foremost, the requirements must be stable and well understood. If the requirements are not stable, the degree of uncertainty in estimating cost will be so large that the conclusion affecting design decisions will be either meaningless, or worse, lead to a false sense of cost containment.
>
> **Technology Baseline:** Substation automation is enabled by technology in computer processing and message communications between intelligent electronic devices (IEDs), which are evolving at an extremely rapid pace. Therefore the second specification required for this methodology must establish a technology baseline that can evolve gracefully with time. If the technology baseline is dead-ended, sustaining cost for maintenance and replenishment is shown to be very high.
>
> **Risk Management Constraints:** All substation automation projects include a phased deployment involving both modernisation of existing substations and building new substations. A risk management plan describing procurement constrains is the last specification required to execute this methodology. These constraints will limit the options for implementing the substation automation target architecture, and are parameterised for use in the cost equations.

Next, a system analysis should be used to perform a fault assessment of the target architecture. Figure 9-1 shows an interactive relationship between the target architecture and fault assessment. This means that the fault assessment could influence the selection of subsystems and components initially identified in the target architecture. The result should partially optimise the target architecture from a fault assessment point of view.

For each subsystem, down to the component level in the target architecture, system analysis should estimate the Mean Time Between Failure (MTBF) and the Mean Time To Repair (MTTR). These performance measures coupled with the parts list are required to define a sparing strategy, which in turn is required to estimate life cycle cost.

Before beginning a cost analysis, the target architecture should be used as the basis for estimating support requirements such as the development and maintenance of documentation and manuals, and the development and implementation of a training program. These estimates will be required to perform a cost analysis.

Using inputs from the fault assessment, sparing strategy, and support functions, a cost analysis for the selected substation automation target architecture begins. Figure 9-1 also shows an interactive relationship between the cost analysis and the target architecture. This relationship means that cost analysis could influence the selection of subsystems and components initially identified in the target architecture. If significant changes in the target architecture occur, a new fault assessment should be performed, which in turn could change the sparing strategy and the support functions.

Estimates of a Five Year Cost Forecast (FYCF) and a Ten Year Cost Forecast (TYCF) should provide a reasonable cost basis to evaluate the substation automation target architecture, sparing strategy and support functions. Comparing the FYCF and TYCF will illustrate how dramatically the uncertainty of the estimate grows. The uncertainty is then used to modify the sparing strategy over the life cycle. When the project team is satisfied with the findings, a Life Cycle Cost Forecast (LCCF) should be estimated, and used as the basis for the substation automation acquisition plan. Requirements for fault analysis, sparing, documentation/manuals, and training facilities should be specified in the buyer's substation automation acquisition plan and in the Request for Quote (RFQ). The objective of the RFQ should be to solicit offers from supplier's innovative substation automation designs that reduce the buyer's risk and financial exposure.

9.1.3 Life cycle

Substation automation life cycle should be based on the timeline model described in IEC 61850-4, System and Project Management. Clause 6 (61850-4-6) describes the substation automation system (SAS) life cycle from a manufacturer and customer point of view:

- The manufacturer's life cycle contains the period between the start of production and the discontinuation of the SAS product family.
- The customer's life cycle contains the period between the site commissioning of the first SAS installation mainly based on a SAS product family and the decommissioning of the latest SAS installation with the same family. A system integrator, who may be different from the manufacturer, will carry out the SAS installation.

During the manufacturer's life cycle of the SAS and its IEDs a number of changes and extensions are required for various reasons such as functional improvements and extensions, technology changes in the hardware, or correction of recognized problems.

These changes lead to updated versions of IED hardware, firmware, software, and supporting tools. A new version of an IED can produce different impacts:

- It influences changes needed to the configuration list of the SAS-product family, in that the new version of the IED requires version changes in other IEDs or in the engineering tool; e.g., to fulfill new overreaching functions. A system test together with relevant IEDs is necessary and leads to a new configuration list.

- If it is independent of other IEDs and compatible with the current configuration list, then the system test of the IED has to check the compatibility with the other IEDs of the product family. If the version of the IED will be changed, then the configuration list of the SAS version has to be extended to include the new version.

The manufacturer is obliged to provide identification of the IED versions:

- In the case of IED software, or the supporting tools software, the version identification information is available.
- For the hardware, the version information is available at the board and at the device levels.
- In the case of an extended or a previously supported capability being discontinued a new configuration list shall be distributed.

The co-ordination of the manufacturer's and the customer's life cycles requires that new versions of the IEDs with identical model numbers must comply with the following rules:

- The hardware must be compatible in form, fit, and function; i.e., all interfaces must perform the same function in the same places, and the size of the boards and the devices must be identical.
- The functional changes in the product software should be declared as a comparison with the previous version.
- The supporting tools shall be downward compatible, which means that the new version of the supporting tool shall serve all existing versions of the same product family.

The manufacturer has to inform the customer about all functional changes and extensions, which are carried out between the last delivery and a new offer.

9.1.3.1 Announcement of product discontinuation

The manufacturer is to inform all customers of the product discontinuation in time to ensure that the customers have the option to order spare products or to prepare extensions.

In the case where the product discontinuation will be carried out without a subsequent functionally compatible product the required notice shall be published sufficiently in advance to allow customers adequate planning, engineering and installation time for replacement equipment.

In the case where a subsequent functionally compatible product will follow the notice may be published in a shorter period in advance. An overlap for delivery of both products for a minimum period is required.

9.1.3.2 Support after discontinuation

During the customer's life cycle of a SAS and its IEDs a number of changes, extensions and maintenance issues will occur. The manufacturer is obliged to support this process after the discontinuation of the SAS product family and its compatible IEDs according to the agreement between system integrator and customer. The following examples could be used for such agreements:

- Special customer agreement to further supply a minimum annual order quantity at special agreed-to prices and delivery conditions in an agreed time period.
- Supply of the same or compatible IEDs (functionally, mounting and wiring) for additional extensions under specific delivery conditions for an agreed time period.

- Supply of spare parts and repair service under specific delivery conditions for an extended time period.
- Administration, maintenance and delivery of all supplied versions of the IED software and the service tool software in accordance with the agreed delivery conditions by the manufacturer. The maintenance of parameter sets is the responsibility of the customers.
- Support in the integration of new products using adaptive interfaces.

The above requirements for the topic "system life cycle" exclude commercially available computing technology (e.g. PCs, CD ROMs).

If the manufacturer and the system integrator are different, support after discontinuation should be agreed in relevant contracts.

9.1.4 Details to implement the methodology

Figure 9-1 identified four analyses to establish the basis for cost analysis. Using the information presented in other chapters of this report, an expanded discussion of each analysis task is provided in this section.

9.1.4.1 Target architecture definition

Developing substation automation target architecture requires three inputs: requirements, a technology baseline, and a specification of risk management constraints.

9.1.4.1.1 Requirements

Automation requirements are best specified in terms of functional and performance requirements imposed on all intelligent electronic devices (IEDs) that enable substation distributed protection, control and monitoring functions. Functional requirements are usually specified in terms of required capabilities. Performance requirements are usually specified in terms of end-to-end operational, or execution, response time. Most open system specifications (standards) adequately address these requirements.

Most important for automation are the functional and performance requirements imposed on the communication system. Technology has now advanced to the stage where multiple functions can be designed into a single IED, thereby increasing design complexity of the IED application processor. Equally, the design complexity of the communication processor has also increased dramatically. Most IED vendors recognise the need to modularise the IED design by separating the application processor and communication processor, and interfacing the two processors through shared memory. In this manner, if either applications or communication changes are required, new hardware/software can be used as long as the interface between the two processors is respected Chapter 8 discusses the current state of communication standards and applications.

9.1.4.1.2 Technology baseline

A technology baseline is usually selected on the basis of derived requirements that will intuitively reduce cost. For example, wiring cost can be significantly reduced if IEDs are connected through a substation local area network (LAN). Additional cost reduction is realised by extending the LAN into the switchyard, or by installing a process bus, to connect instrument transformers, switchgear, and other sensors or monitoring IEDs to the IEDs located in the substation house. Architecturally, IEDs can be configured to operate in a master-slave arrangement, or in a peer-to-peer arrangement. Chapter 5 discusses some of the possible architectures of automation systems, and Chapter 7 discusses the incorporation of wide area functions requiring exchange of data for control and protection.

The degree of integrating protection with control and monitoring is dictated by the technology that ensures secure and reliable communication between IEDs that meet the response time performance requirements.

Technology, which enables configuration management without sending a crew to the substation, will significantly reduce cost.

Communication protocol compatibility, which reduces the need to provide gateways for protocol conversion will also reduce cost. Implied in this objective is the need to use existing communication links to connect substation IEDs to control centre Energy Management System (EMS) and Distribution Management System (DMS) IEDs, thereby eliminate the need for dedicate SCADA communication lines. For the same reason, substation-to-substation communication, or substation to pole-top IEDs, over existing communication lines saves cost.

9.1.4.1.3 Risk management constraints

Herein lays the key to cost containment. Risk management is required because computer technology and communication technology doubles in performance about every two years. Engineering technology is said to double every three or so years. Given a 15-year life cycle, all enabling technology will turnover five to seven times. How to deal with this rapidly changing technology is the objective of risk management.

There is no single textbook answer on how to manage risk. The project manager must rely upon sound judgement and the use of the appropriate tools in dealing with risk. The ultimate decision on how to deal with risk is based in part upon the project manager's tolerance for risk. A common form of qualitative risk rating is as follows:

> **High risk:** Substantial impact on cost, schedule, or technical performance that requires substantial action to alleviate issues, and requires a high priority management attention.
>
> **Moderate risk:** Some impact on cost, schedule, or technical performance that requires special action to alleviate issues, and requires additional management attention.
>
> **Low risk:** Minimal impact on cost, schedule or technical performance, and requires normal management oversight.

Modelling the interaction of two variables can develop risk quantification: probability of failure (P_f) and the effect or consequence of the failure (C_f). Consequences may be measured in terms of technical performance, cost, or schedule. A simple model can be used to highlight areas where the probability of failure (P_f) is high (even if there is a low probability of occurrence). Mathematically, this model can be expressed as the union of two sets, P_f and C_f. Table 9-1 and Table 9-2 shows a mathematical model for risk assessment that apply to substation automation component, which are dominated by hardware and software design technology. In other words, the risk factor (defined as P_f X C_f) will be the largest where both P_f and C_f are large, and may be high if either factor is large.

The risk factor is calculated as: Risk Factor = $P_f + C_f - P_f * C_f$

Table 9-1 A mathematical model for probability of failure

Magnitude	Maturity Factor (P_M)		Complexity Factor (P_C)		Dependency Factor (P_D)
	Hardware P_{Mhw}	Software P_{Msw}	Hardware P_{Chw}	Software P_{Csw}	
0.1	Existing	Existing	Simple design	Simple design	Independent of existing system, facility, or contractor
0.3	Minor redesign	Minor redesign	Minor increases in complexity	Minor increases in complexity	Schedule dependent on existing system facility, or contractor
0.5	Major change feasible	Major change feasible	Moderate increase	Moderate increase	Performance dependent on existing system performance, facility, or contractor
0.7	Technology available, complex design	New software, similar to existing	Significant increase	Significant increase/major increase in number of modules	Schedule dependent on new system schedule, facility or contractor
0.9	State of the art, some research complete	State of the art, never done before	Extremely complex	Extremely complex	Performance dependent on new system schedule, facility, or contractor

Where, $P_f = a*P_{Mhw} + b*P_{Msw} + c*P_{Chw} + d*P_{Csw} + e*P_D$

And where a, b, c, d, and e are weighting factors whose sum equals one.

P_{Mhw} = Probability of failure due to degree of hardware maturity

P_{Msw} = Probability of failure due to degree of software maturity

P_{Chw} = Probability of failure due to degree of hardware complexity

P_{Csw} = Probability of failure due to degree of software complexity

P_D = Probability of failure due to degree of dependency on other items

Table 9-2 A mathematical model for consequence of failure

Magnitude	Technical Factor C_t	Cost Factor C_c	Schedule Factor C_s
0.1 (low)	Minimal or no consequences, unimportant	Budget estimates not exceeded, some transfer of money	Negligible impact on program, slight development schedule change compensated by available schedule slack
0.3 (minor)	Small reduction in technical performance	Cost estimates exceed budget by 1 to 5 percent	Minor slip in schedule (less than 1 month), some adjustment in milestones required
0.5 (moderate)	Some reduction in technical performance	Cost estimates increased by 5 to 20 percent	Small slip in schedule
0.7 (significant)	Significant degradation in technical performance	Cost estimates increased by 20 to 50 percent	Development schedule slip in excess of 3 months
0.9 (high)	Technical goals cannot be achieved	Cost estimates increased in excess of 50 percent	Large schedule slip that affects segment milestones or has possible effect on system milestones

Where, $C_f = f{*}C_t + g{*}C_c + h{*}C_s$

And, where f, g, and h are weighting factors whose sum equals one.

C_t = Consequence of failure due to technical factors

C_c = Consequence of failure due to changes in cost

C_s = Consequence of failures due to changes in schedule

In the case of substation automation, P_f is estimated by looking at hardware and software maturity, complexity, and dependency on interfacing components. The probability of failure, P_f, is then quantified from ratings similar to the factors in Table 9-1. Looking at the technical, cost and schedule implications of failure calculate Cf based on ratings from Table 9-2. For example, consider a substation automation scheme based on using classic RTUs (Remote Terminal Units) for I/O control, and PLCs (Program Logic Controllers) as slave devices to the RTU, which are hardwired to switchgear and instrument transformers. The RTU is the substation control and acts as a server to the SCADA Master in a control centre. This is a relatively mature technology that has been deployed for the last 20 years, and may be characterised as follows:

- Uses off-the-shelf hardware with minor modifications to IED databases
- Is based on simply-designed hardware
- Requires software of somewhat minor increase in complexity
- Involves a new IED data base to be developed by the contractor

Assuming the weighting factors for a, b, c, e, and e are 20%, 10%, 40%, 10%, and 20% respectively, the probability of failure, P_f, would be calculated as follows:

P_M (hardware) = 0.1	0.2 P_{Mhw} = 0.02
P_M (software) = 0.3	0.1 P_{Msw} = 0.03
P_C (hardware) = 0.1	0.4 P_{Chw} = 0.04
P_C (software) = 0.3	0.1 P_{Csw} = 0.03
P_D = 0.9	0.2 P_D = 0.18
	P_f = 0.30

Assuming the weighting factors for f, g, and h are 40%, 50%, and 10% respectively, the consequence of failure, C_f, would be calculated as follows:

C_t = 0.3	0.4 C_t = 0.12
C_c = 0.5	0.5 C_c = 0.25
C_s = 0.5	0.1 C_s = 0.12
	C_f = 0.42

The risk factor would then be 0.30 + 0.42 – (0.30)(0.42) = 0.59, which is classified as medium risk[4]. Because most of the risk in this example arises from software changes, which are controlled by the IED suppliers, we can conclude that the risk can be reduced when each IED developer is held “accountable for work quality and is subject to both incentives and penalties during all phases of the automation system’s life cycle.”

Less mature technologies, such as those described in IEC 61850 and IEEE P1525 are classified as high risk because their calculated risk factor exceeds 0.80. Again IED developer accountability should be strongly worded in the RFQ. Furthermore, either an independent test organization, or an adequately funded utility-owned test facility should be included as part of the substation automation development plan to provide rapid prototyping before deploying the automation solution.

The System Integrator must address the risk management constraints in detail. Chapter 10 discusses the new role of the system integrator, and provides a framework to address these issues.

9.1.4.2 Logistics support: sparing strategy and support functions

Substation automation is best viewed as a “materials project” where the project deliverable may require maintenance, service, and support after development. This support will continue throughout the live cycle of the substation automation project. Providing service to the deliverables of substation automation is referred to as logistics support.

Clearly, the decisions with the greatest chance of affecting life-cycle cost and identifying cost savings are those influencing the design of the substation automation architecture, which will evolve during the planned time period for its deployment. Simply stated, proper planning and

[4] This is classified as medium risk because the utility’s perception is that there is some impact on cost, schedule, or technical performance that requires special action to alleviate issues, and requires additional management attention.

substation automation design can save a utility hundreds of millions of dollars[5] once the new or modified substations are commissioned.

The two key parameters used to evaluate the performance of substation automation systems are supportability and readiness. Supportability is the ability to maintain or acquire the necessary human and material resources to support the system. Readiness is a measure of how good we are at keeping the system performing as planned and how quickly we can make repairs during shutdown. Clearly, proper planning during the design stage of substation automation can reduce supportability requirements, increase operational readiness, and minimize or lower logistics support costs.

The ten elements of logistic support are:

Maintenance planning: The process conducted to evolve and establish maintenance concepts and requirements for the lifetime of the substation automation system.

Manpower and personnel: The identification and acquisition of personnel with the skills and grades required to operate and support a substation automation system over its lifetime.

Supply support: All management actions, procedures, and techniques used to determine requirements to acquire, catalogue, receive, store, transfer, issue, and dispose of secondary items. This includes provisioning for initial supports as well as replenishment supply support.

Support equipment: All equipment (mobile or fixed) required supporting the operation and maintenance of the substation automation system. This includes associated multiuse end-items; ground –handling and maintenance equipment; and test and automatic test equipment. It includes the acquisition of logistics support for the support and test equipment itself.

Technical data: Recorded information regardless of form or character (such as manuals and drawings) of a scientific or technical nature. Computer programs and related software are not technical data; documentation of computer programs and related software are. Also other information related to contract administration.

Training and training support: The processes, procedures, techniques, training devices, and equipment used to train personnel to operate and support the substation automation system. This includes individual and crew training; new equipment training; initial, formal, and on-the-job training; and logistic support planning for training equipment and training device acquisitions and installations.

Computer resource support: The facilities, hardware, software, documentation, manpower, and personnel needed to operate and support embedded computer systems[6].

Facilities: The permanent or semi-permanent real property assets required to support the substation automation system. Facilities management includes conducting studies to define types of facilities or facility improvement, locations, space needs, environment requirements, and equipment.

[5] US dollars are used to baseline cost because of its stability in the financial market. Local currencies that are relatively stable could easily be used. Local currencies that exhibit instability are much more difficult to use. Uses of unstable currencies are beyond the scope of this report.

[6] Embedded computer systems are those computer processing and memory components integrated into the intelligent electronic devices. Advanced IED technologies used in secondary power system devices such as multifunctional relays are significantly more complex than the first generation of IEDs.

Packaging, handling, storage, and transportation: The resources, processes, procedures, design considerations, and methods to ensure that all system, equipment, and support items are preserved, packaged, handled, and transported properly. This includes environmental considerations and equipment preservation requirements for short- and long-term storage and transportability.

Design interface: The relationship of logistics-related design parameters to readiness and support resource requirements. These logistic-related design parameters are expressed in operational terms rather than as inherent values and specifically relate to substation automation system readiness objectives and support costs.

Appendix E gives more detail on the use of this theoretical cost model.

9.1.5 Conclusion

The mathematical framework for a theoretical cost model is established. However, utilities must collect data to validate the model before accepting its results.

9.2 Example model

Thanks to a qualitative and simple approach, the aim of this life cost model is to help utilities choosing cost effective acquisition, engineering, maintenance, and operation strategies for digital SAS, to approach a technical and economic optimum, over the whole life span of the system. This paper gives an overview of the Cost Breakdown Structures, as exhaustive as possible. An example is shown in this paper concerning the possible choices of a utility in terms of refurbishment strategy.

9.2.1 General context

In order to link this simple model to the theoretical model described in Chapter 9.1, we could say that the CBS – Cost Breakdown Structure- framework for cost analysis is adopted in both models, even if CBS items are different in the two papers and if the uncertainty on total cost is taken into account into two different ways:

- In Chapter 9.1, three parameters (requirements, technology baseline and risk management constraints) influence the SAS target architecture which is directly linked to the cost analysis. This cost analysis is evaluated each period of time and is function of a feedback on the MTBF and MTTR of the system and a consequent sparing strategy.
- In this model, the point is to introduce the uncertainty for each CBS, which can exist or not according to the evolution of the CBS over time. This uncertainty is determined according to the experience feedback (and especially on the failure rates), the requirements (in terms of maintenance, training, tests, etc.) and the existing strategy (depending on the sparing policy, the technology offer, the purchase policy, the investment and operation costs, etc.). For instance, high uncertainties can be observed in the following cases: No maintenance long term contract with the manufacturer and a sudden change in the legal environment. Then, this uncertainty is regularly evaluated: every x years - for instance, if MTBF = 5 years and deployment of SAS over 20 years, x could be chosen equal to 3-. In extreme cases, that are to say for high uncertainties, this uncertainty can be adapted through a change in the development of the system or in the maintenance and operation strategy can achieve and imply a re-evaluation of this uncertainty.

This model was adjusted and validated on the basis of data from significant industrial projects (army, gas and electric water utilities, petrol, and chemical industry). Only the resulting trends and average values are presented on this document.

9.2.2 *General presentation of the life cost model*

The chosen model is presented Figure 9-2.

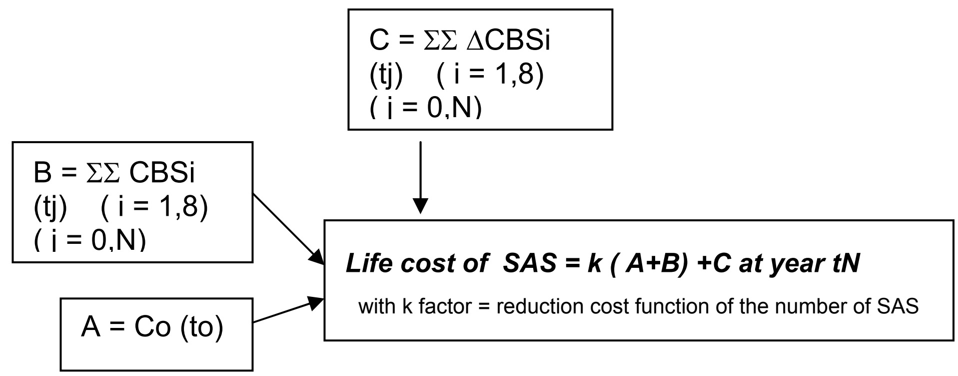

Figure 9-2 Parametric model for estimating life cost

All CBS, described in Table 9-5 can be modelled, and are continuous function of time after commissioning (reference is to), as shown in the following of the document, but in order to simplify the model, discrete values have been considered.

If we want to calculate a total cumulative annual cost, the use of yearly average NPV (Net Present Value) shall weight the sum of the total initial investment cost Co (or A) and the cost B.

In the case of a possible choice between two life cycle strategies, S1 and S2, where $(B+C)_{S1}=(B+C)_{S2}$,but where the C_{S1} is more important tha C_{S2}. The utility will have to define the level of acceptable risks in order to define the best strategy.

Moreover, the uncertainty of Co, which is relatively low (5% to10% of Co according to the return of experience) is taken into account in Co itself.

9.2.3 *Initial investment cost model*

The Co (or A) covers the initial investment cost – the sum of the development and deployment costs described in Table 9-3 and Table 9-4. The validation or agreement cost – tests in laboratory, experiment, product reception and quality assurance- is taken into account in the development cost. In the development cost, in addition to the manufacturers' bill, internal utility costs are taken into account. As for the deployment costs, they should take into account the fact that this phase can last more than one year.

Table 9-3 Development costs

Development costs	Contents
1	Development management and coordination
2	Software development : ▪ existing off the shelf software adaptations, ▪ specific software development and integration
3	Documentation
4	Hardware development : ▪ existing off the shelf hardware adaptations, ▪ specific hardware development
5	Reference system platform (for testing, and later for training, debugging)
6	Validation cost : test procedures and tests tools

Table 9-4 Deployment costs

Deployment costs	Contents
1	Software and hardware acquisition of the core system, wiring cubicles and interface equipment
2	Deployment management and technical coordination ▪ subcontractor management ▪ quality assurance management ▪ project management
3	Initial training
4	Engineering costs ▪ depending on the project or the site constraints ▪ including Configuration parameterisation and setting (site per site)
5	Additional adaptations and or evolution due to the evolution in the needs during the project (ideally zero as specifications should be "frozen" at development stage)

9.2.4 Operation and maintenance cost model

The maintenance and operation structure covers initial spare parts stock, management and organisation for maintenance and operation.

9.2.4.1 Cost item relationships

The various cost items (in relationship with Table E-1 of the theoretical cost model in Appendix E) of the ratio (and indirectly of the life cost) are shown in Table 9-5.

Table 9-5 Cost description

CBS item	Cost description
1	Initial spare parts stock Repairs or replacement by an equivalent equipment Logistic
2	Faults or bugs clearance New versions releases Documentation updates
3	Operation assistance: hotline, on site assistance
3 bis	Additional training for operation people and level 1 and 2 (AFNOR maintenance people
4	Preventive maintenance visits
5	Configuration management (software and hardware) Test and development platforms for site acceptance tests and for training
6	Technical survey for obsolescence detection Elaboration of corresponding technical and financial offers to face it
7	Permanent maintain of competence : knowledge of equipment and of its operational use
8	Activities of supervision and coordination, project management, Elaboration of supervision contracts, Quality assurance

9.2.4.2 Presentation of the chosen model and influence parameters

The choice of operation and maintenance cost elements may be divided into three categories:

- Technical elements: in order to hide their influence when comparing two systems with different technological base line, a ratio approach was chosen (as shown in Chapter 4).
- Service level elements concern the evaluation of the following features: availability, support quality, level of preventive curative corrective maintenance, training, technology survey to anticipate obsolescence, etc. The available data were averaged to give a “standard” service level.
- Organisational elements, the following scheme was adopted:
  - Maintenance level 1 & 2 (AFNOR): client (maintenance tasks requiring only functional knowledge of the SAS)
  - Maintenance level 3 (AFNOR): manufacturer (requires technical knowledge and expertise)

9.2.5 Operation and maintenance cost data practical representation: a part of SAS life cost

To represent the operation and maintenance costs the following ratio is chosen:

AMC_R= AMC Annual Maintenance Costs / (DVC Development Costs + DPC Deployment Costs)

The advantages of this choice are:

- This ratio is commonly used in the industry; some data are available.
- The influence of utility's internal structure (except for maintenance) and many technical elements is hidden.
- The influence of the parameter "time after commissioning" on CBS according to Figure 9-2.

It is shown hereafter that the global life cost (and also AMC ratio) is decreasing with time as in the CBS of AMC, each cost is steady or decreasing with time (except for "bath curve" CBS1).

9.2.5.1 Bath curve applies to CBS1 (equipment repairs)

The initial spare parts stock influences the first years repair costs. Figure 9-4 shows that the number of failures is decreasing with time and rises again at the end of system life, when strategically measures of stocking spare parts can be put in place.

It is important to notice that the effect of "bath curve" is all the less important at the beginning that the technology used is already tested and approved. Then, according to the chosen strategy (choice of t0) and the state of the art of the market at t0, the equipment repairs costs are very different at beginning of the system life (they can decrease or be constant).

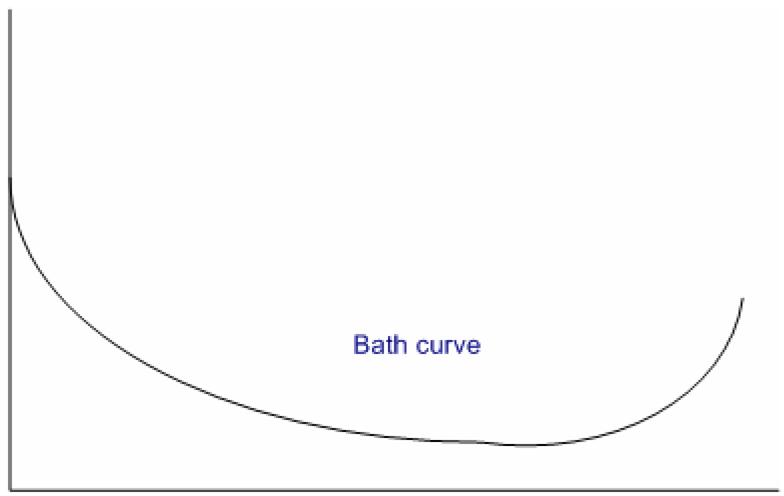

Figure 9-3 Influence of time on CBS item 1

9.2.5.2 Decreasing curve applies to different CBS

9.2.5.2.1 CBS 2: Fault clearance and software debugging

The faults are more numerous at the beginning of the system's life (during the first five years).

Nevertheless, this cost can be steady during the first years of the system's lifetime if the utility signs such maintenance contract with the manufacturer.

9.2.5.2.2 CBS 3 and 3 bis: Operation assistance and training

As concern training and operation assistance, the solicitations from the users are decreasing with time, since they get more and more used to the system.

The training cost contains a lot of uncertainty, for instance if they do not exactly correspond to the need and then be redefined.

9.2.5.2.3 CBS 4: Configuration and tests

Initial configuration phases, use of test platforms require more effort; therefore the annual configuration cost is decreasing with the age of the system.

The configuration uncertainty seems to be very low, according to the return of experience.

9.2.5.2.4 CBS 7: Permanent maintain of competence

Like for CBS3bis concerning training, the solicitation from the users are decreasing with time since competences are increasing.

9.2.5.2.5 CBS 8: Service management tasks

The initial adjustment period is followed by a stabilised phase.

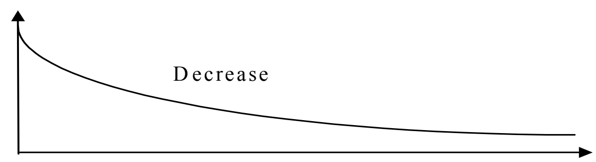

Figure 9-4 Influence of time on CBS

9.2.5.3 Steady curve applies to different CBS

9.2.5.3.1 CBS 4: Preventive maintenance

Preventive maintenance is often a constant cost, fixing the maintenance guidelines and the associated periods. Nevertheless, if the preventive maintenance policy changes during the system's lifetime according to the feedback of curative maintenance and system behaviour, the preventive maintenance cost will vary accordingly. For instance, if the feedback concerning preventive maintenance doesn't show enough gains for the company, the curve can decrease for savings' reasons.

9.2.5.3.2 CBS 6: Technical survey – obsolescence detection

It is a constant cost (realisation costs associated to obsolescence are not included in the CBS model). This cost is a very small part of the total cost.

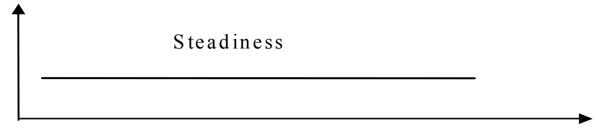

Figure 9-5 Influence of time on CBS

In conclusion, mathematical time dependant equations are associated to each item. Except for "bath curve" CBS1, all are steady or decreasing with time. Therefore the combination is time decreasing too.

With a better knowledge and return of experience concerning maintenance of SAS, the weight of each CBS in the total maintenance and operation cost will be possible to establish.

9.2.6 Influence of the parameter k function of the number of SAS according to Figure 9-6

The number of deployed systems has a decreasing effect on the Annual Maintenance Cost (AMC) of one system because of economies of scale taken into account into maintenance contracts. It can be computed by a corrective factor on the AMC costs.

The stabilisation value is about 70%.

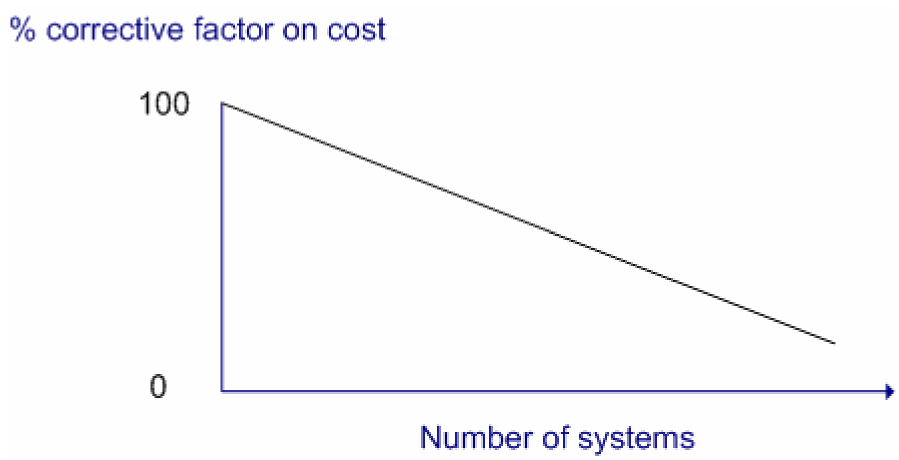

Figure 9-6 influence of the number of systems

For instance, a unique 3 years old system generates an annual maintenance cost of 5% of the initial investment cost (development + acquisition + deployment). The same system in 10 identical exemplars generates a 4% annual maintenance cost (5*0.8). Beyond 100 systems, the decreasing effect disappears.

The curve cost versus number of systems is decreasing:

- Non recurring costs (development, platforms, structure) remain constant
- Costs linked to the number of systems (acquisition, tests, deployment, and training) decrease.

9.2.7 Examples

9.2.7.1 A practical example of investment cost

The following example illustrates the "development costs" and "deployment costs" structure. This approach allows a utility to establish costs scenarios in order to choose the more cost effective engineering method. Total initial base investment is 1.

The estimation was performed on two scenarios (without any training costs, depending on the site specific needs):

- one scenario based on a system engineering in two stages, requiring additional interfaces: it corresponds to a bay per bay refurbishment with temporary interfaces between the new system and the conventional one, with additional configuration and connecting costs.

- one scenario based with a system engineering in one single stage (as it is a refurbishment there is no civil work costs -trenches, cubicles, building-): it corresponds to a new system, built in one shot, without any interface with the traditional system, with a possible additional development cost.

For this example, in order for the utility to optimise its strategy, the bar graph shown in Figure 9-7 can be obtained.

Which can be highlighted from the previous graph is that a comparison can be made between the "one engineering stage strategy" and the "two engineering stage strategy" in terms of development management, system engineering and equipment purchase costs. Moreover, if the graph is not normalised (total initial investment is taken into account), you can also compare real costs and then choose the best strategy.

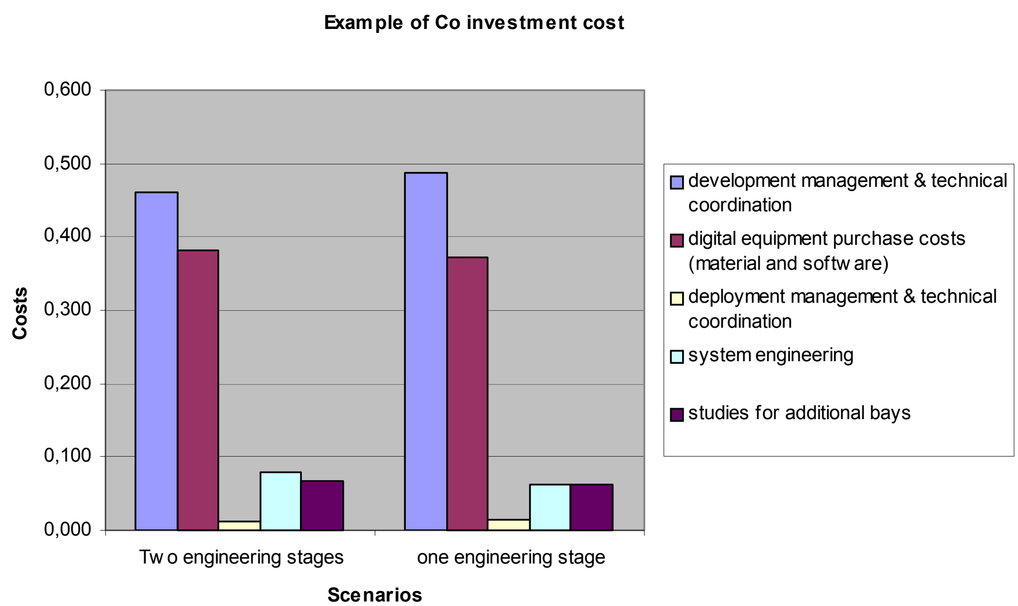

Figure 9-7 Example of Co investment cost

9.2.7.2 *A theoretical simulation for the maintenance and operation costs*

Cumulative operation and maintenance costs may be simulated on the basis of the proposed model over the whole life span of the system. It is an absolute values curve. The initial base investment is 1. The following graph represents annual costs and cumulative costs for an average industrial example (with common data):

Investment is equal to 1. AMC is between 7.5% * Co, the first year, and 1% * Co the last year, regularly decreasing over 20 years.

In this study, no functional evolution is taken into account.

We have not assessed this part of the Life Cost model with a practical example for the following reason: there is a lack of return for experience or feedback on data, the operation of such SAS being too recent.

In this model, technical parameters were not considered (to be able to compare the maintenance costs on different systems and technological baselines) but the time (age of system) parameters - strong decreasing effect on maintenance costs – and the number of systems.

We have therefore at our disposal the basis of a valid model to determine and compare on different systems several maintenance strategies over a settable lifetime period (20 years).

For instance, various scenarios can be simulated and give trends in terms of maintenance strategy:

1. First scenario : Total freezing of the system

➔ This choice may lead to high global costs with significant obsolescence risks

2. Second scenario : Half life functional evolution on the system

➔ This scenario may give cost effective means to avoid early obsolescence

3. Third scenario : Permanent updating of the system

➔In this scenario, costs may remain attractive because initial investments are considerably reduced and all maintenance and evolution costs are uniformly spread over the whole lifetime period.

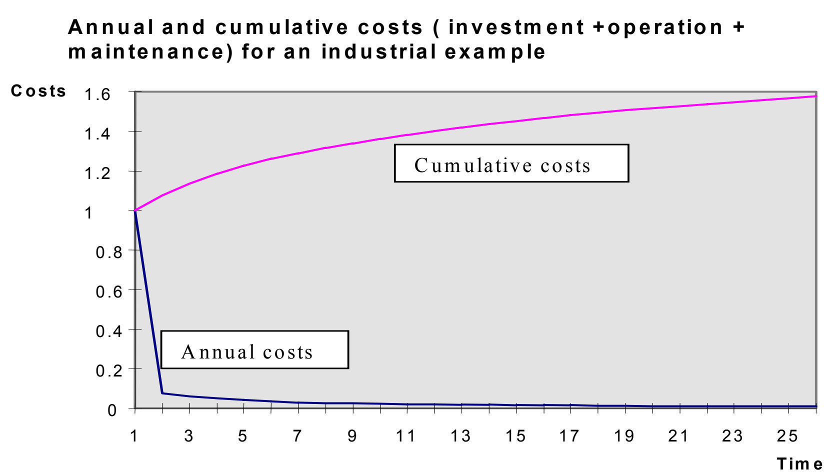

Figure 9-8 Annual and cumulative costs example

9.2.8 Conclusion

In this chapter 9.2, a simple life cost model is established in order to help utilities choosing cost effective acquisition, engineering, maintenance, and operation strategies for digital SAS.

We can divide the problem into two costs:

- A deterministic cost based on data return of experience, which deals with the investment cost: it helps utilities in its near future choices as what to buy, when and how.
- A variable cost obtained through simulations (parameters qualitative influence) which deal with operation and maintenance cost: it helps utilities in its far future industrial strategies.

10 Role of the System Integrator

With the introduction of Intelligent Electronic Devices (IEDs) the role of the System Integrator has changed dramatically. The principal cause of this change is the paradigm shift from a system with unilateral control of slave devices by a single master to one implemented by a fully distributed architecture that, in addition, provides for peer-to-peer communications.

To implement this new paradigm, the most important guideline to the System Integrator is a clear statement from the utility of their vision for substation automation. The purpose of this clause is to clearly describe how the vision of the utility is used by the System Integrator to develop a detailed set of specifications required for system integration.

A system integrator is either an individual, or team, who has the knowledge and capability to assemble all the components of an automation system to meet the utility's concept for substation automation. The system integrator may be an employee of the utility, a consultant to the utility, or a system supplier. Consider two scenarios.

- If the system integrator is the system supplier, the utility is buying a turnkey system.
- If the system integrator is an employee of the utility or a consultant to the utility, the utility developing a solution, which they may deploy as a turnkey solution.

Regardless of which approach is taken, it is clear, from the description of specifications that must be produced, that the System Integrator should be selected at the beginning of the procurement cycle for the substation automation system. If however, the system integrator is the selected system supplier, then it is not practical to include the system integrator at the beginning of the procurement cycle. In this case the utility (or consultant) should develop the framework for all specifications described in Figure 10-1. After the vendor is selected the system integration specifications need to be built-out in detail by the vendor.

As a member of the utility's procurement team, the System Integrator will contribute[7] language to the procurement specification so as to ensure a graceful transition to the future system. Implicit in this approach is the assumption that the System Integrator is not a product vendor or system supplier.

When the utility procures a turnkey system, the system integration functions described here must be included with the requirements in the procurement specification. Final selection of the system supplier should include the utility's assessment of the derived requirements and allocated requirements developed by the system supplier. In this manner the utility can score the credibility of the bids for a turnkey system.

A graceful transition is possible if the substation automation architecture interfaces between IEDs are well specified. By controlling IED's interface specification, IEDs from one supplier can be replaced with IEDs from another supplier with minimum impact on related components. Similarly, revisions to existing IEDs that meet interface specification requirements will have minimum impact on related components. Graceful transition is further enhanced using object-oriented technology, which encapsulates the functionality of the IED, and only allows access to the IED's data through the execution of the object's operations, rather than accessing the data directly. This again, is a form of controlling the IED's functional interfaces.

[7] The System Integrator is only one entity that contributes to the procurement specifications. Legal counsel will also contribute language to the terms and condition of the contract.

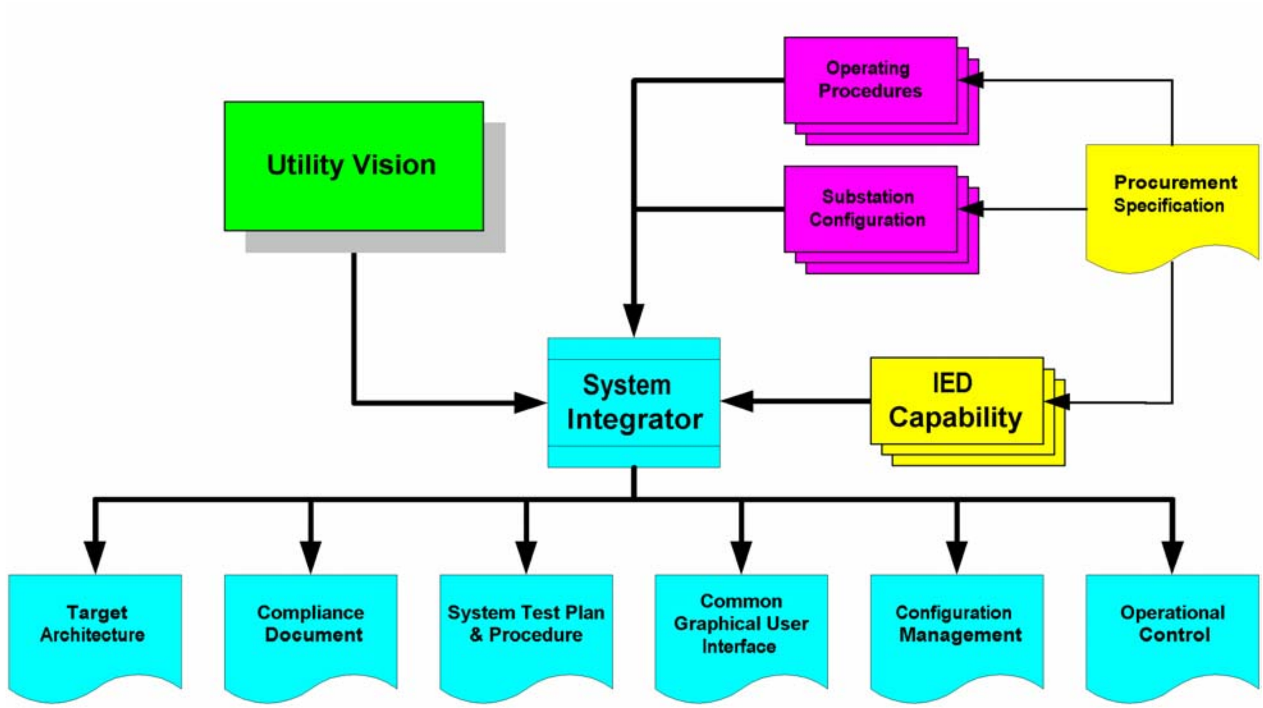

Figure 10-1 System integration specification

Organisationally, the System Integrator must have a close working relationship with the Engineering and Operational Organizations, but should not administratively report to either organisation. This degree of independence will greatly improve the quality assurance of substation automation.

10.1 The vision of the utility

The utility must articulate a vision of what they expect to achieve with their substation automation initiative. As an example, the vision could be stated as follows:

> Substation automation shall be implemented as a distributed open system to ensure a graceful transition from existing substation configurations, and to provide a cost-effective evolution for implementing future substation automation technologies. The system will implement peer-to-peer communications between IEDs so as to guarantee that no single point of failure will jeopardise the integrity of the protection scheme. An open communication system between IEDs will require vendors to implement either approved standards, de facto-standards, or to publish their application program interface, and thereby ensure interoperability and interchangeability of IEDs purchased from different manufacturers, and to provide for third party maintenance of the communication system. Furthermore, the future substation automation system will provide for a common graphical user interface for all users, and a common substation configuration schema for configuring, commissioning and maintaining the substation IEDs.

The utility must insist that all future procurements of substation IEDs and supporting components meet the requirements set forth in their vision statement. Furthermore, the utility should retain the System Integrator in a strong quality assurance role so as to ensure the graceful evolution of substation automation.

10.2 System Integrator responsibilities

Figure 10-1 shows the products generated by the System Integrator based on four fundamental inputs required for substation automation. In addition to the utility's vision described in 10.1, the System Integrator must understand the detailed operating procedures and existing substation configurations. Then, when combined with a detailed description of the IED capabilities provided by each manufacturer, the System Integrator can develop the specifications shown in Figure 10-1.

10.2.1 Target architecture

The first specification developed by the System Integrator is the target architecture. This specification will provide a clear picture of the utility's future substation automation system and provide a reference model for developing migration strategies from legacy systems. The target architecture must identify all substation automation components and their interrelationship.

In addition to one-line diagrams describing the power system components, a substation-centric communication network diagram is needed to describe the communication relationship of all substation automation components. The System Integrator may provide an electronic description[8] of the substation power system one-line diagrams and communication network diagrams.

Previous chapters discussed examples of the substation distributed communication architecture. For this example, a firewall is shown between the Utility Wide Area Network (WAN) and the router to the Substation Ethernet Local Area Network (LAN). System interfaces to the Utility WAN are described in IEC 61968 and IEC 61970, which use a common interface reference model.

An IRIG-B or GPS timing wire is used to synchronise the IED clocks so that data from multiple sources can be combined for post-fault analysis. A high-speed database server connected to the LAN is used to maintain all substation configuration data, and to record all substation event data.

Instrument transformers, other measurement units/sensors, and switchgear are connected to the IEDs by either hardwire or through a process bus as described in IEC 61850. Some instrument transformers, switchgear and other sensors have IEDs that provide the capability to communicate over the LAN which is extended from the control house into the switchyard as described in IEEE P1525 [B.9.].

A complete description of the functional and performance requirements for the target architecture is needed to establish a baseline description of the features required to ensure interoperability and interchangeability of power system devices and their IEDs. In addition, the System Integrator will describe all requirements for reliability, maintainability, etc., and will identify particular requirements that significantly influence life cycle cost.

[8] An electronic description may be in the form of a CAD (computer aided design) drawing. XML data schema is the best technology to implement the electronic description because standard web browsers can be used to access the data.

10.2.2 Applicable compliance documents

Compliance is best implemented by listing all applicable compliance documents. These documents should be cross-referenced in a table that describes the system test and operating conditions that must comply with one or more specific compliance requirements. Compliance documents may need clarification to better understand how to use the document, and how to apply the compliance requirement. Therefore the System Integrator may, for a specific clause in a compliance document, add the modifications or clarification needed to tailor the compliance document for a specific substation configuration and operating procedure.

The cross-reference compliance table will provide the capability to perform a management audit of all substation automation capabilities that have passed system level testing. IED requirements that have passed system level testing with qualifications will be clearly identified in the cross-reference compliance table, and supporting documents describing the qualification will be referenced.

10.2.3 System test plans & procedures

The System Integrator will prepare system test plans and procedures for each substation configuration. The test plans may be time phased to show a phased build-out of the substation automation system. The system test procedures should however be specific to a test sequence and acceptance criteria for a particular substation automation configuration as described in IEC 61850 [B.5.], IEEE P1646 [B.10.], and IEEE PC37.115 [B.11.].

Acceptance criteria may require special instrumentation to either measure directly the performance of the substation automation system, or to collect measurements that will be used to evaluate the performance and by analysis determine whether or not the acceptance criteria has been satisfied. Each test plan will completely describe the acceptance criteria and evaluation method. An example of this requirement is developed in the following paragraphs.

Figure 10-2 shows the basic reference model to describe the response time performance

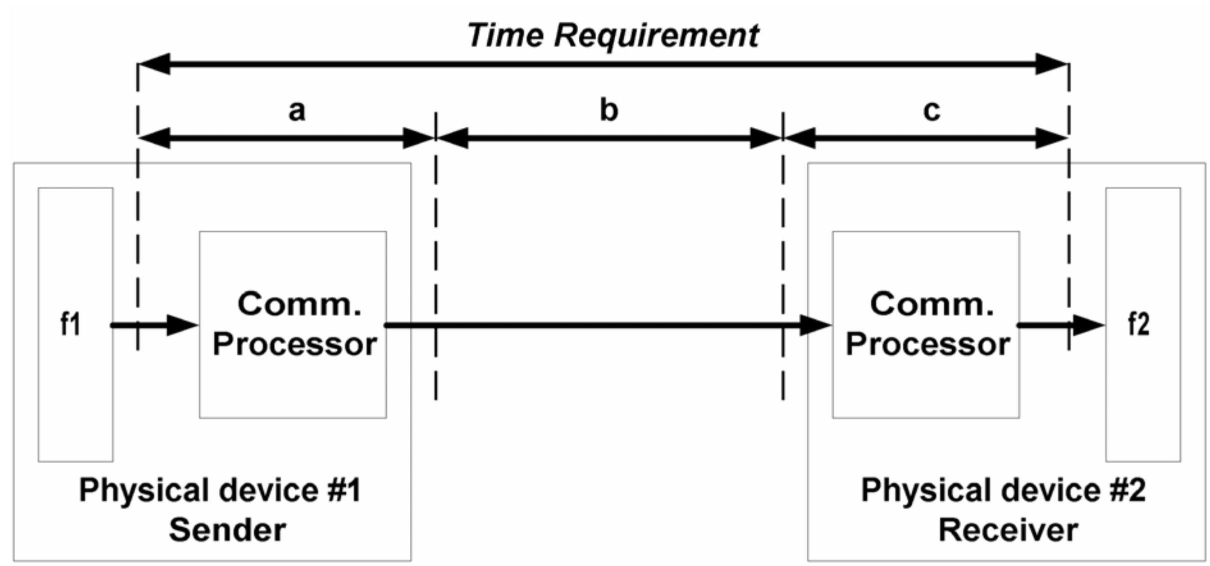

Figure 10-2 Response time performance components

requirements. Communication performance needs to be measured in terms of timing between the sending application and the receiving application as shown in Figure 10-2. The time requirement is the sum of a+b+c, where “a” and “c” is the time required in each IED communication processor to package and unpack the information transmitted. The time required to transmit the message over the communication network is “b”. Accurate time stamping is required to support this analysis.

Measuring “b” will require a network communication-monitoring device, which can trap network messages and time-stamp those messages with an accurate time of when the message leaves a sending communication processor, and the time when the message is received by a receiving communication processor.

10.2.4 Common Graphical User Interface

A common graphical user interface (GUI) is needed to effectively implement the vision for substation automation. Given the high probability that the future substation automation system will include power system devices and IEDs from different manufacturers, the computer-aided engineering tools and operating GUIs should have a common look and feel. A few basic principles should be enforced to achieve this objective.

- Windows may be fixed-pane-formatted to minimize overlap between windows reserved for security notification, system status, alarm status, main menu, and work zones.
- Point-click-drag-drop manipulation of graphical objects should be used to minimize the need for a user to type instructions in a text box.
- Submenus should be attached to graphical objects so as to ease the navigation to detailed information needed by the user[9].
- A standard, commercially popular, mark-up language should be used to define the semantics of all data and documents that can be shared over the communication network[10].

10.2.5 Configuration management

For example, if the utility vision emphasized no single point of failure, dual substation LANs is used. This requires that new IEDs be dual ported with a hot switchover capability. IEDs that are not dual ported must be replicated to ensure reliable and continuous operation.

Figure 10-1 shows that when the configuration of the automation system changes; e.g. the addition of dual-ported IEDs, the System Integrator must have a management procedure defined to keep track of and update the documentation and event data records of the automation system. Future automated substations may include a high-speed database server connected to the LAN. The System Integrator must define the configuration management specification that maintains all substation configuration data and manages the records of all event data.

The database server may be implemented using RAID technology; therefore the System Integrator must define the backup scheme so as to provide hot switchover when a failure occurs[11].

[9] Knowledge-based technology and commercial tools should be used to implement the navigational scheme.
[10] XML (Extensible Markup Language) is an open, text-based markup language that provides structural and semantic information to data.
[11] Although RAID machines are mostly used with EMS and DMS data, some substation automation designs are now considering their use in the substation.

10.2.6 Operational control

Figure 10-1 shows that operating procedures, which have been marked up to include the new substation IEDs are vitally important to the System Integrator to produce a specification for substation ***integrated*** protection, control and data acquisition. Emphasis on "***integrated***" is derived from the utility's vision for substation automation. Furthermore, based on an integrated concept, the System Integrator must define the operational control specification that addresses four areas of communication: access control, settings management, report management and time synchronisation.

10.2.6.1 Access control

The System Integrator must define a schema for access control that provides the level of security needed for the utility's operating procedure. The System Integrator must define a communication schema that seamlessly integrates security so as to provide data source authentication, data integrity, confidentiality and protection against replay attacks. This schema must be enabled by the communication protocol selected for substation automation. Specifically, this area of the operational control specification should address the following:

- The level of password protection required for fully implementing select-before-operate (SBO) procedures over the communication network. Given the basic nature of distributed communication architecture, predefined passwords provided by the device vendor may no longer be adequate to guarantee that an operator has control over a specific operation without the possibility of interruption by another operator using the same predefined password.
- IEDs must provide the capability to verify the access authority of a client that takes control of an operation, prohibit operation by another client until the take-control parameters have been completed, or the take-control operation has timed-out.

10.2.6.2 Settings management

The System Integrator must define the schema for settings management that provides for positive control and verification of individual settings as well as group settings. Operationally, settings maybe input to the IED from a remote terminal, from the local substation MMI computer or, in some cases, on the front panel of the power system device.

Because the utility vision emphasized reduced cost, interoperability and interchangeability of power system components, a standard browser based on the common GUI should be implemented in all workstations that can communicate to the substation IEDs[12]. The schema for settings management should be based on the features of the browser and GUI, and should not require the user to manipulate settings based on parameter names and addresses used for communication between IEDs.

10.2.6.3 Report management

Figure 10-3 shows a Generic Reporting Model (GRM) that should be used by the System Integrator to define the schema for report management. Detailed specifications to implement

[12] XML is a logical choice to define the settings data syntax. Vendors are rapidly adopting XML and demonstrating its power as a gateway between autonomous heterogeneous systems. It is extensible, easily understood and managed, and platform-, language-, vendor independent. Specific requests made vial XML to server are coordinated into several underlying request to different systems supported by state-of-the-art communication software. They are then intelligently mapped back up to an interactive Web page or commonly deployed Database Management System (DBMS).

the GRM may be extracted from IEC 61850 or IEEE P1525. Both standards use an object-oriented framework to manage reporting.

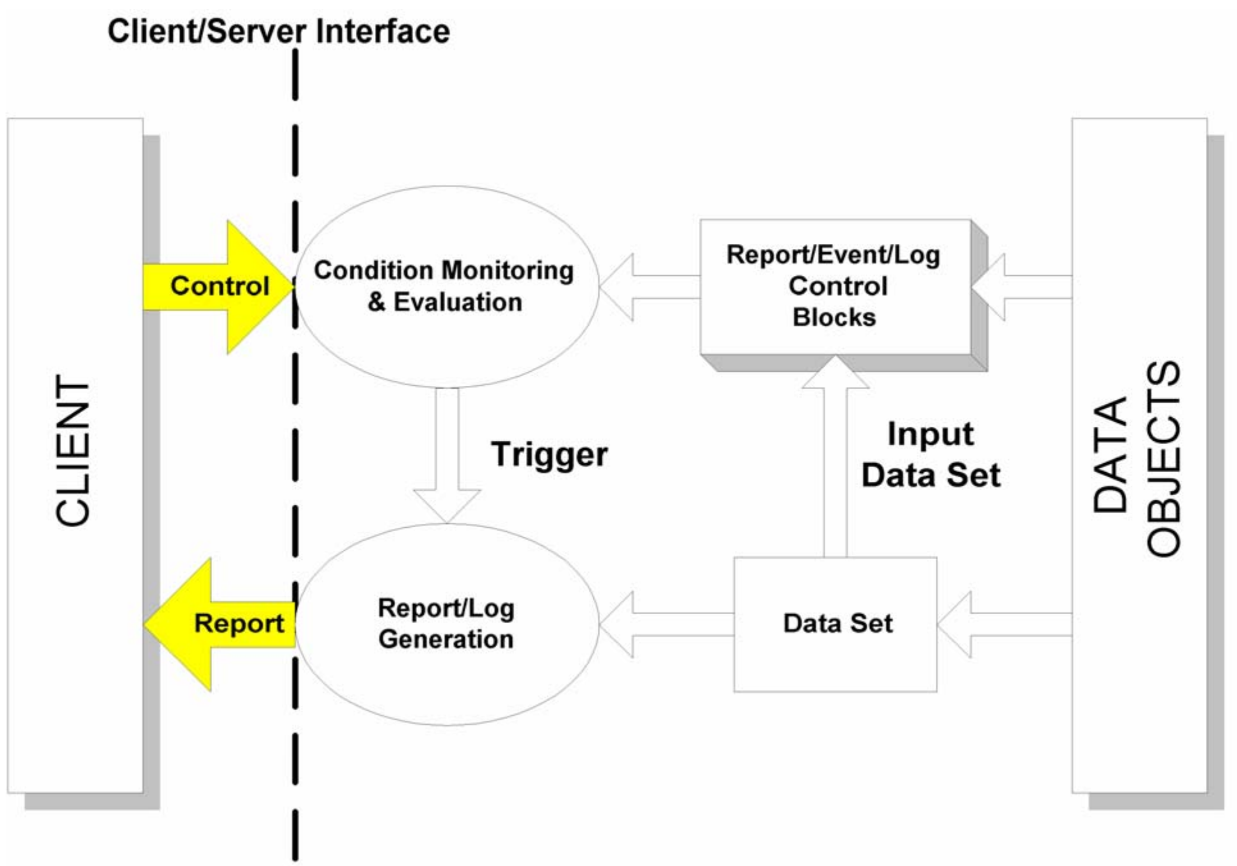

Figure 10-3 Generic Reporting Model

All IEDs networked on the substation LAN must implement in their communication processor the functional components shown in Figure 10-3. These functions are used to enable spontaneous reporting (report-by-exception and cyclic reporting), journal reporting (sequence-of-events), and report-on-request from the client.

The vertical dashed-line in Figure 10-3 defines the interface between the Client and the Server. The System Integrator must provide detailed explanations and operating procedures to implement the following Server capabilities:

- Control of the Server reporting functions shall be specified by input parameters from the Client to the Server.
- The Server shall provide the capability to load these parameters into the Application Processor condition monitoring algorithms.
- The Server shall provide the capability to generate reports whenever condition-monitoring triggers are activated.
- Data objects shall be used to define the report control blocks needed to support condition monitoring and evaluation.
- Data sets shall be used to define the information to be reported.

10.2.6.4 *Time synchronisation*

Time synchronisation for transmission substation integrated protection, control and data acquisition, in the past, required a target architecture that includes distribution of synchronised time over a separate timing wire using the IRIG-B time standard or GPS clock. It is possible to use the local substation computer clocks (connected to a GPS receiver) as the time source and distribute this time over the substation LAN. With IEEE 1588, IED clock synching to the sub-microsecond level over the substation LAN can be achieved. Small distribution substations may only require time tagging to 10 ms.

The System Integrator must define the time synchronisation specification that provides the time-stamping accuracy needed for protection operations and post-fault analysis. All IEDs whose data may be used in post fault analysis must have internal clocks that are settable to the specified precision. As a point of reference, the IED clocks should be settable to an order of magnitude more precise than the desired time tag. Thus, if time tagging to the nearest millisecond is a requirement the clock must be settable to 0.1 ms, or if the requirement is to the nearest 0.1 ms, then the clock must be settable to 0.01 ms. In other words, the IED's clock must be settable to an order of magnitude greater than the requirement for time tagging.

10.3 *Conclusion*

The advanced capabilities inherent in modern substation automation systems require the utility to rethink the role of the system integrator. An approach to the new roles described in this chapter provides the utility a framework for building new substations or modernising existing substation.

11 Findings

This report concludes with a summary of findings developed in each area of investigation. These findings provide significant insight into the benefits that can be realized in a utility's well-managed substation automation program. Because chapters are written independently, beginning with Chapter 2, conclusions are listed for each chapter.

11.1 Chapter 2 findings

1. The utilities in their effort to automate the existing substations should focus on two aspects that shall influence the optimum control of its power system management business. These two aspects are economical and technical.
2. The information about the power system gives the utility the strength to be more successful and competitive in a free market where there will be a competition between utilities.
3. For the following reasons, SA is expected to reduce operational cost.
    - Personal reduction by implementation of remotely controlled substations. This is not only the dispatching personal but also the field and maintenance crews that can be better co-ordinated and guided due to remote information about the current situation in substations and in the network.
    - Faster fault location and clearance, what cause shorter supply interruption and therefore better economic results. This is also valid for failures of control and protection equipment.
    - Sequential switching and expert systems, which perform sophisticated functions faster and more precisely than human operator.
    - Better and more co-ordinated network control functions as voltage/VAR control, network reconfiguration, supply reestablishment after faults, etc.
4. SA is expected to reduce maintenance cost for primary equipment, control equipment, and protection equipment because it takes less time to troubleshoot and fix problems.
5. SA is expected to reduce installation cost because less cabling and space is required for control and protection, and there is less need for equipment dedicated for each function.
6. SA is expected to improve the ability to get the required data, document all changes and upgrades to the network, add new functions to existing modern equipment, and shorten the period of problem diagnosis thereby increasing the reliability of the substations.

11.2 Chapter 3 findings

1. Today the required functionality to protect and operate a substation is generally available. Also enhanced functionality is available with manufacturer specific solutions. Interoperability of equipment from different manufacturers will in future be achieved with the emerging 61850 communication.
2. Gradual improvements in functionality will most probably be seen in the fields of protection, diagnostics of primary and secondary equipment and in the engineering tools. The Interoperability of equipment from different vendors will in the near future be the biggest improvement with 61850.

11.3 Chapter 4 findings

1. NV Remu experience is that station automation systems have made a major contribution in the past few years. A shift has taken place, not only in the technology, but also for the employees involved. The number of different functions has not increased in the last few years, the transmission stations still do the same thing, whereas at the same time investment has halved. After a peak in 1995, when everything was reported, nowadays a critical look is taken at whether certain reports are useful and necessary.
2. One point for attention is the maintenance of the systems. NV Remu is faced with an increasing number of different systems. Each system has its own specific programming method. Particularly due to the increasing complexity, NV Remu employees are being called on to an ever-greater extent. For the time being NV Remu will continue the policy that the systems must be able to be maintained by its own employees.
   - Iberdrola has used automation systems since 1996, with more than 100 automated substations at the moment. The overall experience is remarkable, and the systems have operated as they were designed to. The major benefits are total life costs reduction, including investment costs, and improved reliability.
   - Iberdrola is moving towards more integration, and simplification of external securities. The availability of huge information, and the possibility of implementing advanced functionality are seen as an advantage, but have not been fully utilised yet.
   - The major drawback of these systems is maintenance. There is a strong dependence on the manufacturer, for support and spares. As the technology evolves very fast, it is not foreseen that this situation will change in the near future.
   - In order to avoid on site software modifications and new software versions during commissioning, factory tests have been established, improving total installation times. Thorough software tests are considered a critical issue for this technology.

11.4 Chapter 5 findings

1. In the standard manufacturer's offer in metal clad switchgear, differences in terms of architecture are minor: They come from the number of networks used and their types, the number of computers and their locations, the redundancy and integration level of supported functions, the distribution or centralisation of databases and calculators. Therefore, there are few alternatives to the architecture that is usually chosen.
2. The evolution of the technology, together with further cost and operation optimisation goals, lead to the definition of a new generation of architecture for the SAS that offers more technological and functional choices. However, from a customer's point of view, the SAS architecture is constrained by various factors such as dependability, substation progressive refurbishment, use of different suppliers, etc.
3. Therefore the main choices concern the integration threshold between protection and control, the distribution or centralisation choices of various functions and the existence of redundancies due to specific customer's reliability and availability requirements. The general trend is towards a growing distribution (better availability, modularity), and towards a growing integration (cost and space optimisation). It is expected that future communication standards, such as IEC 61850, will enable the development of new architecture that will be more performance and more cost effective.
4. Because IEC 61850 is standards-based, communication between IEDs supplied by different vendors can b e achieved. Replacing parallel wiring between protection and high

voltage equipment (e.g., CTs, VTs, and switchgear) by a digital process bus will provide additional future benefits.

5. The development of an efficient cost estimation methodology based on utility's data (yet to be established - see Chapter 9) is another benefit. Compiling these data will provide a relatively precise measure of the cost and reliability of a distributed open-architecture implementation.

11.5 Chapter 6 findings

1. MV substations are less important for the integrity of the entire power system and physical dimensions of the MV substation, especially MV switchgear, are smaller. Since there are so many MV substations in the network and they are less important for the power system as a whole, price optimisation in the process of automation is necessary. This is done in less redundancy used and less functionality applied.
2. Because substation control system often controls MV network objects (feeder automation) it has to be able, to control part of equipment locally (S/S HMI) and part of equipment remotely (LDC) at the same time.
3. Basically, there are two configurations of the control system:
    - Decentralised system with smaller intelligent decentralised bay units interconnected with communication links (station bus) to the station level. Processing power is located in every bay.
    - Centralised system with one centrally located unit at the station level. Amount of needed wiring is not so critical if MV metalclad switchgear is used, as it is small in physical dimensions.
    - Basic suggested configuration is the distributed one, where IEDs are interconnected using station bus. Configuration remains the same as in HV substations, since MV is normally combined with HV in the same substation.

11.6 Chapter 7 findings

1. Modern substation automation systems are fully capable of automatically performing fixed pre-programmed schemes, regardless of where the data is originated. LANs and WANs being accepted as the fast communication backbone to transfer data from one device to another opens the possibility to use the data in whatever device interconnected to the communication network.
2. There is however several factors that still form a restriction for the practical implementation of such schemes. Factors that have to be taken into account very seriously are, among others data security, data availability, and communication speed, and response time.
3. Although LAN/WAN-oriented communication protocols use a physical LAN to communicate, the models and structures used are still the classic SCADA/ Telecontrol systems. This implicitly means that expanding the database of individual devices with the desired remote data will result in expanding individual device databases, thus requiring more time and effort to maintain these databases.
4. Taking into account, that Ethernet is a non-deterministic (collision-based) protocol, proper measures must be taken to ensure that during operation, the desired data is made available to the function to be performed on-time and with the proper reliability and predictability.

5. Emerging standards like IEC 61850 take more consideration of these conditions and factors than the current standards, in particular in multi-vendor environments. However, at present IEC 61850 is restricted to applications inside a substation LAN. There is still considerable work to be done to harmonize this standard to a level beyond the substation (SCADA level).
6. Taking these conditions into account, the incorporation of LAN and WAN networks in power network automation, control and protection represents a huge potential for the development of new and more efficient schemes and functions.

11.7 Chapter 8 findings

1. The Internet or Intranet technologies (Web technologies) enter more and more the area of automation issues especially monitoring, parameterisation and maintenance.
2. As there is a potential for reducing the operating and maintenance costs, online monitoring functions will become more and more important. For example, the periodic oriented maintenance is too expensive and will change to condition oriented maintenance.
3. The current international trend is towards standardised hardware and modular software.
4. The integration of a steadily increasing number of functions within multifunction devices will continue towards a maximum integration of functions. Experiences point out that the allowed degree of integration has not yet been realised, particularly at the higher voltage levels (transmission). Considerable scope therefore still exists for further integration of functions up to the maximum allowed levels.
5. Concurrent with the developments in technology, which allow more protection, control and other functions to be integrated into less equipment, users are developing new philosophies to continually adapt to and take advantages of the changing environment. Driven by the open market there is a high ongoing re-organisation within utilities. Thus more and more utilities will approach the new technology by examining the degree of automation and benefit of the existing secondary technique.
6. There is an increasing use of inter-device serial communication, particularly by optic fibre; following recent developments in communications technology that has more readily facilitated inter-device communications/data sharing. Ongoing developments of LAN and WAN are occurring to satisfy the increasing communication performance requirements.
7. As the use of multifunction modern numerical devices increases, resulting in schemes with fewer hardware devices and reduced intra-scheme wiring, the engineering effort is moving from scheme design to functional design, which eventually will realised by device engineering.
8. The development of an optical process bus and process bus interfaces to plant and IEDs. These developments open the way for the introduction of new current and voltage sensors. Further developments are taking place with primary equipment configurations; e.g., combination of circuit breaker and disconnector, incorporating built-in current and voltage sensors, representing an integration of primary and secondary components at the process level.
9. Improved management of primary equipment by implementing algorithms on the bay level protection/control units to monitor item of primary equipment, with the acquired diagnostic databases at station level.
10. Utility relay engineers are now required to gain a more comprehensive knowledge as a result of computer technology, modern serial communications, the sharing of data with other disciplines and the trend towards system engineering.

- In short term to medium term, the integration will be limited to the combination of functionalities to reduce the number of hardware units and the achievement of an information system. In the longer term the wireless substation will emerge, comprising integrated systems in which bay level devices communicate directly with the primary plant by means of a process bus. A possible intermediate short-term step will encompass the implementation of interfacing modules between a particular manufacturer process bus and legacy IEDs. This is not envisaged in the longer term because it adds installation costs.
- The number of non-conventional instrument transformers will rise. In the next few years international standards will be available. The benefits of non-conventional instrument transformers are the missing saturation, the electrical isolation, and the missing electro-magnetical influence by other equipment and the smaller size. Therefore it will be expected that measuring systems with optical sensors will rise within the next 5 to10 years.

11.8 Chapter 9 findings

1. A formal cost methodology is needed to estimate life-cycle cost. A utility that does not have the needed expertise to implement a formal cost methodology should contract with an accredited consulting firm to install the needed software and procedures, and train the personnel in its use.
2. Key features of a formal cost methodology should include the following features
   - Substation life cycle costs should be estimated to support the selection of architectural options and purchase decisions for substation automation. Modern cost analysis techniques using personal computer spreadsheet analysis tools are available to facilitate the cost analysis by providing algorithms to calculate both non-recurring and recurring costs. The selected software tool should include the capability for an analyst to completely customize the Cost Breakdown Structure (CBS), and enter any type of cost equation. It should support calculations over time using an appropriate inflation rate, provide sensitivity analysis, and Net Present Value (NPV) calculations.
   - Non-recurring costs should include initial facility development and component costs using a purchasing strategy that considers when cost is paid during the life cycle. Uncertainty in non-recurring cost due to economic factors and technology changes must be estimated and included in the cost function.
   - Recurring costs should include all training and facility/component maintenance and support costs. The cost tends to ramp-up sharply during the initial build-out or modernization phase; but after the substation is commissioned for operation, the sustaining cost for operation tends to become quite stable.

11.9 Chapter 10 findings

1. With the introduction of Intelligent Electronic Devices (IEDs) the role of the System Integrator has changed dramatically. The principal cause of this change is the paradigm shift from a system with unilateral control of slave devices by a single master to one implemented by a fully distributed architecture that, in addition, provides for peer-to-peer communications.
2. To implement this new paradigm, the most important guideline to the System Integrator is a clear statement from the utility of their vision for substation automation.

3. The utility must articulate a vision of what they expect to achieve with their substation automation initiative.

11.10 Summary of findings

The report concludes with a summary of findings in each area addressed by CIGRE Working Group B5.07. These findings provide significant insight into the benefits that can be realized in a utility's well-managed substation automation program.

1. Substation automation is expected to reduce operational cost, maintenance cost as well as installation cost. SA is a relatively young technology and is still developing constantly. It is difficult to assess cost benefit of SA systems due to the variety of implementations and lack of sufficient statistical data.
2. Practical experience show good results with automated systems. Well-maintained, modern automated substations have better (or at least similar) reliability then conventional systems. On the other hand the technical life cycle of these products seem to be shorter than the economical life cycle could be. Problems of obsolescence of HW and SW support can be more dominant then technical system failures.
3. It is not sufficient to judge the benefits and costs of SA against the classical preceding technology alone, without considering the benefits of reduced size, cabling and maintenance and without considering the increase in functional possibilities which are still unexploited.
4. The basic functionality of SA has not changed much from the classical protection, control and automation. But functionality in modern automated systems will gradually increase with the emerging technologies and new market requirements.
5. Future standardisation will most probably strengthen the convergence of architecture of the different SA system offerings. Technological differences could be found in other areas then architecture or classical functionalities. Adaptability, changeability and compatibility are some of these areas.
6. SA is forcing information technology into the substation. New skills are required from all the people involved. IT technology also has an important impact on life cycle, spare parts strategy and tools.
7. There are a variety of different approaches to refurbish and automate an existing substation. No recommendation can be given of weather to refurbish individual components (e.g., protection relays) – one per one and possibly over a long time span, or to refurbish the entire secondary equipment – all at once. It all depends on the utilities plans, substation and grid conditions. An experienced System Integrator could assist the utility in finding their appropriate way
8. Open system standards (IEC 61850) will become available to implement modern substation automation communication architectures, and provide the enabling technology needed to improve interoperability between IEDs of different vendors. But a standard that will cover all historical functional and operational requirements for all utilities will probably be difficult to achieve. Therefore where full interoperability is required the users of the standard should accept the framework of the standard. It has also to be considered that every standard needs a certain period of time to mature and to become generally accepted.
9. A best estimate of life cycle cost (LCC) and sensitivity of LCC to uncertainties is critical to making informed decisions. Architectural options to implement substation automation should be included in the LCC trade space.

10. With the introduction of Intelligent Electronic Devices (IEDs) the role of the System Integrator has changed dramatically. The principal cause of this change is the paradigm shift from a system with unilateral control of slave devices by a single master to one implemented by a fully distributed architecture that, in addition, provides for peer-to-peer communications. To effectively implement this technology the utility must have a vision of what they expect from the substation automation system.

A Definition of acronyms

Term	Definition
ACSI	Abstract Communication Service Interface
AEP	American Electric Power
AMR	Automatic Meter Reading
AMRA	Automatic Meter Reading Association
API	Application Program Interface
ASDU	Application Service Data Unit
ASN	Abstract Syntax Notation
ATM	Asynchronous Transfer Mode
CAD	Computer Aided Design
CASM	Common Application Service Models
CB	Circuit Breaker
CBS	Cost Breakdown Structure
CC	Control Centre
CD	Compact Disk Committee Draft
CDV	Committee Draft for Vote
ComU	Communications Unit
COSEM	Companion Specification for Energy Metering
C/P	Control and Protection Unit
CT	Current Transformer
CU	Control Unit
DAPU	Data Acquisition and Processing Unit
DBMS	Database Management System
DLMS	Device Language Message Specification

Term	Definition
DMS	Distribution Management System
ECT	Electronic Current Transducer
EDI	Electronic Data Interchange
EDIFACT	Electronic Data Interchange for Administration, Commerce and Transport
E/F	Earth Fault
EM	Electromagnetic
EMS	Energy Management System
EPA	Enhanced Performance Architecture
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers
EPRI	Electric Power Research Institute
ET	Electrical Current Transducer
EVT	Electronic Voltage Transducer
IRIG-B	Inter-Range Instrumentation Group (Format B)
I/O	Input/Output
FDIS	Final Draft International Standard
FMS	Fieldbus Message Specification
FYCF	Five Year Cost Forecast
GIS	Gas insulated switchgear
GOMSFE	Generic Object Models for Substation & Feeder Equipment
GPS	Global Positioning System
GUI	Graphical User Interface
HMI	Human Machine Interface
HV	High Voltage

Term	Definition
ICCP	Inter-Control Centre Communications Protocol
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronic Engineers
I/O	Input / Output
IS	International Standard
ISDN	Integrated Service Data Network
ISO	International Standardization Organization
LAN	Local Area Network
LCC	Life Cycle Cost
LCCF	Life Cycle Cost Forecast
LV	Low Voltage
MMI	Man Machine Interface
MMS	Manufacturing Message Specification
ms	Milliseconds
MTBF	Mean Time Between Failure
MTTR	Mean Time To Repair
MU	Merging Unit
MV	Medium Voltage
NCC	Network Control Centre
NPV	Net Present Value
O/C	Overcurrent
OSI	Open System Interconnect
OSU	Operations Support Unit
PB	Process Bus

Term	Definition
PC	Personal Computer
PLC	Program Logic Component or Program Logic Controller
PSTN	Public Switched Telephone Network
PU	Protection Unit
R&D	Research and Development
RAID	Redundant Array of Independent Disks
RFQ	Request for Quote
ROM	Read Only Memory
RRM	Report Reference Model
RTU	Remote Terminal Unit
SAS	Substation Automated System
SB	Station Bus
SBO	Select –Before-Operate
SC	Secondary Converter, Star Coupler, or Study Committee
SCADA	Supervisory Control and Data Acquisition
SCSM	Specific Communication Service Mapping
SG	Switch Gear
SU	Station Unit
TASE	Telecontrol Application Service Element
TC	Technical Committee
TCP/IP	Transmission Control Protocol/Internet Protocol
TR	Technical Report
TYCF	Ten Year Cost Forecast
UA	User Association
UCA®	Utility Communication Architecture

Term	Definition
ULTC	Under Load Tap Changer
UML	Unified Modeling Language
VT	Voltage Transformer
WAN	Wide Area Network
WBS	Work Breakdown Structure
WD	Working Draft
XML	Extensible Markup Language

B Bibliography

Reference ID	Description
[B.1.] CIGRE Paper 34/35-01	Application of broadband telecommunications and time transfer systems for teleprotection
[B.2.] CIGRE Progress Report 34/35-02	Potential of new telecommunication technologies for power system protection
[B.3.] CIGRE Paper 34-104	Digital communications for power system protection: security, availability and speed
[B.4.] CIGRE Paper 34-110	Present state and trend of application of communication including LAN to protection and substation control
[B.5.] IEC 61850	Communication Networks and Systems in Substations
[B.6.] IEC 61968	System Interfaces for Distribution Management
[B.7.] IEC 61970	System Interfaces for Energy Management
[B.8.] IEEE 1344	IRIG Time Code Standard
[B.9.] IEEE P1525	Draft Standard for Substation Integrated Protection, Control and Data Acquisition Communications
[B.10.] IEEE P1646	Draft Standard Communication Delivery Time for Electric Power Substation Automation
[B.11.] IEEE PC37.115	Draft Standard Test Method for Substation Integrated Protection, Control and Data Acquisition Communication System
[B.12.] IEEE PSRC H5 Working Group Report	Application of peer-to peer communications for protective relaying
[B.13.] ISBN 0-471-3942-8	Kerzner, Harold. “Project Management: a systems approach to planning, scheduling and controlling.” 7th edition.
[B.14.] GAL	Gal, Stelian. “Primary Equipment Monitoring, An Answer for Efficiency Increasing of the Electric Utility.
[B.15.] WG 13-09	CIGRE WG 13-09. Monitoring and Diagnostic Techniques for Switching Equipment.

C Use of information for condition monitoring

The improvement of the equipment operation reliability and safety has to be a continuous process, which is justified by ensuring continuous supply of electricity to customers. The continuous monitoring and the diagnose techniques can contribute, in an essential way, to ensure improved equipment reliability. Deteriorating tendencies can be identified in advance, and if it is the case, respective elements can be isolated before reaching the state of total failure (collapse).

C.1 What is expected of monitoring installations in substations

Functional and performance specifications for the monitoring system should be maintained by the utility. Most likely, monitoring the functionality in substation where only the secondary equipment is retrofitted (primary equipment is not) is lower in substation where both primary and secondary equipment is retrofitted.

For the EHV substations the targets of the monitoring consist of:

- Identifying the equipment to be monitored (circuit breakers, disconnectors, current transformers, voltage transformers, power transformers and auto-transformers, secondary equipment).
- Analysis of equipment in normal and faulty conditions (information for analysis, the correct operation of the secondary equipment, secondary system supervision, fault reports and analysis, and status reports of equipment).
- Maintenance and refurbishment planning assistance (relevant equipment parameter evaluation, adaptation of the maintenance methods to the equipment real condition, and improvement of the maintenance procedures).

C.2 Methods of supervising of different devices

Parameter identification is critical to the design of a quality monitoring system. Assigning a value to each parameter is based on evaluating the correct and complete health of the equipment, and the cost to acquire and process the data measured for these parameters. The objective is to design a monitoring system that minimizes the cost/benefit ratio.

C.2.1 Monitoring circuit breakers

The content of adequate information offered could be contact-wear, which can be estimated by counting the number of circuit breaker operations and current disconnects. Figure C-1 shows an evaluation of the degree of wear using the on-line monitoring data for a type 10-110kV circuit breaker.

The reference curve shown in Figure C-1 is based on pair values (switch current and number of operations) guaranteed by the manufacturer. The switching capacity of a HV circuit breaker, defined in CEI publication 56, can also be evaluated through the number of operations and corresponding values of the short-circuit current guaranteed by the manufacturer

For a certain percentage-wear the operational duty slope of the breaker's switching sub-assembly remains identical with the standard duty slope. Based on [GAL], it is therefore possible to calculate the number of interruptions of the fault current for several percentages of wear; e.g., 50%, 25%, 10%. These curves are shown in Figure C-1.

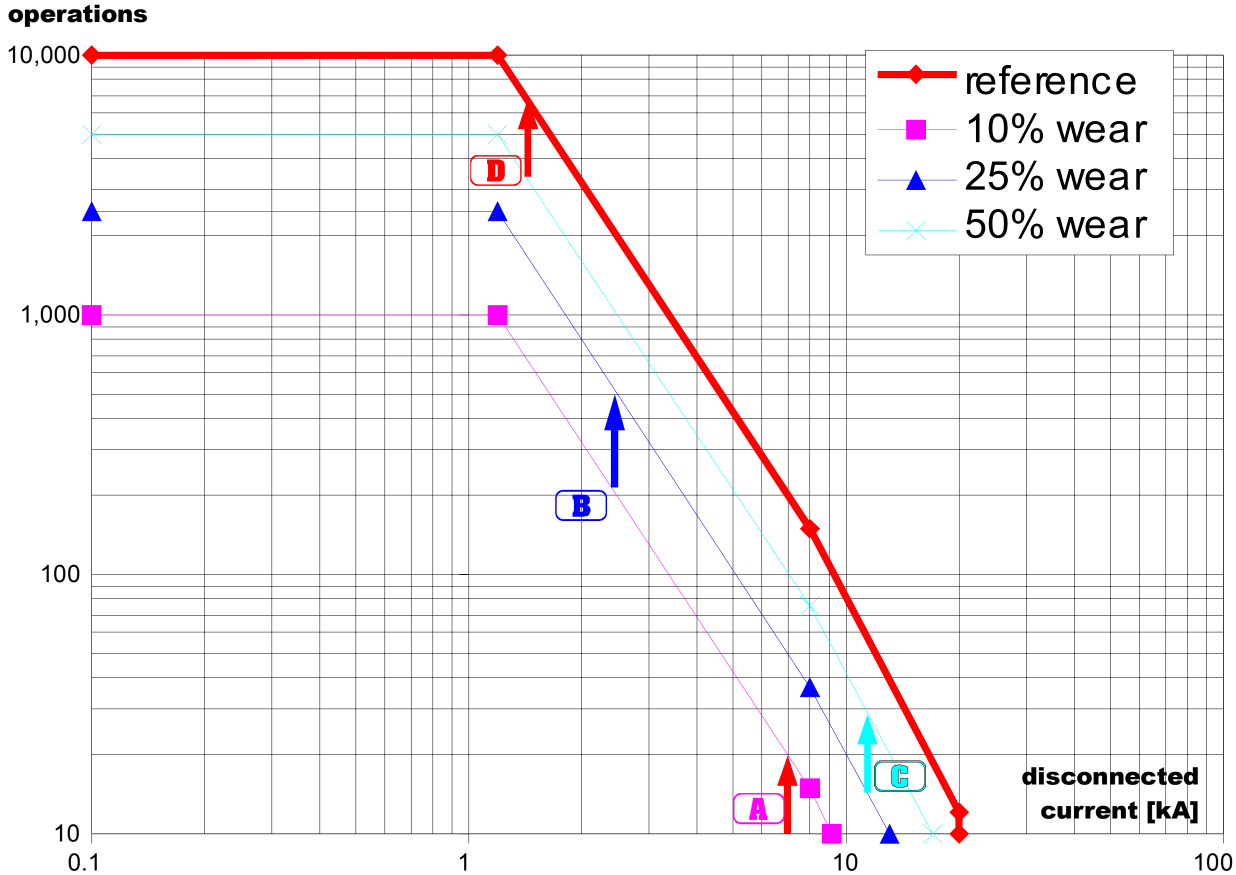

Figure C-1 Example of breaker wear curves

C.2.2 Example of switch acoustic impression

By acquiring and comparing the vibration “fingerprints” or signature with a reference, changes in the mechanical condition of the device can be determined from changes in the vibration patterns. Vibration patterns can be measured using accelerometers.

C.2.3 Monitoring disconnectors and earthing switches

The following parameters needed to monitor disconnectors and earthing switches are:

- Recording of motor current and voltage
- Storage of the records
- Comparison with a reference curve
- Calculation of the motor running time
- Monitoring of motor during the idle state.

This information could be acquired only with future equipment.

C.2.4 Monitoring current and voltage transformers

Measurements made during maintenance could provide information about main isolation, partial discharges level, and Anti-Ferro-resonant circuit resistance.

C.2.5 *Monitoring power transformers and auto-transformers*

On large transformers there are multiple stages of cooling. When the transformer gets hot, there are pumps to circulate oil through the cooling loop. If the oil doesn't circulate the transformer will be damaged. Monitoring equipment must be designed to reliably detect faults in an incipient phase before the transformer or autotransformer is damaged.

There are several ways to detect a faulty oil pump. One approach is by logic: A command is sent to the oil pump to operate, but the temperature continues to increase. Another approach is to use a "sail" switch in the oil pump outlet to detect movement of the oil. Another approach is to measure the monitor the small pressure differential across the pump. Another is to monitor the running current of the pump motor.

Monitored data can be used to estimate the transformer age and remaining lifetime. These data are also used to determine when to inspect the insulating bushings.

Signalling (alarms) and disconnection functions can be monitored by a signalling relay measurement of oil limit temperature overrun with two thresholds: a signalling contact and a disconnecting contact. A signalling relay monitoring non-operation of the oil circulation pumps or cooling fans can correlate the x with the transformer's load. The signal is transmitted within minutes. Disconnection may be required to prevent damage.

C.2.5.1 *Data collection*

Data collected and reported by the monitoring system should include voltage from the primary side, primary line currents obtained from the current transformers, oil temperature from the transformer topside, ambient temperature, and network voltage frequency.

Monitored states should include:

- Gas Buchholtz relay position of 2 signals corresponding to the state of the signalling and release circuits
- Operational state of the protected equipment for the HV and/or LV insulating bushings capacitor type, 2 normally open contacts (signalling and release)
- Oil pumps state based on data obtained from the pump motors
- Cooling fan state based on data obtained from the fan motors
- State of MV and LV transformer switches
- Oil level from the conservatory
- Normally open contacts for the maximum level and minimum level
- The state of the relay that is part of the tap selector, which is normally an open contact.

C.2.5.2 *Software facilities*

The software required for monitoring power transformers and autotransformers should include the following:

- Data displayed in tables and graphics form
- All monitored data displayed in the desired time interval
- Calculation of apparent powers for a phase and in a triphase system corresponding to the transformer load on the HV side
- Highlighting the overload periods
- Select the sizes presented simultaneously on the graphic
- Printing the desired data

- Monitored transformer marking, its power, its manufacturing series, the substation name, etc
- Protection functions doubling in case of damages or abnormal conditions
- Transformer age estimation from the themic point of view
- An over-control function of the monitoring system (e.g.; the hydrogen or partial discharges monitoring, etc.) or of tap selector connection.

C.2.5.3 *Online monitoring of moisture in the transformer oil*

A capacity humidity sensor can be used to monitor the relative humidity in the transformer oil. These measurements and the oil temperature are then used to estimate the abnormal rate of paper degradation by detecting an increase in the overall moisture content.

C.2.5.4 *Intelligent transformer fault monitoring*

A transformer incipient fault monitor can be used to measure the parts per million (ppm) composite value of gas generated by faults. This instrument should also detect and measure hydrogen and carbon monoxide gas in the oil, top oil temperature and load current. The monitoring device that receives this data could then evaluate the status and capability limits of the transformer, and estimate the remaining life of its components.

D Overview of communication standards for electric power systems

D.1 Inside substations

D.1.1 IEC 60870-5 Series

D.1.1.1 *Introduction*

IEC Technical Committee 57 has defined a standard for relatively simple, bit serial communication: IEC 60870-5. The standard is optimised for efficient and reliable transfer of process data and commands to and from geographically widespread systems over low-speed (up to 64 kbps) fixed and dial-up connections. It harmonises with the OSI reference model through its Enhanced Performance Architecture (EPA), which uses three layers from the full seven-layer OSI model.

IEC 60870-5 communication standard consists of the IEC 60870-5 protocol standard series (with international standard status) and the IEC 60870-5 companion standard series. The Companion standard specifies the information services in a specific domain of activity, and specifies in detail the use of protocol standard parts for specific telecontrol tasks. The IEC 60870-5 protocol standard and companion standard series specify communication protocols optimised for telecontrol systems that require short response times in relatively low-speed networks. A detailed list of the parts of IEC 60870-5 is shown in Table D-1.

Table D-1 IEC 60870-5 document parts

Standard	Description
IEC 60870-5-1	Transmission frame formats
IEC 60870-5-2	Link transmission procedures
IEC 60870-5-3	General structure of application data
IEC 60870-5-4	Definition and coding of application information elements
IEC 60870-5-5	Transmission protocols - Basic application functions
IEC 60870-5-101	Transmission protocols - Companion Standard for Basic Telecontrol Tasks
IEC 60870-5-102	Companion Standard for the Transmission of Integrated Totals in Electric Power Systems
IEC 60870-5-103	Companion Standard for the Informative Interface of Protection Equipment
IEC 60870-5-104	Network Access for IEC 60870-5-101 using Standard Transport Profiles

The companion standards –101, –102, and –104 are described in D.4; they do not standardise communication inside substations.

D.1.1.2 *IEC 60870-5-103*

Title: Companion standard for the informative interface of protection equipment

Publication date: 1997
Objective: Designed for substation automation

This standard used to upload protection data's is applicable for substation automation systems with star coupled protection devices using point-to-point links and a master slave transmission procedure. Figure D-1 shows a typical configuration of substation communication. The dashed lines show possible communication links according to IEC 60870-5-103.

Figure D-1 Typical configuration of bay to station level communication in a HV substation

IEC 60870-5-103 describes two methods of information exchange. The first is based on explicitly specified ASDUs (Application Service Data Units) and application procedures for transmission of standardised messages, and the second uses generic services for transmission of nearly all possible information. Another extension is introduced by help of reserved areas for private use; e.g., for the function type of generator protection, busbar protection, etc.

All known implementations only use the compatible definitions. Compatible information exchange is defined for protection equipment with the most common protection principles as function types. In the understanding of the standard, protection devices are multifunctional relays. The function types do not only cover the main protection function, but also provide information from additional protection related functions.

An important goal of IEC 60870-5-103 for the informative interface of protection equipment is the ability of linking protection devices of different vendors and different generations to a station control system without applying any additional adaptive effort. Even exchangeability of protection devices is maintained if no information objects of the so-called private range are used.

D.1.2 IEC 61850

Title: Communication networks and systems in substations
Publication date: Future standard

Objective: Designed for substation automation

IEC 61850 defines a comprehensive communication standard for substations. This includes a consistent data and service model at all communication level. Operational information (indications, commands, and measured values) are coded and transmitted in the same way on a possible process bus and station bus. The use of the same application interfaces and protocol stacks at the station bus and process bus levels ensures that "gateway-free" communication links are established within the station.

The objective of IEC 61850 is to design a communication system that provides interoperability between the functions to be performed in a substation, but residing in equipment (physical devices) from different suppliers, meeting the same functional and operational requirements. Functional requirements have to be met independent of substation size and operational conditions. The functions of a substation automation system are control and supervision, as well as protection and monitoring of the primary equipment and of the grid. Other functions are related to the system itself; e.g., supervision of the communication.

A detailed list of the parts of IEC 61850 is shown in Table D-2.

Table D-2 IEC 61850 document parts

Standard	Status, Year	Title
IEC 61850-1	TR, 2003	Introduction and overview
IEC 61850-2	CDV, 2002	Glossary
IEC 61850-3	IS, 2002	General requirements
IEC 61850-4	IS, 2002	System and project management
IEC 61850-5	IS, 2003	Communication requirements for functions and device models
IEC 61850-6	FDIS, 2003	Configuration description language for communication in electrical substations related to IEDs
IEC 61850-7-1	IS, 2003	Basic communication structure for substations and feeder equipment – Principles and models
IEC 61850-7-2	IS, 2003	Basic communication structure for substations and feeder equipment – Abstract communication service interface (ACSI)
IEC 61850-7-3	IS, 2003	Basic communication structure for substations and feeder equipment – Common data classes
IEC 61850-7-4	IS, 2003	Basic communication structure for substations and feeder equipment – Compatible logical node classes and data classes
IEC 61850-8-1	FDIS, 2003	Specific communication service mapping (SCSM) – Mapping to MMS (ISO/IEC 9506 Part 1 and Part 2) and to ISO/IEC 8802-3
IEC 61850-9-1	IS, 2003	Specific communication service mapping (SCSM) – Sampled values over serial unidirectional multidrop point to point link
IEC 61850-9-2	FDIS, 2003	Specific communication service mapping (SCSM) – Sampled values over ISO/IEC 8802-3
IEC 61850-10	CD, 2003	Conformance testing
IEC 61850-7-401	NP, 2002	Power Quality Monitoring Addendum to IEC 61850 - Logical nodes, data objects and definitions for exchanging information

Standard	Status, Year	Title
		about power quality.

D.1.3 IEC 62010

Title: Communication Requirements of HV Switchgear Assemblies
Publication date: future standard
Objective: Designed for switchgear automation

Working Group 11 of TC 57 in IEC is working on a product standard that would specify the requirements of HV Switchgear and Assemblies such that they support the horizontal substation communication standard IEC 61850. The work will also include the issues of testing and monitoring. This latter issue considered important because it is an area where this type of digital communications has the potential to provide cost savings. The Working group concentrate its effort on.

Ratings and Classifications: Unlike a traditional product standard this section of the document needed to specify the functions and the communication services that the switchgear shall support, and the necessary performance levels. Specifying the performance levels, particularly timing requirements, is an area that continues to present difficulties.

Testing: It was decided to re-investigate all areas of testing to ensure that while supporting IEC 61850, the tests are practical and gives potential users of the standard confidence that the equipment will perform its intended function without the risk of mal-operation.

PICOM List: Since the issue of the original report the list of PICOMs (Communication Signals, CIGRE Report Dec 1996) had become out dated. This was mainly because the signals have been optimised for communication purposes by the use of common types of signals. For example the same signal may be used to trip a circuit breaker as to open during normal switching operations. The Group decided that this list was still of value in the standard and it is to be updated accordingly.

D.1.4 IEEE-SA TR 1550, UCA™ 2.0

Title: IEEE-SA Technical Report on Utility Communications (UCA™), Version 2.0
Publication date: 1999
Objective: Designed for substation and feeder automation

The Electric Power Research Institute (EPRI) developed a communication architecture networking all components of an electric utility. This architecture is named the Utility Communication Architecture (UCA™). IEEE-SA TR1550 documents the version of UCA™, known as UCA™ 2.0 as it was specified in 1999.

The objective of EPRI's UCA™ project is to achieve a standardised networking of all control components such as control centres, power plants, substations, energy management systems, switchgears and customer's interfaces. Two critical components to understand are the data model and the common application service model. The model, which describes the data of the bays including protection and control, is outlined in the data model GOMSFE (Generic Object Models for Substation and Feeder Equipment). The model, which describes the necessary services needed to exchange messages, commands, data, etc. between the primary and secondary devices, is outlined in the service model CASM (Common Application Service Models). Both papers are included in IEEE-SA TR 1550.

D.1.5 IEEE 1379

Title: Recommended Practice for Data Communications Between Remote Terminal Units and Intelligent Electronic Devices in a Substation
Publication date: 2000
Objective: Designed for substation automation

This recommended practice present a uniform set of guidelines for communications and interoperation of IEDs and Remote Terminal Units (RTUs) in an electric utility substation. It does not establish an underlying communication standard. Instead, it provides a specific limited subset of two existing communication protocols, to encourage understanding and timely application. Both DNP and IEC 60870-5-101 have been specified inside. A mechanism for adding data elements and message structures to this recommended practice is described.

The purpose of IEEE 1379 is to illustrate a recommended practice that will eliminate the need for time consuming and costly efforts by implementers to interface their equipment to other equipment on a project-by-project basis.

D.1.6 IEEE PC37.115

Title: Test Method for Use in the Evaluation of Message Communications between Intelligent Electronic Devices in an Integrated Substation Protection, Control and Data Acquisition System
Publication date: Future standard
Objective: Designed for substation automation

IEEE PC37.115 defines standard communication modelling, terminology, evaluation criteria and performance measures for communication test scenarios, which specify messages to be exchanged between electrical power substation intelligent electronic devices (IEDs). These scenarios define message transactions between applications within the substation, and between substation IEDs and remotely located applications. The scenarios do not specify the communication protocol required to implement the transactions.

There are currently no coherent communication modelling, terminology and communication test scenarios for the evaluation of one or more implementation concepts for communication between substation IEDs within a substation or between a substation and remote IEDs. Utilities and vendors will use this standard to evaluate, on a common basis, one or more implementation solutions.

D.1.7 Profibus

Title: General Purpose Field Communication System, Application Layer Service Definition
Publication date: EN 50170-5-2:1995
Objective: Designed for industrial automation

PROFIBUS is a vendor-independent, open field bus standard for a wide range of applications in manufacturing and process automation. Vendor-independence and openness are ensured by the international standards EN 50170, EN 50254 and IEC 61158. PROFIBUS allows communication between devices of different manufacturers without any special interface adjustment. PROFIBUS can be used for both high-speed time critical applications and complex communication tasks. PROFIBUS offers functionally graduated communication protocols (Communication Profiles): DP and FMS. Depending on the application, the transmission technologies (Physical Profiles) RS-485, IEC 61158-2 or fiber optics are available. Application Profiles define the options of protocol and transmission technology required in the respective application area for the individual device types. These profiles also define vendor-independent device behaviour.

PROFIBUS is intended for automation applications that are close to the process and makes simple bus interfaces with real-time behaviour possible. This standard allows field automation components of different manufacturers to be interconnected in a distributed system and guarantees reliable communication. Such a system is called an "open system". In addition the PROFIBUS protocol makes possible the easy integration into hierarchically higher automation systems (Manufacturing Automation Protocol, MAP). Thus the interconnection expense is minimised.

D.1.8 Modbus

Title: MODBUS
Publication date: de facto standard since 1979
Objective: Designed for industrial automation

MODBUS Protocol is a messaging structure developed by Modicon in 1979, used to establish master-slave/client-server communication between intelligent devices. It is a de facto standard, and used as network protocol in the industrial manufacturing environment.

MODBUS is an application layer messaging protocol, positioned at level 7 of the OSI model that provides client/server communication between devices connected on different types of buses or networks. MODBUS is a request/reply protocol and offers services specified by function codes. MODBUS function codes are elements of MODBUS request/reply PDUs.

D.1.9 LON

Title: LON, LonTalk, LonWorks
Publication date: 1988
Objective: Designed for industrial automation

The term LON (Local Operating Network) was chosen to distinguish the network from a LAN (Local Area Network), developed for computer networks and office automation. A protocol called LonTalk® has been specified for operating a LON. LonWorks is a digital serial fieldbus based on CSMA network access and the LonTalk protocol.

LonWorks control networks are a standard for networking controls and machines in building, industrial, home, transportation, and utility automation applications. A LON network is intended for device control of intelligent network nodes and does not support the transmission of multimedia data.

D.1.10 IEC 61000-6-5

Title: Electromagnetic compatibility (EMC) - Part 6-5: Generic standards - Immunity for power station and substation environment
Publication date: 2001
Objective: Designed for environmental condition of devices

This technical specification sets immunity requirements for apparatus intended for use by Electricity Utilities in the generation, transmission and distribution of electricity and related telecommunication systems. The locations covered are the power stations and the substations where apparatus of Electricity Utilities are installed. Immunity requirements are given for the frequency range 0 Hz to 400 GHz, but only in respect of electromagnetic phenomena for which detailed test procedures, test instrumentation and test set-up are given in existing IEC basic standards.

The immunity requirements are suitable for satisfying the particular needs related to the functions and tasks of equipment and systems, for which reliable operation is required under actual electromagnetic conditions; in this respect, this technical specification establishes performance criteria for the different functional requirements.

D.2 Instrument transformer

D.2.1 IEC 61850-9-1

Title: Specific Communication Service Mapping (SCSM) – Serial Unidirectional Multidrop Point-to-point Link
Publication date: 2003
Objective: Designed for substation automation

This part of IEC 61850 (see D.1.2) specifies the specific communication service mappings for the communication between bay and process level and specially it specifies a mapping on a serial unidirectional multidrop point-to-point link. The scope of this part is for the use in substations as a link between electronic current (ECT) or voltage transducers (EVT) and bay devices such as protection, meter or bay controller. The intended use of this mapping is for low cost applications with simple protection schemes, and for retrofitting in existing substations only. If higher requirements on sampling rate, further sampled measured value data sets in addition to the universal data set, inter-bay communication and synchronisation apply, these will be covered by IEC 61850-9-2.

IEC 61850-9-1 applies to newly manufactured electronic current and voltage transducers (ECT and EVT) having a digital output, for use with electrical measuring instruments and electrical protective devices. For digital output, IEC 61850-9-1 takes into account a point-to-point connection from the electrical transducer to electrical measuring instruments and electrical devices. This mapping allows interoperability between devices from different manufacturers. IEC 61850-9-1 does not specify individual implementations or products, nor does it constrain the implementation of entities and interfaces within a computer system. IEC 61850-9-1 specifies the externally visible functionality of implementations together with conformance requirements for such functionality.

D.2.2 IEC 61850-9-2

Title: Specific Communication Service Mapping (SCSM) – Sampled values over ISO/IEC 8802-3
Publication date: Future standard
Objective: Designed for substation automation

This part of IEC 61850 defines the specific communication service mapping for the transmission of sampled values according to the abstract specification in IEC 61850-7-2. The mapping is that of the abstract model on a mixed stack using direct access to an ISO/IEC 8802-3 link for the transmission of the samples in combination with IEC 61850-8-1.

The purpose of this SCSM definition is to supplement IEC 61850-9-1 to include the complete mapping of the sampled value model. This part of IEC 61850 applies to electronic current and voltage transformers (ECT and EVT) having a digital output, merging units, and intelligent electronic devices e.g. protection units, bay controllers and meters.

D.2.3 IEC 60044-7 and -8

Title: Instrument transformers - Part 7: Electronic voltage transformers, Part 8: Electrical current transducers

Publication date: Part 7 - 1999, Part 8 - 2002
Objective: Designed for substation automation

Both parts of IEC 60044 apply to newly manufactured non-conventional sensors, i.e. electrical current transducers and voltage transducers having a digital output or analogue output. The outputs are designed for use with electrical measuring instruments and electrical protective devices at nominal frequencies from 15 Hz to 100 Hz. The standard covers optical arrangements with electrical components. Three-phase voltage transducers are not included, but some of the requirements apply.

Accuracy requirements that are necessary for use with electrical measuring instruments, for use with electrical protective relays and particular for forms of protection in which the prime requirement is to maintain the accuracy up to several times are included.

For analogue output, the electrical transducer may include the secondary signal cable. For digital output, this standard takes into account a point-to-point connection from the electrical transducer to electrical measuring instruments and electrical devices. Some information has been added in order to ensure the compatibility of this point-to-point link with the overall system of communication in the substation, thus allowing data exchange between all kinds of substation devices. This information builds what is called the mapping of the link layer of the point-to-point serial link. This mapping allows interoperability between devices from different manufacturers.

A general block diagram of electronic transducers with a digital output is shown in Figure D-2. Up to seven electronic current transducers (3 measuring ECTs, and/or 3 protective ECTs and/or one neutral ECT) and up to five electronic voltage transducers (3 protective/measuring EVTs and/or one bus-bar EVT and/or one neutral EVT) is grouped together using a merging unit (MU). This merging unit supplies the secondary equipment with a time coherent set of current and voltage data.

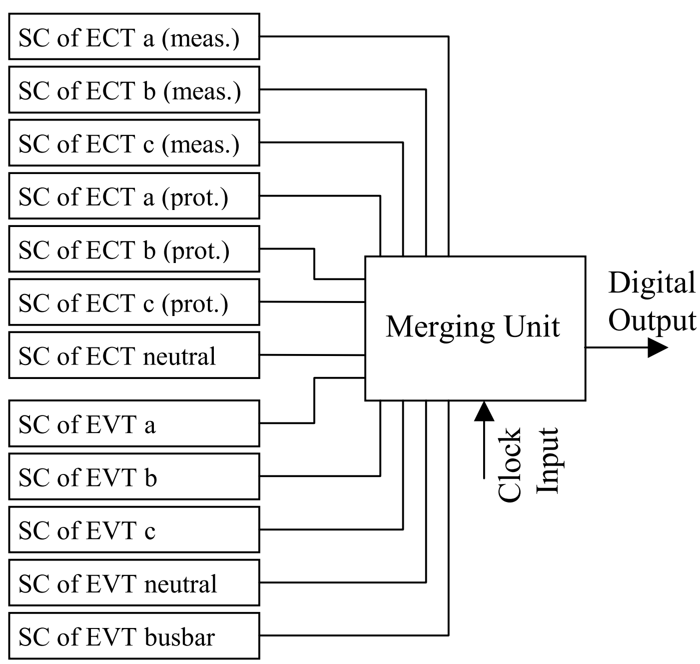

Figure D-2 Digital interface block diagram

A secondary converter (SC[13]) is an arrangement that converts the signal transmitted through the transmitting system into a quantity proportional to the current between the primary terminals, to supply measuring instruments, meters and protective or control devices. For ETs with analogue output the secondary converter directly supplies measuring instruments, meters and protective or control devices. For electrical instrument transducers with digital output the secondary converter is generally connected to a merging unit before supplying the secondary equipment.

D.3 Metering

D.3.1 IEC 60870-5-102

Title: Companion Standard for the Transmission of Integrated Totals in Electric Power Systems
Publication date: 1996
Objective: Designed for electrical power SCADA

IEC 60870-5-102 standardised the transmission of integrated totals representing the amount of electrical energy transferred between power utilities, or between a power utility and independent power producer on a HV or MV network as a part of energy management systems functionality. It is not concerned with LV networks or the interfaces to the energy consumption meters.

In general the values of integrated totals are transmitted at periodic intervals to update the energy interchanges between utilities or between heavy industry and utilities. The periodically received information is used for supervisory and control purposes of energy distribution in wide area networks. The defined protocol is based on the three-layer reference model EPA. The standard utilizes IEC 60870-5.

D.3.2 IEC 61107

Title: Data exchange for meter reading, tariff and load control - Direct local data exchange, Edition 2
Publication date: 1996
Objective: Designed for local meter reading

IEC 61177 specifies hardware and protocol specifications for local systems in which a hand held unit is connected to only one tariff device at a time. Connection can be permanent or plugged-in through an electrical or optical coupling. The protocol uses the basic reference model for communication between open systems (OSI). Edition 3 of IEC 61107 was merged into IEC 62056-21 Ed. 1.0 (see D.3.3).

IEC 61107 is designed for hand held terminal readout of billing data (channel with high capacity and reliability but which is only available for a very limited time): no selective data access, restricted access security, inefficient encoding (ASCII). IEC 61107 defines only the data transmission part, i.e. even if the data can be transported correctly it is not guaranteed that the client can interpret its meaning. IEC 61107 allows a variety of “customer specific” solutions.

[13] SC is the secondary converter of the electrical transducer of phase A.

D.3.3 IEC 62056

Title: Data exchange for meter reading, tariff and load control - Direct local data exchange
Publication date: 1996 till today and future
Objective: Designed for local meter reading

Table D-3 describes the general document structure of IEC 6205x. Specific parts of IEC 62056 are shown in Table D-4.

Table D-3 IEC 6205x document parts

Standard	Title
IEC 6205x-2	Equipment (ac), general requirements, tests and test conditions
IEC 6205x-3	Equipment (ac), particular requirements
IEC 6205x-4	Tariff and load control
IEC 6205x-5	Payment systems
IEC 6205x-6	Data exchange for meter reading, tariff and load control
IEC 6205x-7	Testing equipment
IEC 6205x-8	Equipment, acceptance testing
IEC 6205x-9	Equipment, dependability

Table D-4 IEC 62056 document parts

Standard	Title
IEC 62056-21	Using direct local connection
IEC 62056-31	Use of local area networks on twisted pair with carrier signalling
IEC 62056-32	Using local area with baseband signaling
IEC 62056-41	Data exchange using wide area networks: Public switched telephone network (PSTN) with LINK+ protocol
IEC 62056-42	Using wide area networks – PSTN with HDLC protocol
IEC 62056-46	Data Link Layer Using HDLC-Protocol
IEC 62056-51	Application layer protocols
IEC 62056-52	Communication protocols management distribution line message specification (DLMS) server
IEC 62056-53	COSEM Application Layer
IEC 62056-61	EDIS Electricity Data Identification System
IEC 62056-62	Interface objects

To prepare international standards for electrical energy measuring and electrical load control equipment (such as watt-hour meters, var-hour meters, maximum demand indicators, telemetering for consumption and demand, equipment for remote meter reading, time switches, equipment for the control of loads and tarifs and consumer services) including the equivalent electronic forms' of these devices and their accessories.

The competitive electricity market requires an ever-increasing amount of timely information concerning the usage of electrical energy. Recent technology developments enable to build intelligent static metering equipment, which are capable of capturing, processing and communicating this information to all parties involved. For further analysis of this information, for the purposes of billing, load-, customer- and contract management, it is necessary to uniquely identify all data in a manufacturer independent way collected manually or automatically, via local or remote data exchange.

D.3.4 IEC 61334-4 DLMS, COSEM

Title: Distribution automation using distribution line carrier systems - Data communication protocols
Publication date: 1996
Objective: Designed for distribution automation

Specific sections of IEC 61334-5 are shown in Table D-5.

Table D-5 IEC 61334-4 document parts

Section	**Title**
Section 1	Reference model of the communication system
Section 32	Data link layer - Logical link control (LLC)
Section 33	Data link layer - Connection oriented protocol
Section 41	Application protocols - Distribution Line Message Specification
Section 42	Application protocols - Application layer

IEC 61334 describes the structure of distribution networks for both medium and low-voltage levels and presents the architecture for a distribution automation system using distribution line carrier systems.

Part 4 provides a basic description of the communication system based on a three-layer model. Application examples are control and monitoring of the distribution network, order broadcast, control of user interfaces, public lighting, automatic meter reading, etc.

Device Language Message Specification (DLMS), which originally stood for Distribution Line Message Specification, was recently renamed. DLMS is a messaging system for exchanging data and control information between devices (applications) in a way that is independent of the communication channel being used and the application function being performed.

DLMS is an official IEC standard (IEC 61334-4-41), which satisfies the following requirements:

- Medium-independent, but simple enough to utilise in low-cost devices and applications
- Minimal protocol overhead, so that DLMS can be used on low-capacity connections
- Applicable in a wide range of products, like meters, switches, protection relays, etc.
- High life cycle cost of the system (installation, maintenance, extension)

Major meter manufacturers started the initiative to provide a specification for truly compatible - and flexible - meters and systems. The DLMS User Association (UA) was founded in 1997. The DLMS UA subsequently took up the initiative. The result was presented in April 1998 as the "Companion Specification for Energy Metering (COSEM)". Data and functions of the meters can be accessed via a standard interface (DLMS/COSEM) independent of the communication channel. This approach relieves the customer management centre of the task of achieving interoperability. Only one driver is necessary for the different meters of the various manufacturers.

D.3.5 American Meter Reading Association (AMRA)

AMRA is an international, non-profit, membership organisation founded in 1986 to address standardisation, justification and deployment practices in the implementation of advanced metering technologies. AMRA and its sister organisations - UKAMRA and EuroAMRA - offer membership services and educational forums that focus on AMR issues affecting electric, gas and water utility-service companies world-wide.

The groups' mission is to support members through accurate and balanced educational forums, identification of new technologies, trends and applications that will facilitate the link between members' business needs and the technology. Educational and networking opportunities sponsored by AMRA, UKAMRA and EuroAMRA help members make informed decisions about AMR and resource-management technology and participate more effectively in the metering, communications and data-management industry.

Automatic Meter Reading (AMR) is the remote collection of consumption data from customers' utility meters using telephony, radio frequency, power-line and satellite communications technologies. AMR provides water, gas and electric utility-service companies the opportunity to increase operational efficiency, improve customer service, reduce data-collection costs and quickly gather critical information that provides insight to company decision-makers.

D.4 Communication to Substations, to Power Plants, and to Control Centres

D.4.1 IEC 60834

Title: Teleprotection equipment of power systems - Performance and testing, Part 1 – Command systems, Part 2 – Analogue comparison systems
Publication date: Part 1 1999, Part 2 1993
Objective: Designed for teleprotection systems

Part 1 applies to teleprotection command systems used to convey command information, generally in conjunction with protection information. It aims at establishing performance requirements and recommended testing methods for command type teleprotection equipment. It specifies performance requirements and recommended testing methods for command type teleprotection equipment. The information conveyed by the teleprotection equipment can be in analogue or digital form. The command type teleprotection equipment referred to in this standard can be power line carrier equipment or voice frequency equipment which is used in connection with various telecommunication systems, such as power line carrier (PLC), radio links, optical fibre, rented circuits, leased or privately owned cables. In addition, the command type teleprotection can be digital equipment, which is used with a digital telecommunication system, or media such as optical fibres, radio links, leased or privately owned digital links. The command type teleprotection equipment may be separate or provided as an integral part of the protection equipment. In addition to teleprotection equipment performance tests, tests have to be carried out on the power supply of the teleprotection equipment. All the tests should be regarded as type tests.

Part 2 applies to narrowband and wideband teleprotection systems used to convey analogue information about the primary quantities such as phase or phase and amplitude.

D.4.2 IEEE 1565-2002

Title: Standard for N times 64 kilobit per second optical fibre interfaces between teleprotection and multiplexer equipment
Publication date: 2002
Objective: Designed for optical fibre interfaces between teleprotection and multiplexer equipment

IEEE 1565 describes the interconnection details for N times 64 kilobit per second connections of teleprotection equipment to digital multiplexers using optical fibre. Physical connection and the communications timing requirements are included.

The purpose of this standard is to allow the interconnection of different vendors' teleprotection equipment with different vendors' multiplexer equipment, without any restriction on the content of the N times 64 kilobit per second data using up to 2 kilometres of 50 or 62.5 micrometer multimode optical fibre.

Existing interface standards between teleprotection equipment's and multiplexers are electrical only. These low energy signal interfaces are susceptible to intra-substation electromagnet interference (EMI). The use of dedicated optic fibres for the intra-substation communication links between teleprotection equipment's and multiplexers eliminates the data corruption common to electrical connections.

D.4.3 IEC 60870-6

Title: Telecontrol equipment and systems - Telecontrol protocols compatible with ISO and ITU-T recommendations
Publication date: See Table D-6
Objective: Designed for electrical power SCADA

A complete list of IEC 60870-6 document parts is shown in Table D-6. The shaded areas in the table are used to distinguish general parts from parts specific to TASE.2 and TASE.1. Scope and purpose discussion of TASE.2 is presented in D.4.4, and the general comment on the status of TASE.1 is presented in D.4.5.

Table D-6 IEC 60870-6 documents

Standard	Application	Status Year	Title and remarks
IEC 60870-6-1	General	TR3 1995	Application Context and Organisation. This technical report shows the place of part 6 within IEC 60870 and fives an overview of its organisation and contents. The aim of part 6 is the standardisation of functional profiles for electric power systems.
IEC 60870-6-2	General	IS 1995	Use of Basic Standards (OSI-Layers 1-4). Considers the standards related to layers 1-4 of the OSI reference model and describes the role and the functions carried out by each layer.

Standard	Application	Status Year	Title and remarks
IEC 60870-6-503	TASE.2	IS 2002 Ed. 2	Services and Protocol. Specifies a method of exchanging time-critical control centre data through wide-area and local-area networks using a full ISO compliant protocol stack. Both centralised and distributed architectures are supported. Includes the exchange of real-time data indications, control operations, time-series data, scheduling and accounting information, remote program control, and event notification.
IEC 60870-6-505	TASE.2	TR 2002	TASE.2 Users Guide. A technical report providing guidance for utility users who are evaluating, procuring, and configuring TASE.2, as well as aid to vendors implementing TASE.2 in their products. Describes the individual server and data objects comprising TASE.2, with cross references to the specification. Provides the basic understanding needed to use the TASE.2 specifications in an informed manner.
IEC 60870-6-802	TASE.2	IS 2002 Ed. 2	TASE.2 Object Models.
IEC 60870-6-501	TASE.1	IS 1995	TASE. 1 Service definitions. Defines the services provided by a telecontrol specific application-service-element – the Telecontrol Application Service Element No. 1 (TASE.1) – for the exchange of process data in telecontrol systems.
IEC 60870-6-502	TASE.1	IS 1995	TASE.1 Protocol definitions. Specifies the protocol for the services provided by an application-service-element – the Telecontrol Application Service Element No. 1 (TASE.1) – to support the exchange of process data between telecontrol systems.
IEC 60870-6-504	TASE.1	TR2 1998	TASE.1 User conventions. A technical report, which defines rules for the usage of the TASE.1 Application Programming Interface (TAPI); i.e., parameter usage and service primitive sequencing.
IEC 60870-6-701	TASE.1	IS 1998	Functional profile for providing the TASE.1 application service in end systems. Describes the functional profile, which defines the provision of the TASE.1 communication services

Standard	Application	Status Year	Title and remarks
			between two control centre end systems.
IEC 60870-6-601	Transport profile	IS 1994	Function profile for providing the connection-oriented transport service in an end system connection via permanent access to a packet switched data network.
IEC 60870-6-602	Transport profile	TS 2001	TASE transport profiles. A technical specification describing the transport profiles for the IEC 60870-6 series over WAN with reference to international standardised profiles used by distributed SCADA/EMS applications in control centres, power plants, and substations.

D.4.4 IEC 60870-6, TASE.2

The Telecontrol Application Service Element (TASE.2) protocol (also known as Inter-Control Centre Communications Protocol, ICCP) allows for data exchange over Wide Area Networks (WANs) between a utility control centre and other control centres, other utilities, power pools, regional control centres, and Non-Utility Generators. Data exchange information consists of real-time and historical power system monitoring and control data, including measured values, scheduling data, energy accounting data, and operator messages. This data exchange occurs between one control centre's SCADA/EMS host and another centre's host, often through one or more intervening communications processors.

D.4.5 IEC 60870-6, TASE.1

ELCOM90 (see D.4.6) was the basis for TASE.1. Today there is an ongoing process to withdraw this standard.

D.4.6 ELCOM90

Title: Electricity Utilities Communication
Publication date: 1990
Objective: Designed for electrical power SCADA

ELCOM90 is a standard data communication protocol for the exchange of information between different control centres for the electric utility sector. Such communications may include links to external EMS systems, and to accounting, billing, and management information systems.

ELCOM originates from a Scandinavian initiative to standardise information exchange between control centres. ELCOM is an international accepted de-facto standard running over TCP/IP and X.25 Wide Area Networks. The ELCOM standards consist of two parts. These are the ELCOM provider (OSI layer 6 and 7) and the User Elements (integration part between the provider and the SCADA system). ELCOM90 document parts are shown in Table D-7.

Table D-7 ELCOM90 document parts

Standard	Title
TR 3707	Introducing a transport layer for ELCOM-90 an evaluation of

Standard	Title
	possibilities and implications
TR A3701.02	ELCOM-90 Application programming interface specification
TR A3702.02	ELCOM-90 Application service element, service definition
TR A3703.02	ELCOM-90 Application service element, protocol specification
TR A3704.02	ELCOM-90 Presentation programming interface specification
TR A3705.02	ELCOM-90 Presentation service definition
TR A3706.02	ELCOM-90 Presentation protocol specification
TR A3825.02	ELCOM-90 User element conventions
TR 3759	ELCOM-90 Test procedures for application service element

D.4.7 IEC 60870-5-101

Title: Companion standard for basic telecontrol tasks
Publication date: 2003 Edition 2
Objective: Designed for electrical power SCADA

Several stations, which use the IEC 60870-5-101 protocol, may be assembled into an interconnected installation for controlling and monitoring the operational equipment of a widely distributed electric power system, from a central point.

IEC 60870-5-101 defines the functionality for the interoperability of telecontrol equipment of different manufactures for the communication between substations (outstations) and between substation (outstation) and control centres (central station). Therefore, it applies to telecontrol equipment and systems with coded bit serial data transmission for controlling and monitoring geographically widespread processes. The defined protocol is based on the three-layer reference model.

D.4.8 IEC 60870-5-104

Title: Network Access for IEC 60870-5-101 using Standard Transport Profiles
Publication date: 2000
Objective: Designed for electrical power SCADA

IEC 60870-5-104 will enable Application Data Units, as defined in IEC 60870-5-101, to be transmitted over a variety of digital data networks using the standard TCP-IP transport interface. The future standard intended to enable Telecontrol Application information (ASDUs as defined in IEC 60870-5-101) to be transmitted using Digital Data Networks in place of permanent directly connected analogue data circuits.

The specifications of IEC 60870-5-104 present a combination of the application layer of IEC 60870-5-101 and the transport functions provided by a TCP/IP. Within TCP/IP various network types can be utilised including X.25, FR (Frame Relay, ATM (Asynchronous Transfer Mode, and ISDN (Integrated Service Data Network. Using the same definitions alternative ASDUs as specified in other IEC 60870-5 companion standards may be combined with TCP/IP, but this is not described further in this standard.

D.4.9 Distributed Network Protocol (DNP)

Title: Distributed Network Protocol
Publication date: Placed in public domain early 1993
Objective: Designed for electrical power SCADA

DNP, the Distributed Network Protocol, is an open, public and non-proprietary protocol based on existing open standards to work within a variety of networks. DNP Version 3.0 was originally designed based on three layers of the OSI seven-layer model: application layer, data link layer and physical layer. The application layer is object-based with objects provided for most generic data formats. The data link layer provides for several methods of retrieving data such as polling for classes and object variations. The physical layer defines a simple RS-232 or RS-485 interface and an Ethernet interface.

Harris, Distributed Automation Products, developed DNP. In November 1993, responsibility for defining further DNP specifications and ownership of the DNP specifications was turned over to the DNP Users Group, a group composed of utilities and vendors who are utilising the protocol.

In order to ensure interoperability, longevity and upgrade ability of this protocol the DNP User Group has taken ownership of the protocol and assumes responsibility for its evolution. The DNP User Group Technical Committee evaluates suggested modifications or additions to the protocol and then amends the protocol description as directed by the User Group members.

DNP was developed to achieve interoperability among systems in the electric utility, oil & gas, water/waste water and security industries. The IEEE Standard 1379 (see D.1.5) was published in 1998. It recommends the use of either DNP 3 or IEC 60870-5-101 for remote terminal unit to intelligent electronic device messaging. DNP can also be implemented in any SCADA system for communications between substation computers, RTUs (Remote Terminal Unit, IEDs and master stations; over serial or LAN-based systems. As DNP is based on the IEC 60870-5-101 requirements (see D.4.7), DNP is suitable for application in the entire SCADA/EMS environment. This includes RTU to IED communications, master to remote communications, and even peer-to-peer instances and network applications.

D.4.10 IEC 61970

Title: Energy Management System Application Program Interface
Publication date: Future standard
Objective: Designed for electrical power SCADA
The document parts of IEC 61970 are shown in Table D-8.

Table D-8 IEC 61970 document parts

Standard	Title
IEC 61970-1	Guidelines and general requirements
IEC 61970-2	Glossary
IEC 61970-301	Common information model (CIM) base
IEC 61970-302	Common information model (CIM) financial, energy scheduling and reservations
IEC 61970-401	Component interface specification (CIS) framework
IEC 61970-402	Common data access facility

Standard	Title
IEC 61970-501	Common Information Model (CIM) XML Codification for Programmable Reference and Model Data Exchange

IEC 61970 specifies a Common Information Model (CIM) base set of packages which provide a logical view of the physical aspects of Energy Management System (EMS) information within the electric utility enterprise that is shared between applications. The CIM is an abstract model that represents all the major objects in an electric utility enterprise typically contained in an EMS information model.

By providing a standard way of representing power system resources as object classes and attributes, along with their relationships, the CIM facilitates the integration of EMS applications developed independently by different vendors, between entire EMS systems developed independently, or between an EMS system and other systems concerned with different aspects of power system operations, such as generation or distribution management. This is accomplished by defining standard application program interfaces to enable these applications or systems to access public data and exchange information independent of how such information is represented internally. The object classes represented in the CIM are abstract in nature and may be used in a wide variety of applications. The use of the CIM goes far beyond its application in an EMS. This standard should be understood as a tool to enable integration in any domain where a common power system model is needed to facilitate interoperability and plug compatibility between applications and systems independent of any particular implementation.

D.4.11 IEC 61968

Title: System Interfaces for Distribution Management
Publication date: Future standard
Objective: Designed for electrical power SCADA

IEC 61968 document parts are shown in Table D-9.

Table D-9 IEC 61968 document parts

Standard	Title
IEC 61968-1	Interface Architecture And General Requirements
IEC 61968-2	Glossary
IEC 61968-3	Interface Standard For Network Operation
IEC 61968-4	Interface Standard For Records And Asset Management
IEC 61968-5	Interface Standard For Operational Planning And Optimisation
IEC 61968-6	Interface Standard For Maintenance And Construction
IEC 61968-7	Interface Standard For Network Extension Planning
IEC 61968-8	Interface Standard For Customer Inquiry
IEC 61968-9	Interface Standard For Meter Reading And Control
IEC 61968-10	Interface Standard For Systems External To, But Supportive Of, Distribution Management

Standard	Title
IEC 61968-11	Distribution Information Exchange Model (DIEM)

IEC 61968 defines interfaces for the major elements of an interface-architecture for Distribution Management Systems (DMS). This standard identifies and establishes requirements for standard interfaces based on an Interface Reference Model (IRM). Subsequent parts of this standard are based on each interface identified in the IRM.

IEC 61968 is limited to the definition of interfaces and is implementation independence. They provide for interoperability among different computer systems, platforms, and languages. Methods and technologies used to implement functionality conforming to these interfaces are considered outside of the scope of these standards; only the interface itself is specified in these standards. As used in IEC 61968, a DMS consists of various distributed application components for the utility to manage electrical distribution networks. These capabilities include monitoring and control of equipment for power delivery, management processes to ensure system reliability, voltage management, demand-side management, outage management, work management, automated mapping and facilities management.

D.4.12 IEC 62271-003 (IEC 62210)

Title: Power system control and associated communications - Data and communication security
Publication date: Future technical report
Objective: Designed for safety, security and reliability in operation of systems in electrical utilities

IEC 62210 applies to computerised supervision, control, metering, and protection systems in electrical utilities. The content deals with security aspects related to communication protocols used within and between such systems, the access to, and use of the systems.

Safety, security and reliability have always been important issues in the design and operation of systems in Electrical Utilities. The deregulated market has imposed new threats: knowledge of assets of a competitor and the operation of his system can be beneficial and acquisition of such information is a possible reality.

D.5 Related specifications and reports

D.5.1 IEC 61400-25

Title: Wind turbines - Communication standard for remote control and monitoring of wind power plants
Publication date: Future standard
Objective: Designed for communication with wind power plants

This document provides a standard for interconnection of monitoring and control systems for wind power plants. It provides requirements relevant to the specification, engineering, use, testing, diagnosis, and maintenance of the information to be shared in wind power systems.

The standard has been prepared with the anticipation that it would be applied by:

- The wind power plant manufacturer striving to reuse the information models defined in this standard and to meet interoperability between devices
- The wind power plant purchaser in specifying such interoperability requirements

- The wind power plant planner for the system integration
- The wind power plant testing process

This standard re-uses the definitions specified in IEC 61850-7-4, IEC 61850-7-3, IEC 61850-7-2, IEC 61850-7-1, and IEC 61850-8-1. The document defines information, information description methods, and information exchange for monitoring and control systems for wind power plants. The information defined in this standard comprises mainly wind power plant specific information like status, counters, measurands, and control information of various parts of a wind power plant, e.g., turbine, generator, gear, rotor, and grid. This standard defines also a profile of generic information specified in IEC 61850-7-4 and 61850-7-3 for the use in this standard.

D.5.2 IEC 62195 TR

Title: Power system control and associated communications - Deregulated energy market communications
Publication date: Technical report published in April 2000
Objective: Designed for communication between market participants

IEC 62195 is a technical describing electronic communications in deregulated energy markets. It identifies the requirements and functional needs for communications in deregulated energy markets.

IEC 62195 makes a clear distinction between communications for control of energy systems and communications for the market. Addresses the interrelation and interworking between these separate fields.

E Cost Model

A cost model is described in terms of its cost breakdown structure and parameters, and cost estimating methods.

E.1 Cost breakdown structure and parameters

Collecting data to verify the cost model is an emerging science. Good cost data is available for simple automation schemes. Some data exists for migrating from simple automation schemes to LAN-based master-slave distributed processing within the substations. Very little data exists for new substations using advanced LAN-based peer-to-peer distributed processing within the substations, using the Utility WAN for communication outside of the substation.

Considering this situation, one objective of the cost model is to establish a framework for cost distribution in terms of a cost breakdown structure (CBS), and then identify those cost variables for which the Utility should collect data. These data will also provide the basis to verify the algorithms proposed in this cost model, or to recommend changes to the cost model.

E.1.1 Cost breakdown structure

A general framework for distributing cost is defined in terms of a CBS. CBS categories are easily mapped to a work breakdown structure (WBS), which can be used to accumulate actual costs. There is however a difference in the accuracy required for cost control of funded project as compared to that required for evaluating substation automation design alternatives. The framework should be such that actual or measured costs based on real projects can be aggregated, and used to estimate costs for each design alternative. This report addresses only the higher level of cost aggregation.

A recommended CBS framework for cost analysis is presented in Table E-1. General management and administrative support should be estimated as a percentage of base cost. Base cost is the sum of costs aggregated from estimates of engineering, design, construction, maintenance, support, test, and purchased component costs.

Table E-1 Recommended CBS framework for cost analysis

CBS identifier	Description	Cost parameter	Remarks
1.0	General management	GM	Estimate as a percentage of base cost
2.0	Administrative support	AS	Estimate as a percentage of base cost
3.0	Engineering	E	Base cost
4.0	Design	D	Base cost
5.0	Construction	C	Base cost
6.0	Maintenance	M	Base cost
7.0	Support	S	Base cost
8.0	Test	T	Base cost
9.0	Purchased components	PC	Base cost
10.0	Phase out	PO	Base cost

Within this framework, cost parameters linked to the substation automation target architecture need to be defined and identified as non-recurring costs or recurring costs. Of course these cost parameters are a function of both core requirements, and derived requirements to implement a candidate technology baseline. Risk management constraint parameters should also be included in these cost equations. Uncertainty in lower level cost estimates need to be rolled-up into the aggregate cost for each CBS identifier in Table E-1.

E.1.2 Non-recurring cost parameters

Non-recurring costs include initial facility development cost, and other one-time component costs based on the following parameters:

- Number of components, system deployment strategy.
- Costs to produce the component.
- Development cost: these are costs associated with specific designs, and testing prototype and models.
- Implementation costs expected to occur after approval of the design such as redesign.
- Various additional costs for licenses, fees, etc.
- Purchasing strategy parameters (schedule parameters dates of payment of the various components).

Qualitative parameters (environmental constraints, level of integration) and various risk parameters, economic factors, and technology dependant parameters (obsolescence, etc.) may be included in the component cost equations.

E.1.3 Recurring cost parameters

Recurring costs are scheduled training and maintenance costs that can be reliably predicted.

E.1.3.1 *Training cost*

Training is a time dependant parameter based on contracts with the system provider, or with the individual vendors providing system components. Due to the introduction of new technology, training cost tends to be higher during the initial building phase. With time the learning curve stabilizes and training cost are reasonably constant during the operational phase. Staff turnover is the principle factor that will determine the increase (multiplier) in training cost during the operational phase.

E.1.3.2 *Maintenance cost*

Maintenance is composed of two primary components:

- Annual fixed maintenance cost during operational phase based on annual expenditures for preventive and curative maintenance, dependent on failure rates.
- Maintenance cost during scheduled modernisation phases including repair and replacement costs estimated on the basis of predicted failure and replacement of major system components, and improvements necessary to bring the system up to current standards at given points in time.

Scheduled maintenance or predictive maintenance strategies should be considered to reduce maintenance cost, or to at least reduce the uncertainty in estimating maintenance cost. Two examples are repair versus replacement and software reengineering versus COTS (Commercial off the Shelf) software replacement.

E.2 Cost estimating methods

Today, industrial firms and utilities are adopting the life-cycle costing approach that has been developed and used by military organizations. Simply stated, LCC requires that decisions made during the Research and Development (R&D) process be evaluated against the total life-cycle cost of the substation automation system.

Life cycle costing requires that early estimates be made. The estimating method selected is based on the problem context (i.e., decisions to be made, required accuracy, complexity of the substation automation system, and the supplier's development status of system components and integration) and the operational considerations for deploying substation automation. Both informal and formal estimating methods are used. Table E-2 shows the advantages and disadvantages of each method.

Table E-2 Estimating methods

Estimating Technique	Application	Advantages	Disadvantages
Engineering estimates (empirical)	Reprocurement, Deployment and commissioning Development	• Most detailed technique • Best inherent accuracy • Provides best estimating base for future program changes	• Requires detailed program and product definition • Time-consuming and may be expensive • Subject to engineering bias • May overlook system integration costs
Parametric estimates and scaling (statistical)	Deployment and commissioning Development	• Application is simple and low cost • Statistical data base can provide expected values and prediction intervals • Can be used for equipment or systems prior to detail design or program planning	• Requires parametric cost relationships to be established • Limited frequently to specific subsystems or functional hardware of systems • Depends on quality and quantity of data used for statistical analysis • Limited by data and number of independent variables
Equipment or subsystem analogy estimates (comparative)	Reprocurement Deployment and commissioning Development Program planning	• Relatively simple • Low cost • Emphasizes incremental program and automation product changes • Good accuracy for similar systems	• Requires analogous product and program data • Limited to stable technology • Narrow range of applications • May be limited to systems and equipment build by the same supplier
Expert opinion	All program phases	Available when there are insufficient data, parametric cost relationships, or program and product definition	• Subject to bias • Increase product or program complexity can degrade estimates • Estimate substantiation is not quantifiable

One can see from the list of advantages and disadvantages the strong coupling between risk management discussed earlier and cost estimating. For example, complexity and lack of stable automation technology specifications increase risk and limit or degrade cost estimates.

Table E-3 shows the opportunity for cost reduction at the end of each life-cycle phase[14]. These data were collected by the United States Department of Defence. At the end of the demonstration and validation phase (which is completion of R&D) 85 percent of the decisions affecting the total life cycle cost will have been made, and the cost reduction opportunity is

[14] These numbers have not been validated and should only be used as examples.

limited to a maximum of 22 percent (excluding the effects of learning curve experiences). Following deployment and commissioning, 95 percent of the decisions will have been made, and the cost reduction opportunity is limited to 15 percent, which can be realized during the operation phase. Table E-3 shows, from a business point-of-view, the importance of trade-off studies and prototype demonstration to validate the design decisions.

Table E-3 Opportunity for cost reduction

End of Life-cycle phase	% Cost Reduction Opportunity	% Decisions affecting LCC will have been made	Remark
Conceptual definition	35	70	Trade-off studies and recommendations accepted
Demonstration and validation	22	85	Prototype operated under reasonable load conditions validates design.
Deployment and commissioning	15	95	

Table E-4 shows that at the end of concept formulation, 70 percent of the cumulative life cycle cost is committed by the utility. Clearly, this shows the importance of spending the time and energy to establish a concrete substation automation baseline supported by a realistic operational scenario, well defined system alternatives, and freezing the subsystem configurations.

Table E-4 Actions affecting life cycle cost

Program Phase	Action	Cumulative percent of LCC committed
Concept formulation	Describe operational scenario	20
	Define fixed and tradable alternatives	27
	Develop system alternatives	45
	Identify and freeze subsystem configurations	70
Concept validation	Provide system deployment feasibility	75
	Validate prototype configurations	85
Development	Provide preliminary designs	87
	Provide detailed designs	90
	Provide operations and product support plans	95
Deployment and commissioning	Integrated system test complete	97

Based on the lessons learned from validating substation automation prototype configurations, 85 percent of the cumulative life cycle cost is committed by the utility. At this point, the utility should have sufficient confidence in their risk management/containment plan and understanding of life cycle cost to proceed with the first phase of acquisition.

Completing detailed designs supported by operations and product support plans by the selected suppliers will increase to 95 percent the cumulative life cycle cost committed by the utility.

Based on satisfactory completion of integrated system test and commissioning of the automation substations in phase one, 97 percent of the cumulative life cycle cost is committed by the utility.

Thus, for every 12 percent of LCC that the utility puts into R&D, 28 percent is needed downstream for development, deployment and commissioning, and 60 percent is needed for operations and support.

