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Kommunikationsnetværk og systemer i understationer – Del 5: Kommunikationskrav til funktioner og enhedsmodeller

Communication networks and systems in substations – Part 5: Communication requirements for functions and device models

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EUROPEAN STANDARD **EN 61850-5**

NORME EUROPÉENNE

EUROPÄISCHE NORM October 2003

ICS 33.200

English version

Communication networks and systems in substations
Part 5: Communication requirements for functions and device models
(IEC 61850-5:2003)

Réseaux et systèmes de communication dans les postes
Partie 5 : Prescriptions relatives à la communication pour les fonctions et les modèles de dispositifs
(CEI 61850-5:2003)

Kommunikationsnetze und -systeme in Stationen
Teil 5: Kommunikationsanforderungen für Funktionen und Gerätemodelle
(IEC 61850-5:2003)

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European Committee for Electrotechnical Standardization
Comité Européen de Normalisation Electrotechnique
Europäisches Komitee für Elektrotechnische Normung

Central Secretariat: rue de Stassart 35, B - 1050 Brussels

Ref. No. EN 61850-5:2003 E

Foreword

The text of document 57/641/FDIS, future edition 1 of IEC 61850-5, prepared by IEC TC 57, Power system control and associated communications, was submitted to the IEC-CENELEC parallel vote and was approved by CENELEC as EN 61850-5 on 2003-10-01.

The following dates were fixed:

– latest date by which the EN has to be implemented at national level by publication of an identical national standard or by endorsement	(dop)	2004-07-01
– latest date by which the national standards conflicting with the EN have to be withdrawn	(dow)	2006-10-01

Annexes designated "normative" are part of the body of the standard.
Annexes designated "informative" are given for information only.
In this standard, annex ZA is normative and annexes A to J are informative.
Annex ZA has been added by CENELEC.

Endorsement notice

The text of the International Standard IEC 61850-5:2003 was approved by CENELEC as a European Standard without any modification.

Annex ZA
(normative)

Normative references to international publications with their corresponding European publications

This European Standard incorporates by dated or undated reference, provisions from other publications. These normative references are cited at the appropriate places in the text and the publications are listed hereafter. For dated references, subsequent amendments to or revisions of any of these publications apply to this European Standard only when incorporated in it by amendment or revision. For undated references the latest edition of the publication referred to applies (including amendments).

NOTE When an international publication has been modified by common modifications, indicated by (mod), the relevant EN/HD applies.

Publication	Year	Title	EN/HD	Year
IEC 60044-8	- [1)]	Instrument transformers Part 8: Electronic current transformers	EN 60044-8	2002 [2)]
IEC 60870-4	- [1)]	Telecontrol equipment and systems Part 4: Performance requirements	HD 546.4 S1	1992 [2)]
IEC 61346	Series	Industrial systems, installations and equipment and industrial products - Structuring principles and reference designations	EN 61346	Series
IEC/TS 61850-2	- [1)]	Communication networks and systems in substations Part 2: Glossary	-	-
IEC 62053-22	- [1)]	Electricity metering equipment (a.c.) - Particular requirements Part 22: Static meters for active energy (classes 0,2 S and 0,5 S)	EN 62053-22	2003 [2)]
IEEE C37.2	1996	Electrical Power System Device Function Numbers and Contact Designations	-	-

[1)] Undated reference.

[2)] Valid edition at date of issue.

INTERNATIONAL STANDARD

IEC 61850-5

First edition
2003-07

Communication networks and systems in substations –

Part 5: Communication requirements for functions and device models

Reference number
IEC 61850-5:2003(E)

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INTERNATIONAL ELECTROTECHNICAL COMMISSION

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COMMUNICATION NETWORKS AND SYSTEMS IN SUBSTATIONS –

Part 5: Communication requirements for functions and device models

FOREWORD

1) The International Electrotechnical Commission (IEC) is a worldwide organization for standardization comprising all national electrotechnical committees (IEC National Committees). The object of IEC is to promote international co-operation on all questions concerning standardization in the electrical and electronic fields. To this end and in addition to other activities, IEC publishes International Standards, Technical Specifications, Technical Reports, and Guides (hereafter referred to as "IEC Publication(s)"). Their preparation is entrusted to technical committees; any IEC National Committee interested in the subject dealt with may participate in this preparatory work. International, governmental and non-governmental organizations liaising with the IEC also participate in this preparation. IEC collaborates closely with the International Organization for Standardization (ISO) in accordance with conditions determined by agreement between the two organizations.
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International Standard IEC 61850-5 has been prepared by IEC technical committee 57: Power system control and associated communications.

The text of this standard is based on the following documents:

FDIS	Report on voting
57/641/FDIS	57/649/RVD

Full information on the voting for the approval of this standard can be found in the report on voting indicated in the above table.

This publication has been drafted in accordance with the ISO/IEC Directives, Part 2.

The content of this part of IEC 61850 is based on existing or emerging standards and applications. In particular the approach to formulate the requirements is based upon

CIGRE Technical Report, Ref. No. 180, *Communication requirements in terms of data flow within substations*. CE/SC 34 03, 2001, 112 pp. Ref. No. 180

K.P. Brand, *Communication requirements in terms of data flow within substations – Results of WG34.03 and standardization within IEC*, **Electra** 173, 77-85 (1997)

IEEE-SA TR 1550-2003: *IEEE-SA Technical Report on Utility Communications Architecture (UCA™), Version 2.0, Part 4: UCA Generic Object Models for Substation and Feeder Equipment (GOMSFE).*

IEC 61850 consists of the following parts, under the general title *Communication networks and systems in substations*.

Part 1: *Introduction and overview*

Part 2: *Glossary* [1]

Part 3: *General requirements*

Part 4: *System and project management*

Part 5: *Communication requirements for functions and device models*

Part 6: *Configuration description language for communication in electrical substations related to IEDs* [2]

Part 7-1: *Basic communication structure for substation and feeder equipment – Principles and models*

Part 7-2: *Basic communication structure for substation and feeder equipment – Abstract communication service interface (ACSI)*

Part 7-3: *Basic communication structure for substation and feeder equipment – Common data classes*

Part 7-4: *Basic communication structure for substation and feeder equipment – Compatible logical node classes and data classes*

Part 8-1: *Specific communication service mapping (SCSM) – Mappings to MMS (ISO/IEC 9506-1 and ISO/IEC 9506-2) and to ISO/IEC 8802-3* [2]

Part 9-1: *Specific communication service mapping (SCSM) – Sampled values over serial unidirectional multidrop point to point link*

Part 9-2: *Specific communication service mapping (SCSM) – Sampled values over ISO/IEC 8802-3* [2]

Part 10: *Conformance testing* [2]

This publication has been drafted in accordance with the ISO/IEC Directives, Part 2.

The committee has decided that the contents of this publication will remain unchanged until 2005. At this date, the publication will be

- reconfirmed;
- withdrawn;
- replaced by a revised edition, or
- amended.

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1 To be published.

2 Under consideration.

INTRODUCTION

The IEC 61850 series is intended to provide interoperability between all devices in substations. Communication between these devices has to fulfil a lot of requirements imposed by all the functions to be performed in substations. Depending on the philosophy both of the vendor and of the user and on the state-of-the-art in technology, the allocation of functions to devices and control levels is not commonly fixed. This results in different requirements for the different communication interfaces within the substation. The IEC 61850 series shall support any allocation of functions.

The IEC 61850 series should have a long lifetime but be able to follow the fast changes in communication technology by both its technical approach and its document structure. Figure 1 shows the relationship of this part of the IEC 61850 series to subsequent parts of the IEC 61850 series. The IEC 61850 series has been organized so that changes to one part do not require a significant rewriting of another part, i.e. the parts are based on the communication requirements in this part of the IEC 61850 series; the derived modelling requirements in subsequent parts will not change the requirements of this part of the IEC 61850 series. The general parts, the requirement specification and the modelling parts are independent from any implementation. The implementation needed for the use of the IEC 61850 series is defined in some dedicated parts.

This part of the IEC 61850 series defines the communication requirements for functions and device models for substations.

The modelling of communication requires the definition of objects (for example, data objects, data sets, report control, log control) and services provided by objects (for example, get, set, report, create, delete). This is defined in IEC 61850-7-x with a clear interface to implementation. To use the benefits of communication technology, in the IEC 61850 series, no new OSI stacks are defined but a standardized mapping on existing stacks is given in IEC 61850-8-x and IEC 61850-9-x. A substation configuration language (IEC 61850-6) and a standardized conformance testing complement the IEC 61850 series. Figure 1 shows the general structure of the documents of the IEC 61850 series, as well as the relative position of IEC 61850-5 within this series.

NOTE To keep the layered approach of the IEC 61850 series which does not mix application and implementation requirements, terms such as client, server, data objects, etc. are normally not used in this part of the IEC 61850 series (requirements). In IEC 61850-7-x (modeling), IEC 61850-8-x and IEC 61850-9-x (specific communication service mapping) terms belonging to application requirements such as PICOMs are normally not used.

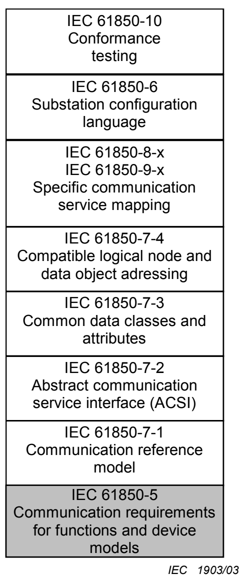

Figure 1 – Relative position of this part of the IEC 61850 series

COMMUNICATION NETWORKS AND SYSTEMS IN SUBSTATIONS –

Part 5: Communication requirements for functions and device models

1 Scope

This part of IEC 61850 applies to Substation Automation Systems (SAS). It standardizes the communication between intelligent electronic devices (IEDs) and the related system requirements.

The specifications of this part refer to the communication requirements of the functions being performed in the substation automation system and to device models. All known functions and their communication requirements are identified.

The description of the functions is not used to standardize the functions, but to identify communication requirements between technical services and the substation, and communication requirements between Intelligent Electronic Devices within the substation. The basic goal is interoperability for all interactions.

Standardizing functions and their implementation is completely outside the scope of this part of IEC 61850. Therefore, a single philosophy for allocating functions to devices cannot be assumed in the IEC 61850 series. To support the resulting request for free allocation of functions, a proper breakdown of functions into parts relevant for communication is defined. The exchanged data and their required performance are defined. These definitions are supplemented by informative data flow calculations for typical substation configurations.

Intelligent electronic devices from substations such as protective devices are also found in other installations such as power plants. Using this part of IEC 61850 for such devices in these plants also would facilitate the system integration but this is beyond the scope of this part of IEC 61850.

2 Normative references

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

IEC 60044-8, *Instrument transformers – Part 8: Electronic current transformers*

IEC 60870-4, *Telecontrol equipment and systems – Part 4: Performance requirements*

IEC 61346 (all parts), *Industrial systems, installations and equipment and industrial products – Structuring principles and reference designations*

IEC 61850-2, *Communication networks and system in substations – Part 2: Glossary* [3]

IEC 62053-22, *Electricity metering equipment (a.c.) – Particular Requirements – Part 22: Static meters for active energy (classes 0,2 S and 0,5 S)*

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3 To be published.

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

NOTE Informative references are found in the Bibliography.

3 Terms and definitions

For the purpose of this part of IEC 61850, the following terms and definitions as well as those given in IEC 61850-2[4], apply.

3.1
function
task which is performed by the substation automation system. Generally, a function consists of subparts called logical nodes, which exchange data with each other. By definition, only logical nodes exchange data and, therefore, a function that exchanges data with other functions must have at least one logical node. As a consequence, only data contained in logical nodes can be exchanged in the context of the IEC 61850 series.

3.2
distributed function
function which is performed in two or more logical nodes that are located in different physical devices. Since all functions communicate in some way, the definition of a local or a distributed function is not unique but depends on the definition of the functional steps to be performed until the function is completed. In case of the loss of one LN or one related communication link, the function may be blocked completely or show a graceful degradation, if applicable.

3.3
system
set of interacting entities which perform a common functionality. Its backbone is some communication mechanism.

3.3.1
logical system
communicating (via its logical nodes) set of all application functions performing some overall task such as “management of a substation” in the context of IEC 61850

3.3.2
physical system
interaction set of all devices hosting these functions and the interconnecting physical communication network. The boundary of a system is given by its logical or physical interfaces. Examples are industrial systems, management systems, information systems, and within the scope of the IEC 61850 series, substation automation systems. The backbone of physical system is its communication system.

3.3.3
substation automation system
system which operates, protects, monitors, etc. the substation, i.e. the primary system. For this purpose, it uses fully numerical technology and serial communication links (communication system).

3.3.4
primary system
common term for all power system equipment and switchgear

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4 To be published.

3.3.5
secondary system
interaction set of all components and systems in the substation for operation, protection, monitoring, etc, i.e. the primary system. In case of full application of numerical technology, the secondary system is synonymous with the substation automation system.

3.3.6
communication system
interconnected set of all communication links

3.4
device
mechanism or piece of equipment designed to serve a purpose or perform a function, for example a breaker, relay, or substation computer. Communication relevant properties are described in a proper device related model.

3.4.1
intelligent electronic device
is any device incorporating one or more processors with the capability to receive or send data/control from or to an external source, for example electronic multifunction meters, digital relays, controllers. An entity capable of executing the behavior of one or more specified logical nodes in a particular context and delimited by its interfaces. If not stated otherwise intelligent electronic devices have an internal clock by definition providing for example time tags. This adds the requirement of a system wide time synchronization of all these clocks if applicable.

3.4.2
physical device
equivalent to an intelligent electronic device as used in the context of the IEC 61850 series

3.5
Logical Node
LN
smallest part of a function that exchanges data. A Logical Node (LN) represents the function within a physical device; it performs some operations for that function. A LN is an object defined by its data and methods. Logical nodes related to primary equipment are not the primary equipment itself but its intelligent part or image in the secondary system, i.e. local or remote I/Os, intelligent sensors and actuators, etc.

3.6
connection
the links between entities

3.6.1
logical connection
communication link between logical nodes

3.6.2
physical connection
communication link between physical devices

3.7
interchangeability
the possibility to replace a device from the same vendor, or from different vendors, utilizing the same communication interface and as a minimum, providing the same functionality, and with no impact on the rest of the system. If differences in functionality are accepted, the exchange may also require some changes somewhere in the system. Interchangeability requires standardization of functions and, in a strong sense, of devices also. Both such requirements are outside the scope of the IEC 61850 series.

3.8
interoperability
ability of two or more intelligent electronic devices from the same vendor, or different vendors, to exchange information and use that information for correct co-operation. Interoperability is a prerequisite of interchangeability.

3.9
PICOM
Piece of Information for COMmunication describing an information transfer on a given logical connection with given communication attributes between two logical nodes. It also contains the information to be transmitted and, in addition, requirement attributes such as performance. It does not represent the actual structure and format for data that is exchanged over the communication network. This information is found in the parts IEC 61850-8 and IEC 61850-9. The assumed logical point-to-point connection describes the source and sink of this information transfer but does not prescribe the communication procedures. Therefore, multicast and broadcast procedures are not excluded.

NOTE The PICOM approach was adopted from CIGRE working group 34.03 (according to CIGRE – Technical Report, Ref.No.180) and allows for performance requirements also.

3.10
bay
closely connected subparts of the substation with some common functionality. Examples are the switchgear between an incoming or outgoing line and the busbar, the buscoupler with its circuit breaker and related isolators and earthing switches, the transformer with its related switchgear between the two busbars representing the two voltage levels, the diameter (see definition) in a 1½ breaker arrangement, virtual bays in ring arrangements (breaker and adjacent isolators), etc. These subparts very often comprise a device to be protected such as a transformer or a line end. The control of the switchgear in such a subpart has some common restrictions like mutual interlocking or well-defined operation sequences. The identification of such subparts is important for maintenance purposes (what parts may be switched off at the same time with a minimum impact on the rest of the substation) or for extension plans (what has to be added if a new line is linked in). These subparts are called “bays” and are managed by devices with the generic names “bay controller” and “bay protection”. The functionality of these devices represents an additional logical control level below the overall station level that is called “bay level”. Physically, this level must not exist in any substation; i.e. there may be no physical device “bay controller” at all.

3.11
diameter
applies to a 1½-breaker arrangement and comprises the complete switchgear between the two busbars, i.e. the 2 lines and the 3 circuit breakers with all related isolators, earthing switches, CTs and VTs. The diameter has some common functional relationship both for operation, maintenance and extensions.

3.12
level functions
functions related to some control levels of the substation automation system

3.12.1
bay level functions
functions using mainly the data of one bay and acting mainly on the primary equipment of one bay. The definition of bay level functions considers some kind of a meaningful substructure in the primary substation (see 3.10) configuration and, related to this substructure, some local functionality or autonomy in the secondary system (substation automation). Examples for such functions are line protection or bay control. These functions communicate via the logical interface 3 within the bay level and via the logical interfaces 4 and 5 to the process level, i.e. with any kind of remote I/Os or intelligent sensors and actuators. Interfaces 4 and 5 may be hardwired also but hardwired interfaces are beyond the scope of the IEC 61850 series.

3.12.2
process level functions
all functions interfacing to the process, i.e. basically binary and analogue I/O functions such as data acquisition (including sampling) and issuing of commands. These functions communicate via the logical interfaces 4 and 5 to the bay level.

3.12.3
station level functions
refer to the substation as a whole. There are two classes of station level functions; i.e. process related station level functions and Interface related station level functions

3.12.4
process related station level functions
functions using the data of more than one bay or of the complete substation and acting on the primary equipment of more than one bay or of the complete substation. Examples of such functions are station-wide interlocking, automatic sequencers or busbar protection. These functions communicate mainly via the logical interface 8.

3.12.5
interface related station level functions
functions representing the interface of the SAS to the local station operator HMI (Human Machine Interface), to a remote control center TCI (telecontrol interface) or to the remote engineering workplace for monitoring and maintenance TMI (telemonitoring interface). These functions communicate via the logical interfaces 1 and 6 with the bay level and via the logical interface 7 and the remote control interface to the outside world. Logically, there is no difference if the HMI is local or remote. In the context of the substation at least a virtual interface for the SAS at the boundary of the substation exists. The same applies both for the TCI and TMI. These virtual interfaces may be realised in some implementations as proxy servers.

4 Abbreviations

GPS	Global Positioning System (time source)
HMI	Human Machine Interface
I/O	Input and Output contacts or channels (depending on context)
IED	Intelligent Electronic Device
IF	(Serial) Interface
LAN	Local Area Network
LC	Logical Connection
LN	Logical Node
MMS	Manufacturing Message Specification
NCC	Network Control Center
OSI	Open System Interconnection
PC	Physical Connection
PD	Physical Device
PICOM	Piece of Information for COMmunication
SAS	Substation Automation System
TCI	TeleControl Interface (for example, to NCC)
TMI	TeleMonitoring Interface (for example, to engineers workplace)

5 Substation automation system functions

5.1 Introduction

The functions of a substation automation system (SAS) refer to tasks, which have to be performed in the substation. These are functions to control, monitor and protect the equipment of the substation and its feeders. In addition, there exist functions, which are needed to maintain the SAS, i.e. for system configuration, communication management or software management.

5.2 Logical allocation of functions and interfaces

The functions of a substation automation system may be logically allocated on three different levels (station, bay/unit, or process). These levels are shown by the logical interpretation of Figure 2 together with the logical interfaces 1 to 10.

a) *Process level functions* are all functions interfacing to the process. These functions communicate via the logical interfaces 4 and 5 to the bay level.

b) *Bay level functions* (see bay definition in Clause 3) are functions using mainly the data of one bay and acting mainly on the primary equipment of one bay. These functions communicate via the logical interface 3 within the bay level and via the logical interfaces 4 and 5 to the process level, i.e. with any kind of remote I/Os or intelligent sensors and actuators. Interfaces 4 and 5 may also be hardwired, but hardwired interfaces are beyond the scope of the IEC 61850 series.

c) There are two classes of *station level functions*:

   1) *Process related station level functions* are functions using the data of more than one bay or of the complete substation and acting on the primary equipment of more than one bay or of the complete substation. These functions communicate mainly via the logical interface 8.

   2) *Interface related station level functions* are functions representing the interface of the SAS to the local station operator HMI (Human Machine Interface), to a remote control center TCI (TeleControl Interface) or to the remote engineering for monitoring and maintenance TMI (TeleMonitoring Interface). These functions communicate via the logical interfaces 1 and 6 with the bay level and via the logical interface 7 and the remote control interface to the outside world.

NOTE 1 Interface 2 regarding remote protection (teleprotection) is outside the scope of this part of IEC 61850. Since the same kind of data is exchanged over this interface as within the substation, the future use of the IEC 61850 series is recommended.

NOTE 2 The remote control interface to the network control center (IF10) is outside the scope of this part of IEC 61850. The related IEC standards are IEC 60570-5-101 and IEC 60570-5-104. To reduce the efforts for the gateway to the NCC, a future alignment would be very convenient. Since partly the same data are exchanged between the control centers as between the substation and the NCC, a coordination with the related standard IEC 60870-6 (TASE2) is recommended. The standard should be used for a future seamless communication structure from the process level to the network control center. Since the use of interface 7 and the interface 10 may be overlapping, a co-ordination of the standards for both interfaces is recommended.

NOTE 3 Process level and bay level functions in particular may be found integrated in a single device without a physical separation. This does not change the logical structure but the physical implementation (see 5.3).

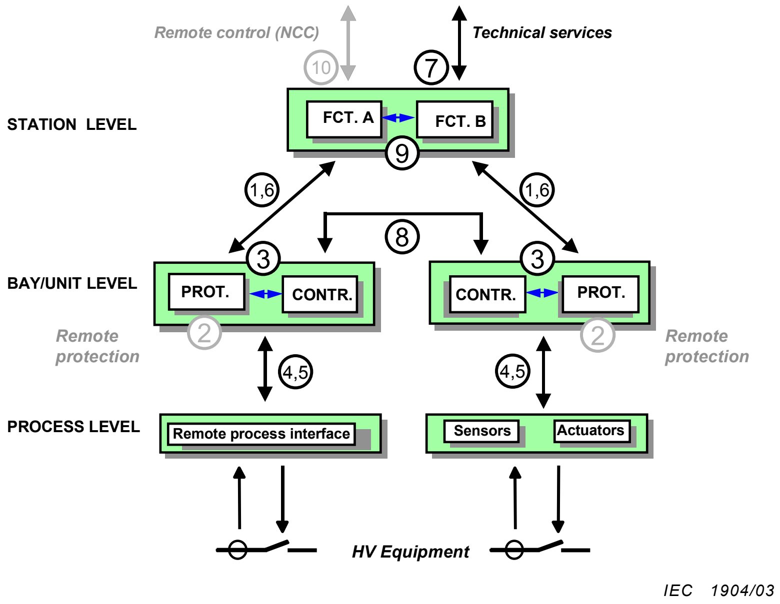

Figure 2 – Levels and logical interfaces in substation automation systems

The meaning of the interfaces

IF1: protection-data exchange between bay and station level

IF2: protection-data exchange between bay level and remote protection (outside the scope of this part of IEC 61850)

IF3: data exchange within bay level

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

IF5: control-data exchange between process and bay level

IF6: control-data exchange between bay and station level

IF7: data exchange between substation (level) and a remote engineer's workplace

IF8: direct data exchange between the bays especially for fast functions such as interlocking

IF9: data exchange within station level

IF10: control-data exchange between substation (devices) and a remote control center (outside the scope of this part of IEC 61850)

The devices of a substation automation system may be installed **physically** on different functional levels (station, bay, and process). This refers to the physical interpretation of Figure 2.

NOTE 4 The distribution of the functions in a communication environment may occur through the use of wide area network, local area network, and process bus technologies. The functions are not constrained to be deployed within/over any single communication technology.

1) *Process level devices* are typically remote process interfaces such as I/Os, intelligent sensors and actuators connected by a process bus as indicated in Figure 2.

2) *Bay level devices* consist of control, protection or monitoring units per bay.

3) *Station level devices* consist of the station computer with a database, the operator's workplace, interfaces for remote communication, etc.

5.3 The physical allocation of functions and interfaces

Despite of the similarity of logical and physical levels there is no unique way for mapping the logical function structure to the physical device structure. The mapping is dependent on availability and performance requirements, cost constraints, the state of the art in technology, etc.

The *station computer* may act as a client only with the basic HMI, TCI and TMI functions. All other station level functions may be distributed completely over the bay level devices. In this case, the interface 8 is the backbone of the system. On the other side, all station wide functions such as interlocking etc. may reside in the station computer acting now both as client and server. In this case, the interface 1 and 6 take over the complete functionality of interface 8. Many other solutions are possible.

The bay level functions may be implemented in dedicated *bay level devices* (protection unit, control unit, without or with redundancy) or in combined protection and control units. Some may be moved physically down to the process level supported by the free allocation of functions.

If there are no serial interfaces 4 and 5, the process level functions are implemented in the bay level devices. The realization of the serial interfaces 4 and 5 may include remote I/O devices only or intelligent sensors and actuators, which provide some bay level functionality on process level already.

The logical interfaces may be implemented as dedicated physical interfaces (plugs). Two or more may also be combined into a single common physical interface. In addition, these interfaces may be combined and implemented into one or more physical LANs. The requirements for these physical interfaces depend upon the allocation of functions to levels and devices.

5.4 The role of interfaces

Not all interfaces have to be present in a substation. This flexible approach covers both the retrofit of existing substations and the installation in new substations, at present and in the future.

The numbering of interfaces according to Figure 2 is helpful for the identification of the type of interfaces needed in substations and for data flow calculations.

The interface numbers allow the easy definition of the two important LANs or bus systems: Often, interfaces 1, 6, 3, 9, 8 are combined with the **station/interbay bus** since it connects both the station level with the bay level and the different bay level IEDS with each other. Interfaces 4 and 5 are combined with the **process bus**, which connects the bay level with the process level and the different process level IEDs with each other. Very often, the process bus is restricted to one single bay only. If the process bus is extended to other bays, it may also take over the role of interface 8, at least for raw data.

Interface 7 is dedicated for external communication with a remote monitoring center. It could also be realized by a direct interface to the station/interbay bus. Interface 2, dedicated to communication with a remote protection device and interface 10, dedicated to remote control are outside the scope of this part of IEC 61850 (see also NOTE 1 and NOTE 2 of 5.2).

According to the function allocation, the message types of Clause 13 based on communication performance requirements may be assigned to the different interfaces. The free allocation of functions means that such an assignment may not be common for all substation automation systems.

6 Goal and requirements

6.1 Interoperability

The goal of the IEC 61850 series is to provide interoperability between the IEDs from different suppliers or, more precisely, between functions to be performed in a substation but residing in equipment (physical devices) from different suppliers. Interchangeability is outside the scope of IEC 61850. Interchangeability needs in addition to the interoperability according to IEC 61850 also standardized functionality (see 3.1).

Interoperability for devices from different suppliers has the following aspects:

a) the devices shall be connectable to a common bus with a common protocol (syntax);

b) the devices shall understand the information provided by other devices (semantics);

c) the devices shall together perform a common or joint function if applicable (distributed functions).

Since there are no constraints regarding system structure and data exchange, some static and dynamic requirements shall be fulfilled to provide interoperability.

6.2 Static design requirements

The goal of interoperability for any configuration results in the following requirements, which are not completely independent from each other:

a) The free allocation of functions to devices shall be supported by the communication; i.e. communications must be able to permit any function to take place in any device. It does not mean that all devices must support all functions.

b) The functions of the substation automation system (SAS) and their communication behavior shall be described device independent, i.e. with no reference to any implementation in IEDs.

c) The functions shall be described only as far as necessary for the identification of the information to be exchanged.

d) The interaction of device independent distributed functions shall be described by the logical interfaces in between. These logical interfaces may be freely allocated to physical interfaces or LANs for implementation.

e) The functions used today and their communication requirements are well known but the IEC 61850 series shall be open also for communication requirements arising from future functions.

6.3 Dynamic interaction requirements

The goal of interoperability for any data exchange results in the following requirements, which are not completely independent from each other:

a) The IEC 61850 series shall define generic information to be communicated and generic communication behavior of the functions to support planned and future functional extensions of the substation automation system. Extension rules shall be given.

b) The information transfer data shall be defined with all related attributes (see PICOMs).

c) The exchanged data shall carry all attributes for an unambiguous understanding of the receiver.

d) The acceptable overall transfer time of exchanged data shall be defined and guaranteed in any situation.

6.4 Response behavior requirements

Since interoperability is also claimed for a proper running of functions, the reaction of the application in the receiving node has to be considered.

a) The reaction of the receiving node has to fit into the overall requirement of the distributed function to be performed.

b) The basic behavior of the functions in any degraded case, i.e. in case of erroneous messages, lost data by communication interrupts, resource limitations, out of range data, etc. has to be specified. This is important if the overall task cannot be closed successfully, for example if the remote node does not respond or react in a proper way.

These requirements are function related local issues and, therefore, outside the scope of the IEC 61850 series. But the requirement left for the IEC 61850 series is the provision of proper quality attributes to be transferred with the data under consideration.

6.5 Approach to interoperability

To approach interoperability, the functions to be performed in substations are identified and categorized according to their different communication requirements in the rest of this document. The requirements for its data exchange shall be clearly defined. The interoperability for freely allocated and distributed functions implies a proper decomposition of functions in communicating entities. The requested mutual understanding of devices from different suppliers results in a proper data and communication service model (IEC 61850-7-x). The mapping of this model to state-of-the-art communication stacks shall be defined unambiguously (IEC 61850-8-x and IEC 61850-9-x).

6.6 Conformance test requirements

Interoperability depends both on the device properties and the system design and engineering. Conformance tests shall be performed to verify that the communication behavior of a device as system component is compliant with the interoperability specification of IEC 61850. These tests specify what shall be applied on a device to check that the communication function is correctly performed with a complementary device. Also the pass criteria have to be well defined. Conformance tests may involve the use of various simulators to represent the context of the substation and of the communication network.

Definitions of the conformance tests will be given in IEC 61850-10.[5]

7 Rules for function definition

To get the communication requirements in a substation, an identification of all functions is necessary. The function description considers the LN and PICOM approach and consists of three steps:

a) Function description including the decomposition into LNs.

b) Logical node description including the exchanged PICOMs.

c) PICOM description including the attributes.

Any identification of functions in substations will be incomplete, but the assumption is made that the identified functions cover in a very representative way all communication requirements in substations.

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[5] Under consideration.

7.1 Function description

The function description, given in Annex G, provides the following information

a) Task of the function.

b) Starting criteria for the function.

c) Result or impact of the function.

d) Performance of the function.

e) Function decomposition.

NOTE This point describes how functions are decomposed using LNs and how many decomposition sets typically exist. This information is very important since the communication is based on interacting LNs.

f) Interaction with other functions.

7.2 Logical Node description

The Logical Node description – given later in the body of this part of the IEC 61850 series – provides the following information:

a) grouping according to their most common application area;

b) short textual description of the functionality;

c) IEEE device function number if applicable (for protection and some protection related logical nodes only);

d) abbreviation/acronym used within the documents of the IEC 61850 series;

e) relation between functions and logical nodes in tables (see Annex H) and in the function description (see Annex G);

f) exchanged PICOMs described in tables (see Annex A).

7.3 PICOM description

The PICOM description – as given in Clause 10 – provides the following information:

a) semantics;

b) logical point-to-point connection;

c) performance requirements;

d) type of data.

8 Categories of functions

Different categories of functions are identified. Some functions may belong not only to the given category and its category allocation is only a convention. Only the functions are listed in the following Subclauses; the function description is given in Annex G.

8.1 System support functions

a) Network management.

b) Time synchronization.

c) Physical device self-checking.

8.2 System configuration or maintenance functions

a) Node identification.

b) Software management.

c) Configuration management.

d) Operative mode control of Logical Nodes.

e) Setting.

f) Test mode.

g) System security management.

8.3 Operational or control functions

a) Access security management.

b) Control.

c) Operational use of spontaneous change of indications.

d) Synchronous switching (point-on-wave switching).

e) Parameter set switching.

f) Alarm management.

g) Event (management and) recording.

h) Data retrieval.

i) Disturbance/fault record retrieval.

8.4 Local process automation functions

a) Protection function (generic).

b) Distance protection (example of protection function).

c) Bay interlocking.

d) Measuring, metering and power quality monitoring.

8.5 Distributed automatic support functions

a) Station-wide interlocking.

b) Distributed synchrocheck.

8.6 Distributed process automation functions

a) Breaker failure.

b) Automatic protection adaptation (generic).

c) Reverse blocking (For example, for automatic protection adaptation).

d) Load shedding.

e) Load restoration.

f) Voltage and reactive power control.

g) Infeed switchover and transformer change.

h) Automatic switching sequences.

9 The logical node concept

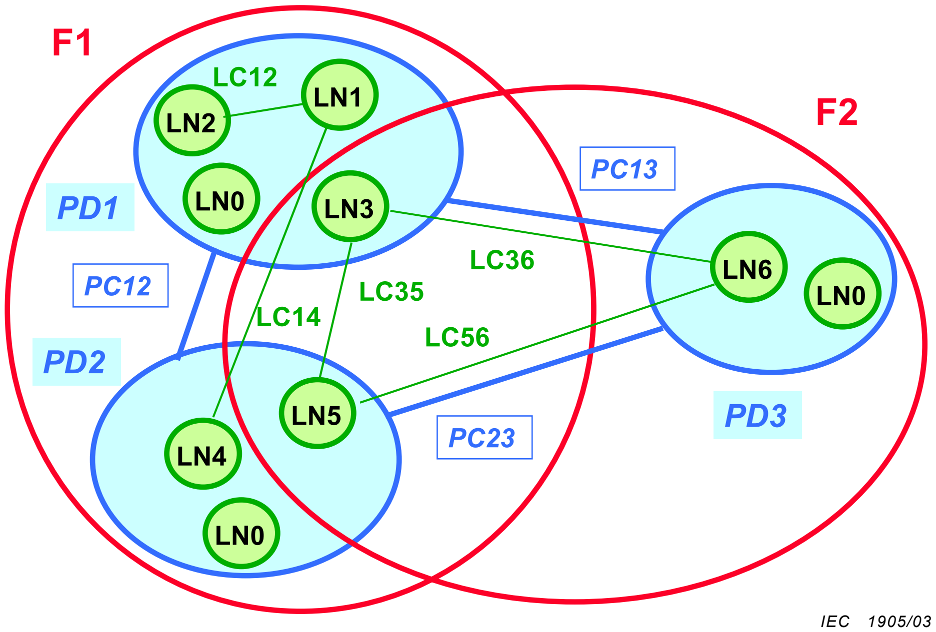
9.1 Logical nodes and logical connections

To fulfill all the requirements stated above, especially the free distribution and allocation of functions, all functions are decomposed into logical nodes (LN) that may reside in one or more physical devices. There are some data to be communicated which refer not to any function but to the physical device itself such as nameplate information or the result of device self-supervision. Therefore, a logical node “device” is needed and will be introduced as LLN0.

The LNs are linked by logical connections (LC) for a dedicated exchange of data in between. Therefore, the IEC 61850 series shall define the communication between these LNs.

This approach is shown in Figure 3. The logical nodes (LN) are both allocated to functions (F) and physical devices (PD). The logical nodes are linked by logical connections (LC), the devices by physical connections (PC). Any logical node is part of a physical device; any logical connection is part of a physical connection. The logical node "device" dedicated for any physical device is displayed as LN0 (in the four letter code introduced in Figure 3 for all logical nodes, LLN0).

Since it is impossible to define all functions for present and future use, or their distribution and interaction, it is very important to specify and standardize the interaction between the logical nodes in a generic way.



See 9.1 for an explanation.

Figure 3 – The logical node and link concept

9.2 The need for a formal system description

The static structure of the communication system describes where the data are potentially coming from (sending LN) and going to (receiving LN). This structure has to be engineered or negotiated during the set-up phase of the system. Opening and closing communication channels dynamically at run time will always refer to the given static structure. To control the free allocation and to create interoperable systems, a strong formal device and system description for communication engineering shall be provided. Such a formal description (substation configuration language) is defined in IEC 61850-6[6].

6 Under consideration.

9.3 Requirements for logical node behavior

Each receiving LN shall know what data are needed for performing its task; i.e. it shall be able to check if the delivered data are complete and valid and of the proper quality. In real-time systems such as substation automation, the most important validity criterion is the age of the data. The sending LN may set most quality attributes. The decision that data are “old” is the genuine task of the receiving LN. Missing or incomplete information is covered since in this case, no data with an acceptable age are available. Therefore, the requirements for communication providing interoperability between distributed LNs are reduced to the standardization of the data to be available or needed and the assignment of validity (quality) attributes in an appropriate data model as defined in IEC 61850-7-x.

The requirements mentioned above imply that the sending LN is also the source of the primary data, i.e. it keeps the most up-to-date values of these data, and that the receiving LN is processing these data for some related functionality. In case of mirrored data (data base image of the process, proxy server, etc.) these mirrored data shall be kept as up-to-date (“valid”) as needed by the function using these data.

In case of corrupted or lost data, the receiving LN cannot operate in a normal way, but may be in a degraded mode. Therefore, the behavior of the LN both in the normal and degraded mode has to be well defined, but the degradation behavior of the function has to be designed individually depending on the function and is beyond the scope of this part of IEC 61850. The other LNs of the distributed function and the system supervision shall also be informed about this degradation by a standardized message or proper data quality attributes, so that necessary actions are taken. If there is for example enough time, a request for sending valid data could also be sent out (retry). The detailed sequential behavior of the distributed functions cannot be standardized at all.

Examples of data based complex interoperability are the different interlocking algorithms (for example Boolean or topology based interlocking) which can be performed with the same data set (the position indications of the switchgear).

Since the Logical Node concept covers essential requirements in a consistent and comprehensive way, this concept itself is seen as a requirement, which shall be used in the detailed modeling given in IEC 61850-7-x.

9.4 Examples for decomposition of common functions into logical nodes

In Figure 4, there are examples of common functions given

a) synchronized circuit breaker switching;

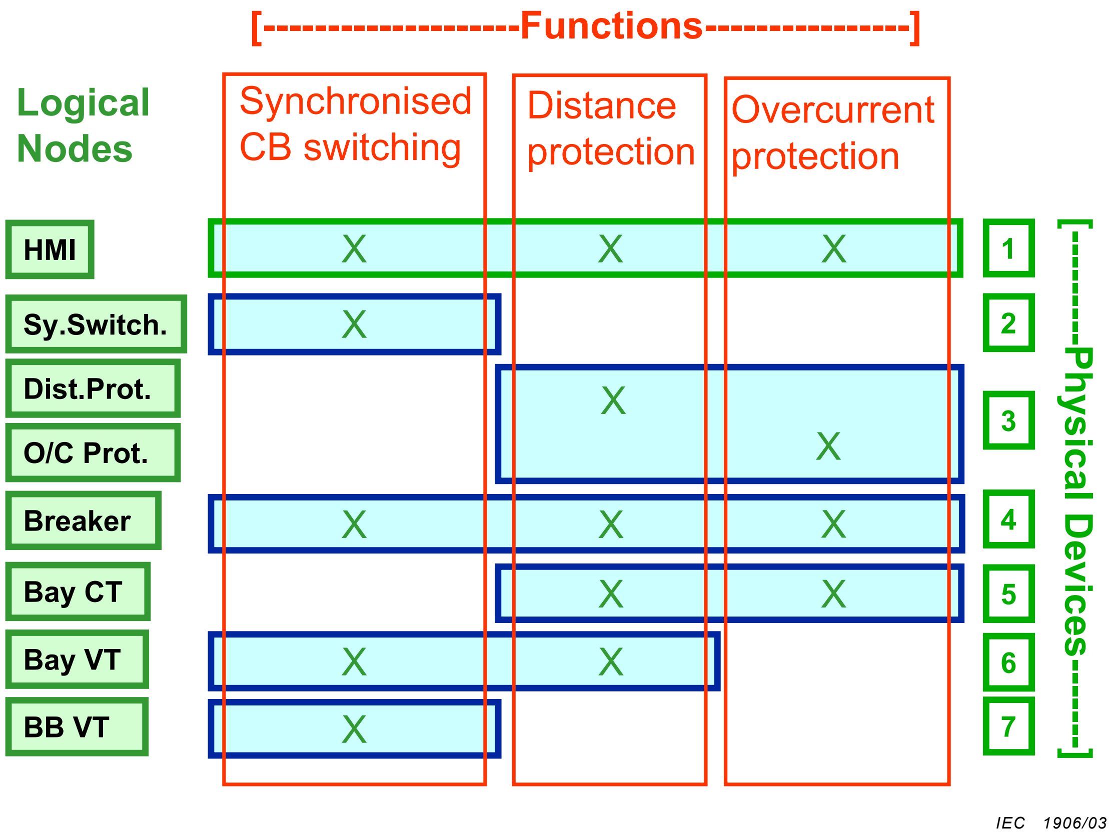
b) distance protection;

c) overcurrent protection.

The functions are decomposed into logical nodes listed in Figure 4, the allocated physical devices are described by numbers

1) Station computer.
2) Synchronized switching device.
3) Distance protection unit with integrated overcurrent function.
4) Bay control unit.
5) Current instrument transformer.
6) Voltage instrument transformer.
7) Busbar voltage instrument transformer.

The logical node “device” (LLN0) as contained in any physical device is not shown.



See 9.4 for explanations.

Figure 4 – Examples of the application of the logical node concept

10 The PICOM concept

PICOMs introduced by CIGRE WG34.03 (according to **CIGRE Technical Report, Ref.No.180**) are used to describe the information exchanged between LNs. The components or attributes of a PICOM are:

a) Data, meaning the content of the information and its identification as needed by the functions (semantics).

b) Type, describing the structure of the data, i.e. if it is an analog or a binary value, if it is a single value or a set of data, etc.

c) Performance meaning the permissible transmission time (defined by performance class), the data integrity and the method or cause of transmission (for example periodic, event driven, on request).

d) Logical connection, containing the logical source (sending logical node) and the logical sink (destination or receiving logical node).

NOTE PICOMs describe exchanged information ("content") and communication requirements ("attributes"). The "bits on the wire" are found in the mappings, i.e. in IEC 61850-8-x and IEC 61850-9-x.

10.1 Attributes of PICOMS

There are three types of attributes defined by their purpose.

10.1.1 PICOM attributes to be covered by any message

- Value: value of the information itself if applicable.
- Name: for identification of the data.
- Source: the LN where the signal comes from.
- Sink: the LN where the signal goes to.
- Time tag: absolute time to identify the age of the data if applicable.
- Priority of transmission: to be used for:
  - LN input queues (if more than one);
  - LN input and output (re-transmission order) in case of intermediate LNs.
- Time requirements: cycle time or overall transfer time to check the validity with help of the time tag.

NOTE To specify the communication requirements, pairs of sources and sinks have to be identified. Sometimes, multicast and broadcast messages may be more convenient for the communication, but this is a matter of implementation.

10.1.2 PICOM attributes to be covered only at configuration time

- Value for transmission (see 10.1.1): test or default value if applicable.
- Attributes for transmission (see 10.1.1).
- Accuracy: classes or values.
- Tag information: if time tagged or not (most data will be time tagged for validation).
- Type: analog, binary, file, etc.
- Kind: alarm, event, status, command, etc.
- Importance: high, normal, low.
- Data integrity: the importance of the transmitted information for checks and retransmissions (details formulated as requirements, see Clause 14).

10.1.3 PICOM attributes to be used for data flow calculations only

- Value for transmission/configuration: (see 10.1.1): test or default value if applicable.
- Attributes for transmission/configuration: (see 10.1.1).
- Format: value type of the signal: I, UI, R, B, BS, BCD, etc.
- Length: the length: i bit, j byte, k word.
- State of operation: reference to scenarios.

NOTE Format and length are a matter of implementation and not a requirement. For data flow calculations, assumptions about these two attributes have to be made.

10.2 PICOMs and data models

The information exchange described by PICOMs is based on data which are provided by LNs. Very often, these data are defined in a data model for the source (see for example IEC 81850-7-4). The result is that in the data model, there shall exist at least one data (status and values) or one data change (event) per PICOM.

11 List of logical nodes

Most of the functions consist of a minimum of three logical nodes, i.e. the LN with the core functionality itself, the process interface LN and the HMI (Human-Machine Interface) LN meaning human access to the function. If there is no process bus, the LNs of the remote process interface are allocated to another physical device (in the example shown in Figure 5, the physical "Protection device").

If we call a function for example "protection function" we refer mostly to its core functionality only. Therefore, the function list given for example in CIGRE working group 34.03 (published as CIGRE Technical Report, Ref.No.180) is a list of logical nodes according to definitions in the IEC 61850 series. The standardization of functions in substations is not within the scope of the IEC 61850 series. But if any of these functions is used, its communication shall be based on the LN structure. All details needed to model the communication based on the Logical Nodes defined here are given and standardized in IEC 61850-7-x.

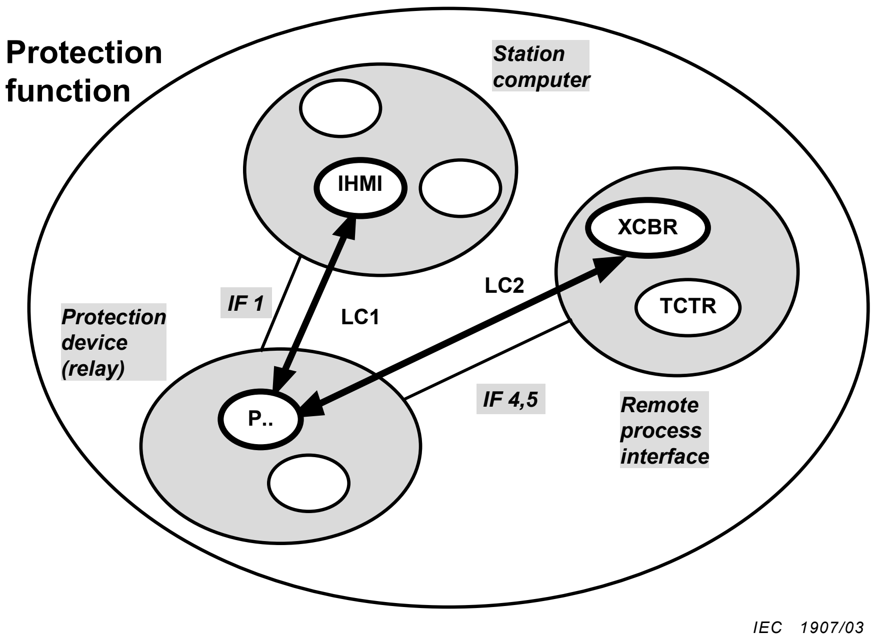


Figure 5 – Protection function consisting of 3 logical nodes

The 3 logical nodes (IHMI = operator interface, P..=protection, XCBR=circuit breaker to be tripped) residing in 3 physical devices (station computer, protection device and remote process interface). The abbreviations for LN designation are the same as those introduced in the tables of Clause 11.

Table columns of Clause 11

Logical Node displays a short description of the task of the LN for common understanding. For full understanding the data to be exchanged have to be considered also.

IEC 61850 means abbreviations/acronyms with a systematic syntax used by the IEC 61850 series

IEEE C37.2-1996 means device function numbers and contact designations used in IEEE if applicable

Description or comments displays the description of the IEEE device number if applicable or/and other descriptive text.

Note that the reference to the IEEE device number does not mean the related devices, but rather its core functionality (see definition of LN and Figure 5) in the context of this part of IEC 61850.

11.1 Logical Nodes for protection functions

11.1.1 Protection

Logical Node	IEC 61850	IEEE C37.2-1996	Description or comments
Transient earthfault protection	**PTEF**		Transient earth faults happen if there is a fault to ground (isolation breakdown) in compensated networks. The fault disappears very fast since there is not sufficient current to feed it. No trip happens but the fault direction/location has to be detected to repair the faulted part. At least the degradation of the impacted line/cable is reported.
Zero speed and underspeed protection	**PZSU**	14	An underspeed device is a device that functions when the speed of a machine falls below a pre-determined value.
Distance protection	**PDIS**	21	A distance relay is a relay that functions when the circuit admittance, impedance, or reactance increases or decreases beyond a predetermined value. The change of the impedance seen by PDIS is caused by a fault. The impedance characteristic is a closed line set in the complex impedance plane. The reach of the distance protection is normally split into different zones (for example 1 to 4 forward and 1 backward) represented by dedicated characteristics.
Volt per Hz protection	**PVPH**	24	Voltage per Hertz relay is a relay that functions when the ratio of voltage to frequency exceeds a preset value. The relay may have an instantaneous or a time characteristic.
(Time) Undervoltage protection	**PTUV**	27	An undervoltage relay is a relay which operates when its input voltage is less than a predetermined value.
Directional power/reverse power protection	**PDPR**	32	A directional power relay is a relay which operates on a predetermined value of power flow in a given direction, or upon reverse power flow such as that resulting from the motoring of a generator upon loss of its prime mover.

Logical Node	IEC 61850	IEEE C37.2-1996	Description or comments
Directional earth fault protection for compensated networks based on wattmetric principle	**PWDE**	32	This directional power relay is a relay which operates on a predetermined value of earth fault power flow in a given direction in compensated networks. Depending on protection philosophy and quality of current transducers, it is used as a fault indication only or also for tripping (see Annex J).
Undercurrent/underpower protection	**PUCP**	37	Undercurrent or underpower relay is a relay that functions when the current or power flow decreases below a predetermined value.
Loss of field/Underexcitation protection	**PUEX**	40	Field relay is a relay that functions on a given or abnormal low value or failure of machine field current, or on an excessive value of reactive component of armature current in an AC machine indicating abnormal low field excitation Underexcitation results in under power.
Reverse phase or phase balance current protection	**PPBR**	46	Reverse-phase or phase-balance current relay is a relay that functions when the polyphase currents are of reverse-phase sequence, or when the polyphase currents are unbalanced or contain negative phase-sequence components above a given amount
Phase sequence or phase-balance voltage protection	**PPBV**	47	Phase-sequence or phase-balance voltage relay is a relay that functions upon a pre-determined value of polyphase voltage in the desired phase sequence or when the polyphase voltages are unbalanced, or when the negative phase-sequence voltage exceeds a given amount.
Motor start-up protection	**PMSU**	48, 49, 51, 66	By supervising the motor start-up, this protection prevents any overload of the motor.
Thermal overload protection	**PTTR**	49	Machine or transformer thermal relay is a relay that functions when the temperature of a machine armature winding or other load-carrying winding or element of a machine or power transformer exceeds a predetermined value.
Rotor thermal overload protection	**PROL**	49R	See above (49)
Stator thermal overload protection	**PSOL**	49S	See above (49)
Instantaneous overcurrent or rate of rise protection	**PIOC**	50	Instantaneous overcurrent or rate-of-rise relay is a relay that functions instantaneously on an excessive value of current or on an excessive rate of current rise.
AC time overcurrent protection	**PTOC**	51	AC time overcurrent relay is a relay when the AC input current exceeds a predetermined value, and in which the input current and operating time are inversely related through a substantial portion of the performance range.
Voltage controlled/dependent time overcurrent protection	**PVOC**	51V	See above (PTOC/51), with voltage control/dependency.
Power factor protection	**PPFR**	55	Power factor relay is a relay that operates when the power factor in an AC circuit rises above or falls below a predetermined value.
(Time) Overvoltage protection	**PTOV**	59	Overvoltage relay is a relay which operates when its input voltage is more than a predetermined value.
DC overvoltage protection	**PDOV**	59DC	See above (PTOV/59).

Logical Node	**IEC 61850**	**IEEE C37.2-1996**	**Description or comments**
Voltage or current balance protection	**PVCB**	60	Voltage or current balance relay is a relay that operates on a given difference on voltage, or current input or output, of two circuits.
Earth fault protection/Ground detection	**PHIZ**	64	Ground detector relay is a relay that operates on failure of machine or other apparatus insulation to ground.
Rotor earth fault protection	**PREF**	64R	See above (PHIZ/64).
Stator earth fault protection	**PSEF**	64S	See above (PHIZ/64).
Interturn fault protection	**PITF**	64W	See above (PHIZ/64).
AC directional overcurrent protection	**PDOC**	67	AC directional overcurrent relay is a relay that functions on a desired value of AC overcurrent flowing in a predetermined direction.
Directional earth fault protection	**PDEF**	67N	See above (PDOC/67).
DC time overcurrent protection	**PDCO**	76	DC overcurrent relay is a relay that functions when the current in a DC circuit exceeds a given value.
Phase angle or out-of-step protection	**PPAM**	78	Phase-angle measuring or out-of-step protective relay is a relay that functions at a predetermined phase angle between two voltages or between two currents or between voltage and current.
Frequency protection	**PFRQ**	81	Frequency relay is a relay that responds to the frequency of an electric quantity, operating when the frequency or change of frequency exceeds or is less than a predetermined value.
Differential protection	**PDIF**	87	Differential protective relay is a protective relay that functions on a percentage or phase angle or other quantitative difference of two currents or some other electrical quantities.
Phase comparison protection	**PPDF**	87P	See above (PDIF/87).
Differential line protection[1]	**PLDF**	87L	See above (PDIF/87).
Restricted earth fault protection	**PNDF**	87N	See above (PDIF/87).
Differential transformer protection	**PTDF**	87T	See above (PDIF/87): Special for transformers are inrush currents with dominant third harmonic which have to be considered by the differential transformer protection.
Busbar protection[2]	**PBDF**	87B	See above (PPDF/87): the complexity of the busbar node with changing topology up to a split into two or more nodes needs special means such as a dynamic busbar image. It has to be considered that at least a second busbar protection algorithm exists which is based on the direction comparison of the fault direction in all feeders.
Motor differential protection[3]	**PMDF**	87M	See above (PDIF/87)
Generator differential protection[3]	**PGDF**	87G	See above (PDIF/87)

[1] The logical node differential line protection (PLDF) is used for the communication within the station. The communication between the two relays of two stations (Interface 2) is beyond the scope of the IEC 61850 series.

[2] The decentralized busbar protection consists in addition to the central decision making instance of the PBDF of an instance per bay with appropriate preprocessing and trip output.

[3] Both the motor protection and the generator protection are no simple functions to be each represented by a single LN, but a set of related LNs. The most important component is the differential LN mentioned here.

All main protection LNs have a communication structure as shown in Figure 6.

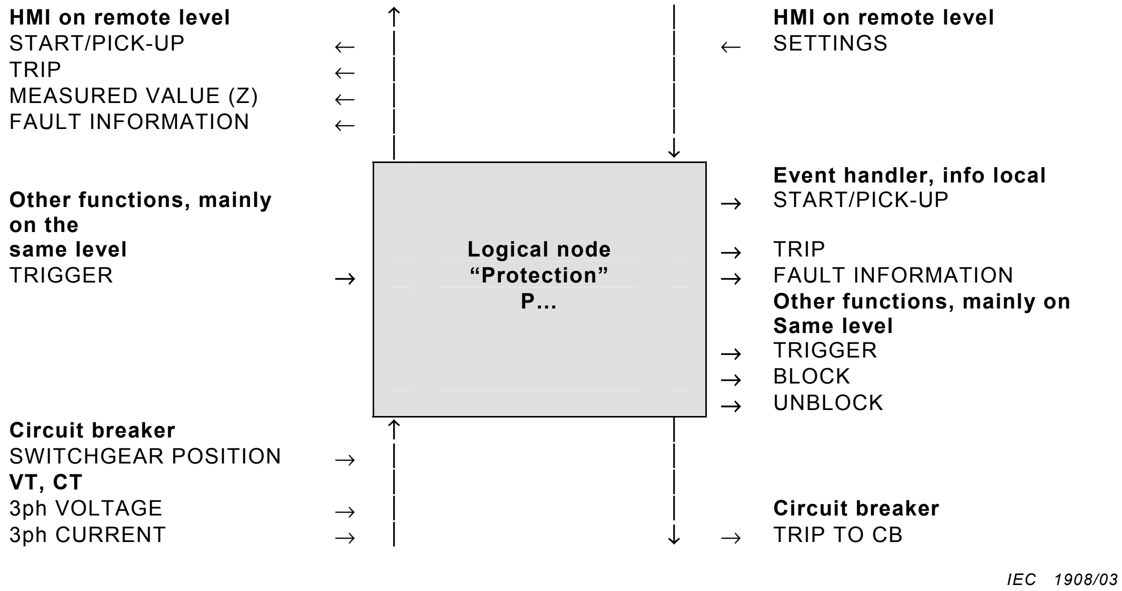


Figure 6 – The basic communication links of a logical node of main protection type

Data from and to the process (switchgear XCBR, current transformer TCTR, voltage transformer TVTR) referring to interface 4 and/or 5
Data to logical nodes on the same level referring to interface 3 and/or 8
Data to logical nodes such as IHMI on the station level referring to interface 1

11.1.2 Logical Nodes for protection related functions

Logical node	IEC 61850	IEEE C37.2-1996	Description or comments
Disturbance recording (bay/process level: acquisition)	**RDRE**		Acquisition functions for voltage and current waveforms from the power process (CTs, VTs), and for position indications of binary inputs. Calculated values such as power and calculated binary signals may also be recorded by this function if applicable.
Disturbance recording (station level: evaluation)	**RDRS**		The disturbance recording evaluation is needed as a server for HMI on station level (or even on a higher level) or for calculation of combined disturbance records.

Logical node	IEC 61850	IEEE C37.2-1996	Description or comments
Automatic reclosing	**RREC**	79	AC closing relay is a relay that controls the automatic reclosing and locking out of an AC circuit interrupter (IEEE C37.2-1996). After any successful protection trip, the automatic reclosing tries 1 to 3 times to reclose the open breaker again with different time delays assuming a transient fault.
Breaker failure	**RBRF**	50BF	Instantaneous overcurrent or rate-of-rise relay is a relay that functions instantaneously on an excessive value of current or on an excessive rate of current rise (IEEE C37.2-1996). In case of a breaker failure, the fault is not cleared. Therefore, neighboring breakers have to be tripped.
Carrier or pilot wire protection[1]	**RCPW**	85	Carrier or pilot-wire receiver relay is a relay that is operated or restrained by a signal used in connection with carrier-current or DC pilot-wire fault relaying (IEEE C37.2-1996).
Fault locator	**RFLO**		The fault locator calculates from the protection information (for example the fault impedance of the LN distance function) the location of the fault in km
Synchrocheck/synchronizing or synchronism check	**RSYN**	25	Synchronizing or synchronism-check device is a device that operates when two AC circuits are within the desired limits of frequency, phase-angle and voltage, to permit or to cause the paralleling of these two circuits (IEEE C37.2-1996). To avoid stress for the switching device and the network, closing of the circuit breaker is allowed by the synchrocheck only, if the differences of voltage, frequency and phase angle are within certain limits.
Power swing blocking	**RPSB**	78	Phase-angle measuring or out-of-step protective relay is a relay that functions at a predetermined phase angle between two voltages or between two currents or between voltage and current.

[1] A *de facto* communication device which establishes an analog connection between two relays (for example distance or differential protection) in two adjacent substations. If this connection is not serial, it is beyond the scope of the IEC 61850 series, if it is serial it belongs to interface 2, which is also beyond the scope of the IEC 61850 series. The involved picoms all refer to the related protection lns, for example PLDF and PDIS.

11.2 Logical Nodes for control

11.2.1 Control

Logical Node	IEC 61850	Description or comments
Alarm handling (creation of group alarms and group events)	**CALH**	For the communication, there is no difference between alarms and events if a time tag is added to any data transmitted. If several events or alarms have to be combined to group alarms, a separate, configurable function is needed. The related LN may be used to calculate new data out of individual data from different logical nodes. Remote acknowledgement with different priority and authority shall be possible. The definition and handling of alarms is an engineering issue.
Switch controller Controls any switchgear, i.e. the devices described by XCBR and XSWI	**CSWI**	The switch control LN handles all switchgear operations from the operators and from related automatics. It checks the authorization of the commands. It supervises the command execution and gives an alarm in case of an improper ending of the command. It asks for releases from interlocking, synchrocheck, autoreclosure, etc. if applicable.
Point-on-wave breaker controller Controls a circuit breaker with point-on-wave switching capability	**CPOW**	The point-on-wave breaker controller LN provides all functionality to close or open a circuit breaker at a certain instant of time, i.e. a certain point of the voltage or current wave. It is started by a request either from CSWI or from RREC. Comparing the voltages on both sides of the open breaker in the same way as the synchrocheck function (LN RSYN) it tries to close the contacts exactly at this time when the voltage difference is at an absolute minimum (preferable zero) to get the lowest stress for switchgear and line. This also applies if one of the voltages is zero. For opening, the point of minimum stress is calculated referring to the current wave. The selection command activates the voltage selection. It calculates the point of minimum stress and issues a closing or opening (depending on the intended command) execute command with an absolute time referring to the requested point-on-wave. For these calculations, the conditions in all three phases are considered. If switching per phase is applicable, three execution times are provided.
Interlocking function - at station level and/or - at bay level	**CILO**	Interlocking may be totally centralized or totally decentralized. Since the interlocking rules are basically the same on bay and station level and based on all related position indications, the different interlocking LNs may be seen as instances of the same LN class Interlocking (IL). 1) Interlocking of switchgear at <u>bay level</u> All interlocking rules referring to a bay are included in this LN. Releases or blockings of requested commands are issued. In the case of status changes affecting interlocking, blocking commands are issued. 2) Interlocking of switchgear at <u>station level</u> All interlocking rules referring to the station are included in this LN. Releases or blockings of requested commands are issued. Information with the LN bay interlocking is exchanged.

11.2.2 Interfaces, logging, and archiving

Logical node	IEC 61850	Description or comments
Operator interface - control local at bay level - control at station level	**IHMI**	1) Front-panel operator interface at bay level to be used for configuration, etc. and local control. 2) Local operator interface at station level to be used as workplace for the station operator. The role of the different HMI is not fixed for most of the functions and is defined in the engineering phase.
Remote control interface or telecontrol interface	**ITCI**	Telecontrol interface to be used for remote control from higher control level. Basically, the TCI will communicate the same data as the station level HMI or a subset of these data. The role of the different interfaces is not fixed for most of the functions and is defined in the engineering phase.
Remote monitoring interface or telemonitoring interface	**ITMI**	Telemonitoring interface to be used for remote monitoring and maintenance using a subset of all information available in the substation and allows no control. The role of the different interfaces is not fixed for most of the functions and is defined in the engineering phase.
Archiving	**IARC**	Archiving to be used as sink and source for long-term historical data, normally used globally for the complete substation on station level.
In case of seamless communication, some of the remote interfaces may exist only virtually. Depending on the outside world, they may be proxy servers or also any kind of gateway.		

11.2.3 Automatic process control

Logical Node	IEC 61850	Description or comments
Automatic tap changer control	**ATCC**	Automatic function to keep the voltage of a busbar within a specific range using tap changers. This node operates the tap changer automatically according to given setpoints or by direct operator commands (manual mode).
Automatic voltage control	**AVCO**	Automatic function to keep the voltage of a busbar within a specific range independently of the means used.
Reactive control	**ARCO**	Automatic function to keep the reactive power flow in a substation within a specific range using capacitors and/or reactances.
Earth fault neutralizer control (control of Petersen coil)	**ANCR**	The grounding of the transformer star point influences the short circuit in a network. This grounding is dynamically determined by a Petersen coil (LN ENF) controlled by ENFC.
Zero-voltage tripping	**AZVT**	If a line connected to a substation is without voltage longer than a predefined time, the line is switched off automatically. In contrast to the PTUV which has settable deviation from the nominal voltage, AZVT is a binary function only (voltage/no voltage).

Logical Node	IEC 61850	Description or comments
Automatic process control (a generic, programmable LN for sequences, unknown functions, etc.)	**GAPC**	Several functions are sequences. They are collected in the LN type Generic Automatic Process Control (GAPC). This is a generic node for all undefined functions. These sequences may be implemented with standard PLC languages. The data access and exchange is entirely the same as for all other LNs. Examples are 1) Load shedding To shed in a very selective way parts of the consumers to avoid the collapse of the network in overload situations. This load-shedding function may not be restricted only on frequency criteria such as PFRQ but include actual power balance, etc. 2) Infeed transfer switching To detect a weak infeed (for example to an industrial plant) and to switch over to another feeding line. Boundary conditions have to be considered such as the synchronization of motors, if applicable 3) Transformer change To switchover in case of overload to another transformer or to distribute the load more evenly to all related transformers on the busbar. 4) Busbar change To start by one single operator command a sequence of switching operations resulting in a busbar change of a dedicated line or transformer, if applicable. 5) Automatic clearing and voltage restoration To trip all circuits connected to a busbar after detecting zero-voltage conditions (black-out) and to close the same breakers following certain pre-defined rules.

11.2.4 Metering and measurement

Logical Node	IEC 61850	Description or comments
Measuring - for operative purpose	**MMXU**	To acquire values from CTs and VTs and calculate measurands such as r.m.s. values for current and voltage or power flows out of the acquired voltage and current samples. These values are normally used for operational purposes such as power flow supervision and management, screen displays, state estimation, etc. The requested accuracy for these functions has to be provided. NOTE The measuring procedures in the protection devices are part of the dedicated protection algorithm represented by the logical nodes Pxyz. Protection algorithms such as any function are outside the scope of the IEC 61850 series. Therefore, the LN Mxyz shall not be used as input for Pxyz. Fault related data such as fault peak value, etc. are always provided by the LNs of type Pxyz and not by LNs of type Mxyz.
Metering - for commercial purpose	**MMTR**	To acquire values from CTs and VTs and calculate the energy (integrated values) out of the acquired voltage and current samples. Metering is normally also used for billing and has to provide the requested accuracy. A dedicated instance of this LN may take the energy values from external meters for example by pulses instead directly from CTs and VTs.

Logical Node	IEC 61850	Description or comments
Sequences and imbalances - for example for stability purpose	**MSQI**	To acquire values from CTs and VTs and to calculate the sequences and imbalances in a three/multi-phase power system.
Harmonics and interharmonics - for example for power quality purpose	**MHAI**	To acquire values from CTs and VTs and to calculate harmonics, interharmonics and related values in the power system mainly used for determining power quality.

11.3 Physical device

11.3.1 Common identification and behavior

Logical Node	IEC 61850	Description or comments
Logical node device	**LLN0**	This LN contains the data related to the IED of the Physical Device (PD) independent from all included logical nodes (device identification/name plate, messages from device self-supervision, etc.). This LN may also be used for actions common to all included logical nodes (mode setting, settings, etc.), if applicable. This LN does not restrict the dedicated access to any single LN by definition. Possible restrictions are a matter of implementation and engineering.
It may be convenient for modeling in IEC 61850-7-4 to introduce more of such nodes for example for device substructures, but this is not a requirement.		

11.4 System and device security

Logical Node	IEC 61850	Description or comments
General security application	**GSAL**	Containing logs about security violations.

11.5 LNs related to primary equipment

The switchgear related logical nodes represent the power system, i.e. the world seen by the substation automation system via the I/Os. Using switchgear related LNs means a dedicated grouping of I/Os predefined according to a physical device such as a circuit breaker (see XCBR in 11.5.1).

11.5.1 Switching devices and substation parts

Logical Node	IEC 61850	IEEE C37.2-1996	Description or comments
The LN “circuit breaker” covers all kinds of circuit breakers, i.e. switches able to interrupt short circuits • without point-on-wave switching capability • with point-on-wave switching capability	**XCBR**	52	An AC circuit breaker is a device that is used to close and interrupt an AC power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions (IEEE C37.2-1996). If there is a single-phase breaker, this LN has an instance per phase. These three instances may be allocated to three physical devices mounted in the switchgear.

Logical Node	IEC 61850	IEEE C37.2-1996	Description or comments
The LN “switch” covers all kinds of switching devices not able to switch short circuits • load breakers • disconnectors • earthing switches • high-speed earthing switches	**XSWI**	89 52	Line switch is a switch used as a disconnecting, load-interrupter, or isolating switch on an AC or DC power circuit (IEEE C37.2-1996). If there is a single-phase switch, this LN has an instance per phase. These three instances may be allocated to three physical devices mounted in the switchgear.

These LNs represent the mentioned switching devices and related equipment with their entire inputs, outputs and communication relevant behavior in the SAS.

11.5.2 LN for monitoring by sensors

Logical Node	IEC 61850	IEEE C37.2-1996	Description or comments
Insulation medium supervision	**SIMS**		LN to supervise the insulation medium, for example the gas volumes of GIS (Gas Insulated Switchgear) regarding density, pressure, temperature, etc.
Monitoring and diagnostics for arcs	**SARC**		LN to supervise the gas volumes of GIS (Gas Insulated Switchgear) regarding arcs switching or fault arcs.
Monitoring and diagnostics for partial discharge	**SPDC**		LN to supervise the gas volumes of GIS (Gas Insulated Switchgear) regarding signatures of partial discharges.

These LNs represent the mentioned sensors with their entire inputs and communication relevant behavior in the SAS.

11.5.3 Instrument transformers

Logical Node	IEC 61850	Description or comments
Current transformer	**TCTR**	There is one instance per phase. These three/four instances may be allocated to different physical devices mounted in the instrument transformer per phase.
Voltage transformer	**TVTR**	There is one instance per phase. These three/four instances may be allocated to different physical devices mounted in the instrument transformer per phase.

These LNs represent the mentioned instrument transformers with all its data and related settings (if applicable), and communication relevant behavior in the SAS.

11.5.4 Power transformers

Function	IEC 61850	Description or comments
Power transformer	**YPTR**	Connects the voltage levels of the power system in different configurations (Δ, Y, two/three windings).
Tap changer	**YLTC**	Device allocated to YPRT allowing changing taps of the winding for voltage regulation.
Earth fault neutralizer (Petersen coil)	**YEFN**	Variable inductance (plunge core coil) allowing adaptive grounding of transformer star point to minimize the ground fault current.
Power shunt	**YPSH**	To bypass the resistor of a resistive grounded transformer star point for fault handling.

These LNs represent the mentioned power transformers and related equipment with all its data and related settings (if applicable), and communication relevant behavior in the SAS.

11.5.5 Further power system equipment

Function	IEC 61850	Description or comments
Auxiliary network	ZAXN	Generic node for information exchange with auxiliary networks (power supplies).
Battery	ZBAT	Provides data about battery status and for control of the charging/de-charging cycles.
Bushing	ZBSH	Provides properties and supervision of bushings as used for transformers or GIS-line connections.
Power cable	ZCAB	Supervised power system element.
Capacitor bank	ZCAP	Controls reactive power flow.
Converter	ZCON	Frequency conversion incl. AC/DC conversion.
Generator	ZGEN	Generic node for information exchange with generators.
Gas isolated Line (GIL)	ZGIL	Mixture of data from SIMS, SARC and SPDC.
Power overhead line	ZLIN	Supervised overhead line.
Motor	ZMOT	Generic node for information exchange with motors.
Reactor	ZREA	Controls reactive power flow.
Rotating reactive component	ZRRC	Controls reactive power flow.
Surge arrestor	ZSAR	Generic node for information exchange with surge arrestors.
(Thyristor controlled) frequency converter	ZTCF	Frequency conversion including AC/DC conversion.
Thyristor controlled reactive component	ZTCR	Controls reactive power flow.

These LNs represent the mentioned power system equipment with all its data and related settings (if applicable), and communication relevant behavior in the SAS. Since entities like generators are outside the scope of substations but have often an communication interface to Substation Automation Systems anyhow, they are described as minimum by one single LN only. If the data exchange needs more details, these have to be covered by appropriated PICOMs or the additional use of generic LNs such as GGIO.

11.5.6 Generic process I/O

Function	IEC 61850	Description or comments
Generic I/O	GGIO	Outputs such as analog outputs, auxiliary relays, etc. not covered by the above-mentioned switchgear related LNs are sometimes needed. In addition, there are additional I/O's representing devices not predefined such as horn, bell, target value etc. There are input and outputs from non-defined auxiliary devices also. For all these I/O's, the Generic Logical Node GIO is used to represent a generic primary or auxiliary device (type X…, Y… , Z…).

11.6 LNs related to system services

Function	IEC 61850	Description or comments
Time master	**STIM**	LN to provide the time to the system (setting and synchronization).
System supervision	**SSYS**	LN to start, collect and process all data for system supervision.
Test generator	**GTES**	LN to start tests by using process signals, but avoiding any impact on the process (blocking of process outputs).

System functions such as time synchronization and system supervision are requirements from the substation automation system and have to be supported by the IEC 61850 series. Depending on the selected stack, these support functions may be provided from a level below the application. The test generator (GTES) depends on the function to be tested and is therefore declared as a generic logical node.

12 The application of LN (informative)

12.1 Basic principles

12.1.1 Free allocation of LNs

The free allocation of functions or LNs respectively is not restricted to the common level structure. The levels below are mentioned as common supplementary information only. All the figures shown with these levels are only examples, demonstrating the requested flexibility and interaction.

12.1.2 Station level

These logical nodes represent the station level, i.e. not only the station level IHMI, but all other functions such as station wide interlocking (CILO), alarm and event handling (CALH), station-wide voltage control (ATCC), etc. The most common prefix is I, but others such as A and C may appear also.

12.1.3 Bay level

These logical nodes represent the bay level control, automatic, measuring, and protection functions (for example, CILO, ATCC, MMXU, CSWI, PDIS, PZSU, PDOC, ...). Therefore, for combined control and protection devices, the protection LN appears here together with the control LN. If there is no process bus, the LNs of bay level and process level appear together in one single physical device. The XCBR then represents the I/O card functionality and the CSWI the control processor functionality. The most common prefixes are P, C and A but others such as X may also appear.

12.1.4 Process/switchgear level

These logical nodes represent the power (primary) system, i.e. the power system world as seen from the secondary system via the I/Os. They may contain some simple functionality such as device-related supervision as well as blocking. In case of intelligent I/Os, logical nodes from the bay level may move also down to the process level. The most common prefixes are X, Y and Z.

12.2 Basic examples

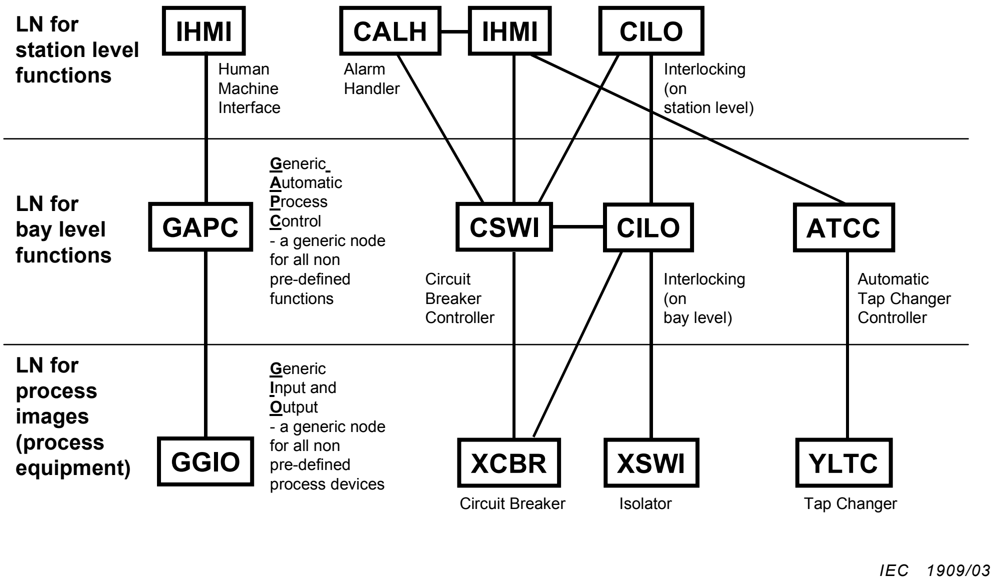


Figure 7 – Decomposition of functions into interacting LNs on different levels: examples for generic automatic function, breaker control function and voltage control function

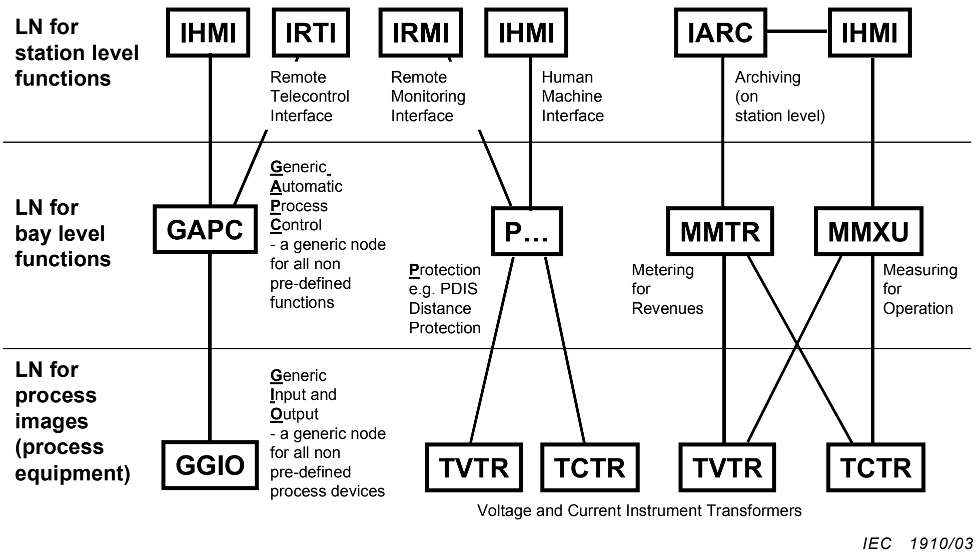


Figure 8 – Decomposition of functions into interacting LN on different levels: examples for generic function with telecontrol interface, protection function and measuring/metering function

12.3 Additional examples

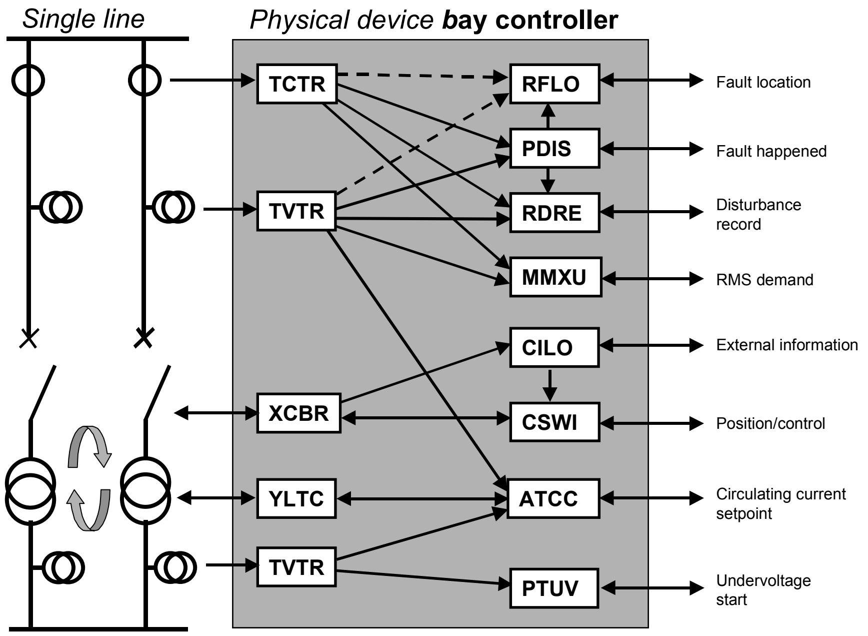


Figure 9 – Example for control and protection LNs of a transformer bay combined in one physical device (some kind of maximum allocation)

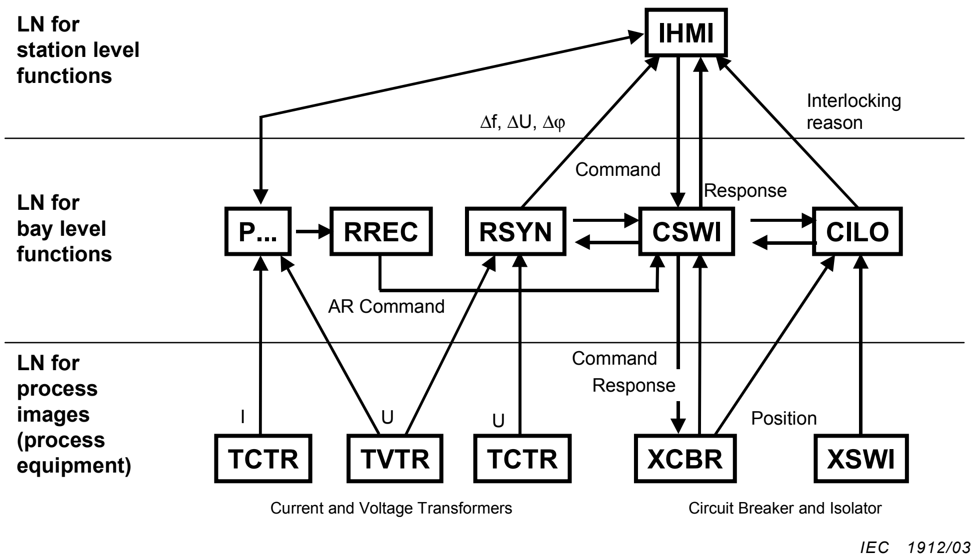


Figure 10 – Example for interaction of LNs for switchgear control, interlocking, synchrocheck, autoreclosure and protection

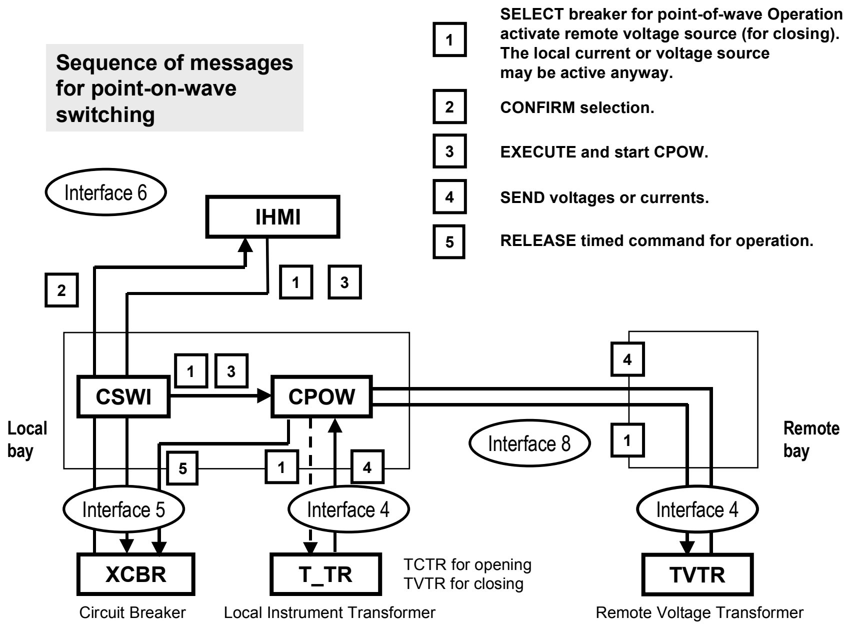


Figure 11 – Example for sequential interacting of LNs (local and remote) for a complex function such as point-on-wave switching – Sequence view

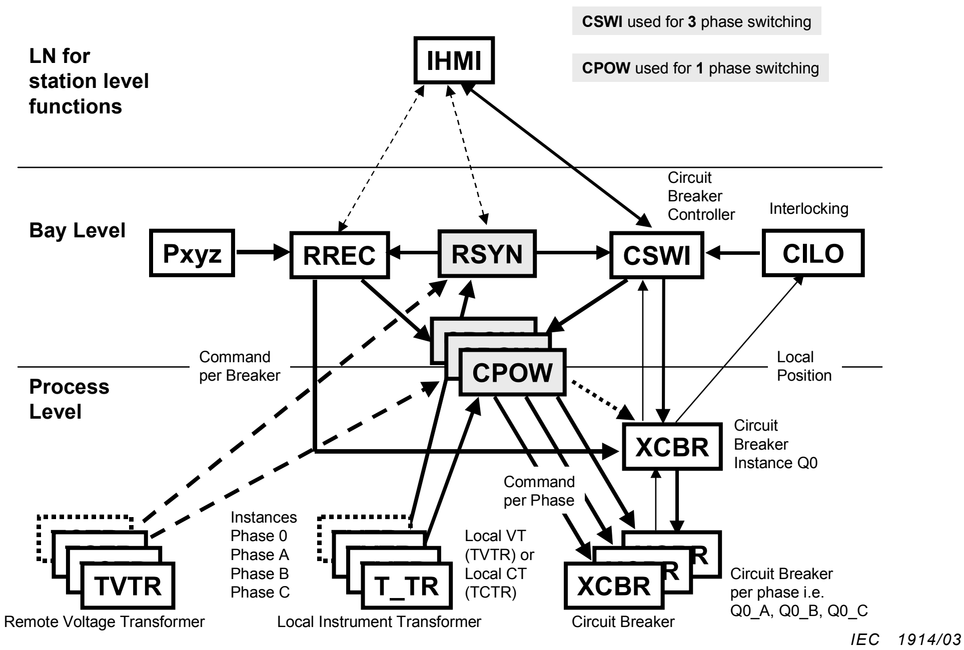


Figure 12 – Example for functional interacting of LNs (local and remote) for a complex function such as point-on-wave switching – Architecture view

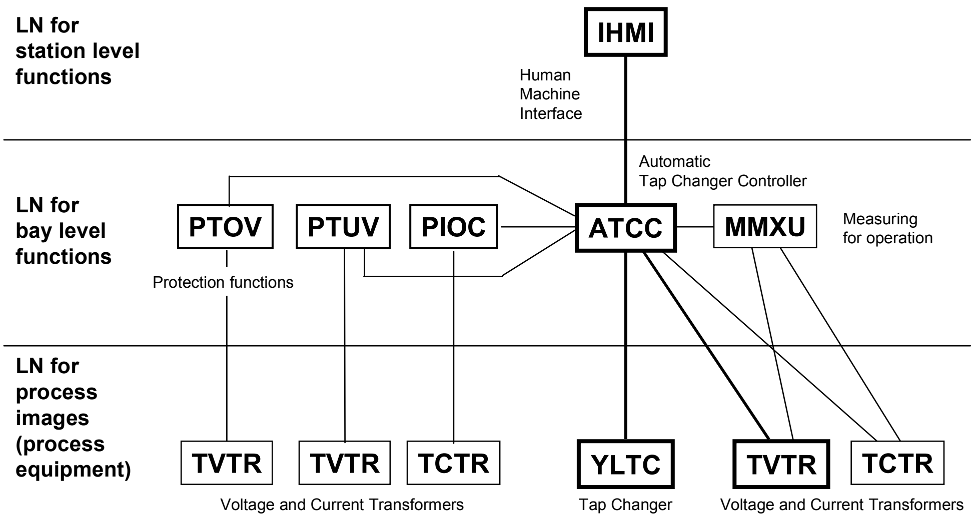


Figure 13 – Example for automatic tap changer control for voltage regulation

The protection functions PTOV, PTUV, and PIOC are for over- and under-voltage and over-current response functions, MMXU is for demand related quantities. Settings and manual operation are issued by IHMI.

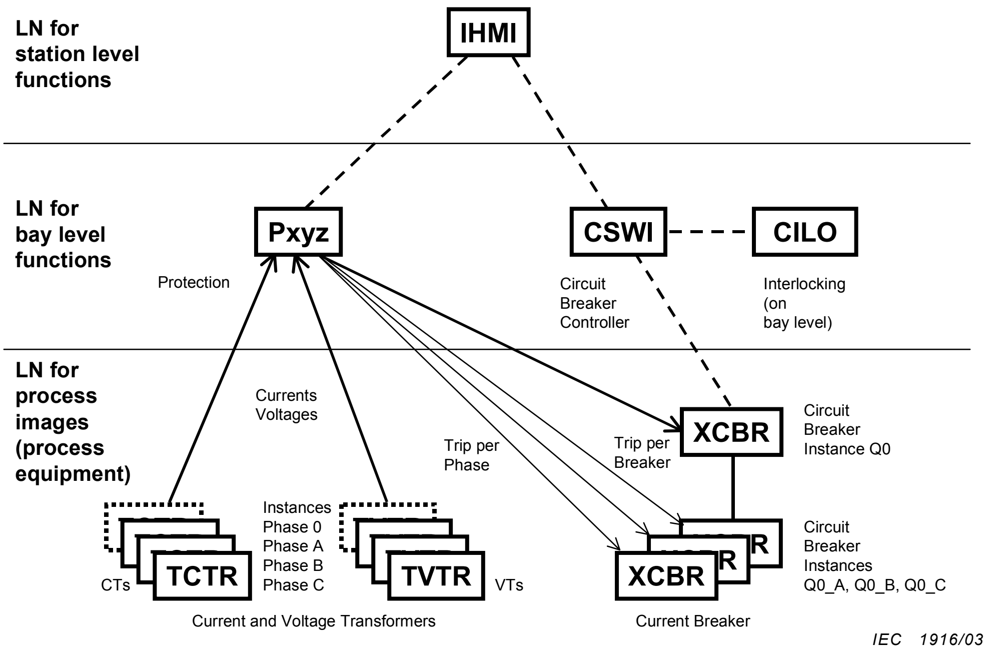


Figure 14 – Circuit breaker controllable per phase (one instance of XCBR per phase) and instrument transformers with measuring units per phase (one instance of TCTR or TVTR per phase)

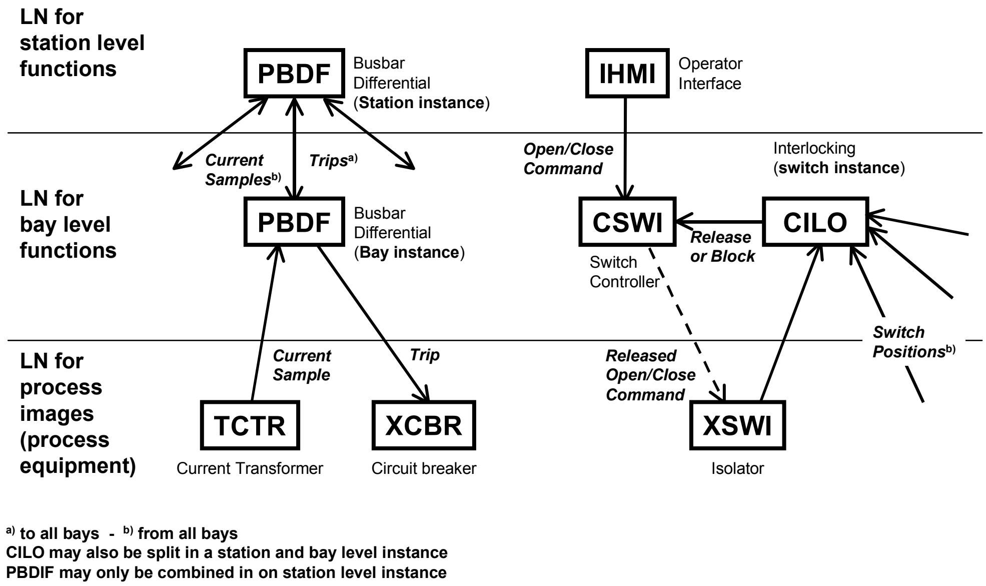


Figure 15 – Distributed busbar protection (LN instances of PBDF for central unit and for units per bay - left) and interlocking (LN instance of CILO) on bay level per switch/circuit breaker (right)

12.4 Remarks on modeling

All the modeling for implementation is defined in IEC 61850-7-x. The following Subclauses illustrate some important points of the relationship between this part of IEC 61850 and IEC 61850-7-x.

12.4.1 Object classes and instances

The LNs described here provide the common functionality for all implementations, i.e. they represent LN classes in terms of object modeling. In a real implementation, the LNs appear as individuals (individual identification, individual data to be exchanged), i.e. they represent LN instances in terms of object modeling. LN instances from the same LN class may appear in devices once or many times.

12.4.2 Requirements and modeling

The communication requirements described in this part of IEC 61850 are independent from any modeling. To reach the goal of interoperability, a proper modeling as a basis for the implementation of this part of IEC 61850 is requested and described in IEC 61850-7-x.

12.4.3 LN and modeling

The logical nodes in this part of IEC 61850 are defined by the requirements only. If a client-server model is used for the modeling, some of the interface LNs such as IHMI, ITCI, and ITMI may appear as clients only and, therefore, have no data objects. As result, they have no modelling requirements.

The introduction of additional structures such as logical devices (see IEC 61850-7-x) which are composed of logical nodes is not an application requirement, but may be helpful for the modeling. Since the requirements in this part of IEC 61850 refer neither to a specific device allocation nor to a specific function implementation, no requirements for a physical device model are specified. Any physical device modelling including additional data objects is, therefore, also a matter of IEC 61850-7-x.

Splitting and combining of logical nodes in IEC 61850-7-x for more convenient modeling do not impact the requirements of this part of IEC 61850.

13 Message performance requirements

13.1 Introduction

The communication between LNs is described by thousands of individual PICOMs. Nevertheless, there are a lot of similarities between these PICOMs; for example, all PICOMs describing trips have, besides the individual sources, more or less identical communication requirements as those described by the PICOM attributes. Therefore, a classification of PICOMs would both allow the obtention of a comprehensive overview of the requirements and support of a strong modeling and definition of the requested communication performance.

In a first step, all PICOMs from as many LNs as possible are identified and allocated to a PICOM type using a common purpose and having common attributes. The result is found in B.2.

The resulting PICOM types with its most important common attributes are given in clause B.3. The broad range of transfer time requirements reflects the individual needs of the functions. Since higher time requirements always cover lower ones, the requirements may be condensed in figures for the message types introduced in 13.5.

Essential for a proper running of functions and crucial for any performance requirements of the supporting communication system is the maximum time allowed for the data exchange. In the context of this part of IEC 61850, this time is called “transfer time” and clearly defined in 13.4.

To define time tags and transfer times, the basic requirements for the description of time have to be clear. These requirements are stated in 13.2 and 13.3. Transfer time requirements are system requirements, time tag requirements are device requirements but refer to the system support function “Time synchronization”.

In 13.7, the PICOM types are grouped in 7 message types and the range of its attributes is structured by performance classes. Suggestions to typical applications and interface allocation are also given.

The introduction and use of message types are described in 13.5, the introduction and use of performance classes are described in 13.6.

System performance requirements shall also be tested, for example with system simulators. Its testing will be properly addressed in IEC 61850-10[7].

13.2 Basic time requirements

As IEC 61850 series compatible devices from multiple vendors become distributed not only in the substation but also around the power system, a common format for time tagging done by these devices shall be used. Specific requirements for the time model and format are as follows:

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[7] Under consideration.

a) Accuracy – depending on the application, different time accuracy is required. Requirements are defined below.
b) The time stamp shall to be based on an existing time standard (UTC is generally accepted as the base time standard).
c) The time model shall to be able to track leap seconds and provide enough information to allow the user to perform delta time calculation for paired events crossing the leap second boundary.
d) The time stamp model shall contain sufficient information for the client to be able to compute a date and time without additional information such as the number of leap seconds from the beginning of time.
e) The timestamp information shall be easily derived from commercially available time sources (for example GPS).
f) The overall time model shall include information to allow computation of local time.
g) The time model shall allow for half-hour offsets for local time.
h) The time model shall indicate whether daylight saving is in effect or not.
i) The format shall last at least 100 years.
j) The timestamp format shall be compact and easily manipulated by machine.

These basic time requirements are system requirements, but the system consists of devices. Therefore, the devices shall support these requirements, if applicable.

13.3 Event time definition

There are three different kinds of events, which need a dedicated time allocation procedure:

- If an event is defined as a result of computation (internal or calculated event), allocation of time (time tagging) shall be done immediately within the time resolution of the clock. No special measures are needed.
- If an event is defined as a change of a binary input, the delay of the debouncing procedure of the input contact has to be considered. The event time shall be locally corrected.
- If an event is defined as a change of an analogue input, the delay of the filtering procedure of the input circuit has to be considered. The event time shall be locally corrected.

This strong event time definition results in the requirement that the time tag of the transmitted binary or analogue event/value be as accurate as possible and needs no correction at the receiving end. This is at least valid in the scope of the IEC 61850 series since any time correction regarding debouncing and filtering is defined a local issue outside the scope of the IEC 61850 series.

13.4 Transfer time definition

When the transfer time is specified below, this means the complete transmission of a message including necessary handling at both ends. The time counts from the moment the sender puts the data content on top of its transmission stack up to the moment the receiver extracts the data from its transmission stack.

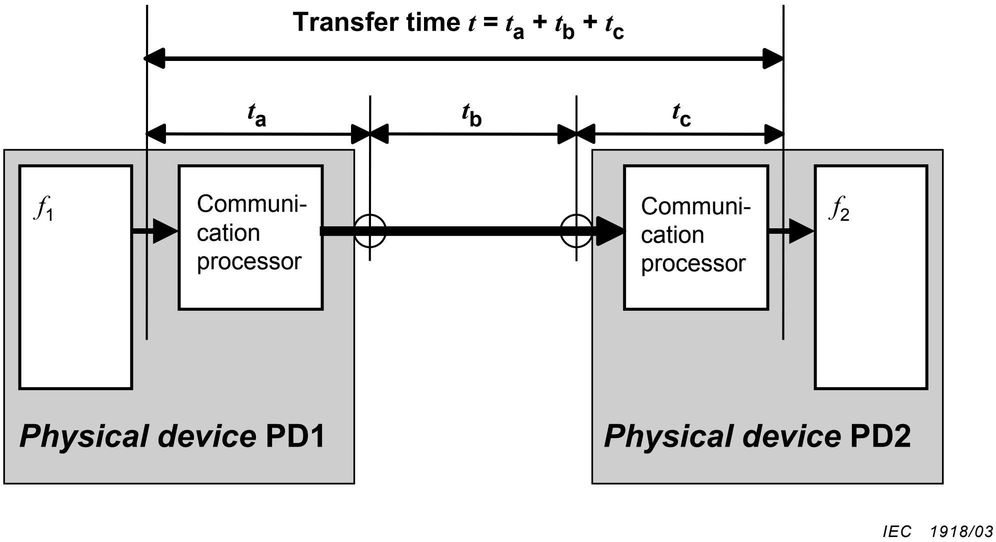


Figure 16 – Definition of transfer time

The time requirement is applicable for the complete transmission chain as indicated in Figure 16. In physical device PD1, a function f_1 sends data to another function f_2, located in physical device PD2. The transfer time will however consist of the individual times of the communication processors and the network transfer time, including wait times and time used by routers and other devices that are part of the complete network. Any testing and verification of the transfer time must be performed during the site acceptance testing, since the physical devices and network equipment might be supplied from different manufacturers.

13.5 The introduction and use of message types

As mentioned above, the result of communication requirements in terms of PICOMs between LNs is that the various communication links within a Substation Automation System are required to transport messages of varying complexity with regard to their content, length, allowed worst case transfer time and security. The message types being carried will vary from moment to moment depending on the activity both in the substation and on the system.

The main difference between PICOMs and message types are that PICOMs refer to information transfer based strictly on one single dedicated functionality, and include source and sink. The message types are based on a grouping of the performance related PICOM attributes and, therefore, define the performance requirements to be supported. Since the performance requirements are defined per message, they are independent of the size of the substation. Scenarios with multiple messages for substations are given in Clause 14.

13.6 The introduction and use of performance classes

To allow for different requirements of the substations, some message types are also subdivided into performance classes. There are two independent groups of performance classes, one for control and protection, another one for metering and power quality applications. Since the performance classes are defined according to the functionality needed, they are independent from the size of the substation.

Within a specific substation, all communication links do not necessarily need to support the same performance class. Station level communications and process level communications may be selected independently of each other and within the process level, different performance classes can be used for communications in different bays, depending on the number and rating of equipment located in each bay.

13.6.1 Control and protection

Performance class P1 applies typically to a distribution bay or to bays where low requirements otherwise can be accepted.

Performance class P2 applies typically to a transmission bay or if not otherwise specified by the customer.

Performance class P3 applies typically to a transmission bay with top performance synchronizing feature and breaker differential.

13.6.2 Metering and power quality

Performance class M1 refers to revenue metering with accuracy class 0.5 (IEC 62053-22) and 0.2 (IEC 60044-8) and up to the 5th harmonic.

Performance class M2 refers to revenue metering with accuracy class 0.2 (IEC 62053-22) and 0.1 (IEC 60044-8) and up to the 13th harmonic.

Performance class M3 refers to quality metering up to the 40th harmonic.

13.7 Message types and performance classes

13.7.1 Type 1 – Fast messages

This type of message typically contains a simple binary code containing data, command or simple message, for example “Trip”, “Close”, “Reclose order”, “Start”, “Stop”, “Block”, “Unblock”, “Trigger”, “Release”, “State change”, maybe also “State” for some functions. The receiving IED will normally act immediately in some way by the related function on receipt of this type of message since, otherwise, no fast messages are needed.

13.7.1.1 Type 1A “Trip”

The trip is the most important fast message in the substation. Therefore, this message has more demanding requirements compared to all other fast messages. The same performance may be requested for interlocking, intertrips and logic discrimination between protection functions.

a) For Performance Class P1, the total transmission time shall be in the order of half a cycle. Therefore, 10 ms is defined.
b) For Performance Class P2/3, the total transmission time shall be below the order of a quarter of a cycle. Therefore, 3 ms is defined.

13.7.1.2 Type 1B “Others”

All other fast messages are important for the interaction of the automation system with the process but have less demanding requirements compared to the trip.

a) For Performance Class P1, the total transmission time shall be less than or equal to 100 ms.

b) For Performance Class P2/3, the total transmission time shall be in the order of one cycle. Therefore, 20 ms is defined)

NOTE These messages are typical for interfaces IF3, IF5, and IF8.

13.7.2 Type 2 – Medium speed messages

These are messages, as defined in 13.7.1, where the time at which the message originated is important but where the transmission time is less critical. It is expected that IEDs will have their own clocks. The message shall include a time-tag set by the sender, and the receiver will normally react after an internal time delay, which then will be calculated from the time given in the time-tag. Normal "state" information also belongs to this type of message.

This type may alternatively include a single measurand, such as a r.m.s. value calculated from type 4 signals.

The total transmission time shall be less than 100 ms.

NOTE These messages are typical for interfaces IF3, IF8, and IF9.

13.7.3 Type 3 – Low speed messages

This type includes complex messages that may require being time-tagged. This type should be used for slow speed auto-control functions, transmission of event records, reading or changing set-point values and general presentation of system data. Whether a time-tag is required (normally) or not (exception) will be stated by the actual application. Time tagged alarms and events for normal alarm/event handling and non-electrical measurands such as temperature also belong to this type, but some automatic functions in general and some dedicated values (for example pressure) of generally slow-speed functions may request message type 2.

The total transmission time shall be less than 500 ms.

NOTE These messages are typical for nearly all interfaces of Figure 2, at least for its use for parameter setting: IF1, IF3, IF4, IF5, IF6, IF5, IF7, IF8, and IF9.

13.7.4 Type 4 – Raw data messages

This message type includes the output data from digitizing transducers and digital instrument transformers independent from the transducer technology (magnetic, optic, etc.).

The data will consist of continuous streams of synchronized data from each IED, interleaved with data from other IED.

NOTE These messages are typical for interfaces IF4, and in some applications, for IF8.

Table 1 – Raw data for protection and control

Data type	Class	Transmission time (ms) defined by trip time	Resolution (Bits) Amplitude	Rate (Samples/s) Frequency
Voltage	P1	10,0	13	480
Current			13	
Voltage	P2	3,0	16	960
Current			16	
Voltage	P3	3,0	16	1 920
Current			18	

For convenience, the resolution is given in bits.

Table 2 – Raw data for metering

Data type	Class	Accuracy classes and harmonics	Resolution (Bits) Amplitude	Rate (Samples/s) Frequency
Voltage	M1	Class 0.5 (IEC 62053-22) Class 0.2 (IEC 60044-8) Up to 5th harmonic	12	1 500
Current			14	
Voltage	M2	Class 0.2 (IEC 62053-22) Class 0.1 (IEC 60044-8) Up to 13th harmonic	14	4 000
Current			16	
Voltage	M3	Class 0.1 (not defined by IEC) Up to 40th harmonic	16	12 000
Current			18	

For convenience, the resolution is given in bits.

13.7.5 Type 5 – File transfer functions

This type of message is used to transfer large files of data for recording, information purposes, settings, etc. Data must be split into blocks of limited length, to allow for other communication network activities. Typically, the bit lengths of the file type PICOMs are equal to or greater than 512 bits.

Transfer times are not critical there are no specific limits. Typically, the time requirements are equal to or greater than 1 000 ms.

For remote access, the request for file transfer shall have an access control; i.e. the access needs some authorization (see 13.7.7). Therefore, this request messages shall be of type 7.

NOTE In case of configuration setting, these messages are typical for nearly all interfaces: IF1, IF3, IF4, etc. In case of disturbance recording, these messages are typical for interfaces IF1, IF6, IF7 and if the records are stored near the process, IF4.

13.7.6 Type 6 – Time synchronization messages

This type of message is used to synchronize the internal clocks of the IED in the SAS. Depending of the purpose (time tagging of events or sampling accuracy of raw data) different classes of time synchronizing accuracy are required.

The accuracies requested in this Subclause are functional requirements. Its up to the implementation if for example, the time synchronizing of the clocks in IEDs has to be one order of magnitude better than requested by the functional requirements. IEC 61850-8 and IEC 61850-9 shall define, how the time synchronization mechanism is implemented.

No direct requirements for the synchronization messages are defined except for the resulting time accuracy in the whole system.

13.7.6.1 Standard IED synchronizing for control and protection events

Time performance class	Accuracy (ms)	Purpose
T1	± 1	Time tagging of events
T2	± 0,1	Time tagging of zero crossings and of data for the distributed synchrocheck. Time tags to support point on wave switching.

NOTE These messages are typical for nearly all interfaces because of the system-wide synchronization: IF1, IF3, IF4, IF5, IF6, IF5, IF8, and IF9. The time performance class needed depends strongly on the supported functionality. For synchronizing of digital instrument transformers and Type 4 messages, see 13.7.6.2.

13.7.6.2 Standard IED synchronizing for instrument transformers

The requested time accuracy results from the referenced performance classes (column 3) introduced above. To give some indications on the related power system values, columns 4,5 and 6 have been added.

Time performance class	Accuracy (μs)	Reference		Phase angle (‘) 50 Hz	Phase angle (‘) 60 Hz	Fault location (m)
T3	± 25	P1		27	32	7 500
T4	± 4	P2	M1	4	5	1 200
T5	± 1	P3	M2/3	1	1	300

NOTE The performance classes T3, T4, and T5 are typical for interfaces IF4, and in some applications, for IF8.

13.7.7 Type 7 – Command messages with access control

This type of message is used to transfer control orders, issued from local or remote HMI functions, where a higher degree of security is required. All messages using interface 7 (external technical services) shall include access control. This type of message is based on Type 3, with additional password and/or verification procedures.

These command messages propagating over some control levels from the operator down to the switchgear or to some other controllable object may be converted to messages requesting type 1 properties at least on process level.

NOTE These messages are typical for the operators access via a local or remote HMI: IF1, IF6 and IF7.

14 Requirements for data integrity

Integrity means that for a given background noise the resulting errors are below a certain acceptable limit. In IEC 61850-3, the three integrity classes according to IEC 60870-4 are referenced. Data integrity was also introduced as a PICOM attribute in 10.1.2. All safety related messages such as commands and trips with direct impact on the process shall have the highest integrity class, i.e class 3. All other messages may be transmitted with a lower data integrity, but not lower then class 2.

Normally, the noise level is given and cannot be influenced. Nevertheless, to reach integrity three groups of known measures exist in order to limit its impact.

1) Proper design of devices and the communication system, for example protecting enclosures and the use of fiber optic links.
2) Apply an appropriate coding, i.e. a Hamming distance.
3) Use of at least two step sequences such as select-before-operate (SBO) for commands.

The use of these measures is beyond the scope of this part of IEC 61850, but the required data integrity shall be considered in modeling the services (IEC 61850-7-2, for example SBO) and defining the mapping (IEC 61850-8-x, 61850-9-x, for example coding)

15 System performance requirements

15.1 Introduction

To ensure that the transmission times specified in Clause 13 are met under any operating conditions and contingencies in the substation, the dynamic performance must be considered and studied in the planning stage.

IEC 61850-1 defines main types of substations with examples of typical functionality levels. A number of possible bus structures are also presented, the actual communication bus structure must be selected on the base of requirements and desired performance class, as specified in Clause 13**.**

The contents of this Clause are methods to prove that the dynamic performance requirements will be met for a given substation, considering the fact that substations in different countries have different layouts as well as allocation of functions. Due to the various substation layouts, different protection schemes and control functions, each substation project must be evaluated separately.

Two approaches for such calculations are available. One is based on the PICOM model; the other one is a simulation of LAN performance.

15.2 Calculation methods

15.2.1 The PICOM method

According to the classification in IEC 61850-1, four different substation types have been chosen for a process of calculating dynamic scenarios. The calculation method and sample calculations are presented in I.1.

The calculation method uses a common database for functions, associated information elements and algorithms. Basically, functions and associated information have been listed in the CIGRE Technical Report Ref. No. 180 and are used by IEC technical committee 57 working groups during the standardization process. Physical devices are used to build up the functional model for each scenario, an aggregation of logical nodes and associated PICOMs is used to define each physical device. The database for the calculations contains about 100 logical nodes and 1 400 PICOMs that have been identified for substation communication. PICOM attributes include performance requirements, logical node assignment, and state of operation and their cause.

The data flow on selected interfaces in the networks can be calculated under different states of operation of a substation, for example normal, abnormal and emergency states. The interfaces can be combined in various ways, depending on how the actual network is used. Both process and station busses are considered. They can be looked at combined, separately or exclusively.

This calculation method does only consider the data content. No overhead for framing, message structure, etc. is included. When selecting an actual physical network, the overhead caused by the chosen stack must be considered and added to the data rates given by the original calculation.

The PICOM model does not automatically consider messages sent over Interface 2 (teleprotection signaling), since Interface 2 is beyond the scope of this part of IEC 61850. It is however conceivable to add an IED to for example a radio frame and use the substation bus for communication between the protective devices and the radio links. In such cases, this data flow must be added into the calculation. For example in protection schemes where distance protections are set to overreach with remote end blocking, the resulting burst of communication over interface 2, caused by a fault on one of the lines, will far exceed any other source of data flow.

This method is useful in determining total data rates. For the determination of the overall transfer times, a LAN simulation program or equivalent must be used.

15.2.2 LAN simulation method

Once the physical network is chosen and a communication stack is selected, a LAN simulation program can be used to verify the design. Such a program will consider all overhead, message structures, addressing, multicasting, collisions etc.

A LAN simulation program will give average and maximum delay times as output, and the results can be directly verified against the required overall transfer time from Clause 13.

An example using this procedure, for an Ethernet bus and three sigma delay times, is described in I.2.

15.3 Calculation results

When results of calculations of different substations are compared, substations of quite different complexity might yield similar busloads, while almost similar substations can get very different loading figures. The reason is that actual requirements on protection and control functions, as well as the allocation of logical nodes to physical devices have a large impact on the results.

The PICOM analysis for all substations shows communication network loading of 750 kBytes to 1 200 kBytes with a process samples and a loading of less than 500 kBytes without them.

The LAN simulation analysis for a critical multiple fault incident on substation T2-2 shows that all critical circuit breakers receive a trip command in less than 4 ms using special broadcast messages mapped on MMS/OSI protocol. For the Ethernet network, either a 10 Mbit/s switched hub or a 100 Mbit/s shared hub has been used for the substation LAN. The simulation assumed no process bus, and all the trip commands were delivered over the substation LAN.

15.4 Summary

In most cases studied, the abnormal or emergency loads on the substation bus will add between 50 % and 100 % to the normal load. On process level, there is no noticeable difference between loading cases, since most physical devices attached send constant data streams, that are unaffected by contingencies.

The most important issue when planning the substation communication, are a proper assignment of freely allocable logical nodes to physical devices and the arrangement of the communication network itself to minimize point-to-point communication requirements. The PICOM model is a useful tool for this purpose.

When setting up the LAN simulation model, great care must be taken to ensure a proper configuration of messages, since this also will have a large impact on the result. The PICOM model assumes that all messages are sent as single data objects. Multicast messages can be taken into account, but not messages with multiple data objects. Combining data objects into object oriented or multi-command messages in a suitable way can result in a noticeable reduction of the total traffic. This will be clearly shown when LAN simulation studies are performed.

When defining the actual network and stacks, it is equally important to combine data objects in such a way that the traffic is minimized.

The main result of the calculations and studies should be to ensure that the requirements on transmission times, stated in Clause 13, can be kept for various message types. A LAN simulation program can verify this.

16 Additional requirements for the data model

For interoperability, a data model shall describe the syntax and semantics of exchanged data

16.1 Requirements for the addressing of logical nodes

Since communications take place between logical nodes, which are not specifically allocated to devices, each logical node (LN) shall be addressable by itself (requirement).

For the logical addressing scheme, a hierarchical name structure and an object data dictionary specialized for electrical substations such as the IEC 61346 series shall be used.

16.2 Requirements for the data model

The data model shall support the following features:

Self-description shall be provided by all devices regarding functions (LNs) and transmittable data (PICOMs). Standardized rules shall allow interoperable extensions within the framework of the IEC 61850 series. Both will avoid the need of a private range in the IEC 61850 series.

All information to be used by HMIs shall be retrievable as ASCII text (at least optional in the language of the operator). The presentation of the information itself by the HMI is out of the scope of the IEC 61850 series.

For an unambiguous machine-machine communication, i.e. for data exchange without operator interference, the data (PICOM) identifiers and attributes shall also be understandable for machines.

Annex A
(informative)

Logical nodes and related PICOMs

The PICOMs are defined from the source point of view. For compact description, PICOMs common to a lot of protection LNs are combined in PICOM groups.

A.1 PICOM groups

Table A.1 – PICOM groups

Group	PICOM name	Source	Sink 1	Sink 2	Sink 3	Sink 4	Sink 5
Fault handling with start (P_fh_1)		**P…**					
	Start indication	P…	CALH	IHMI	ITCI		
	Trip indication	P…	CALH	IHMI	ITCI	RBRF	
	Trip command	P…	XCBR				
	Settings	P…	IHMI	ITCI	ITMI		
	Fault information	P…	IHMI	ITCI	ITMI		
	<Depending on function/some examples given>	P…					
Fault handling without start (P_fh_2)		**P…**					
	Trip indication	P…	CALH	IHMI	ITCI	RBRF	
	Trip command	P…	XCBR				
	Settings	P…	IHMI	ITCI	ITMI		
	Fault information	P…	IHMI	ITCI	ITMI		
	<Depending on function/some examples given>	P…					
Fault handling without start and trip (P_fh_3)		**P…**					
	Trigger indication	P…	CALH	IHMI	ITCI		
	Trigger	P…	P…	R…	A…	C…	
	Settings	P…	IHMI	ITCI	ITMI		
	Fault information	P…	IHMI	ITCI	ITMI		
	<Depending on function/some examples given>	P…					

A.2 Logical node list

Table A.2 – Logical node list

LN	PICOM name	Source	Sink 1	Sink 2	Sink 3	Sink 4	Sink 5
Transient earth fault protection		**PTEF**					
	P_fh_3	PTEF	*CALH*	*IHMI*	*ITCI*	*P…R…*	*A…C…*
	<fault signature>	PTEF					
Zero speed and underspeed protection		**PZSU**					
	P_fh_1	PZSU	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<Rotor locked>	PZSU	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<Underspeed>	PZSU	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*

Distance protection		**PDIS**					
	P_fh_1	PDIS	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<Fault impedance Z>	PDIS					
	Operated	PDIS	RREC				
	Trigger	PDIS	RDRE	RFLO			
V per Hz protection		**PVPH**					
	P_fh_1	PVPH	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
Undervoltage protection		**PTUV**					
	P_fh_1	PTUV	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<minimum voltage>	PTUV					
Directional power /reverse power protection		**PDPR**					
	P_fh_1	PDPR	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<power direction>	PDPR					
Directional earth fault wattmetric protection		**PWDE**					
	P_fh_1	PWDE	*CALH*	*IHMI*	*ITCI*	*XCBR*	
	<fault direction>	PWDE					
Undercurrent/underpower protection		**PUCP**					
	P_fh_1	PUCP	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<minimum current>	PUCP					
	<minimum power>	PUCP					
Loss of field/underexcitation protection		**PUEX**					
	P_fh_1	PUEX	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<Field value>	PUEX					
Reverse phase or phase balance current protection		**PPBR**					
	P_fh_1	PPBR	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<phase sequence>	PPBR					
	<negative phase sequence component>	PPBR					
Phase sequence voltage protection		**PPBV**					
	P_fh_1	PPBV	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<phase sequence>	PPBV					
Motor start-up protection		**PMSU**					
	P_fh_1	PMSU	*CALH*	*IHMI*	*ITCI*	*ZMOT*	*XCBR*
	<Restart inhibited>	PMSU					
	<Restart inhibition time>	PMSU					
Overload protection, thermal protection		**PTTR**					
	P_fh_1	PTTR	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<Actual temperature>	PTTR					
	<Integrated current>	PTTR					
Rotor thermal overload protection		**PROL**					
	P_fh_1	PROL	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<Actual temperature>	PROL					
	<Integrated current>	PROL					
Stator thermal overload protection		**PSOL**					
	P_fh_1	PSOL	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*

	<Actual temperature>	PROL					
	<Integrated current>	PROL					
Instantaneous overcurrent or rate of rise protection		**PIOC**					
	P_fh_1	PIOC	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<peak current>	PIOC					
	<rise of current>	PIOC					
AC time overcurrent relay same holds for		**PTOC**					
	P_fh_1	PTOC	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<peak current>	PTOC					
Voltage controlled/dependent time overcurrent protection		**PVOC**					
	P_fh_1	PVOC	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<peak current>	PVOC					
Power factor protection		**PPFR**					
	P_fh_1	PPFR	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<power factor>	PPFR					
Overvoltage protection		**PTOV**					
	P_fh_1	PTOV	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<maximum voltage>	PTOV					
DC overvoltage protection		**PDOV**					
	P_fh_1	PDOV	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
Voltage or current balance protection		**PVCB**					
	P_fh_1	PVCB	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<Voltage difference>	PVCB					
Earth fault protection/ground detection		**PHIZ**					
	P_fh_1	PHIZ	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<Zero current>	PHIZ					
Rotor earth fault		**PREF**					
	P_fh_1	PREF	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<Zero current>	PREF					
Stator earth fault		**PSEF**					
	P_fh_1	PSEF	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<Zero current>	PSEF					
Interturn fault		**PITF**					
	P_fh_1	PITF	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<Zero current>	PITF					
AC directional overcurrent protection		**PDOC**					
	P_fh_1	PDOC	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<peak current>	PDOC					
	<direction>	PDOC					
Directional earth fault protection		**PDEF**					
	P_fh_1	PDEF	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
	<peak current>	PDEF					
	<direction>	PDEF					

DC time overcurrent	**PDCO**					
P_fh_1	PDCO	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
<peak current>	PDCO					
Phase angle or out of step (trip) protection	**PPAM**					
P_fh_1	PPAM	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
<phase angle>	PPAM					
Frequency protection	**PFRQ**					
P_fh_1	PFRQ	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
<Frequency>	PFRQ					
<Change of rate>	PFRQ					
Restoration release	PFRQ	*GAPC*				
Shedding request	PFRQ	*GAPC*				
Differential protection (see below)	**PDIF**					
Phase comparison protection	**PPDF**					
P_fh_1	PPDF	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
<phase angle difference>	PPDF					
Line differential protection	**PLDF**					
P_fh_2	PLDF	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
<Current difference>	PLDF					
Operated	PLDF	RREC				
Trigger	PLDF	RDRE				
Restricted earth fault protection	**PNDF**					
P_fh_2	PNDF	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
<Current difference>	PNDF					
Transformer differential protection	**PTDF**					
P_fh_2	PTDF	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
<Current difference>	PTDF					
Busbar protection	**PBDF**					
P_fh_2	PBDF	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
<Current difference>	PBDF					
<Faulted zone information>	PBDF					
Motor differential protection	**PMDF**					
P_fh_2	PMDF	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
<Start-up current>	PMDF					
<Violating value>	PMDF					
Generator differential protection	**PGDF**					
P_fh_2	PGDF	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
<Current difference>	PGDF	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
<maximum voltage>	PDOV					

Disturbance recording (acquisition at bay/process level)	**RDRE**					
Fault record	RDRE	RDRS				
<time and date of rec.>	RDRE					
<Cause of rec.>	RDRE					
<waveform data>	RDRE					
<current phase 1>	RDRE					
<current phase 2>	RDRE					
<current phase 3>	RDRE					
<voltage phase 1>	RDRE					
<voltage phase 2>	RDRE					
<voltage phase 3>	RDRE					
<Event data>	RDRE					
<settings>	RDRE					
<parameters last fault>	RDRE					
<parameters last fault -1>	RDRE					
<parameters last fault -2>	RDRE					
Recorder faulty	RDRE	CALH	IHMI	ITCI	RDRS	
Recorder memory full	RDRE	CALH	IHMI	ITCI	RDRS	
Recorder operated	RDRE	CALH	RDRS			
Trigger	RDRE	RDRE				
Settings	RDRE	IHMI	ITCI	RDRS		
Disturbance recording (evaluation at station level)	**RDRS**					
Date and time	RDRS	RDRE				
Fault record	RDRS	IARC				
<time and date of rec.>	RDRS					
<Cause of rec.>	RDRS					
<waveform data>	RDRS					
<current phase 1>	RDRS					
<current phase 2>	RDRS					
<current phase 3>	RDRS					
<voltage phase 1>	RDRS					
<voltage phase 2>	RDRS					
<voltage phase 3>	RDRS					
<Event data>	RDRS					
<settings>	RDRS					
<parameters last fault>	RDRS					
<parameters last fault -1>	RDRS					
<parameters last fault -2>	RDRS					
Settings	RDRS	IHMI	ITCI	RDRE		
Automatic reclosing	**RREC**					
Alarms	RREC	CALH				
Events	RREC	CALH				
Bay auto reclose status	RREC	IHMI	ITCI			

	Commands to circuit breaker directly or via CPOW	RREC	XCBR	CPOW			
	<Close to circuit breaker>	RREC					
	Sync request	RREC	RSYN				
	Command to circuit breaker with controlled switching	RREC	CSWI				
	<Close to circuit breaker>	RREC					
	Settings	RREC	IHMI	ITCI			
Breaker failure		**RBRF**					
	Fault information	RBRF	IHMI	ITCI			
	Trip indication	RBRF	CALH	IHMI	ITCI		
	Trip command	RBRF	XCBR				
	Settings	RBRF	IHMI	ITCI			
Carrier or pilot wire protection		**RCPW**					
	P_fh_3	PMDF	*CALH*	*IHMI*	*ITCI*	*P…R…*	*A…C…*
Fault locator function		**RFLO**					
	Fault location	RFLO	IHMI	ITCI			
	Settings	RFLO	IHMI	ITCI			
Synchrocheck		**RSYN**					
	In synchronism indication	RSYN	CSWI	IHMI	ITCI	RREC	GAPC
	Settings	RSYN	IHMI	ITCI			
Power swing blocking		**RPSB**					
	P_fh_3	PMDF	*CALH*	*IHMI*	*ITCI*	*P…R…*	*A…C…*
Alarm Handling		**CALH**					
	Function supervision	CALH	IHMI	ITCI	*SSYS*		
	Alarms (sum)	CALH	IHMI	ITCI			
	Alarm indication	CALH	IHMI	ITCI			
	Alarm list update	CALH	IHMI	ITCI			
	Alarms (list)	CALH	IARC				
	Acknowledge	CALH	IHMI	ITCI			
	Event indication	CALH	IHMI	ITCI			
	Events (sum)	CALH	IHMI	ITCI			
	Event list update	CALH	IHMI	ITCI			
	Events (history list)	CALH	IARC				
	Settings	CALH	IHMI	ITCI			
Switch controller (command handling at bay level)		**CSWI**					
	Commands to switch directly or via CPOW if applicable	CSWI	X…	*XCBR*	*XSWI*	*CPOW*	
	<switch ON>	CSWI					
	<switch OFF>	CSWI					
	Function supervision	CSWI	CALH	IHMI	ITCI		
	Indications	*CSWI*	*SSYS*				
	Events/Position change	CSWI	CALH	IHMI	ITCI		
	Position indications	CSWI	IHMI	ITCI			
	No-operation information	CSWI	IHMI	ITCI			
	Releases	CSWI	IHMI	ITCI			
	Request	CSWI	CILO				

	Sync request	CSWI	RSYN				
	Settings	CSWI	IHMI	ITCI			
Point on wave breaker controller		**CPOW**					
	Commands to breaker directly	CPOW	XCBR				
	<Breaker ON>	CPOW					
	<Breaker OFF>	CPOW					
	Function supervision	CPOW	CALH	IHMI	ITCI		
	Indications	CPOW	*SSYS*				
	Events/Position change	CPOW	CALH	IHMI	ITCI		
	Position indications	CPOW	IHMI	ITCI			
	No-operation information	CPOW	IHMI	ITCI			
	Releases	CPOW	IHMI	ITCI			
	Settings	CPOW	IHMI	ITCI			
Interlocking		**CILO**					
	Events	CILO	CALH	IHMI	ITCI	*SSYS*	
	Indications	CILO	CSWI	IHMI	(CILO)	*SSYS*	
	Releases	CILO	CSWI	(CILO)			
	Request	CILO	(CILO)				
	Switchgear position	CILO	(CILO)				
	Settings	CILO	IHMI	ITCI	(CILO)		
Operator interface at device or station level – same for **remote control interface** (maybe with some restrictions)		**IHMI** **ITCI**					
	Acknowledge	IHMI	CALH				
	Commands	IHMI	GGIO	GAPC	…		
	Commands to switchgear and transformers	IHMI	CSWI	ATCC			
	Examples	IHMI					
	<Switch ON>	IHMI					
	<Switch OFF>	IHMI					
	<tap changer UP>	IHMI					
	<tap changer DOWN>	IHMI					
	Indications	IHMI	CALH	ITCI	IHMI	ITMI	*SSYS*
	Settings (for configuration/operation to all LN if applic.)	IHMI	P…	A…	C…	I…	A…
	Settings (for configuration/operation to all LN if applic.)	IHMI	G…	M…	L…	T…	X…
	Settings (for configuration/operation to all LN if applic.)	IHMI	Y…	Z…	S…		
	Examples	IHMI					
	<Date and time>	IHMI					
	<Mode of operation>	IHMI					
	<In service>	IHMI					
	<Reclose release>	IHMI					
	<parameters for CB>	IHMI					
	<parameters for disconnects>	IHMI					
	<parameters for tap changer >	IHMI					
	<parameters for current data acquisition>	IHMI					
	< : >	IHMI					

Remote monitoring interface	**ITMI**					
Acknowledge	ITMI	CALH	IHMI			
Commands (if applicable/no operation of switchgear)	ITMI	GGIO	GAPC	ATCC	…	
Settings (for configuration/operation to all LN if applic.)	ITMI	P…	A…	C…	I…	A…
Settings (for configuration/operation to all LN if applic.)	ITMI	G…	M…	L…	T…	X…
Settings (for configuration/operation to all LN if applic.)	ITMI	Y…	Z…	S…		
Archiving	**IARC**					
Events	IARC	IHMI	ITCI			
Function supervision	IARC	IHMI	ITCI			
Indications	IARC	IHMI	ITCI	*SSYS*		
Stored values/records	IARC	IHMI	ITCI	ITMI	RDRS	
<disturbance records>	IARC					
<statistics>	IARC					
Settings	IARC	IHMI	ITCI	ITMI		
Automatic tap changer control	**ATCC**					
Commands	ATCC					
<tap changer UP>	ATCC	YLTC				
<tap changer DOWN>	ATCC	YLTC				
Switchgear operation	ATCC	CSWI				
Function supervision	ATCC	CALH	IHMI	ITCI		
<status M-Process not o.k.>	ATCC					
<status peripherals units not o.k. >	ATCC					
<status sub-units>	ATCC					
<power supply voltage>	ATCC					
<spontaneous buffer overflow>	ATCC					
<parallel operation error>	ATCC					
Operation supervision	ATCC	CALH	IHMI	ITCI		
<undervoltage>	ATCC					
<overvoltage>	ATCC					
<overcurrent>	ATCC					
Mode of operation	ATCC	IHMI	ITCI			
<local operation>	ATCC					
<remote operation>	ATCC					
<manual operation>	ATCC					
<automatic operation>	ATCC					
<single operation>	ATCC					
<parallel operation>	ATCC					
Settings	ATCC	IHMI	ITCI			
<local operation>	ATCC					
<remote operation>	ATCC					
<manual operation>	ATCC					
<automatic operation>	ATCC					
<undervoltage limit>	ATCC					
<overvoltage limit>	ATCC					

	<overcurrent limit>	ATCC					
	<selected setpoint>	ATCC					
	<selected line comp.>	ATCC					
Automatic voltage control		**AVCO**					
	Commands	AVCC					
	<tap changer UP>	AVCC	YLTC				
	<tap changer DOWN>	AVCC	YLTC				
	Function supervision	AVCO	CALH	IHMI	ITCI		
	Mode of operation	AVCO	CALH	IHMI	ITCI		
	Settings	AVCO	IHMI	ITCI			
Reactive control		**ARCO**					
	Function supervision	ARCO	CALH	IHMI	ITCI		
	Mode of operation	ARCO	CALH	IHMI	ITCI	ZRRC	ZTCR
	Settings	ARCO	IHMI	ITCI			
	Switchgear operation	ARCO	CSWI				
Earth fault neutralizer (Petersen coil) control		**ANCR**					
	Commands	ANCR					
	<plunge core UP>	ANCR	YEFN				
	<plange core DOWN>	ANCR	YEFN				
	Function supervision	ANCR	CALH	IHMI	ITCI		
	Mode of operation	ANCR	CALH	IHMI	ITCI		
	Settings	ANCR	IHMI	ITCI			
Zero voltage tripping		**AZVT**					
	P_fh_2	PGDF	*CALH*	*IHMI*	*ITCI*	*RBRF*	*XCBR*
Automatic process control (generic, programmable)		**GAPC**					
	Examples below:	GAPC					
Load shedding		***GAPC***					
	Function supervision	GAPC	IHMI	ITCI			
	Mode of operation	GAPC	IHMI	ITCI			
	Operation indication	GAPC	IHMI	ITCI			
	Switchgear operation	GAPC	CSWI				
	Settings	GAPC	IHMI	ITCI			
Infeed transfer switching		***GAPC***					
	Function supervision	GAPC	IHMI	ITCI			
	Operation indication	GAPC	IHMI	ITCI			
	Switchgear operation	GAPC	CSWI				
	Settings	GAPC	IHMI	ITCI			
Transformer change		***GAPC***					
	Function supervision	GAPC	IHMI	ITCI			
	Operation indication	GAPC	IHMI	ITCI			
	Switchgear operation	GAPC	CSWI				
	Settings	GAPC	IHMI	ITCI			

Busbar change	***GAPC***					
Function supervision	GAPC	CALH	IHMI	ITCI		
Operation indication	GAPC	CALH	IHMI	ITCI		
Switchgear operation	GAPC	CSWI				
Switchgear position	GAPC	IHMI	ITCI			
Commands	GAPC	CSWI				
Settings	GAPC	IHMI	ITCI			
Automatic clearing and voltage restoration	***GAPC***					
Function supervision	GAPC	CALH	IHMI	ITCI		
Operation indication	GAPC	IHMI	ITCI			
Switchgear operation	GAPC	IHMI	ITCI			
Sync request	GAPC	RSYN				
Indications	GAPC	IHMI	ITCI			
Commands	GAPC	CSWI				
Settings	GAPC	IHMI	ITCI			
Measuring (acquisition and calculation)	**MMXU**					
Function supervision	MMXU	CALH	IHMI	ITCI		
Integrated totals	MMXU	IARC	IHMI	ITCI		
<energy (quadrant I)>	MMXU					
<energy (quadrant II)>	MMXU					
<energy (quadrant III)>	MMXU					
<energy (quadrant IV)>	MMXU					
<max power (quadrant I)>	MMXU					
<max power (quadrant II)>	MMXU					
<max power (quadrant III)>	MMXU					
<max power (quadrant IV)>	MMXU					
Metering values	MMXU	IHMI	ITCI			
Settings	MMXU	IHMI	ITCI	MMXU		
Metering (acquisition and calculation)	**MMTR**					
Function supervision	MMTR	CALH	IHMI	ITCI		
Integrated totals	MMTR	IARC	IHMI	ITCI		
<energy (quadrant I)>	MMTR					
<energy (quadrant II)>	MMTR					
<energy (quadrant III)>	MMTR					
<energy (quadrant IV)>	MMTR					
<max power (quadrant I)>	MMTR					
<max power (quadrant II)>	MMTR					
<max power (quadrant III)>	MMTR					
<max power (quadrant IV)>	MMTR					
Metering values	MMTR	IHMI	ITCI			
Settings	MMTR	IHMI	ITCI			
Reports	MMTR	IHMI	ITCI			

Sequences and imbalances		**MSQI**					
	Function supervision	MSQI	CALH	IHMI	ITCI		
	Calculated values	MSQI	IARC	IHMI	ITCI		
Harmonics and interharmonics		**MHAI**					
	Function supervision	MHAI	CALH	IHMI	ITCI		
	Calculated values	MHAI	IARC	IHMI	ITCI		
Logical node device		**LLN0**					
	ID-data	LLNO	IHMI	ITCI	ITMI		
	<identifiers/…>	LLNO					
	Settings	LLNO	IHMI	ITCI	ITMI		
	<configuration>	LLNO					
General security application		**GSAL**					
	Events	GSAL	CALH	IHMI	ITCI	ITMI	
	Diagnostic data	GSAL	IHMI	ITCI	ITMI		
Circuit breaker		**XCBR**					
	Function supervision	XCBR	CALH	IHMI	ITCI		
	<position/blocking for closing>	XCBR					
	<position/blocking for opening>	XCBR					
	<Auto reclosure lockout>	XCBR					
	<main circuit alarm>	XCBR					
	<main circuit warning>	XCBR					
	<auxiliary circuit alarm>	XCBR					
	<auxiliary circuit warning>	XCBR					
	<operating mechanism alarm>	XCBR					
	<operating mechanism warning>	XCBR					
	<power supply alarm>	XCBR					
	<power supply waning>	XCBR					
	Events	XCBR	CALH	IHMI	ITCI		
	Position indication	XCBR	CSWI	IHMI	ITCI		
	<position/CB ON>	XCBR					
	<position/CB OFF>	XCBR					
	<position/CB INTERMED>	XCBR					
	s-t-diagram	XCBR	CSWI	IHMI	ITCI		
	Status indications	XCBR	XCBR	IHMI	ITCI		
	<Local mode>	XCBR					
	<Remote mode>	XCBR					
	<opening time>	XCBR					
	<closing time>	XCBR					
	<general lockout>	XCBR					
	Measurands/counter values	XCBR	TCPT				

<position/operations counter, perm>	XCBR					
<position/operations counter, resetable>	XCBR					
<various data>	XCBR					
Diagnostic data	XCBR	CSWI	IHMI	ITCI		
ID-data	XCBR	CSWI	IHMI	ITCI		
<identifiers/…>	XCBR					
<…/manufacturer id>	XCBR					
<…/HV bay-id>	XCBR					
<…/address>	XCBR					
<…/hardware version>	XCBR					
<…/firmware version>	XCBR					
<…/software version>	XCBR					
<nameplate/…	XCBR					
<…/Rated Voltage>	XCBR					
<…/Rated lightning impulse withstand voltage>	XCBR					
<…/Rated short duration power frequency withstand voltage>	XCBR					
<…/Rated frequency>	XCBR					
<…/Rated normal current>	XCBR					
<…/Rated short time withstand current>	XCBR					
<…/Rated breaking-current>	XCBR					
<…/Rated duty cycle>	XCBR					
<…/Auxiliary Voltage>	XCBR					
Settings	XCBR	CSWI	IHMI	ITCI		
Disconnector/earth switch/…	**XSWI**					
Function supervision	XSWI	CALH	IHMI	ITCI		
Events	XSWI	CALH	IHMI	ITCI		
Position indication	XSWI	IHMI	ITCI			
<position ON>	XSWI					
<position OFF>	XSWI					
<position INTERMED>	XSWI					
s-t-diagram	XSWI	IHMI	ITCI			
Settings	XSWI	IHMI	ITCI			
Insulation medium supervision, for example GIS-SF6-Mon.	**SIMS**					
Function supervision	SIMS	CALH	IHMI	ICTI		
Alarms	SIMS	CALH	IHMI	ICTI		
<low pressure 3 alarm>	SIMS					
Events	SIMS	IHMI	ICTI			
<over pressure>	SIMS					
<low pressure 1 warning>	SIMS					
<low pressure 2 warning>	SIMS					
Diagnostic data	SIMS	IHMI	ICTI			
Settings	SIMS	IHMI	ICTI			

GIS-ARC-monitoring		**SARC**					
	Function supervision	SARC	CALH	IHMI	ITCI		
	Alarms	SARC	CALH	IHMI	ITCI		
	<alarm ARC occurred>	SARC					
	Events	SARC	CALH	IHMI	ITCI		
	Diagnostic data	SARC	IHMI	ITCI			
	Settings	SARC	CSDA	IHMI	ITCI		
GIS-PD-monitoring		**SPDC**					
	Function supervision	SPDC	CALH	IHMI	ICTI		
	Events	SPDC	CALH	IHMI	ICTI		
	<warning PD occurred>	SPDC					
	Diagnostic data	SPDC	IHMI	ICTI			
	Settings	SPDC	IHMI	ICTI			
Current transformer (CT)		**TCTR**					
	Process value (current sample)	TCTR	P…	R …	M …	A …	
	Settings	TCTR	IHMI	ITCI			
Voltage transformer (VT)		**TVTR**					
	Process value (voltage sample)	TVTR	P…	R …	M …	A …	
	Settings	TVTR	IHMI	ITCI			
Power transformer		**YPTR**					
	Function supervision	YPTR	CALH	IHMI	ITCI		
	Events	YPTR	CALH	IHMI	ITCI		
	Settings	YPTR	ATCC	IHMI	ITCI		
Tap changer		**YLTC**					
	Function supervision	YLTC	CALH	IHMI	ITCI		
	Events	YLTC	CALH	IHMI	ITCI		
	Tap changer motor running	YLTC	ATCC				
	Tap position (BCD)	YLTC	ATCC	IHMI	ITCI		
	Settings	YLTC	ATCC	IHMI	ITCI		
Earth fault neutralizer (Petersen coil)		**YEFN**					
	Function supervision	YEFN	CALH	IHMI	ITCI		
	Events	YEFN	CALH	IHMI	ITCI		
	Coil changer motor running	YEFN	GAPC				
	Coil position	YEFN	IHMI	ITCI	ITCI		
	Settings	YEFN	GAPC	IHMI	ITCI		
Power shunt		**YPSH**					
	Function supervision	YPSH	CALH	IHMI	ITCI		
	Events	YPSH	CALH	IHMI	ITCI		
	Shunt switch running	YPSH					
	Shunt position	YPSH	GAPC	IHMI	ITCI		
	Settings	YPSH	GAPC	IHMI	ITCI		

Auxiliary network	**ZAXN**					
Battery	**ZBAT**					
Bushing	**ZBSH**					
HV cable	**ZCAB**					
Capacitor bank	**ZCAP**					
Converter	**ZCON**					
Generator	**ZGEN**					
Gas isolated line (GIL)	**ZGIL**					
Power overhead line	**ZLIN**					
Motor	**ZMOT**					
Reactor	**ZREA**					
Rotating reactive component	**ZRRC**					
Surge arrestor	**ZSAR**					
Thyristor controlled frequency converter	**ZTCF**					
Thyristor controlled reactive component	**ZTCR**					
Generic general I/O	**GGIO**					
Alarms	GGIO	CALH	IHMI	ITCI		
Events	GGIO	CALH	IHMI	ITCI		
Aux. device supervision	GGIO	GAPC	CALH	ARCO	ATCC	
Indications	GGIO	IHMI	ITCI			
Settings	GGIO	IHMI	ITCI			
Status	GGIO	SSYS				
Time synchronization/central clock	**STIM**					
Operation indication	STIM	LLN0				
Time	STIM	*All if appli-cable*				
System supervision	**SSYS**					
Events	SSYS	IHMI	ITCI	CALH		
Function supervision	SSYS	IHMI	ITCI			
Indications	SSYS	IHMI	ITCI	SSYS		
Failure	SSYS	CALH	IHMI	ITCI		
Restart unit operation	SSYS	CALH	IHMI	ITCI		
Stop unit operation	SSYS	CALH	IHMI	ITCI		
Unit buffer overflow	SSYS	CALH	IHMI	ITCI		
Urgent error	SSYS	CALH	IHMI	ITCI		
Test generator	**GTES**					
Test message	GTES	*All if applic-able*				

Annex B
(informative)

PICOM identification and message classification

B.1 Introduction

The communication between LNs is described by the exchange of thousands of individual PICOMs. Nevertheless, there are a lot of similarities between these PICOMs, for example all PICOMs describing trips have besides the individual sources more or less identical communication requirements as described by the PICOM attributes. Therefore, a classification of PICOMs would result both in a comprehensive overview on the requirements and in the support of a strong modeling and definition of the requested communication performance.

In a first step, all PICOMs from as many LNs as possible are identified and allocated to a PICOM type using a common purpose and having common attributes. The result is found in B.2.

The resulting PICOM types with their most important common attributes are given in B.3. The broad range of transfer time requirements reflects the individual needs of the functions. Since the higher ones always cover lower requirements, the requirements may be condensed in figures for the message types introduced below.

Essential for a proper running of functions and crucial for any performance requirements of the supporting communication system is the maximum time allowed for the data exchange. In the context of this part of IEC 61850, this time is called “overall transfer time” and is clearly defined in 13.2.

In 13.7, the PICOM types are condensed to 7 message types and the range of its attributes is structured by performance classes. Some hints to typical applications and interface allocation are also given.

The introduction and use of message types is described in 13.5, the introduction and use of performance classes in 13.6.

B.2 Identification and type allocation of PICOMs

Table B.1 – Identification and type allocation of PICOMs – Part 1

PICOM TYPE ID[a]	1	5	6	7	10	10	12	12	22	24	9	10	17	19	16	13	18	12	10	10	10	10	11	26	10
													19		17			10		11		11			
PICOM / LOGICAL NODE	Current/voltage	Non-electric process data	Fault information (short)	Fault info (long)	Start indication	Trip indication	Operated	Trigger	Trip command	Settings	Fault record	Recorder memory full	In service	Mode of operation	Status	Station interlocking	External conditions	Synchronism detected	Fuse failure detected	Group alarm	Alarm indication	Alarm list update	Alarm list	Acknowledgement	Alarm
P… (Protection)			X	X	X	X	X	X	X	X															
RDRE (Disturbance recording at bay level)							X	X		X	X	X													
RDRS (Disturbance recording at station level)										X	X														
RREC (Automatic reclosure)										X			X		X	X	X								X
RBRF (Breaker failure)			X			X			X	X															
RCPW (Carrier or pilot wire relay)																									
RFLO (Fault locator)			X	X						X															
RSYN (Synchrocheck)										X								X							
RPSB (Power swing blocking)																									
CALH (Alarm handling)										X										X	X	X	X	X	
CSWI (Switch controller)										X															
CILO (Interlocking)										X															
ATCC (Tap changer controller)										X															
IHMI (Human machine interface)										X			X	X										X	
ITCI (Telecontrol interface)										X			X	X										X	
ITMI (Telemonitoring interface)									?	X				X										X	
IARC (Archiving)			X	X						X	X														
AVCO (Voltage Control)										X				X	X										
ARCO (Reactive control)										X				X											
ANCR (Earth fault neutralizer control)																									
AZVT (Zero voltage tripping)			X	X	X	X	X	X	X	X															
GAPC (Automatic process control)										X				X	X										

[a] PICOM TYPE ID gives a rough classification of all requested PICOM according to their attributes.

Table B.2 – Identification and type allocation of PICOMs – Part 2

PICOM TYPE ID[a]	10	10	10	11	10	27	28	10	10	21	21	10	16	17	12	14	14	4	4	6	9	25	4	25	24
		11	11									12			12										
PICOM / LOGICAL NODE	Event indication	Group event	Event list update	Event list archive	Event	Date and time	Synchronization (clock)	Recorder faulty	Function supervision	Command to switchgear	Command to aux. devices	Indications	Position indications	No-operation information	Releases	Request to ITL	Request to SYNC	Integrated totals	Metered values	Reports	Archived data	s-t-diagram	counter values	diagnostic data	ID data
P… (Protection)																									
RDRE (Disturbance recording at bay level)								X																	
RDRS (Disturbance recording at station level)						X		X																	
RREC (Automatic reclosure)					X				X	X							X								
RBRF (Breaker failure)																									
RCPW (Carrier or pilot wire relay)																									
RFLO (Fault locator)																									
RSYN (Synchrocheck)																									
RPSB (Power swing blocking)																									
CALH (Alarm handling)	X	X	X	X		X	X		X																
CSWI (Switch controller)					X				X	X		X	X	X	X	X	X								
CILO (Interlocking)										X			X		X		X								
ATCC (Tap changer controller)					X				X		X	X	X	X											
IHMI (human machine interface)						X	X			X	X	X			X										
ITCI (Telecontrol interface)						X				X	X				X										
ITMI (Telemonitoring interface)						X									X										
IARC (Archiving)					X				X			X									X				
AVCO (Voltage control)									X	X	X		X												
ARCO (Reactive control)									X	X															
ANCR (Earth fault neutralizer control)																									
AZVT (Zero voltage tripping)																									
GAPC (Automatic process control)									X	X		X	X			X	X								

[a] PICOM TYPE ID gives a rough classification of all requested PICOM according to their attributes.

Table B.3 – Identification and type allocation of PICOMs – Part 3

PICOM TYPE ID[a]	**1**	**5**	**6**	**7**	**10**	**10**	**12**	**12**	**22**	**24**	**9**	**10**	**17**	**19**	**16**	**13**	**18**	**12**	**10**	**10**	**10**	**10**	**11**	**26**	**10**
													19		**17**			**10**		**11**		**11**			
PICOM / **LOGICAL NODE**	**Current/voltage**	**Non-electric process**	**Fault information**	**Fault info (long)**	**Start indication**	**Trip indication**	**Operated**	**Trigger**	**Trip command**	**Settings**	**Fault record**	**Recorder memory full**	**In service**	**Mode of operation**	**Status**	**Station interlocking**	**External conditions**	**Synchronism detected**	**Fuse failure detected**	**Group alarm**	**Alarm indication**	**Alarm list update**	**Alarm list**	**Acknowledgement**	**Alarm**
MMXU (Measuring)										X							X		X	X					
MMTR (metering)										X															
MSQI (Sequences ...)										X							X		X	X					
MHAI (Harmonics ...)										X							X		X	X					
LLN0 (Device supervision and identification)							X																		X
GSAL (General security application)			X							X											X				X
XCBR (Circuit breaker)							X			X															
XSWI (Disconnector)										X															
SIMS (Insulation medium supervision)										X															X
SARC (Arc detection)										X															X
SPDC (Partial discharge)										X															X
TCTR (Current transformer)	X									X															
TVTR (Voltage transformer)	X									X															
YPTR (Power transformer)		X						X		X															
YLTC (Tap changer)															X										X
YEFN (Earth fault neutraliser, Petersen coil)																									
YPSH (Power shunt)																									
ZGEN (Generator)		X								X					X										X
ZTCF (Thyistor controlled condenser)		X								X					X										X
ZCON (Converter)		X								X					X										X
ZMOT (Motor)		X								X					X										X
ZSAR (Surge arrestor)		X								X					X										X
ZTCR (Thyistor controlled reactor)	X									X					X										X
ZRRC (Rot.contr.reac.)	X									X					X										X
ZCAP (Capacitor bank)	X									X					X										X
ZREA (Reactor)	X									X					X										X
ZCAB (Cable mon.)	X	X								X					X										X
ZGIL (Gas isolated line)	X	X								X					X										X
ZLIN (Power OH line)	X	X								X					X										X
ZBAT (Battery)	X	X								X					X										X
ZAXN (Auxiliary network)	X	X								X					X										X
GGIO (Generic I/O)	X		X					X		X					X		X								X
STIM (Time master)										X															
SSYS (System Supervision)				X				X		X											.				X
GTES (Test generator)																									

[a] **PICOM TYPE ID gives a rough classification of all requested PICOM according to their attributes.**

Table B.4 – Identification and type allocation of PICOMs – Part 4

PICOM TYPE ID[a]	10	10	10	11	10	27	28	10	10	21	21	10	16	17	12	14	14	4	4	6	9	25	4	25	24
		11	11									12			12										
PICOM LOGICAL NODE	Event indication	Group event	Event list update	Event list archive	Event	Date and time	Synchronization (clock)	Recorder faulty	Function supervision	Command to switchgear	Command to aux.	Indications	Position indications	No-operation information	Releases	Request to ITL	Request to SYNC	Integrated totals	Metered values	Reports	Archived data	s-t-diagram	Counter values	Diagnostic data	ID data
MMXU (Measuring)										X							x		x	x					
MMTR (metering)										X															
MSQI (Sequences ...)										X							x		x	x					
MHAI (Harmonics ...)										X							x		x	x					
LLN0 (Device super-vision and identification					X																				X
GSAL (General security application)					X																				X
XCBR (Circuit breaker)					X				X	X															
XSWI (Disconnector)					X				X				X									X			
SIMS (Insulation medium supervision)					X				X															X	
SARC (Arc detection)					X				X															X	
SPDC (Partial Discharge)					X				X															X	
TCTR (Current transformer)																									
TVTR (Voltage transformer)																									
YPTR (Pow.transf.3ph)					X				X															X	X
YLTC (Tap changer)					X							X	X	X											
YEFN (Earth fault neutr., Petersen coil)																									
YPSH (Power shunt)																									
ZGEN (Generator)					X				X			X												X	X
ZTCF (Converter)					X				X			X												X	X
ZCON (Converter)		X								X					X										X
ZMOT (Motor)					X				X			X													
ZSAR (Surge arrestor)					X							X													
ZTCR (Thyistor controlled reactor)					X																				
ZRRC (Rot.contr.reac.)					X																				
ZCAP (Capacitor bank)					X																				
ZREA (Reactor)					X																				
ZCAB (Cable mon.)					X				X															X	
ZGIL (Gas isolated line)					X				X															X	
ZLIN (Power OH line)	X	X								X					X										X
ZBAT (Battery)					X				X															X	
ZAXN (Aux. network)	X	X								X					X										X
GGIO (Generic I/O)					X				X	X	X	X	X	X	X									X	X
STIM (Time master)						X	X																		
SSYS (System. Supervision)					X				X			X													
GTES (Test generator)																									

[a] PICOM TYPE ID gives a rough classification of all requested PICOM according to their attributes.

B.3 Table of PICOM types

The PICOM types appearing by the decomposition of Logical Nodes into PICOMs according to the PICOM Table are summarized in the following Table with their range of attributes:

Table B.5 – PICOM types – Part 1

PICOM TYPE ID	Meaning of PICOM and its value attribute[1]	Type mode	Number of value attributes combined - range - typical figures	Size of value attribute in bits[2]	Transfer time[3] (response/cycle) • range • typical figure given in ms	Message type[4]
1	Process value (sample)	Value Cyclic	1 to 8 1, 2, 3, 5	16	• 10 • 0,1; 0,5; 1; 2; 5; 10	4[a]
2	Process value (r.m.s.)	Value Cyclic	1 to 8 1, 2, 3, 5	16	• 1 000 •50; 100; 500; 1 000	2[b]
3	Measured value (calculated) such as energy	Value Cyclic Request	1 to 64, 4, 6, 64	16	• 1 000 • 100; 500; 1 000	3
4	Metered value (calculated) such as energy	Value Cyclic Request	1 to 512 1, 512	16	• 1 000 • 100; 500; 1000	3
5	Process value (non-electrical) such as temperature	Value Cyclic	1 to 8 1	16	• 1 000 to 5 000 • 1 000; 5 000	3[c]
6	Report (calculated) such as energy list	File Request	1	1024	• 1 000 to 5 000 • 1 000; 5 000	5
7	Fault value (calculated) such as fault distance	Value Request	1 to 2 1	16	• 1 000 to 5 000 • 1 000; 5 000	3
8	Mixed fault info (calculated) extensive	File Request	1	512	• 1 000 to 5 000 • 1 000; 5 000	5
9	Mixed fault data (calculated) such as disturbance recording	File Request	1	20 000 20 0000	• 5 000	5
10	Event/alarm	Event Sponta-neous	1 to 16 1	1	• 100 to 1 000 • 100; 500; 1000	3[d]
11	Event/alarm list/group	File Sponta-neous Request	1	128 1 024	• 100 to 1 000 • 100; 500; 1000	5
12	Trigger (calculated) for example for start of another function	Event Sponta-neous	1	1	• 10 to 1 000 • 10; 50; 100; 1 000	1
13	Complex block or release (calculated)	Event Sponta-neous	1	16	• 10 to 100 • 10; 100	1
14	Request (calculated) for synchrocheck, interlocking, etc.	Event Sponta-neous Request	1	1	• 10 to 100 • 10; 100	2
15	Fast broadcast Message, for example for block/release	Event Sponta-neous	1	1	• 1 • 1	1
See notes to Table B.6.						

Table B.6 – PICOM types – Part 2

PICOM TYPE ID	Meaning of PICOM and its value attribute[1]	Type mode	Number of value attributes combined - range - typical figures	Size of value attribute in bits[2]	Transfer time[3] (response/cycle) • range • typical figure given in ms	Message type[4]
16	Process state	Status Request Cyclic	1	1	• 1 to 100 • 1; 10; 20; 50; 100	2[e]
17	Calculated state	Status Request	1	1	• 1 to 100 • 1; 10; 20; 50; 100	2[e]
18	External condition	Status Request Cyclic	1	1	• 1 to 100 • 1; 10; 20; 50; 100	2[e]
19	Mode of operation	Status Request Cyclic	1	1 16	• 10 to 100 • 10; 100	3
20	Process state changed	Event Sponta-neous	1	1	• 1 to 10 • 1; 10	1
21	Command	Cmd. Sponta-neous	1, 5	1	• 1 to 1000 • 1; 2; 5; 10; 50; 100; 1 000	7[f]
22	Trip	Cmd. Sponta-neous	1	1	• 1	1
23	Set point	Value Sponta-neous	1	16	• 100 to 1 000 • 100; 1 000	3
24	ID Data, setting	File Sponta-neous Request	1	1 024	• 1 000 to 5 000 • 1 000; 5 000	5
25	Diagnostic data	File Sponta-neous Request	1	1 024	• 5 000	5
26	Acknowledge by operator or auto.	Cmd. Sponta-neous	1	1	• 10 to 1 000 • 10; 100; 1 000	3
27	Date and time	Value Cyclic Request	1	32	• 100 to 1 000 • 100; 1 000	3
28	Synchronization "pulse"	Cmd. Cycl.	1	1	• 0,1 to 10 • 0,1; 0,5; 1; 2; 5; 10	6

[1] By basic definition, a PICOM consists of one data element (value only). Some of these basic data elements may be combined if this makes sense from the application point of view.

[2] Without a time tag; not a requirement but some idea about the net data and input for data flow calculations are necessary.

[3] See 12.2 for a definition.

[4] According to 12.5.

[a] Accuracy 25 µs or less.

[b] In future, some values regarding power quality may be of message type 1a.

[c] Special values such as pressure may need message type 2.

[d] Alarms and events as seen from the alarm and event handling, automatics may need message class 2.

[e] For some fast functions, message type 1 may be requested.

[f] The command message created as type 7 by the operator may be propagate at lower levels faster, for example according to type 1 on the process bus such as a trip.

Annex C
(informative)

Communication optimization

To reduce the load on the communication system whilst retaining full flexibility, the following principles should be considered:

Appropriate use of spontaneous transfers and cyclically polling between the logical nodes to reduce the load, instead of cyclically asking for the value. Note that these that spontaneous transfers are seen from the user layer, and that lower layers may have to ask for information cyclically.

Transmit a long (comprehensive) data description in the initialization phase and short identifiers in the operative phase.

Annex D
(informative)

Rules for function definition

To identify the communication requirements in terms of the LN and PICOM approach, the function definition consists of three steps:

1) function description including the decomposition into LNs;
2) logical node description including the exchanged PICOMs;
3) PICOM description including the attributes.

D.1 Function description

D.1.1 Task of the function

For each function a description is given to understand its task within the substation automation system independently of its distribution into LNs. This section should also specify the context needed for the execution of the function.

D.1.2 Starting criteria for the function

There is always some reason why a specific function is initiated, for example

- a human operator starts this function via an HMI,
- another function sends a request (typical of automatics),
- a status change in the process triggers this function (typical of protection).

This start reason has to be defined.

D.1.3 Result or impact of the function

Any function results either in some change of the process (for example by switching a breaker), in some trigger for another function or in some notification of the human operator. This result or impact has to be defined.

D.1.4 Performance of the function

This section should define the requested overall performance of the function from a system and application point of view. Therefore, total requested response is the sum of the starting time, the internal processing time, the overall transfer time per PICOM, and the delay time in the related process interface. This means that the pure data transfer time on the communication link has to be shorter than this figure. Additional performance criteria for example include the accuracy needed for the synchronization.

D.1.5 Function decomposition

This section describes how the function may be decomposed in LNs and how many decomposition sets typically exist.

D.1.6 Interaction with other functions

Data may be exchanged with other functions. These data and their importance for the function under consideration should be stated.

D.2 Logical Node description

D.2.1 Introduction

For each LN, a description is given to understand its task within the overall function. Especially, the context needed for the execution of the LN should be specified.

D.2.2 Starting criteria

The starting criteria and other inputs of the LN from a communication point of view should be identified.

D.2.3 Input and outputs by PICOMs

The input and outputs of the LN are described by the data to be exchanged, i.e. by PICOMs with all related attributes as given in 7.1, but without implementation or coding rules.

Inputs may be start, trip, block, settings, fault record, fault information, time tagged events, supervision alarm, position indication, position indication, commands, request for information, etc.

The meaning of starting criteria and inputs depends on the LN under consideration.

a) Data coming from (input) and data going to (output) the communication network are described informally here. This means data with all related application attributes.
b) The sending LN is the source and the receiving LN is the sink of the data stated within the context of the overall function.
c) The receiving LN has to know what it needs, i.e., it should be able to check if the delivered data are complete and valid for performing its task. It has to be able to check the quality of the incoming data, including its age. Therefore, all data have to be time tagged, if the communication system does not deliver data in well-defined time slots (implicit time tagging). Each sending LN has to identify possible doubts about the quality of the data sent and issue error messages if applicable.

D.2.4 Operation modes

Other LNs of distributed functions have to be informed about any degradation by a PICOM. If the receiver has enough time, a request for sending valid data could be sent. Nevertheless, the reaction in case of degraded data exchange has to provide a fail-safe behavior of the function. A PICOM is also required for return to normal mode.

The detailed sequential behavior of the distributed LNs is beyond the scope of this part of IEC 61850. The requirement for interoperable communication between distributed LNs should be based on standardization of syntax, semantics and quality of the data to be exchanged.

D.2.5 Performance

The performance requirements for the communication in substations are based on the performance attributes of the PICOMs.

Annex E
(informative)

Interaction of functions and logical nodes

The interaction between functions is described by the interaction of the related LNs.

There are basically two types of interaction between LNs.

1) Informative interactions: the exchanged data provide some information. The exchanged data are not a prerequisite for the performing the function of the LN and, therefore, the LNs stay autonomously. Functions composed by such LNs are often called local functions or stand-alone functions.
2) Functional interactions: the exchanged data are needed to perform the functions, they are not autonomous. Functions composed by such LNs are often called distributed functions.

Annex F
(informative)

Categories of functions

Different categories of functions are identified. Some functions may belong not only to the given category: their category allocation is only a convention.

F.1 System support functions

These functions are used to manage the system itself. They have no direct impact on the process. These support the whole system. These functions are normally performed continuously in the background of the system. Their goal is a well running system with synchronized nodes. Examples include:

- network management.
- time synchronization.
- node self-checking.

F.2 System configuration or maintenance functions

These functions are used to set-up or evolve (maintain) the system. They include the setting and changing of configuration data and the retrieval of configuration information from the system. These functions are performed only once in the configuration or set-up phase of the substation automation system. Upgrades, extensions or other major changes will also call up these functions later in the life cycle of the system. The response time of system configuration or maintenance functions and, therefore, of the related communication does not have to be much faster than one second (human time scale). Examples include:

- node identification.
- software management (download, activation and retrieval of software).
- configuration management (download, activation and retrieval of configuration data).
- operative mode control of LN.
- setting (parameter set).
- test mode.
- system security management.

F.3 Operational or control functions

These functions are needed for the normal operation of the substation every day. In these functions, an HMI either local or remote is included. These HMIs are used to present process or system information to an operator or to allow him to control the process by commands. The response times of the operational functions and, therefore, of the related communication do not have to be much faster than one second (human time scale). Examples include:

- access control and identification.
- operative mode control.
- control for example of switches (commands and back-indications).
- management of spontaneous change of indications.
- parameter set switching (subset of setting).

- alarm management.
- event management.
- data retrieval.
- disturbance recorder/fault data retrieval.
- log management.

F.4 Local process automation functions

These functions operate directly on the process with process and system data without the interference of the operator. Local automation functions are not local in a strong sense, but consist of three LN in minimum. There is the LN with the core functionality itself, which is called local automation function in the context of this part of IEC 61850. In addition, there is the process interface LN and the HMI (Human-Machine Interface) LN providing the human access to the function. Examples include:

- main protection functions.
- some protection related functions (others belong to the maintenance or operational functions).
- local automatic functions.
- metering functions.

F.5 Distributed automatic support functions

These functions automatically check the conditions which are needed (block or release) by the operational functions or by the process automation functions without the interference of the operator. They do not act directly on the process. They are security related to avoid damage for people or equipment. Normally, they consider information from the whole substation and may be implemented locally or distributed. Since the distributed solution calls especially for the standardization of communication, these functions are listed here. The local versions always behave like a local automation function. Examples include:

- interlocking.
- distributed synchrocheck.

F.6 Distributed process automation functions

These functions are automatic functions acting with process and system data directly on the process without the interference of the operator. They are characterized by the allocation of LNs to different devices for example to the bay control or protection units of all bays. – Examples include:

- breaker failure.
- automatic protection adaptation.
- voltage and reactive power control.
- load shedding and restoration.
- infeed and transformer change.
- automatic switching sequences.

Annex G
(informative)

Functions

G.1 System support functions

G.1.1 Network management

G.1.1.1 Task

Network management is needed to configure and maintain the communication network. The communication network is composed out of nodes.

The basic task is the node identification. Both the addition and the removal of a node have to be detected. All nodes have allocated identification and status information. The network management evaluates this information. The identification of a node is distributed with broadcast service to all other nodes when the node gets on-line. A human operator or a system may request the identification of the logical node.

G.1.1.2 Starting criteria

- Set up or restart of the system.
- Operator request from an HMI.
- Addition of a physical or logical node.
- Call by a configuration manager.

G.1.1.3 Result

All nodes are identified and configured to a system. The actual status of all physical devices (LN0) and logical nodes is known. The actual status and the data traffic for all physical and logical links between the LNs is known. Degraded nodes and links are detected and their impact on the system is minimized. The resources of the communication network are properly shared. Interoperability is supported by the means of the network. The system is a reliable and safe status.

G.1.1.4 Performance

Depending on the different performance requirements for the communication, different performance levels for the network management function are allowed. The range of these levels is between 1 ms and 1 min.

To reach a very high availability, the node identification times should be very short. They should be same as the self-check times. Depending on the function of interest, they will be in the order of seconds or minutes.

G.1.1.5 Decomposition

IHMI, ITCI, ITMI, LLN0, any other LN, system supervision SSYS.

G.1.1.6 Interaction

Physical device self-checking, configuration management, operative mode control of LN, alarm management, event management.

G.1.2 Time synchronization

G.1.2.1 Task

Time synchronization is used for the synchronization of the devices within the system. One LN with a precision time source acts as the time master. A second LN of the same type may be defined to act as a backup time master. The time is normally provided by an external source (radio or satellite clock).

Time synchronization consists of two subtasks:

- Setting of absolute time in the distributed nodes by the time master or via MMI. This task is done by mapping the time from the user layer to the application layer.
- Continuous synchronization of the clocks in the distributed nodes. For the requested high efficiency, this task is preferentially done by means already provided by the protocol stack (somewhere between application and link layer).

Therefore, the time synchronization method should standardized per stack.

G.1.2.2 Starting criteria

System start-up, continuous clock messages, changes by HMI.

G.1.2.3 Result

The time in all devices of the system is synchronized with the requested accuracy.

G.1.2.4 Performance

For the accuracy of time requirements, five classes are defined in 13.7.6 of this part of IEC 61850.

NOTE 1 These are functional requirements. It is up to the implementation if for example, the time synchronizing of the clocks in IEDs has to be one order of magnitude better than that requested by the functional requirements.

NOTE 2 These figures can be matched only if both the time synchronization and the tagging mechanism within the IEDs provide this performance, but should also be supported by the communication services.

G.1.2.5 Decomposition

External time source (radio/for example DCF77, satellite/GPS):

time master STIM, device clock in LLN0.

G.1.2.6 Interaction

No direct interaction, but time synchronization is important for functions such as synchronized switching, event management, distributed synchrocheck or sampling of CT/VT data.

G.1.3 Physical device self-checking

G.1.3.1 Task

The self-check detects if a physical device is fully operational, partially operational or not operational. More detailed information is proprietary and available via generic services.

If a human operator or a system supervision function requests a self-check from a device, a link should be established to the LN, which is related to common device properties (LN0).

If a human operator or a system supervision function wants to be spontaneously informed about changes of self-check information, he has to establish a link to this device common LN0 and subscribe this self-check information.

The LN common for the physical device performs a self-check at device level at regular intervals.

G.1.3.2 Starting criteria

System start-up, event driven status messages, request by HMI or system supervision function.

G.1.3.3 Result

Self-check information of this is an output provided to the user requesting the information.

G.1.3.4 Performance

To reach a very high availability, the self-check times should be very short. Depending on the function of interest, they will be in the order of seconds or minutes.

G.1.3.5 Decomposition

IHMI, ITCI, ITMI, LLN0, SSYS, CALH.

G.1.3.6 Interaction

Network management.

System configuration or maintenance functions.

G.1.4 Software management

G.1.4.1 Task

The functions are implemented by software. The software management function is used to:

- Download software to a device.
- Upload software from a device.
- Get the list of software contained in a device and its identification.
- Activation of the software.

The requesting human operator or system supervision function should be informed of the result of its request (accepted or failed). There is no back-up procedure in case of failure.

Software to be loaded is considered as a single file from the communication point of view. Software identification is manufacturer-specific and considered as a string.

The operational performances of the device may be reduced during software downloading and should be specified by the manufacturer.

Starting the software and reading its status are part of another function ("Operative mode control of LN").

G.1.4.2 Starting criteria

The starting criterion is a request. It is motivated for example, by the download of a new release which adds functions or fixes bugs and/or extends the functionality.

G.1.4.3 Result

The device will be ready for the execution of the new software.

G.1.4.4 Performance

Software download should be less than 5 min.

G.1.4.5 Decomposition

IHMI, ITCI, ITMI, LLN0, any other LN, SSYS.

G.1.4.6 Interaction

Configuration management, operative mode control of LN, access security management.

G.1.5 Configuration management

G.1.5.1 Task

A device may contain one or more databases in order to customize and co-ordinate its behavior with the rest of the system.

The function is used to:

- Download a database to a device.
- Upload a database from a device.
- Get the list of databases contained on a device, their identification and their status.
- Change the status of a database in a device.
- Activation or deactivation of the configuration data.

The requesting human operator or system supervision function should be informed of the result of its request (accepted or failed). There is no back-up procedure in case of failure.

Each database is considered as a single file from the communication point of view. Database identification is manufacturer-specific and considered as a string.

The status of a database is:

- Loaded.
- Ready to be executed.
- Executed.

The database is first loaded. A second step is to make it ready to be executed. When entering into the executing step, the previous executed database, if any, it replaced by the new one. The previous one enters in the ready to execute state. It may then be uploaded.

Operational performances of the device should not be affected during software downloading and when changing the executed database from one to another. The continuity of service has to be maintained. If operational performances are affected, it should be specified in detail by the manufacturer.

G.1.5.2 Starting criteria

The starting criterion is a request. It is motivated by the download of a new database adding functions, fixing bugs or substation extension/modification.

G.1.5.3 Result

The device will be use the new database.

G.1.5.4 Performance

Database download should be less than 5 min. Switching between two databases should be less than 1 min.

G.1.5.5 Decomposition

IHMI, ITCI, ITMI, LLN0, any other LN, SSYS.

G.1.5.6 Interaction

Network management, software management, operative mode control of LN, data retrieval.

G.1.6 Operative mode control of Logical Nodes

G.1.6.1 Task

The operative mode control function allows an authorized operator to start and stop any logical node in the system or to get its status to control and supervise the behavior of the system.

The status of a LN is one of the following:

- Not existent. The equipment does not know the LN. Therefore, no communication takes place at all, also no LN supervision and system information.
- Stopped. The LN is known by the equipment but is idle. No communication regarding the function of the LN takes place in either direction. Only LN supervision information that is needed to maintain the “known” status is exchanged.
- Started. The LN is known by the equipment and is performing its tasks with no restriction. Full communication in both directions (send and receive).
- Maintenance. The LN is known by the equipment and is performing its tasks with some restrictions (local resources corrupted, change of a parameter under processing, etc.). The data exchange is restricted. The most common examples are:
  - full or limited data exchange, but with indication of test status,
  - blocking of control direction to avoid outputs to the process during testing, etc.,
  - blocking of the monitoring direction to avoid unnecessary alarms,
  - blocking of both communication directions during local tests of the LN function.

Logical links are only permitted with LNs that are started or in maintenance modes.

The operator is able to:

- Get the list and status of the LN supported by equipment.
- Subscribe to the status of one or more LN supported by equipment.
- Start a LN when stopped.
- Stop a LN when started.

- Force a LN into maintenance when started.
- Resume a LN when in maintenance.

NOTE This function is only permitted after completion of the security check function (authorization). It defines some specific operator request codes.

G.1.6.2 Starting criteria

Operator request, for example for initialization of a device or reconfiguration of the system.

G.1.6.3 Result

The device will be running.

G.1.6.4 Performance

Less than 1 s.

G.1.6.5 Decomposition

IHMI, ITCI, ITMI, LLN0, any other LN.

G.1.6.6 Interaction

Network management, software management, and configuration management.

G.1.7 Setting

G.1.7.1 Task

The setting function allows an operator to read and to change one or more parameters affecting the behavior of the functionality represented by the LN.

The changes of values will become active after the operator has read back what has been sent, confirmed his settings, and the application has then successfully performed a consistency check on its setting values. This allows changing multiple interrelated parameters without violating their consistency.

Depending on the setting and the implementation of the application, the operator may be obliged to force the LN or the application into maintenance mode during the change of the settings. The IEC 61850 series does not specify the cases where this should be done, but permits a LN or an application to answer that a given setting change needs to be ‘frozen’ first.

To avoid setting conflicts in the case where several operators attempt to simultaneously change the settings of a LN, a change session has to be opened with the LN for changes to be made, and only one change session can be open at a time. Multiple reading, however, is allowed.

An application on a LN may have several possible parameter sets, but only one active set. It is possible to switch any of the defined sets in the active state. How many sets are possible respectively defined, is implementation dependent, but should be shown as an application parameter. Switching of the active set does not need a change session; it is a single operation step, so that no problem with multiple access occurs. But parameter set switching should be blocked, if a change session is open.

The function does not specify the list of parameters that can be set, but only the way of doing it.

Change of settings should be protected by a password per LN. Use of passwords for reading or switching of active set is optional (customer requirement).

Previous setting values of an LN should be stored, and a return to previous values should be possible, if either the application consistency check refuses the new values, or if after some time the new values prove to be insufficient. It is recommended to archive more than only the last released parameter set for possible reuse/fall back (for example the three last ones).

NOTE It is not prescribed where these sets are to be archived. Common sense would store the last released set on the LN, and all others on the operator HMI side.

G.1.7.2 Starting criteria

A human operator starts the setting function.

Switching of active parameter sets can be started by a human operator, or by some automatic function based on change of state.

G.1.7.3 Result

The possible results are:

- information for the human operator about existing and active parameters in all LN applications;
- changed settings for some LN applications;
- changed active parameter set for some LN applications.

G.1.7.4 Performance

The communication performance should allow feedback of read values within 1 s, sending value sets and read back within 2 s. A consistency check on a confirmed new set, or a switching of the active set may last several seconds, depending on the application and its implementation. Performance is not critical, the above mentioned values are average values, not worst case requirements.

G.1.7.5 Decomposition

IHMI, ITCI, ITMI, LLN0, any other LN.

G.1.7.6 Interaction

Automatic process functions such as ‘automatic protection adaptation’ may trigger the function ‘setting’ as parameter set switching, which should be interlocked against simultaneous parameter setting by the operator. Since setting refers to any LN, there is an interaction with all functions.

G.1.8 Test mode

G.1.8.1 Task

The test mode function allows the local or remote operator to check any function of the system also using process signals but avoiding any impact on the process (blocking of process outputs) at any time.

G.1.8.2 Starting criteria

Operator request.

G.1.8.3 Result

Positive or negative test results provide information to the operator on what functions or parts of the system are in proper operation.

G.1.8.4 Performance

Test sequence depending on the functionality to be tested. Test analysis should be within the human operator response time (about 1 s). Detailed evaluation may take much more time.

G.1.8.5 Decomposition

IHMI, ITCI, ITMI, LLN0, GTES, any other LN.

G.1.8.6 Interaction

Access security management, alarm management, event management, and operative mode control.

G.1.9 System security management

G.1.9.1 Task

The system security management function allows the control and supervision of the security of the system against unauthorized access and loss of activity. The function monitors and provides all activities regarding security violations.

G.1.9.2 Starting criteria

System start.

G.1.9.3 Result

All acquired data are logged, the security level is known at any time. Dedicated data may result in immediate blocking of sensitive functions such as the attempted system access. The operator or system supervisor is informed by an alarm.

G.1.9.4 Performance

The security supervision function should be as comprehensive as possible. In case of breached security, blocking should be issued immediately (10 ms). Any alarm should be provided within the human operator response time (about 1 s).

G.1.9.5 Decomposition

IHMI, ITCI, ITMI, LLN0, GSAL, CALH.

G.1.9.6 Interaction

Network management, access security management, alarm management, and event management.

G.2 Operational or control functions

G.2.1 Access security management

G.2.1.1 Task

The human access to functions or the related LNs, especially to operational functions, has to be controlled by a set of rules. The access security management in between the different LNs, i.e. for automatic functions, is handled during the system configuration by the function node identification. The access security management as described here is related to HMI type of users only.

The set of rules defines:

- Authentication

The accessed LN is responsible for ensuring that the user has the authority to use the LN application. The LN should support authentication. In certain circumstances (for example sensitive information retrieval or high security control), an encryption procedure may be used in conjunction with authentication. The user authentication process allows the LN to differentiate between users (for example substation operators, administrators, maintenance staff, etc) and then allows the LN to model different access rights for these users.

- Access control

Access control is to provide the capability to restrict an authenticated user to a pre-determined set of services and object attributes. Access control is implemented using privileges:

- A **create** privilege allows the user to create certain classes of application objects within the specific LN.
- A **delete** privilege allows the user to delete application objects within the specific LN.
- A **view** privilege allows the user to acquire details concerning the existence of an object and the object definition.
- A **set/write** privilege allows the user to set attribute values of an object.
- A **get/read** privilege allows the user to get attribute values of an object.
- An **execute** privilege allows the user to execute the permitted application service.

Each LN should provide access types of users with an allocated set of access rights. The sets of access rights may be defined by:

- The type of action: control of the process, control of the system, maintenance of the system, etc.
- The area of knowledge of the operator: protection, control, etc.
- The level of expertise of the operator: manager, substation operator, administrator, etc.
- The name of the bay or diameter, or equipment, or voltage level concerned, when different customers, etc share a substation controlled by a same system.

Access control privileges may be dynamically altered and have to allow the resolution of conflicting requirements of multiple users.

G.2.1.2 Starting criteria

- Log in of an operator, selection of an action in the user node.
- Authentication is performed at the time when the user is linked to the LN.
- Access control is validated at the time of access to an object or service.

G.2.1.3 Result

Authentication is reported with either a positive response or a negative response to the user. A negative response will cause all subsequent object or service access requests to be rejected with a 'not authenticated' error code.

Access control to an object or service, after successful authentication, is reported with either a positive response or a negative response to the user. A negative response will include an error code to indicate the reason for access denial.

G.2.1.4 Performance

Not critical to the security management, but should meet the demands of the LN application.

G.2.1.5 Decomposition

IHMI, ITCI, ITMI, LLN0, any other LN.

G.2.1.6 Interaction

All functions with operator access.

G.2.2 Control

G.2.2.1 Task

The control function allows an operator or an automatic function to operate HV/MV equipment such as switchgear or transformer and any auxiliary equipment in the substation. The control is applied to a controlled item.

The control function is used to:

- open or close a breaker, disconnector or earthing switch;
- raise or lower a transformer tap;
- set to On or Off a LV equipment.

The control function may optionally include a “Select” step, used to check that the control may be valid and to eventually lock a resource.

Control is subject to miscellaneous filters that check that there will be no damage if the control is issued. This functions are listed under “System control functions” and include (optional per control):

- Control unity (on the controlled item, in the bay, in the voltage level, in the substation).
- Interlock validity. Interlocking is a parallel function that delivers a status to enable or disable a control (if interlock is set to on). The control message may contain an interlock violation status to bypass it.
- Synchrocheck validity. When closing a breaker, the synchrocheck will verify some electrotechnical conditions and enable or not the control, depending on its type.
- Time validity. The control contains a time attribute that specifies the time limit for issuing the control. This avoids issuing an old control that would have been stacked into the network.
- Locked status. A controlled item may be under lock status when the substation is partly in maintenance mode. This prohibits any control on a breaker if an operator is performing some repair on the line for example. Note that locking an item is an example of control.
- Control privilege. This is needed if an operator expects to control an item to check his privileges.
- Substation and bay mode status. The substation should be in remote mode to enable remote control (i.e. from SCADA) and in local mode to enable control issued inside the substation. The bay mode should be in remote mode to enable control from the station level or remote control level (SCADA).
- State of the controlled item. The control should lead the controlled item into an authorized state (for example, it is impossible to open an open disconnector). When the controlled item is in an unknown state (for example, double point status have the same value), this filter is optionally suppressed.

Control is cancelled if one of these filters is not verified or if a cancel order is received from the control point.

G.2.2.2 Starting criteria

Request from a human operator or from an automatic function.

G.2.2.3 Result

Changes in the process by changed status of the process (primary equipment).

G.2.2.4 Performance

Depending on the controlled object under consideration.

Depending on the starting criteria, i.e. about ≤ 1 s for a human operator, ≤ 100 ms for automatics.

G.2.2.5 Decomposition

IHMI, ITCI, GAPC, CSWI, XCBR, XSWI, (GGIO).

G.2.2.6 Interaction

Access security management, management of spontaneous change of indications, synchronized switching, bay level interlocking, station wide interlocking, distributed synchrocheck.

G.2.3 Operational use of spontaneous change of indications

G.2.3.1 Task

To monitor all spontaneous changes of states (indications) in the substation and to provide this information to all functions which need this information.

G.2.3.2 Starting criteria

Change of a state in the power equipment, for example position change of a circuit breaker

G.2.3.3 Result

Information about this change provided to all functions which need this information.

G.2.3.4 Performance

Depends on the source of this change and the use of the information about this change.

Detection ≤ 1 ms, transmission ≤ 1 s for a human operator, ≤ 100 ms for automatic functions.

G.2.3.5 Decomposition

CALH, CILO, IHMI, ITCI, ITMI, all other LNs related to primary equipment (X…, Y…, Z…) including GGIO

G.2.3.6 Interaction

Control, alarm management, event management, bay level interlocking, station-wide interlocking.

G.2.4 Synchronized switching (point-on-wave switching)

G.2.4.1 Task

The synchronized switching function allows closing or opening of the circuit breaker on a dedicated "instant in time" with a very high accuracy to limit the transient switching stress both for the breaker and the object to be energized e.g. for the line. Since waves mean the sinusoidal currents and voltages, the dedicated "instant in time" refers to a "dedicated point on wave". Therefore, synchronized switching is synonymous with point-on-wave switching.

G.2.4.1.1 Closing

The contacts of the breaker should be closed at the instant of equal potential on both sides to avoid or minimize strokes in between. Therefore, the time-dependent potentials (samples with amplitude, frequency and phase information measured for example, by VTs) from both sides of the breaker have to be compared for the calculation of the proper instant of contact. This calculated instant of time should be obtained within 0,1 ms of the closing operation to minimize strokes appearing for contact distances below the voltage-dependent isolation distance.

For this purpose, the local/bay potential has to be compared with a remote potential from the busbar or from another bay. Using the knowledge about the actual busbar configuration, the proper remote VT has to be selected. This information may be provided from the station level or may already be known at the bay level.

The high accuracy needed for comparison of the voltage sample could be provided by synchronized sampling or by asynchronous samples, time tagged with the same accuracy for waveform reconstruction. This is a matter of function implementation and the selected communication implementation (bus/stack).

G.2.4.1.2 Opening

The contact separation of the breaker should occur at a certain instant of time near current zero with a jitter of 1 ms to reach optimum arcing time.

The information from the local/bay CT is needed only to calculate this instant of time.

G.2.4.1.3 Common

Since this goal is determined by the mechanical behavior of the breaker, this behavior is monitored during any switching operation. Based on this monitoring, the settings of the function are adapted from operation to operation.

G.2.4.2 Starting criteria

Selection of breaker for synchronized switching.

G.2.4.3 Result

In case of closing: the circuit breaker has been closed at point of wave accurate <0,1 ms

In case of opening: the circuit breaker has been opened at point of wave accurate <1 ms

G.2.4.4 Performance

Command sequence steps ≤1 s.

Accuracy for closing time in relation to the wave ≤0,1 ms.

Closing time < 500 ms depending on the type of breaker.

Time synchronization for the used samples <50 µs.

G.2.4.5 Decomposition

IHMI, ITCI, CSWI, XCBR, TCTR, TVTR (local and remote).

G.2.4.6 Interaction

Control, bay level interlocking, station wide interlocking, automatic switching sequences.

G.2.5 Parameter set switching

G.2.5.1 Task

An application on a LN may have several possible parameter sets, but only one active set. It is possible to switch any of the defined sets in the active state. How many sets are possible respectively defined, is implementation dependent, but should be shown as an application parameter. Switching of the active set does not need a change session but is a single operation step, so that no problem with multiple access occurs. Switching should however be blocked, if a change session is open.

The parameter set switching is a subset of the setting from the system configuration or maintenance functions restricted to changes of predefined parameters sets needed to cope with changing operating conditions. The restriction to predefined parameter sets drastically reduces the consistency checks requested.

All other features are the same as for the setting function.

G.2.6 Alarm management

G.2.6.1 Task

The alarm management function allows an operator to visualize, to acknowledge and to clear alarms. Several operators may simultaneously have access to this function. The alarms are presented in alarm list(s) and marked in process or system overview displays if applicable.

An alarm is generated when data from the system takes a value that should be taken into consideration by the operator. The data may be representative of the process state or of the substation automation system itself. The value may be invalid, unexpected, out of limit, etc. The data may be issued from a single piece of equipment or calculated with data coming from several pieces of equipment (group alarms).

The status of an alarm is calculated with:

- The presence and the value of the data that has generated the alarm (one or more data).
- The actions performed by the operator on this alarm.

The alarm will remain if the cause has disappeared, until the operator has acknowledged and cleared the alarm. If alarms are sent to different places, the request for single or multiple acknowledgements has to be defined.

An alarm has several attributes that should be displayed to the operator:

- Location/source of the alarm.
- Cause of the alarm.
- Alarm acknowledged or not.
- Urgency and gravity of the alarm.
- Audible alarms (if applicable).

G.2.6.2 Starting criteria

Status changes from “normal” to “alert” or “emergency”, status changes from “alert” to “emergency”.

G.2.6.3 Result

Inform the local or remote operator of a critical situation in the primary or secondary system.

Acknowledgement of the alarm.

G.2.6.4 Performance

The needed performance for alarm detection depends on the function in consideration. The information to the operator and acknowledgement confirmation has to be done within the human operator time scale (1 s).

G.2.6.5 Decomposition

IHMI, ITCI, ITMI, CALH, any other LN.

G.2.6.6 Interaction

Physical device self-checking, event management, any function.

G.2.7 Event management (SER)

G.2.7.1 Task

To continually collect and process the status changes from equipment, operator control actions and changes in the process state, and to chronologically record the events with date and time information. All equipment is included, i.e. typically plant, protection and control equipment. The archiving and display of events in event lists would typically be done in workplaces at station level; the detection and time tagging would typically be done at bay level or below. Nevertheless, there is also event buffering and maybe also display of events at bay level and also event detection on station level, for example for operator actions.

The content of event lists may, if applicable, be different for different operator places. The events in the lists may be sorted and selected according to their attributes (source, cause, time, etc.).

Whether the events are polled from the higher level device or sent automatically (event driven) up to the higher level device depends on the implementation of communication. In any case, the events should be locally stored and retrievable on request if the communication comes back after some downtime.

This function provides all features of a Sequence of Event Recorder (SER).

G.2.7.2 Starting criteria

- Continuous scanning (for example from station level workstation).
- Change of state.
- Request (for example after a communication outage).

G.2.7.3 Result

The event database will be updated with the event, including the identification, the date and the time. If applicable, the events are printed.

G.2.7.4 Performance

Events have to be time tagged at the source with an accuracy of 1 ms for process data. Some data may have a lower accuracy, for example operator actions are often time tagged with reference to the human operator time scale (1 s).

G.2.7.5 Decomposition

IHMI, ITCI, ITMI, CALH, any other LN.

G.2.7.6 Interaction

Since nearly all LNs may be sources of events, all functions interact with the event management function.

G.2.8 Data retrieval of configuration data and settings

G.2.8.1 Task

To get data from one LN, to another dedicated LN which requested the data. The requesting IED would typically be located at the station level and the data typically stored in the LN of an IED placed at bay level. Typical data would be configuration data and relay settings. The typical reasons for retrieving the data will be for the purposes of display, verification and bulk storage such data. Relay settings may, however, be requested for the purposes of display, editing and changing the original settings of the source LN.

G.2.8.2 Starting criteria

- Operator request from station level.
- Autopoll from station level

G.2.8.3 Result

Data is received at the requesting LN. The data will be in the form of a file or files, which may be stored.

G.2.8.4 Performance

The performance or speed of uploading will depend on the size of the file. Settings and measurement data should upload in less than 1 s.

G.2.8.5 Decomposition

IHMI, ITCI, ITMI, LLN0, all other settable LNs.

G.2.8.6 Interaction

Configuration management.

G.2.9 Disturbance/fault record retrieval

G.2.9.1 Task

To get a disturbance/fault record held in the LN of an IED to the dedicated LN which requested the data. The requesting IED would typically be located at the station level and the record typically stored in the LN of an IED placed at bay level. The normal reasons for retrieving a record will be for the purpose of display and bulk storage of fault data.

G.2.9.2 Starting criteria

- Operator request from station level,
- Autopoll from station level

G.2.9.3 Result

The record is received by the requesting LN. The record will be in the form of a file or files, which may be stored.

G.2.9.4 Performance

The performance or speed of uploading will depend on the size of the file. A single fault record should upload within 5 s.

G.2.9.5 Decomposition

IHMI, ITCI, ITMI, RDRE, RDRS, IARC, TVTR, TCTR, all LNs related to primary equipment (X…, Y…, Z…) including GGIO.

G.2.9.6 Interaction

Protection function, management of spontaneous change of indications.

G.2.10 Log management

Function covered by event management.

G.3 Local process automation functions

G.3.1 Protection function (generic)

G.3.1.1 Task

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

If a protection function is listed as a local process automation function, it operates independently from other functions or communication links. In the case of a remote process interface (I/O) separated by a process bus, these parts also have to be in proper operation.

G.3.1.2 Starting criteria

The monitoring part of the function operates if the function is started.

The function issues a start (pickup) signal in the case of an alert situation (boundary crossing 1) and a trip in the case of an emergency situation (boundary crossing 2).

G.3.1.3 Result

The endangered object is in a safe mode, i.e. switched off normally.

G.3.1.4 Performance

Depending on the type of protection function, the requested performance for fault detection and tripping is between 10 ms and 100 ms. These internal requirements of the protection function itself evolve into communication requirements in the case of a process bus transferring the trip command.

G.3.1.5 Decomposition

IHMI, ITCI, ITMI, P…, TCTR, TVTR, XCBR, other primary equipment related LNs.

G.3.1.6 Interaction

Alarm management, event management, disturbance/fault record retrieval, other protection functions, automatic protection adaptation, reverse blocking.

G.3.2 Distance protection (example of a protection function)

G.3.2.1 Task

The line distance protection function is related to the protection of one line.

It monitors the line impedance using voltage and current. The line distance protection starts and trips if changes in the line impedance, admittance or reactance exceed a certain predefined limit. It has different zones in reach. The fault distance is given at least as fault impedance (or admittance, reactance) which could be converted in the geographical distance to the fault location.

G.3.2.2 Starting criteria

The monitoring part of the function is set into operation if the function is started.

The function issues a start (pickup) signal in the case of an alert situation (impedance crosses boundary 1) and a trip in case of an emergency situation (impedance crosses boundary 2).

G.3.2.3 Result

The line is protected by switching off the fault current using the related line circuit breakers.

G.3.2.4 Performance

Continuously monitoring voltage and currents with samples from a few hundred Hz up to a few thousand Hz. To reach an accurate fault location, the relative accuracy of voltage and current samples should be ≤ 25 µs. The response time (tripping time) should be in the order of 5 ms to 20 ms. These internal requirements of the protection function itself evolve to communication requirements in the case of a process bus transferring the trip command.

G.3.2.5 Decomposition

IHMI, ITCI, ITMI, PDIS, TCTR, TVTR, XCBR, other primary equipment related LNs.

G.3.2.6 Interaction

Alarm management, event management, disturbance/fault record retrieval, other protection functions, and automatic protection adaptation.

G.3.3 Bay interlocking

G.3.3.1 Task

According to interlocking rules, commands to the switchgear are supervised and in the case of a possible malfunction or danger, blocked by the bay level interlocking function.

Interlocking rules are implemented in the bay unit and always checked before the switchgear is operated. As an example, the circuit breaker cannot be closed if the grounding disconnector at the feeder side is in the ‘on’ position.

For test purposes, the interlocking rules can be changed or set out of operation by the HMI online.

G.3.3.2 Starting criteria

The recalculation of interlocking conditions starts by any position change of the switchgear (circuit breaker, isolator, grounding switch). Depending on the implementation, the recalculation may start not before switchgear selection.

G.3.3.3 Result

Release or blocking of the intended switching operation. Depending on implementation, the interlocking reason may also be supplied to the HMI.

G.3.3.4 Performance

All types of selection, release or blocking signals have to be transmitted with an overall transfer time of about 10 ms. The recalculation time of the interlocking is beyond the scope of this part of IEC 61850, but should be in the order of the human operator time (1 s).

G.3.3.5 Decomposition

IHMI, ITCI, CILO, CSWI, XCBR, XSWI, (PTUV), if applicable.

G.3.3.6 Interaction

Control, bay level interlocking in other bays, station-wide interlocking.

G.4 Distributed automatic support functions

G.4.1 Station-wide interlocking

G.4.1.1 Task

The interlocking function is solved here in a distributed way, including the reservation principle for intended switching operations.

The communication needed between the distributed units providing together station-wide interlocking is by preference solved using a general bay to bay communication with no special adaptation.

The following general requirements to the implementation concept should be fulfilled as far as possible:

- Command handling performance should be sufficiently high, i.e. response time below 1 s from the moment a command is given by the operator until the switch starts to move.

- Interlocking safety should be sufficiently high, i.e. no permanent or temporary node failure should lead to a dangerous command, and the probability of (spontaneous) undetected state changes during the command handling time should be sufficiently low.
- Engineering effort for configuration and handling of possible fault situations should be low.
- The solution should be flexible so that special conditions can be fulfilled, for example two commands executing at the same time.
- Standard communication messages according to the data dictionary should be used. No application level programs for the communication network with special messages should be necessary.

G.4.1.2 Starting criteria

Position change of a switching device or request of the command function.

G.4.1.3 Result

Release or block of all switching devices or of the switching device of interest.

G.4.1.4 Performance

- Blocking and release 10 ms.
- Reservation 100 ms.
- Recalculation < 1 s.

G.4.1.5 Decomposition

IHMI, ITCI, CILO, CSWI, XCBR, XSWI, (PTUV) – if applicable.

G.4.1.6 Interaction

Control, bay level interlocking.

G.4.2 Distributed synchrocheck

G.4.2.1 Task

The function distributed synchrocheck allows the release of the "Close" command in a proper time window where the differences of the voltages on both sides of the open breaker are within an acceptable range regarding amplitude, frequency and phase.

For this purpose, the local/bay voltage has to be compared with a remote voltage from the busbar or from another bay. Using the knowledge about the actual busbar configuration, the proper remote VT has to be selected. This information may be provided by the station level or already known at the bay level.

The high accuracy needed for comparison of the voltage sample could be provided by synchronized sampling or by asynchronous samples time tagged with the same accuracy for waveform reconstruction. This is a matter of function implementation and the selected communication implementation (bus/stack). By definition, at least the remote voltage is delivered via a serial bus (for example interface 9).

The functionality of the voltage comparison part with all related requirements is the same as that of the closing part of the "Synchronized switching" function. The conventional (non-distributed) "Synchrocheck" function has the same functionality, but needs no serial communication, as it gets all voltages hardwired.

G.4.2.2 Starting criteria

Selection of the circuit breaker for closing may be used for start. If this function is continuously running, no start is needed.

G.4.2.3 Result

Time window for “close release” of the selected circuit breaker.

G.4.2.4 Performance

- Release calculation ≤ 1 s.
- Time synchronization for samples < 50 μs.
- Time synchronization for zero crossing time tag 0,1 ms.

G.4.2.5 Decomposition

IHMI, ITCI, RSYN, TVTR (local and remote).

G.4.2.6 Interaction

Control, automatic switching sequences.

Distributed process automation functions.

G.4.3 Breaker failure

G.4.3.1 Task

If a breaker gets a trip signal by some protection (for example line protection) does not open because of an internal failure, the fault has to be cleared by the adjacent breakers. The adjacent breakers may include breakers at remote substations (remote line ends). For this purpose, the breaker failure protection is started by the protection trip and supervises if the fault current disappears or not. If not, a trip signal is sent to all adjacent breakers after a preset delay.

G.4.3.2 Starting criteria

The protection trip makes the breaker failure protection alert.

G.4.3.3 Result

The fault is cleared by the adjacent breakers.

G.4.3.4 Performance

Fast detection of the trip signal and the fault current and very fast reset in the case of a disappearing fault current. Delay settable ≤ 100 ms. The trip transfer time should be in the order of 5 ms.

G.4.3.5 Decomposition

IHMI, ITCI, ITMI, P…, RBRF, TCTR, CSWI.

G.4.3.6 Interaction

Protection.

G.4.4 Automatic protection adaptation (generic)

G.4.4.1 Task

The protection specialist may change the protection parameters (settings) if needed by static or slow predictable power system reconfiguration.

If the conditions for protection change dynamically during operation, the parameters of the protection may be changed by local or remote functions. Very often complete pre-tested sets of parameters are changed rather than single parameters.

G.4.4.2 Starting criteria

Changes in conditions are detected and communicated by some other functions.

G.4.4.3 Result

The protection function is adapted to the changed power system condition.

G.4.4.4 Performance

Depending on the considered function and the rate of changes in conditions in the power network, the change command has to be communicated between 1 ms and 100 ms.

G.4.4.5 Decomposition

IHMI, ITCI, ITMI, P…

G.4.4.6 Interaction

Protection.

G.4.5 Reverse blocking function (for example, for automatic protection adaptation)

G.4.5.1 Task

When a fault occurs in a radial network, the fault current flows between the source and the fault location:

– the upstream protections are triggered;
– the downstream protections are not triggered;
– only the first upstream protection has to trip.

The reverse blocking function is a distributed function that eliminates a fault in a minimum and constant time, wherever it occurs in a radial electric network. It offers a full tripping discrimination and a substantial reduction in delayed tripping of the circuit breaker located nearest to the source (the first upstream protection/breaker). It concerns phase overcurrent and earth fault protections of different types: definite time (DT) and IDMT (standard inverse time SIT, very inverse time VIT and extremely inverse time EIT).

G.4.5.2 Starting criteria

When a protection is triggered by an overcurrent

– it sends a blocking signal to the upstream protections;
– it trips (opens) its associated circuit breaker if it does not receive a blocking signal issued by a downstream protection.

G.4.5.3 Result

Only the first upstream protection has tripped its associated breaker in a minimum time.

G.4.5.4 Performance

Depending on the applied time delay based fault discrimination scheme, the block command has to be communicated within 5 ms (transfer time).

G.4.5.5 Decomposition

IHMI, ITCI, ITMI, P… (more than one).

G.4.5.6 Interaction

Protection, automatic protection adaptation.

G.4.6 Load shedding

G.4.6.1 Task

To shed the load in the case of supply shortage, in order to stabilize the power frequency.

G.4.6.2 Starting criteria

The power frequency drops below a certain limit (multiple limits, for example four levels): $f < f_n$.

The decay of frequency is faster than a given limit: $\mathrm{d}f/\mathrm{d}t > (\mathrm{d}f/\mathrm{d}t)_m$.

The power flow is not balanced: $\Sigma P_i \neq 0$ (production ≠ consumption).

G.4.6.3 Result

The load is reduced to such an extent that the power balance is zero, i.e. the frequency stays at its nominal value or within an acceptable, predefined range.

G.4.6.4 Performance

f, $\mathrm{d}f/\mathrm{d}t$ relay oriented, not communication oriented.

G.4.6.5 Decomposition

IHMI, ITCI, ITMI, GAPC, PFRQ, MMXU, CSWI, XCBR, XSWI, (GGIO).

G.4.6.6 Interaction

Control, protection (frequency), automatic switching sequences.

G.4.7 Load restoration

G.4.7.1 Task

Restore the local grid (busbar) after a tripping of one or more feeders. The complete busbar has maybe been tripped by the busbar protection. The reconnection of feeders and consumers is made in a proper sequence according to some predefined priority and/or according to the network conditions.

G.4.7.2 Starting criteria

Disappearance of the fault condition or manually from the HMI.

G.4.7.3 Result

All feeders and consumers are reconnected and the power delivery is restored.

G.4.7.4 Performance

Within the human operator time or switchgear time scale, i.e. ≤ 1 s per switching step.

G.4.7.5 Decomposition

IHMI, ITCI, ITMI, GAPC, CSWI, XCBR, XSWI.

G.4.7.6 Interaction

Control, distributed synchrocheck, automatic switching sequences.

G.4.8 Voltage and reactive power control

G.4.8.1 Task

The voltage on a busbar in the power network depends on the position of the transformer taps and on the amount of reactive power to be moved around. By controlling both the taps and the reactive power, the voltage is kept at its nominal value or in a very small well-defined range. The control is made by changing the tap positions or by stepwise switching of capacitor or reactor banks. Very often, only one these means are available for such a control function in the substation under consideration.

G.4.8.2 Starting criteria

Deviations of *U* or *Q* from their set points. For more than one transformer, the circulating reactive current is above its accepted limit.

G.4.8.3 Result

The voltage or the reactive power is back to its nominal value or in a very small well-defined range. The circulating reactive current is below its accepted limit.

G.4.8.4 Performance

Rapid detection, but response limited by the switching mechanism.

G.4.8.5 Decomposition

IHMI, ITCI, ATCC, ARCO, TVTR, (TCTR), YLTC, YPTR.

G.4.8.6 Interaction task

Control, protection (transformer differential, over-/undervoltage)

G.4.9 Infeed switchover and transformer change

G.4.9.1 Task

a) Busbars with multiple infeed possibilities have to be switched over to another infeed in the case where the main infeed is disturbed or lost. The switchover has to take place bump less in such a way that no problems regarding the synchronization of lines and loads (for example motors) appear.

b) In case of parallel transformers, the load of an overloaded, endangered or faulted transformer has to be switched over to a healthy, parallel running transformer. The switchover has to take place bump less in such a way that no problems regarding the synchronization of lines and loads (for example motors) appear. This also includes a proper control of the tap position of the transformer.

G.4.9.2 Starting criteria

a) Disturbance or loss of an infeeding line.

b) Overloaded, endangered or faulted transformer.

G.4.9.3 Result

Uninterrupted (if applicable) power flow by a sound feeding line or transformer.

G.4.9.4 Performance

≤ 100 ms.

G.4.9.5 Decomposition

IHMI, ITCI, PTUV (infeed) or PTDF/PTTR (transformer), TVTR, TCTR, YPTR, GAPC, RSYN, CSWI, XCBR, XSWI.

G.4.9.6 Interaction

Control, distributed synchrocheck, voltage and reactive power control, automatic switching sequences.

G.4.10 Automatic switching sequences

G.4.10.1 Task

To change the process state by one single operator command if a sequence of switching operations is also needed. This function facilitates the task of the operator, especially in complex substations, avoids unnecessary switching and may also be used for automatics.

G.4.10.2 Starting criteria

Request from a human operator or from an automatic function.

G.4.10.3 Result

Changes in the process by changed status of the process (primary equipment).

G.4.10.4 Performance

Depends on the controlled objects under consideration.

Depends on the starting criteria, i.e. about ≤ 1 s for a human operator, ≤ 100 ms for automatics.

G.4.10.5 Decomposition

IHMI, ITCI, GAPC, CSWI, XCBR, XSWI.

G.4.10.6 Interaction

Access security management, control, bay level interlocking, station wide interlocking, distributed synchrocheck.

Annex H
(informative)

Results from the function description

H.1 Function-function interaction

Table H.1 – Function-function interaction – Part 1

FUNCTION	FUNCTION																
	Network management	Time synchronization	Physical device self-checking	Node identification	Software management	Configuration management	Operative mode control of LN	Setting	Test mode	System security management	Access security management	Control	Management of spontaneous change of indications	Synchronized switching	Parameter set switching	Alarm management	Event management/log management
Network management	o		x	x		x	x									x	x
Time synchronization	-	o	-	-	-	-	-	-	-		-	-	-	x	-	-	x
Physical device self-checking	x	-	o													x	
Node identification	x	-		o													
Software management		-			o	x	x				x						
Configuration management	x	-			x	o	x										
Operative mode control of LN	x	-			x	x	o										
Setting	-	-	-	-	-	-	-	o	-		-	-	-	-	-	-	-
Test mode		-							o		x					x	x
System security management	-	-	-	-	-	-	-	-	-	o		-	-	-	-	-	-
Access security management	-	-	-	-	-	-	-	-	-		o	-	-	-	-	-	-
Control		-									x	o	x	x			
Management of spontaneous change		-										x	o				
Synchronized switching		-										x		o		x	x
Parameter set switching	-	-	-	-	-	-	-	-	-		-	-	-	-	o	-	-
Alarm management	x	-	x	-	-	-	-	-	-		-	-	x	-	-	o	-
Event management/log management	-	-	-	-	-	-	-	-	-		-	-	x	-	-	-	o
Data retrieval		-				x											
Disturbance/fault record retrieval		-											x				
Protection function (generic)/examples		-														x	x
Bay level interlocking		-										x					
Station wide interlocking		-										x					
Distributed synchrocheck		x										x					
Breaker failure		-															
Automatic protection adaptation/examples		-															
Reverse blocking function		-															
Load shedding		-										x					
Load restoration		-										x					
Voltage and reactive power control		-										x					
Infeed switchover and transformer change		-										x					
Automatic switching sequences		-									x	x					

Key:
o Identical function (diagonal of the interaction matrix).
x Dedicated function interaction.
- Common service interaction.

Table H.2 – Function-function interaction – Part 2

	FUNCTION													
FUNCTION	Data retrieval	Disturbance/fault record retrieval	Protection function (generic)	Bay level interlocking	Station wide interlocking	Distributed synchrocheck	Breaker failure	Automatic protection adaptation	Reverse blocking function	Load shedding	Load restoration	Voltage and reactive power control	Infeed switchover and transformer	Automatic switching sequences
Network management														
Time synchronization	-	-	-	-	-	x	-	-	-	-	-	-	-	-
Physical device self-checking														
Node identification														
Software management														
Configuration management	x													
Operative mode control of LN														
Setting	-	-	-	-	-	-	-	x		-	-	-	-	-
Test mode														
System security management	-	-	-	-	-	-	-	-		-	-	-	-	-
Access security management	-	-	-	-	-	-	-	-		-	-	-	-	-
Control				x	x	x								
Management of spontaneous change														
Synchronized switching				x	x									
Parameter set switching	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Alarm management	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Event management/log management	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Data retrieval	o													
Disturbance/fault record retrieval		o	x											
Protection function (generic)/examples		x	o					x	x					
Bay level interlocking				o	x									
Station wide interlocking				x	o									
Distributed synchrocheck						o								
Breaker failure			x				o							
Automatic protection adaptation/examples			x					o						
Reverse blocking function			x						0					
Load shedding			x							o				x
Load restoration						x					o			x
Voltage and reactive power control			x									o		
Infeed switchover and transformer change						x						x	o	x
Automatic switching sequences				x	x	x								o

Key:
o Identical function (diagonal of the interaction matrix).
x Dedicated function interaction.
- Common service interaction.

H.2 Function decomposition into logical nodes

Table H.3 – Function decomposition into Logical Nodes – Part 1

	FUNCTION														
LOGICAL NODE	**Network management**	**Time synchronization**	**Physical device self-checking**	**Node identification**	**Software management**	**Configuration management**	**Operative mode control of LN**	**Setting**	**Test mode**	**Access security management**	**Control**	**Management of spontaneous change**	**Synchronized switching**	**Parameter set switching**	**Alarm management**
P… (Protection, Generic)		-	-	x	x	x	x	x	x	x				x	
RDRE (Disturbance Recording At Bay Level)		-	-	x	x	x	x	x	x	x				x	
RDRS (Disturbance Evaluation At Station Level)		-	-	x	x	x	x	x	x	x				x	
RREC (Automatic Reclosing)		-	-	x	x	x	x	x	x	x				x	
Rbrf (Breaker Failure)		-	-	x	x	x	x	x	x	x				x	
RCPW (Carrier Or Pilot Wire Relay)		-	-	x	x	x	x	x	x	x				x	
RFLO (Fault Locator)		-	-	x	x	x	x	x	x	x				x	
RSYN (Synchrocheck)		-	-	x	x	x	x	x	x	x				x	
RPSB (Power Swing Blocking)		-	-	x	x	x	x	x	x	x				x	
CALH (Creation Of Group Alarms/Events)		-	-	x	x	x	x	x	x	x		x		x	x
CSWI (Switch Controller)		-	-	x	x	x	x	x	x	x	x		x	x	
CILO (Interlocking Bay/Station)		-	-	x	x	x	x	x	x	x		x		x	
IHMI (Human Machine Interface)	x	-	x	x	x	x	x	x	x	x	x	x	x	x	x
ITCI (Telecontrol Interface)	x	-	x	x	x	x	x	x	x	x	x	x	x	x	x
ITMI (Telemonitoring Interface)			x	x	x	x	x	x	x	x		x		x	
IARC (Archiving)		-	-	x	x	x	x	x	x	x				x	
ATCC (Automatic Tap Changer Control)		-	-	x	x	x	x	x	x	x				x	
AVCO (Voltage Control)		-	-	x	x	x	x	x	x	x				x	
ARCO (Reactive Control)		-	-	x	x	x	x	x	x	x				x	
ANCR (Earth Fault Neutral Control/Petersen coil)		-	-	x	x	x	x	x	x	x				x	
AZVT (Zero Voltage Tripping)		-	-	x	x	x	x	x	x	x				x	
GAPC (Automatic Process Control)		-	-	x	x	x	x	x	x	x			x	x	
MMXU (Measurand Unit /for operational purposes)		-	-	x	x	x	x	x	x	x				x	
MMTR (Metering/Acquistion And Calculation)		-	-	x	x	x	x	x	x	x				x	
MSQI (Sequences And Imbalances)		-	-	x	x	x	x	x	x	x				x	
MHAI (Harmonics And Interharmonics)		-	-	x	x	x	x	x	x	x				x	

Key:

x dedicated function decomposition.

- common service function decomposition.

Table H.4 – Function decomposition into Logical Nodes – Part 2

LOGICAL NODE	FUNCTION: Network management	Time synchronization	Physical device self-checking	Node identification	Software management	Configuration management	Operative mode control of LN	Setting	Test mode	Access security management	Control	Management of spontaneous	Synchronized switching	Parameter set switching	Alarm management
LLN0 (related to PD)	x	x	x	x	x	x	x	x	x	x				x	
GSAL (Generic Security Application)	x	x	x	x	x	x	x	x	x	x				x	
XCBR (Circuit Breaker)		-	-	x	x	x	x	x	x	x	x	x	x	x	
XSWI (Disconnector)		-	-	x	x	x	x	x	x	x	x	x		x	
SIMS (Insulation Medium Supervision)		-	-	x	x	x	x	x	x	x		x		x	
SARC (Arc Detection)		-	-	x	x	x	x	x	x	x		x		x	
SPDC (Partial Discharge Detection)		-	-	x	x	x	x	x	x	x		x		x	
TCTR (Current Transformer)		-	-	x	x	x	x	x	x	x				x	
TVTR (Voltage Transformer)		-	-	x	x	x	x	x	x	x			x	x	
YPTR (Power Transformer)		-	-	x	x	x	x	x	x	x		x		x	
YLTC (Tap Changer)		-	-	x	x	x	x	x	x	x		x		x	
YEFN (Earth Fault Neutralizer/Petersen Coil)		-	-	x	x	x	x	x	x	x		x		x	
YPSH (Power Shunt)		-	-	x	x	x	x	x	x	x		x		x	
ZGEN (Generator)		-	-	x	x	x	x	x	x	x		x		x	
ZTCF (Thyristor Controlled Converter)		-	-	x	x	x	x	x	x	x		x		x	
ZCON (Converter)		-	-	x	x	x	x	x	x	x		x		x	
ZMOT (Motor)		-	-	x	x	x	x	x	x	x		x		x	
ZSAR (Surge Arrestor)		-	-	x	x	x	x	x	x	x		x		x	
ZTCR (Thyristor Controlled Reactive		-	-	x	x	x	x	x	x	x		x		x	
ZRRC (Rotating Reactive Component)		-	-	x	x	x	x	x	x	x		x		x	
ZCAP (Capacitor Bank)		-	-	x	x	x	x	x	x	x		x		x	
ZREA (Reactor)		-	-	x	x	x	x	x	x	x		x		x	
ZCAB (Cable Monitoring)		-	-	x	x	x	x	x	x	x		x		x	
ZGIL (Gas Isolated Line Monitoring)		-	-	x	x	x	x	x	x	x		x		x	
ZBAT (Battery Monitoring)		-	-	x	x	x	x	x	x	x		x		x	
ZAXN (Auxiliary Network)		-	-	x	x	x	x	x	x	x		x		x	
GGIO (Generic I/O)		-	-	x	x	x	x	x	x	x	x	x		x	
STIM (Time Master)		x	-	x	x	x	x	x	x	x					
SSYS (System Supervision)	x	x	x	x	x	x	x	x	x	x					
GTES (Test Generator)		-	-	x	x	x	x	x	x	x				x	

Key:

x Dedicated function decomposition.

- Common service function decomposition.

Table H.5 – Function decomposition into Logical Nodes – Part 3

	FUNCTION														
LOGICAL NODE	**Event management/log**	**Data retrieval**	**Disturbance/fault record**	**Protection function**	**Bay level interlocking**	**Station wide interlocking**	**Distributed synchrocheck**	**Breaker failure**	**Automatic protection**	**Reverse blocking function**	**Load shedding**	**Load restoration**	**Voltage and reactive power**	**Infeed switchover and**	**Automatic switching**
P… (Protection, generic)	x	x		x				x	x	x	x			x	
RDRE (Disturbance Recording At Bay Level)	x	x	x												
RDRS (Disturbance Evaluation At Station Level)	x	x	x												
RREC (Automatic Reclosing)	x	x		x											
RBRF (Breaker Failure)	x	x						x							
RCPW (Carrier Or Pilot Wire Relay)	x	x		x											
RFLO (Fault Locator)	x	x		x											
RSYN (Synchrocheck)	x	x		x			x							x	
RPSB (Power Swing Blocking)	x	x		x											
CALH (Creation Of Group Alarms/Events)	x	x													
CSWI (Switch Controller)	x	x										x		x	x
CILO (Interlocking Bay/Station)	x	x			x	x									
IHMI (Human Machine Interface)	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
ITCI (Telecontrol Interface)	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
ITMI (Telemonitoring Interface)	x	x	x	x				x	x	x	x	x	x	x	x
IARC (Archiving)	x	x	x												
ATCC (Automatic Tap Changer Control)	x	x											x		
AVCO (Voltage Control)	x	x											x		
ARCO (Reactive Control)	x	x											x		
ANCR (Earth Fault Neutral. Control/Petersen coil)	x	x													
AZVT (Zero Voltage Tripping)	x	x													
GAPC (Automatic Process Control)	x	x									x	x			x
MMXU (Measurand Unit /Op.)		-	-	x	x	x	x	x	x	x				x	
MMTR (Metering/Acquisition And Calculation)		-	-	x	x	x	x	x	x	x				x	
MSQI (Sequences And Imbalances)		-	-	x	x	x	x	x	x	x				x	
MHAI (Harmonics And Interharmonics)		-	-	x	x	x	x	x	x	x				x	

Key:

x Dedicated function decomposition.

- Common service function decomposition.

Table H.6 – Function decomposition into Logical Nodes – Part 4

	FUNCTION														
LOGICAL NODE	**Event management/log**	**Data retrieval**	**Disturbance/fault record**	**Protection function (generic)**	**Bay level interlocking**	**Station wide interlocking**	**Distributed synchrocheck**	**Breaker failure**	**Automatic protection**	**Reverse blocking function**	**Load shedding**	**Load restoration**	**Voltage and reactive power**	**Infeed switchover and**	**Automatic switching**
LLN0 (related to PD)	x	x													
GSAL (Generic Security Application)	x	x													
XCBR (Circuit Breaker)	x	x	-	x	x	x	x								x
XSWI (Disconnector)	x	x	-		x	x									x
SIMS (Insulation Medium Supervision)	x	x	-												
SARC (Arc Detection)	x	x	-												
SPDC (Partial Discharge Detection)	x	x	-												
TCTR (Current Transformer)	x	x	-	x				x						x	
TVTR (Voltage Transformer)	x	x	-	x			x						x	x	
YPTR (Power Transformer)	x	x	-											x	
YLTC (Tap Changer)	x	x	-												
YEFN (Earth Fault Neutralizer/Petersen Coil)	x	x	-												
YPSH (Power Shunt)	x	x	-												
ZGEN (Generator)	x	x	-	x											
ZTCF (Thyristor Controlled Converter)		-	-	x	x	x	x	x	x	x		x		x	
ZCON (Converter)		-	-	x	x	x	x	x	x	x		x		x	
ZMOT (Motor)	x	x	-	x										x	
ZSAR (Surge Arrestor)	x	x	-												
ZTCR (Thyristor Controlled Reactive	x	x	-												
ZRRC (Rotating Reactive Component)	x	x	-												
ZCAP (Capacitor Bank)	x	x	-												
ZREA (Reactor)	x	x	-												
ZCAB (Cable Monitoring)				x											
ZGIL (Gas Isolated Line Monitoring)				x											
ZBAT (Battery Monitoring)				x											
ZAXN (Auxiliary Network)		-	-	x	x	x	x	x	x	x		x		x	
GGIO (Generic I/O)	x	x	.	x											
STIM (Time Master)	x	x													
SSYS (System Supervision)			-												
GTES (Test Generator)	x	x													

Key:

x Dedicated function decomposition.

- Common service function decomposition.

Annex I
(informative)

Performance calculations

I.1 PICOM method

I.1.1 Approach

This annex describes dynamic performance calculations for data exchange on different communication networks within the substation. Due to the various substation layouts, different protection schemes and control functions, it is difficult to calculate exact dynamic performance requirements. It is therefore necessary to classify typical substations according their size and function. The main types of substations are described in IEC 61850-1. Four different types have been chosen for an evaluation process on dynamic scenarios. Real substations could be classified by using this scheme, but the layout might depend on application, geographical zone, utility philosophy etc. Common amounts on incoming and outgoing feeders, transformers and couplings should help to cover different solutions within one selected subtype and to define real substations according to these recommendations by national bodies. The substation definitions used for performance calculation also contain protection schemes and control functions according to the real necessities.

The evaluation process recommends a common database for functions, associated information elements and algorithms. Basically, functions (logical nodes) and associated information (PICOMs) had been listed in CIGRE – Technical Report, Ref.No.180 and used by IEC Technical Committee 57 working groups during the standardization process. PICOM attributes include performance requirements, logical node assignment, and state of operation and their cause. Together with models of selected substations the data flow on substation networks could be evaluated under different states of operation of a substation. The results are compared for different operation states and different substation types.

I.1.2 Evaluation of dynamic performance requirements

I.1.2.1 Selected substations and associated layouts

The following four substation layouts and configurations had been selected to ensure that the influence of layouts on the busload evaluation could be defined. Transmission and distribution substations were represented in order to cover a wide range of applications. T2-2 was evaluated on the basis of two different layouts according to regional usage, but with the same amount of feeders and transformers.

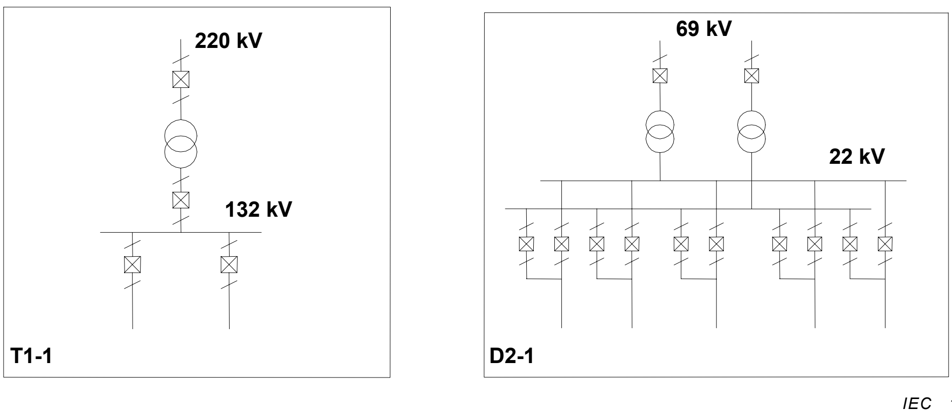


Figure I.1 – T1-1 small size transmission substation/ D2-1 medium size distribution substation

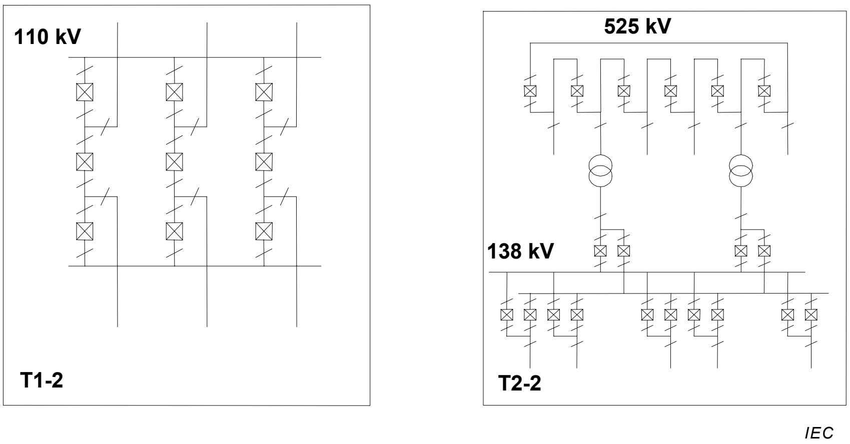


Figure I.2 – T1-2 small size transmission substation with one and a half breaker scheme/T2-2 large size transmission substation with ring bus

Table I.1 – Definition of the configuration of all substations evaluated

Example	Number of busbars	Number of incoming feeders	Number of outgoing feeders	Number of couplings	Number of transformers
T1-1	1	1	2	-	1
D2-1	2	2	5	-	2
T1-2	2	-	6	1	-
T2-2	2	4	5	-	2

I.1.2.2 Assigned protection and control functions (logical nodes)

Due to different substation arrangements and protection and operation philosophies over the world, it is necessary to define functions of the secondary equipment regarding existing applications. Logical nodes and their assignment to physical devices is based on existing protection and operation schemes and done separately for each scenario. The assignment of logical nodes to physical devices for each scenario is directly shown in the Figures I.3, I.4 and I.6, and referenced in captions of Figures I.5, I.7 and I.8.

I.1.2.3 Busload evaluation assumptions

In general, two different kinds of assumptions have been made:

1) Substation communication over one single network (normal state of operation, worst case).
2) Substation communication using the TC 57 communication model according to Figure 2 excluding Interface 2 and 9 (worst-case only).

Results listed in I.2 are calculated from worst-case and normal state of operation scenarios. The worst-case scenario includes normal, emergency, abnormal and post-fault state of operations and assumes the highest performance class per signal for all signals. All evaluated busloads exclude any protocol overhead, but are based on broadcast architecture of the (virtual) communication system. The busload represents the necessary bandwidth of the virtual (selected) communication link, which is able to cover all PICOM dependent performance requirements. The assignment of any PICOM to a communication link according to the IEC 61850 interfaces 1 – 9 is done for each PICOM separately.

The definition of the states of operation are taken from CIGRE – Technical Report, Ref. No. 180:

Normal:
Basic control and supervision tasks (parameter, measurands, commands).

Abnormal/alert:
Transformer overload, alert protection (overload, start/pick-up, some alarm and events).

Emergency/fault:
Action of protection (trip, alarms, events).

Post-fault:
Collection of fault information (fault parameters, disturbance records).

I.1.3 Results of calculations

I.1.3.1 Overview

Table I.2 – Overview of the main results of the performed calculations based on one common bus system covering all interfaces excluding interface 2 and 9

Example	T1-1	D2-1	T1-2 [a]	T2-2 (Double-busbar/ double-busbar)	T2-2 [a] (Ringbus/straight busbar)
Incoming feeders	1	2	-	4	4
Outgoing feeders	2	4	6	8	8
Transformers	1	2	-	2	2
Physical devices	57	121	25	252	60
Non-conventional CT and VTs	X	X	-	X	-
Data flow (normal state of operation) (D_n) kByte/s	244	392	388	849	949
Data flow (worst-case) (D_w) kByte/s	442	830	788	1 748	1 737
D_n/D_w	0,551	0,472	0,493	0,486	0,546

[a] Calculation with special assumption on performance requirements and communication bus systems.

The comparison between both T2-2 calculations might lead to the conclusion that the worst-case data flow is more or less independent from the busbar arrangement by a given substation size. In this special case, cyclic data analogue values or high-speed digital information defines the basic busload. Nevertheless, protection schemes, control functions and time requirements as well as the presence/absence of a process bus must be taken into account.

I.1.3.2 Substation T1-1

The protection scheme and associated control functions of this transmission substation are shown in the Figure I.3.

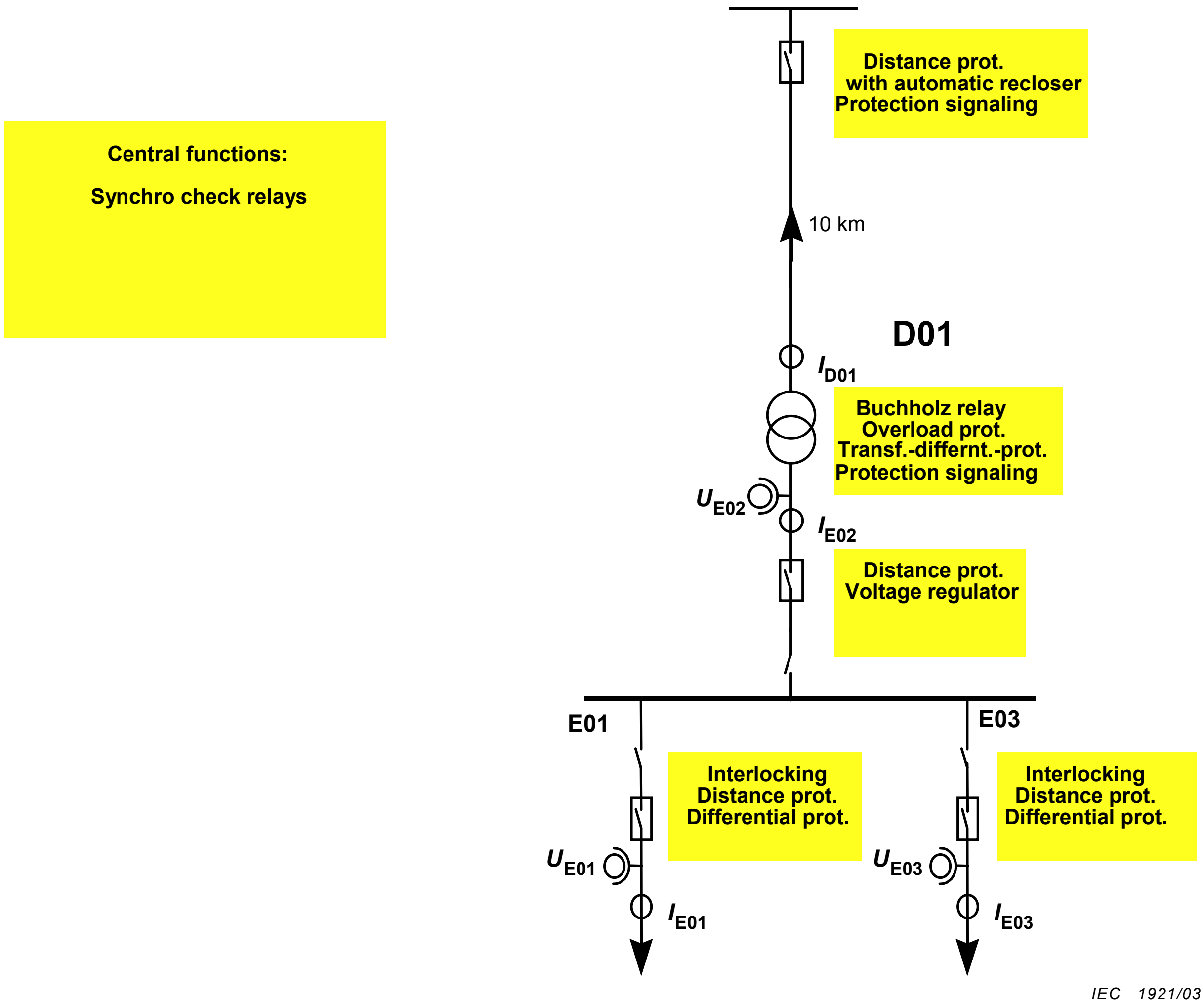


Figure I.3 – Substation of type T1-1 with allocation functions

Table I.3 – Results for the substation T1-1

Interface number	State of operation	Maximum busload (kByte/s)	Remarks
Single network	Normal	244	
Single network	Worst-case	442	
1, 3, 6	"	123	Station bus
8	"	24	Station bus
4, 5	"	295	Process bus, all feeders
4, 5	"	192	Process bus, feeders =E01 to =E03
4, 5	"	65	Process bus, feeder =E01

I.1.3.3 Substation D2-1

The protection scheme and associated control functions of this distribution substation with two HV – bays are shown in the Figure I.4.

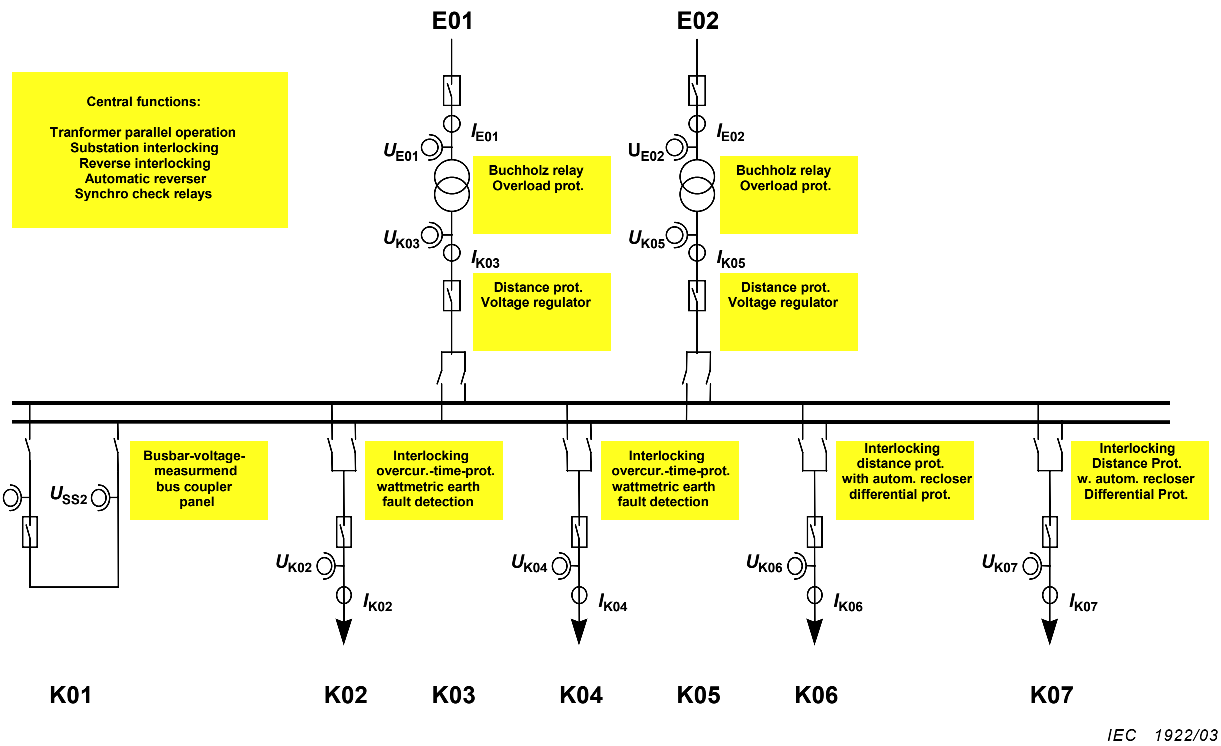


Figure I.4 – Substation of type D2-1 with allocated functions

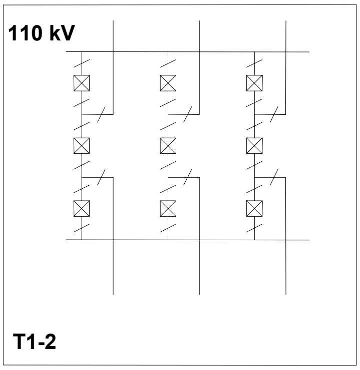
Table I.4 – Results for the substation D2-1

Interface number	State of operation	Maximum busload (kByte/s)	Remarks
Single network	Normal	392	
Single network	Worst-case	830	
1, 3, 6	"	259	Station bus, 1, 3, 6
8	"	12	Station bus, 8
4, 5	"	67	Process bus, only feeder =K06 (see Figure I.4)

I.1.3.4 Substation T1-2

This substation has only been evaluated in a single network configuration with a limited performance requirement for class 1 and 2 PICOMs. Therefore, a performance requirement of 4 ms is assumed. In addition, only conventional c.t.'s and v.t.'s are directly connected to the protection relays.

The protection scheme and associated control functions of this transmission substation are based on the T2-2 scenario (I.1.3.5):



IEC 1923/03

Figure I.5 – Substation of type T1-2 (functions allocated in the same way as for T2-2 in Figure I.6)

Table I.5 – Results for the substation T1-2

Interface number	State of operation	Maximum busload (kByte/s)	Remarks
Single network	Normal	388	Minimum time requirements (performance class 1 and 2) = 4 ms
Single network	Worst-case	783	"

I.1.3.5 Substation T2-2

This substation has been evaluated only in two different layouts with respect to regional usage.

I.1.3.5.1 Double-busbar/double-busbar-arrangement of this

The protection scheme and associated control functions transmission substation are shown in Figure I.6.

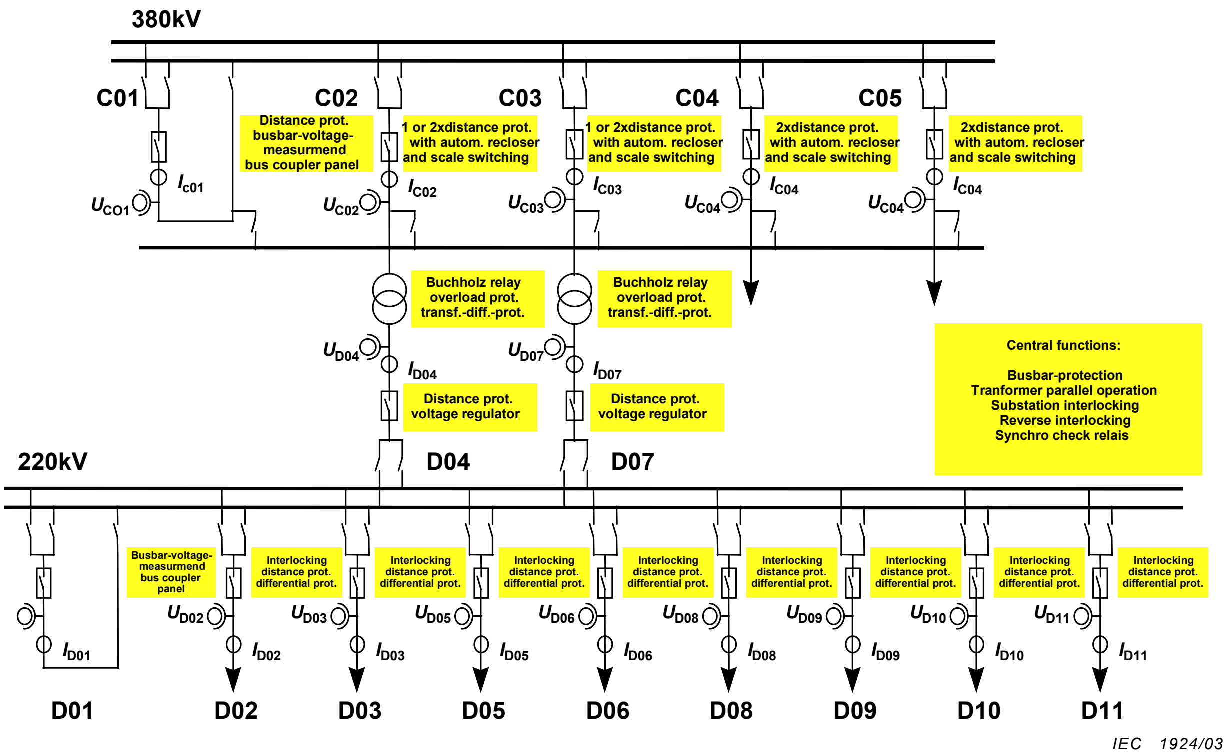


Figure I.6 – Substation of type T2-2 with allocated functions

Table I.6 – Results for the substation T1-2

Interface number	State of operation	Maximum busload (kByte/s)	Remarks
Single network	Normal	849	
Single network	Worst-case	1 748	
1, 3, 6	"	489	Station bus, 1, 3, 6
8	"	36	Station bus, 8
4, 5	"	77	Process bus, only feeder =C04 (see Figure I.6)
4, 5		75	Process bus, only feeder =D02 (see Figure I.6)

I.1.3.5.2 Ring-bus/straight-bus-arrangement

For comparison purposes; a single network configuration with a limited performance requirement for class 1 and 2 PICOMs. A performance requirement of 4 ms is therefore assumed. In addition, only conventional c.t.'s and v.t.'s are directly connected to the protection relays. The protection scheme and associated control functions of this transmission substation is shown in Figure I.7 and is also the basic model for the LAN simulation method described in Clause I.2.

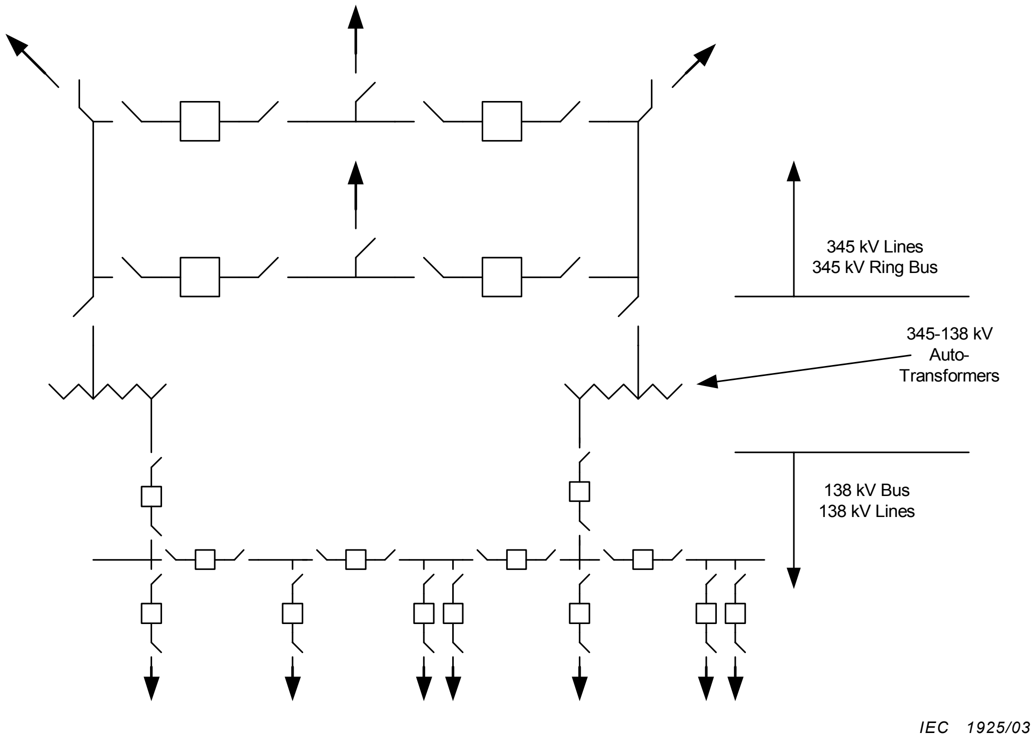


Figure I.7 – Large transmission substation with a ring similar to type T2-2 (function allocation described in Clause I.2)

Table I.7 – Results for the substation according to Figure I.7 (function allocation described in Clause I.2)

Interface number	State of operation	Maximum busload (kByte/s)	Remarks
Single network	Normal	949	Minimum time requirements (performance class 1 and 2) = 4 ms
Single network	Worst-case	1 737	"

I.2 LAN simulation method for dynamic performance evaluation

I.2.1 Approach

A three-step process was used for dynamic performance evaluation of a substation LAN. Firstly, a typical substation protective relaying system was examined to determine the LAN traffic that would be generated by a particularly severe incident in a transmission substation. Secondly, using that level of LAN traffic, the issue of message simultaneity was studied using a simulation program. Thirdly, using that simulation program, runs were made to determine the LAN performance over a wide range of simultaneous messages (10 to 100) utilizing 10 Mbit/s and 100 Mbit/s shared and switched hub Ethernet LANs. The process steps for the evaluation are given in the following sections.

I.2.1.1 Determination of LAN traffic

The substation in question is a relatively standard 345 kV to 138 kV transmission substation. There are four 345 kV lines into a single ring bus and eight 138 kV lines into a sectionalized straight bus. There is a 345 kV to 138 kV autotransformer tapped off two of the 345 kV lines. There is a quad built tower carrying two 345 kV lines and two 138 kV lines entering the station. The station single line diagram is shown if Figure I.8.

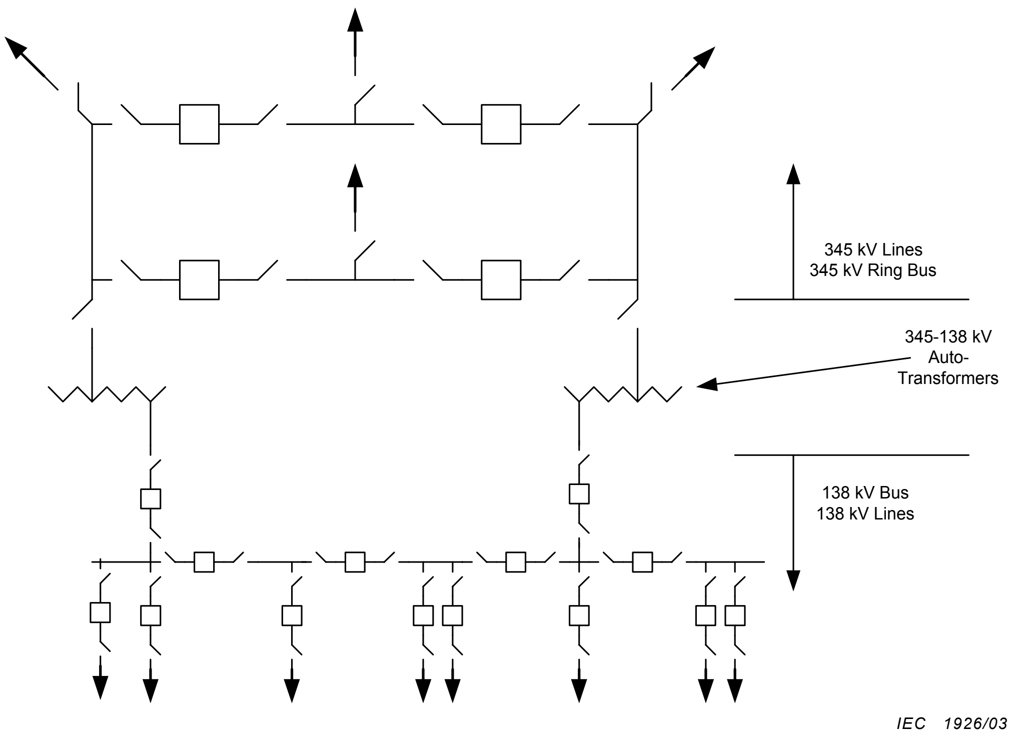


Figure I.8 – Large transmission substation with a ring similar to T2-2 (function allocation see text below)

Each 345 kV line protection consists of a system 1 package and a system 2 package. Each system package has two independent microprocessor relay units. System 1 has two communication subsystems – DTT (Direct Transfer Trip) and either DCR (Directional Comparison Relaying) or PCR (Phase Comparison Relaying). System 2 has only DTT (Direct Transfer Trip).

Each 138 kV line protection package consists of a single protection system. This system consists of two independent microprocessor relay units and two communication subsystems – DTT and either DCR or PCR.

There is a substation LAN that has the performance requirement of being able to deliver a trip signal – from the sending IED (Intelligent Electronic Device) application layer to the receiving IED application layer – in 4 ms. There is no process bus. VTs and CTs are directly hard wired to the protective relays. For the purpose of this case, it was assumed that, hard wired to each breaker, there is a Breaker IED that contains the breaker control, reclosing, and breaker failure relaying functions. Messages to a Breaker IED were used to trip and close its breaker, initiate auto reclosing, and to initiate breaker failure protection.

The scenario also assumes there are Relaying Communication (RC) IEDs responsible for the communication of relay information, which are hard wired to the directional comparison (DCR) and direct transfer trip (DTT) relaying channel equipment (i.e. power line carrier, audio tone, microwave, optical, etc.). The DCR and DTT relaying communication channel equipment are not hard wired to their respective protective relays. Instead, trip and block signals to the remote line ends are initiated by the protective relay IEDs by sending DTT or PTT (Permissive Transfer Trip) messages over the substation LAN to the relaying communications IEDs. Outputs from the relaying communications IEDs then trigger the channel equipment. Received commands from the relaying channel equipment will also generate LAN signals. The IED – LAN configuration diagrams are in Figures I.9 and I.10. The diagrams show 85 protection and control IEDs.

The scenario assumes that a section of the quad built tower fails and falls to the ground, creating faults on all four of its lines (2 kV to 345 kV and 2 kV to 138 kV). There is also a breaker failure during this incident. Protection engineers analyzed this event and determined that the IEDs would generate 144 point to point commands (equivalent to individual wire connections in a conventional installation). Each of these is also equivalent to an individual PICOM.

These additional assumptions were made:

- All IEDs are connected to one LAN. There may be a redundant LAN, but it would not reduce traffic on this LAN.
- All protection, control, and monitoring are via the protection IEDs. There are no bay controllers.
- All outputs from the IEDs are treated equally, with no intentional time delay for outputs such as reclose initiate or breaker failure initiate.
- A given transmission line will not both receive and initiate DCR signals for this internal fault case.
- Channel time is assumed to be zero. Thus, a remote command to trip will arrive on the LAN at the same time as local trip commands.
- All messages use an unacknowledged protocol.
- Tripping is initiated by the line relays about 1 cycle (16 ms) after the fault occurs.
- Transformer protection initiates tripping about 3 cycles (50 ms) after the fault occurs, and is therefore not included in the initial “blast” of messages on the LAN.
- The case assumes that all relays operate correctly. False operations will generate additional messages.
- The Digital Fault Recorder (DFR) will be a separate device that will monitor all LAN traffic for sequence of events. No LAN traffic will be directed to the DFR.

In Table I.8, the column of “point to point commands” is the list of individual IED outputs (PICOMs). A number of these commands are from one IED to the same destination IED, and can therefore be combined in one message. These are shown in the column “multi-command point to point messages”. In addition, the information in many of the multi-command messages must be sent to multiple destinations, and so may be multicast. A multicast message, when broken down, will be received by each device or function shown in the point to point command column.

Table I.8 – 138 kV affected (faulted) lines and related messages

Device	Multicast message	Point to Point Commands (PICOMs)	Multi-command point to point messages
Relay 1	1	Trip Breaker X	1
		Initiate Auto Reclose	
		Initiate Brkr Fail Protect	
		Stop Block on DCR Comm	1
		Send DTT on DTT Comm	1
Relay 2	1	Trip Breaker X Initiate Auto Reclose Initiate Brkr Fail Protect	1
		Stop Block on DCR Comm Send DTT on DCR Comm	1 1
RC Comm	1	Trip Breaker X Initiate Auto Reclose	1
		Initiate Brkr Fail Protect	
Totals	3 messages/line × 2 lines = 6	13 Commands/line × 2 lines = 26 PICOMs	7 messages/line × 2 lines = 14

A similar analysis was made for the 138 kV unaffected lines, and for all four of the 345 kV lines. Considering all of the IEDs, this single contingency event generates 144 Point to Point Commands (PICOMs). If combined into messages, it generates 60 multi-command point to point messages. If multicast messages are used, the total drops to 38 messages. Thus, for the purposes of LAN congestion evaluation, 38 multicast messages were used. Tables in Clause I.2.3 provide details and summarize the LAN traffic caused by this incident. It should be noted that over half of the traffic (20 of 38 messages) are via the relaying communications IEDs (Interface 2) because of the type of relaying schemes used (directional comparison and transfer trip).

I.2.1.2 Message simultaneity

In contention based systems such as Ethernet, performance is substantially affected by the number of collisions that occur. Using the COMNET III simulation program, the performance of 10 MBit and 100 MBit shared and switched hub systems has been measured. The shared Ethernet LAN architecture consists of all 85 IEDs communicating with each other over a single shared link. The switched hub architecture contains four Ethernet switched hubs. The IEDs are distributed with each hub connected to 20 to 22 IEDs. The effect of SCADA and file transfer background traffic on event driven messages on Ethernet LANs had been examined earlier. These studies showed that a background traffic load of 5 times the normal SCADA traffic plus two large file transfers (oscillographic fault records) had no measurable effect on event driven message delivery times. Thus, the COMNET III simulations did not include any background traffic.

For the first runs, it was assumed that all 38 messages arrived on the LAN in the same µs. However, microprocessor based protective relay IEDs operate in a sampling mode. Most modern designs have A/D sampling in the 1 kHz to 4 kHz range (sampling intervals of 0,25 ms to 1 ms). Furthermore, except for phasor measurement units, the sampling clocks are not synchronized between IEDs. Thus, even with identical IEDs, the probabilities are extremely low that a single power system event would cause multiple IEDs to react and generate multicast messages within the same µs or even the same 100 µs window.

Additional runs were therefore made to determine the effect of spreading the 38 messages over wider time windows. These runs used normal distributions of 10 µs, 100 µs, and 1 000 µs (1 ms). Each message was assumed to be the minimum Ethernet packet length of 256 bytes. The results are shown in Table I.9 and Table I.10. The right hand column is the sum of the average message delay plus a 3-sigma variation.

Table I.9 – Message delays of 38 – 256 byte multicast messages on a shared hub network

LAN speed (MBit/s)	Standard deviation of message distribution time (µs)	Average message delay (ms)	3 sigma maximum message delay (ms)
10	1	6,36	21,93
10	10	6,34	21,34
10	100	6,03	20,73
10	1 000	4,07	16,43
100	1	1,10	3,76
100	10	0,64	2,53
100	100	0,61	2,56
100	1 000	0,05	0,29

Table I.10 – Message delays of 38 messages on a switched hub network

LAN speed (MBit/s)	Standard deviation of message distribution time (µs)	Average message delay (ms)	3 sigma maximum message delay (ms)
10	1	0,68	1,70
10	10	0,67	1,68
10	100	0,59	1,27
10	1 000	0,43	0,67
100	1	0,07	0,17
100	10	0,06	0,15
100	100	0,05	0,07
100	1 000	0,04	0,06

These results show that there is not much change in message delay when the standard deviation was increased from 1 µs to 10 µs to 100 µs, but there is a substantial change in performance when the window was increased from 100 µs to 1 000 µs. Given the sampling rates in present microprocessor based IED designs, it was concluded that a normal distribution around 1 000 µs (1 ms) should be the baseline for further analysis. No runs were made for longer times.

I.2.1.3 Impact of message volume on LAN dynamic performance

Additional runs were made to determine the Ethernet LAN performance at various message levels, all with a normal distribution of 1 ms. The results are shown in Table I.11 and Table I.12.

Table I.11 – Message delays of a variable number of messages on a shared hub network

LAN speed (MBit/s)	Number of network messages	Average message delay (ms)	3 sigma maximum message delay (ms)
10	10	0,41	1,19
10	20	1,43	6,23
10	30	2,94	12,69
10	38	4,07	16,43
10	50	5,77	23,11
10	60	7,14	29,64
10	74	9,37	35,29
100	10	0,03	0,04
100	20	0,03	0,11
100	30	0,04	0,18
100	38	0,05	0,29
100	50	0,08	0,52
100	60	0,15	1,05
100	74	0,24	1,74
100	90	0,40	2,75
100	100	0,49	3,36

Table I.12 – Message delays of a variable number of messages on a switched hub network

LAN speed (MBit/s)	Number of network messages	Average message delay (ms)	3 sigma maximum message delay (ms)
10	10	0,41	0,61
10	20	0,42	0,59
10	30	0,42	0,64
10	38	0,43	0,67
10	50	0,45	0,81
10	60	0,47	0,89
10	74	0,48	0,91
10	90	0,50	1,04
10	100	0,52	1,20
100	10	0,04	0,06
100	20	0,04	0,06
100	30	0,04	0,06
100	38	0,04	0,06
100	50	0,04	0,06
100	60	0,04	0,06
100	74	0,04	0,06
100	100	0,04	0,06

I.2.2 Conclusions

- The use of multicast messages can substantially reduce the LAN traffic generated by a fault. In the Commonwealth Edison scenario (as described in the following bulleted items), the total is reduced from 144 to 38 messages.

- For analysis purposes, a reasonable assumption is that messages generated by an event (fault) can be spread over 1 ms.

- A 10 MBit shared hub Ethernet network has limited performance. It can deliver less than 20 messages in 4 ms (approximately 15 by interpolation).

- Three LANs (10 Mbit/s switched hub, 100 Mbit/s shared hub, and 100 Mbit/s switched hub) all can deliver 100 messages within 4 ms if spread over 1 ms.

I.2.3 Summary and details of LAN traffic

Table I.13 – Summary table

		Multicast messages	**Point to Point Commands (PICOMs)**	**Multi-command point to point messages**
Each 138 kV line	Affected	3	13	7
	Unaffected	2	2	2
Each 345 kV line	Affected	6	49	13
	Unaffected	4	4	4
2 affected 138 kV lines		6	26	14
6 unaffected 138 kV lines		12	12	12
2 affected 345 kV lines		12	98	26
2 unaffected 345 kV lines		8	8	8
Totals		38	144	60

Table I.14 – 138 kV affected lines

Device	Multicast message	Point to Point Commands (PICOMs)	Multi-command point to point messages
Relay 1	1	Trip Breaker X	1
		Initiate Auto Reclose	
		Initiate Brkr Fail Protect	
		Stop Block on DCR Comm	1
		Send DTT on DTT Comm	1
Relay 2	1	Trip Breaker X	1
		Initiate Auto Reclose	
		Initiate Brkr Fail Protect	
		Stop Block on DCR Comm	1
		Send DTT on DCR Comm	1
RC Comm	1	Trip Breaker X	1
		Initiate Auto Reclose	
		Initiate Brkr Fail Protect	
Affected	3 messages/line × 2 lines = 6	13 Commands/line × 2 lines = 26	7 Commands/line × 2 lines = 14

Table I.15 – 138 kV unaffected lines (per line)

Device	Multicast messages	Point to Point Commands (PICOMs)	Multi-command point to point
Relay 1	1	Send Block on DCR Comm Channel	1
Relay 2	1	Send Block on DCR Comm Channel	1
RC comm received		no signals	0
Non-affected	2 messages/line × 6 lines = 12	2 commands/line × 6 lines = 12	2 × 6 = 12 Messages

Table I.16 – Total 138 kV lines

138 kV	Multicast messages	Point to Point Commands (PICOMs)	Multi-command point to point
Total	18 Messages	38 Point to Point Commands	26 Messages

Table I.17 – 345 kV affected lines/per line/per relay system – Relay 1

Device	Multicast message	Point to Point Commands (PICOMs)	Multi-command point to point
Relay 1	1	Trip Breaker X1	1
		Initiate Auto Reclose X1	
		Initiate Brkr Failure Protect X1	
		Trip Breaker X2	1
		Initiate Brkr Failure Protect X2	
		Trip 138 kV Transformer Breaker	1
		Initiate Brkr Fail Protect-Transf Brkr	
		Stop Block on DCR or Start PTT on PTT Comm Channels (System 1 only)	1
		Send DTT on DTT Comm Channel	1

Table I.18 – 345 kV affected lines/per line/per relay system – Relay 2

Device	Multicast message	Point to Point Commands (PICOMs)	Multi-command point to point
Relay 2	1	Trip Breaker X1	1
		Initiate Auto Reclose X1	
		Initiate Brkr Fail Protect X1	
		Trip Breaker X2	1
		Initiate Brkr Fail Protect X2	
		Trip 138 kV Transformer Breaker	1
		Initiate Brkr Fail Protect-Transformer Brkr	
		Stop Block on DCR or Start PTT on PTT Comm Channel (System 1 only)	1
		Send DTT on DTT Comm Channel	1

Table I.19 – 345 kV affected lines/per line/system communications

Device	Multicast message	Point to Point Commands (PICOMs)	Multi-command point to point
Relay Comm IED	1	From Communications to Relay Logic Input (System 1 only)*	1
		Trip Breaker X1	1
		Initiate Auto Reclose X1	
		Initiate Brkr Fail Protection X1	
		Trip Breaker X2	1
		Initiate Brkr Fail Protection X2	
		Trip 138 kV Transformer Breaker	1
		Initiate Brkr Fail Protect Transformer Brkr	

Table I.20 – 345 kV affected lines

Device	Multicast message	Point to Point Commands (PICOMs)	Multi-command point to point
Totals 1	For 2 Systems/Line × 3 = 6	49	13
Totals 2	For 2 Affected Lines × 6 = 12	98	26

Table I.21 – 345 kV unaffected lines/per line

Device	Multicast message	Point to Point Commands (PICOMs)	Multi-command point to point
System 1 Relay 1	1	Start Block Stop PTT on DCR or PTT Comm Channel	1
System 1 Relay 2	1	Send Block Stop PTT on DCR or PTT Comm Channel	1
Comm Rcvr System 1		No signals	0
System 2 Relay 1	1	Start Block Stop PTT on DCR or PTT Comm Channel	1
System 2 Relay 2	1	Start Block Stop PTT on DCR or PTT Comm Channel	1
Comm Rcvr System 2		No signals	0
Unaffected	4 messages × 2 lines = 8	4 Point to Point Commands × 2 lines = 8 Point to Point	4 Multi-command × 2 lines = 8

Table I.22 – Total 345 kV lines

345 kV	Multicast message	Point to Point Commands (PICOMs)	Multi-command point to point
Total	20	106	36

Table I.23 – Total LAN

LAN	Multicast message	Point to Point Commands (PICOMs)	Multi-command point to point
TOTAL	38	144	60

I.2.4 Ethernet shared and switched hub configurations

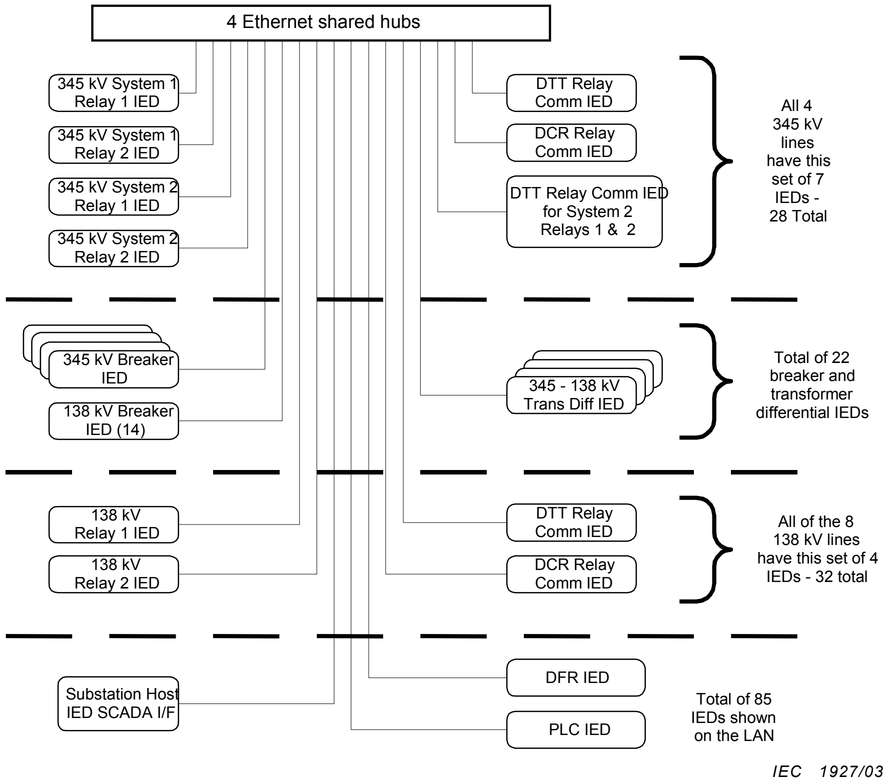


Figure I.9 – Ethernet configuration with shared hub

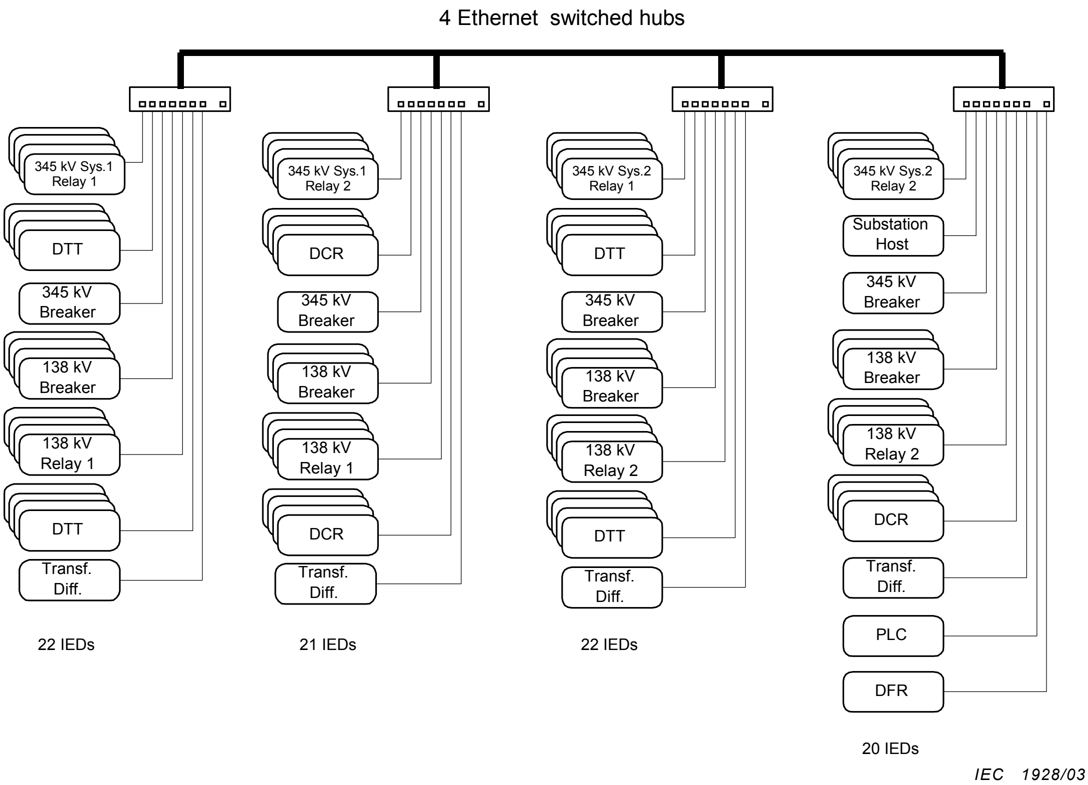


Figure I.10 – Ethernet configuration with switched hubs

Annex J
(informative)

Examples for protection functions in compensated networks

PTEF (Protection Transient Earth Fault) and PWDE (directional earth fault protection for compensated networks based on watt-metric principle) are typically used functions to detect the location of an earth fault in a compensated network. The PTEF detects the transient charging current related with the network capacitance. Therefore the PTEF can only detect the beginning of an earth fault. The PWDE (directional earth fault protection for compensated networks based on watt-metric principle) detects the residual phase to earth current. Therefore the PWDE is able to notify also the end of an earth fault and its direction if feasible.

The feeders of the faulty line will indicate a forward earthfault while the other feeders may indicate a reverse earthfault.

At the beginning of the earth fault PTEF and maybe PWDE provides information about the transient earth fault happening, at the end of the earth fault PWDE informs about the fault time and direction if feasible.

J.1 The Transient Earth Fault (PTEF)

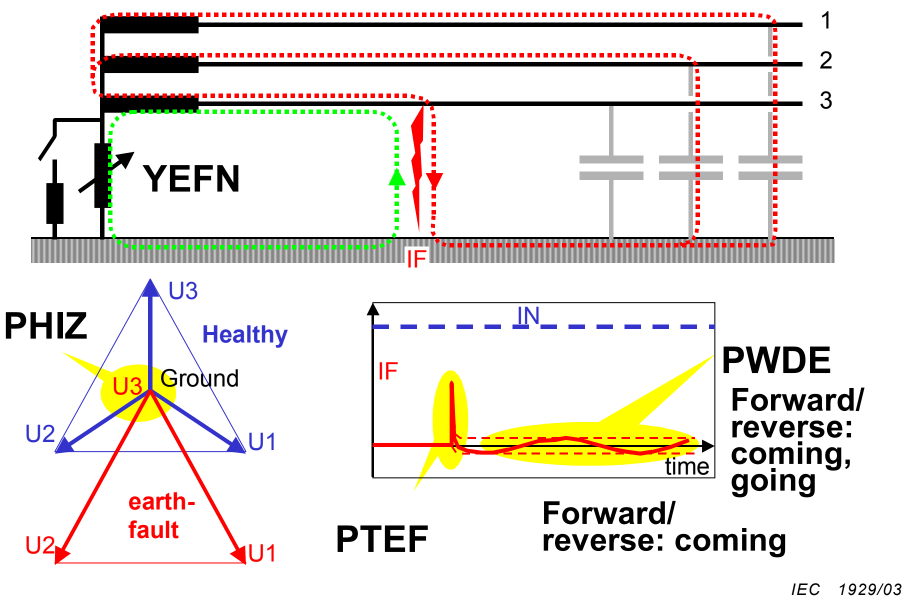


Figure J.1 – The transient earth fault in a compensated network

J.2 Short term bypass (YPSH)

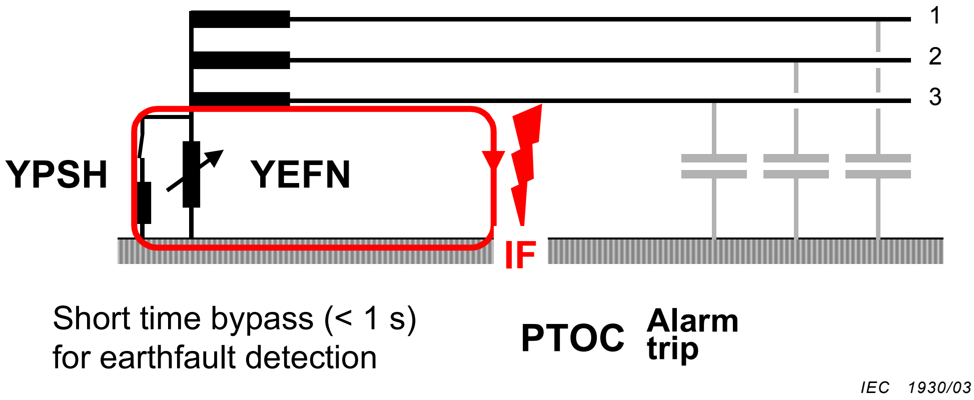


Figure J.2 – Short term bypass for single earth fault in compensated networks

J.3 The double earth fault (PTOC)

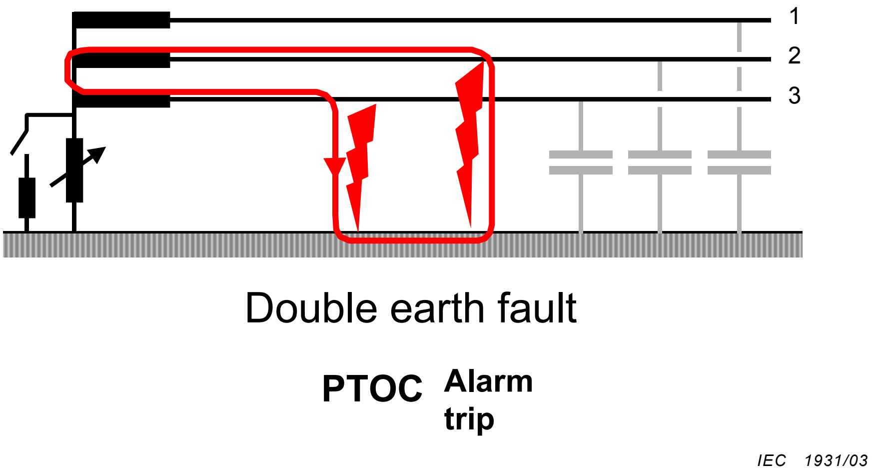


Figure J.3 – The double earth fault in compensated networks

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Excerpt of CIGRE Report 34-03 published in *Electra*

K.P. Brand, *Communication requirements in terms of data flow within Substations – Results of WG34.03 and standardization within IEC*, **Electra** 173, 77-85 (1997)

The full report of CIGRE WG34-03 is titled

CIGRE – Technical Report, Ref.No.180 – *Communication requirements in terms of data flow within substations.* CE/SC 34 03, 2001, 112 pp. Ref. No. 180

Egne notater/Notes: