



BSI Standards Publication

Communication networks and systems for power utility automation

Part 5: Communication requirements for functions and device models

National foreword

This British Standard is the UK implementation of EN 61850-5:2013+A1:2022. It is identical to IEC 61850-5:2013, incorporating amendment 1:2022. It supersedes BS EN 61850-5:2003 which is withdrawn.

The start and finish of text introduced or altered by amendment is indicated in the text by tags. Tags indicating changes to IEC text carry the number of the IEC amendment. For example, text altered by IEC amendment 1 is indicated by **A1** **A1**.

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Date	Text affected
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**Communication networks and systems for power utility automation -
Part 5: Communication requirements for functions and device models
(IEC 61850-5:2013)**

Réseaux et systèmes de communication
pour l'automatisation des systèmes
électriques -
Partie 5: Exigences de communication
pour les modèles de fonctions et
d'appareils
(CEI 61850-5:2013)

Kommunikationsnetze und -systeme für
die Automatisierung in der elektrischen
Energieversorgung -
Teil 5: Kommunikationsanforderungen
für Funktionen und Gerätemodelle
(IEC 61850-5:2013)

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European Foreword

The text of document 57/1286/FDIS, future edition 2 of IEC 61850-5, prepared by IEC/TC 57 "Power systems management and associated information exchange" was submitted to the IEC-CENELEC parallel vote and approved by CENELEC as EN 61850-5:2013.

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- latest date by which the national standards conflicting with the document have to be withdrawn (dow) 2016-03-06

This document supersedes EN 61850-5:2003.

EN 61850-5:2013 includes the following significant technical changes with respect to EN 61850-5:2003:

- extension from substation automation systems to utility automation systems;
- including the interfaces for communication between substations (interfaces 2 and 11);
- requirements from communication beyond the boundary of the substation.

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IEC 60834-1:1999	NOTE	Harmonised as EN 60834-1.
IEC 60870-5 Series	NOTE	Harmonised as EN 60870-5 Series (not modified).
IEC 61000-4-30	NOTE	Harmonised as EN 61000-4-30.
IEC 61850-3	NOTE	Harmonised as EN 61850-3.
IEC 61850-7 Series	NOTE	Harmonised as EN 61850-7 Series (not modified).
IEC 61850-7-1	NOTE	Harmonised as EN 61850-7-1.
IEC 61850-7-2	NOTE	Harmonised as EN 61850-7-2.
IEC 61850-7-3	NOTE	Harmonised as EN 61850-7-3.
IEC 61850-7-4	NOTE	Harmonised as EN 61850-7-4.
IEC 61850-8 Series	NOTE	Only Part 8-1 is Harmonised as EN 61850-8-1.
IEC 61850-9 Series	NOTE	Harmonised as EN 61850-9-2 Series (not modified).
IEC 61850-10	NOTE	Harmonised as EN 61850-10.

European foreword to Amendment 1

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Annex ZA (normative)

Normative references to international publications with their corresponding European publications

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements 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.

NOTE 1 Where an International Publication has been modified by common modifications, indicated by (mod), the relevant EN/HD applies.

NOTE 2 Up-to-date information on the latest versions of the European Standards listed in this annex is available here: www.cenelec.eu.

Replace the references in Clause 2 with the following references:

<u>Publication</u>	<u>Year</u>	<u>Title</u>	<u>EN/HD</u>	<u>Year</u>
IEC 60617	-	Graphical symbols for diagrams - 12-month subscription to regularly updated online database comprising parts 2 to 13 of IEC 60617	-	-
IEC 60834-1	1999	Teleprotection equipment of power systems - Performance and testing - Part 1: Command systems	EN 60834-1	1999
IEC 60834-2 (mod)	1993	Performance and testing of teleprotection equipment of power systems - Part 2: Analogue comparison systems	HD 543.2 S1	1995
IEC 60870-4	1990	Telecontrol equipment and systems. Part 4: Performance requirements	HD 546.4 S1	1992
IEC 60870-5	series	Telecontrol equipment and systems. Part 5: Transmission protocols	EN 60870-5	series
IEC 61000-4-15	2010	Electromagnetic compatibility (EMC) - Part 4-15: Testing and measurement techniques - Flickermeter - Functional and design specifications	EN 61000-4-15	2011
IEC 61000-4-30	2015	Electromagnetic compatibility (EMC) - Part 4-30: Testing and measurement techniques - Power quality measurement methods	EN 61000-4-30	2015
IEC 61508	series	Functional safety of electrical/electronic/programmable electronic safety-related systems	EN 61508	series
IEC/TR 61850-1	2013	Communication networks and systems for power utility automation – Part 1: Introduction and overview		-
IEC/TS 61850-2	2019	Communication networks and systems in substations - Part 2: Glossary		-

EN 61850-5:2013/A1:2022 (E)

IEC 61850-3	2013	Communication networks and systems for EN 61850-3 power utility automation - Part 3: General requirements	2014
IEC 61850-4	2011	Communication networks and systems for EN 61850-4 power utility automation - Part 4: System and project management	2011
IEC 61850-6	2009	Communication networks and systems for EN 61850-6 power utility automation - Part 6: Configuration description language for communication in electrical substations related to IEDs	2010
+ A1	2018	+ A1	2018
IEC 61850-7-1	2011	Communication networks and systems for EN 61850-7-1 power utility automation - Part 7-1: Basic communication structure - Principles and models	2011
+ A1	2020	+ A1	2020
IEC 61850-7-2	2010	Communication networks and systems for EN 61850-7-2 power utility automation - Part 7-2: Basic information and communication structure - Abstract communication service interface (ACSI)	2010
+ A1	2020	+ A1	2020
IEC 61850-7-3	2010	Communication networks and systems for EN 61850-7-3 power utility automation - Part 7-3: Basic communication structure - Common data classes	2011
+ A1	2020	+ A1	2020
IEC 61850-7-4	2010	Communication networks and systems for EN 61850-7-4 power utility automation - Part 7-4: Basic communication structure - Compatible logical node classes and data object classes	2010
+ A1	2020	+ A1	2020
IEC/TR 61850-7-5	-	Communication networks and systems for - power utility automation - Part 7-5: IEC 61850 modelling concepts	-
IEC/TR 61850-7-500	2017	Communication networks and systems for - power utility automation - Part 7-500: Basic information and communication structure - Use of logical nodes for modelling application functions and related concepts and guidelines for substations	-
IEC/TR 61850-7-510	2012	Communication networks and systems for - power utility automation - Part 7-510: Basic communication structure - Hydroelectric power plants - Modelling concepts and guidelines	-

IEC/TR 61850-7-6	2019	Communication networks and systems for - power utility automation - Part 7-6: Guideline for definition of Basic Application Profiles (BAPs) using IEC 61850	-
IEC/TS 61850-7-7	2018	Communication networks and systems for - power utility automation - Part 7-7: Machine-processable format of IEC 61850-related data models for tools	-
IEC 61850-8-1	2011	Communication networks and systems for EN 61850-8-1 power utility automation - Part 8-1: Specific communication service mapping (SCSM) - Mappings to MMS (ISO 9506-1 and ISO 9506-2) and to ISO/IEC 8802-3	2011
+ A1	2020		+ A1 2020
IEC 61850-8-2	2018	Communication networks and systems for EN IEC 61850-8-2 power utility automation - Part 8-2: Specific communication service mapping (SCSM) - Mapping to Extensible Messaging Presence Protocol (XMPP)	2019
IEC 61850-9-2	2011	Communication networks and systems for EN 61850-9-2 power utility automation - Part 9-2: Specific communication service mapping (SCSM) - Sampled values over ISO/IEC 8802-3	2011
+ A1	2020		+ A1 2020
IEC/IEEE 61850-9-3	2016	Communication networks and systems for - power utility automation - Part 9-3: Precision time protocol profile for power utility automation	-
IEC 61850-10	2012	Communication networks and systems for EN 61850-10 power utility automation - Part 10: Conformance testing	2013
IEC/TR 61850-80-3	2015	Communication networks and systems for - power utility automation - Part 80-3: Mapping to web protocols - Requirements and technical choices	-
IEC/TR 61850-90-1	2010	Communication networks and systems for - power utility automation - Part 90-1: Use of IEC 61850 for the communication between substations	-
IEC/TR 61850-90-2	2016	Communication networks and systems for - power utility automation - Part 90-2: Using IEC 61850 for communication between substations and control centres	-
IEC/TR 61850-90-4	2020	Communication networks and systems for - power utility automation - Part 90-4: Network engineering guidelines	-
IEC/TR 61850-90-5	2012	Communication networks and systems for - power utility automation - Part 90-5: Use of IEC 61850 to transmit synchrophasor information according to IEEE C37.118	-

EN 61850-5:2013/A1:2022 (E)

IEC/TR 61850-90-12	2020	Communication networks and systems for - power utility automation - Part 90-12: Wide area network engineering guidelines	-	-
IEC 61869	series	Instrument transformers	EN 61869	series
IEC/TR 62357-1	2016	Power systems management and associated information exchange - Part 1: Reference architecture	-	-
IEC 81346	series	Industrial systems, installations and equipment and industrial products - Structuring principles and reference designations	EN IEC 81346	series
IEEE Std C37.2-2008	2008	Electrical Power System Device Function - Numbers, Acronyms, and Contact Designations	-	-

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INTERNATIONAL ELECTROTECHNICAL COMMISSION

COMMUNICATION NETWORKS AND SYSTEMS FOR POWER UTILITY AUTOMATION –

Part 5: Communication requirements for functions and device models

FOREWORD

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This consolidated version of the official IEC Standard and its amendment has been prepared for user convenience.

IEC 61850-5 edition 2.1 contains the second edition (2013-01) [documents 57/1286/FDIS and 57/1309/RVD] and its amendment 1 (2022-03) [documents 57/2448/FDIS and 57/2467/RVD].

International Standard IEC 61850-5 has been prepared by IEC technical committee 57: Power systems management and associated information exchange.

The changes, corrections and updates have been made mainly according to the comments received.

The major changes of this consolidated version with regard to the edition 2 are as follows:

- a) extensions of the requirements with some Logical Nodes
- b) errors and typos have been corrected
- c) harmonization of all Logical Node descriptions (impact on all Logical Node tables)
- d) re-organization of selected clause structures
- e) updating of headlines
- f) re-ordering subclauses in the chapter about performances

to provide

- ease of reading and understanding of the requirements for the IEC 61850 series
- consistent and updated requirement references for the data model and communication service parts

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

A list of all the parts in the IEC 61850 series, published under the general title *Communication networks and systems for power utility automation*, can be found on the IEC website.

Future standards in this series will carry the new general title as cited above. Titles of existing standards in this series will be updated at the time of the next edition.

The committee has decided that the contents of the base publication and its amendment will remain unchanged until the stability date indicated on the IEC web site under webstore.iec.ch in the data related to the specific publication. At this date, the publication will be

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

IMPORTANT – The 'colour inside' logo on the cover page of this publication indicates that it contains colours which are considered to be useful for the correct understanding of its contents. Users should therefore print this document using a colour printer.

INTRODUCTION

This part of IEC 61850 is part of a set of standards, the IEC 61850 series. The IEC 61850 series is intended to provide interoperability between all devices in power utility automation systems. Therefore, it defines communication networks and systems for power utility automation, and more specially the communication architecture for subsystems like substation automation systems. The sum of all subsystems may result also in the description of the communication architecture for the overall power system management.

Communication between these devices in subsystems and between the subsystems within the overall power utility automation system fulfils a lot of requirements imposed by all the functions to be performed in power utility automation systems starting from the core requirements in substations. These requirements are stated both for the data to be organized in a data model and for the data exchange resulting in services. Performance of the data exchange means not only transfer times but also the quality of the data exchange avoiding losses of information in the communication.

Depending on the philosophy both of the manufacturer and the user and on the state-of-the-art in technology, the allocation of functions to devices and control levels is not commonly fixed. Therefore, the standard shall support any allocation of functions. This results in different requirements for the different communication interfaces within the substation or plant, at its border and beyond.

The IEC 61850 series shall be long living but allow following the fast changes in communication technology by both its technical approach and its document structure. The IEC 61850 series has been organized so that at least minor changes to one part do not require a significant rewriting of another part. For example, the derived data models in subsequent parts (IEC 61850-7-x) and mappings to dedicated stacks (IEC 61850-8-x and IEC 61850-9-x) based on the communication requirements in IEC 61850-5 will not change the requirements defined in IEC 61850-5. In addition, the general parts, the requirement specification and the modelling parts are independent from any implementation. The implementation needed for the use of the standard is defined in some few dedicated parts referring to main stream communication means thus supporting the long living of the standard and its potential for later technical changes.

This consolidated version of IEC 61850-5:2013 and its Amendment 1 defines the communication requirements for functions and device models for power utility automation systems.

The modelling of communication requires the definition of objects (e.g., data objects, data sets, report control, log control) and services accessing the objects (e.g., get, set, report, create, delete). This is defined in IEC 61850-7 with a clear interface to implementation. To use the benefits of communication technology, in this standard no new protocol stacks are defined but a standardized mapping on existing stacks is given in IEC 61850-8 and IEC 61850-9. A System configuration language (IEC 61850-6) for strong formal description of the system usable for software tools and a standardized conformance testing (IEC 61850-10) complement the standard.

NOTE 1 To keep the layered approach of the standard not mixing application and implementation requirements, terms like client, server, data objects, etc. are normally not used in IEC 61850-5 (requirements). In IEC 61850-7 (modelling), -8 and -9 (specific communication service mapping) terms belonging to application requirements like PICOM are normally not used.

NOTE 2 Specific requirements concerning extensions of part 8 are covered in separate technical reports, e.g. IEC TR 61850-80-3.

COMMUNICATION NETWORKS AND SYSTEMS FOR POWER UTILITY AUTOMATION –

Part 5: Communication requirements for functions and device models

1 Scope

A1 The specifications of this document refer to general, respectively core, communication requirements of the application functions in all domains of power utility automation systems. Dedicated communication requirements and most examples of application functions in this document are from the domain substation automation but may be reused in or extended to other domains within power utility automation systems. Note that sometimes instead of the term substation automation domain the term substation domain is used, especially if both the switchyard devices (primary system) and the automation system (secondary system) are regarded.

The description of the application functions is not used to standardize these functions, but to identify communication requirements between Intelligent Electronic Devices (IEDs) hosting these functions within plants and substations in the power system, between such stations (e.g. between substation for line protection) and between the plant or substation and higher-level remote operating places (e.g. network control centres) and maintenance places. In addition interfaces to remote technical services (e.g. maintenance centres) are considered. The general scope is the communication requirements for power utility automation systems. The basic goal is interoperability for all interactions providing a seamless communication system for the overall power system management. Another prerequisite for interoperability is a commonly defined method for time synchronization.

Standardizing application functions and their implementation is completely outside the scope of this document. Therefore, it cannot be assumed a single philosophy of allocating application functions to devices. To support the resulting request for free allocation of these functions, a proper breakdown of these functions into parts relevant for communication is defined. The exchanged data and their required performance are defined.

The same or similar IEDs from substations like protective and control devices are found in other domains like power plants also. Using this document for such devices in these plants facilitates the system integration e.g. between the power plant control and the related substation automation system. For some of such other application domains like wind power plants, hydro power plants and distributed energy resources specific standard parts according to the IEC 61850 series have been already defined and published. **A1**

2 Normative references

A1 The following documents are referred to in the text in such a way that some or all of their content constitutes requirements 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 60617, *Graphical symbols for diagrams – 12-month subscription to regularly updated online database comprising parts 2 to 13 of IEC 60617*

IEC 60834-1:1999, *Teleprotection equipment of power systems – Performance and testing – Part 1: Command systems*

IEC 60834-2:1993, *Performance and testing of teleprotection equipment of power systems – Part 2: Analogue comparison systems*

IEC 60870-4:1990, *Telecontrol equipment and systems. Part 4: Performance requirements*

IEC 60870-5 (all parts), *Telecontrol equipment and systems – Part 5: Transmission protocols*

IEC 61000-4-15:2010, *Electromagnetic compatibility (EMC) – Part 4-15: Testing and measurement techniques – Flickermeter – Functional and design specifications*

IEC 61000-4-30:2015, *Electromagnetic compatibility (EMC) – Part 4-30: Testing and measurement techniques – Power quality measurement methods*

IEC 61508 (all parts), *Functional safety of electrical/electronic/programmable electronic safety-related systems*

IEC TR 61850-1:2013, *Communication networks and systems for power utility automation – Part 1: Introduction and overview*

IEC TS 61850-2:2019, *Communication networks and systems for power utility automation – Part 2: Glossary*

IEC 61850-3:2013, *Communication networks and systems for power utility automation – Part 3: General requirements*

IEC 61850-4:2011, *Communication networks and systems for power utility automation – Part 4: System and project management*

IEC 61850-6:2009, *Communication networks and systems for power utility automation – Part 6: Configuration description language for communication in electrical substations related to IEDs*
IEC 61850-6:2009/AMD1:2018

IEC 61850-7-1:2011, *Communication networks and systems for power utility automation – Part 7-1: Basic communication structure – Principles and models*
IEC 61850-7-1:2011/AMD1:2020

IEC 61850-7-2:2010, *Communication networks and systems for power utility automation – Part 7-2: Basic information and communication structure – Abstract communication service interface (ACSI)*
IEC 61850-7-2:2010/AMD1:2020

IEC 61850-7-3:2010, *Communication networks and systems for power utility automation – Part 7-3: Basic communication structure – Common data classes*
IEC 61850-7-3:2010/AMD1:2020

IEC 61850-7-4:2010, *Communication networks and systems for power utility automation – Part 7-4: Basic communication structure – Compatible logical node classes and data object classes*
IEC 61850-7-4:2010/AMD1:2020

IEC TR 61850-7-5, *Communication networks and systems for power utility automation – Part 7-5: IEC 61850 modelling concepts*

IEC TR 61850-7-500:2017, *Communication networks and systems for power utility automation – Part 7-500: Basic information and communication structure – Use of logical nodes for modeling application functions and related concepts and guidelines for substations*

IEC TR 61850-7-510:2012, *Communication networks and systems for power utility automation – Part 7-510: Basic communication structure – Hydroelectric power plants – Modelling concepts and guidelines*

IEC TR 61850-7-6:2019, *Communication networks and systems for power utility automation – Part 7-6: Guideline for definition of Basic Application Profiles (BAPs) using IEC 61850*

IEC TS 61850-7-7:2018, *Communication networks and systems for power utility automation – Part 7-7: Machine-processable format of IEC 61850-related data models for tools*

IEC 61850-8-1:2011, *Communication networks and systems for power utility automation – Part 8-1: Specific communication service mapping (SCSM) – Mappings to MMS (ISO 9506-1 and ISO 9506-2) and to ISO/IEC 8802-3*

IEC 61850-8-1:2011/AMD1:2020

IEC 61850-8-2:2018, *Communication networks and systems for power utility automation – Part 8-2: Specific communication service mapping (SCSM) – Mapping to Extensible Messaging Presence Protocol (XMPP)*

IEC 61850-9-2:2011, *Communication networks and systems for power utility automation – Part 9-2: Specific communication service mapping (SCSM) – Sampled values over ISO/IEC 8802-3*

IEC 61850-9-2:2011/AMD1:2020

IEC/IEEE 61850-9-3:2016, *Communication networks and systems for power utility automation – Part 9-3: Precision time protocol profile for power utility automation*

IEC 61850-10:2012, *Communication networks and systems for power utility automation – Part 10: Conformance testing*

IEC TR 61850-80-3:2015, *Communication networks and systems for power utility automation – Part 80-3: Mapping to web protocols – Requirements and technical choices*

IEC TR 61850-90-1:2010, *Communication networks and systems for power utility automation – Part 90-1: Use of IEC 61850 for the communication between substations*

IEC TR 61850-90-2:2016, *Communication networks and systems for power utility automation – Part 90-2: Using IEC 61850 for communication between substations and control centres*

IEC TR 61850-90-4:2020, *Communication networks and systems for power utility automation – Part 90-4: Network engineering guidelines*

IEC TR 61850-90-5:2012, *Communication networks and systems for power utility automation – Part 90-5: Use of IEC 61850 to transmit synchrophasor information according to IEEE C37.118*

IEC TR 61850-90-12:2020, *Communication networks and systems for power utility automation – Part 90-12: Wide area network engineering guidelines*

IEC 61869 (all parts), *Instrument transformers*

IEC TR 62357-1:2016, *Power systems management and associated information exchange – Part 1: Reference architecture*

IEC 81346 (all parts), *Industrial systems, installations and equipment and industrial products – Structuring principles and reference designations*

3 Terms and definitions

 For the purposes of this document, the terms and definitions given in IEC TS 61850-2, as well as the following apply.

ISO and IEC maintain terminological databases for use in standardization at the following addresses:

- IEC Electropedia: available at <http://www.electropedia.org/>
- ISO Online browsing platform: available at <http://www.iso.org/obp> 

3.1 General

3.1.1

application function

task which is performed in or by power utility automation systems

Note 1 to entry: Generally, an application function consists of subparts which may be distributed to different IEDs, which exchange data with each other. More precisely these sub-functions implemented in the IEDs exchange data. Also, between different functions data are exchanged. The exchanged data exposed to the communication system shall be standardized based on the semantic content to be understandable by the receiving function. For this purpose, the standard groups the exchanged data in objects called Logical Nodes which refer to the name of the allocated functions by their mnemonic name.

3.1.2

local function

application function which is performed by sub-functions in one physical device

Note 1 to entry: If the performance of the functions is not depending on functions in other devices no standardized link is needed. Sometimes, functions with a weak dependency only from other ones are also called local functions. The loss of such links should not result in blocking these functions but in worst case to some graceful degradation.

3.1.3

distributed function

application function which is performed by sub-functions in two or more different physical devices

Note 1 to entry: The exchanged data is contained in Logical Nodes having a common semantic reference to the distributed function. 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 defined as complete. In case of losing the data of one Logical Node or losing one included communication link the function may be blocked completely or show a graceful degradation if applicable.

3.1.4

system

set of interacting entities which perform a common functionality

Note 1 to entry: The backbone of the system is the data exchange. 

3.1.5

logical system

communicating set of all application functions performing some overall task like "management of a substation" or "management of a plant"

Note 1 to entry: The boundary of a logical system is given by its logical interfaces. The backbone of the logical system is the communication relationship between its functions and sub-functions. The exchanged data are grouped in Logical Nodes.

3.1.6

physical system

set of all interacting devices hosting the application functions and the interconnecting physical communication network

Note 1 to entry: The boundary of a physical system is given by its physical interfaces. Examples are industrial systems, management systems, information systems, and within the scope of this standard, substation or power utility automation systems. The backbone of physical system is its communication system together with all implemented data.

3.1.7

substation automation system

system which operates, protects, monitors, etc. the substation, i.e. the primary system

Note 1 to entry: For this purpose, it uses fully numerical technology and digital communication links (LAN as communication system).

Note 2 to entry: See 3.1.9 for a definition of primary system.

3.1.8

secondary system

power utility automation system

interacting set of all components and subsystems to operate, to protect and to monitor the primary system

Note 1 to entry: In case of full application of numerical technology, the secondary system is synonymous with the power utility automation system. For this purpose, it uses fully numerical technology and digital communication links (WAN as communication system). Substation automation systems are one kind of power utility automation systems responsible for the nodes in the power system or power grid.

Note 2 to entry: See 3.1.9 for a definition of primary system.

3.1.9

primary system

power system

set of all components for generating, transmitting and distributing electrical energy

Note 1 to entry: Parts of the power system are also all consumers of electrical energy.

Note 2 to entry: Examples are generators, power transformers, and switchgear in substations, overhead line and cables.

3.1.10

communication system

interconnected set of all communication links

Note 1 to entry: Depending on the size it is called either LAN (local area network) as used in substations or plants, or WAN (wide area network) as used globally in the power utility system.

3.1.11

device

mechanism or piece of equipment designed to serve a purpose or to perform a function

Note 1 to entry: Communication relevant properties are described in the related device model.

Note 2 to entry: Examples are a breaker, relay, or the computer of the operator's work place.

3.1.12

intelligent electronic device (IED)

device incorporating one or more processors with the capability to execute application functions, store data locally in a memory and exchange data with other IEDs (sources or sinks) over a digital link

Note 1 to entry: Examples are electronic meters, digital/numerical relays, and digital controllers. They host the data according to the data model and allow exchanging data according to the IEC 61850 services/interfaces, if not stated

otherwise, intelligent electronic devices have an internal clock by definition. This allows fulfilling the requirements for time tagging of events or synchronized sampling. The clocks of different IEDs have to be synchronized for time coherent data if requested by the hosted application functions.

Note 2 to entry: This note applies to the French language only.

3.1.13

physical device

intelligent electronic device as used in the context of this standard

3.1.14

abstract data models for communication

data standardized with their semantic meaning exchanged between the application functions hosted by the IEDs

Note 1 to entry: All application functions shall trust these data and perform their algorithm using this data. The formal description of the automation system by SCL is also based on this standardized data.

3.1.15

PICOM

Piece of Information for COMMunication describing the information transfer with given communication attributes between two Logical Nodes

Note 1 to entry: It contains, in addition to the information to be transmitted, requirement attributes like performance and was adopted from CIGRÉ working group 34.03. It does not represent the actual message structure and the format for data as exchanged over the communication network. This implementation information is found in the standard parts IEC 61850-8-x and IEC 61850-9-x. The assumed logical point-to-point connection describes the source and sink of this information transfer but does not define the communication procedures like client-server or publisher-subscriber for multicast and broadcast.

Note 2 to entry: This note applies to the French language only.

3.1.16

A1 Logical Node (LN) A1

object where standardized data for communication are grouped according to their relationship to application functions

Note 1 to entry: The granularity of data or to how many Logical Nodes (LN) the data are distributed depends on the granularity of the application functions. The granularity stops at the smallest function parts which may be implemented as single- stand-alone application functions acting also as atomic building blocks for complex application functions. The Logical Nodes may be seen also as containers containing the data provided by a dedicated function for exchange (communication). The name of the Logical Node is then the label attached to this container telling to what function the data belong. Logical Nodes related to primary equipment are not the primary equipment itself but a data image in the secondary system needed for performing the application functions of the power utility automation system.

3.2 Connections

3.2.1

logical connection

A1 communication link between application functions represented by Logical Nodes A1

3.2.2

physical connection

A1 communication link between intelligent electronic devices (IEDs) and is providing all logical connections for the implemented application functions represented by Logical Nodes A1

3.2.3

exposed connection

communication link outside the IED i.e. between IEDs

Note 1 to entry: The data running over exposed connections are visible and may be used by other IEDs requesting interoperability. Therefore, these data and the related communication procedures shall be standardized according to IEC 61850 series. An exception may be data which are needed for some private purpose not impacting the interoperability.

3.2.4

hidden connection

communication inside the IED

Note 1 to entry:  This data exchange is not visible and cannot be used by other IEDs therefore not requesting interoperability. It should be noted that by distributing combined application functions in one IED to more than one IED hidden connections may get exposed ones which shall be standardized. 

3.2.5

digital connection

any communication data coded and transmitted as bits

3.2.6

serial connection

communication with data coded and transmitted as series of bits over one communication line

3.3 Relations between IEDs

3.3.1

interoperability

the ability of two or more intelligent electronic devices (IED) from the same manufacturer, or different manufacturers, to exchange information and use that information for their own functionality and correct co-operation with other IEDs

Note 1 to entry: Interoperability is within the scope of the standard and is a prerequisite for interchangeability (see 3.3.2).

3.3.2

interchangeability

the possibility to replace an IED by an IED from the same manufacturer or from a different manufacturer providing the same functionality with no impact on the rest of the system

Note 1 to entry: Interchangeability requires standardization of application functions and, in a strong sense, of IEDs also. Both such requirements are outside the scope of this standard. Utilizing interoperable IEDs (see definition of interoperability in 3.3.1) with the same communication interface and about the same data (LNs) according to IEC 61850 series, with the same functionality and performance or minor accepted differences, the exchange may be possible but some engineering actions may be still needed. This depends on the implementation of the standard and is always within the responsibility of the engineer of the IEDs, not of IEC 61850 series.

Note 2 to entry: Re-engineering and re-testing are not needed.

3.4 Substation structures

3.4.1

bay

closely connected subpart of the substation with some common functionality

Note 1 to entry: Examples are the switchgear between an incoming or outgoing line and the busbar, the bus coupler with its circuit breaker and related isolators and earthing switches, the transformer with its related switchgear between the two busbars representing the two voltage levels, the diameter (see 3.4.2) in a 1 ½ 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 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 may not exist in any substation; i.e. there may be no physical device "bay controller" at all. The functionality of this level may be hosted by other IEDs.

3.4.2

diameter

complete switchgear between the two busbars of a 1-½-breaker arrangement, i.e. the 2 lines and the 3 circuit breakers with all related isolators, earthing switches, CTs and VTs

Note 1 to entry: It has some common functionality and restriction like a bay both for operation, maintenance and extensions. Therefore, the "diameter protection" and "diameter control" represents a special type of bay level (see 3.5.3). In most cases these bay level application functions may be implemented in one or many IEDs. In the last case e.g. one of three control IEDs may be responsible each for one the three circuit breakers of the diameter. One of two protection IEDs may be responsible each for one of the two lines being connected to the diameter.

3.5 Power utility automation functions at different levels

3.5.1

network level functions

power system application functions which exceed at least the boundary of one substation or plant

Note 1 to entry: Examples of such functions are line protection, telecontrol, telemonitoring, etc.

3.5.2

station level functions

 power system application functions referring to the substation or plant as whole 

Note 1 to entry: There are two classes of station level functions; i.e. process related station level functions and interface related station level functions.

3.5.3

bay level functions

 application functions using mainly the data of one bay and acting mainly on the primary equipment of one bay 

Note 1 to entry: In the context of this standard a bay means any subpart of the substation like a line feeder, a diameter or a transformer feeder. The definition of a bay is considering some kind of a meaningful substructure in the primary substation configuration and some local functionality, restriction 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 IF3 (Fig. 2) within the bay level and via the logical interfaces IF4 and IF5 to the process level, i.e. with any kind of remote I/Os or intelligent sensors and actuators. Interfaces IF4 and IF5 may be hardwired also but hardwired interfaces are outside the scope of IEC 61850 series.

Note 2 to entry: Bay is defined in 3.4.1.

3.5.4

process level functions

 application functions interfacing to the process, i.e. basically binary and analogue I/O functions like data acquisition (including sampling) and issuing of commands related to one primary object (e.g. circuit breaker)

Note 1 to entry: These functions communicate via the logical interfaces IF4 and IF5 to the bay level. The process level functions may be implemented in the bay level IEDs together with the bay level functions if no process bus is applied. If a process bus is applied the process level functions are implemented in process level IEDs. 

3.5.5

process related station level functions

 application 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

Note 1 to entry: Examples of such functions are station wide interlocking, automatic sequencers or busbar protection. These functions communicate mainly via the logical interface IF8. 

3.5.6

interface related station level functions

 application functions representing the interface of the power automation system to the local station operator named HMI (human machine interface), to a remote control centre named TCI (telecontrol interface) or to the remote engineering workplace for monitoring and maintenance named TMI (telemonitoring interface)

Note 1 to entry: These functions communicate in substations via the logical interfaces IF1 and IF6 with the bay level and via the logical interface IF7 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 there exists at least one logical interface for

the substation automation system at the boundary of the substation. Same holds both for the TCI and TMI. These logical interfaces may be realized in some implementations as proxy servers. 

3.6 Miscellaneous

3.6.1

local issue

 some functionality which is performed only inside an IED without communication to other IEDs which is outside the scope of IEC 61850 series 

Note 1 to entry: Since the standard defines data to be exchanged and communications but not application functions this term refers in most cases to a local function like the display of data or how an application reacts if it is missing data or if it gets bad data. Since this depends from the detailed behaviour of the function and its implementation it cannot be standardized within the scope of IEC 61850 series.

3.6.2

granularity

 extent to that the application function and their allocated data are split in sub-functions and subgroups respectively 

Note 1 to entry: Any sub-function which may be implemented also in an IED not containing all other related sub-functions has to communicate in a standardized way with other IEDs hosting these related sub-functions. The guideline is the maximum required granularity to have data grouping which fits in nearly any distribution of functions and sub-functions.

4 Abbreviations

	CT	Current Transformer 
	FACTS	Flexible AC Transmission Systems 
	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
	ISO	International Organization for Standardization
	LAN	Local Area Network
	LC	Logical Connection
	LN	Logical Node
	MMS	Manufacturing Message Specification
	NCC	Network Control Centre
	OSI	Open System Interconnection
	PC	Physical Connection
	PD	Physical Device
	PICOM	Piece of Information for COMMunication
	SAS	Substation Automation System
	SGAM	Smart Grid Architecture Model 
	TCI	Telecontrol Interface (for example, to Network Control Centre, NCC)
	TMI	Telemonitoring Interface (for example, to engineers workplace)
	VT	Voltage Transformer 
	WAN	Wide Area Network

5 Power utility automation functions

5.1 General

The power utility automation functions refer to tasks which have to be performed by the **A1** power utility automation system **A1**. These are functions to operate, supervise, protect and monitor the system to keep it running in the best way as possible and to guarantee the reliable and economic power supply. Since both the sensors and actuators for these tasks are implemented in a power plant being the generating node or in a substation being the **A1** connecting node **A1** in the power grid, the **A1** power utility automation system **A1** may be seen as front-end to all these functions and, therefore, a very important subsystem. The SAS is used as an example in the following for defining the communication requirements for application functions and device models.

A1 How the domains and application functions are grouped is outside this document which is requirement focused. But it should be noted that a structured bridge between requirements and implementation exists by the Smart Grid Architecture Model (SGAM) as referenced in the IEC TC 57 reference architecture (IEC 62357-1). **A1**

5.2 Example substation automation system

5.2.1 General

The **A1** application functions **A1** of a substation automation system (SAS) refer to tasks which have to be performed in the substation. These are **A1** application functions **A1** to control, monitor and protect the equipment of the substation and its feeders. In addition, there exist **A1** application functions **A1**, which are needed to maintain the SAS, i.e. for system configuration, communication management or software management and, very important, for time synchronization.

5.2.2 Logical allocation of application functions and interfaces

A1 The application functions of a substation automation system may be allocated logically to 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 12.

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

Bay level application functions (see bay definition above) are all functions using mainly the data of one bay and acting mainly on the primary equipment of this one bay. These application 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 outside the scope of the IEC 61850 series.

There are two classes of station level application functions:

Process related station level application functions are application 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 application functions communicate mainly via the logical interface 8.

Interface related station level application functions are application functions representing the interface of the SAS to the local station operator (Human machine interface (HMI)), to a remote control centre (Telecontrol interface (TCI)) or to the remote engineering place for monitoring and maintenance (Telemonitoring interface (TMI)). These functions communicate via the logical interfaces 1 and 6 with the bay and via the logical interfaces 7 and 10 to the outside world. **A1**

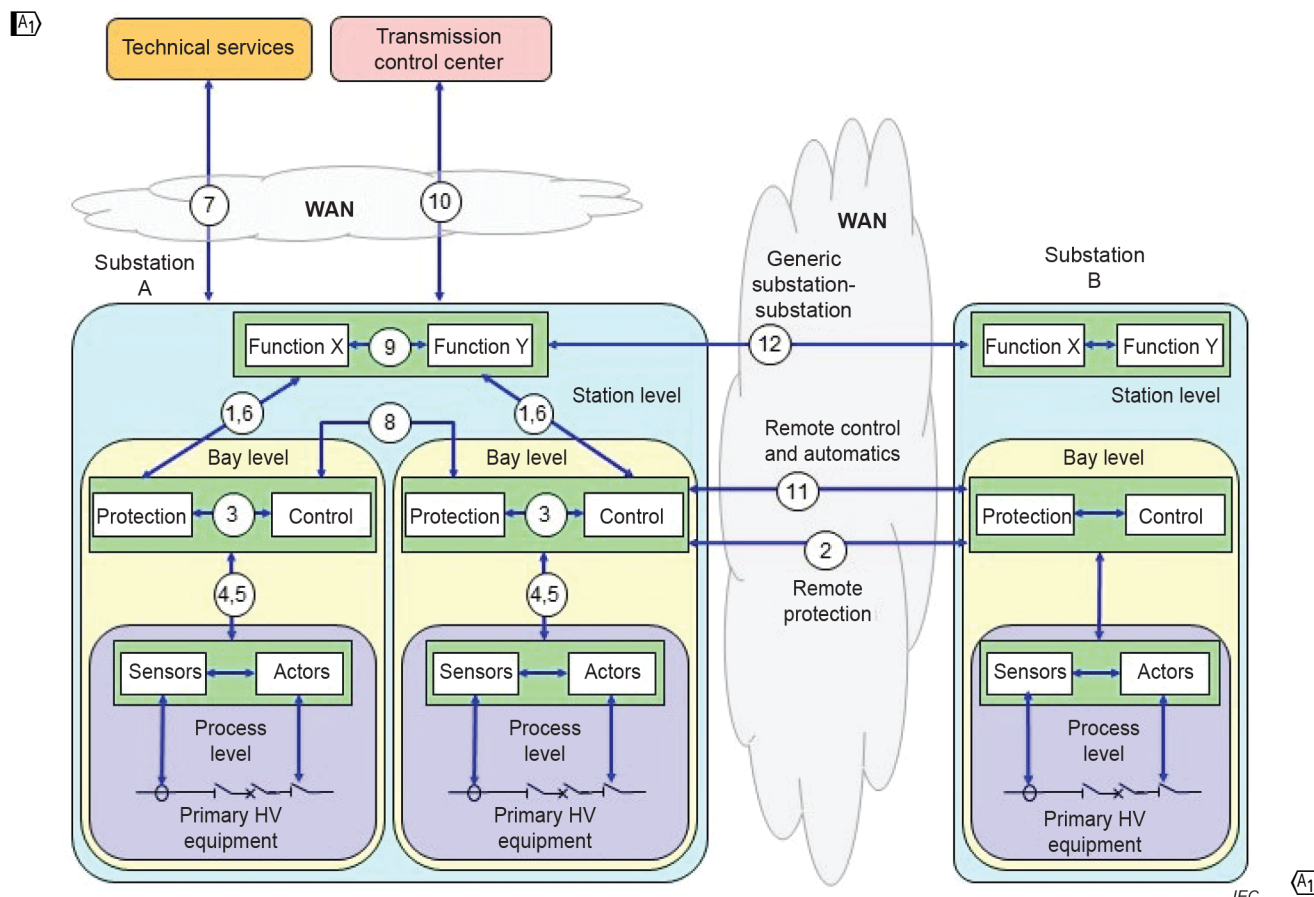


Figure 2 – Levels and logical interfaces in substation automation systems

The meaning of the interfaces:

- IF1: protection-data exchange between bay and station level
- IF2: protection-data exchange between bay level and remote protection (e.g. line protection)
- IF3: data exchange within bay level
- IF4: digitized analogue data exchange between process and bay level (samples from CT and VT)
- 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 distributed functions
- IF9: data exchange within station level
- A1** IF10: control-data exchange between the substation and remote Network Control Centre(s) **A1**
- IF11: control-data exchange between substations. This interface refers mainly to binary data e.g. for interlocking functions or other inter-substation automatics
- IF12: generic substation-substation link e.g. for FACTS control

- A1** Measurements in different kinds e.g. RMS values or synchrophasors, may be part of the different interfaces. Furthermore, requirements for time synchronization to be covered by the different interfaces are depending on the application functions.

The cloud(s) around IF2, IF11 and IF12 indicate(s) that there may be also an external communication system applied for which the requirements as defined in IEC 61850-50-1,

IEC 61850-90-2, IEC 61850-90-5, IEC 61850-90-12 or IEC 61850-80-3 may apply. In case of implementation based on external communication systems, which are not in accordance with the data model and services defined in the IEC 61850 series, some kind of protocol conversion is needed.

NOTE The distribution of the functions in a communication environment may occur through the use of Wide Area Network (WAN), Local Area Network (LAN) and Process Bus technologies. At requirement level, the functions are not constrained to be deployed within/over any single communication technology.

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

- a) process level devices are typically remote process interfaces like I/Os, intelligent sensors and actuators connected by a process bus as indicated in Figure 2;
- b) bay level devices consist of control, protection or monitoring units per bay;
- c) station level devices consist of the station computer with a database, the operator's workplace, interfaces for remote communication, etc. ^(A1)

5.2.3 The physical allocation of functions and interfaces

^(A1) 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 depending on availability and performance requirements, cost constraints, the state of the art in technology, etc. It is influenced also by the operation philosophy and the acceptance of the users i.e. of the power utilities.

The station computer may act as client only with the basic application functions HMI, TCI and TMI. All other station level application 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 these station wide application functions like 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 application 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 of these application functions may be moved physically down to the process level supported by the free allocation of functions.

If there are no interfaces 4 and 5, the process level application functions are implemented in the bay level devices. The realization of the 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 be combined also 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 the application functions to levels and devices.

The teleprotection interface 2 may be also implemented as dedicated link (power line carrier, etc.) or combined with other boundary interfaces as 7, 10, 11 and 12 connected physically to WAN. ^(A1)

5.2.4 The role of interfaces

^(A1) Not all interfaces have to be present in any substation. This flexible approach covers both the retrofit of existing substations and the installation in new substations, today and tomorrow.

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

The interface numbers allow defining easily the two important LANs or bus systems: Commonly, the interfaces 1, 6, 3, 9, 8 are combined to the station bus which connects both the station level with the bay level and the different bays itself. The interfaces 4 and 5 are combined to 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.

The interface 7 is dedicated for external communication with a remote monitoring/maintenance centre. It could be realized by a direct interface to the station bus also.

According to the function allocation, the message types of Clause 10 based on communication performance requirements may be assigned to the different interfaces. The free allocation of application functions means that such an assignment may not be common for all substation automation systems. ^{A1}

5.3 Other application examples

5.3.1 Substation – Substation

The communication between ^{A1} Substations ^{A1} is also introduced in Figure 2 referring to interfaces 2, 11 and 12. The requirements are the same as inside the substation. Binary values (blocking, release, etc. for distance protection and automatics) and analogue values (samples of current for current differential protection) have to be exchanged depending on the application functions applied. Differences are the longer communication distance and the potential transparent use of an external communication system with higher or lower bandwidth which may increase the transmission delay ^{A1} and impact other constraints like jitter and channel symmetry. ^{A1}

5.3.2 ^{A1} Substation – Network Control Center ^{A1}

The communication between the ^{A1} Substation and the Network Control Center ^{A1} is also introduced in Figure 2 referring to interface 10. The requirements are the same as inside the substation for the connection between bay and station level. Binary values (status information, events, alarms, commands, etc. for remote control) and ^{A1} measured ^{A1} values (calculated values e.g. for the energy flow, synchrophasors) have to be exchanged depending on the ^{A1} application functions ^{A1} applied. Differences are the longer communication distance and the potential transparent use of an external communication system with higher or lower bandwidth which may increase the transmission delay ^{A1} and impact other constraints like jitter. ^{A1}

5.3.3 Wind

Basic application functions like collecting binary and analogue data and issuing commands are the same as for substations. The specific requirements are to model the wind power generating part (wind turbine as primary mover and connected generator) and the environmental conditions like wind strength and direction. The wind power automation system has also an interface to the network system management similar as interface 10 in substations.

5.3.4 Hydro

Basic applications like collecting binary and analogue data and issuing commands are the same as for substations. The specific requirements are to model the hydro power generating part (water turbine as primary mover and connected generator) and the environmental conditions like water level and flow. The hydro power automation system has also an interface to the network system management similar as interface 10 in substations.

5.3.5 ^{A1} DER and distribution automation

Distributed Energy Resources (DER) may be defined as a distributed set of one or more energy service resources, including generators, energy storage, and controllable load, that are connected at the medium or low voltage levels (distribution power system). Some DERs

considered as sources of renewable energy, while others are fossil fuel based, or a combination of different types. They may provide energy as well as ancillary services. Communications may include direct interactions with utility automation systems, through facility energy management systems which manage their own DERs, and through aggregators. Some typical types of DER include:

- Wind turbines and wind power plants
- Photovoltaic systems (PV) and PV plants: PV plus battery storage
- Hydro and thermal generation
- Pumped water storage systems
- Battery-based energy storage systems
- Gas turbines
- Combined heat and power (CHP)
- Electric vehicles (EVs) and their chargers: electric vehicle service elements (EVSE)
- Virtual Power Plants (VPP) and micro grids
- Biomass plants
- Fuel cells

Automation systems for distributed energy resources may have also an interface to some higher level power control system similar as interface 10 in substations. Due to more limited amount of information to be exchanged and restrictions in bandwidth / and or communication technologies additional communication mappings like IEC 61850-8-2 may apply. Related requirements are gathered in IEC 61850-80-3.

Similar requirements and solutions may apply for Distribution Automation. 

5.3.6 FACTS and Power Conversion

Flexible AC Transmission Systems (FACTS) devices or controllers are used to enhance controllability and increase or limit power transfer capability of the electric network. It uses power electronic or other static equipment to control AC power system parameters to achieve this. There exist several different power system applications of FACTS controllers classified in to two kinds based on how the FACTS Controller is connected to the power system grid; Shunt connected and Series connected. Some other examples for application may also exist.

Power converters are progressively used in all areas of an electrical system. Although their different technologies, various applications (e.g. HVDC long distance transmission, HVDC back-to-back, UHVDC, grid access, SFC, railway grid converters) and topologies (e.g. long-distance Overhead Lines, DC cable, back-to-back, mono/bipolar topologies, serial converters, parallel converters, multiterminal DC grids) may differ significantly from each other, they all have one thing in common: A power conversion process always considers and modifies the current flow between the converter as such and a connected electrical grid at a defined Point of Connection.

5.3.7 Distribution Automation and Feeder Automation

Distribution Automation (DA) is a concept emerged in the 1970s to promote the application of computer and communication technologies for the betterment of distribution system operating performance. It is in general used as an umbrella term to capture the deployment of automation technologies for protection, control, monitoring, and operation of distribution systems. These technologies enable electric utilities to monitor, control, and operate distribution components in a real-time or non-real-time mode. "The move towards smart and active distribution networks which support the high penetration of Distributed Energy Resources (DERs) and provide better supply reliability and operation efficiency has started. As a result, DA concepts are also being extended in the form of Advanced Distribution Automation or (ADA), which includes automation of DERs and demand response programs. 

6 Goal and requirements

6.1 Interoperability

The goal of this standard is to provide interoperability between the IEDs from different manufacturers or, more precisely, between $\boxed{A_1}$ application functions $\boxed{A_1}$ to be performed in the power system $\boxed{A_1}$ hosted $\boxed{A_1}$ in the IEDs from different manufacturers. Interchangeability is outside the scope of this standard, but the objective of interchangeability will be supported by following this standard.

$\boxed{A_1}$ Reaching this goal means to address four basic requirements:

- a) To have a lower layer connectivity;
- b) To talk the same language regarding syntax, semantic and convention;
- c) To use the same model (how to describe a device or an equipment);
- d) To have a common configuration language giving the means to organise all exchanges between IEDs (who is who, who needs what, who sends what to who...).

NOTE This goal of interoperability for this standard refers to interoperability between application functions. This is of special importance for transfer time requirements and compliance testing.

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

To reach interoperability in systems with IEDs from different manufacturers, the dedicated task of the system integrator should be allocated to one party/person from the beginning. The system integrator is responsible that the delivered system is performing as specified by the customer. $\boxed{A_1}$

6.2 Static design requirements

The standard shall support all configurations for Power Utility Automation Systems and, especially for Substation Automation Systems to suit the needs of all users (power utilities) and $\boxed{A_1}$ to be applied $\boxed{A_1}$ to the related technologies. This shall be valid today and in the future.

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

- $\boxed{A_1}$ a) The free allocation of application functions to devices shall be supported by the communication; i.e. communications shall be able to permit any function to take place in any device. It does not mean that all devices shall support all application functions. This allows fulfilling different system design philosophies and enabling future improvements. The application functions of the power utility automation system and their communication behaviour shall be described device independent i.e. from the implementation in IEDs.
- b) The application functions shall be described as far as necessary only to identify the information to be exchanged. This shall allow grouping the data to be exchanged properly according to production and consumptions of data by the functions. Any standardization of application functions itself is outside the scope of this standard.
- c) To keep interoperability, all existing means within IEC 61850 series shall be used before private extensions are made. For all such extensions restrictive and well-defined rules shall be given.
- d) The interaction of device independent distributed application functions shall be described by the logical interfaces in between. For implementation these logical interfaces may be freely allocated to physical interfaces and to LANs or WANs if applicable.
- e) The application functions used today and their communication requirements are well known but the standard shall be open also for communication requirements arising from any future function.
- f) To keep interoperability easy there shall be a minimum number of protocols defined in Parts 8-x and 9-x as valid at one time by an application domain. $\boxed{A_1}$

- g) To reach interoperability in projects with real IEDs connectors depending on the communication medium should be defined. Otherwise, patch cables or boxes have to be used.
- h) The system configuration with all data exchanged and the communication mechanisms applied shall be described in a strong formal way. Details are out of scope of this part but within the scope of IEC 61850-6.

6.3 Dynamic interaction requirements

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

- A1 a) The standard shall define generic information to be communicated and generic communication behaviour of the application functions to support planned and future functional extensions of the substation automation system. Extension rules shall be given. A1
- b) The transfer of information (data) shall be defined with all related attributes (see PICOMs).
- A1 c) The exchanged information (data) shall carry all attributes for unambiguous understanding by the receiver. If this is fixed information, they may be provided from the sender to the receiver already at engineering time. A1
- A1 d) The maximal allowed transfer times shall fulfil the requirements of the application functions involved. Therefore, it shall be defined as overall transfer time (performance) from application to application including the coding at the sender side, the delay in the communication network and the decoding at the receiver side. A1
- e) The acceptable overall transfer time (performance) of exchanged data shall be defined in performance classes. The performance of the related class shall be guaranteed in any situation. Exceptions are outside the scope of this part and shall be indicated for implementations.
- f) Performance shall include not only the transfer time but also other figures like quality related data as data integrity etc.
- A1 g) A safe system means that the system is never in an unsafe i.e. unknown state. The probability for such safeness is never 100 %. The related standard IEC 61508 is dependent on a lot of parameters from design and production to function and system engineering. As far as the communication functions are referred to this safety they shall allow the highest safety class requested. A1
- h) The protection against cyber-attacks and all unauthorized actions belong also to the data integrity. Proper means shall avoid or minimize such kind of risks. The needed measures like encryption or Role Based Access (RBAC) are outside the scope of this part of the standard but they shall not impact the usability like maintenance measures (quick replacement of a faulty IED etc.).

6.4 Response behaviour requirements

Since interoperability is claimed for proper A1 running of all application functions in the system A1, the reaction of the application in the receiving node shall be considered. The exchanged data may have quality attributes and operative attributes. Quality attributes like “good” or “bad” emerging by dedicated system supervision automatically. Operation modes like “on”, A1 “off” or “in test mode” A1 are created by the operator or maintenance people. These modes may request certain quality attributes for the data like “test data”.

- a) The reaction of the receiving node shall fit into the overall requirement of the distributed application function to be performed.
- b) The generic reaction on operation modes and related attributes shall be standardized as part of the interoperability.
- c) The dedicated response on quality attributes i.e. in any degraded case like on erroneous messages, lost data by communication interrupts, resource limitations, out of range data, etc. belongs to the function itself and, therefore, is outside the scope of the standard. But this behaviour shall be described in the function or IED manual elsewhere. This is important

if the overall task cannot be closed successfully, e.g. if the remote node does not respond in time or does not react in a proper way.

The reaction and the behaviour of the $\boxed{A_1}$ application functions $\boxed{A_1}$ itself are function related local issues and, therefore, outside the scope of this standard. But the requirement left for this standard is the provision of proper quality attributes to be transferred with the data under consideration.

6.5 Approach to interoperability

To approach interoperability, the $\boxed{A_1}$ application functions $\boxed{A_1}$ to be performed in power systems and, especially, in substations are identified in the following clauses to find the appropriate data objects for exchange which shall be standardized. The requirements for data exchange shall be clearly defined. The interoperability for freely allocated and distributed functions shall imply an appropriate decomposition of functions in communicating entities to get the right object oriented grouping of data for standardization.

The requested mutual understanding of devices from different manufacturers shall result in a proper data and communication service model as given in IEC 61850-7-x series. Last not least, the mapping of this model to state-of-the-art communication stacks (coding/decoding) shall be defined unambiguously in IEC 61850-8-x and IEC 61850-9-x series. $\boxed{A_1}$ Configuration files standardized in part IEC 61850-6 support interoperability by appropriate engineering tools. $\boxed{A_1}$

It should be noted that interoperability is not a device property but a system goal.

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 behaviour of a device as system component is compliant with the interoperability definition of this standard. Since the goal of $\boxed{A_1}$ IEC 61850 is interoperability $\boxed{A_1}$, conformance with the standard means that interoperability is proven. The conformance test specification shall describe what tests have to be applied to a device checking that the communication function is correctly performed with a complementary device or, generally, with the rest of the system. Also the pass criteria have to be well defined. Since it is not possible to test any device against any other device on the market, conformance tests may involve the use of various simulators to represent the context of the system and of the communication network.

If it is not possible to test an IED in a reasonable test system for interoperability then a limited performance test shall prove conformance of the data model according to the implemented functions with IEC 61850-5 and of the implemented services according to the communication behaviour needed by implemented $\boxed{A_1}$ application functions $\boxed{A_1}$ according to IEC 61850-5. This will reduce the risk not to match interoperability in the system.

The engineering process as such is outside the scope of the standard. Nevertheless, building interoperable systems requests standardized configuration files to be exchanged between engineering tools. $\boxed{A_1}$ Therefore, the tools shall also fulfil all requirements for such an exchange of the relevant configuration files. Definitions of the configurations files and testable tool requirements are defined in IEC 61850-6. Definitions of the needed conformance tests both for IEDs and tools are given in IEC 61850-10. $\boxed{A_1}$

7 Categories of application functions

7.1 General

Different $\boxed{A_1}$ categories of application functions $\boxed{A_1}$ are identified. Some functions may belong not uniquely to the given category and its category allocation is a convention only. $\boxed{A_1}$ The category of the function is defined below but the functions are listed as below only in the following subclauses only. $\boxed{A_1}$ Generic function descriptions are given in Annex F.

7.2 System support functions

These functions are used to manage the system itself. They have no direct impact on the applications but support the total system. These functions are performed continuously in the background of the system. Their goal is a well running system with synchronized nodes  *Text deleted.* . Examples:

- network management,
- time synchronisation,
- physical device self-checking,
-  communication supervision. 

7.3 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 once in the configuration or set-up phase of the power automation system only. Upgrades, extensions or other major changes will call up these functions later in the life cycle of the system also. The response time of system configuration or maintenance functions and, therefore, of the related communication has not to be much faster than 1 s (human time scale). Examples:

- node identification,
- software management,
- configuration management,
- system security management,
- setting,
- operative mode control of functions by data,
- test mode.

7.4 Operational or control functions

These  application functions  are needed for the normal operation of the substation or plant every day. In these application functions, an HMI either local or remote is included. They are used to present process or system information to an operator or to allow him the process control by commands. The  feedback response times  of the operational functions and, therefore, of the related communication have not to be much faster than 1 s (human time scale). Examples:

- access security management,
- control,
- operational use of spontaneous change of indications,
- synchronous switching (point-on-wave switching),
- changing of parameters and parameter set switching,
- alarm management,
- event (management and) recording,
- data retrieval,
- disturbance/fault record retrieval.

7.5 Bay local process automation functions

“Bay local”  application functions mean  that the data are acquired by the sensors (CT, VT) of one bay and that the resulting actions (commands/trips/releases) are performed by actuators (switches) in the same bay. The word “bay” stands here for any restricted local substructure  of the substation, respectively of the substation automation system .

These **A1** application functions **A1** are operating with process and system data directly on the process 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 standard part. In addition, there is the process interface LN and the HMI (human-machine interface) LN providing the human access to the function. Examples out of the domain substation automation:

- **A1** protection functions like overcurrent or distance protection, **A1**
- bay interlocking,
- measuring, metering and power quality monitoring.

7.6 Distributed process automation functions

“Distributed” **A1** application functions mean **A1** that the data are acquired by the sensors (CT, VT) of more than one bay and that the resulting actions (commands/trips/releases) are performed by actuators (switches) in more than one bay. Also, the functionality may split to different IEDs (i.e. being decentralized) as for the decentralized busbar protection with bay units for pre-processing the current samples, acquiring the input for the busbar image and issuing the trips, and the central unit keeping the actual busbar image and making the trip decision.

A1 These application functions check automatically without the interference of the operator the conditions, which are needed (block or release) by the operational functions or by the process automation functions. They do not act directly on the process. They are safety related to avoid danger for people or damage for equipment. Normally, they consider information from the whole plant or substation and are implemented locally or distributed. Since the distributed implementations especially call for the standardization of communication, these functions are listed here. The local implementations behave always like a local automation function. Examples out of the domain substation automation: **A1**

- station-wide interlocking,
- distributed synchrocheck,
- breaker failure,
- **A1** automatic protection adaptation (generic): most simple example reverse blocking, **A1**
- load shedding,
- load restoration,
- voltage and reactive power control,
- infeed switchover and transformer change,
- automatic switching sequences.

For some functions depending on their implementation the definition of “local” and “distributed” may not be unambiguous. For the requirements it is important only that the potentially decentralized character of functions is noticed i.e. an appropriate communication support must be provided by the communication system according to this document.

8 Description and requirements of application functions

8.1 Approach

To get **A1** the **A1** communication requirements in a substation or plant, the identification of all application functions is necessary. IEDs **A1** host **A1** a lot of simple and complex application functions different from manufacturer to manufacturer. The identification of these functions has to be done independently from the implementation of IEDs. In addition, these functions have to be divisible in pieces with indivisible core functionality which may be implemented by alone by itself also. This allows covering all implementations today and tomorrow by dedicated combinations. Each of these core pieces have allocated the level data objects (Logical Nodes,

LN) which contain all data to be exchanged (Piece of Information for Communication, PICOM) between these core functions respectively between the IEDs which host these functions.

This approach consists of three steps.

- function description including the decomposition represented by LNs with the allocated data;
- PICOM description including the attributes;
- Logical Node (LN) description.

Any identification of $\boxed{A_1}$ application functions $\langle A_1 \rangle$ both in power systems and in substations or plants $\boxed{A_1}$ may $\langle A_1 \rangle$ be incomplete, but the assumption is made that the identified functions cover in a very representative way all communication requirements needed.

8.2 $\boxed{A_1}$ Application function description $\langle A_1 \rangle$

The function description – more details are found in the Annex – provides the following information:

- task of the function,
- starting criteria for the function,
- result or impact of the function,
- performance of the function,
- interaction with other functions,
- function decomposition if applicable.

The last bullet refers how functions are $\boxed{A_1}$ decomposed by using $\langle A_1 \rangle$ LNs and how many decomposition sets exist typically. This information is very important since the communication requirements shall be based on interacting functions with maximum granularity for multiple use.

8.3 The PICOM description

8.3.1 The PICOM approach

The PICOM (Piece of Information for Communication) is focused by definition on the exchanged data between two application functions or subfunctions. Also functions like HMI and Gateway are included. Both the sending and the receiving part shall be identified. The communication requirements are based on such point-to-point connections. If multicast and broadcast messages maybe more convenient for the communication is a matter of implementation.

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

Tables of exchanged data (PICOMs) between identified functions out of the domain substation automation are found in the $\boxed{A_1}$ Annex. $\langle A_1 \rangle$

8.3.2 The content of PICOM description

PICOMs introduced by CIGRÉ WG34.03 are used to describe the information to be $\boxed{A_1}$ exchanged $\langle A_1 \rangle$ between LNs. The components or attributes of a PICOM are:

- data referring to the content of information and its identification as needed by the functions (semantics);
- logical connection containing the logical source (sending logical node, source) and the logical sink (receiving logical node, sink);

- type describing the structure of the data, i.e. if it's an analogue or a binary value, if it's a single value or a set of data, etc.;
- performance meaning the permissible transmission time (defined by performance class), the data integrity and the method or cause of transmission (e.g. periodic, event driven, on request).

8.3.3 Attributes of PICOMs

There are three types of attributes defined by their purpose.

8.3.4 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
- **A1** Priority of transmission **A1**: 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

8.3.5 PICOM attributes to be covered at configuration time only

- Value for transmission (see above): test or default value if applicable
- Attributes for transmission (see above)
- 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 re-transmissions (details formulated as requirements, **A1** see 11.4.2) **A1**

8.3.6 PICOM attributes to be used for data flow calculations only

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

Format and length are a matter of implementation and not a requirement. But for data flow calculations, assumptions about these two attributes have to be made or taken **A1** from the applied implementation. **A1**

8.4 Logical node description

8.4.1 The logical node concept

To set up a data model for the data to be exchanged per function, the data at the source shall be defined in the standard.

The logical node description – listed later in the body of this part – provides the following information:

- grouping according to their most common application area,
- short textual description of the functionality,
- IEEE device function number if applicable (for protection and some protection related logical nodes only),
- IEC graphical or alphanumeric symbol if applicable,
- abbreviation/acronym used within the documents of IEC 61850,
- relation between functions and logical nodes in tables and in the function description (see Annex F).

8.4.2 Logical nodes and logical connections

To facilitate fulfilling all the requirements stated above, especially the interoperability and both the arbitrary distribution and allocation of application functions, the data of all these functions shall be grouped in objects with a high level semantic meaning. The Logical Node concept groups for the object oriented approach the data in function related objects called Logical Nodes (LN). Any Logical Node resides in one physical device (IEDs). Depending on the functionality of the IED, a large number of Logical Nodes may be hosted by one IED.

The granularity of data or in how many Logical Nodes the data are distributed depends on the granularity of functions which may be implemented stand-alone and re-used for other IEDs. The Logical Nodes may be seen as containers of the data provided by a dedicated function for exchange (communication). The Name of the Logical Node is then the label attached to this container telling to what function the data belong. Logical nodes related to primary equipment are not the primary equipment itself but data images in the secondary system to be needed for performing the application functions and the data exchange in the power utility automation system.

There are some data to be communicated which do not refer to any application function but to the physical device (IED) itself like nameplate information or the result of device self-supervision. Therefore, a logical node “physical device” is needed named LPHD as seen later. There may be also common data (mostly administrative ones) for all functions respectively LNs in a device which may be contained in a logical node LLN0.

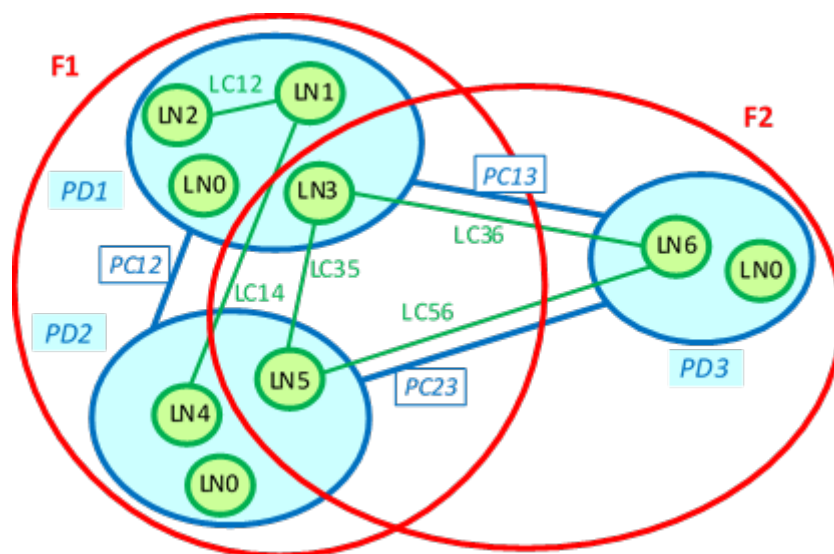
This naming of LNs is given here only to understand the Figures below. The names of the Logical Nodes shall be mnemonic regarding to the application functions allocated.

The Logical Nodes representing the boundary of the automation system with the external equipment like switchgear shall be able to provide also data from the external non-electronic equipment like the name plate of a switchgear component which is different from the name plate of the corresponding IED. The same is valid for health information from the external equipment if available.

The LNs are linked by logical connections (LC) for a dedicated exchange of data in between. Therefore, the standard 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 “physical device” dedicated for any physical device is displayed as LPHD and the common data of all LNs in a logical device are in LLN0.

Since it is impossible to define all functions for today and tomorrow and any kind of distribution and interaction, it is very important to specify and standardize the interaction between the logical nodes in a generic way.

This logical node concept shall be used by the IEC 61850-5. The modelling details are found in the parts 7-x of the series (IEC 61850-7-x).



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Figure 3 – The logical node and link concept (explanation see text)

8.4.3 Examples for decomposition of common functions into logical nodes

In Figure 4, examples of common application functions of the domain substation are given

- synchronized circuit breaker switching,
- distance protection,
- overcurrent protection.

The functions are decomposed into logical nodes listed in the figure; the allocated physical devices (IEDs) are described by numbers

- 1) station computer,
- 2) synchronized switching (point on wave 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 “physical device” (LPHD) as contained in any physical device is not shown.

Logical Nodes	[-----Functions-----]			Physical Devices
	Synchronised CB switching	Distance protection	Overcurrent protection	
HMI	X	X	X	1
Sy.Switch.	X			2
Dist.Prot.		X		3
O/C Prot.			X	3
Breaker	X	X	X	4
Bay CT		X	X	5
Bay VT	X	X		6
BB VT	X			7

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Figure 4 – Examples of the application of the logical node concept
(explanation see text)

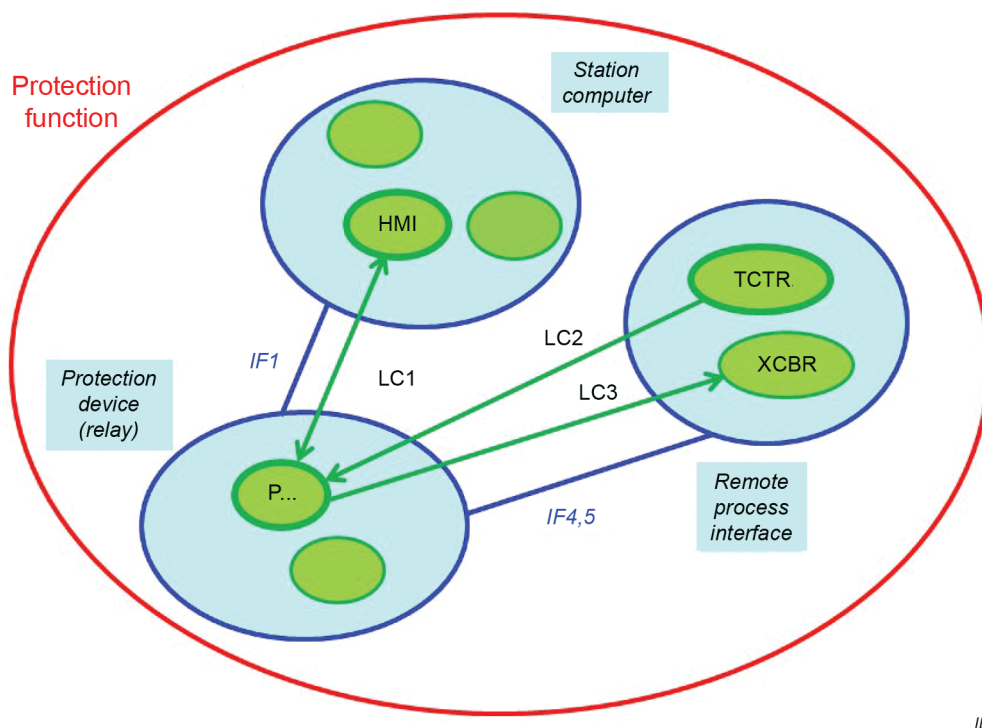
8.5 List of logical nodes

8.5.1 Logical Node allocation and distributed application functions

Most of the functions may be represented in minimum by three logical nodes, i.e. the LN with the data of the core application function itself, the LN representing the process interface and the LN representing the HMI (Human-Machine Interface meaning the gender neutral human access to the function in the system like by an operator). 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 more than one protection function is hosted by the protection device, their trips (operates) have to be combined to a common trip by the additional LN PTRC (trip conditioning).

To have a modular, object oriented function related data model we shall use the function name (e.g. “protection function”) for its core functionality only. Therefore, the function list given e.g. in the report of CIGRÉ 34.03 is a list of logical nodes according to definitions in IEC 61850 series. The standardization of application functions in substations or plants itself is not within the scope of IEC 61850-5. But if any of these functions is used the data communicated shall be based on the introduced LN structure. All details needed to model the data in IEDs potentially communicated and the communicated data itself shall be based on the Logical Nodes defined here. The Logical Nodes are standardized with all their data and attributes in Part 7 of the series (IEC 61850-7-x).

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IEC

Figure 5 – Protection function consisting of three Logical Nodes A1

The three Logical Nodes (HMI, P.=protection, XCBR=circuit breaker to be tripped) reside in three physical devices (Station computer, Protection device and Remote process interface). The Logical Node names are the same as introduced in the tables below. If more than one protection function is hosted by the protection device, their trips (operates) have to be combined to a common trip by the additional LN PTRC (trip conditioning).

8.5.2 Explanation of tables

A1 In the tables below the following columns are used. A1 The column headers and Logical Node names are written in bold.

Functionality allocated to LN describes in one term the functionality where the Logical Node is allocated to.

A1 IEC 60617 A1 means the IEC graphical symbols according to IEC 60617 in the alphanumeric representation if available.

A1 IEEE C37.2 A1 means device function numbers and contact designations used in IEEE Std C37.2-2008. Note that the reference to the IEEE device number means not the related devices but its **core functionality only** (see definition of LN and Figure 5) in the context of this standard. Because of their device related definition there is not always a 1:1 relation to the function related definition of Logical Nodes. Allocations of contact designations can also not be made to contact designations. A result, therefore exist not Logical Nodes for all IEEE numbers.

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

LN function means abbreviations/acronyms as defined in IEC 61850-5 with the systematic syntax used in IEC 61850-7-4 focused on functional requirements.

LN class A1 means the abbreviations/acronyms A1 as defined in IEC 61850-7-4 to reduce consistency, but the order has to follow the tables in part 5.

LN class naming displays the short name of the LN class from IEC 61850-5

A1 8.5.3 Defining and modelling of protection functions

In Table 8 the Logical Nodes for the requested protection functions are listed with related definitions and references.

Table 8 – Logical Nodes for protection functions

Functionality allocated to LN	IEC 60617	IEEE C37.2	Description or comments	LN function	LN class	LN class naming
Transient earth fault protection			This LN shall be used to represent the transient earth fault protection function. This type of fault happens 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.	PTEF	PTEF	Transient earth fault
Sensitive directional earth fault		(37) (67N)	This LN shall be used to represent the directional earth fault protection function in compensated and isolated networks. The use of "operate" is optional and depends both on protection philosophy and on instrument transformer capabilities (see Annex I). For compensated networks, this function is often called watt-metric directional earth fault protection. The very high accuracy needed for fault current measurement in compensated networks may require phase angle compensation. This shall be realized by the related LN TCTR with correction data for the current transformer. NOTE In the comparison table provided in IEEE C37.2-2008 PSDE has no IEEE device number associated.	PSDE	PSDE	Sensitive directional earth fault
Thyristor protection			This LN shall be used to represent a thyristor (valve) protection function in a power plant. This function will typically be included in the excitation system.	PTHF	PTHF	Thyristor protection
Over speed protection	$\omega >$	12	This LN shall be used to represent a protection function that operates on machine overspeed.	POVS		
Zero speed and under speed protection	$\omega <$	14	This LN shall be used to represent a protection function that operates when the speed of a machine falls below a predetermined value.	PZSU	PZSU	Zero speed or underspeed