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Applications of IEC 61850 Standard to Protection Schemes

Working Group

B5.36

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Conseil International des Grands Réseaux Électriques
International Council on Large Electric Systems

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A special thanks to Rui for his contribution to CIGRE over the past years. We all miss you a lot.

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2 INTRODUCTION

The electric power industry is in the process of intensive integration of Intelligent Electronic Devices (IEDs) in substations throughout power systems. The success of this effort is to a great extent a function of the development of a universal platform that will allow microprocessor based protection and control devices to interoperate (communicate seamlessly) over the substation local area network (LAN) or the utility wide area network (WAN). Microprocessor based multifunctional protective relays and control devices are the preferred IEDs in today's substation integration programs. However, the process of integration is slowed down by the fact that each IEDs manufacturer has typically used many different communication protocols and user interface software tools.

Interoperability between protective relays from different vendors in the substation becomes a necessity in order to achieve substation level interlocking, protection and control functions, and improve the efficiency/use of microprocessor based relay applications. Substation integration and automation can help a utility to achieve reduced installation, maintenance and operational costs. This is possible because of the integration of microprocessor based devices (particularly protective relays) into complex transmission substation schemes or even System Integrity Protection Scheme (SIPS). Protection functions based on exchange of signals between multiple protection devices exist today in the form of wiring between outputs and inputs of the different IEDs. The future goal is to replace expensive hardwired systems with ones based on the exchange of digital signals between IEDs over a substation LAN.

A major obstacle in previous integration processes is the fact that in the past IEDs from different manufacturers or even from the same vendor use different communication protocols, profiles and user interfaces for real time data acquisition, data archiving, substation control and fault record extraction. This significantly reduces the benefits of integration because of the need for additional hardware (such as protocol converters), software (multiple user interface programs) and, increase engineering and staff training costs.

This requires a significant joint effort by experienced industry professionals, who until recently came from completely different fields such as power system protection, metering, information systems, communications, energy control systems, etc. One solution to this problem is the object oriented approach to the client-server and peer-to-peer communication between IEDs in the substation and across the power system. The development of user friendly graphical interfaces to allow the configuration of the protective device to send and receive data over the network is also required.

The IEC 61850 international standard for communications in substations brings a new era in the development of substations. It affects not only the design of the substation protection, monitoring and control system, but also the design of the substation secondary circuits. High-speed peer-to-peer communications using GOOSE messages and Sampled Analogue Values (SAV) allow development of distributed applications based on status, current and voltage values communicated between devices connected to the substation local area network.

IEC 61850 is already established as the toolbox for configuring IEDs for communication between them both inside a substation and outside. It is expected to progressively replace the existing protocols and facilitate inter-operability between vendors. The standard is a means to build substation automation projects more than a goal in itself. As with any major technological change the temptation is to initially just copy what was done with the previous technology.

More than two decades of substation control systems have now clearly defined the content of Substation Automation Systems and IEC 61850 should NOT just emulate what was done before.

Fast automation scheme is one of the main benefits to be obtained with IEC 61850. One aim is initially to replace the conventional wiring between devices. New protection schemes will appear that are not easily feasible with the conventional technology. This might be within a substation or between substations. It is essential not only to identify the communication requirements, but also the capability of the subscribing devices to be configured with the right logic. Such arrangement minimizes the hardware needs between IEDs since many hardwired signals can be replaced by communication messages. This will improve substation design and maintenance, aid standardization of hardware communication interfaces and focuses on version control.

Logical dataflow needs to be analysed carefully in order to avoid congestion on the Ethernet network. GOOSE messages, used to transmit peer-to-peer data are continuously repeated, so just subscribing to any data might consume too many resources for fast automation. Defining abnormal conditions is also essential such as the cases when some devices are missing, when the communication is broken, when an IED is out of service or fails, etc. Special attention to redundancy and self-healing mechanisms should be given with the communication system when used to exchange critical messages between IEDs. The objective of the B5.36 this technical brochure is to identify a range of protection schemes using IEC 61850, and elaborate technical recommendations and rules to be used as a reference in order to help maintain safe and reliable power systems. Whilst this document covers many applications, there will no doubts be other existing and future innovative requirements and applications to which the principles and mechanism presented here may well apply.

3 GLOSSARY

3.1 Terms and definitions

Attribute: named element of data and of a specific type. [IEC 61850-8-1]

Back-up protection: Protection which is intended to operate when a system fault is not cleared or an abnormal condition is not detected within the required time either because of failure or inability of other protection to operate or failure of the appropriate circuit breaker(s) to trip.

Bay: The part of a substation within which the switchgear and control gear relating to a given circuit is contained

Bay unit: A bay unit within a numerical busbar and breaker-failure protection is the interface between the protection and the primary system process comprising the main CTs, disconnectors and circuit-breaker and performs the associated data acquisition, pre-processing and control functions. It also provides the electrical insulation between the primary system and the internal electronics of the IEDs.

Breaker control device (or controller): Control device for HV circuit breaker

Busbars: In a substation, the busbar assembly is necessary to make a common connection for several circuits

Busbar blocking scheme: A busbar protection scheme utilizing non-directional and/or directional overcurrent relays to provide a simple busbar protection at distribution substations

Bus coupler circuit-breaker: In a substation a circuit-breaker which is located between two busbars and which permits the busbars to be coupled; it may be associated with selectors in case of more than two busbars

Bus-tie circuit-breaker – see 'switched busbar circuit-breaker'

Central unit: The central unit within distributed numerical busbar and breaker-failure protection is the device typically used for system configuration, operating parameters, busbar replica, assignment of bays, system synchronization, communications control etc.

CIM: In electric power transmission and distribution, the Common Information Model (CIM), a standard developed by the electric power industry that has been officially adopted by the International Electro-technical Commission (IEC), aims to allow application software to exchange information about the configuration and status of an electrical network.

Circuit-breaker: A switching device, capable of making, carrying and breaking currents under normal circuit conditions and also making, carrying for a specified time and breaking currents under abnormal circuit conditions such as those of short circuit.

Circuit-breaker failure protection: A protection which is designed to clear a system fault by initiating tripping of other circuit breaker(s) in the case of failure to trip of the appropriate circuit breaker.

Circuit-breaker fail back-trip: The tripping of all circuit-breakers connected to the same busbar as the failed circuit-breaker.

Circuit-breaker fail remote trip: The tripping of directly connected remote circuit-breakers when the protection system is associated with a feeder circuit-breaker.

Circuit-breaker fail re-trip: Following an unsuccessful tripping command this function is intended to provide initiation of a second tripping command to the main circuit-breaker via a second trip coil and/or alternative cable route.

Client: entity that requests a service from a server, or which receives unsolicited data from a server. [IEC 61850-7-1]

Critical assets: Facilities, systems and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.

Cyber assets: In a substation, they are the programmable electronic devices and communication networks including hardware, software, and data.

Critical cyber Assets: Cyber Assets which are essential to the reliable operation of Critical Assets.

Dataset: permits the grouping of data and data attributes. Used for direct access and for reporting and logging. The attribute DataSet shall identify a DATA-SET that is contained in the LOGICAL-NODE.

DAR: Delayed Low-Speed autoreclosing dead time. This is normally used for three phase reclosing.

Disconnector: A switching device which provides, in the open position, an isolating distance in accordance with specified requirements.

Ethernet: is a family of computer networking technologies for local area networks (LANs) commercially introduced in 1980. Systems communicating over Ethernet divide a stream of data into individual packets called frames. Each frame contains source and destination addresses and error-checking data so that damaged data can be detected and re-transmitted.

The standards define several wiring and signalling variants. The original 10BASE5 Ethernet used coaxial cable as a shared medium. Later the coaxial cables were replaced by twisted pair and fibre optic links in conjunction with hubs or switches. Data rates were periodically increased from the original 10 megabits per second, to 100 gigabits per second. Since its commercial release, Ethernet has retained a good degree of compatibility. Features such as the 48-bit MAC address and Ethernet frame format have influenced other networking protocols.

EMI: Electromagnetic Interference.

Fault clearance: The power system must be designed and operated to avoid instability, loss of synchronism, voltage collapse, undesired load shedding and unacceptable frequency and voltage. Good protection practices help meet these objectives by detecting and clearing faults rapidly. Rapid fault clearance helps: prevent severe power swings or system instability, minimize disruption of system, power transfer capability, prevent unreliable services, limit or prevent damage to equipment.

Fault clearance time: The time interval between the fault inception and the fault clearance.

Feeder bay: In a substation, the bay relating to a feeder or a link to a transformer, a generator or another substation.

Feeder circuit breaker: In a substation, a circuit breaker which is located within a feeder bay and through which a feeder can be energized.

Feeder disconnector: A disconnector which is located in series at the end of a feeder, within a substation bay, in order to isolate the feeder from the system.

GOOSE: Generic Object Oriented Substation Event (IEC GOOSE) supports the exchange of a wide range of possible common data (digital and analogue) organized by a DATA-SET.

High impedance differential protection: Current differential protection using a current differential relay whose impedance is high compared with the impedance of the secondary circuit of the saturated current transformer.

HSAR: High Speed Autoreclosing dead time normally used for single and three phase reclosing.

IED: Intelligent Electronic Device.

Intertripping: The tripping of circuit-breaker(s) by signals initiated from protection at a remote location independent of the state of the local protection.

Instrument transformer: A transformer intended to supply measuring instruments, meters, relays and other similar apparatus.

Isolator: see 'disconnector'

LAN: Local Area Network.

Logical node: smallest part of a function that exchanges data. A logical node is an object defined by its data and methods.

Low impedance differential protection: Current differential protection using a current differential relay whose impedance is not high compared with the impedance of the secondary circuit of a saturated current transformer.

Main protection: Protection expected to have a high priority in initiating fault clearance or an action to terminate an abnormal condition in a power system. Note: - For a given item of plant, two or more main protections may be provided.

Merging unit: interface unit that accepts multiple analogue CT/VT and binary inputs and produces multiple times synchronized serial unidirectional multi-drop digital point to point outputs to provide data communication via the logical interfaces 4 and 5. [IEC 61850-9-1]

Multicast: uni-directional, connectionless communication between a server and a selected set of clients. [IEC 61850-6]

Numeric protection: A numeric protection performs analogue to digital conversion on samples of the secondary voltage and/or current signals and uses numerical methods to determine relay operation.

Peer-to-peer: is a communications model in which each party has the same capabilities and either party can initiate a communication session. Other models with which it might be contrasted include the client/server model and the master/slave model. In some cases, peer-to-peer communications is implemented by giving each communication node both server and client capabilities.

Primary protection (USA): see 'main protection'

Process bus: is the communication bus between the primary equipment installed in the yard and the IEDs installed in the control room. The Process layer of the substation is related to gathering information such as Voltage, Current and status information from the transformers and transducers connected to the primary power system process – the transmission of electricity. IEC 61850 defines the collection of this data via two different protocol definitions, namely, Part 9.1 which defines a Unidirectional Multidrop Point-to-Point fixed link carrying a fixed dataset and Part 9.2 which defines a "configurable" dataset that can be transmitted on a multi-cast basis from one publisher to multiple subscribers.

Protected zone: The portion of a power system protected by a given protection system or a part of that protection system. The boundary of the protected zone is defined by the position of the current transformers in order to identify the location of the fault. The position of the circuit breakers is chosen in order to facilitate the isolation of the fault.

Protection equipment: Equipment incorporating one or more protection relays and, if necessary, logic elements intended to perform one or more specified protection functions. *Note: protection equipment is part of a protection system.*

Protection relay: A measuring relay which, either solely or in a combination with other relays, is a constituent of protection equipment.

Protective relay (USA): see 'protection relay'

Redundancy: In an item is the existence of more than one means for performing a required function.

Substation automation system: provides automation within a substation and includes the IEDs and communication network infrastructure. [IEC 61850-1]

Sampled analogue value: IEC 61850-9-2 is used to transmit the signals (voltage, current as well as status information) from Non-Conventional or Conventional Instrument Transformers to IEDs such as Protective Relays using a Merging Unit. The digitally formatted and time stamped multicast Sampled Analogue Values are transmitted via Fibre Optic to IEDs.

SCL: Substation Configuration Language.

Server: on a communication network, a functional node that provides data to, or that allows access to its resources by, other functional nodes. A server may also be a logical subdivision, which has independent control of its operation, within the software algorithm (and/or possibly hardware) structure. [IEC 61850-6]

Sampled measured value: See sampled analogue value.

Station bus: The station bus provides primary communications between the various Logical Nodes, which provide the various station protection, control, monitoring, and logging functions.

Tie-breaker: see 'switched busbar circuit-breaker'

3.2 Abbreviations

AR	Auto-Recloser Device
BF	Breaker Failure Protection
BCU	Bay Control Unit
CID	Configured IED Description File
CIM	Common Information Model
CS	Check Sync Device
DSAS	Digital Substation Automation System
DT/IDMT	Definite Time / Inverse Definite Minimum Time
ICD	IED Configuration Description File
IED	Intelligent Electronic Device
LAN	Local Area Network
MCR	Mesh Corner Recloser Unit

MICS	Model Implementation Conformance Statement
PICS	Protocol Implementation. Conformance Statement
SAS	Substation Automation System
SAV	Sampled Analogue Value
SCADA	Supervisory Control And Data Acquisition
SCD	Substation Configuration Description File
SIPS	System Integrity Protection Schemes
SSD	Single Line Diagram File
SMV	Sampled Measured Value
SNTP	Simple Network Time Protocol.
TCP/IP	Transmission Control Protocol/Internet Protocol
UFLS	Under Frequency Load Shedding
WAN	Wide Area Network
XML	Extensible Mark-up Language

Table 3-1: Abbreviations

4 INTRODUCTION TO IEC 61850

4.1 Introduction

IEC 61850 is the international Standard applicable to Substation Automation systems (SAS). It provides the engineering definitions and processes for configuration and parameterisation of the functions required for communication between intelligent electronic devices (IEDs) in the substation, and the related system requirements. It is therefore not a protocol itself but rather the configuration of IEDs with interoperability to communicate using a protocol.

4.1.1 <u>Not a Protocol</u>

The title of the Standard is: “Communication networks and systems for power utility automation”.

Whilst the title of the standard refers to communication, this is in the respect of the engineering processes to configure the IEDs and functions to be able to communicate between each other with interoperability using appropriate protocols as the delivery mechanism.

> *“Interoperability is a property of a product or system, whose interfaces are completely understood, to work with other products or systems, present or future, without any restricted access or implementation.” (http://en.wikipedia.org/wiki/Interoperability)*

The title of the Standard should not be misinterpreted as merely “another protocol”. Misinterpretation may be underestimating the benefits of the Standard to engineering of the system and/or unrealistic expectations of the use of the Standard. Misinterpretation inevitably leads to ensuing frustration, disappointment, extensive additional engineering with the inevitable result of avoidance of further interest/use.

“Mere” protocols don’t ensure realistic or practical use can be made of the information for any or all of these or other reasons. Hence the communication process can be said to be “not interoperable” without extensive additional effort by the recipient or on the part of the sender to obtain or provide additional explanation.

Generally communication protocols deal with the entire structure of the message frame in order to convey a message with prescribed or un-prescribed “payload” from one application to another. This can be likened to addressing an envelope for sending via postal services. Since many power system professionals have developed expertise generally outside of mainstream communications technology specifically, this analogy will be used in this and the next section to clarify communication technology aspects.is useful to continue.

When sending a letter, there may well be certain rules (protocol) associated with the requirements for the envelope size, weight, postage stamp, address format etc. However these do not prescribe the type of content, language etc. that may be conveyed inside the envelope itself. Hence it is quite feasible to successfully receive an envelope but find that its contents are of no interest to you, perhaps is out of date (lost in the mail), is in another language, is poorly written as to not convey any particular meaning that you can understand or the reason it was sent to you.

4.1.2 <u>Engineering Process, Data Model and Data Exchange Mechanisms</u>

In order to achieve interoperability between IEDs, IEC 61850 prescribes the standardised:

a) Engineering process in support of the function requiring configuration of the communication between the IEDS - the Part 6 System Configuration Language (SCL),

b) Roles and requirements of the engineering tools required at each phase of the engineering process,

c) Engineering files and content exchanged between phases and tools of the IEC 61850 focused work flow process and life cycle,

d) IED specification and capability statement documents,

e) Communication services (the methods used to access and exchange data):

   i. Hierarchy "vertical" communication e.g. SCADA-IED and IED-SCADA client-server commands and report messages,

   ii. Peer-to-peer "horizontal" communication e.g. IED-to-IED real-time publisher/subscriber multicast messaging

f) Types and performance requirements for the different types of messages to enable and facilitate the functionality,

g) Communication system features and performance requirements for real time (sub-millisecond) critical functions to be supported,

h) Structure of the content of the messages,

i) Standardized object oriented data models for primary plant and functions,

j) Associated other standards required to be used in association with this Standard,

k) Specified project management engineering processes, work flow and tools with specific roles,

l) Definition of IED conformance testing

The Standard also provides mechanisms in the engineering process to include key information required for the communication process and protocol to be successful for the intended purpose. In this regard, the Standard does provide elements associated and required for the communication protocol. This includes aspects such as:

i. IP address and name of recipient,

ii. IP address and name of sender,

iii. Nature of the information:
   a. publisher-subscriber for any recipient (advertising/"junk-mail" to some, source of vital discount information to others),
   b. specific client-server messages (addressee only)
   c. reporting (magazine subscription)
   d. priority action required (final notice, payment due),

iv. the means of getting the message to its destination:
   a. standard (sea mail),
   b. medium (air mail),

    c. fast (priority mail), or
    d. ultra-fast and secure (personal courier delivery),

v. overall latency requirements (end-to-end pick up to delivery time),

vi. etc.

The standard already includes mapping of data onto Ethernet offering many advantages, most significantly including:

a) High-speed data rates (100 Mbit/s, 1 Gbit/s, and more recently 10 Gbit/s on the LAN and >1Tbit/s potential on WAN fibres) rather than ≤ 100’s kbit/s used by most serial protocols, PDH radio channels/time slots and power line carrier technology,

b) Multiple client/server connections,

c) Ethernet is an open standard and widely used and supported,

d) Fibre Ethernet is suited to the substation environment as it is not susceptible to EMI

4.2 History

The industry’s experiences have demonstrated the need and the opportunity for developing standard communication protocols, which would support interoperability of IEDs from different vendors. Interoperability in this case is the ability to operate on the same network or communication path sharing information and commands.

The IEC 61850 standard was based partly on UCA2.0, a substation automation concept developed in the USA under EPRI. Work on both Standards had begun in the early 1990’s. In 1997, IEEE/EPRI and IEC TC57 decided to merge both standards to provide a global and unique substation automation solution.

IEC 61850 Part 3 General Requirements was the first Part to be published in January 2002. With the release of other parts, in particular the data models and communication services Parts, it is generally taken that the Standard was available for use in 2004. Consequently there has been some 10 years exposure of the Standard in the industry at large and some 20 years since the Working Groups first started developing the concepts. The Standard is therefore not in any way a “recent fad” with “short term prospects until the next Standard replaces it. The Standard itself is fully expected to continue development with new Parts, and new Editions of old Parts for many years to come. However it is a proven technology with already over some 6,000 reference sites world-wide supported by some 300 certified server IEDs and some 16 certified client systems/IEDs.

Part	Current Version Released yyyy-mm	Part	Current Version Released yyyy-mm
1	Ed1 2003-04	7-4	Ed2 2010-03 ~~Ed1 2003-05~~
2	Ed1 2003-08	7-410	Ed1 2007-08
3	Ed1 2002-01	7-420	Ed1 2009-03
4	Ed2 2011-04 ~~Ed1 2002-01~~	8-1	Ed2 2011-06 ~~Ed1 2004-05~~
5	Ed1 2003-07	9-1	~~Ed1 2003-05~~ (totally withdrawn)
6	Ed2 2009-12 ~~Ed1 2004-03~~	9-2	Ed2 2011-09 ~~Ed1 2004-04~~
7-1	Ed2 2011-07 ~~Ed1 2003-07~~	10	Ed1 2005-05
7-2	Ed2 2010-08 ~~Ed1 2003-05~~	80-1	Ed1 2008-12
7-3	Ed2 2010-12 ~~Ed1 2003-05~~	90-1	Ed1 2010-03

Table 4-1: Current Versions of each Part as at 2012-09

Many new parts are still in preparation and several more planned as on-going work, whilst some parts have already progressed to publication of Edition 2. It is therefore not possible or logical to simply state that systems and or IEDs are either compliant to IEC 61850 in general (which parts and which versions), or to IEC 61850 Ed 2 standard since clearly some Parts are currently, and may remain for some time, as Edition 1.

In addition to the formal Edition of any Part, it is important to follow the interim changes to the Standard some of which are considered as critical to system deployment. The full history of these interim amendments is published in the TISSUES database (http://www.tissues.iec61850.com) to which anyone can contribute new items. The subsequent Edition of the Standard will have incorporated all prior TISSUES reflecting the complete up to date content of that Part.

4.3 Concepts

As seen in Figure 4-1, it enables integration of all protection, control, measurement and monitoring functions within a substation. In order to allow a free allocation of functions to IEDs, interoperability is provided between functions to be performed in a substation but residing in equipment (physical devices) from different suppliers. The functions may be split physically into parts performed in different IEDs but communicating with each other (distributed function). Therefore, the communication behaviour of such parts called logical nodes (LN) supports the requested interoperability of the IEDs. The functions (application functions) of a SAS are control and supervision, as well as protection and monitoring of the primary equipment and of the grid. Other functions (system functions) are related to the system itself, for example supervision of the communication.

The IEC 61850 standard defines the information and information exchange in a way that it is independent of a concrete implementation (i.e., it uses abstract models). The standard also uses the concept of virtualization. Virtualization provides a view of those aspects of a real device that are of interest for the information exchange with other devices. Only those details that are required to provide interoperability of devices are defined in the IEC 61850 series.

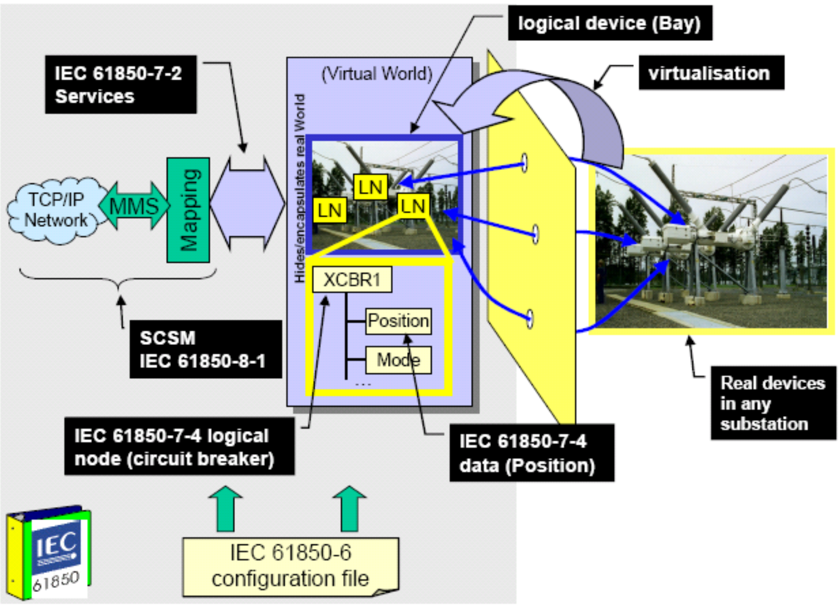

Figure 4-1: Substation Virtualization According to IEC 61850 standard

4.4 Interoperability and interchange-ability

A major benefit of IEC 61850 is interoperability. IEC 61850 standardizes the data model and services required to interface with substation IEDs. This responds to the utilities' desire of having easier integration for different vendors' products, i.e. interoperability. It means that data is accessed in the same manner in different IEDs from either the same or different IED vendors, even though, for example, the protection algorithms of different vendors' relay types remain different.

One of the main objectives of IEC 61850 is to allow the communication requirements of IEDs to be directly configured from a configuration file generated at system configuration time. At the system configuration level, the capabilities of the IED are determined from an IED capability description file (ICD) which is provided with the product. Using a collection of these ICD files from varying products, the entire protection and automation of a substation can be designed, configured and tested (using simulation tools) before the system is even installed into the substation.

IEC 61850 does not prescribe 'blind' interchange-ability of IEDs.

> **"Interchangeability is beyond this communication standard"**
> IEC 61850 Part 1, Chapter 4, 2nd paragraph.

Apart from performance and setting requirements, IEDs may only be directly swapped out without additional engineering if three fundamental requirements are met by the replacement IED:

a) The IEC 61850 'top-down' principles and processes (refer clause 4.11) were used at the outset. It is unreasonable to expect subsequent engineering processes ('top-down' IEC 61850 or otherwise) could 'blindly' take up the original engineering and do some scheme modification, system augmentation or IED replacement if the fundamental engineering and SCL files have not been established in the first place.

- ❖ SCD file exists
    - Note that if the original engineering process merely took an ICD and created multiple instances of that file (most likely incorrectly called CID since they probably have no Substation section binding and no

communication section information of the other IEDs it is talking to) then you will NOT have the equivalent of an SCD.

- Taking several such “CID” and 'adding' them together does not necessarily, certainly not easily, create an SCD "CID"1 + "CID"2 + "CID"3 << SCD.

b) The same or greater IEC 61850 capabilities and implementation solutions including numbers of instances supported, data models, naming conventions/restrictions, mappings:

- Configurable Logical Device hierarchy
  - Logical Nodes and instance support
    - Data Objects
      - Attributes
- Communication Services
- Prefix naming conventions/limitations
- Types of Datasets: vendor-defined, configurable, dynamic
- IED Configuration Tool can import SCD file
- Both IED Configuration Tools do not prescribe/limit use of non-Logical Node fields in the IED sections of the SCD file (e.g. “.Name”, “.desc”, “.Type”, “.configVersion” etc.).
- No vendor prescription for mapping virtual signals via GGIO (http://www.tissues.iec61850.com/tissue.mspx?issueid=864)
  - GGIO can be renamed according to physical function allocation
    - As ‘proxy’ for a non-IEC 61850 IED providing an IEC 61850 Logical Node function (http://www.tissues.iec61850.com/tissue.mspx?issueid=880).
    - As a ‘private’ Logical Node name defined under a private namespace to represent miscellaneous physical functions not defined by IEC 61850 H, K, S, T, W, X, Y, or Z. Logical Nodes (doors, push buttons, lights: http://www.tissues.iec61850.com/tissue.mspx?issueid=900)

b) The same or greater proprietary capabilities and configurations of I/O, indications, menus, logic and compatible tools.

- Physical dimensions
- Wire I/O requirements
- Wire I/O terminal mappings to LNsNumber of LEDs and specific allocation (not part of the IEC 61850 data models)
- Number of push buttons and allocation
- Menu facilities and language
- Proprietary scheme logic configuration and associated tool configuration file import / export.

The Standard has been scoped do as not to prescribe particular functional requirements but provide a platform on which functions can be realised more consistently. However it does not purport to be the unique Standard for the features and capabilities for any IED as offered in the competitive market. Whilst many aspects have been structured in the Standard it should not be taken as blind "plug-and-play".

4.5 The Data Model

To ease understanding, the data model of any IEC 61850 IED can be viewed as a hierarchy of information. The categories and naming of this information are standardized in the IEC 61850 specification.

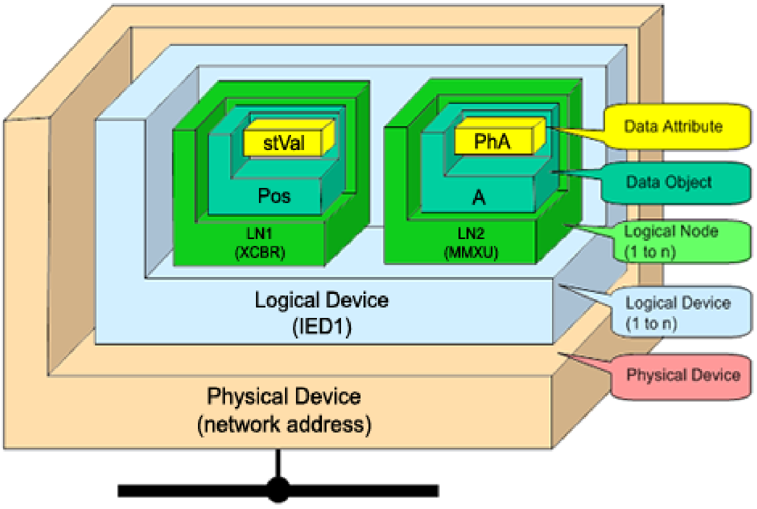

Figure 4-2: Data Model Layers in IEC 61850

The levels of this hierarchy can be described as follows:

4.5.1 Physical Device

It identifies the actual IED within a system.

4.5.2 Logical Device

It identifies groups of related Logical Nodes within the Physical Device. The allocation of Logical Nodes to specific Logical Devices is not defined in the standard.

4.5.3 Logical Node

It identifies the major functional areas within the IEC 61850 data model. Logical Nodes are instantiated in an IED or computer using prefix characters and/or an instance number.

4.5.4 Common Data Class

A Common Data Class is a composite set of data attributes, defined by the standard to relate to substation applications. In particular it specifies common data classes for:

a) Status information,

b) Measured information,

c) Controllable status information,

d) Controllable analogue set point information,

e) Status settings,

f) Analogue settings.

And specifies the data attribute types used in these common data classes.

4.5.5 Data Attribute

This is the actual data (measurement value, status, description, etc.). For example, **stVal** (status value) indicating actual position of circuit breaker for Data Object type **Pos** of Logical Node type **XCBR**. The data model for a server is described in the Model Implementation Conformance Statement (MICS) document.

4.5.6 The communication services

The communication services are the methods used to access and exchange data throughout the system. The IEC 61850 standard defines the services for the following functions.

4.5.7 Client - server associations

It permits communication to be established between a client and a server.

4.5.8 Data model interaction

It permits retrieval of data model information (allows self-description of an IED) and allows writing of data values (for example for IED configuration).

4.5.9 Dataset

It permits the grouping of data and data attributes. Used for direct access, GOOSE and for reporting and logging.

4.5.10 Substitution

It supports replacement of a process value by another value.

4.5.11 Setting Group Control

It defines how to switch from one set of setting values to another one and how to edit setting groups.

4.5.12 Buffered Report, Unbuffered Report and Log

Generating reports and logs based on parameters set by the client. Reports may be triggered by changes of process data values (for example, state change or dead band) or by quality changes. Logs can be queried for later retrieval. Reports may be sent immediately or deferred. Reports provide change-of-state and sequence-of-events information exchange. The difference between buffered and un-buffered reporting is that the former is able to store events during communication breaks and continue the sequence of events once the connection to the client is re-established.

4.5.13 Control

It describes the services to control, for example, devices. Direct and Select Before Operate control types are specified.

4.5.14 Generic Substation Event (GSE)

It supports a fast and reliable system-wide distribution of input and output data values; peer-to-peer exchange of IED binary status information, for example, a trip signal. The GOOSE messages are not command signals. They are multicast reports of the change of state of a protection element used in a distributed protection scheme.

4.5.15 Tripping model in IEC 61850

Depending on the protection scheme, one or more protection functions can operate on a Circuit Breaker. All operate signals coming from protection LN are combined to a trip command in one protection trip conditioning LN (PTRC). PTRC handles the trip signal conditioning (minimum trip command duration, single/three-pole decision, etc.).

Therefore, in general, there shall be a PTRC LN between every protection LN and the circuit breaker node (XCBR).

4.5.16 Transmission of Sampled Values

Fast and cyclic transfer of sampled analogue values, for example, from instrument transformers.

4.5.17 Time Synchronization

It provides the time base for the device and system, using SNTP.

4.5.18 File Transfer

It defines the exchange of large data blocks such as disturbance record files.

The communication services for a client or server (or publisher or subscriber) are described in the Protocol Implementation Conformance Statement (PICS) document.

4.6 Architecture

Part 5 of the IEC 61850 Standard introduces a view of a substation automation system comprising three hierarchical levels (station, bay and process), and hence two levels of communication network connecting these hierarchical levels are described – the station bus and the process bus, although these may co-exist on the same LAN cable.

A simplified diagram with the communications architecture of an IEC 61850 **Substation** and **Process Bus** based substation automation system is shown in **Figure 4-3**

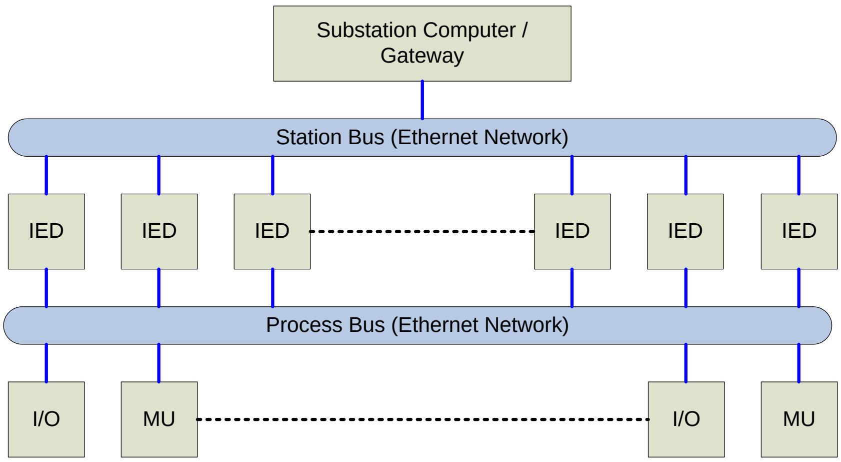

Figure 4-3: Simplified IEC 61850 substation communication architecture

The Merging Units (MU) interfacing with conventional or non-conventional instrument transformers multicast sets of measured sampled values (currents and voltages) to multiple IEDs in the substation over the substation local area network.

A "**Process Bus**" normally will support services defined in IEC 61850-9-2 for sampled analogue values, but may also provide information such as the status of breakers and switches and possibly trip commands through an input/output unit (I/OU) using the services defined in IEC 61850-8-1. In some cases the Merging Unit and the Input / Output unit can be combined in a single device.

The IEDs interface with the process bus via the Ethernet network. They use this information for fault detection, faulted phase selection and protection elements operation etc., and can take action based on their functionality. This is typically to operate their relay outputs in order to trip a breaker or to initiate some other protection or control function (e.g. BF Breaker Failure or AR Auto-Reclose functions).

Interaction between different IEDs and the clients in the IEC 61850 based protection systems are achieved based on the exchange of communication messages over the "**Station Bus"** (see **Figure 4-3**).

The IEC 61850 Standard does not prohibit the station bus and process bus from being combined in one physical Ethernet network. Today, however, the segregation of the yard network from the control room network and concerns about sufficient bandwidth for Sampled Values means that in practice they are often separate physical Ethernet networks requiring at least two Ethernet ports per IED. As 1 Gbit/s or 10 Gbit/s Ethernet networks are deployed for IEC 61850 applications, it is possible that station bus and process bus messages can be combined over a common fibre with possibly only one Ethernet port per IED, apart from any requirements for dual communication system connectivity (e.g. Parallel Redundant Protocol (PRP) or High-availability Seamless Redundancy (HSR) both requiring two ports)..

A Proxy Server is a network entity located between a client application and one or multiple physical devices, and acts as a client/server.

For Client-Server communication, the data model of each physical device can be re-created by the proxy server to serve the transmitted information (e.g. when a device that is not IEC 61850 compliant is to be integrated). For GOOSE and SAV, the messages are published by the proxy server with the same format as from the physical device. A separate logical device is used to represent every legacy device.

Logical Devices enable the building of proxy servers, in such a way that Logical Devices are – from a functional point of view – transparent. Each Logical Device can be identified independently of its location (whether in a separate physical device connected to the network or in a proxy server).

Parts 8-1 and 9-2 of the IEC 61850 Standard specify exchanging time-critical and non-time-critical data through local-area networks (LAN) using ISO/IEC 8802-3 frames over 10/100TX or 100FX physical media – i.e. Ethernet. However, the standard is open concerning the physical topology of the Ethernet communication network. Further consideration of physical topologies is given in section 9.3 in Chapter 9.

4.7 Traffic Patterns found in IEC 61850 substations

Most traffic in IEC 61850 automation systems is based on Ethernet, as depicted below. In the station bus we may find:

a) Protection traffic based on GOOSE messages, which are multicast Ethernet frames,

b) Control and monitoring traffic, reports and commands, which are based on MMS over TCP/IP,

c) Synchronization information, based on SNTP/UDP/IP and IEEE1588,

d) Management information, being the most common used protocols, FTP for exchanging SCD/CID files and HTTP for accessing IED's configuration parameters via their built–in web servers.

In the process bus we may find:

e) SAV Sample analogue values, which are multicast Ethernet frames,

f) Position Status and Breaker Tripping/Closing traffic based on GOOSE messages, which are multicast Ethernet frames,

g) Synchronization information, based on IEEE1588.

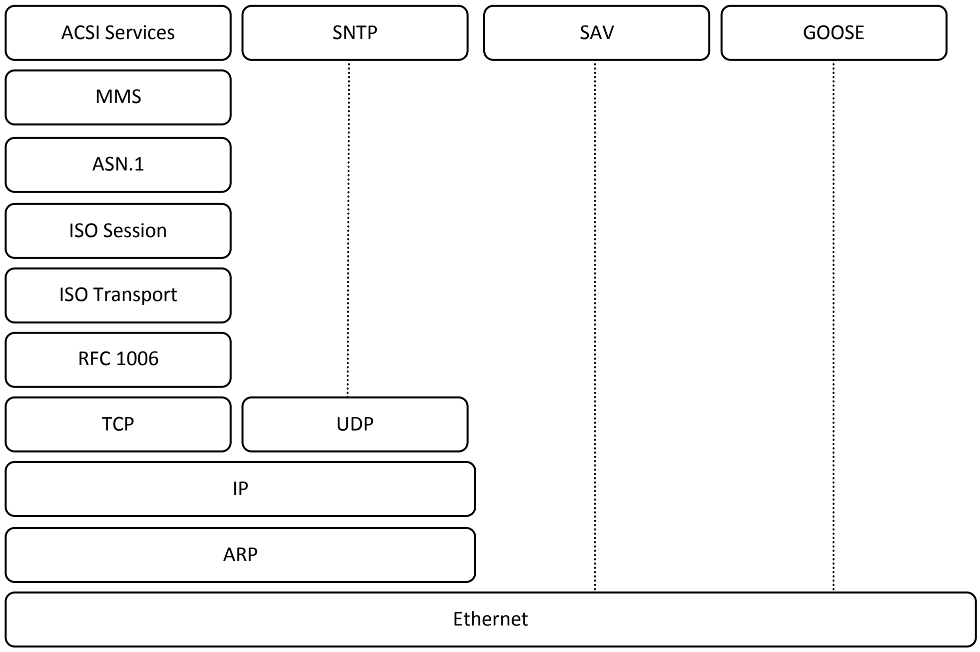

Figure 4-4: IEC 61850 standard stack

As shown in Figure 4-4, it is clear that an IEC 61850 will face the same security challenges as any Ethernet based automation system. For that reason, we will focus right now on understanding the main threats we will face for Ethernet networks.

From a protection point of view, the Ethernet based traffic for GOOSE messages and Samples Analogue Values is more critical, more details are provided related to the security threats~~,~~ which are dealt with in Chapter 4.12.

4.8 Performance

Performance of the communication is discussed in Part 5 of the IEC 61850 standard. Part 5 defines both performance classes and message types, and states the maximum transfer times applicable to each.

For protection, Part 5 defines three performance classes:

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

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

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

Part 5 defines various message types:

a) Type 1A Fast messages for “Trip”

b) Type 1B Fast messages for “Others” (functions such as “Close”, “Reclose order”, “Start”, “Stop”, “Block”, “Unblock”, “Trigger”, “Release”)

c) Type 2 – Medium speed messages

d) Type 3 – Low speed messages

e) Type 4 – Raw data messages

f) Type 5 – File transfer functions

g) Type 6 – Time synchronization messages

h) Type 7 – Command messages with access control

In order to perform protection schemes that are time-critical, certain performance levels are required for the high speed peer-to-peer (GSE) messaging. Chapter 6.2 briefly describes network impact on scheme performance. Section 9.3 in Chapter 9 of this Technical Brochure discusses the actual performance requirements for the GSE messaging used for the protection schemes discussed in Chapters 7 and 8 of this this Technical Brochure.

It should be recognized that where messaging for protection schemes are routed through proxy servers, lower performances will result.

4.9 Applications

Most applications to date have concentrated on client server data exchange for substation automation purposes. Applications of GOOSE have been limited by the opportunities to retrofit and user confidence in replacing hardwired solutions with communication-based solutions. There are today some pilots or advanced projects to demonstrate the use of Process Bus IEC 61850-9-2.

Nevertheless, some valuable experience is being gained both in GOOSE and SAV schemes. Examples are discussed in Chapter 7 and 8 of this this Technical Brochure.

4.10 Modelling of Multifunctional IEDs in IEC 61850

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

A Logical Node is “the smallest part of a function that exchanges data”. It is an object that is defined by its data and methods and when instantiated, it becomes a Logical Node Object. Multiple instances of different logical nodes become components of different protection, control, monitoring and other functions in a substation automation system. They are used to represent individual functional units in such a function. A multifunctional protection IED has a complex functional hierarchy that needs to be modelled according to the definitions of the IEC 61850 model.

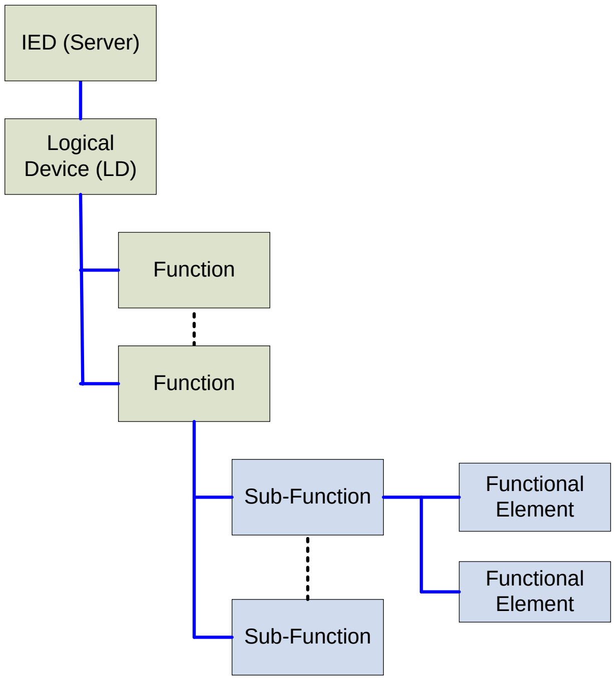

Figure 4-5: Device Functional Hierarchy

Logical nodes are grouped in logical devices, usually to represent specific functions that are part of a server. Sometimes if the IED has a more complex hierarchy it is necessary to introduce intermediate layers in the model – sub-functions.

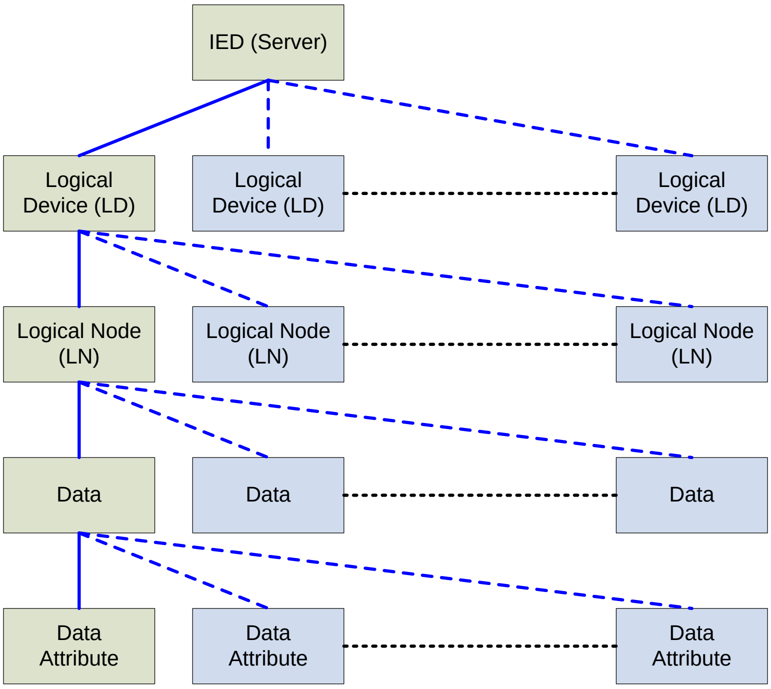

Figure 4-6: Object Hierarchy

The above described IED functional hierarchy needs to be appropriately represented based on the modelling hierarchy presented in Part 7 of IEC 61850. The standard does not only model the IEDs, but also the communications architecture and the primary substation equipment. The substation model is based on CIM.

In case of protective relays with more complex functional hierarchy it might be necessary to group together several logical nodes in a functional group such as Distance protection. The fact that a logical node belongs to a functional group of logical nodes can be represented by a functional group name.

When there are different functions and certain functional elements have to be grouped together, (for example for enabling or supervision of a group of functional elements) the modelling needs to be done using the available object hierarchy and the naming conventions for the data objects defined in IEC 61850. The model in this case will include multiple logical devices as shown in Figure 4-7. It shows the functional configuration of a transmission line protection relay. The model of such device in IEC 61850 can be done by mapping the different functions supported by the relay to different logical devices. One logical device will represent the primary protection functions. Another will define the Measuring function and a third – the Disturbance recorder. A Fault Locator and a Circuit Breaker Monitor will be modelled with additional Logical Devices.

If we go further down in the functional hierarchy, the Protection Logical Device will include multiple protection functions. Each of these protection functions can be enabled or disabled. When a protection function is Disabled, it means that all Functional elements (Logical Nodes) included in it become Disabled as well. This is one of the reasons that require the functional grouping, which according to IEC 61850 Edition 2 can be done using the nesting of Logical Devices.

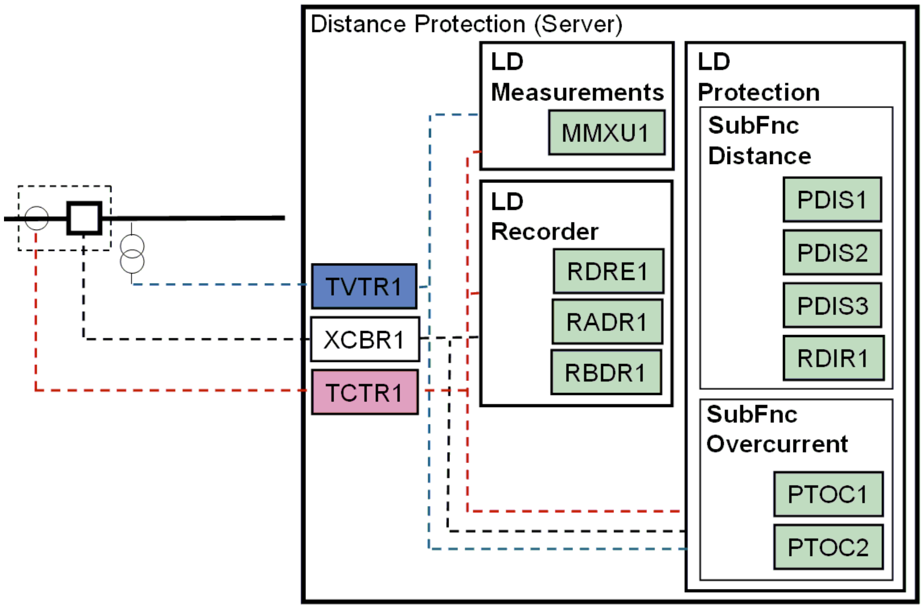

Figure 4-7: Distance Protection Relay = Simplified Object Model

4.11 System Configuration Language

An IEC 61850 based Substation Automation System is described using the System Configuration Language (SCL) which is based on the eXtensible Mark-up Language (XML) and allows the exchange of configuration data between different tools, possibly from different manufacturers.

Depending on the purpose of the SCL file, six types are defined in Part 6 Edition 2:

a) IED configuration description (**.icd file**): provides LN capability and data-model of an IED not yet used in any application;

b) System Specification Description (**.ssd file**): consists in the single line diagram and the LN requirements only on a functional point of view;

c) System Configuration Description (**.scd file**): defines all the specific substation automation system details, from the communication to the LN allocation – which IED performs which function;

d) System Exchange Description (.sed file): provides the information required to be given to the System Configuration Tool for another project where communication is to be established between the systems,

e) Instantiated IED Description (.iid file): provides a subset of the specific IED configuration in relation to the configured data model,

f) Configured IED Description (**.cid file**): is the part of .scd file concerning a specific IED which is loaded into the IED. This file configures the IED with the necessary IEC 61850 parameters that are needed to make the device work in the system (e.g. address, name values assigned according to the specific project names, etc.).

Note:

There may be other aspects of the IED that must also be configured that are not prescribed within IEC 61850 and hence included in the CID file. This includes Input / Output mapping and configuration, indicator allocations, button allocations, menu and language and any IED logic associated with the functionality.

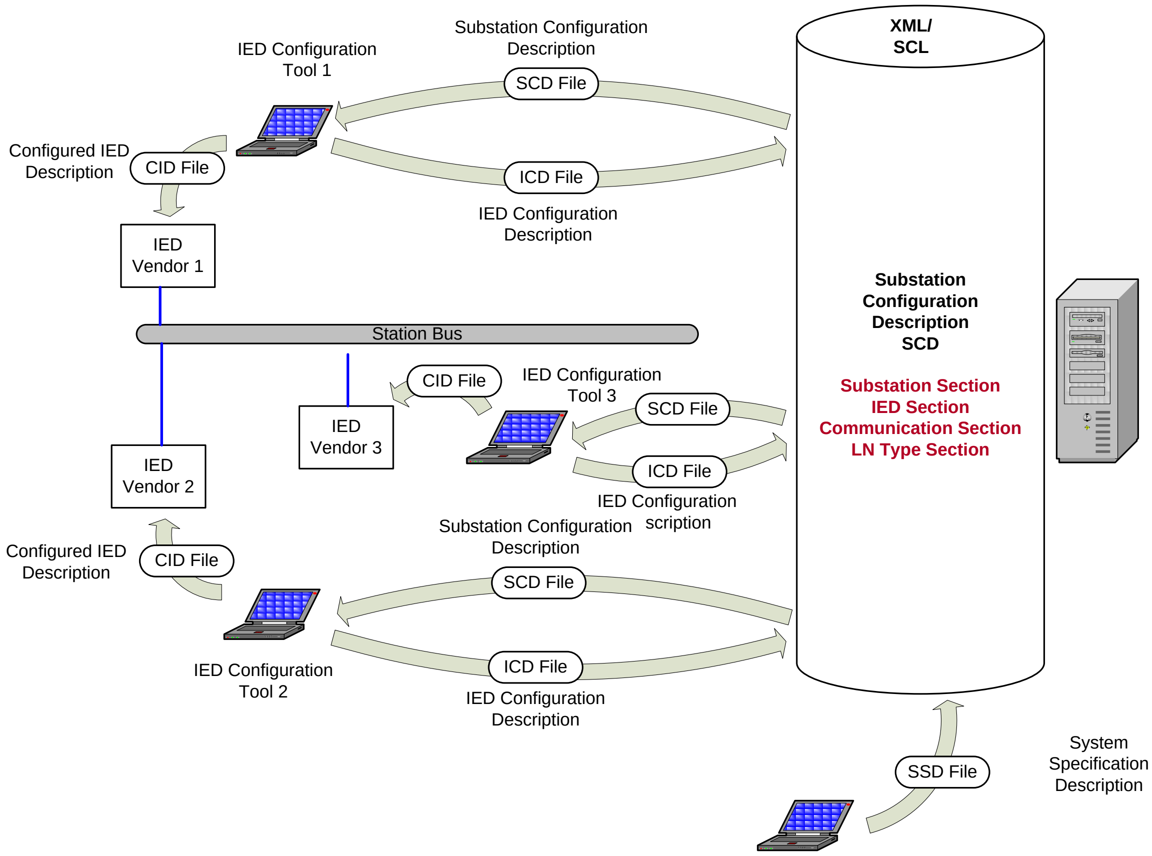

Figure 4-8: IEC 61850 system configuration

The table identifies each of the SCL files, their principle characteristics, and the tool which creates them and which tools use them according to the so called "top-down" engineering process.

IED Related Files	System Related Files
ICD **IED Capability Description** .Name = Template Created by the IED Configuration Tool or available from the vendor Used by the System Specification Tool Used by the System Configuration Tool	
	SSD **System Specification Description** Binding SLD + Functions + Data Types Created by the System Specification Tool Used by the System Configuration Tool
	SCD **System Configuration Description** SSD + IEDs + Communication + Data Types Created by the System Configuration Tool Used by IED Configuration Tools
	SED **System Exchange Description** Information to be shared between two SCD Created by the System Configuration Tool Used by other System Configuration Tools
IID **Instantiated IED Description** .Name assigned per serial number Data model only Created by the IED Configuration Tool from the SCD file or may be obtained partially configured from the vendor Used by the System Configuration Tool	
CID **Configured IED Description** .Name assigned per serial number Substation section Own IED section Communication section Portion of other IEDs Created by the IED Configuration Tool from the SCD file Loaded into the IEDs (along with other files to configure non-IEC 61850 and proprietary elements as well as any specific instance settings not defined in the SCD	

Table 4-2: SCL Files and Their Evolution in the Engineering Process

This 'hierarchy' and use by each tool as a process flow is shown in more detail in **Figure 4-9** and Figure **4-10**. The SCL files can be seen as the mechanism to transfer design information from one tool as input to the next tool in the process.

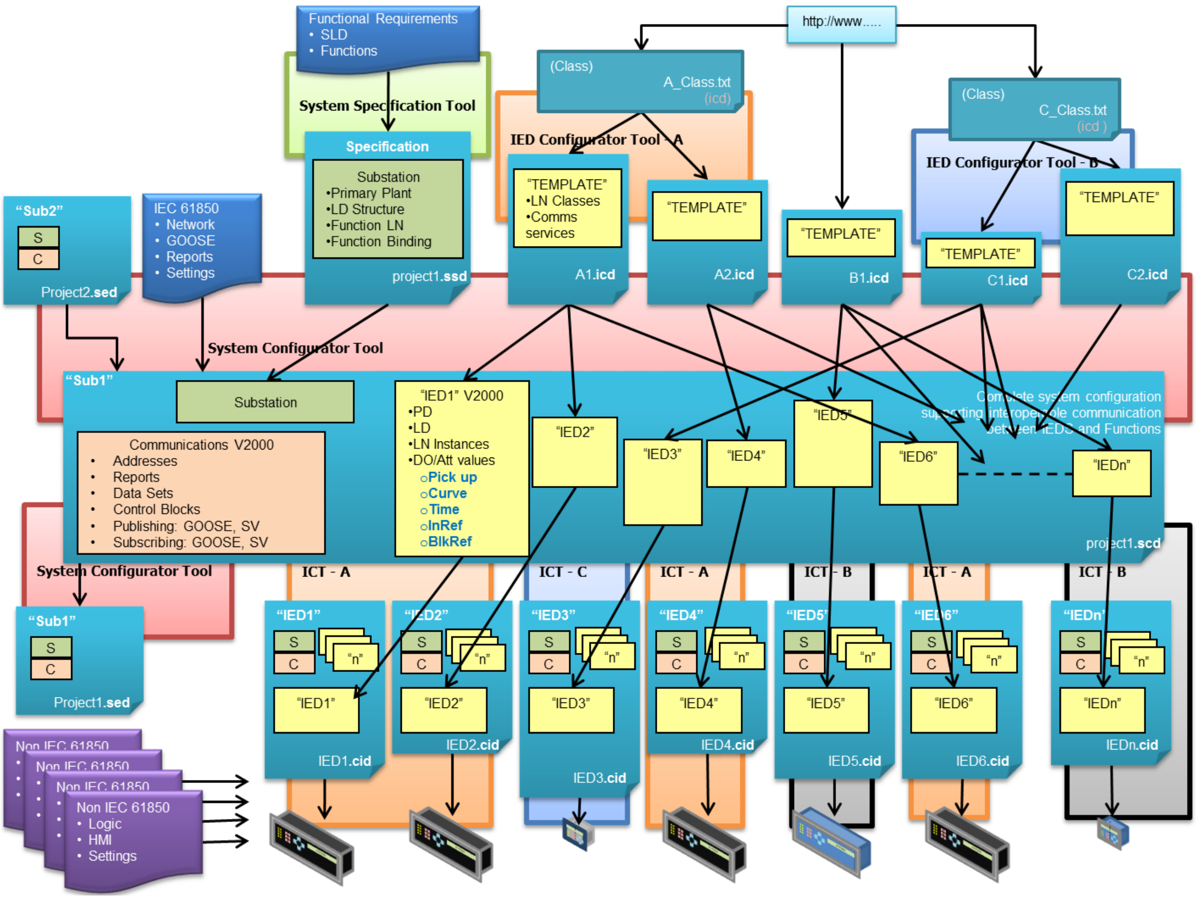

Figure 4-9: IEC 61850 'Top-Down' SCL File Hierarchy and Evolution

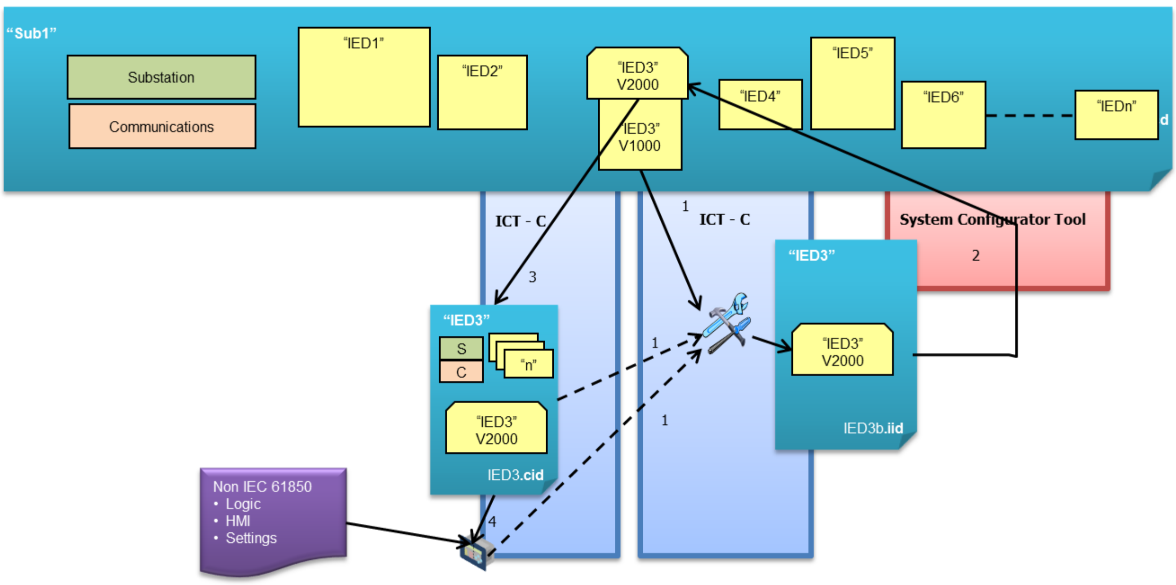

Figure 4-10: IEC 61850 Instance Model Modification: IID File

In some cases, the SSD and/or the SCD file may not be created in the engineering process being based on the so-called “bottom-up” approach. This process essentially uses the IED Configurator Tool to create multiple copies of the ICD and configure them for the project as CID files to be loaded into the IEDs.

Note that the SSD file has key information binding the Single Line Diagram topology, the primary plant and equipment and the functions required in the system e.g. instance TCTR1 is related to the physical current transformer T1 in Bay 1 of the E voltage level(110 kV to <220 kV). This is essentially creating the Substation Section of the SCL files.

Note also that the SCD file includes the substation section from the SSD file as well as all the IED instances and communication configuration. The SCD is also able to incorporate the specific function settings such as the pic-up, time delay, curve etc. of the Logical Nodes.

The CID file as effectively a subset not only includes the specific IED configuration details but also some selected information from the Substation Section and some selected information from the Communication Section relative to the other IEDs this particular IED is going to be communicating with.

Consequently using the IED Configurator Tool to create the CID directly from the ICD means that this additional information generated by the SSD and SCD stage may not be included.

Simply put if there are three CID files generated “Bottom Up”, simply combining the files in some form of text merge will not create the equivalent of an SCD file due to the missing information:

ICD.icd x 3 produces CID1.cid, CID2.cid, and CID3.cid

CID1.icd + CID2.icd + CID3.icd ≠ SCD

In terms of future usability of the files, CID files which don’t include for example Bay or primary plant references cannot simply be copied when additional bays are added simply because the notion of a Bay is not identified in the files. This is not to say that such engineering process is wrong per se, in fact it is within the capability of the tools to do so, however this may severely limit the objectives of creating Reusable Engineering where entire new bays can be created by simple “copy & paste” as so called “5-minute engineering”.

4.12 Cyber Security

A critical aspect to look at when cyber security is deployed to comply with national requirements such as NERC CIP and international requirements such as IEC 62351 is to identify the critical assets and critical cyber assets in a substation.

Typical critical assets and critical cyber assets are all the hardware and software installed in a substation which would affect the reliability or operability of the substation and consequently the power system if one of them is compromised or destroyed.

Every critical cyber asset within a substation should be included in an electronic Security Perimeter. The Responsible Entity within the Utility shall identify and document the Electronic Security Perimeter(s) and all Access Points to this/these Perimeter(s).

Typically a physical security perimeter and an electronic security perimeter are defined to protect all critical assets and critical cyber assets in a substation. The physical security perimeter could be the wall or the fence of the substation.

The access points in the substation automation architecture are:

a) Ethernet Links to SCADA,

b) Ethernet links to configuration and maintenance software,

c) Serial links to SCADA

It is important to emphasize that IEC 61850 was initially designed for communication within the substation. When IEC 61850 is used outside the substation, then there are further issues to be considered.

CIGRE Technical Brochure 419 (“Treatment of Information Security for Electric Power Utilities”) and Technical Brochure 427 (“The Impact of Implementing Cyber Security Requirements using IEC 61850”) provide extensive discussion on cyber-security. Joint Working Group B5.46 work is focused on “Application and Management of Cyber Security Measures for Protection and Control systems”.

5 BENEFITS OF IEC 61850

5.1 Introduction

In an open market, power transmission and distribution network operators need to run the power systems reliably and efficiently at minimum operating cost. There is a world-wide incentive to achieve these operational objectives by taking advantage of the capability of substation automation systems. It becomes important that there is only one standard protocol moving to the future so as to allow the elimination of the diversity of protocols that exist today. The standard must be for an open communication system which permits equipment from different manufacturers to operate seamlessly together. With the aging of the workforce and the introduction of such new technology, there is also a need to develop tools that are easy to use, facilitate the better engineering, commissioning and maintenance practices.

The readers could also refer to the Working Group B5.11 (TB 326), WG B5.12 (TB 466) and WG B5.18 (TB 329).

5.2 Reduction in Costs

One important goal for the utilities today is to improve efficiency and, therefore, to cut costs wherever possible. However, this must not endanger the safety and reliability of the grid performance and by no means lower the grid transmission capacity or availability.

The use of IEC 61850 can lead to a reduction in both capital expenditure and the costs associated with asset maintenance. Examples of potential savings include:

a) By making use of signalling through process and station busses within a substation, the amount and complexity of wiring can be considerably reduced leading to significant cost savings. This brings less cabling and potential savings both inside the control building using a station bus and, furthermore, between the switchyard and the building when using process bus.

b) The application of Low Power Instrument Transformers (LPIT – previously called non-conventional instrument transformers) such as Optical or Rogowski Coil CTs/VTs could bring further cost benefits as they are more lightweight offering the possibility to eliminate separate stanchions and hence reduction of required real-estate of the substation.

c) Hardware savings follow due to the fact that the number of IO in the IEDs can be reduced.

d) Less wiring also leads not only to less installation costs, but also less testing and maintenance costs during the lifetime of the substation automation system.

e) Furthermore, any subsequent modifications to schemes involving connections between IEDs will also become less expensive as changes to hardwiring will be minimized.

f) The use of a common international standard also opens up the substation automation market to more competition – potentially giving the user a larger selection of IEDs, suppliers and system integrators. It also allows users to avoid common mode failures by using different vendor equipment.

g) Through the WAN, it will be possible to more easily get hold of any equipment data. This applies for non-time critical data (disturbance records, event reports, setting parameters, etc.). Better use of data will lead to improvements in asset management and a reduction in device count … assuming that is it is correctly integrated with asset databases!

5.3 Safeguarding Investments

Digital electronics have made a great impact as it has helped realize substation automation and has made communications largely an explicit part of the automation system. In parallel, communication technology itself has recently been evolving particularly fast because of the rising capability of processors, memories and the advancement in fibre optics. The lifespan of a substation, especially the high voltage switchyard with all primary equipment and the control building, is much longer (e.g. 40-50 years) than that of the substation automation system, protective relays and communication equipment that have lower technology lifetimes. Applications within substations are generally stable over a long time, but in view of the trend in the last twenty years, the substation automation technology may change significantly during the lifetime of the substation itself.

The standard must provide means to support updating, extending, testing and maintaining the substation automation system and its communication system, over the whole lifetime of the substation.

Backward compatibility between the old and the new technology is definitely desirable because it would make the transition from the old to new much smoother and less costly. The present communication technology, such as IP-based networks and Ethernet, is considered to provide the best compatibility to future evolutions in communication technology.

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

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

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

5.3.1 Higher Performance

The substation automation system solutions should improve performance regarding e.g. capacity, speed and efficiency in fault tracing, maintenance and re-energization after grid faults.

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

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

Process bus implementation gives further advantages by using non-conventional CT instrument transformers are also not affected by CT saturation and the opening of secondary CT circuit conditions like the conventional ones.

5.3.2 Simplifying Engineering

The standard must provide means to support updating, modifying, extending and maintaining the substation automation system and its communication system, over the whole lifetime of the substation.

IEC 61850 defines also the Substation Configuration description Language (SCL) which allows the configuration of an automation system to be defined and the setting of the standardized parameter of IEDs from different manufacturers to be fixed by the user or any of the manufacturers involved.

Due to less hardwiring in the substation, engineering is simpler and less expensive both in the initial phase, when the substation is built, and in any modifications made later due to changes needed for any reason.

Refurbishments, augmentations and replacements are also facilitated by the defined object models and communications avoiding re-engineering of the same information engineered originally e.g. an overcurrent element sending an operate signal to a circuit breaker will always be the PTOC.Op attribute being communicated to the XCBR, once configured this never has to be changed or re-engineered regardless of which IEDs are involved, even decades after the first commissioning and during several IED replacements (provided no vendor-specific prescription of intervening GGIO (refer Part 10, Ed1, TISSUE 864: http://www.tissues.iec61850.com/tissue.mspx?issueid=864).

Using IEC 61850 engineering processes (Part 6) will reduce project time, simplify system integration with other engineering tools and reduce maintenance if the appropriate engineering processes, tools and training are developed at the outset. This will not happen instantly and will take a dedicated program of change management to achieve the full sustainable benefits are obtained.

5.3.3 Flexibility

The standard should be flexible and it shall allow changes in user's preferences and requirements like extensions as well as changes due to the manufacturers' innovations e.g. there will be functions tomorrow which are not thought of today.

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

IEC 61850 does not specify any mandatory system topology, the use of both station bus and process bus at the same time, or if station and process bus should be separated or not.

The utility has the flexibility to specify the system topology according to the criticality of the substation (reliability, redundancy requirements). Nevertheless, the implementation of process bus between the primary equipment (instrument transformers, disconnectors, breakers) and bays looks promising for the future by removing most of the wires within the yard.

If non-conventional CTs can easily be constructed to have better accuracy than conventional ones and if they can be made more flexible, e.g. by introducing a programmable ratio, this will also be of advantage.

Process bus can be used also with conventional instrument transformers, as the merging units can be made to interface either with new technology or conventional equipment.

5.3.4 Reliability

5.3.4.1 Mal-operation Risk Reduction, Reliability Improvement

Reliability in augmentation of the system or replacement of IEDs is perhaps the most profound risk reduction in substations due to the use of IEC 61850.

Wire based engineering and systems are prone to errors in engineering, fabrication, construction, installation, testing and even not-up-to-date as-built/as-operating documentation are arguably the most common causes of equipment damage, blackouts, and more seriously, personal injury or death.

Such consequential events are generally traceable back to human error in drawing new wires to the wrong terminals at the design stage, physically connecting wires to the wrong terminals, applying wrong configurations or settings, all whilst being nominally repeat instances of the original engineering. Even if a bay is to be added with identical functionality in a wire-based system, extensive testing and re-testing is carried out to detect human error in the new physical system implementation.

On the other hand, an entire existing IEC 61850 bay configuration (same substation or from bay libraries) can be copied to a new bay with only the new bay name and IP addresses changing. This configuration has already been proven by years of in service operation, thus allowing reduced commissioning time whilst avoiding all these opportunities for human error.

Furthermore, there are many and significant risks to equipment and life associated with CTs and VTs and their associated wiring to the IEDs. Current transformers have been known to explode with shards of 10cm porcelain thrown some 300 metres away and/or cause fire balls engulfing neighbouring equipment causing cascading primary plant explosion.

The implementation of Process Bus (that part of the LAN to which primary plant interface IEDs are connected) eliminates the thousands of wires and terminations for the cabling to the secondary system IEDs.

The risk of a CT circuit being inadvertently open circuited by any means, including links left loose/open or rodent attack, is completely eliminated from the point of connecting the CT/VT sensor to a Merging Unit with IEC 61850 9-2 Sampled Value messages to the IEDs. Moreover, if the wire-wound CT/VT is replaced by Low Power instrument Transformer sensors (LPIT previously referred to as non-conventional instrument transformers NCIT), these offer far greater dynamic range and linearity avoiding issues of ankle point, saturation and transients, thus potentially improving the overall protection system performance and hence reliability for correct detection of faults.

Process Bus is generally agreed to have been the slowest element of IEC 61850 to be adopted and implemented by the industry. However it should be noted that issues such transmitting CT/CVT samples over communication links and synchronisation of multiple IEDs sampling CT and VT waveforms has long been achieved with systems such as 1-pulse-per-second over co-axial cable since numerical low impedance bus bar protection became available with remote I/O IEDs in the late 1980's. Optical CT/VT technology is also well proven with the first installations in substations as early as 1984. Optical CTs have also been in extensive use for revenue metering on Independent Power Producers where the dynamic range of measurement from importing to exporting of power is orders of magnitude beyond the capabilities of wire-wound CT.

5.3.4.2 Full System In-Service Operational Monitoring and Restoration

Reliability is partially an outcome of high availability systems. Availability is the ratio of system "up-time" to the total time in service and is given by the formula:

$$\text{Availability} = \frac{\text{Mean Time Between Failures}}{\text{Mean Time Between Failures + Mean Time To Restore}}$$

Consequently not only is Availability (reliability) improved by designing out potential failure modes and procuring appropriate IEDs, but also by designing-in mechanisms that will facilitate faster restoration times. This includes failure detection, easier replacement without re-engineering and being able to reliably re-commission with the minimum essential testing.

Whilst some aspects of hardwired systems may be monitored by functions such as trip circuit supervision, not all aspect scan be monitored such as the wiring between bays and IEDs. Most breakages of the wiring between IEDs (often due to links being left open) may exist for many months until the next routine testing of that function and circuit, or worse, only realised as the cause of the next inadvertent trip or blackout.

The reliability of IEC 61850 systems is immediately far superior due to the ability of the communication system to be continuously monitored with alarms given immediately when any problems occur.

Furthermore, the same entire IED configuration as was in operation immediately prior the failure can be loaded into replacement IEDs. This dramatically reduces requirements and time for extensive testing of correct connections and configuration, even if the replacement IED is of a different type but providing the same functionality.

In the ultimate 'best practice' solutions, it is even possible to create systems that can fully restore systems to service remotely when an IED fails. This is particularly possible with the use of both IEC 61850 8-1 and 9-2 messages. CIGRE Working Group B5.51 focus is on "Requirements and Use of Remotely Accessed Information for SAS Maintenance and Operation".

Part 8-1 effectively eliminates all the wire based signalling between IEDs and 9-2 eliminates the need for wire based CT and VT connections. Since the IED, and its peers, are now solely relying on the communication network for all functionality, the failure of an IED could be expected to be catastrophic.

However the presence of a spare IED already connected to the LAN and functionally tested, perhaps even operating in a standby mode, would allow the technicians to remotely access the substation, disable the faulty IED, load the same configuration into the spare and re-establish the system operation all within a matter of minutes compared to several hours of call out response and undertaking extensive re-wiring, re-testing etc. This scenario is shown in

Figure **5-1** as the system when it fails and subsequently being restored by reconfiguring the spare IED in "5-minutes" as shown in Figure 5-2.

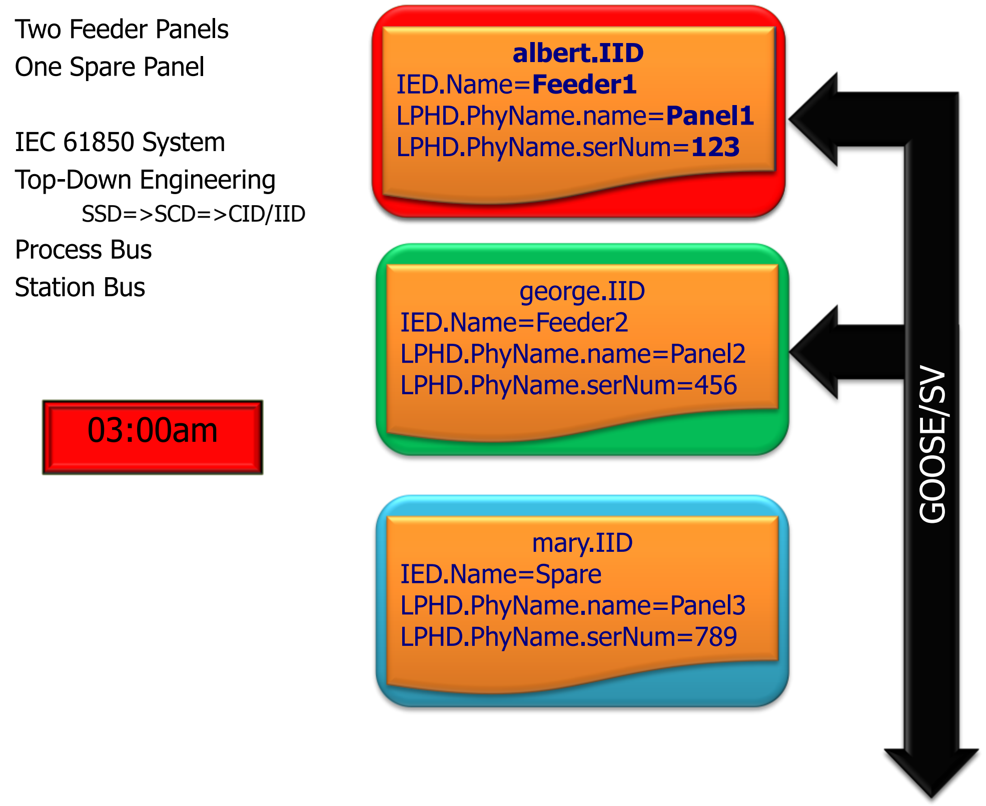

Figure 5-1: Failed System "3:00am"

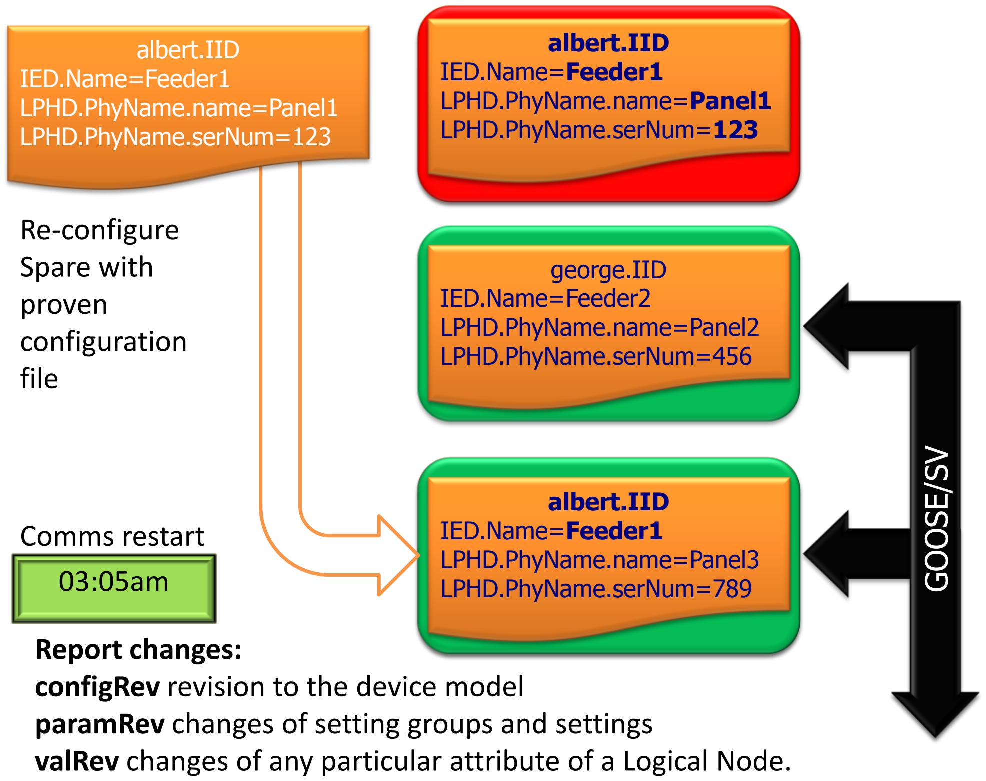

Figure 5-2: Restored System "3:05 am"

5.4 Other advantages of IEC 61850 compared with other standards

IEC 61850 is a standard which covers the communications at all the three levels of equipment in a substation, namely at Station Level, Bay Level and Process Level. Other communication protocols such as DNP3, Modbus, etc. cover the communications at only one or two of these three levels because most standards were developed for specific purposes.

The advantages of IEC 61850 compared to these protocols are:

a) IEC 61850 specifies high speed communication based on GOOSE message (time critical data) and use of report by exception rather than polling as used in master-slave serial communication protocols. For this it uses publisher / subscriber and client / server mechanisms respectively.

b) The Ethernet topology also allows having more than one client which eases the implementation of redundancy in comparison with master/slave architecture.

c) In case of failure of one client or server, the IEC 61850 communication between the other clients and servers is not affected which is not the case of conventional master-slave communication architecture.

d) The use of multicasting (i.e. one device sending a message simultaneously to several devices inside one logical LAN-segment) improves the performance of time-critical messages (GOOSE messages). It reduces network message traffic and communication time by eliminating the need to repeat messages to each individual device sequentially.

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

f) Any changes in communication technology in the future will cause minimum changes in the abstract models and services and may only require mapping to a new profile.

g) In IEC 61850, the data model is clearly defined and is also easy to extend without losing the interoperability.

h) The IEC 61850 defines a series of data names and associated rules for extension (Logical Nodes and their attributes) that avoid the interpretation between the different projects actors and facilitate the integration of the different components of the system as well as the integration of the system with its environment (primary devices, remote control).

i) Unlike legacy protocols such as Modbus, IEC 61850 devices can self-describe themselves to client applications without any manual configuration of the data objects. Self-description facilitates automatic configuration.

j) Unlike legacy protocols, IEC 61850 specifies a standard configuration language based on XML and using the Logical Nodes described above. This allows formally exchanging configuration data between system tools and avoids the manual association of data references between tools.

k) Time sync methodologies such as SNTP are a key component of IEC 61850. SNTP time synchronization accuracy in the range of 1 ms is sufficient for event reporting but not for process bus. Development of an IEEE 1588 profile is on-going and will allow time sync over Ethernet in future IEC 61850 based substation, ensuring a time synchronization accuracy better than 1 microsecond.

l) The transmission rate of 100 Mbit/s allows fast data transfer, for example faster disturbance recorder extraction than serial protocol can do.

m) IEC 61850 uniquely provides data with a quality attribute and a time stamp which improves the reliability of information as such as validity (good, invalid, reserved, questionable) and test (to support commissioning – see chapter 10).

n) In conventional substation automation systems, data concentrators and protocol gateways are required between different IED's, HMI and RTU. With IEC 61850 and substation LAN, all data is transmitted in one standard format and such data concentrators and protocol gateways are only needed for SCADA communication links.

o) IEC 61850 provides a standardized reporting capability that will be invaluable in the development of automated analysis and diagnostic tools.

For more information, you can refer to WG B5.11 (TB 326), WG B5.12 (TB 466) and WG B5.18 (TB 329).

6 GENERAL RECOMMENDATIONS

6.1 Obstacles on IEC 61850 Implementation and Incentives

Since the release of the new IEC 61850 standard in 2004, many utilities consider the implementation of IEC 61850 station bus to replace the existing hardwired protection and control schemes as for example CB failure initiation/trip, bus blocking scheme, A/R scheme, load shedding, automatic restoration, control interlocking, etc.

However the main obstacles and barriers for the acceptance of IEC 61850 and its wide spread implementation / application could be summarized as follows:

a) Needs for more skilled personnel,

b) Needs of new tools to support IEC 61850 implementation for engineering, testing and maintenance,

c) Lifetime of additional electronic components, for example switches, merging unit, etc.,

d) Doubts in GOOSE signal reliability and security,

e) Some substation IEDs are still using legacy protocols which can represent a significant investment,

f) Lack of a standard method for presenting GOOSE messages in AC/DC schematics,

g) Different implementation of IEC 6150 services by vendors,

Despite of the obstacles, many incentives are also mentioned as follows:

a) Brings new possibilities of information sharing and exchanging between devices and applications in the substation,

b) The wide range of services and detailed models can make it acceptable as a world-wide communication standard in power system application,

c) Monitoring of the GOOSE messages (copper wired signals are not!) and LAN devices,

d) Easier to design, maintain and expand with the right tools …,

e) Less wiring, bay standardization, overall cost reduction during lifetime of the substation (engineering, installation, maintenance)

f) Live testing can be made without outage,

g) Improve self-monitoring of the complete substation automation IEDs and system,

h) Improve the substation safety by replacing analogue circuits with communication links,

i) Maintenance simplified due to interoperability and hopefully one day, interchangeability! The aim of the IEC 61850 is not interchangeability.

6.2 Contingency Requirements for Network Communication and Processing

A networked communications system can be leveraged to support rather sophisticated capabilities, such as the ability of a system to continue operation in spite of failures.

When implementing a protection scheme based on IEC 61850, it is important to check what happens when any system component, for example IEDs, merging unit, a switch or a fibre fail:

a) Is a contingency mode of operation feasible, whereby the scheme operation can continue, even with acceptable degradation? What would this require in terms of programming and wiring?

b) If any system component fails, what are the consequences?

  - ❖ Are too many critical resources associated with the same IED?
  - ❖ Is distributing them among several IED the right approach?
  - ❖ Can critical functionality be replicated in two IEDs, so that it is still available if one of the IEDs fails?

This would require that IEDs and their applications be able to tell when other system components fail (for example, through interlocks, watchdog monitoring, etc.) and that they be able to subscribe to messaging from non-failed devices with the same capabilities when redundancy exists. Otherwise the system needs to adapt its behaviour due to the fact that there is a missing message. In some cases, where the criticality is not such an issue, no contingency requirement will be defined.

6.3 Procedure for Specifying IEC 61850 based Protection Schemes

Implementation of any IEC 61850 function can be made easier or harder by virtue of the particular IED capabilities. It is essential that asset owners develop specifications which don't merely ask for "all IEDs shall be IEC 61850 compliant" – detailed consideration of the application requirements are fundamental and critical. This goes beyond just identifying key Logical Nodes, but also Logical Devices, Data Objects and Attributes essential for the system to be realised easily and of course 'in-service' operation, maintenance, test, replacement augmentation and enhancement activities.

6.3.1 Specification of a System AS a System

Special attention should be given to the specification and implementation of the whole scheme with respect to future changes when IEDs or functions are added, replaced or removed:

a) Is the solution using appropriate and correct IEC 61850 data modelling and communications?

b) What changes can/can't be made without reconfiguration of all the existing IEDs?

c) Does changing any part of the system require testing of the other parts of the system?

d) How complex is the logic to be realized in the different IEDs? What is the reusability / scalability transferability of the logic for future designs or other vendors' IEDs?

e) What is the impact on the communication in terms of network load?

f) How can the scheme be debugged in case of problems (message analysis)?

g) What is the impact of replacement of a device without a fully identical data model and communications support?

h) Is the solution 'vendor independent'?

i) Does the solution suffer any implementation restrictions (mappings, naming conventions, optional elements etc.)?

6.3.2 Individual Scheme/ Function Specification

The general procedures for specifying IEC 61850 protection schemes, particularly considering operational and maintenance requirements as well as future system modification (Reusable Engineering), consist of the following steps:

a) Determine functional requirements based on:
   - ❖ the layout of the substation from an electrical point of view,
   - ❖ the identification of the types of equipment,
   - ❖ the identification of the protection and control philosophy,
   - ❖ the performance requirements,
   - ❖ the identification of what data is available or necessary,
   - ❖ the consideration of protection schemes – identify what events will cause what actions by what equipment,
   - ❖ the determination of information flow requirements – identify what information is required from each substation device and what information should be sent to each substation device,
   - ❖ the determination of information security requirements and the contingency operation.
   - ❖ the Logical Device hierarchy and operation control modes,
   - ❖ the required/available 'isolation' / operation mode control mechanisms and facilities,
   - ❖ the required/available testing mechanisms and facilities to connect PCs and equipment,
   - ❖ the acceptance or otherwise of requirements for GGIO mapping.

b) Users will determine which logical nodes and data are needed for which applications.

c) Check availability of required IEC 61850 logical nodes and data in the approved devices.

d) Develop IEC 61850 data exchanges within the substation. The data to be exchanged between devices and applications in the substation must be defined:
   - ❖ GOOSE based messages,
   - ❖ Samples Analogue Value messages,
   - ❖ Client / Server messages.

These steps define explicitly what IEC 61850 data items are sent, where, and under what conditions within the substation. Therefore, it is important to ensure that the actual data exchanges are clearly defined:

a) the maximum transfer times,

b) the maximum response times,

c) the maximum size of messages,

d) security,

e) availability,

f) backup and/or redundancy,

g) other performance criteria.

Logical dataflow needs to be analysed carefully in order to avoid a bottleneck on the Ethernet network and IED itself. The use of managed switches and VLAN is essential to reduce the traffic on the LAN when necessary.

6.3.3 Failure Mode Specification

Defining and engineering contingency mechanisms and process for abnormal conditions (Failure Mode and Effects Analysis) is also essential use cases such as:

a) Some devices are not installed/operational (future bays, bays out of service for maintenance etc.),

b) Communication system has failed (no messages, storming etc.),

c) When an IED is out of service or fails,

d) How reliable is the solution? Is a graceful degradation possible?

Special attention to redundancy and self-healing mechanisms should be taken into account with the communication system when used to exchange critical messages between IEDs.

6.3.4 Engineering Process Specification

Essential to all this is the tool requirements and compatibility for the complete engineering process recognising that there are other pre-post and mid process interfaces between the IEC 618509 SCL methodology. “Top-Down” engineering (ICD=>SSD=>SCD=>CID) offers many benefits in its own right for ‘reusable engineering’ but may not be fully supported by all vendors tools.

6.3.5 Documentation Systems and Format Specification

Finally the entire system should be specified with a view of what documentation mechanisms and formats are available throughout the entire engineering and operational life cycle of the system. CIGRE WG B5.39 is currently working on what such requirements may be, but it is clearly a complex issue. Certainly selection of tools that provide automation of documentation output and inclusion of other self-documentation aids in the engineering files can be a significant benefit to the project and the asset owner and maintainer.

6.3.6 Scheme Augmentation Considerations

The design of any IEC 61850 scheme inherently involves the configuration of IEDs for the sending and receiving of messages.

The messages to be **sent** from a particular IED are clearly relative to the functionality performed by the IED. An IED providing a protection function will naturally be required to send GOOSE messages relative to the protection operations and Reports to SCADA on the detail of those operations etc.

If there is an augmentation of the substation to add an extra bay,,, the configuration of the new IED for the bay as far as sending messages simply “copy and paste” of the instance from another bay. This is **Reliable & Reusable Engineering** since the configuration of the new IED, as far as sending messages is concerned, is using the same configuration that is reliably operating in the existing bays. This applies to the outward server communications in client/server as well as for GOOSE and Sampled Value mechanisms in publisher/subscriber.

This leaves the process of commissioning having the only requirement to prove the IED is actually communicating correctly to the network – the functionality of sending certain messages does not need, in principle, to be fully re-proven – so called “5-minute engineering and commissioning”.

On the other hand the configuration of IEDs to receive messages needs careful consideration at the design phase of how the scheme operates and what is involved when the scheme is augmented for example with an extra bay.

The client/server communications are relatively straight forward since the client (e.g. substation HMI or Control Centre Master Station) will send certain commands to the bays based on their bay number. The bay IED will respond accordingly.

In the case of publisher subscriber GOOSE and Sampled Values, the IEDs in one bay may well be dependant for correct performance on certain messages from other bays. The configuration of this requires the receiving IED to subscribe to certain GOOSE messages identified by the GOiD contained in the message. The GoID provides identification of the sending IED and the particular DataSet that it contains.

It is therefore evident if the function in the receiving IED needs to receive a certain GOOSE from each of the other bays it has to subscribe to multiple GOOSE messages. If an extra bay is added, an extra message must be added to the list of subscribed GOOSE in the existing IEDs.

Since the subscription to messages is included in the IED instance in the SCL files, that existing IED configuration must be updated and loaded to the IED. Since this is a complete reload of the IED configuration normal practice for security and reliability requires re-testing to verify the configuration has been loaded correctly without corruption to the functionality or performance of the IED.

Consequently it is possible with some scheme designs involving signals in each bay being received by IEDs in each of the other bays will need extensive reconfiguration of the existing IEDs and associated full scheme re-testing when a new bay is added. This can be a time consuming task given the complexity of multi-function IEDs, not to forget the potential implications on redundancy provisions and/or system outage requirements for safety.

This can be a significant issue over the 50 year life of the substation due to the different organisations and staff that may be involved. It is highly likely that the original Systems Integrator may not be the same organisation, department or staff responsible for the future augmentation projects.

However it is also feasible in some instances to derive slightly different implementation solutions and configurations that obviate such wide spread IED reconfiguration and retesting for otherwise straight forward augmentations.

Note 1: The readers could also refer to the Working Group B5.18 (TB 329).

Note 2: The recommendations regarding network design have been covered by IEC 61850-90-4.

6.4 The Problem of Logic

IEC 61850 is specifically for the engineering process to configure IEDS to communicate interoperability. IEC 61850 specifically does not standardise algorithms e.g. as may be used by one vendor for their PDIS function versus another vendor's different algorithm. However the parameterisation and settings associated with both PDIS elements as well as the inputs to and outputs of the PDIS that must be communicated over the system are standardised semantics to facilitate then Reusable Engineering process.

One of the 'associated' configurations of a protection scheme is the scheme logic. Currently IEC 61850 does not provide Logical Nodes as logic elements such as

a) AND gate,

b) OR gate,

c) Inverter gate,

d) Time delay,

e) Set/Reset latch,

f) Etc.

These logic elements have been considered as ‘local issues’ not specifically needing to be communicated over the LAN and hence not within the IEC 61850 area of interest of configuration of the communicating elements. Logic is therefore to be handled by the vendor’s proprietary IED Configuration Tool outside of the IEC 61850 environment. IEC TC57 WG10 is currently reviewing aspects for potential inclusion of some form of logic within the IEC 61850 area. In some cases there may be outputs of the logic elements that need to be communicated to IEC 61850 Logical Nodes and/or the signals from one logic element to another can be considered as a form of communication, notwithstanding that it may not appear on the LAN and only within the IED – it is nevertheless a configuration of the scheme. In the meantime, implementing any scheme using IEC 61850 must also consider the interaction of logic to the scheme operation.

The first issue is the semantics of the logic. One of the essential features of IEC 61850 in creating Reusable Engineering is the defined semantics. A PTOC.Op semantic is always known to be the operation status of the overcurrent element. However the semantics of an AND gate output status is not related to a defined function of the SAS as it is a combination of functions. This is shown in

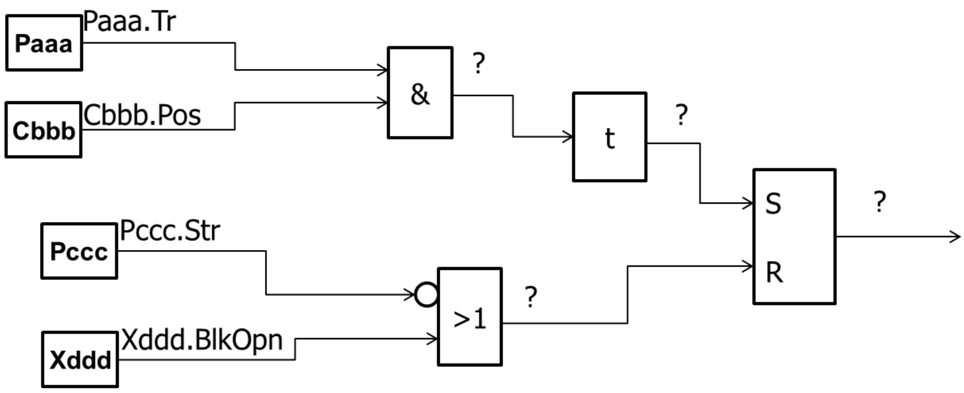

Figure 6-1: Semantics of Logic?

The second issue that must be considered in logic systems is the mechanism to specify that logic. IEC 61131 in essence only defines the tool set for implementing a logic scheme. The format of the engineering files produced by the IEC 61131 based tool is not specifically defined by IEC 61131. Some IEC 61131 tools may well produce an XML format file but at this stage the structure and semantics of those files is entirely proprietary and hence not readily able to be integrated into a generic ‘vendor-agnostic’ SCD file where the same logic configuration could be extracted by different vendor IED Configuration Tools for use in different IEDs.

Whilst the objective of IEC 61850 is specifically not interchangeability (Part 1, Chapter 4), as far as the overall engineering process is concerned, logic is an area where the configuration of the logic elements can yield considerable benefits in IED engineering effort. There are some moves to integrate IEC 61449 as a more universal function block to assist in more ’universal’ definition of the logic

Therefore in any scheme engineering process, consideration must be given to the effort and the reusability of any logic requirements.

6.5 Logical Device Grouping/Hierarchy

Fundamental to any protection scheme is the ability to easily control its behaviour at the level of individual functions. IEC 61850 now has the ability to specify a Logical Device hierarchy (also referred to as nesting or grouping) using the GrRef Data Object. If LD hierarchy is not implemented, it may be necessary to use multiple controls instead of a group control that encompasses several ‘child’ Logical Devices and associated Logical Nodes.

The scheme implementation, and indeed the IED selection to suit system and design and operational requirements, must give consideration of the requirement and ability to define specific Logical Device hierarchy arrangements.

As an example it may be useful to be able to ‘switch off’ all the measurement functions which report to SCADA and disturbance recorder functions whilst undertaking commissioning or routine maintenance on the IED itself or other IEDs in the system.

The Protection Logical Device itself may have several sub-devices refer two examples in such as differential protection versus Breaker Fail protection. Whilst the transformer differential protection is being tested with the transformer on line the mode of the differential Logical Device needs to be set so as not to cause the XCBR trip. On the other hand, it is required to maintain normal operation of other internal protection functions e.g. PTUF under frequency or PTUV under voltage, and/or the IED must respond to breaker fail operation GOOSE from other the downstream feeders. An example of grouping of LD as hierarchy is shown in Figure 6-2 and Figure 6-3.

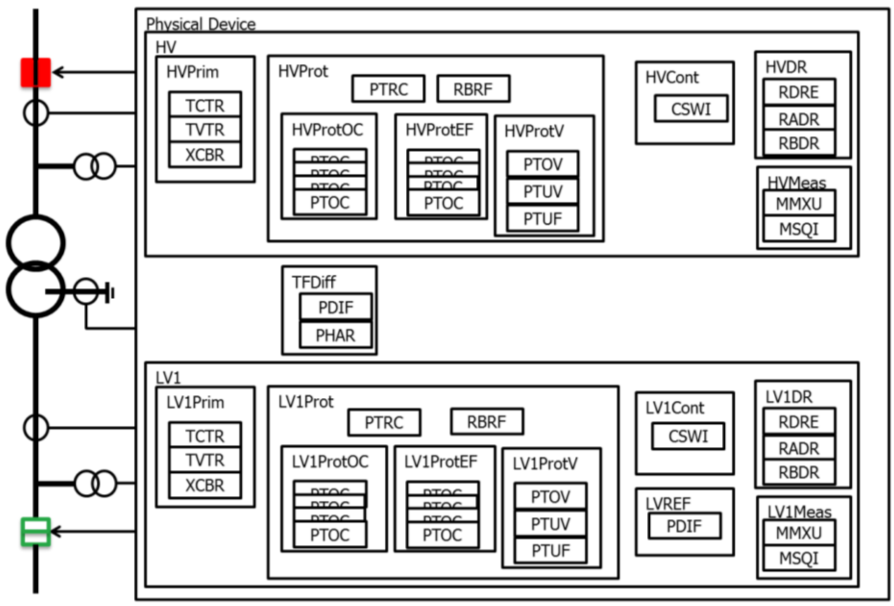

Figure 6-2: Example LD Nesting: T/F IED

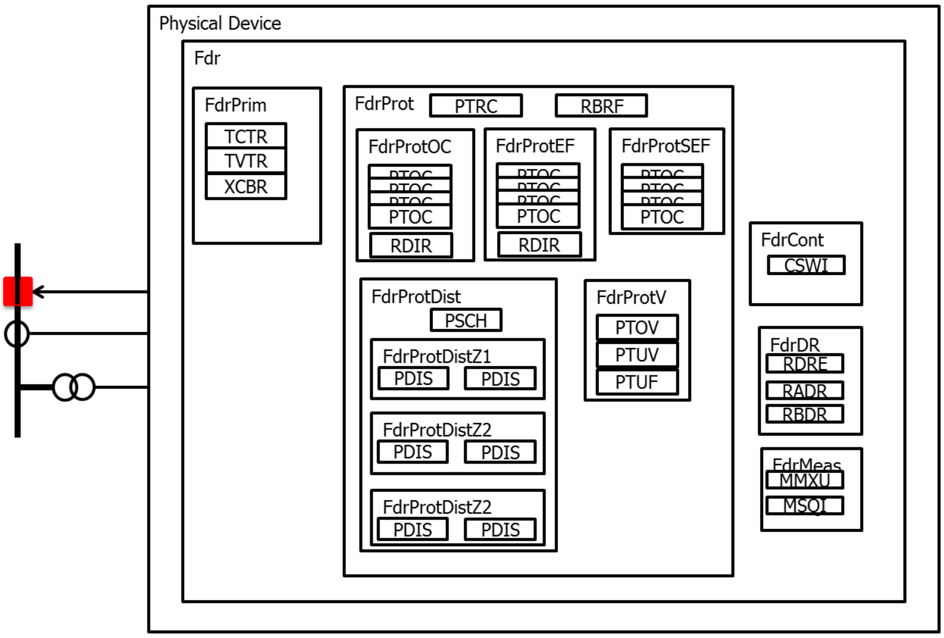

Figure 6-3: Example LD Nesting: Line Distance and Overcurrent IED

6.6 Instance Modelling

In considering any application it is ultimately necessary to identify the full data model requirements for the system. It is not sufficient to assume that as an "intelligent electronic device" that all required pieces of information are provided by any conformant IED. This extends to the requirements for the number of instances of a Logical Node and the required Data Objects and Attributes required for each instance. If these are not specified at the IED procurement stage, they will not necessarily be available in the chosen IEDs.

IEC 61850 7-4 Ed2 Clause 5.11.1 provides specific guidance on how complex functions such as multiple stages must be modelled. Examples of this are shown in Figure 6-4 for multistage overcurrent/earth fault IED and Figure 6-5 for a 3-zone ph-ph and ph-g distance IED.

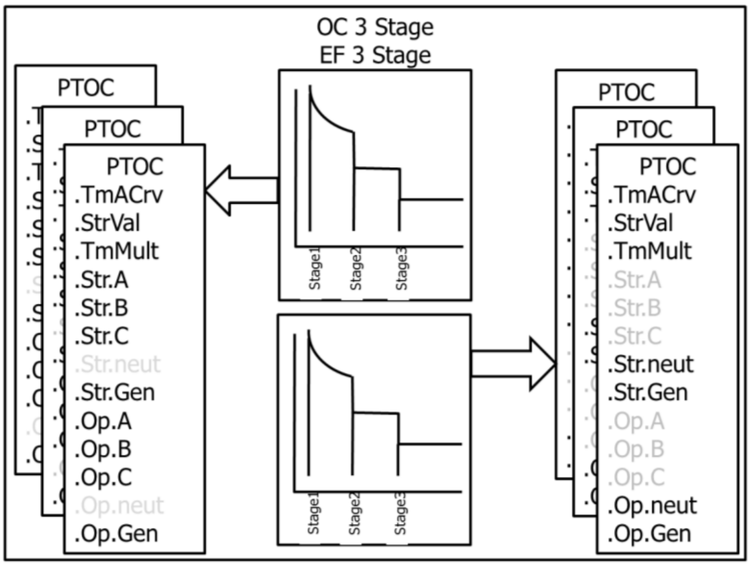

Figure 6-4: Logical Node, Data Objects and Attributes Instance Modelling – O/C–E/F IED

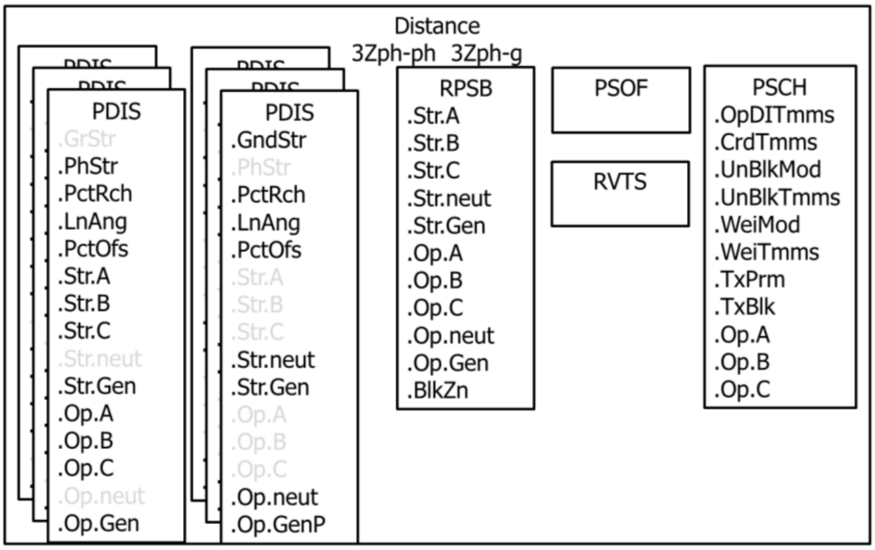

Figure 6-5: Logical Node, Data Objects and Attributes Instance Modelling – Distance IED

6.7 Optimising DataSets: PTRC

Multifunction IEDs will have numerous protection functions with multiple Logical Node instances as discussed above. In order to minimise the number of GOOSE messages being published and subscribed, the PTRC Logical Node provides a common output of the IED which 'follows' the source protection function Logical Nodes Pxxx. This is in effect the same mechanism in non-IEC 61850 IEDs using a common output contact for multiple functions.

The PTRC is structured effectively as a multi-dimensional OR gate as shown in Figure 6-6.

Each of the ".Str" inputs to the PTRC will result in replication of any operated status as PTRC1.St = 1. This is therefore any "any protection started" signal from the IED.

Similarly each of the ".Op" inputs to the PTRC will result in replication of a combined PTRC1.Op = 1. This is therefore any "any protection operated" signal from the IED.

In addition the PTRC provides an additional "treated" output as a PTRC.Tr = 1 which is maintained from the same start time as the PTRC1.Op for a specified duration defined as PTRC.TrPlsTmms.

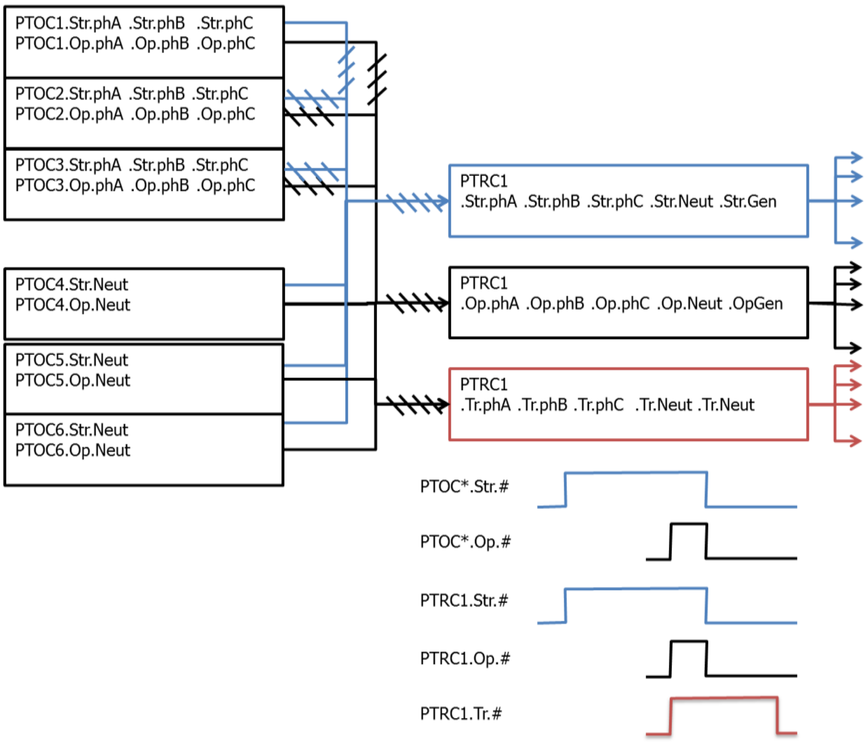

Figure 6-6: Optimised GOOSE – Use of PTRC

7 IMPLEMENTATION OF EXISTING HARDWIRED PROTECTION SCHEMES INTO IEC 61850-8-1 STATION BUS

7.1 Introduction

Until now substation protection and control have been mostly based on hardwired signals. They are used for protection and control functions at bay and substation levels to share information resulting in a large amount of wires and cables.

Wiring and cabling at substation is an expensive and cumbersome engineering practice. The cost of copper wire, ducts, cable-trays, routing cares and counter-measures to avoid electromagnetic interference, challenged substation engineers for a long time, mainly in the early stages of digital protection and control. The protection relays are historically hardwired for interfaces for analogue and digital input and outputs. These interfaces are also hardwired with other components of the protection scheme, i.e., auxiliary relays, remote terminal units, etc.

Figure 7-1 represents a traditional protection scheme used in wired-base substation designs.

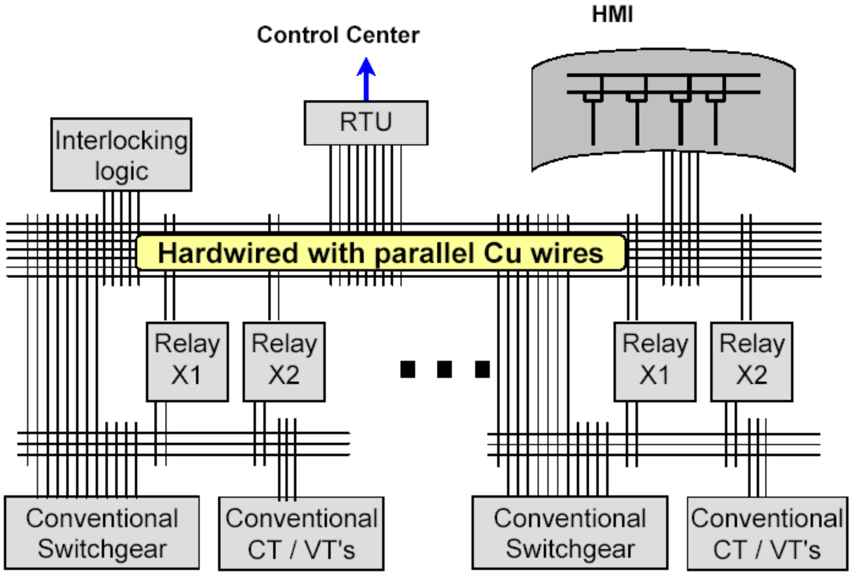

Figure 7-1: Traditional Protection Scheme for wire-based Substations

In the following sections a number of existing hardwired protection schemes are described and then methods are proposed for how their functionality could be implemented using IEC 61850. These examples were identified from the results of the survey (see appendix) conducted by the WG.

Note:
In the following examples, an “operated” signal is used to represent the operation of the protection element. In many non IEC 61850 compliant protection devices, the operation of a protection element maybe called a “trip of this protection element”.

The “operated” signal is normally mapped to a relay contact to trip the circuit breaker or initiate any other actions, for example breaker failure initiation, Auto Reclose initiation, etc.

It is fundamental to recognise that GOOSE is a message which contains a Data Set with a number of individual elements representing the status of an IEC 61850 Logical Node Data Object and any associated attributes e.g. if a function has operated, its “.Op” DO will be true and represented in the DataSet as a value of 1, otherwise it would be 0. GOOSE is therefore NOT a command to trip or do anything in particular. Indeed the status change from 0 to 1, or change from 1 to 0 are equally valid as causing some action in various subscribing functions.

Devices and functions which subscribe to the GOOSE and extract particular element status are configured / programmed to do certain subsequent actions based on these status inputs. For example one LN and DO may be a PTOC.Op indicating a particular protection function(s) has operated – i.e. a fault condition has been detected according to the algorithm and characteristic with the settings as defined in the LN Setting Data Objects causing PTOC.Op to change from False to True (0 to 1).

This PTRC.Op may be included in one (or more) Data Sets and subsequently the GOOSE message which is subscribed to by several different IEDs and functions. These functions may act in significantly different ways based on the same status change of 0 to 1 such as:

a) Open a CB,
b) Close a fault Thrower,
c) Start autoreclose cycle,
d) Start Disturbance Recorder,
e) Start CB Fail element,
f) Register the event in the SOE log,
g) Flash the protection trip LED,
h) Turn on the yard lights,
i) Sound the alarm siren,
j) etc.

The discussions in the following sections describe the GOOSE Dataset content and associated publishers and subscribers necessary for the overall functionality required.

7.2 Transmission Bus Protection: Directional Comparison Scheme

7.2.1 <u>Introduction</u>

Faults on power system busbars pose very high risks of equipment damage and danger to personnel if left un-cleared. Busbar differential protection is the most representative example of a complex hardwiring scheme. Presently most applied busbar protections (low, medium and high impedance schemes) need to acquire current data from all bays (feeders, transformers, bus-couplers, etc.) connected to the protected busbar and to initiate a tripping of all circuit breakers connected to the faulty bus section in order to selectively clear an internal fault. In case of complex bus arrangement, due to circuit switches operational conditions, it should also be necessary to acquire the position status of disconnect switches and circuit breakers to identify the faulted busbar section or faulty breaker (breaker fail protection). Different IEC 61850 migration approaches can be undertaken depending of the bus bar scheme topologies (distributed or centralized bus protection).

There is no direct benefit to migrate a High Impedance bus differential protection to IEC 61850 due to the type of protection scheme (dedicated CTs, principle, etc.) and hardwired information connected (current signals, trip command). For a distributed low impedance differential protection, the hardwired signals between the line protection and the bay unit such as breaker failure could be replaced by using the station bus. The implementation of the process bus standardizes the communication used between the bay units (e.g. Merging Unit) and the central unit rather than the previous proprietary protocols used by each vendor. Future applications are described in chapter 8.

Directional comparison busbar protection scheme can be used to clear transmission busbar faults and be achieved by simple interconnection of overcurrent or distance relays with directional elements which are already specified for their primary task of feeder protection.

The advantages offered by such a busbar directional comparison scheme are:

a) Faster busbar fault clearance compared to tripping initiated by upstream feeder protection for distribution systems.

b) Busbar protection at minimal additional cost - the blocking scheme uses overcurrent/directional elements already provided in the feeder protection relays.

c) Backup busbar protection for sub-transmission systems.

d) Fault and disturbance records stored for busbar faults, allowing fault analysis.

e) Blocking schemes can be easily modified to suit substation extension.

For transmission substations, the directional comparison scheme can be used as backup protection in complement with an existing high or low impedance bus relay.

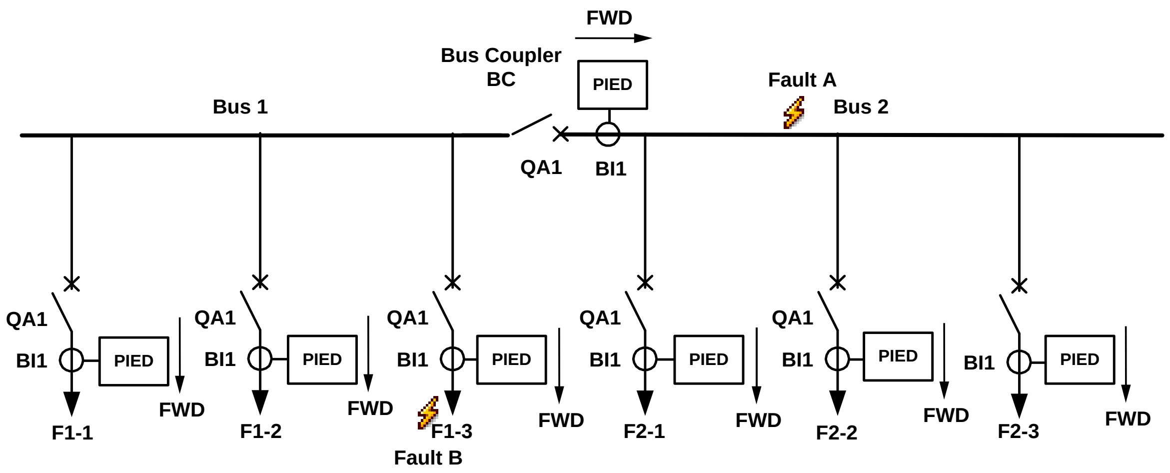

Figure 7-2: Busbar Directional Comparison Scheme

Figure 7-2 shows a typical transmission substation layout with two busses. The bus Coupler breaker is designated "BC"; and the feeders F1-1, F1-2, F1-3, F2-1, F2-2 and F2-3.

Figure 7-3 shows the different symbol used in the Technical Brochure.

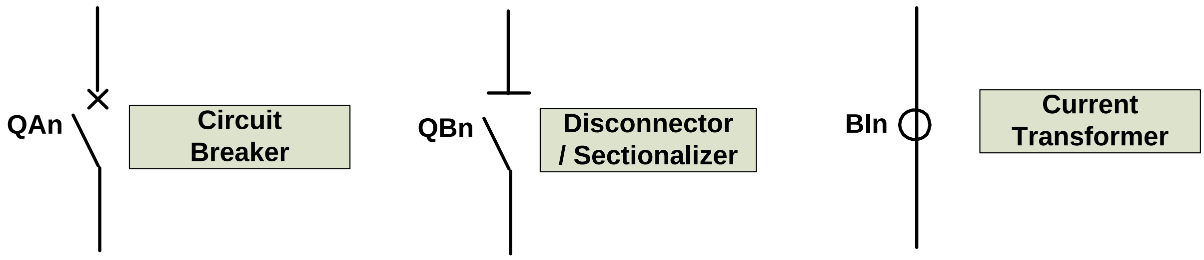

Figure 7-3: Definition of Symbols used

Note that the following conventions have been observed:

a) The Comparison Scheme will provide two distinct bus sections, Zone 1 for the left hand side of the busbar (Bus 1), and Zone 2 for the right (Bus 2).

b) The forward direction for feeder relays is away from the busbar

c) The benefits of standardization can be gained by choosing the forward direction for the bus coupler relay to be for current flow from Zone 1 of the busbar into Zone 2. Typically this equates to current flow from left to right on-site.

d) The positions of the current transformers define the boundaries of each of the zones of busbar protection, so ideally all the relays are positioned on the line side of their circuit breakers. It does not matter if the bus coupler relay is on the left hand side of the circuit breaker provided that its forward direction is from bus section 1 to bus section 2, as shown in the Figure 7-2. The relays are split up into two zones, so that a fault on one side of the busbar does not cause isolation of the whole substation.

7.2.2 Description of the Signal Interactions

Each of the relays protecting the feeders or transformers, or installed on the sectionalized breakers connected to the protected bus will send a wired signal indicating the detection of a fault combined with the fault direction determined by the relay (RDIR).

In case of a fault on any of the protected elements (e.g. Fault B), one or more PIEDs (overcurrent or distance relay) will detect a fault in the forward direction (e.g. F1-3) and the rest will see a reverse fault or no fault (e.g. F1-1, F1-2, BC, and if the bus coupler (BC) is closed, F2-1, F2-2 and F2-3) indicating to the Bus Protection Function that this an external fault to the distributed bus protection.

If the fault is on the bus (e.g. Fault A), all PIEDs will see a reverse fault or no fault (if no source connected to the feeder), i.e. no IED will see a forward fault except the IED installed in the bus coupler (BC) if closed.

The decision whether the fault is external or on the bus is made based on the exchange of wired signals between the different PIEDs participating in this directional comparison scheme.

7.2.3 Use of IEC GOOSE Message

As shown in the Figure 7-4, all the IEC 61850 based PIEDs (protective IED) are connected to the station bus. The Bus Protection Function based on the Directional Comparison Scheme can be integrated either in a standalone IED or in any single PIED.

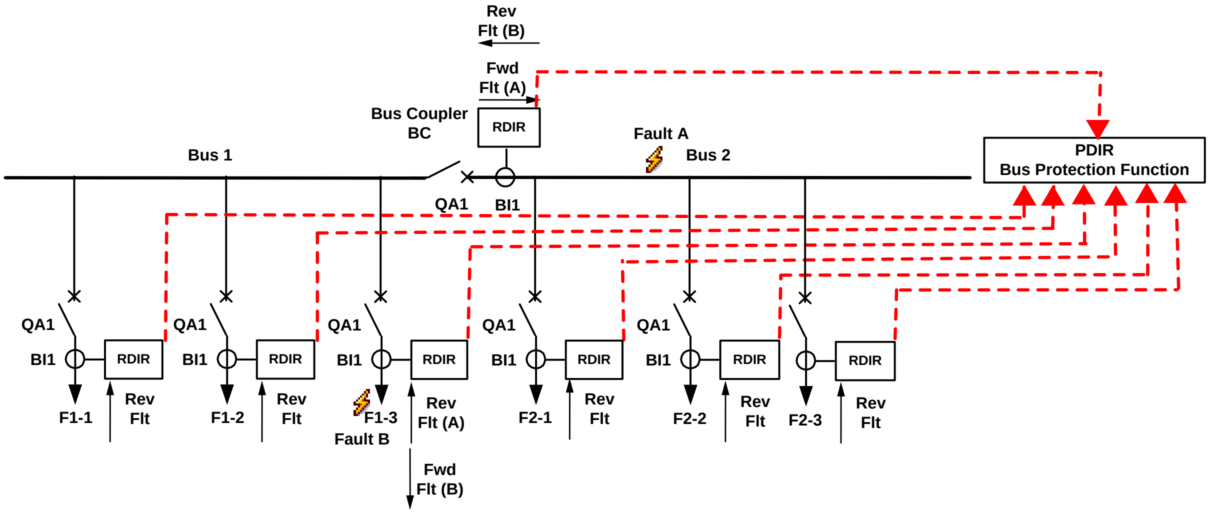

Figure 7-4: Busbar directional comparison scheme based on IEC 61850

As described in the previous section, the decision whether the fault is external or on the bus is made based on the exchange of communication messages between the different PIEDs participating in this directional comparison scheme. The requirements for high-speed operation determine the need for peer-to-peer communications. The proposed architecture is shown in Figure 7-5.

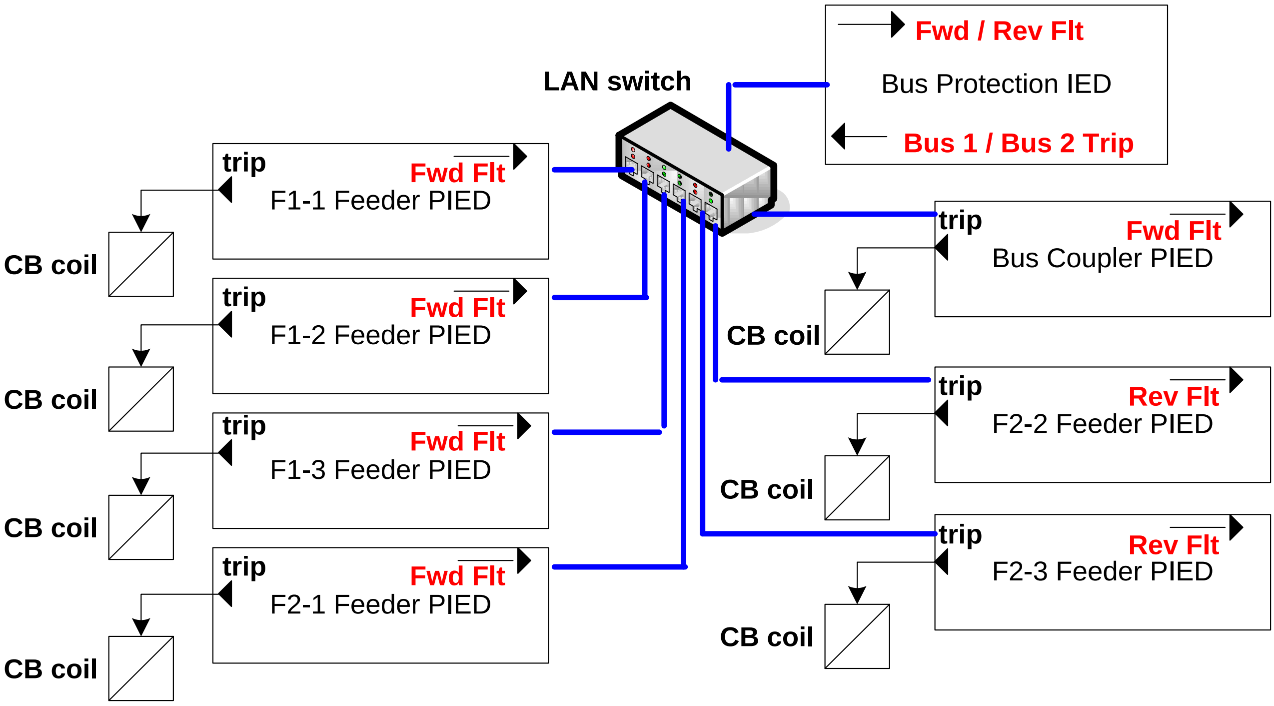

Figure 7-5: Ethernet Architecture for Busbar directional comparison scheme

Note that the blue solid lines as shown in the Figure 7-5 represent the station bus communication network with GOOSE messaging.

The

Figure **7-6** and Figure 7-7 show the programmable scheme logics which need to be downloaded into the Bay Controller and Protection IEDs.

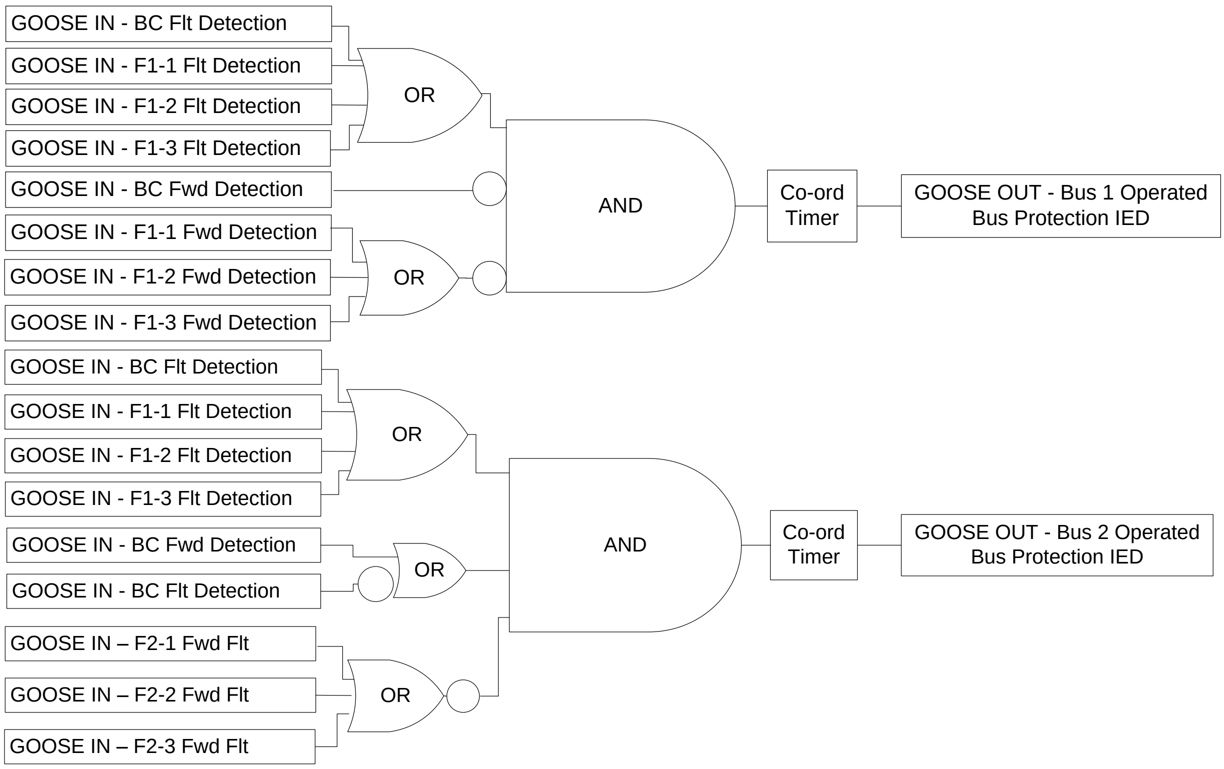

Figure 7-6: Directional Comparison Scheme Logic implemented into the Bay Controller IED

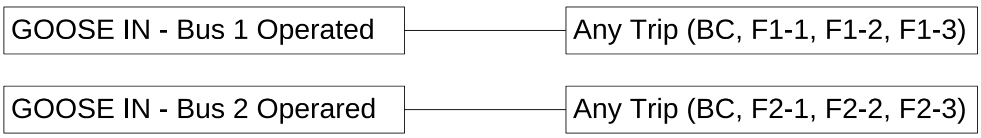

Figure 7-7: Directional Comparison Scheme Logic implemented into each protection PIED

Note 1:
The Fault Detection Signal could be issued by the start of any appropriated protection Logical Node, for example a phase / ground overcurrent.

The Bus Protection IED for example a Bay Controller has to be programmed to subscribe to GOOSE messages from all PIEDs with directional detection elements connected to the protected bus. GOOSE messages are used to replace hard wired control signal exchange between PIED's for interlocking and protection purposes.

In the following example, PTOC element is used for fault detection. Some other protection elements such as PTUV, PDIS, etc. can be used for fault detection as well or combined together.

The publishing IEDs must provide the following PD/LN.DO.Attributes in the GOOSE message Datasets:

IED Name	IED internal signal description	Source IED name/Published GOOSE Data Object
Feeder F1-1 PIED	Forward detection Fault Detection	Fdr1-1/RDIR.Dir (forward) Fdr1-1/PTOC.Str (True)
Feeder F1-2 PIED	Fwd Detection Flt Detection	Fdr1-2/RDIR.Dir (forward) Fdr1-2/PTOC.Str (True)
Feeder F1-3 PIED	Fwd Detection Flt Detection	Fdr1-3/RDIR.Dir (forward) Fdr1-3/PTOC.Str (True)
Feeder F2-1 PIED	Fwd Detection Flt Detection	Fdr2-1/RDIR.Dir (forward) Fdr2-1/PTOC.Str (True)
Feeder F2-2 PIED	Fwd Detection Flt Detection	Fdr2-2/RDIR.Dir (forward) Fdr2-2/PTOC.Str (True)
Feeder F2-3 PIED	Fwd Detection Flt Detection	Fdr2-3/RDIR.Dir (forward) Fdr2-3/PTOC.Str (True)
Bus Coupler BC	Fwd Detection Flt Detection	BusBS/RDIR.Dir (forward) BusBS/PTOC.Str (True)
Bus Protection IED	Bus 1 operated Bus 2 operated	BusPro1/PTRC.Tr. (True or False) BusPro2/PRTC.Tr (True or False)

Table 7-1: Publisher GOOSE Table for Busbar directional comparison scheme

Note 2: Abbreviation
BusPro: Logical Device Bus Protection,
Fdr: Logical Device Feeder Protection,
Str: Start
Tr: Trip,
Dir: Directional

The subscribing IEDs must have the following PD/LN.DO.Attributes available from the subscribed GOOSE message Datasets:

IED Name	Source IED name /Subscribed GOOSE Data Object	Subscribed IED signal description	Function using the subscribed signal(s)
Bus Protection BusPro	FdrX.X/RDIR.Dir (forward) FdrX.X/PTOC.Str (True) from F1-1, F1-2, F1-3, F2-1, F2-2, F2-3, BS	Directional detection Fault Detection	Directional Comparison Scheme (PDIR)
Feeder F1-1 Fdr1-1	BusPro1/PTRC.Tr. (True)	Bus 1 operated	Feeder Tripping (PTRC)
Feeder F1-2 Fdr1-2	BusPro1/PTRC.Tr. (True)	Bus 1 operated	Feeder Tripping (PTRC)
Feeder F1-3 Fdr1-3	BusPro1/PTRC.Tr. (True)	Bus 1 operated	Feeder Tripping (PTRC)
Feeder F2-1 Fdr2-1	BusPro2/PTRC.Tr. (True)	Bus 2 operated	Feeder Tripping (PTRC)
Feeder F2-2 Fdr2-2	BusPro2/PTRC.Tr. (True)	Bus 2 operated	Feeder Tripping (PTRC)
Feeder F2-3 Fdr2-3	BusPro2/PTRC.Tr. (True)	Bus 2 operated	Feeder Tripping (PTRC)
Bus Coupler BS BusBS	BusPro1/PTRC.Tr. (True) BusPro2/PTRC.Tr. (True)	Bus 1 operated Bus 2 operated	Bus Coupler Tripping (PTRC)

Table 7-2: Subscriber GOOSE Table for Busbar directional comparison scheme

In case of a fault, the distributed bus protection function in the bay controller IED monitors the GOOSE messages coming from the individual relays included in the distributed bus protection function of the system. If all messages indicate reverse or no-fault condition and none gives a forward fault direction, the bus protection function identifies a bus fault and sends a GOOSE message to trip all breakers connected to the faulty bus (Bus 1 or Bus 2).

A small time delay is required in order to ensure that all relays have had sufficient time to detect the fault and determine the direction of the fault. All relays protecting primary equipment connected to the bus act in this application as the sending IEDs, while the bay controller is the receiving IED.

The benefit of the peer-to-peer communications based distributed bus protection is that it provides fast fault clearance for bus faults without the need for any additional protection equipment (if the function is implemented in a bay controller IED). It replaces a high or low-impedance bus protection device and in some cases may eliminate the need for addition or replacement of current transformers.

Note 3:
In cases when the clearing time is critical especially for transmission substations, it is recommended to use differential protection scheme for busbar protection in order to ensure secure and fast trip time. However, if the proposed scheme is found reliable enough and the required trip time met the scheme operating time, the logical scheme described above can be implemented in each individual IED to reduce the fault clearing time. Each IED will have to subscribe to the messages from all other IEDs. The drawbacks are increased complexity and, in case of expansion, that all IEDs have to be modified to reflect the change.

Note 4:
In case of loss of one device, the above directional blocking scheme might not operate correctly. To improve the reliability of the scheme in case of a critical location, you may need to subscribe to redundant messages. In such a case, a loss of one device should not affect

the performance of the scheme. The presence of GOOSE messages and the status of the individual IEDs should be monitored and considered into the proposed scheme to ensure a contingency plan in case of system component failure. The behaviour of invalid or test mode messages should be determined for each protection function (inhibit, ignore, trip).

Note 5:
Prior implementing such a busbar protection scheme, the user has to check the GOOSE subscription capabilities in each IED. The number of Feeders is limited by the number of subscription IEDs performing the bus bar protection function is able to handle.

Note 6:
Such a busbar protection scheme could be used for sub-transmission substations where the use of a standalone centralized or distributed busbar protection system may not preferred due to its costs. The performance of the scheme should define the maximum operating time as well as the required reliability.

For Transmission substations, where tripping performance is mandatory (lower than 1 cycle), a standalone differential bus protection is preferred.

7.2.4 Direction selection

Nominally the choice which is the forward or reverse direction simply means a distinction of which ".Str" the subscribing IED needs to use.

However this choice can be optimised to provide for identical configuration of the IEDs as shown in the following schemes:

Figure 7-8 Shows that if the directional elements are chosen to be Forward pointing away from the associated CB, the feeder IEDs have to be alternatively configured as subscribing to the FWD ".Str" signals or the REV ".Str" signals. This can lead to additional effort in the instantiation process and with two different GOOSE subscription possibilities and may lead to considerable re-configuration of all feeders if an extra bay is added in between two existing bays.

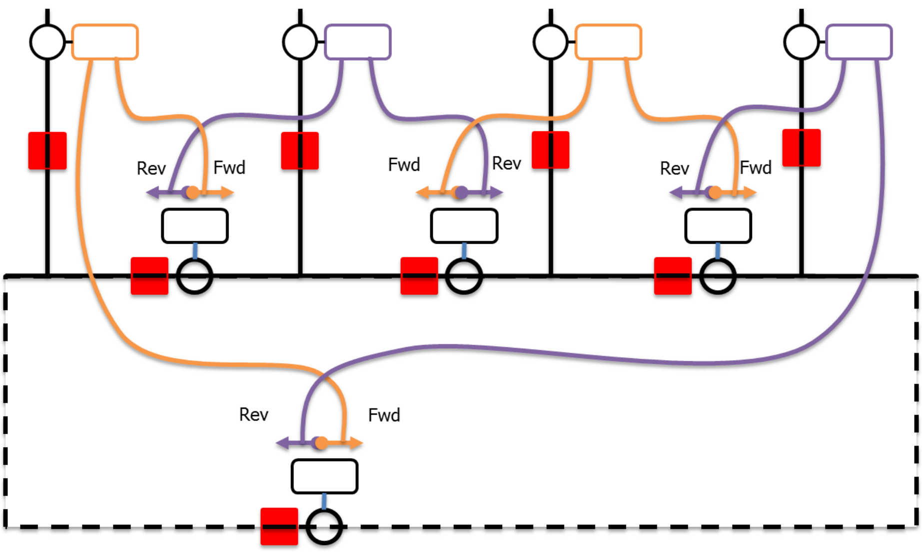

Figure 7-8: Direction away from CB: Alternating Feeder IED Subscription

Figure 7-9 however shows that if the direction is consistently chosen as to the left or right, the subscribing IEDs will all have consistent subscription requirements for one FWD ".Str" and one REV ".Str" thereby saving confusion and potential difficulty when inserting an extra bay.

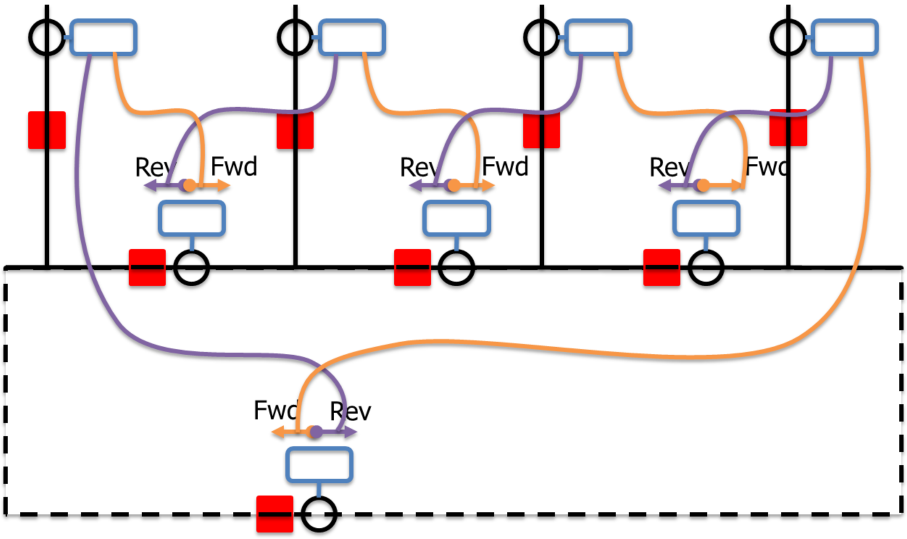

Figure 7-9: Alternating Direction: Consistent IED Subscription

7.3 Transmission Line Protection: Intertrip scheme

7.3.1 <u>Introduction</u>

The benefits of GOOSE messages as demonstrated in the substation environment makes them also attractive for communications between substations.

Even at this stage GOOSE is defined as a multicast message within the substation, extension of the substation LAN allows its use between substations. A good use for such applications is for high-speed unit protection. For distance applications the requirement is for improving the unit protection performance, by allowing the relay to connect directly to the signalling channel available between line ends, rather than using conventional binary inputs and output contacts to signal via other intermediate equipment. However, communications devices are still widely used.

High-speed fault clearing for different faults on transmission lines can be achieved by advanced communications based protection schemes. Direct relay-to-relay communications allow significant reduction in the overall cost of accelerated transmission line protection schemes. At the same time, they reduce the total operating time of the protection for any fault within the zone of protection. With the use of IEC 61850 high-speed peer-to-peer GOOSE messages to replace proprietary communications or the hard wiring between the different devices used in such distributed protection scheme, it is also possible to improve the availability and reliability of the transmission line protection system.

The readers can also refer to the IEC 61850-90-1 reports.

7.3.2 <u>Description of the Signal Interactions</u>

Communications based schemes allow considerable improvement in the overall fault clearing time for any fault within the zone of protection. These teleprotection schemes can be grouped into three main operation modes. In each mode, the decision to send a command is made by a local protective relay operation and can be the result of operation of different protection elements.

a) In **Intertripping**, (direct or transfer tripping) applications, the command is not supervised at the receiving end by any protection relay and simply causes a breaker trip operation. Since no checking of the received signal by another protection device is performed, it is absolutely essential that any noise on the signalling channel isn't seen as being a valid signal. In other words, an intertripping channel must be very secure. The use of 32 bit CRC for GOOSE messages ensures a very high level of error checking that is not supported by any of the proprietary communication protocols used by relay manufacturers today for substation to substation communications.

b) In **Permissive** applications, tripping is only permitted when the command coincides with a protection operation at the receiving end. Since this applies a second, independent check before tripping, the signalling channel for permissive schemes does not have to be as secure as for Intertripping channels.

c) In **Blocking** applications, tripping is only permitted when no signal is received, but a protection operation has occurred. In other words, when a command is transmitted, the receiving end device is blocked from operating even if a protection operation occurs. Since the signal is used to prevent tripping, it is clear that a signal is received whenever possible and as quickly as possible. In other words, a blocking channel must be fast and dependable.

The protection function that sends the permissive or blocking signal to the remote end determines the type of scheme used. If this is a distance element, we usually talk about Permissive Under-reaching or Over-reaching schemes, or Blocking schemes. A directional element can also be used to initiate the transmission of a signal to the remote end of the protected line.

One thing that is important to understand is that the GOOSE messages sent between substations are in reality not Intertripping, Permissive and Blocking signals as GOOSE messages are not command signals.

In order to perform an Intertripping scheme the device publishing the GOOSE message will send the message for example when the Breaker Failure function operates (RBRF) and requires the tripping of a breaker at the remote end of the line with the failed breaker in order to clear the fault. The device that performs the tripping has to subscribe to the GOOSE message indicating the Breaker Failure operation (PSCH) and trip the breaker (PTRC) it controls when it receives it.

For a Permissive Overreaching Scheme the sending device will include in the GOOSE message information about the start of the Zone 2 distance element (PDIS2). The receiving IED needs to subscribe to this message and perform the Permissive Overreaching Scheme logic (PSCH) in order to trip the local breaker (PTRC).

For a Permissive Under-reaching Scheme the sending device will include in the GOOSE message information about the start of the Zone 1 distance element (PDIS1). The receiving IED needs to subscribe to this message and perform the Permissive Under-reaching Scheme logic (PSCH) in order to trip the local breaker (PTRC).

The channel for a directional comparison Permissive scheme is keyed by operation of the forward looking elements of the relay. If the remote relay has also detected a forward fault upon receipt of this signal, the relay will operate. Such schemes offer some significant advantages, especially when high-speed directional detection methods based on superimposed current and voltage components are used.

In Blocking Schemes, the sending relay will include in the GOOSE message information about the operation about the start of a reverse looking distance element. The receiving IED needs to subscribe to this message and perform the Blocking Scheme logic in order to trip the local breaker.

In the case of a Directional Comparison Blocking scheme the signalling channel is keyed from the operation of the directional element that detects reverse faults. The receiving IED needs to subscribe to this message and perform the Blocking Scheme logic in order to trip the local breaker.

7.3.3 Implementation of Accelerated Schemes

The implementation of accelerated transmission line protection schemes depends on the requirements of the application, the available communications channel and the substation communications protocol.

7.3.3.1 Conventional Implementation using an External Communication Device

Electromechanical, solid state and early microprocessor based relays used intermediate equipment to transmit the intertripping, permissive or blocking signal to the relay at a remote end of the protected line. To achieve that at the sending end an output contact of the protection relay is wired to an input of the teleprotection IED. An output of the teleprotection IED receiving the signal in the remote substation is wired to an input of the relay receiving the accelerating signal used by the transmission line protection scheme. This conventional implementation of accelerated scheme is shown in Figure 7-108.

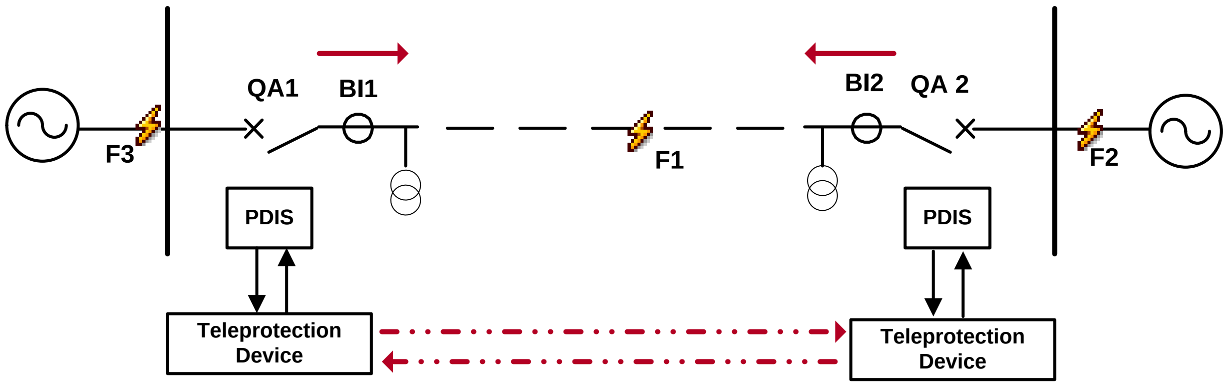

Figure 7-10: Conventional implementation of accelerated scheme

7.3.3.2 Conventional Implementation Using Direct Relay-to-Relay Communication

The availability of serial communications interface in later versions of microprocessor based transmission line protection relays allowed the implementation of accelerated schemes without the use of intermediate teleprotection IEDs. The exchange of permissive or blocking signal in this case is using a proprietary communications protocol between the relays at the ends of the protected transmission line. This implementation has advantages over the conventional one described above due to improvements in performance and reliability by eliminating the hardwired interface between the relays and teleprotection IEDs at the sending and receiving ends of the distributed application.

An accelerated scheme implementation using direct serial communications between the relays at both ends of the protected transmission line is shown in Figure 7-11.

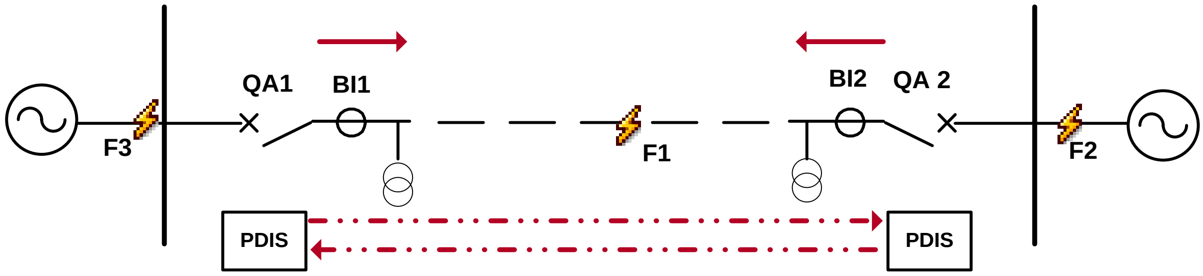

Figure 7-11: Accelerated scheme using serial communications

7.3.4 Use of IEC GOOSE Message

If power line carrier signalling equipment is available for communications between the substations, the system will logically be similar to the one shown in Figure 7-10 but the hard wiring between the relay outputs of the protection IEDs and the inputs of the teleprotection IED are replaced with the virtual connects using GOOSE messages. Several GOOSE messages will be required depending on the selected scheme as described below.

If we consider as an example the permissive directional comparison scheme and if the implementation of the monitoring of the status of the breaker is in a dedicated breaker control IED, the following GOOSE messages will have to be used:

a) Change of breaker status should be published by the breaker control IED to indicate to the protection IED if it should use the Echo logic in the accelerated protection scheme.

b) Receiving of a Permissive signal from the remote end should be published by the teleprotection IED. The protection IED uses this message to make a decision if the fault is within the zone of protection.

c) Change of state of the directional element should be published by the transmission line protection IED to indicate to the teleprotection IED to send over the communication link (for example a power line carrier) the permissive signal to the remote end.

d) Directional comparison scheme operation should be published by the transmission line protection IED to indicate to the breaker control IED that it should trip the breaker.

In case of implementation of the breaker control and monitoring function within the transmission line protection IED (which is the typical case at this stage of use of IEC 61850) the number of required GOOSE messages is limited to the following:

a) Receiving of a Permissive signal from the remote end should be published by the teleprotection IED. The transmission line protection IED uses this message to make a decision if the fault is within the zone of protection.

b) Change of state of the directional element should be published by the transmission line protection IED to indicate to the teleprotection IED to send over the communication link (for example a power line carrier) the permissive signal to the remote end.

Figure 7-12 shows this case of implementation of the permissive directional comparison scheme. RDIR is the logical node representing the directional element in each relay.

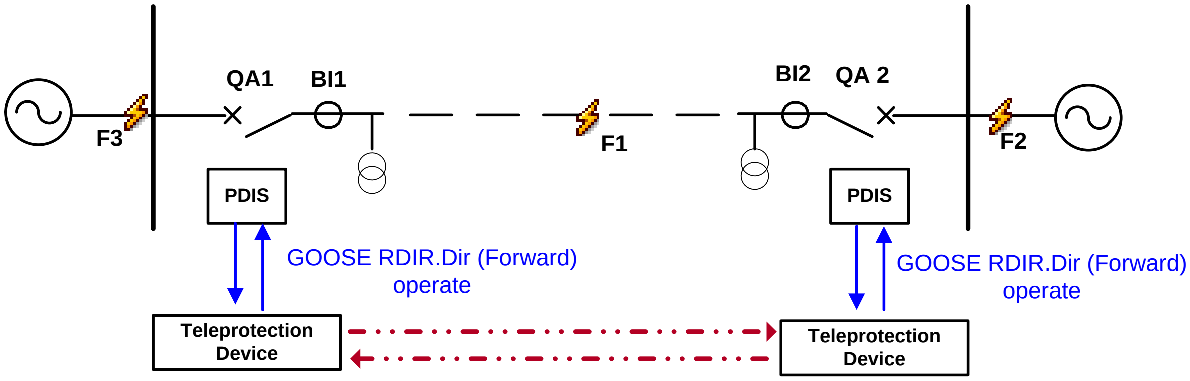

Figure 7-12: Accelerated scheme using GOOSE messages between substation IEDs

The implementation of the directional comparison blocking scheme requires a little different set of GOOSE messages:

a) Receiving of a Blocking signal from the remote end should be published by the teleprotection IED. The transmission line protection IED uses this message to make a decision if the fault is within or outside the zone of protection.

b) Change of the state of the power line carrier channel will be published by the teleprotection IED. The transmission line protection IED uses this signal to avoid mal-operation in the case of power line carrier failure.

c) Change of state of the directional element should be published by the transmission line protection IED to indicate to the teleprotection IED to send over the power line carrier the blocking signal to the remote end.

d) Directional comparison scheme operation should be published by the transmission line protection IED to indicate to the breaker control IED that it should trip the breaker.

Like many other cases protection engineers sometimes push the technology beyond its intended application. The availability of fibre optic cables or SONET rings with Ethernet allows the use of GOOSE messages for direct exchange of directional information between the protection IEDs implementing the accelerated scheme. In this case permissive schemes become the preferred choice due to the fact that they do not have to wait to receive a blocking signal from the remote end, while there is no concern that the permissive signal is not going to get through a faulted phase.

This implementation is achieved by actually extending the substation LAN to the remote substation. Since substation-to-substation communications have been considered out of scope of IEC 61850 and there are no specific security features available, it is important to analyse the potential threats to such implementation. Using VLAN to improve security and proper processing of the data available in the GOOSE messages received by the subscribing protection relays make it very difficult for an intruder to cause an operation of the directional comparison or any other accelerated scheme. The fact that there is also local supervision and detection of a fault condition required for the scheme to operate further reduces the chance for success of an intruder.

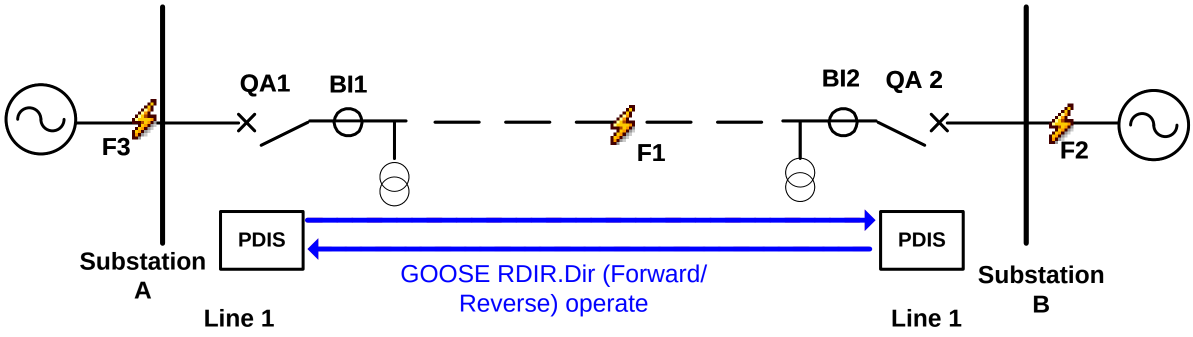

Figure 7-13: Direct GOOSE exchange for Acceleration scheme

Figure 7-13 shows the accelerated scheme implementation using direct exchange of GOOSE messages between the two protection devices. To simplify the diagrams the Ethernet switches are not shown.

The tripping of the breaker again can be achieved directly by the relay when the accelerated scheme operates, or by publishing a GOOSE message that will be received by the breaker control IED which will trip the breaker(s).

One of the advantages of this implementation is that in the case of primary and backup protection schemes both devices at the receiving end can be accelerated, thus improving the reliability of the scheme when one of the sending devices fails.

7.3.5 Hybrid Intertripping

The discussion so far has assumed that both ends of the line use IEC 61850 based protections. The scope of any project and a particular substation inevitably has to consider the impact and any upgrade requirements of the protection system at the other end.

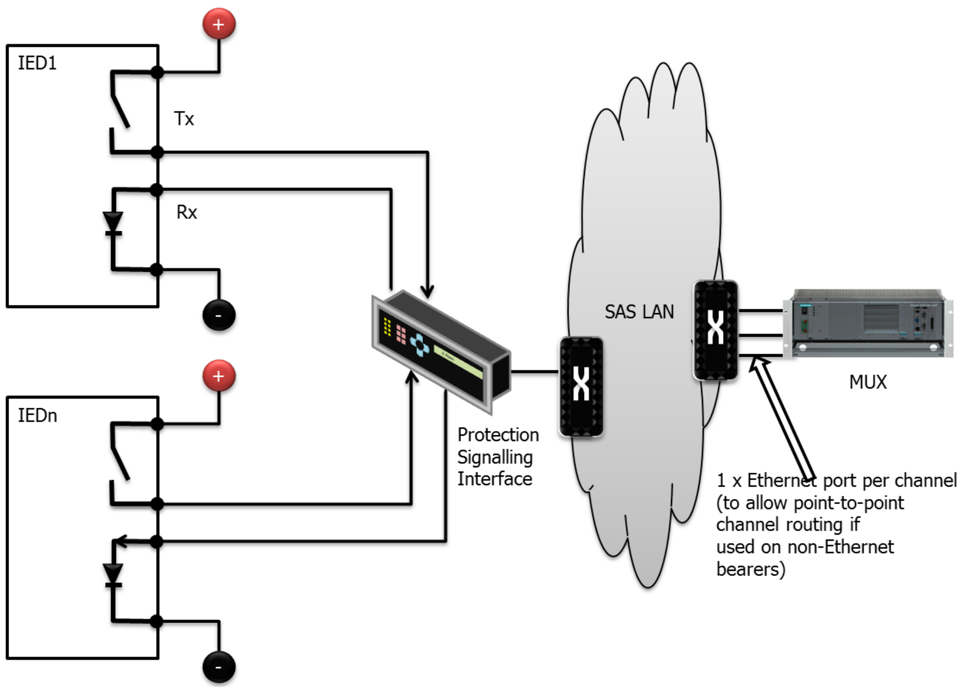

Figure 7-14: Protection Signalling Interface

In order to ensure that GOOSE based signalling between the substation scan be engineered coherently whether the far end is IEC 61850 based devices or not, it is necessary to provide a suitable interface unit at the far end capable of converting between the hard wired intertripping signalling of the far end with the GOOSE messages between the subs. This is easily facilitated using a generic IEC 61850 IED with wire based I/O as shown in Figure 7-14.

Note that the requirements for the MUX in regards to the type of interface cards. At first glance, it would seem that the MUX need only provide one Ethernet port to connect to the LAN. However utility private wide area communications systems are generally organised, at least as far as ‘non-Ethernet’ networks, as point-to-point channel routing. This is a special requirement often needed to support the fundamental requirement to avoid common modes of failure where the two duplicate protection schemes must not operate over the same bearer to maintain independent redundancy. Even though the MUX may be dedicated to one particular telecommunications bearer to the next telecommunications repeater, it is necessary for the telecommunication system configuration engineer to be able to identify not just the immediate bearer selection, but also the entire end-to-end bearer selection to the ultimate destination.

At this stage, there is no configuration mechanism to identify a particular GOOSE message to be routed over a particular path in the SCL engineering process using instantiation of the MUX ICD in the SCD which would then facilitate the use of a single Ethernet port for the MUX.

In the meantime, it is likely the MUX must have multiple Ethernet ports each associated with one particular message and path engineering control. This may need upgrading or replacement of the MUX.

7.4 Transmission Line Protection: Breaker Failure Protection (RBRF)

7.4.1 Introduction

Following inception of a fault one or more main protection devices will operate and issue a trip output to the circuit breaker(s) associated with the faulted circuit. Operation of the circuit breaker is essential to isolate the fault and to prevent damage / further damage to the power system. For transmission/sub-transmission systems, slow fault clearance can also threaten system stability. It is therefore common practice to install circuit breaker failure protection, which monitors that the circuit breaker has opened within a reasonable time. If the fault current has not been interrupted following a set time delay from circuit breaker trip initiation, breaker failure protection (BF) will operate.

BF operation can be used to trip adjacent circuit breakers to ensure that the fault is isolated correctly.

Note: it is not appropriate that BF is initiated for manual opening (tripping) of the CB as the response to a failure to open must be assessed by the Operators rather than causing immediate wider CB tripping. It is also possible that there may be no load current in the breaker at the time which would therefore not give rise to BF operation depending on the particular BF mode (current, time, current & time).

7.4.2 Description of the Signal Interactions

In the following example, an external BF protection device is used as shown in Figure 7-152, and therefore the following signals are conventionally wired:

a) BF initiation signals between main protective relays and the external BF protection. The BF protection will be initiated by the operation of any protective elements (any trip signal).

b) BF trip signal between the external BF protection and a single zone bus relay for example. The BF trip signal will be issued by the external BF protection relay if the Circuit Breaker fails to operate in a given time.

c) Where Main 1 protection sends the trip command to the first CB trip coil and Main 2 protection to the second, the BF protection will firstly give a re-trip command to the coil that was not signalled by the Main protection.

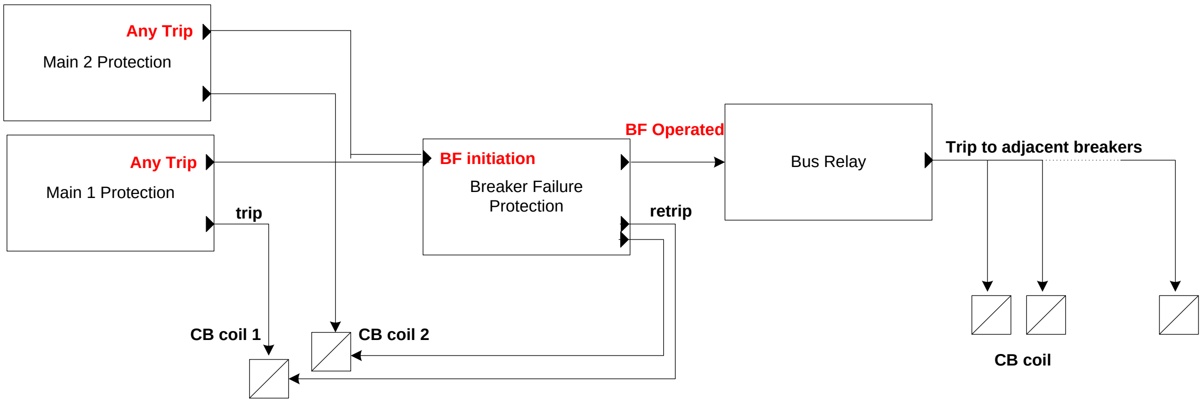

Figure 7-15: Hardwired BF Trip Logic for Breaker Failure Protection scheme

7.4.3 Use of IEC GOOSE Message

Any trip signal from both main protections and BF trip signals can be replaced by GOOSE message as shown in Figure 7-16. The tripping and re-trip signals may remain conventionally wired.

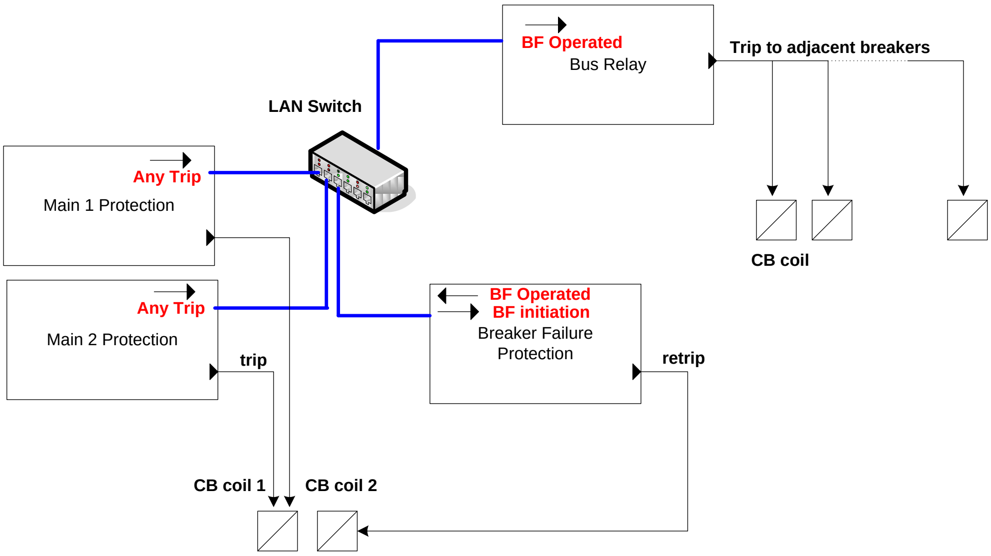

Figure 7-16: Ethernet Architecture for Breaker Failure Protection scheme

All the devices used in the IEC 61850 based breaker failure protection scheme are connected with full duplex Ethernet link to one or more switches depending on the communication topologies (dual ring, redundancy, etc.).

The publishing IEDs must provide the following PD/LN.DO.Attributes in the GOOSE message Datasets:

IED Name	IED internal signal description	Source IED Name/Published GOOSE Data Object
Main 1	Any Trip	Main1/PTRC.Tr (True)
Main 2	Any Trip	Main2/PTRC.Tr (True)
Breaker Failure Protection (BFPro)	BF operated	BFPro/RBRF.Op (True)

Table 7-3: Publisher GOOSE Table for Breaker Failure Protection scheme

The subscribing IEDs must have the following PD/LN.DO.Attributes available from the subscribed GOOSE message Datasets:

IED Name	Source IED Name/Subscribed GOOSE Data Object	Subscribed IED signal description	Function using the subscribed signal(s)
Breaker Failure Protection (BFPro)	Main1/PTRC.Tr (True).	Main 1 Any Trip	BF Protection (RBRF)
Breaker Failure Protection (BFPro)	Main2/PTRC.Tr (True)	Main 2 Any Trip	BF Protection (RBRF)
Bus Protection (BusPro)	BFPro/RBRF.Op (True)	BF operated	Bus Protection Tripping (PTRC)

Table 7-4: Subscriber GOOSE Table for Breaker Failure Protection scheme

Main 1 and Main 2 relays publish GOOSE messages containing any change of state of the LN which may initiate the Breaker Failure protection. The Breaker Failure device subscribes to the Any Trip data in GOOSE messages from Main 1 and Main 2.

As shown in Figure 7-17, these two signals are input to an OR gate mapped to the BF Initiation input of the scheme.

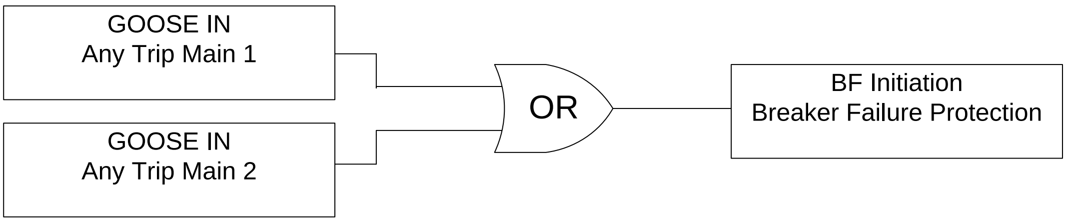

Figure 7-17: BF Trip Scheme Logic implemented in the external BF protection

The breaker failure protection publishes a GOOSE message indicating breaker failure operation. Bus protection subscribes to this message and maps it to its trip outputs to trip the adjacent breakers.

Note 1:
The BF reset signal can be generated by different criteria:

- Breaker Status (52a/52b),
- Undercurrent detector,
- Trip reset,
- Protection function reset.

In the case when the above BF reset criteria are not available in the external BF protection device, it should subscribe to the received GOOSE messages from other devices that implement the reset criteria.

Note 2:
The user has to consider in the above logic, the GOOSE message publication, transmission and subscription time response between the BF IED and the primary/backup IEDs to ensure a reliable reset of the BF function.

7.4.4 Scheme Augmentation Considerations

As discussed in Section 6.3.6, in some schemes involving the requirement of a function to receive GOOSE or Sampled Value messages from other bays, different solutions may involve extensive re-configuration and re-testing of all the IEDs in the existing system as well as any new IEDs associated with the new bay.

CB Breaker Fail is a particular case of this consideration being vitally important since changes to the IEDs may involve complete substation outage to carry out the changes as well as the augmentation itself.

7.4.4.1 BF via Bus Bar Protection IED

As shown in **Figure 7-15** it is common practice in wire-based BF schemes for any BF operation of any bay to be connected to operate the respective bus section multi-trip relay as this is already directly connected to each of the bus section CBs.

This can be directly modelled in IEC 61850 as shown Figure 7-16. Each bay RBRF.OpEx signal is published in its own GOOSE Dataset. The Bus Bar Protection IED must then subscribe to each of the bay GOOSE messages and use those as inputs to the BBP IED PTRC Logical Node to cause the bus trip. A simple 3-bay IED arrangement is shown in Figure 7-18 with the detail for Bay 1 and block format for the other bays.

The BBP IED must therefore subscribe to the information from the three existing bays as

- F1Q1RBRF1.OpEx
- F2Q1RBRF1.OpEx
- F3Q1RBRF1.OpEx

The three existing bay CB interface IEDs then subscribe to one element as:

- W1PTRC.Tr

In the case of F1Q1 failure the CB BF trip action follows the highlighted red route.

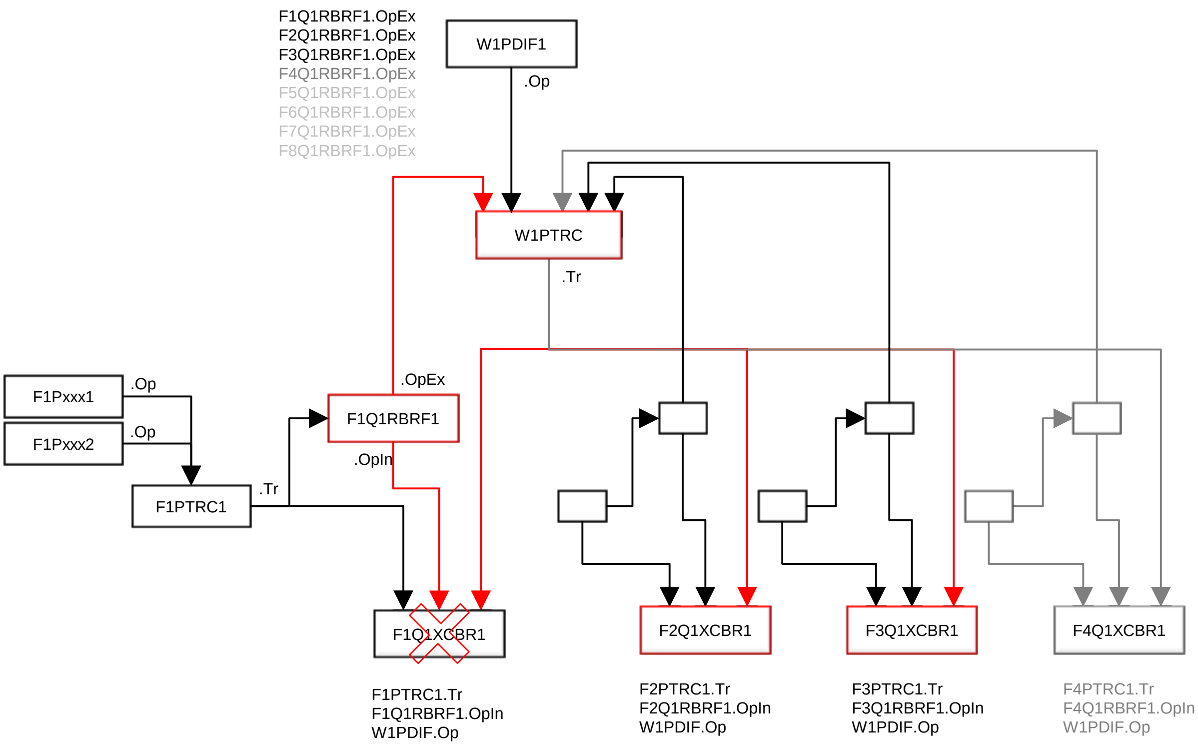

Figure 7-18: BF via Bus Bar Protection IED Augmentation Planning

If an extra bay is added to the substation, only the BBP IED must be reconfigured and retested to confirm it is subscribing to the extra GOOSE from the new bay as well as still subscribing to the existing bays and publishing its operation output PTRC.Tr. Naturally there will always be some work associated with the BBP IED for any augmentations to add an extra bay so the need for reconfiguration and re-testing of the BBP IED s not unexpected.

The existing three bays however do not need to be reconfigured since they are only subscribing to the BBP IED.

However even the requirement to re-configure the BBP IED and retest it can be obviated at the original design stage thus facilitating faster and more reliable. This achieved by pre-configuring the BBP IED with additional GOOSE subscriptions for the ultimate substation layout as shown greyed out in Figure 7-18.

Even if the substation only has a planned ultimate capacity, for example, eight bays, it is possible to configure for the ultimate configuration of the largest substation of all the utility substations perhaps 20 bays to be generous. There is basically no additional scheme configuration effort other than the number of the utilities standard bays are created. This means all systems are consistent and will remain so even if different System Integrators (company, department or staff) are involved in the augmentation works at any time during the life of the substation.

It then remains to include mechanisms to turn these bays on/off according to the bays that are installed and in service. The same mechanisms can also facilitate taking bays out of service for maintenance without disrupting the overall substation and scheme operation.

7.4.4.2 BF Direct to Other Bays

The scheme described above is a classical modelling of a wire-based scheme involving BF being routed through the bus bar protection system. This was necessary in wire-based schemes to benefit from not having to install extensive extra wiring from each bay to every other bay CB trip coils when the BBP multi-trip connections can be used by simply connecting each bay BF operation to the common multi-trip.

However even in wire based schemes this involves a certain time delay for the operation of the multi-trip relay or the subscription and publishing of GOOSE messages by the BBP IED. Where critical clearance times for network faults with CB fail contingency are relatively long, these delays may be inconsequential. However at higher voltages, these delays can give rise to severe timing limitations down to individual milliseconds.

The other consideration is in both wire-based and IEC 61850 cases, the overall BF scheme relies on the BBP IED as a central item to the scheme. If the BBP IED has failed or is out of service for any reason including failure of communication to/from the BBP IED, the entire BF scheme is inoperative and creates a significant power system risk of not only the individual CB failing but the entire BF scheme not operating locally and hence resulting in system instability and regional blackouts to clear the fault by remote overlooking protections as back up or larger zone reach and/or in a second sequence of CB fail time delay at the next larger regional CBs – e.g. all the remote connected substations.

However given the IEC 61850 LAN is in direct communication with all bays, it is possible to eliminate the intervening time delay of the BBP IED and eliminate the‘ common point of failure’ being the BBP IED and its communication connection.

The revised scheme simply involves each bay directly subscribing to the BF GOOSE messages from all other bays. These messages appear on the network regardless of which IEDs are subscribing so there is no additional network traffic.

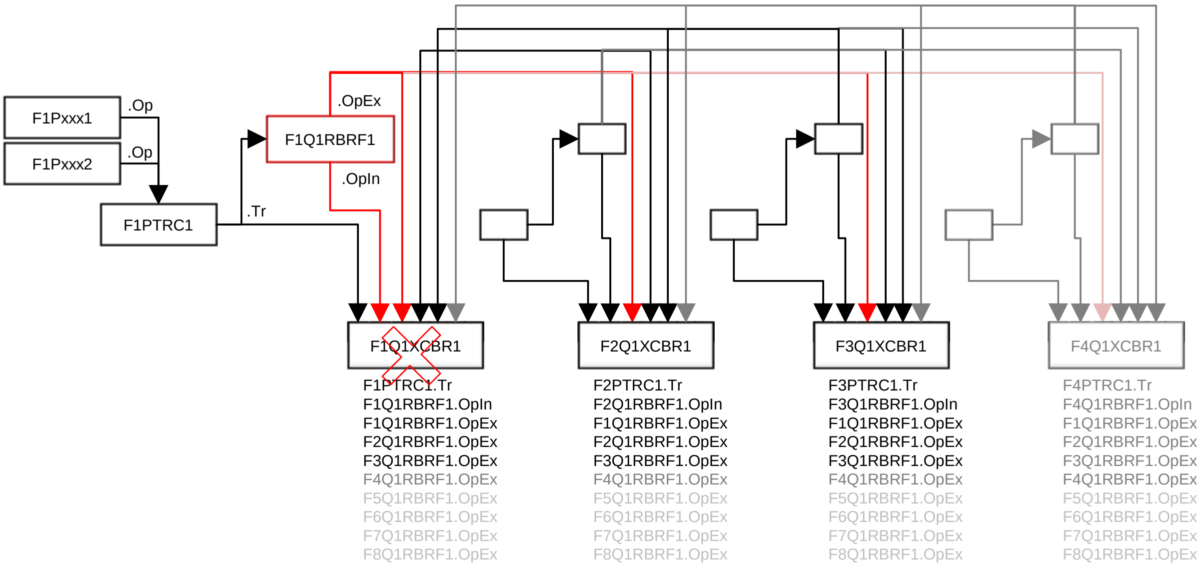

Figure 7-19: BF Direct to Other Bays - Augmentation Planning

Applying the same considerations to the use case of an additional bay, not only does the new bay need to be configured and fully tested, but also all the other bay IEDs must be reconfigured for the additional subscription to the GOOSE from the new bay. Once again, it is not unreasonable to expect work to be done on in the substation associated with the bus being out of service.

However the requirement to reconfigure and re-test all IEDs in all existing bays is similarly obviated by pre-engineering for the ultimate configuration for the substation, or the ultimate configuration of the largest substation in order to retain standardisation throughout the utility.

Scheme	Clause	Master IED	Speed	Augmentation
CBF Via BBP	7.4.4.1	Common Point of Failure/Non-operation	Additional GOOSE latency Additional IED processing	BBP to be reconfigured Can be preconfigured
CBF Direct to Other Bays	7.4.4.2	Not/Applicable	Fastest arrangement	All need to be reconfigured Can be preconfigured

Table 7-5: CBF Scheme Summary Scheme Requirements

7.5 Transmission Line Protection: Automatic reclosing (AR) for One Breaker (internal or external AR device)

7.5.1 <u>Introduction</u>

As most of the transmission line faults are of non-permanent nature, automatic reclosing (RREC) is often used for overhead lines to improve service reliability. Automatic reclosing (AR) functions are initiated by protection operation (pole tripping signals) or circuit breaker tripping. This action starts a function to reclose the breaker after a pre-programmed time, often considering some conditions, like the prevalence of synchronism conditions. AR is mainly made either using one or two shots, high speed AR (HSAR) and delayed AR (DAR). Delayed AR is normally used only in three-phase mode. High speed automatic reclosing can be made in either single-pole or three-pole mode. More sophisticated schemes are required for single-pole tripping and auto-reclosing, as fault type and faulted phase must be correctly identified and incorrect relay tripping during the open pole condition should be avoided.

In substations with double breaker, one and a half breaker and ring bus, normally one of the line breakers is selected for automatic reclosing. In general utilities apply a master - follower scheme, in which the master breaker is closed first and the follower breaker only after a successful AR of the master breaker. This leads to a much more complicated AR scheme, especially if automatic switchover of master breaker is required, e.g. when pre-defined master breaker is out of service.

Today most of line protection IED includes the auto reclosing functionality, reducing the need for separate AR devices and wiring.

7.5.2 External standalone AR device

7.5.2.1 Description of the Signal Interactions

In an example from Finland, the external AR function can be initiated by two different tripping modes, and therefore the following signals are conventionally wired:

a) High speed AR initiation signals between main protective relays and the external AR device. The AR function will be initiated by the operation of the instantaneous element of the line protection such as distance zone 1 or line differential operated signals (instantaneous trip). This could also include aided trip from permissive schemes (not shown in the example)

b) Delayed AR initiation signal between the line protection relays and the external AR device. The AR function will be initiated by the operation of the delayed element of the line protection such as distance element zone 2 and sensitive earth-fault protection (delayed trip).

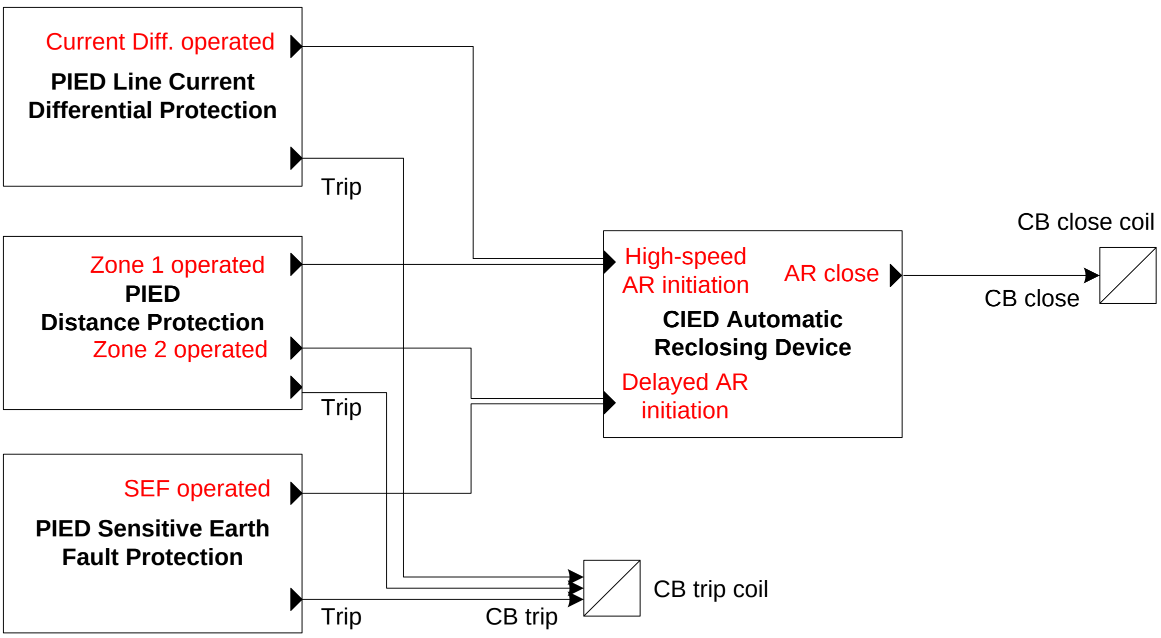

Figure 7-20: Hardwired logic for a standalone AR device

7.5.2.2 Use of IEC GOOSE Message

Both the instantaneous and the delayed trip signals from all line protections to the AR device can be replaced by GOOSE message. The CB trip and close command signals as shown in Figure 7-21 may remain conventionally wired.

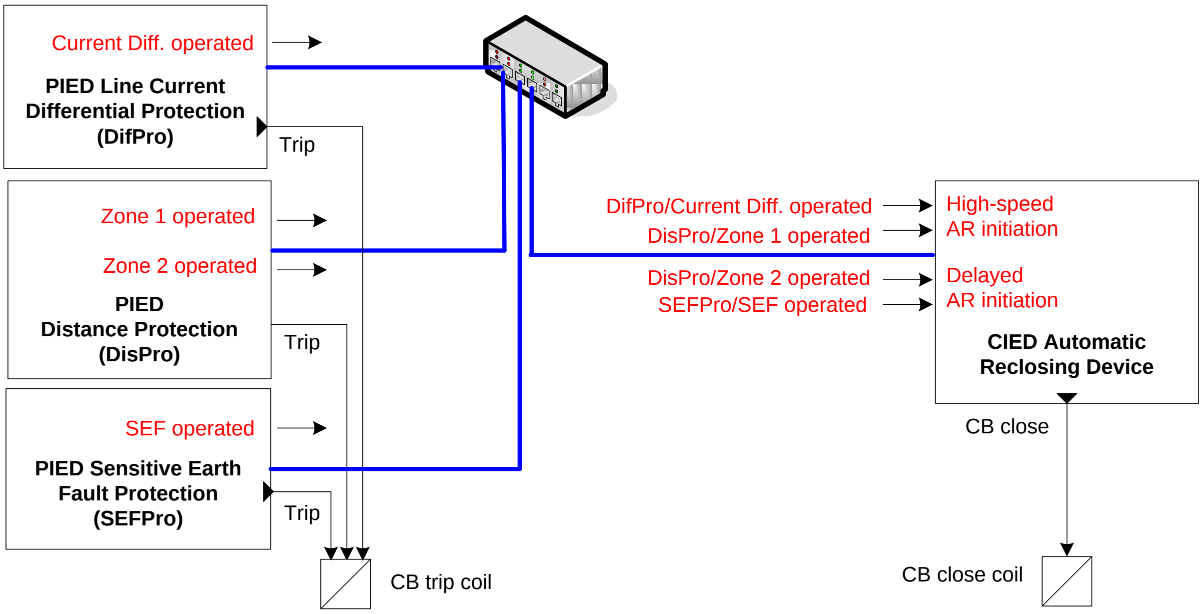

Figure 7-21: Ethernet Architecture for a standalone AR device

All the devices used in the IEC 61850 based automatic reclosing scheme are connected with full duplex Ethernet link to one or more switches depending on the communication architectures (dual ring, redundancy, etc.).

The publishing IEDs must provide the following PD/LN.DO.Attributes in the GOOSE message Datasets:

IED Name	IED internal signal description	Source IED Name/Published GOOSE Data Object
Line Current Diff. Protection (DifPro)	Current Diff. operated	DifPro/PDIF.Op (True)
Distance Protection (DisPro)	Zone 1 operated	DisPro/PDIS1.Op (True)
Distance Protection (DisPro)	Zone 2 operated	DisPro/PDIS2.Op (True)
Sensitive Earth Fault Protection (SEFPro)	Sensitive EF operated	SEFPro/PTOC.Op (True)

Table 7-6: Publisher GOOSE Table for a standalone AR device

The subscribing IEDs must have the following PD/LN.DO.Attributes available from the subscribed GOOSE message Datasets:

IED Name	Source IED Name/Subscribed GOOSE Data Object	Subscribed IED signal description	Function using the subscribed signal(s)
Automatic Reclosing (AR)	DifPro/PDIF.Op (True)	Current Diff. operated	High-speed AR (RREC)
Automatic Reclosing (AR)	DisPro/PDIS1.Op (True)	Zone 1 operated	High-speed AR (RREC)
Automatic Reclosing (AR)	DisPro/PDIS2.Op (True)	Zone 2 operated	Delayed AR (RREC)
Automatic Reclosing (AR)	SEFPro/PTOC.Op (True)	Sensitive EF operated	Delayed AR (RREC)

Table 7-7: Subscriber GOOSE Table for a standalone AR device

Line current differential protection publishes GOOSE messages from its instantaneous PDIF operated (trip) change of state information. Distance protection publishes GOOSE messages from its instantaneous PDIS1 operated (Zone 1 operated) change of state information.

Note:
In some relays, Z1 operated can be also called Z1 trip.

The automatic reclose device subscribes to the abovementioned instantaneous operated (trip) data in GOOSE messages from line current differential protection and distance protection.

These two signals are input to an OR gate mapped to the initiation input of the high-speed automatic reclose scheme in the internal logic of the automatic reclose device.

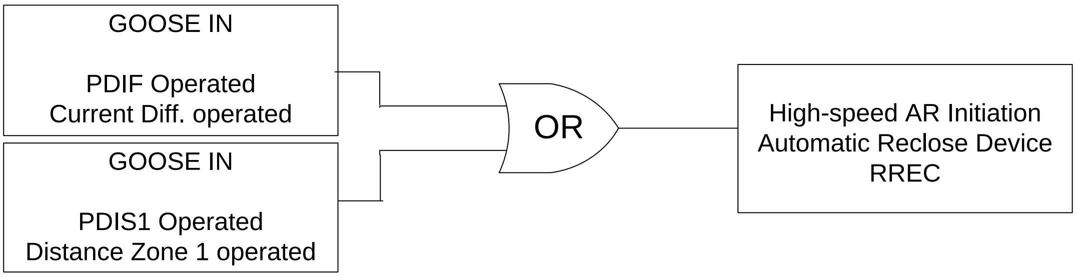

Figure 7-22: High Speed AR initiation logic implemented into the standalone AR device

Distance protection publishes GOOSE messages from its delayed PDIS2 operated (Zone 2 operated) change of state information.

Sensitive earth fault protection publishes GOOSE messages from its PTOC operated (delayed operation) change of state information.

The automatic reclose device subscribes to the abovementioned delayed protection operated (trip) data in GOOSE messages from distance and sensitive earth fault protection.

The abovementioned four signals are input to an OR gate mapped to the initiation input of the delayed automatic reclose scheme in the internal logic of the automatic reclose device.

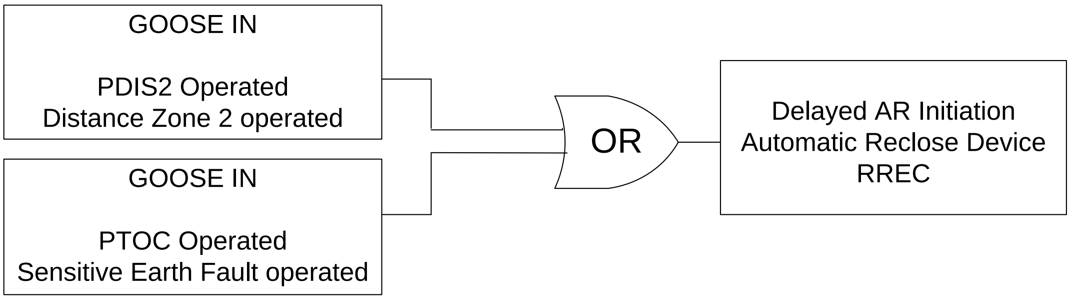

Figure 7-23: Delayed AR initiation logic implemented into the standalone AR device

The initiation of AR sequence proceeds in a way that is programmed into the automatic reclose device. Depending on the configuration, whether e.g. check synchronizing is used and whether this is an integrated part or a separate device, the output relay of the automatic reclose device is energized for giving the CB close command in conventional hardwiring. If check synchronizing (CS) is realized in a separate CS device, GOOSE messages can be used between the AR and CS devices also for their signalling. However, this is not shown here.

7.5.3 Integrated AR into Main Protection IED

7.5.3.1 Introduction

Today most of line protection IED's offer an integrated automatic reclosing functionality which reduces the need for separate AR device and wiring.

7.5.3.2 Description of the Signal Interactions

In an example from Finland, the AR function integrated in the main protection IED being a distance relay can be initiated by two different tripping modes, and therefore the following signals are conventionally wired:

a) High speed AR initiation signal between line current differential relay and the distance protection. The AR function will be initiated by the operation of any instantaneous trip signal of line current differential protection. Any instantaneous trip signal of distance protection zone 1 is part of the internal logic.

b) Delayed AR initiation signal between the sensitive earth-fault protection relay and the distance protection. The AR function will be initiated by the operation of the delayed trip signal from the separate sensitive earth fault protection. Any delayed trip signal of distance protection from zone 2 is part of the internal logic.

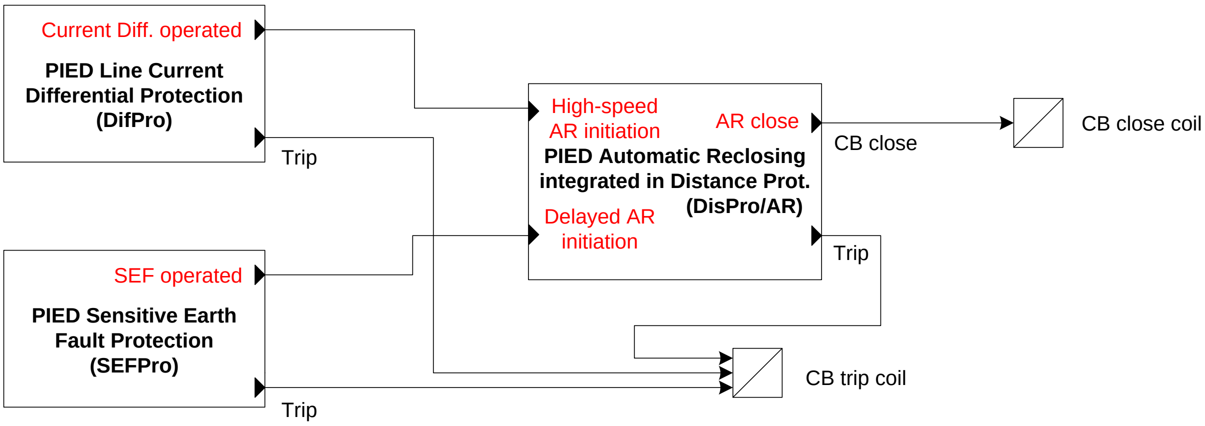

Figure 7-24: Hardwired AR logic integrated into Main Protection

7.5.3.3 Use of IEC GOOSE Message

Both the instantaneous trip signal from line current differential protection and the delayed trip signal from sensitive earth-fault protection to the AR function can be replaced by GOOSE message. The CB trip and close command signals as shown in the Figure 7-25 may remain conventionally wired.

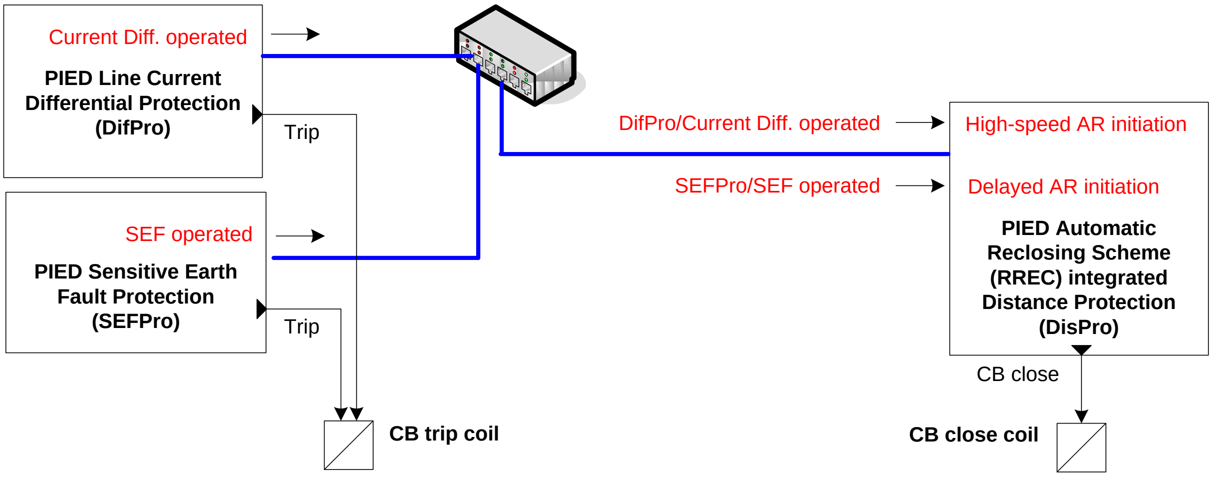

Figure 7-25: Ethernet Architecture for AR logic integrated into Main Protection

All the devices used in the IEC 61850 based automatic reclosing scheme are connected with full duplex Ethernet link to one or more switches depending on the communication architectures (dual ring, redundancy, etc.).

The publishing IEDs must provide the following PD/LN.DO.Attributes in the GOOSE message Datasets:

IED Name	IED internal signal description	Source IED Name/Published GOOSE Data Object
Line Current Diff. Prot. (DifPro)	Current Diff. operated	DifPro/PDIF.Op (True)
Sensitive Earth-Fault Prot. (SEFPro)	Sensitive EF operated	SEFPro/PTOC.Op (True)

Table 7-8: Publisher GOOSE Table for AR logic integrated into Main Protection

The subscribing IEDs must have the following PD/LN.DO.Attributes available from the subscribed GOOSE message Datasets:

IED Name	Source IED Name/Subscribed GOOSE Data Object	Subscribed IED signal description	Function using the subscribed signal(s)
Distance Protection & AR (DisPro)	DifPro/PDIF.Op (True)	Current Diff. operated	High-speed AR (RREC)
Distance Protection & AR (DisPro)	SEFPro/PTOC.Op (True)	Sensitive EF operated	Delayed AR (RREC)

Table 7-9: Subscriber GOOSE Table for AR logic integrated into Main Protection

Line current differential protection publishes GOOSE messages from its instantaneous PDIF operated (trip) change of state information.

The distance protection subscribes to the abovementioned instantaneous PDIF operated (Trip) data in GOOSE messages from line current differential protection.

This signal is an input to an OR gate together with the internal distance PDIS1 operated (Zone 1 trip) signal. This in turn is mapped to the initiation input of the high-speed automatic reclose scheme in the internal logic of the distance protection.

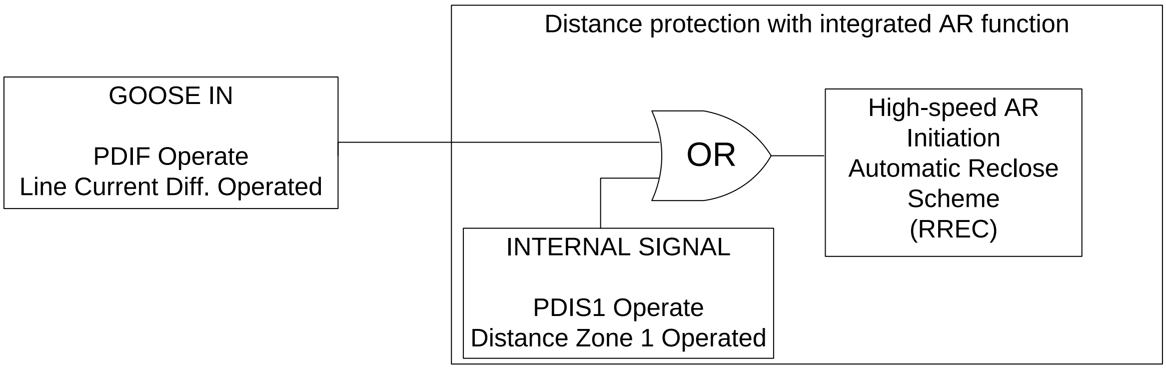

Figure 7-26: High Speed AR initiation logic implemented into Main Protection

Sensitive earth fault protection publishes GOOSE messages from its PTOC operated (delayed trip) change of state information.

The distance protection subscribes to the abovementioned delayed Trip data in GOOSE messages from sensitive earth fault protection.

This signal is an input to the distance protection in which it is mapped to the initiation of the delayed automatic reclose scheme. Delayed AR is also activated by distance zone 2 operated (trip) in the internal logic of the distance protection.

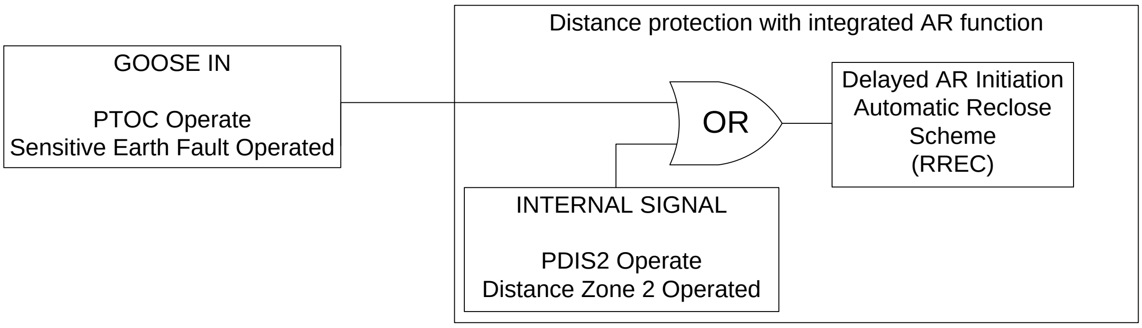

Figure 7-27: Delayed AR initiation logic implemented into Main Protection

The initiation of AR sequence proceeds in a way that is programmed into the integrated automatic reclose scheme in the distance protection. Depending on the configuration, e.g. if check synchronizing (CS) is used, the output relay of the distance protection for giving the CB close command in conventional hardwiring. If check synchronizing is realized in a separate CS device, GOOSE messages can be used between the AR and CS devices also for their signalling. However, this is not shown here.

7.5.4 Integrated AR into Two Redundant Main Protection IEDs

7.5.4.1 Introduction

The majority of today’s line protection IED's include the AR function thereby reducing the need for separate AR devices and wiring.

Some users may require duplication of not only main protection but also AR functions.

7.5.4.2 Description of the Signal Interactions

As an extension of the above examples, duplicated two-shot three-pole AR with high speed and delayed AR are integrated into the two main line protection IEDs. In the example, the Main 1 protection is a line current differential IED and the Main 2 is a distance IED.

Only one AR function is active at any time to avoid coordination issues between the two AR functions integrated in the line protective IEDs. By default the AR function of the Main 1 IED is active and the AR function in the Main 2 IED is on standby.

In addition a sensitive earth-fault protection is used as a backup.

However, additional signals coming from external IEDs such as block AR (e.g. from RTU, HMI), breaker position indication and breaker condition status (e.g. SF_6 low pressure) are not shown here.

Therefore the following signals shown in Figure 7-28 are conventionally wired:

a) High speed AR initiation signal from distance protection to line current differential protection. The HSAR function will be initiated by the operation of the Zone 1 of distance protection

b) Delayed AR initiation signal from sensitive earth-fault protection to both line current differential and distance protection IEDs

c) Delayed AR initiation signal from distance protection to line current differential protection. The DAR function will be initiated by the operation of the delayed operation of distance protection.

d) AR close command is cross wired from AR function of line current differential protection to distance protection to initiate the trip on reclose (TOR) function.

e) A combined signal from IED Watchdog and AR function Out of Service is issued by line current differential protection. This signal is wired to distance protection. When the signal is active, the standby AR function of distance protection takes over and performs the reclosing instead of the one integrated in the line current differential protection (redundancy).

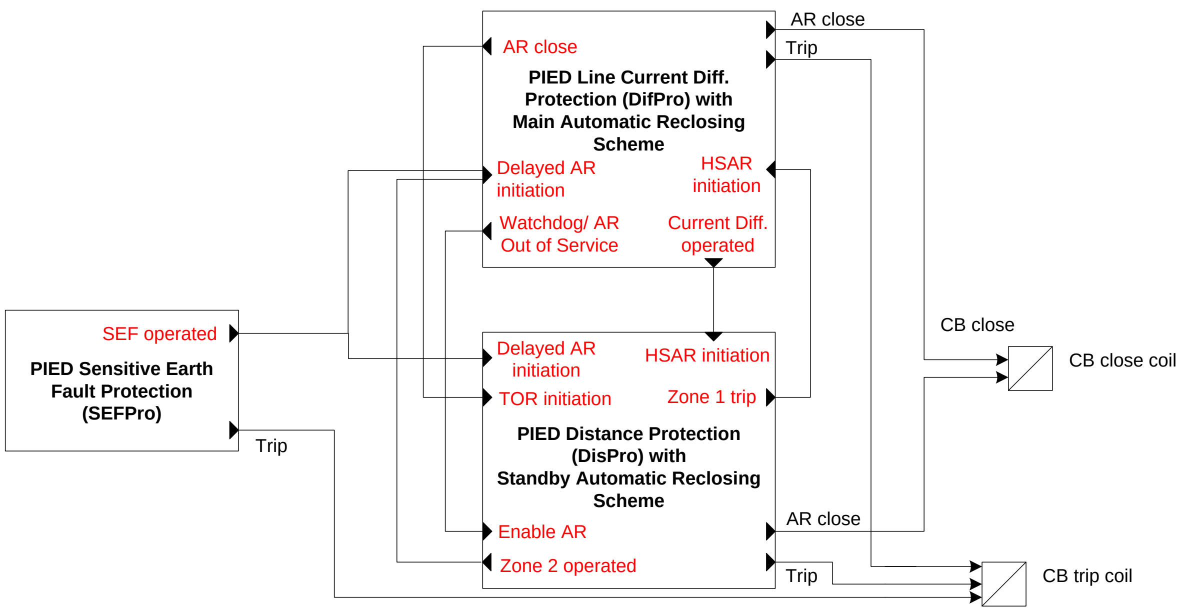

Figure 7-28: Hardwired AR Logic with integrated AR functions in both main protection IEDs

7.5.4.3 Use of IEC GOOSE Message

The instantaneous and delayed trip signals between line current differential and distance protections and the delayed operation signal from sensitive earth-fault protection to both main protection IEDs can be replaced by GOOSE messages. Also the internal Watchdog and AR out of service signals from line current differential to distance protection IED for enabling the standby AR function in distance protection can be replaced by GOOSE messages. Furthermore, AR close signal from the AR function of line current differential protection for TOR initiation in distance protection IED can be replaced as well by GOOSE message. The CB trip and close command signals as shown in the Figure 7-29 may remain conventionally wired. Other external signals are not considered.

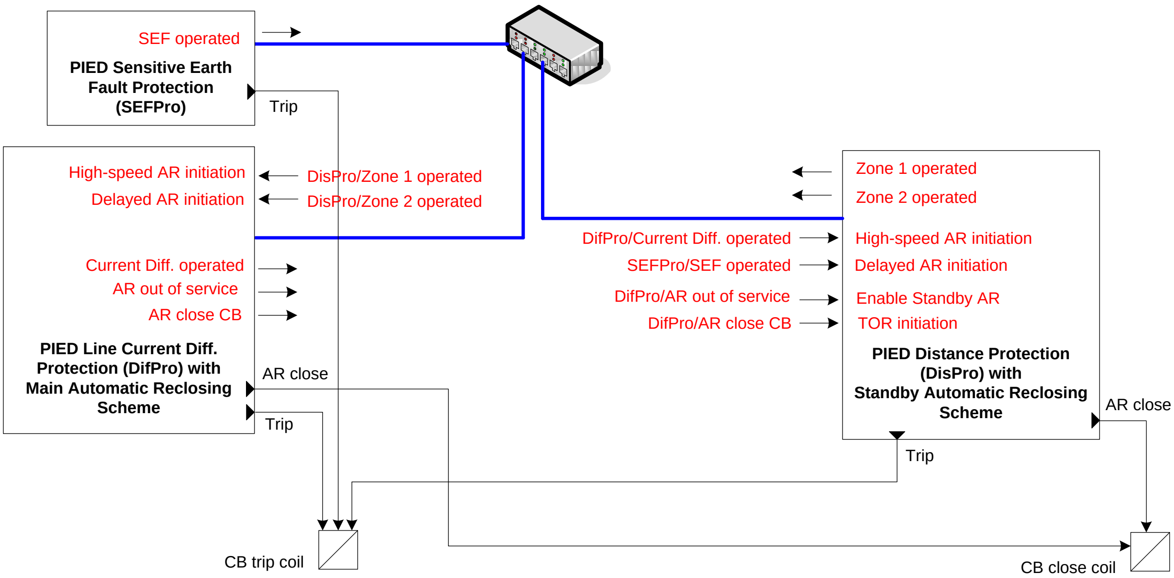

Figure 7-29: Ethernet Architecture with integrated AR functions in both main protection IEDs

The publishing IEDs must provide the following PD/LN.DO.Attributes in the GOOSE message Datasets:

IED Name	IED internal signal description	Source IED Name/Published GOOSE Data Object
Line Current Diff. Protection (DifPro)	Current Diff. operated	DifPro/PDIF.Op (True)
Distance Protection (DisPro)	Zone 1 operated	DisPro/PDIS1.Op (True)
Distance Protection (DisPro)	Zone 2 operated	DisPro/PDIS2.Op (True)
Sensitive Earth-Fault Prot. (SEFPro)	Sensitive EF operated	SEFPro/PTOC.Op (True)
Line Current Diff. Protection & AR (DifPro)	Main 1 AR switched off	DifPro/RREC.Beh (Off)
Line Current Diff. Protection & AR (DifPro)	Main 1 AR Close Command	DifPro/RREC.OpCls (True)

Table 7-10: Publisher GOOSE Table for integrated AR functions in both main protection IEDs

The subscribing IEDs must have the following PD/LN.DO.Attributes available from the subscribed GOOSE message Datasets:

IED Name	Source IED Name/Subscribed GOOSE Data Object	Subscribed IED signal description	Function using the subscribed signal(s)
Diff. Protection & AR (DifPro)	DisPro/PDIS1.Op (True)	Zone 1 operated	High-speed AR (RREC)
Diff. Protection & AR (DifPro)	DisPro/PDIS2.Op (True)	Zone 2 operated	Delayed AR (RREC)
Diff. Protection & AR (DifPro)	SEFPro/PTOC.Op (True)	Sensitive EF operated	Delayed AR (RREC)
Distance Protection & AR (DisPro)	DifPro/PDIF.Op (True)	Current Diff. operated	High-speed AR (RREC)
Distance Protection & AR (DisPro)	SEFPro/PTOC.Op (True)	Sensitive EF operated	Delayed AR (RREC)
Distance Protection & AR (DisPro)	DifPro/RREC.Beh (Off)	Main 1 AR switched off	Enable AR (RREC)
Distance Protection (DisPro)	DifPro/RREC.OpCls (True)	Main 1 AR Close Command	Trip on reclose (TOR)

Table 7-11: Subscriber GOOSE Table for integrated AR functions in both main protection IEDs

Note 1:
The instance number in logical name is used only in case of multiple instances of the logical node representing different stages or zones etc.

Note 2:
As in the above example, the associated mechanism of the hardwired watchdog signal cannot be migrated into IEC 61850 without taking some additional actions. In case of IED failure, no GOOSE messages will be sent by the faulty IED. E.g. the GOOSE presence should be monitored continuously by the receiving IED and the loss of GOOSE message of the associated IED should be considered in the internal IED logic.

An alternative solution could be to cross wire the watchdog signal to another IED (e.g. monitoring device) and publish continuously its status. In this case, there would be an additional GOOSE signal published by the external monitoring device "DifPro/Publisher Present", which is received by the distance protection IED in order to enable the integrated standby AR function.

Line current differential IED publishes a GOOSE message from its instantaneous PDIF operated (trip) change of state information. The standby AR function of distance IED subscribes to the abovementioned protection operated data in the GOOSE message from line current differential IED and will initiate internally the HSAR cycle if the above GOOSE message has been internally assigned to the external HSAR initiation signal and if the standby AR function has been enabled.

The standby AR function of distance IED is will be activated when the AR function of line current differential IED will be set out of service (e.g. for maintenance purpose) OR when distance IED detects the loss of GOOSE from line current differential IED.

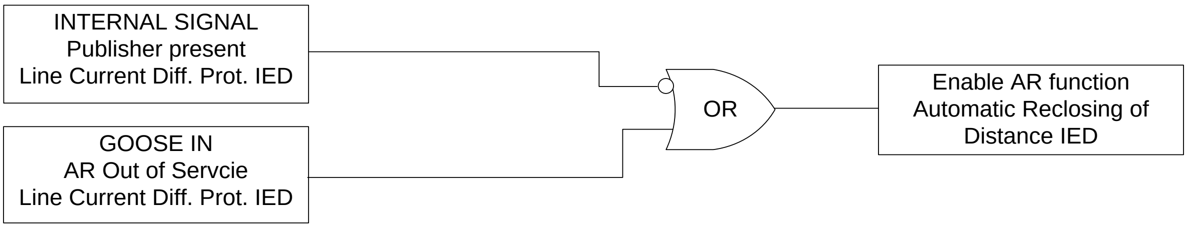

Figure 7-30: Monitoring of loss of IED performed by receiving IED by checking status of "Publisher present" signal for integrated AR functions in both main protection IEDs

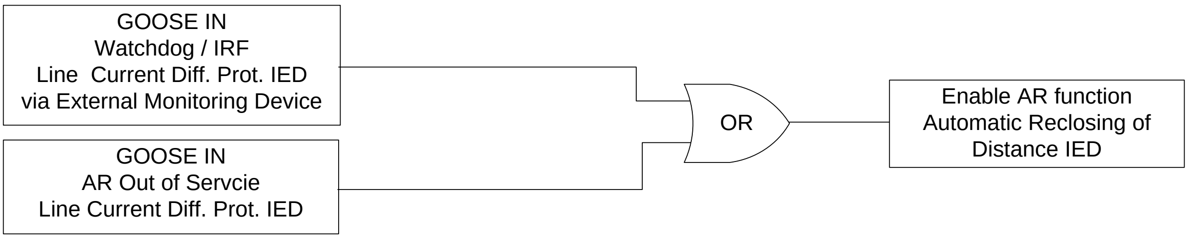

Figure 7-31: Alternative solution based on an external device for monitoring of loss of IEDs for integrated AR functions in both main protection IEDs

Sensitive earth fault protection publishes GOOSE messages from its SEF operated change of state information. Both line current differential and distance IEDs subscribe to the abovementioned delayed protection operated data in GOOSE messages from sensitive earth fault protection.

Distance IED publish GOOSE message from its delayed zone 2 operated change of state information. The Main AR function in line current differential IED subscribe to the abovementioned delayed protection operated data in GOOSE messages from the distance protection.

These two GOOSE signals from distance and SEF protection IEDs will be initiating the internal DAR cycle of line current differential IED.

If an external Check Sync IED is used, the conventional hardwired AR close command of the main protection IEDs could be replaced by GOOSE message as described section 7.6.

In order to initiate the internal trip on reclose logic of distance IED, it will subscribe to the AR close command signal issued by line current differential IED. This signal is mapped to the initiation of TOR logic of the receiving distance IED.

For this application it seems necessary also to use the quality associated with the protection operated status signals in order to avoid wrong AR or TOR initiation during e.g. testing.

7.5.5 AR for Mesh Corner (internal or external A/R device)

7.5.5.1 Introduction

A Mesh Corner (ring bus) arrangement is extensively used by some utilities, either in full or part. For example, it has been commonly used within the UK EHV transmission network. The aim of the arrangement is to reduce the number of high voltage Circuit Breakers required to protect several items of plant, as historically these were more expensive than they are today. Coordinated control logic is required for auto-isolation and Delayed Auto Reclose (DAR) in a mesh substation.

The 4-Switch Mesh substation is illustrated in Figure 7-32. The basic mesh has a feeder at each corner, as shown at mesh corners *MC1, MC2*, *MC3* and *MC4*.

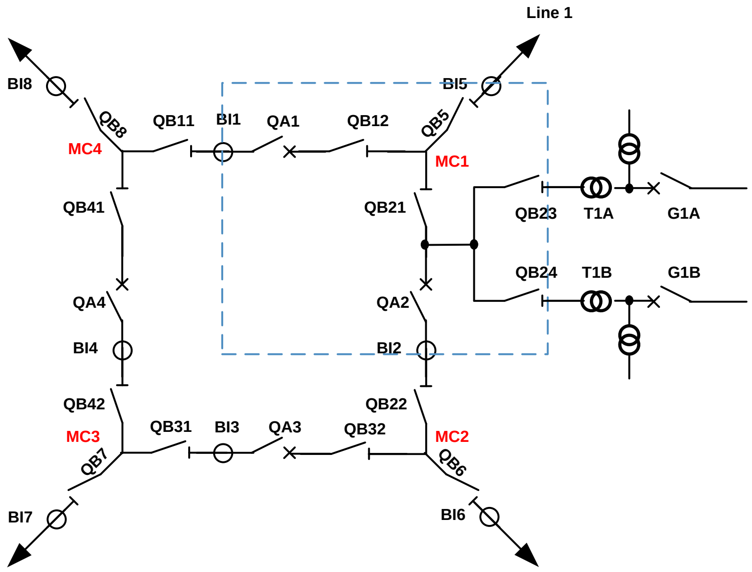

Figure 7-32: Four-switch mesh substation

One or two transformers may also be banked at a Mesh Corner. Mesh Corner protection is required if more than one circuit is fed from a Mesh Corner, irrespective of the CT locations.

Considerable problems can be encountered in the application of auto-reclosing to the mesh substation. For example, circuit breakers *QA1* and *QA2* in Figure 7-32 are tripped out for a variety of different types of fault associated with Mesh Corner 1 (*MC1*), and each requires different treatment as far as auto-reclosing is concerned. Further variations occur if the faults are persistent.

In the case of a fault on any of the plant items, or busbar, all circuit breakers adjacent to the fault operate to isolate fault. Following normal practice, circuit breakers must be reclosed in sequence, so sequencing circuits are necessary for the four mesh breakers. Closing priority may be defined in any order.

A summary of facilities is now given for a 4-Switch Mesh system, based on Mesh Corner *MC1* to show the inclusion of banked transformers; facilities at other corners are similar but omit the operation of equipment solely associated with the banked transformers.

Equipment is provided on the basis of one Mesh Corner Recloser unit (MCR) per Mesh Corner, where each MCR controls one adjacent shared breaker. Although each MCR is an autonomous unit, inter-unit communication guarantees coordinated control of a complete mesh system. This inter-unit communication can be made as a traditional hardwired link or via GOOSE peer-peer communications.

Various switching arrangements can have automatic switching controlled by MCRs – Single Switch, 2 Switch, 3 Switch, 4 Switch, and even more complex systems. A typical Single Switch system would require two MCRs; a 2 Switch system, three MCRs; and 3 and 4 Switch systems, four MCRs.

The MCR is designed to receive protection tripping-related inputs from three types of protection associated with the mesh corner:

a) Mesh Corner Busbar protection

b) Feeder protection

c) Transformer protection

Depending on the protection input, the relay service state and the operation of the reclaim timer on the adjacent circuit breakers, the MCR will perform any auto-isolation of the plant disconnectors and reclosure of the breakers as required.

7.5.5.2 Mesh Corner Busbar protection

The MCR accepts the following input from the Mesh Corner busbar protection:

a) DAR Required

b) DAR Not Required

In the case of a “DAR Not Required”, the busbar fault is considered to be permanent; the MCR will isolate any Feeders and Transformers connected to the corner and Lockout reclosure of the adjacent mesh circuit breakers.

In the case of a “DAR Required”, the MCR will isolate all transformers connected to the corner and then attempt to reclose the adjacent circuit breakers. However under the following circumstances isolation of the corner and lockout of the two breakers will occur:

a) If the reclaim timer is running on either adjacent breaker (indicating closure onto a permanent fault).

b) If there are either no feeders or transformers currently connected to the corner

c) If a mesh corner fault also occurs on an adjacent corner

7.5.5.3 Feeder protection

The MCR accepts the following two inputs from the Feeder protection:

a) DAR Required

b) DAR Not Required

c) Intertrip Receive

On “DAR Required”, the mesh corner relay will leave the feeder connected to the corner and attempt to reclose the adjacent mesh breakers. However if the reclaim timer is running indicating reclosure onto a fault, then the Feeder will be isolated prior to the closure of the mesh breakers.

On receipt of the signal “DAR Not Required”, the MCR will always open the Feeder disconnector prior to the reclosure of the corner.

If an intertrip is received then one of two actions may be taken. In the case where the intertrip signal is received for less than the duration of persistent intertrip timer then the corner will be reclosed with the line connected. However if the duration of the signal is greater than the persistent intertrip timer (this is a signal from the remote end of the line not to reclose the Feeder) the line will be isolated prior to reclosure of the corner.

7.5.5.4 Transformer protection

A single input only is received from the Transformer protection: “DAR Not Required”. On receipt of this signal the MCR will isolate the transformer and then reclose the mesh corner.

The following example application considers the 4 Switch system and the GOOSE scheme to manage the DAR function.

7.5.5.5 Description of the Signal Interactions

In case of a fault on the Line 1 feeder, tripping of circuit breakers *QA1*, *QA2, G1A* and *G1B* is followed by reclosure of *QA1* to give dead line charging of Line 1. Breaker *QA2* recloses in sequence with a Check Sync. Breakers *G1A*, *G1B* reclose with a Check Sync if necessary.

In case of persistent fault on Line 1, circuit breaker *QA1* trips again after the first reclosure and isolator *QB5* is automatically opened to isolate the faulted line. Breakers *QA1*, *QA2*, *G1A* and *G1B* then reclose in sequence as above.

For a transformer fault (local transformer A for example), Automatic opening of isolator *QB5* to isolate the faulted transformer follows tripping of circuit breakers *QA1*, *QA2*, *G1A* and *G1B*. Breakers *QA1*, *QA2* and *G1B* then reclose in sequence, and breaker *G1A* is locked out.

For a remote transformer fault, an intertrip signal is received at the local station to trip breakers *QA1, QA2, G1A* and *G1B* and inhibit auto-reclosing until the faulted transformer has been isolated at the remote station. If the intertrip persists for a defined time it is assumed that the fault cannot be isolated at the remote station. Isolator *QB5* is then automatically opened and circuit breakers *QA1* and *QA2* are reclosed in sequence.

There may be circumstances in which reclosure onto a persistent fault is not permitted – clearly it is not known in advance of reclosure if the fault is persistent or not. In these circumstances, scheme logic inhibits reclosure and locks out the circuit breakers.

7.5.5.6 Use of IEC GOOSE Message

The Mesh Corner Reclose unit uses GOOSE to provide a flexible, distributed scheme for auto-isolation and delayed auto-reclose (DAR) of a mesh bus station. Each MCR controls directly or indirectly one shared breaker. By default the CB auxiliaries located at the left mesh are assigned to one MCR unit only. For any fault on the left mesh corner, the breaker will be directly controlled by the associated MCR unit. If in this arrangement a fault appears on the right mesh, the MCR unit located at the right mesh will perform DAR (Delayed Auto-Reclose) and indirectly control the breaker by GOOSE signalling to the “CBs controlled” function in the MCR unit on the left side of the scheme.

Note that logic signals are mainly passed between adjacent MCR units; only limited number of signals such as circuit breaker reclosure sequencing signals are transmitted between all MCR units. Mesh Corner Relays could work in an integrated auto-switching scheme, thus being able to accommodate any existing scheme in practice.

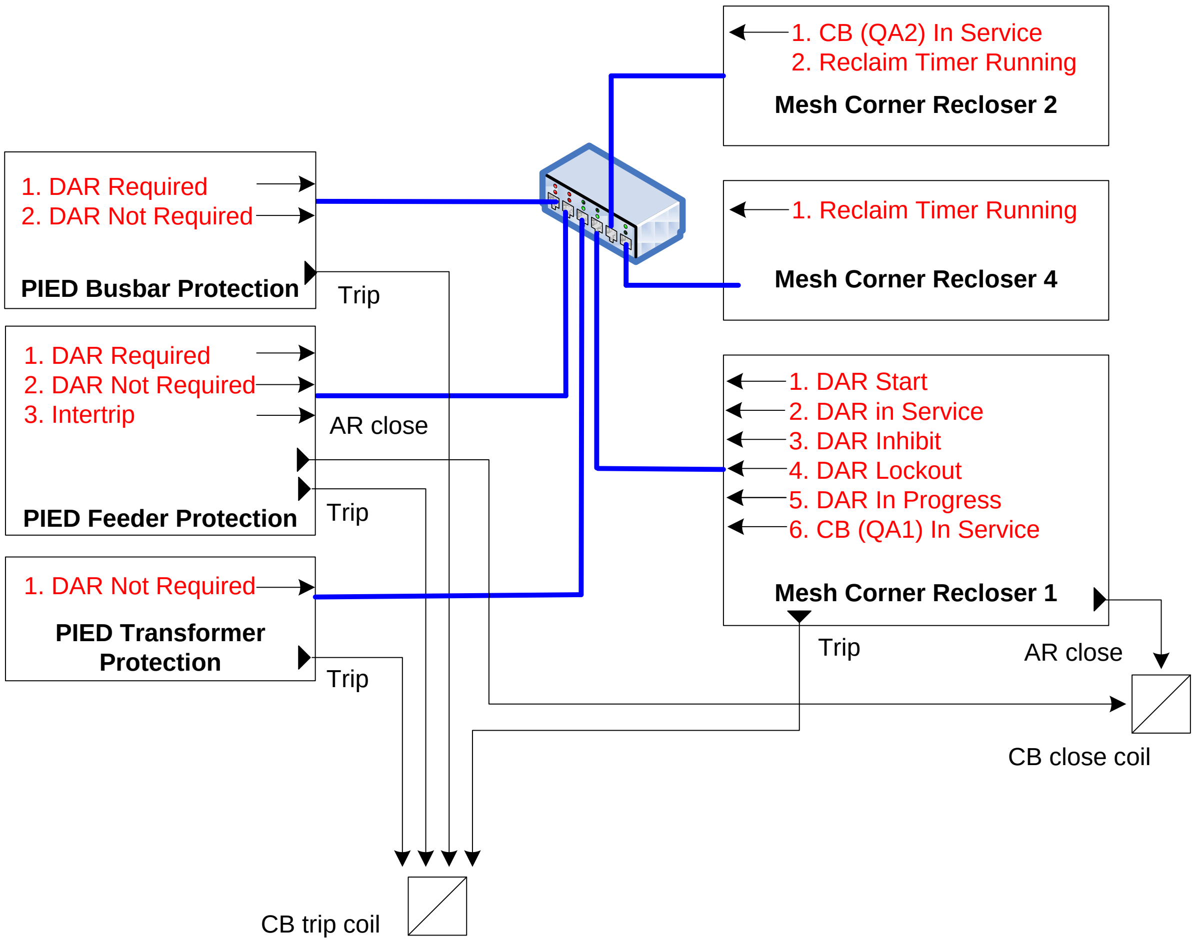

Figure 7-33: Mesh Corner Recloser IED

Tables 7.12 and 7.13 below consider the GOOSE inputs and outputs associated with one MCR, named MC1 (for Mesh Corner 1).

The publishing IEDs must provide the following PD/LN.DO.Attributes in the GOOSE message Datasets:

IED Name	IED internal signal description	Source IED Name/Published GOOSE Data Object
Busbar Protection (BusPro)	DAR Required	BusPro (PDFB)/RREC.BlkRec (False)
Busbar Protection (BusPro)	DAR Not Required	BusPro (PDFB)/RREC.BlkRec (True)
Feeder Protection (FdrPro)	DAR Required	FdrPro (PDIS)/RREC.BlkRec (False)
Feeder Protection (FdrPro)	DAR Not Required	FdrPro (PDIS)/RREC.BlkRec (True)
Feeder Protection (FdrPro)	Intertrip	FdrPro (PDIS)/Intertrip.Str (True)
Transformer Protection (TrPro)	DAR Not Required	TrPro (PTDF)/RREC.BlkRec (True)
Mesh Corner Recloser MC1	DAR Start	MC1/RREC.Op
Mesh Corner Recloser MC1	DAR In Service	MC1/RREC.AutoRec.St=1
Mesh Corner Recloser MC1	DAR Inhibit	MC1/RREC.Inhibit (True)
Mesh Corner Recloser MC1	DAR Lockout	MC1/RREC.Lockout (True)
Mesh Corner Recloser MC1	DAR In Progress	MC1/RREC.AutoRec.St=2
Mesh Corner Recloser MC1	CB (QA1) In Service	MC1/XCBR.EEHealth=1
Mesh Corner Recloser MC2	CB (QA2) In Service	MC2/XCBR.EEHealth=1
Mesh Corner Recloser MC2	Reclaim Timer Running	MC2/RREC.RclT.Start
Mesh Corner Recloser MC4	Reclaim Timer Running	MC4/RREC.RclT.Start

Table 7-12: Publisher GOOSE Table for Mesh Corner Recloser

The subscribing IEDs must have the following PD/LN.DO.Attributes available from the subscribed GOOSE message Datasets:

IED Name	Source IED Name/Subscribed GOOSE Data Object	Subscribed IED signal description	Function using the subscribed signal(s)
Busbar Protection (BusPro) MC1	BusPro (PDFB)/RREC.BlkRec	DAR Required	DAR
Feeder Protection (FdrPro) MC1	FdrPro (PDIS)/RREC.BlkRec	DAR Required	DAR
Feeder Protection (FdrPro) MC1	FdrPro (PDIS)/Intertrip.Str	Intertrip Receive	DAR
Transformer Protection (TrPro) MC1	TrPro (PTDF)/RREC.BlkRec	DAR Required	DAR
Mesh Corner Recloser MC2	MC2/RREC.Op	DAR Start	DAR
Mesh Corner Recloser MC2	MC2/RREC.AutoRec.St	DAR In Service	DAR
Mesh Corner Recloser MC2	MC2/RREC.Inhibit	DAR Inhibit	DAR
Mesh Corner Recloser MC2	MC2/RREC.Lockout	DAR Lockout	DAR
Mesh Corner Recloser MC2		CB1 Req Token	DAR
Mesh Corner Recloser MC2	MC2/RREC.RclT.Start	CB1 Reclaim Timer	DAR
Mesh Corner Recloser MC2		CB Fail	DAR
Mesh Corner Recloser MC2	MC2/XCBR.EEHealth=1	CB (QA1) In Service	DAR

Table 7-13: Subscriber GOOSE Table for Mesh Corner Recloser

7.6 Transmission Line Protection: Check Sync for One or Two Breakers

7.6.1 Introduction

The Check Sync function (RSYN) is used to monitor the conditions of the two parts of the circuit prior to the close of a breaker. It verifies that the voltages on both sides of the breaker, line (V_{LINE}) and busbar (V_{BUS}) are favourable and safe to close (either by line reclosing or by manual closing) and that there will be no oscillations. If these safe limits are not met, Check Sync (CS) relay will not permit the circuit breaker closing.

Verification of synchronism is defined as the comparison of the voltage difference of two circuits with different sources to be joined through an impedance (transmission line, feeder, etc.), or connected with parallel circuits of defined impedances. The voltages on both sides of a breaker are compared before executing its close so as to minimize possible internal damage due to the voltage difference in phase, as well as magnitude and frequency.

In substations with breaker and half, and ring bus, lines are connected through two breakers to the busbars, and therefore two CS units are necessary to verify the closing conditions of both breakers. Today there is also one CS unit which manages two breakers at the same.

Today most of line relays include the Check Sync functionality, reducing the need for separate CS relays and wiring. Anyway, it's still very common to use an external device to do the CS as well as the AR and BF.

7.6.2 External Check Sync for One Breaker

7.6.2.1 Description of the Signal Interactions

In the following example, an external CS and AR device is used for an overhead line with typical line protection relays (the initiation of reclosing signal is coming from the line protection). Control of the CB is done for example by a Bay Control Unit (BCU). For Check Sync functionality, the following signals are conventionally wired:

a) Manual Closing (MC) signal between the bay control unit and the external CS + AR device. After receiving the MC signal from the BCU, the CS + AR device will verify if closing conditions are met, and in that case, MC command will progress.

b) Typically the three line voltages and one busbar voltage. At least one line voltage and one busbar voltage are necessary to check if there are closing conditions or not.

c) Manual close and AR close signals from the CS + AR device to CB close coil.

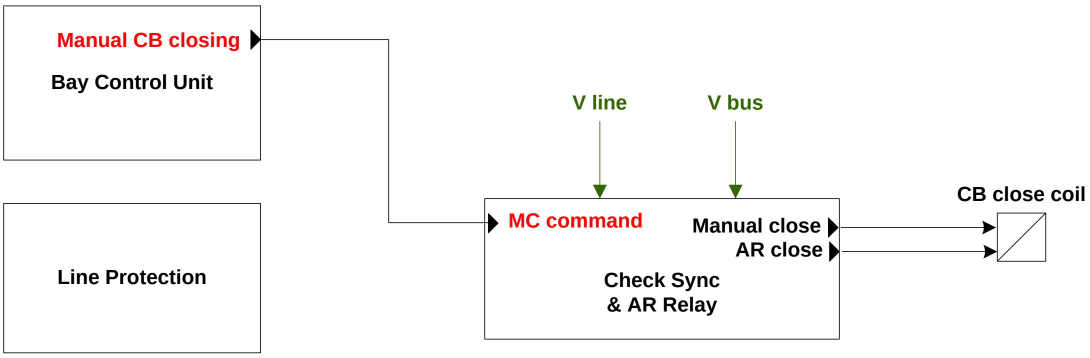

Figure 7-34: Hardwired Check Sync Logic for Standalone Check Sync & AR relay (one breaker application)

7.6.2.2 Use of IEC GOOSE Message

The manual CB close command will be issued by the Bay Control Unit based on the Select Before Operate (SBO) service, and it will interact with the CSWI Logical Node.

The line and busbar voltages can be replaced by analogue GOOSE message. The Manual close and AR close as shown in Figure 7-35 may remain conventionally wired.

The analogue GOOSE signals can be provided as shown in Figure 7-35 by the line protection. In the case where the analogue GOOSE data are coming from different publishing devices, they have to be time synchronized with sufficient accuracy (SNTP is not sufficient in that case).

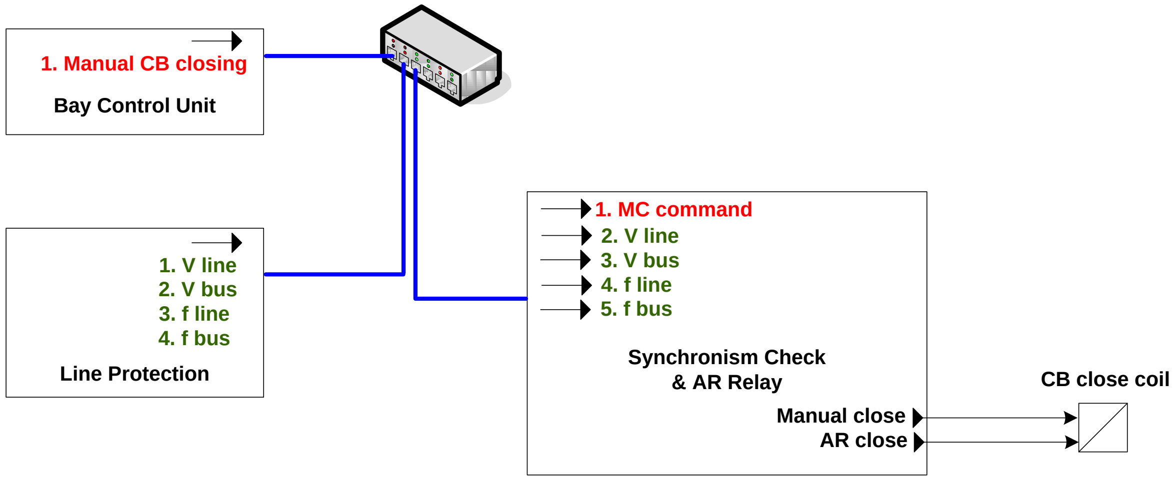

Figure 7-35: Ethernet Architecture for Standalone Check Sync & AR relay (one breaker)

For the following example, the phase-to-ground line voltages are used and A-N as bus voltage reference. The bus voltage used as a reference is normally a settable parameter.

The publishing IEDs must provide the following PD/LN.DO.Attributes in the GOOSE message Datasets:

IED Name	IED internal signal description	Source IED Name/Published GOOSE Data Object
Bay Control Unit (BCU)	Manual CB Closing	BCU/CSWI.Pos.CtlVal (on)
Line Protection (FdrPro)	V Line (magnitude and angle)	FdrPro/MMXU.PhV *mag and angle are required
Line Protection (FdrPro)	f Line	FdrPro/MMXU.Hz
Line Protection (FdrPro)	V Bus (magnitude and angle)	FdrPro/MMXU.PhV *mag and angle are required
Line Protection (FdrPro)	f Bus	FdrPro/MMXU.Hz

Table 7-14: Publisher GOOSE Table for Standalone Check Sync & AR relay (one breaker)

The subscribing IEDs must have the following PD/LN.DO.Attributes available from the subscribed GOOSE message Datasets:

IED Name	Source IED Name/Subscribed GOOSE Data Object	Subscribed IED signal description	Function using the subscribed signal(s)
Check Sync & AR Relay	BCU/CSWI.Pos.CtlVal (on)	Manual CB Closing	Check Sync (RSYN)
Check Sync & AR Relay	FdrPro/MMXU.PhV *mag and angle are required	V Line (magnitude and angle)	Check Sync (RSYN)
Check Sync & AR Relay	FdrPro/MMXU.Hz	f Line	Check Sync (RSYN)
Check Sync & AR Relay	FdrPro/MMXU.PhV *mag and angle are required	V Bus (magnitude and angle)	Check Sync (RSYN)
Check Sync & AR Relay	FdrPro/MMXU.Hz	f Bus	Check Sync (RSYN)

Table 7-15: Subscriber GOOSE Table for Standalone Check Sync & AR relay (one breaker)

Bay Control Unit publishes GOOSE messages from its Manual closing signal change of state information. The CS + AR device subscribes to the abovementioned Manual closing data in GOOSE messages from Bay Control Unit.

Line protection publishes GOOSE messages from its line and busbar voltages change of value information. This information is analogue type, and it’s needed to include within the GOOSE message the magnitude, angle and time stamp of the value change for each of the voltages published. Magnitude is required to check voltage level difference, and angle and time stamp to check voltage phase difference.

For Check Sync functionality, Line protection should also publish line frequency and busbar frequency. The CS + AR device subscribes to the abovementioned data in GOOSE message from the line protection.

Depending on the configuration, Check Sync and AR can be integrated or be separated devices. If Check Sync is realized in a separate CS device, GOOSE messages can be used between the AR and CS devices also for their signalling. However, this is not shown here.

7.6.3 External Check Sync for Two Breakers

7.6.3.1 Description of the Signal Interactions

In the following example, a single external Check Sync and AR device is used for an overhead line in a breaker and a half or ring bus substation. Although some utilities use two separate CS + AR devices, one for each CB. The typical line protection relays are represented with a single box, assuming that include distance protection. Control of the two CBs is done by one Bay Control unit (BCU). For Check Sync functionality, the following signals are conventionally wired:

a) Manual closing signals between the bay control unit and the external CS + AR device. After receiving a MC signal from the BCU, the CS + AR device will verify if closing conditions are met, and in that case, MC command will progress.

b) Typically the three line voltages and two busbar voltages, lateral and central. At least one line voltage and one busbar voltage per CB are necessary to check if there are closing conditions or not.

c) Manual close and AR close signals from the CS + AR device to CBs close coils.

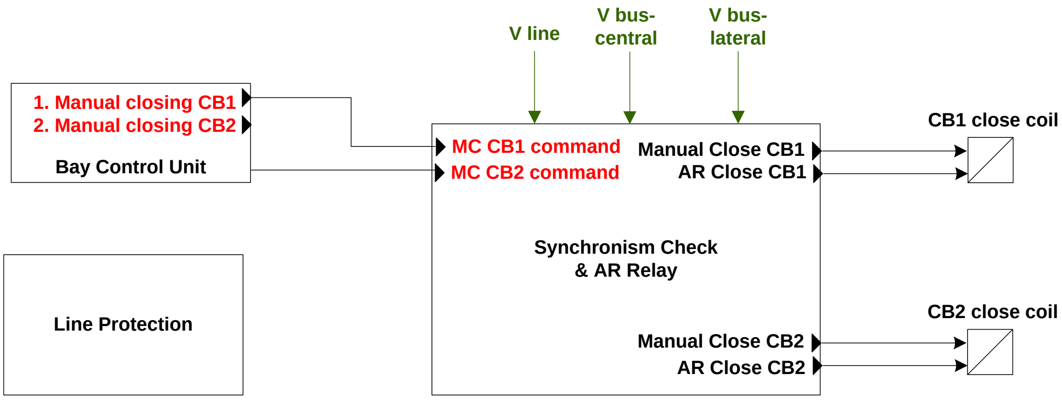

Figure 7-36: Hardwired Check Sync Logic for Standalone Check Sync & AR relay (two breakers application)

7.6.3.1.1 Use of IEC GOOSE Message

As seen in the previous example, the manual CB close command will be issued by the Bay Control Unit based on the Select Before Operate (SBO) service, and it will interact with the CSWI Logical Node. The line and busbar voltages are replaced by analogue GOOSE message.

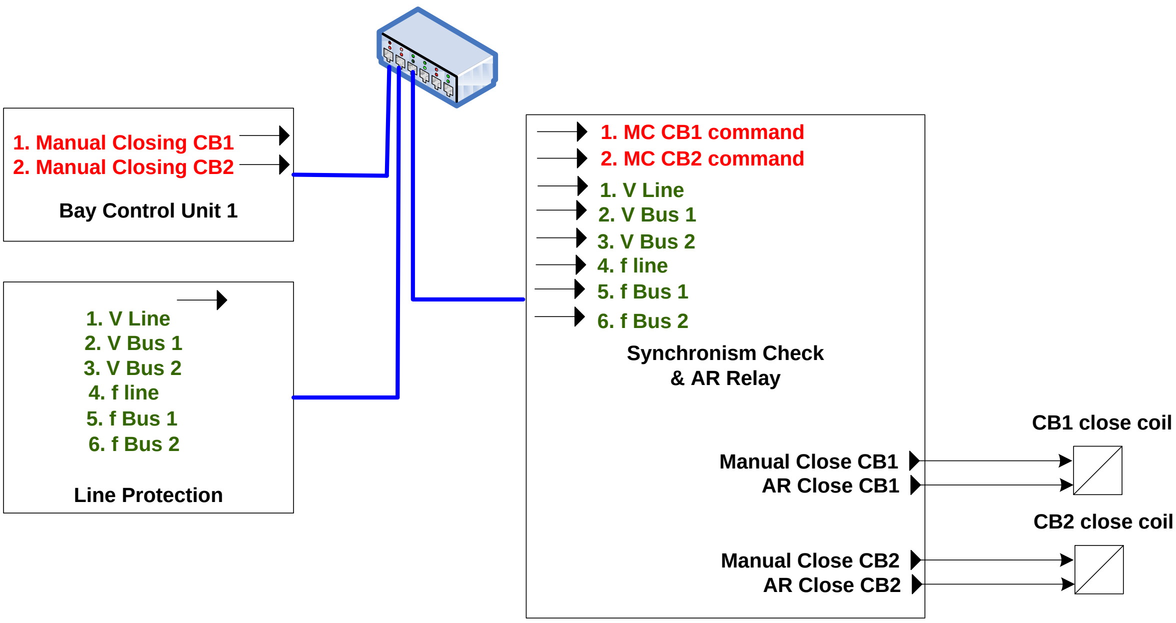

Figure 7-37: Ethernet Architecture for Standalone Check Sync & AR relay (two breakers)

The publishing IEDs must provide the following PD/LN.DO.Attributes in the GOOSE message Datasets:

IED Name	IED internal signal description	Source IED Name/Published GOOSE Data Object
Bay Control Unit (BCU)	Manual CB1 Closing	BCU/CSWI1.Pos.CtlVal (on)
Bay Control Unit (BCU)	Manual CB2 Closing	BCU/CSWI2.Pos.CtlVal (on)
Line Protection (FdrPro)	V Line (magnitude and angle)	FdrPro/MMXU.PhV *mag and angle are required
Line Protection (FdrPro)	f Line	FdrPro/MMXU.Hz
Line Protection (FdrPro)	V Bus1 (magnitude and angle)	FdrPro/MMXU.PhV *mag and angle are required
Line Protection (FdrPro)	f Bus1	FdrPro/MMXU.Hz
Line Protection (FdrPro)	V Bus2 (magnitude and angle)	FdrPro/MMXU.PhV *mag and angle are required
Line Protection (FdrPro)	f Bus2	FdrPro/MMXU.Hz

Table 7-16: Publisher GOOSE Table for Standalone Check Sync & AR relay (two breakers)

The subscribing IEDs must have the following PD/LN.DO.Attributes available from the subscribed GOOSE message Datasets:

IED Name	Source IED Name/Subscribed GOOSE Data Object	Subscribed IED signal description	Function using the subscribed signal(s)
Check Sync & AR Relay	BCU/CSWI1.Pos.CtlVal (on)	Manual CB1 Closing	Check Sync (RSYN)
Check Sync & AR Relay	BCU/CSWI2.Pos.CtlVal (on)	Manual CB2 Closing	Check Sync (RSYN)
Check Sync & AR Relay	FdrPro/MMXU.PhV *mag and angle are required	V Line (magnitude and angle)	Check Sync (RSYN)
S Check Sync & AR Relay	FdrPro/MMXU.Hz	f Line	Check Sync (RSYN)
Check Sync & AR Relay	FdrPro/MMXU.PhV *mag and angle are required	V Bus 1 (magnitude and angle)	Check Sync (RSYN)
Check Sync & AR Relay	FdrPro/MMXU.Hz	f Bus 1	Check Sync (RSYN)
Check Sync & AR Relay	FdrPro/MMXU.PhV *mag and angle are required	V Bus 2 (magnitude and angle)	Check Sync (RSYN)
Check Sync & AR Relay	FdrPro/MMXU.Hz	f Bus 2	Check Sync (RSYN)

Table 7-17: Subscriber GOOSE Table for Standalone Check Sync & AR relay (two breakers)

In addition to the previous example, the line protection should also publish not only the line frequency but as well as the bus 1 and 2 voltages and frequency.

The selection of the Bus Voltage (V_{Bus}) for double busbar or, breaker and half arrangement is made using an external switch. The use of Samples Analogue Value could allow the development of an automatic selection instead of using an external switch.

7.7 Breaker Control IED

7.7.1 Introduction

As previously described for the protection signals, a similar approach can be taken with control and status signals for switches in which GOOSE messages are used as replacements of hardwires. Such a Breaker Control IED can be installed either in the circuit breaker cabinet in the switchyard or within the relay/control room. In the following example, we consider that the BF, AR and CS functions are not integrated into the Breaker Control IED.

7.7.2 Main Functions of Breaker Control IED

In some substation applications, instead of having a separate trip/close wire connected to the same Circuit Breaker for each individual protective or control IED, a Breaker Control IED can be used to combine all trip or close signals from all the IEDs that need to operate the circuit breaker.

In addition, the Breaker Control IED monitors any change of the CB status (e.g. position status, pressure, etc.) via auxiliary contacts and provides them to related IEDs. It will also provide some auxiliary functions such as breaker status supervision and anti-pump circuit.

The main functions of a Breaker Control IED are:

a) Acquisition of primary switch status information

b) Execution of Trip/Close command of the primary switches either locally or remotely (SCADA, Bay Control Unit, protection IEDs, etc.)

c) Phase segregated tripping and closing circuit (no integrated logic such as pole discrepancy).

d) Anti-pumping function which prevents the reclosing of the circuit breaker until the cause of the failure to close has been corrected. If an anti-pump function exists in the circuit breaker itself, the anti-pump function of Breaker Control IED should be put out of service.

e) Circuit Breaker Close and Trip Coil Supervision.

f) Pressure supervision. The Breaker Control IED supervises all kinds of pressure signals to alert and block tripping/closing command depending on pressure level.

7.7.3 Description of the Signal Interactions

When a power system fault occurs, protection IEDs will detect the fault and issue a trip command to the Breaker Control IED. The Breaker Control IED trips the corresponding circuit breakers using hardwires (tripping Phase A, B, C or 3 phase tripping). After the tripping, the Breaker Control IED will acquire the new Breaker Status position (52a / 52b status) which will also be provided to the relevant IEDs using hardwired signals. Additionally other status information might be available such as Low Pressure, etc.

As already described in the previous sections, the trip signal of the protection IEDs is also hardwired to initiate the external AR function. The AR Close Command is hardwired to the Breaker Control IED to execute the reclosing. In addition, the trip signal of the protection IEDs is also hardwired to initiate the external BF function. Re-trip signals are also hardwired to the Breaker Control IED.

The remote Control Command signal (Opening/Closing) from either RTU/SCADA or local Substation Automation Systems or Bay Control Unit is also hardwired to the Breaker Control IED.

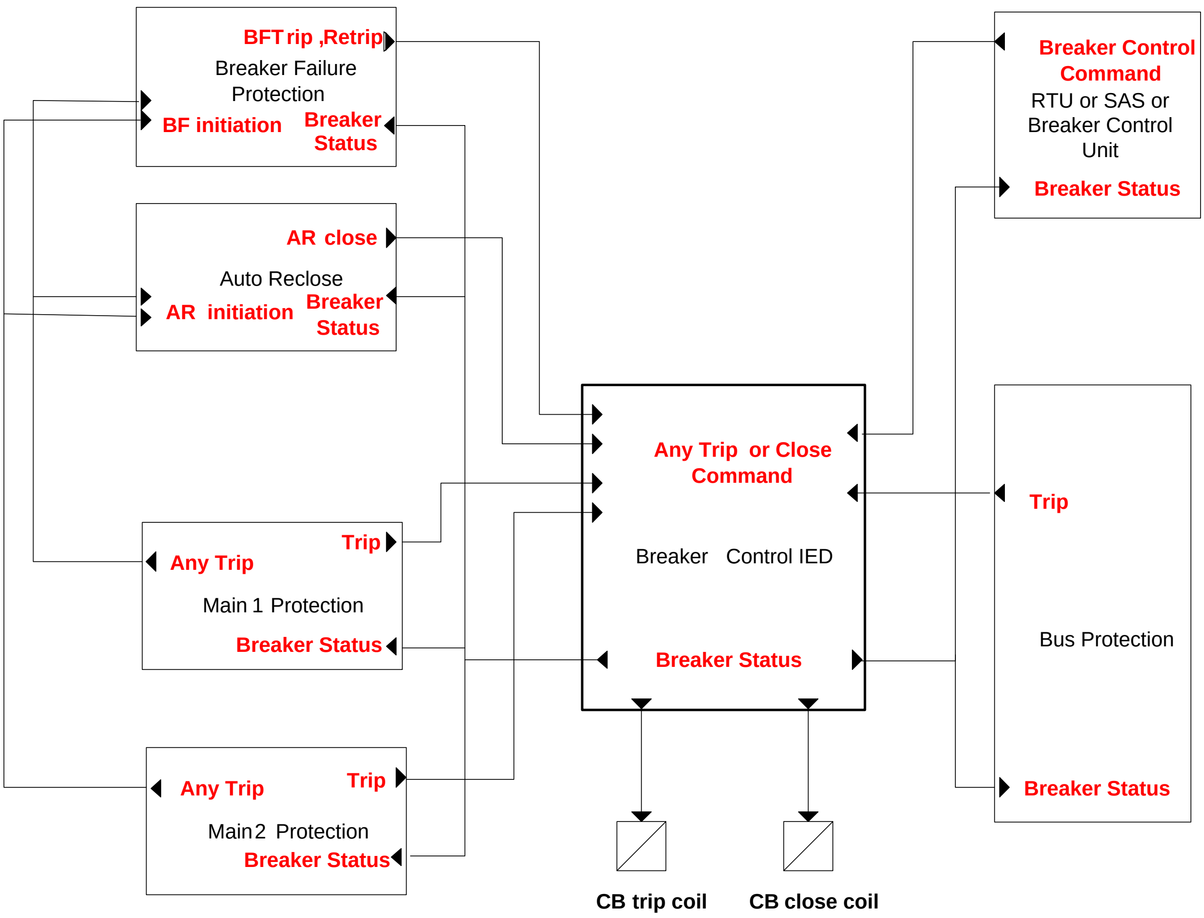

Figure 7-38: Hardwired Logic for Standalone Breaker Controller

7.7.3.1 Use of IEC GOOSE Message

The Figure 7-39 shows a typical application of a Breaker Control IED based on GOOSE communication (to simplify the figure, only the network A is shown while in real projects, a redundant separated Network B may also be available for higher reliability consideration).

In a substation, the Breaker Control IED is located between the secondary devices and the high voltage primary equipment, functioning as a digital interface of the un-digitalized breakers.

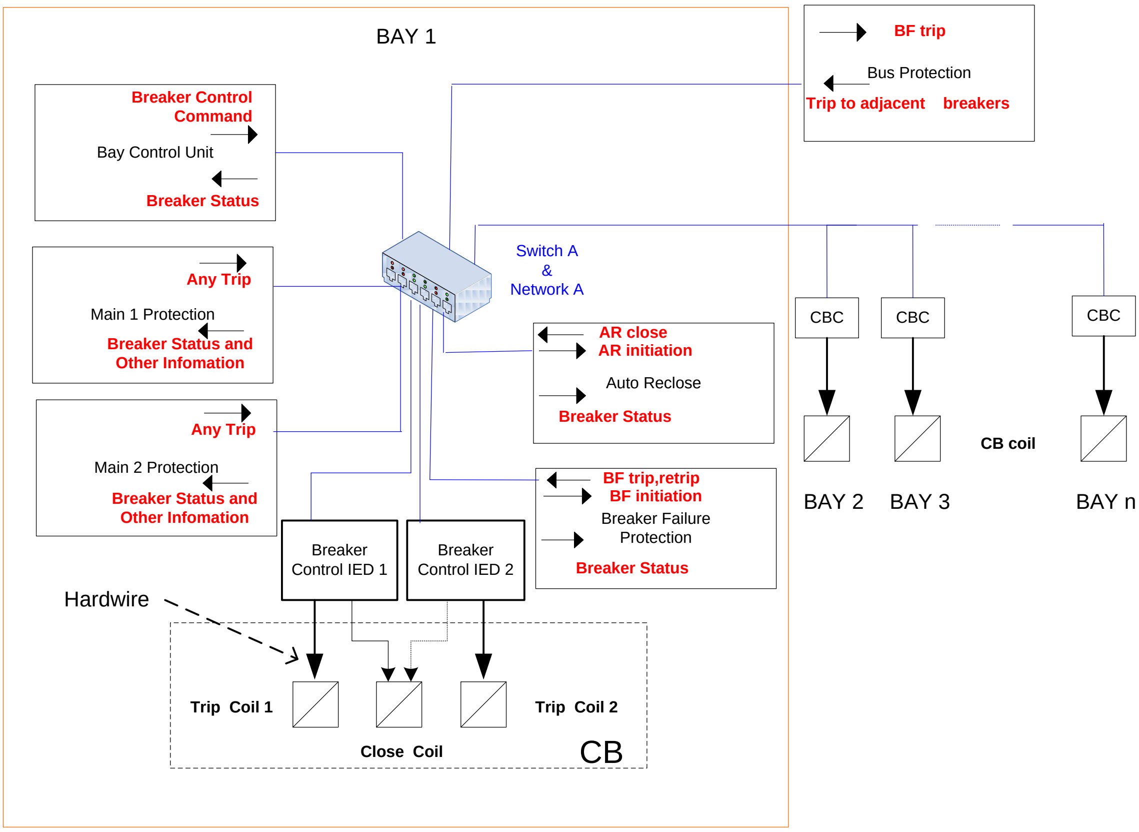

Figure 7-39: Ethernet Architecture for Standalone Breaker Controller

At the process bus level, Breaker Control IED can communicate with upper level intelligent IEDs such as protection devices, Auto Reclosure (AR) and Bay Control Unit (BCU).

For the GOOSE communication, the Breaker Control IED can work as a subscriber and a publisher at the same time, so it can receive and send GOOSE messages simultaneously.

As a publisher, the Breaker Control IED continuously publishes the status information gathered from the breakers to all other IEDs on the process bus, so all the subscriber IEDs (including protection devices, AR and BCU) can receive these messages and thus get the real time information of breaker position status and some other information, these information are useful to these bay level IEDs and can be applied into all kinds of function logic processing.

As a subscriber, the Breaker Control IED receives GOOSE control commands from all the related publishers (such as protection devices, AR, BF and BCU).

7.7.3.1.1 Main Protection device

When system fault occurs, the main protection device will detect the fault and take actions to send the GOOSE trip message to the Breaker Control IED in no time. Meanwhile, the Breaker Control IED receives the trip message from the process bus, identifies it, and trips the corresponding circuit breakers via parallel wires. After the tripping, the Breaker Control IED will get the circuit breaker new open position status by inputs and then publish the updated breaker status information to all related devices including the protective device.

<table>
<tr><th>IED Name</th><th colspan="2">GOOSE Signal</th><th>Publisher</th><th>Subscriber</th></tr>
<tr><td>Main Protection</td><td colspan="2">Any Trip</td><td>X</td><td></td></tr>
<tr><td>Breaker Control IED</td><td colspan="2">Any Trip</td><td></td><td>X</td></tr>
<tr><td rowspan="5">Breaker Control IED</td><td>CB Status</td><td rowspan="5">Breakers Status Information</td><td rowspan="5">X</td><td rowspan="5"></td></tr>
<tr><td>DS/ES Status</td></tr>
<tr><td>Block Signal Status</td></tr>
<tr><td>Discrepancy Status</td></tr>
<tr><td>Other Information</td></tr>
<tr><td>Main Protection</td><td colspan="2">Breaker Status Information</td><td></td><td>X</td></tr>
</table>

Table 7-18: Subscriber / Publisher GOOSE Table for Main Protection device

Note: Abbreviations used

CB: Circuit Breaker

AR: Auto Reclosure

BF: Circuit Breaker Failure protection

DS/ES: Disconnect Switch/Earthing Switch

BCU: Bay Control Unit

7.7.3.1.2 Auto Reclosure

The GOOSE trip message of the Main protection IED can also be received by the AR device, and it can apply this information to initiate the auto re-closing element inside the device. After the Breaker Control IED trips the circuit breaker successfully, it will publish the new open position status of the CB. When receiving this open status information of the CB, the auto reclosing element will operate to send a GOOSE close message.

<table>
<tr><th>IED Name</th><th colspan="2">GOOSE Signal</th><th>Publisher</th><th>Subscriber</th></tr>
<tr><td>Main Protection</td><td colspan="2">Any Trip</td><td>X</td><td></td></tr>
<tr><td>AR</td><td colspan="2">Any Trip ——Initiate</td><td></td><td>X</td></tr>
<tr><td rowspan="4">Breaker Control IED</td><td>CB Status</td><td rowspan="4">Breakers Status Information</td><td rowspan="4">X</td><td rowspan="4"></td></tr>
<tr><td>DS/ES Status</td></tr>
<tr><td>Block Signal Status</td></tr>
<tr><td>Other information</td></tr>
<tr><td>AR</td><td colspan="2">Breakers Status Information</td><td></td><td>X</td></tr>
<tr><td>AR</td><td colspan="2">CB Close</td><td>X</td><td></td></tr>
<tr><td>Breaker Control IED</td><td colspan="2">CB Close</td><td></td><td>X</td></tr>
</table>

Table 7-19: Subscriber / Publisher GOOSE Table for Auto reclosure

7.7.3.1.3 Circuit Breaker Failure protection

When the main protection device detects the fault and sends the GOOSE trip message via the process bus to trip the related circuit breakers, the Breaker Failure protection can also receive the GOOSE trip signal, which can be applied to initiate the breaker failure protection element inside the device.

This initiation signal can also obtained from the Breaker Control IED: when the auxiliary protection device detects a fault, it will send the GOOSE trip message to the Breaker Control IED and it will trip the associated circuit breakers and at the same time transfer the GOOSE trip signal to the BF device as a circuit breaker failure element initiation signal. If for some reason, the protection device finally fails to trip the circuit breaker, the breaker failure element will trip the circuit breaker again via GOOSE message (re-trip signal). For the tripping of the adjacent circuit breakers (back-trip signal), the BF device can directly send a GOOSE trip message to those adjacent Breaker Control IEDs when the breaker failure protection element operates.

IED Name	GOOSE Signal	Publisher	Subscriber
Main Protection	Any Trip(MP)	X	
BF	Any Trip(MP) ——Initiate		X
Auxiliary Protection	Any Trip(AP)	X	
Breaker Control IED	Any Trip(AP)		X
Breaker Control IED	Any Trip(AP)	X	
BF	Any Trip(AP) ——Initiate		X
BF	BF Trip	X	
Bus Protection	BF Trip		X
Breaker Control IED	BF Trip		X
Breaker Control IED	CB Discrepancy Status	X	
BF	CB Discrepancy Status		X

Table 7-20: Subscriber / Publisher GOOSE Table for Breaker Failure Protection

7.7.3.1.4 Bay Control Unit

BCU receive the remote control command via MMS communication from station RTU or SCADA, then it sends corresponding open or close GOOSE message to the Circuit Breaker Controller, which will finally trip or close the breakers via hardwire connection. The GOOSE messages interaction can be defined as following table:

IED Name	GOOSE Signal	Publisher	Subscriber
Breaker Control IED	Breakers Status Information	X	
BCU	Breakers Status Information		X
BCU	Trip or Close	X	
Breaker Control IED	Trip or Close		X

Table 7-21: Subscriber / Publisher GOOSE Table for Bay Control Unit

7.7.3.2 Main Functions of Breaker Control IED

In real life, Breaker Control IED should not only provide the functions of GOOSE message sending/receiving processing and tripping/closing the breakers, but also provide some auxiliary functions such as breaker status supervision and anti-pump circuit. The main functions of Circuit Breaker Controller can be listed as the following.

g) **Gather information from breakers as well as send control commands to them.** The Circuit Breaker Controller contains lots of hardwire input/output contacts which enable it to communicate with the traditional analogue signal based breakers. These contacts permit the Circuit Breaker Controller to gather breakers position status, control pressure status and some other information from the bay breakers and also permit Breaker Control IED to send trip or close control commands to these breakers.

h) **Send breakers information to bay level device via GOOSE message.** After the Breaker Control IED gathers the electrical information from the bay breakers, it will convert these electrical analogue signals into digital signals and publish them at the bay level IEDs via the process bus.

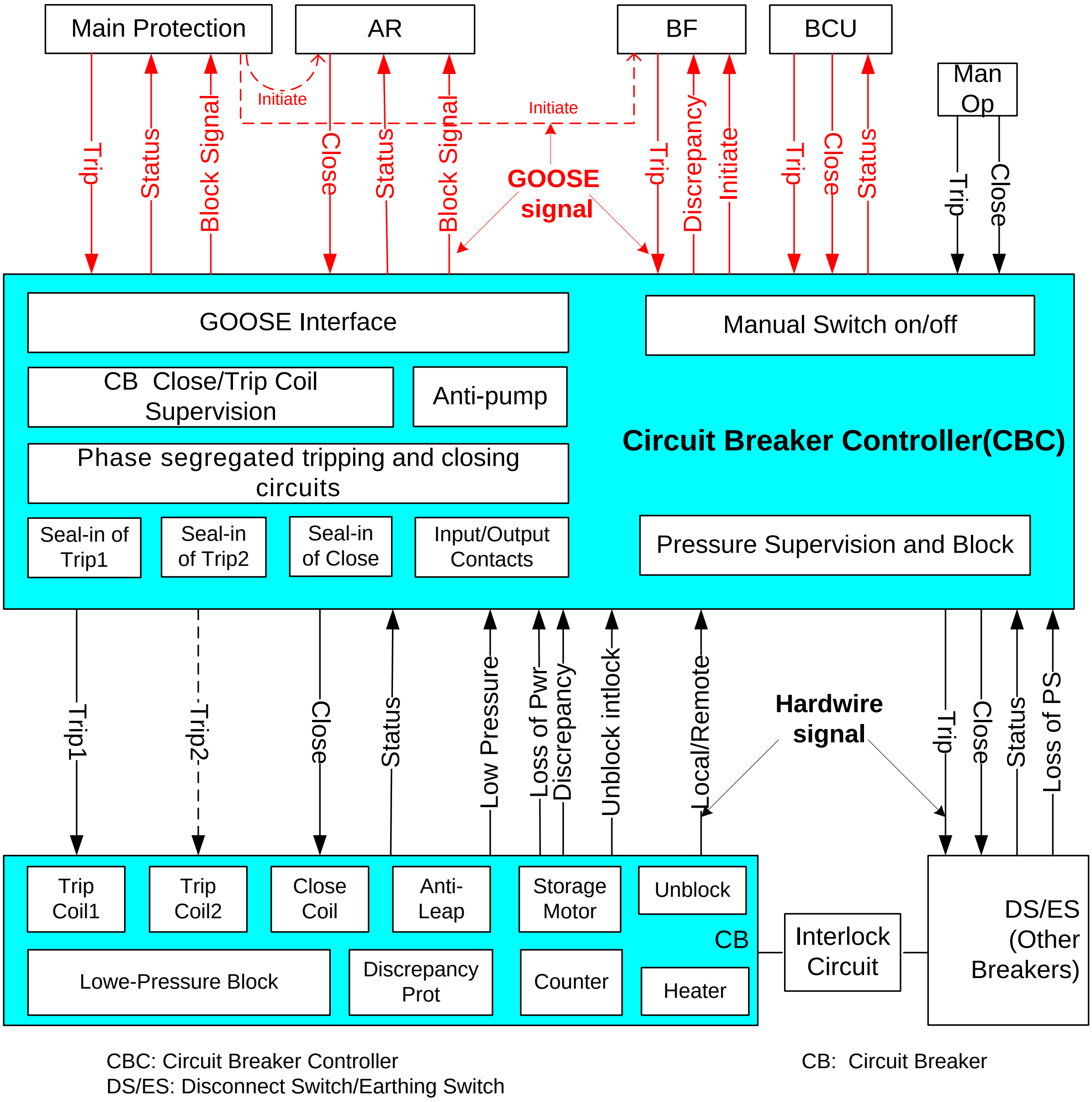

Figure 7-40: BC Functional and Signal Interactions

i) **Receive GOOSE message from bay level device and operate the breakers.** When a power system fault occurs or remote control command is issued, the related protective device or bay control unit will publish the corresponding GOOSE message (i.e. trip command, close command) immediately. As one of the subscribers, the Breaker Control IED is able to receive these GOOSE messages and take the right actions to trip or close the related breaker via hardwire output contacts.

j) **Phase segregated tripping and closing circuits.** The Breaker Control IED may comprise phase segregated tripping circuits and phase segregated closing circuits. Usually, the Breaker Control IED should provide control circuit for a three-phase circuit breaker with one close coil and two trip coils.

k) **Repeated tripping prevention circuit (Anti-pump).** If the breaker is manually closed or automatically re-closed on a permanent fault and the closing signal lasts for relatively long time, the breaker may be closed many times after tripping. Repeated tripping prevention circuits (Anti-pump function) should be provided in Breaker Control IED to prevent such repeated tripping, thus the circuit breaker will trip only once as expected by preventing further closing until the closing circuit has been de-energized by the operator's releasing the control switch. If there is also an anti-pump circuit in the circuit breaker itself, the anti-pump function in Breaker Control IED should be released by configuration.

l) **Circuit Breaker Close Coil Supervision.** The Breaker Control IED sometimes should also provide the function support for circuit breaker close or trip state supervision. The close state supervision can be achieved by auxiliary relays in the device while the corresponding terminal is connected to the negative pole of power supply in series with normal closed auxiliary contact (52b) of circuit breaker. In addition, if this terminal is connected with normal closed auxiliary contact (52b) of circuit breaker and its close coil (CC), these auxiliary relays can provide supervision on close coil as well.

m) **Circuit Breaker Trip Coil Supervision.** Several auxiliary relays in the relay can also be applied to supervise the open state of circuit breaker while the corresponding terminal is connected to the negative pole of power supply in series with normal open auxiliary contact (52a) of circuit breaker. In addition, if this terminal is connected to normal open auxiliary contact of circuit breaker (52a) and its trip coil (TC), the related auxiliary relays can provide supervision on trip coil as well.

n) **Pressure Supervision and Block.** The pressure in breakers is critical for breaker operation, and mal-operation to these breakers in abnormal pressure will decrease the lifetime of the breakers and even damage them. So the Breaker Control IED should supervise all kinds of pressure signals in the related circuit breaker and implement corresponding pressure block when trip or close command comes. These block functions are:

- Operation (trip & close) blocked by abnormal pressure
- Re-closing blocked by low pressure
- Closing blocked by low pressure
- Tripping blocked by low pressure

o) **Manual Switch on/off.** Besides providing the function for protection device tripping and auto-reclosing, the Breaker Control IED should also provide manual switch on/off in the device for convenient operation to the breakers

7.8 Distribution Feeder: Breaker Failure Protection Scheme for One or Two Bus Sections

7.8.1 Introduction

Following inception of a feeder fault the feeder PIED will operate and issue a trip output to the feeder circuit breaker. Operation of the circuit breaker is essential to isolate the fault and prevent damage / further damage to the power system. If rapid fault clearance is required it is common practice to install a BF function, which monitors that the circuit breaker has opened within a reasonable time. If the fault current has not been interrupted following a set time delay from the feeder circuit breaker trip initiation, the BF function will operate. BF operation is used to trip the adjacent circuit breakers to ensure that the fault is isolated correctly.

7.8.2 One busbar section with One Infeed

7.8.2.1 Description of the Signal Interactions

In the following example, the BF function is incorporated in the feeder PIEDs. The following signals are conventionally wired: BF operated signals between the feeder PIEDs 1A and 1B and the incomer CB.

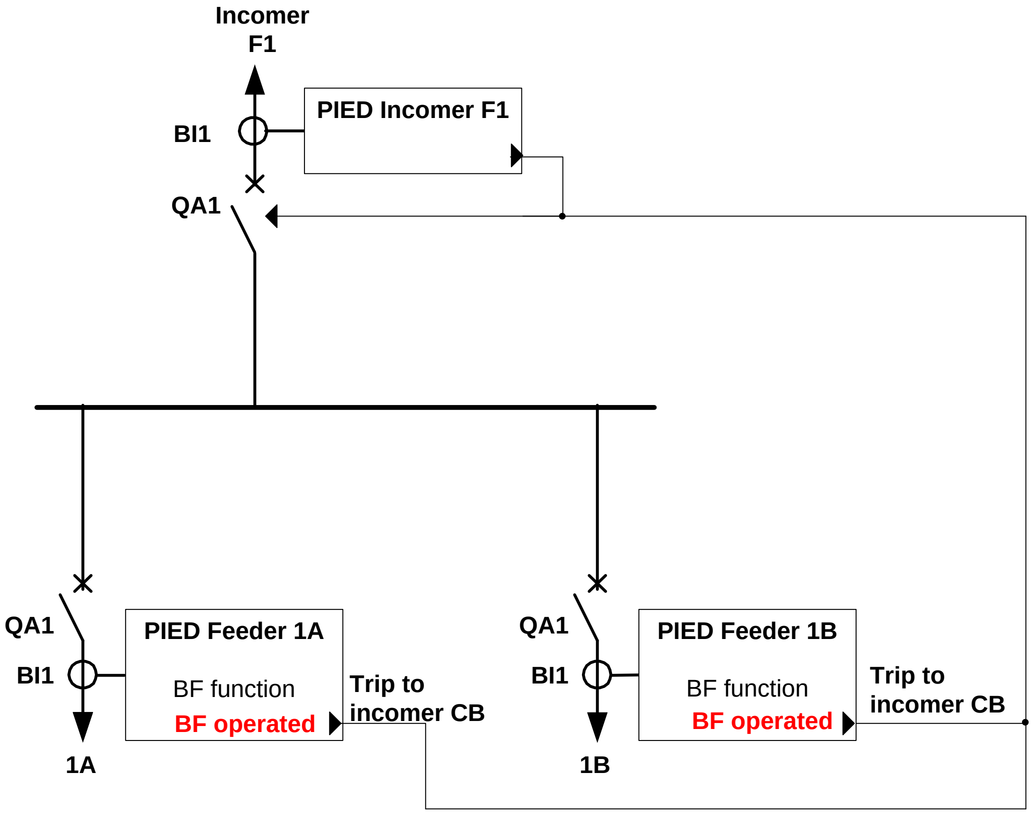

Figure 7-41: BF protection scheme for one busbar section

7.8.2.2 Use of IEC GOOSE Message

The wired BF operated signals can be replaced by GOOSE messages. The tripping of the incomer CB may remain conventionally wired, as shown in Figure 7-42.

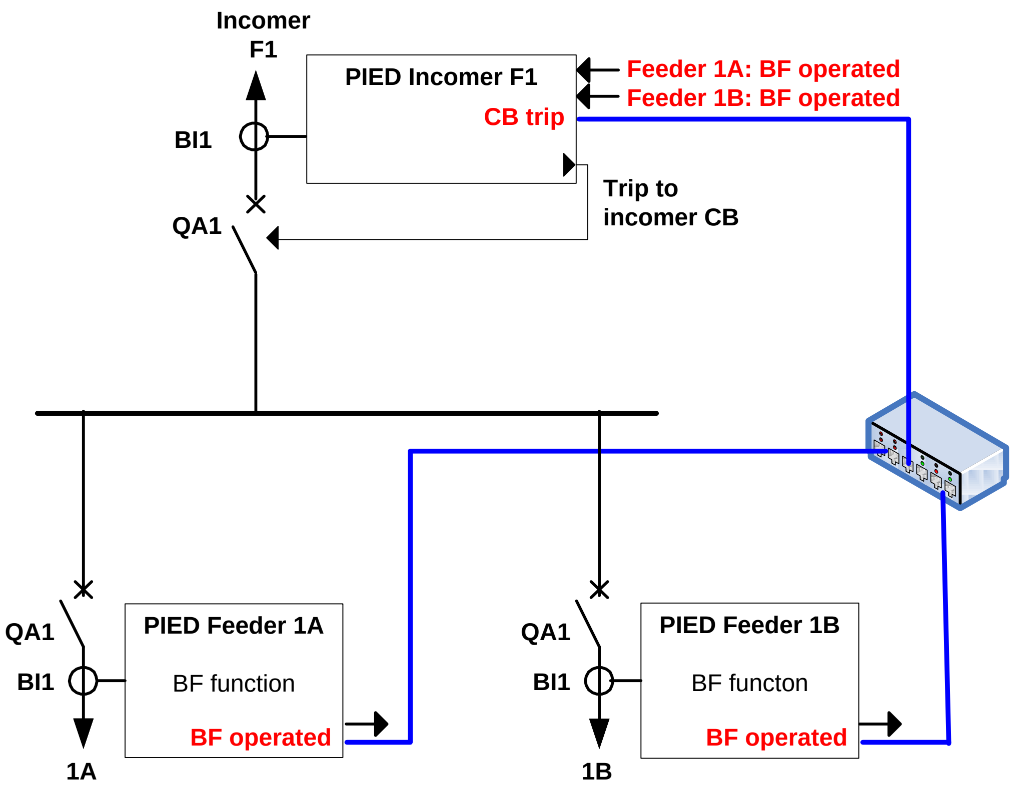

Figure 7-42: BF protection scheme for one busbar section using GOOSE messages

The publishing IEDs must provide the following PD/LN.DO.Attributes in the GOOSE message Datasets:

IED Name	IED internal signal description	Source IED Name/Published GOOSE Data Object
Feeder 1A (Fdr1A)	Breaker Failure operated	Fdr1A/ RBRF.Op (True)
Feeder 1B (Fdr1B)	Breaker Failure operated	Fdr1B/ RBRF.Op (True)

Table 7-22: Publisher GOOSE Table for BF protection scheme (one busbar)

The subscribing IEDs must have the following PD/LN.DO.Attributes available from the subscribed GOOSE message Datasets:

IED Name	Source IED Name/Subscribed GOOSE Data Object	Subscribed IED signal description	Function using the subscribed signal(s)
Incomer F1	Fdr1A/ RBRF.Op (True)	Feeder 1A: Breaker Failure operated	CB trip (PTRC)
Incomer F1	Fdr1B/ RBRF.Op (True)	Feeder 1B: Breaker Failure operated	CB trip (PTRC)

Table 7-23: Subscriber / Publisher GOOSE Table for BF protection scheme (one busbar)

PIED Feeder 1A and PIED feeder 1B publish GOOSE messages containing BF operate change of state information. The incomer PIED subscribes to the BF operate data in GOOSE messages from feeder 1A and feeder 1B.

In the incomer PIED these two PIED internal signals are input to a separate PIED internal logic which OR-connects the two signals. The output (Incomer CB trip) is routed or mapped to the PIED's PRTC trip.

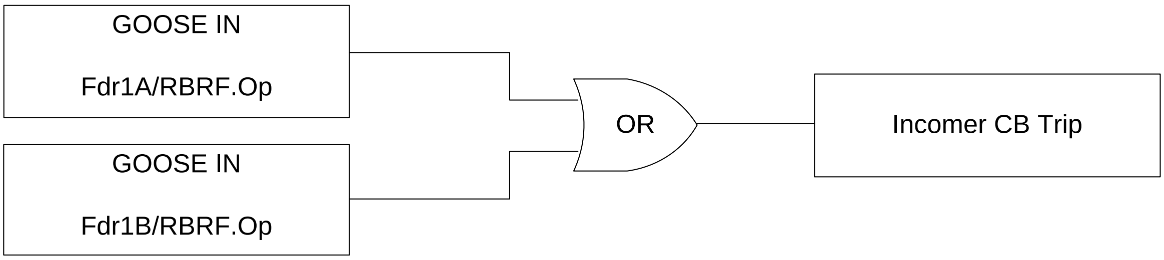

Figure 7-43: Incomer PIED Internal Logic for BF protection scheme (one busbar)

7.8.3 <u>Two busbar sections, each with One Infeed</u>

7.8.3.1 Description of the Signal Interactions

In the following example, the BF function is incorporated in the feeder PIEDs and the bus section PIED. The BF function in the bus section PIED can also be used to monitor the bus section CB opening in case of a CB failure in one of the feeders. Therefore the bus section BF function is started by the BF function operated signals of the feeder PIEDs.

The following signals are conventionally wired:

<u>Bus Zone 1:</u>

a) BF trip signals of the feeder PIEDs 1A and 1B to trip the F1 incomer CB.
b) BF trip signals of the feeder PIEDs 1A and 1B to trip the bus section CB.
c) BF trip signals of the feeder PIEDs 1A and 1B to start the BFP in the bus section PIED

<u>Bus Zone 2:</u>

a) BF trip signals of the feeder PIEDs 2A and 2B to trip the F2 incomer CB.
b) BF trip signals of the feeder PIEDs 2A and 2B to trip the bus section CB.
c) BF trip signals of the feeder PIEDs 2A and 2B to start the BFP in the bus section PIED
d) BF trip signal of the bus section PIED to trip both incomer CBs.

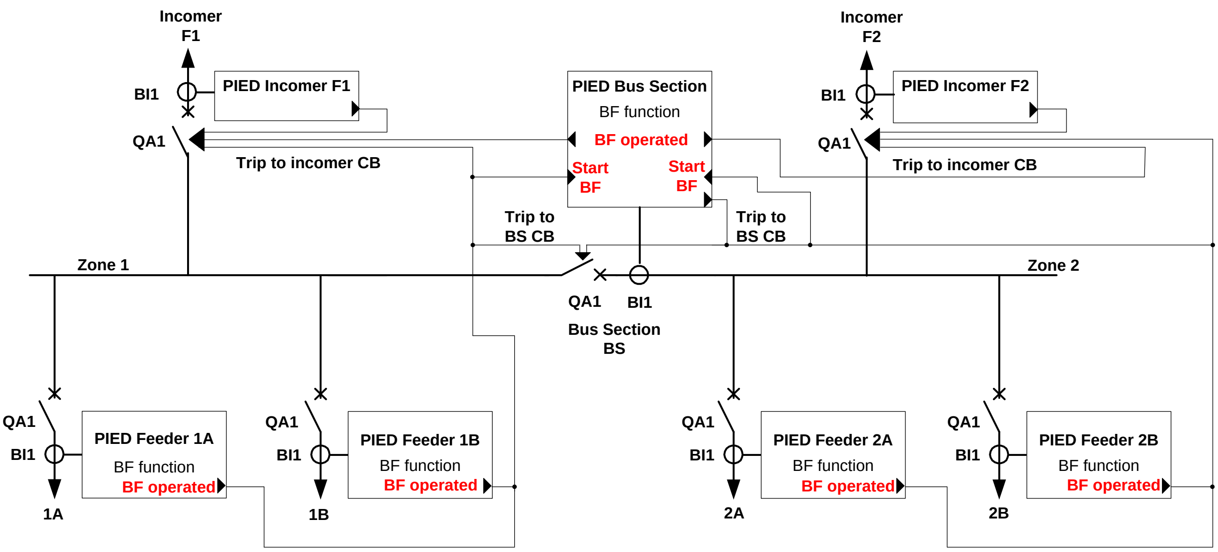

Figure 7-44: BF protection scheme for two busbar sections

7.8.3.2 Use of IEC GOOSE Message

BF trip signals can be replaced by GOOSE messages. Tripping of the incomer CB and the bus section CB may remain conventionally wired, as shown in Figure 7-45.

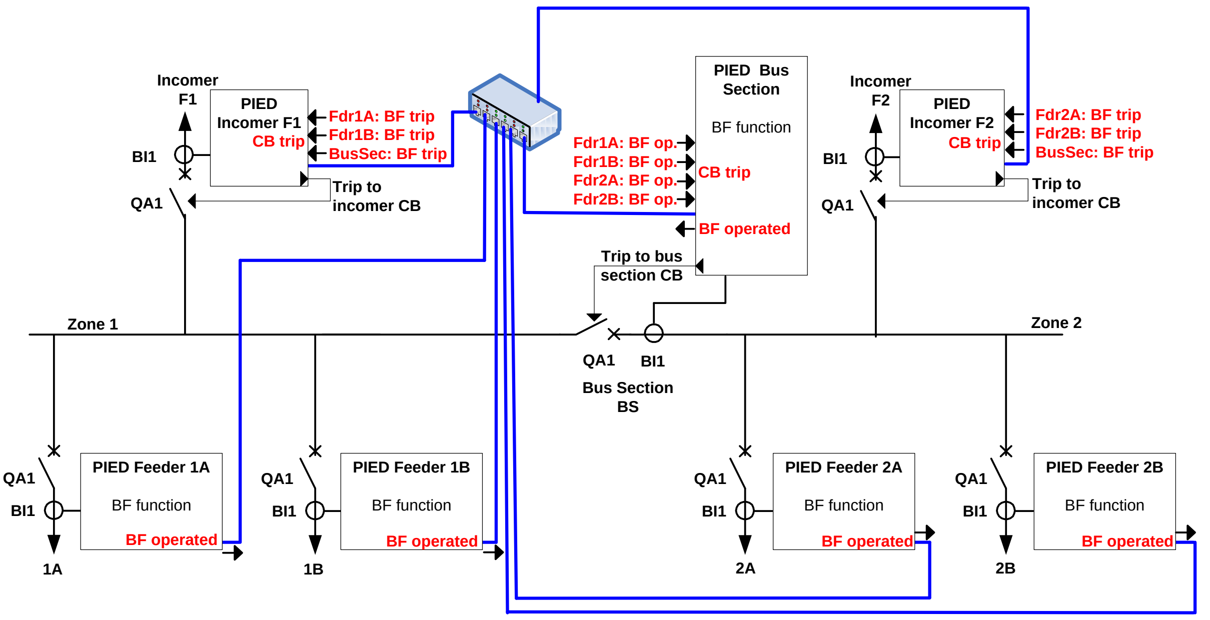

Figure 7-45: BF protection scheme for two busbar sections using GOOSE messages

The publishing IEDs must provide the following PD/LN.DO.Attributes in the GOOSE message Datasets:

IED Name	IED internal signal description	Source IED Name/Published GOOSE Data Object
Feeder 1A (Fdr1A)	Breaker Failure operated	Fdr1A/ RBRF.Op (True)
Feeder 1B (Fdr1B)	Breaker Failure operated	Fdr1B/ RBRF.Op (True)
Bus Section (BusSec)	Breaker Failure operated	BusSec/ RBRF.Op (True)
Feeder 2A (Fdr2A)	Breaker Failure operated	Fdr2A/ RBRF.Op (True)
Feeder 2B (Fdr2B)	Breaker Failure operated	Fdr2B/ RBRF.Op (True)

Table 7-24: Publisher GOOSE Table for BF protection scheme (two busbars)

The subscribing IEDs must have the following PD/LN.DO.Attributes available from the subscribed GOOSE message Datasets:

IED Name	Source IED Name/Subscribed GOOSE Data Object	Subscribed IED signal description	Function using the subscribed signal(s)
Incomer F1	Fdr1A/ RBRF.Op (True)	Feeder 1A: BF operated	Incomer F1 CB trip (PTRC)
Incomer F1	Fdr1B/ RBRF.Op (True)	Feeder 1B: BF operated	Incomer F1 CB trip (PTRC)
Incomer F1	BusSec/ RBRF.Op (True)	Bus Section: BF operated	Incomer F1 CB trip (PTRC)
Incomer F2	Fdr2A/ RBRF.Op (True)	Feeder 2A: BF operated	Incomer F2 CB trip (PTRC)
Incomer F2	Fdr2B/ RBRF.Op (True)	Feeder 2B: BF operated	Incomer F2 CB trip (PTRC)
Incomer F2	BusSec/ RBRF.Op (True)	Bus Section: BF operated	Incomer F2 CB trip (PTRC)
Bus Section	Fdr1A/ RBRF.Op (True)	Feeder 1A: BF operated	Bus Section CB trip (PTRC)
Bus Section	Fdr1B/ RBRF.Op (True)	Feeder 1B: BF operated	Bus Section CB trip (PTRC)
Bus Section	Fdr2A/ RBRF.Op (True)	Feeder 2A: BF operated	Bus Section CB trip (PTRC)
Bus Section	Fdr2B/ RBRF.Op (True)	Feeder 2B: BF operated	Bus Section CB trip (PTRC)

Table 7-25: Subscriber GOOSE Table for BF protection scheme (two busbars)

Feeder PIEDs 1A and 1B of bus section 1 and feeder PIEDs 2A and 2B of bus section 2 publish GOOSE messages containing “BF Operate” change of state information. The bus section PIED publishes as well the “BF Operate” change of state information. The incomer PIED F1 (of bus section 1) subscribes to the “BF operate” data in GOOSE messages from feeder 1A and feeder 1B and the bus section PIED.

The incomer PIED F2 (of bus zone 2) subscribes to the “BF operated” data in GOOSE messages from feeder 2A and feeder 2B and the bus section PIED. The bus section PIED subscribes to all four feeder “BF operated” messages. This is for two means: first to trip the bus section CB and second, to start the internal BF function to monitor the opening of the bus section CB.

In the subscribing PIEDs the following internal logic is required:

Incomer F1

The three signals are input to an OR gate. The OR gate output (F1 incomer CB trip) is routed or mapped to the PIED's PTRC trip.

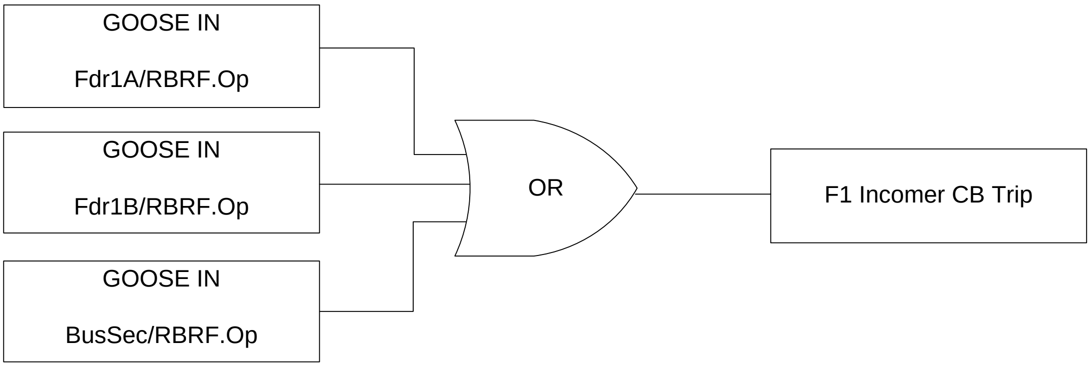

Figure 7-46: Incomer F1 IED internal logic for BF protection scheme (two busbars)

Incomer F2

The three signals are input to an OR gate. The OR gate output (F2 incomer CB trip) is routed or mapped to the PIED's PTRC trip.

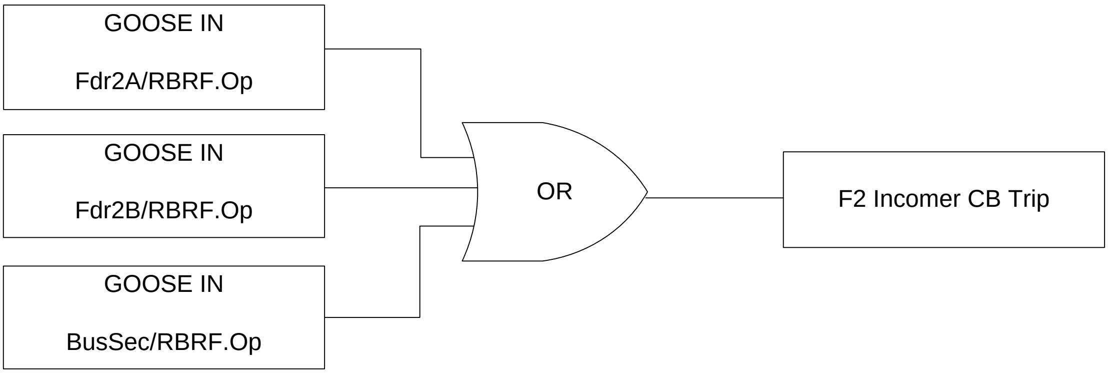

Figure 7-47: Incomer F2 IED internal logic for BF protection scheme (two busbars)

Bus Section

The four signals are input to an OR gate. The OR gate output is routed or mapped to the PIEDs PTRC trip and to the internal BF start.

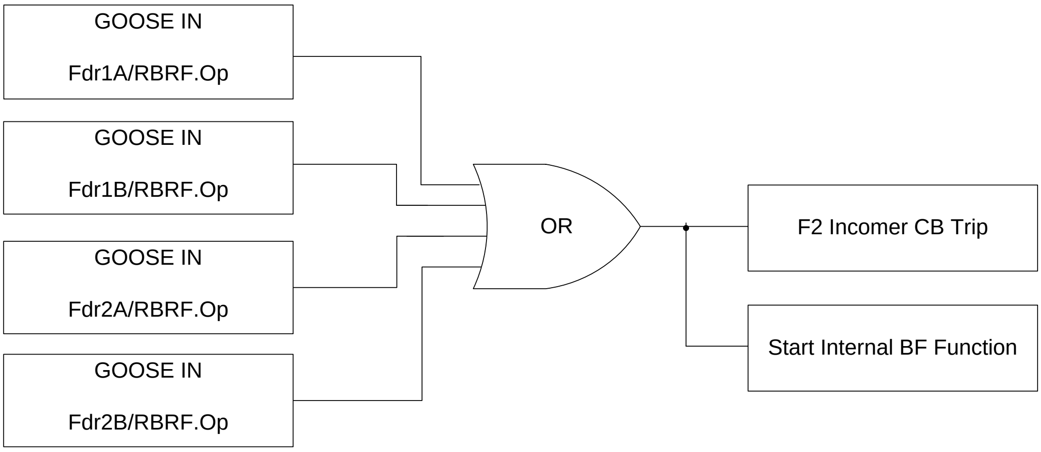

Figure 7-48: Bus section IED internal logic for BF protection scheme (two busbars)

7.9 Sympathetic Tripping or Blocking Scheme

7.9.1 Introduction

The changes of fault conditions in the distribution system impact not only the sensitive loads, but also depending on the load may lead to the undesired operation of protection elements of multifunctional relays on healthy feeders. One such example is the inrush current on healthy feeders with motor loads following the clearing of a short circuit fault on an adjacent feeder.

Detecting the operation of a relay on an adjacent feeder can be used to adjust the sensitive settings of the relays on the healthy feeders for the duration of an inrush condition following the clearing of a fault in a distribution system with a significant number of motor loads. This is known as a sympathetic tripping.

7.9.2 Description of the Signal Interactions

As illustrated in Figure 7-49, as soon as a relay detects a fault on the feeder that it is protecting, it sends a signal to all other feeder relays informing them to expect an inrush as a result of the voltage recovery following the clearing of the fault.

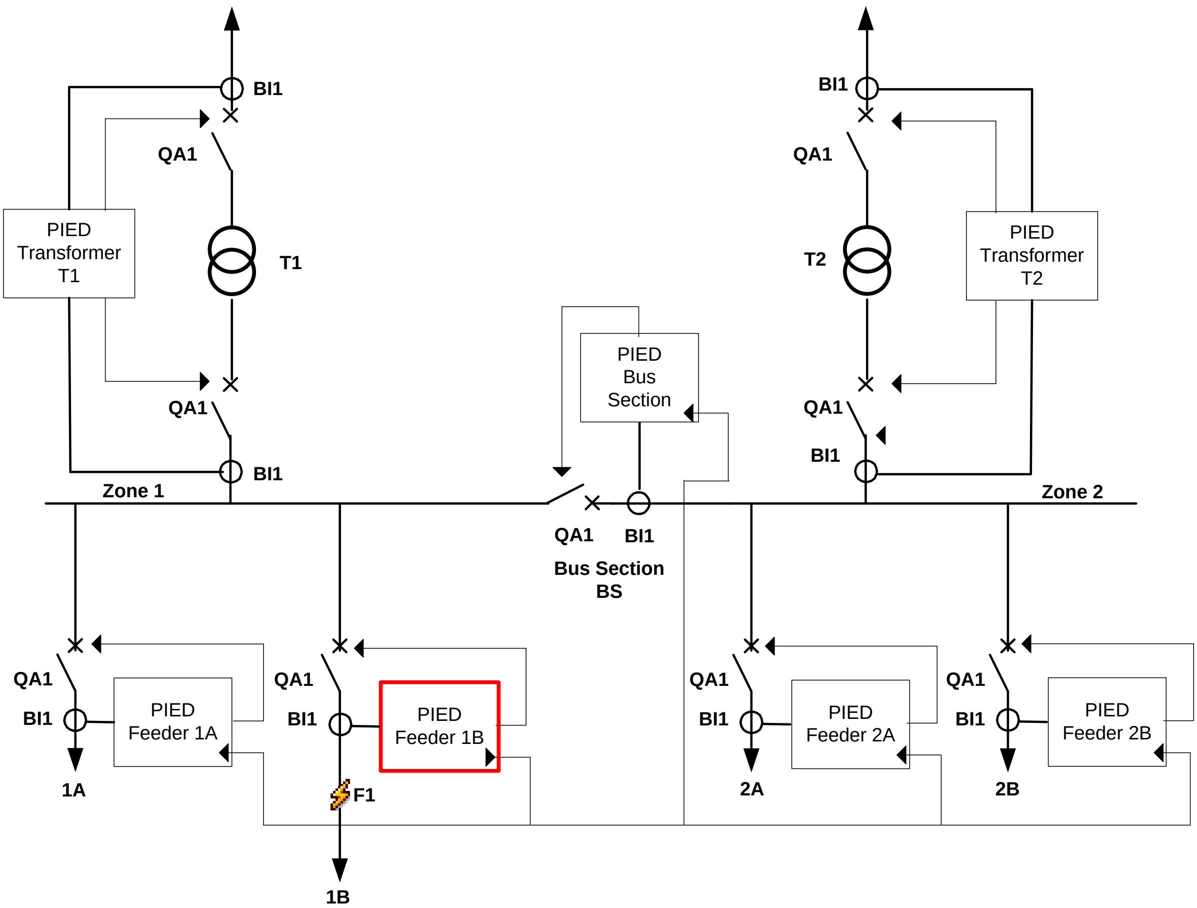

Figure 7-49: Protection against Sympathetic Trip

Each of the relays on the healthy feeders receives a signal from all adjacent feeder protection IEDs and when it receives this signal, it adapts its settings for the period of time that the expected inrush condition is going to last. Two options are usually available:

- block the sensitive overcurrent element
- reduce the sensitivity by increasing the pickup setting for the duration of the inrush

The problem with such a scheme is that it requires a large number of wires between the binary inputs and relay outputs of all distribution feeder protection IEDs. In some cases a large number of inputs and outputs may not be available, thus making it impossible to implement the scheme.

7.9.2.1 Use of IEC GOOSE Message

The use of GOOSE messages significantly simplifies the application of this scheme.

The following is the sequence of messages exchanged between the individual feeder relays:

1. As soon as a relay detects a fault on the feeder that it is protecting and the protection element operates, it sends a GOOSE message indicating that the faulted feeder will be tripped to clear the fault.
2. Each of the relays on the healthy feeders subscribes to GOOSE messages from all adjacent feeder protection IEDs and when it receives a message indicating adjacent feeder fault, it adapts its settings for the period of time that the expected inrush condition is going to last.

The benefit of using GOOSE messages in such a scheme is that instead of the large number of required wires between the binary inputs and relay outputs of all distribution feeder protection IEDs, they just need to publish and subscribe to GOOSE messages from the adjacent feeders' IEDs.

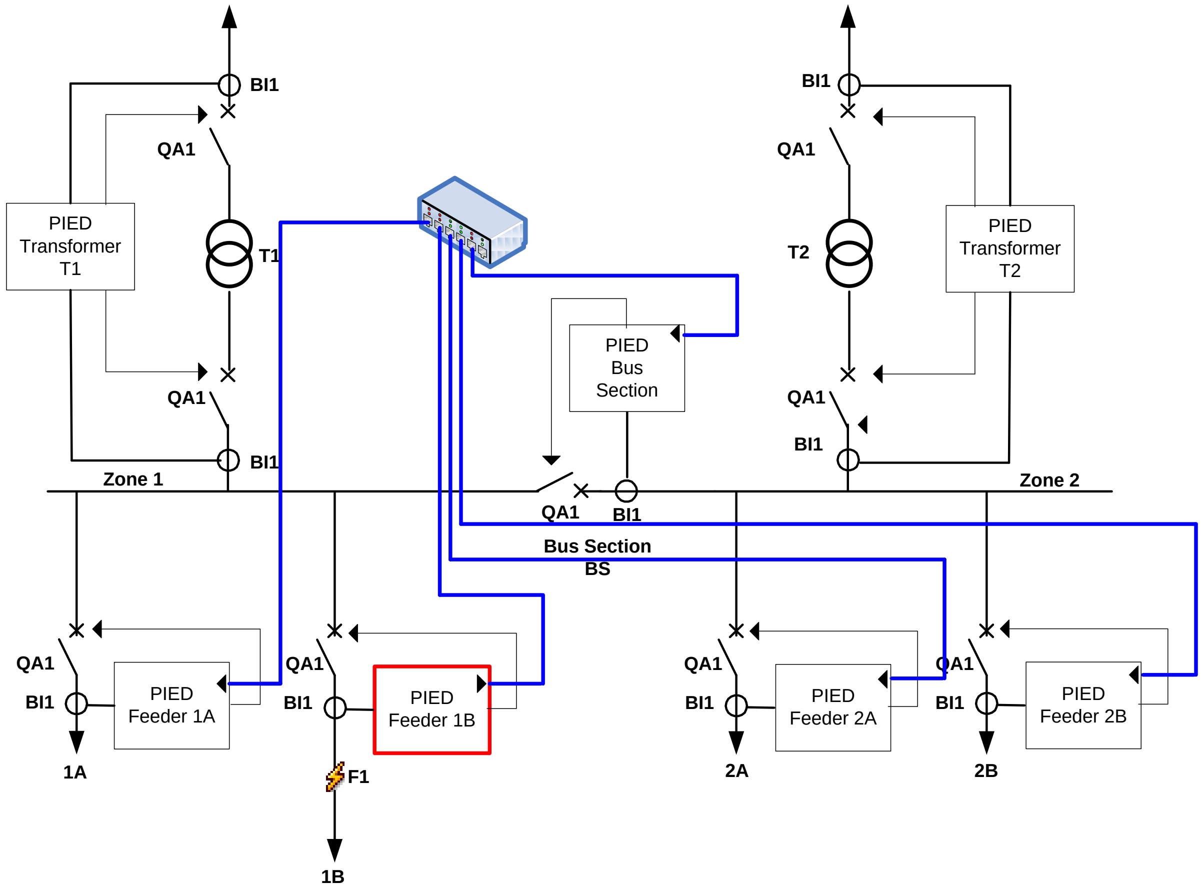

Figure 7-50: Sympathetic Trip Protection using GOOSE messages

7.10 Distribution bus protection

7.10.1 <u>Blocking Scheme</u>

7.10.1.1 Introduction

Figure 7-51 shows a typical distribution substation layout, where one incoming feeder ("incomer S1") supplies a number of outgoing radial feeders (F1-1, F1-2, F1-3, F1-4) from a single busbar (only one bus section). Three phase overcurrent and earth fault relays are already provided for conventional time-graded protection as shown. A busbar blocking scheme needs to be configured which will give fast tripping of the incomer S1 for the busbar fault shown at "A" whilst remaining stable for the feeder fault at "B". The feeder fault would be cleared by overcurrent protection tripping only the relevant outgoing feeder breaker.

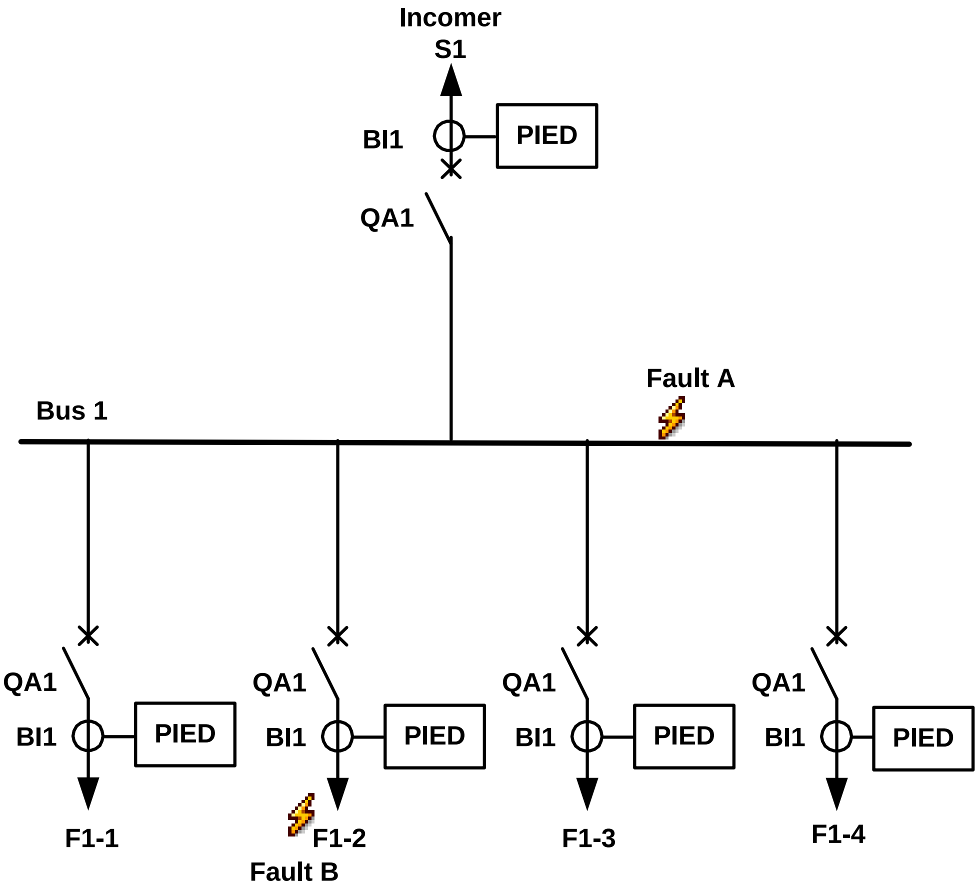

Figure 7-51: Typical Single Distribution Busbar With One Incoming Feeder

Traditionally, the incoming S1 feeder protection would not be able to distinguish between a busbar fault at A, and a close-up feeder fault at B. Busbar protection would be provided by an incoming feeder IDMT/DT relay, which had been set to time grade with all outgoing feeder protection. Hence, clearance of the busbar fault at A could have been slow.

7.10.1.2 Description of the Signal Interactions

Busbar blocking scheme logic provides a means to detect whether a fault is within the protected busbar zone (e.g. at A), or is external to the zone (e.g. at B). This allows the incoming feeder relay to determine whether to trip, or leave outgoing feeder protection to clear the fault, respectively. In a busbar blocking scheme, the detection of the fault current on a downstream device indicates that the fault is beyond this section of busbar. The detecting relay then blocks the upstream device from giving the fast busbar trip.

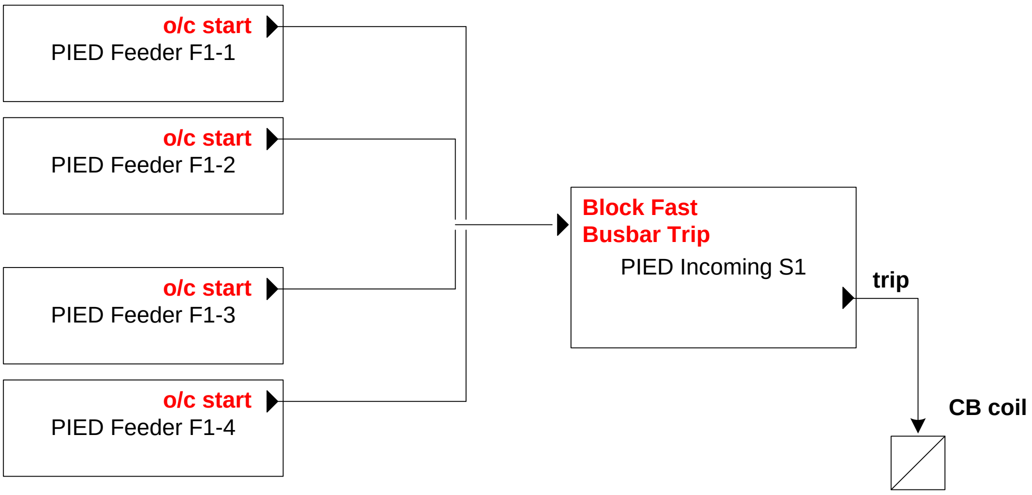

Figure 7-52: Hardwired Blocking Non-Directional Logic

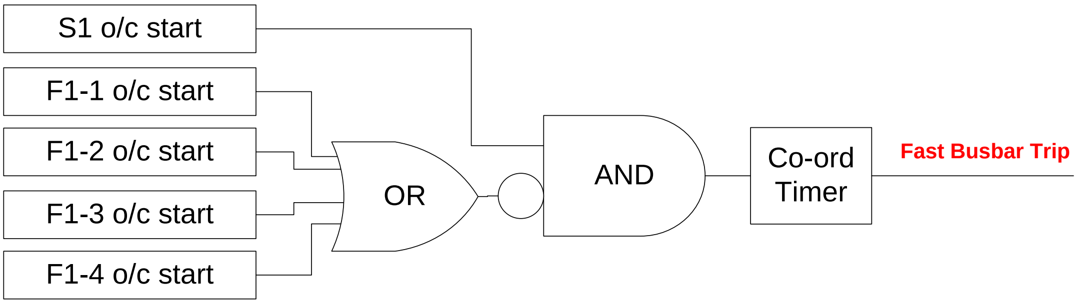

Figure 7-53: Typical logic implemented into the Incoming Feeder

7.10.1.3 Use of IEC GOOSE Message

The o/c start signal from all the outgoing feeders (F1-1, F1-2, F1-3 and F1-4) can be replaced by GOOSE message. The tripping signal as shown in the above figure may remain conventionally wired.

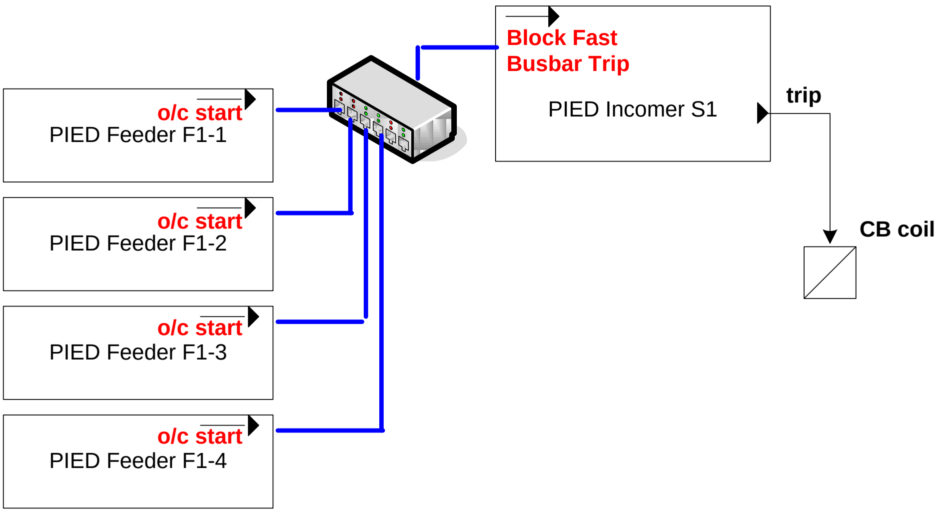

Figure 7-54: Ethernet Architecture for Blocking Non-Directional Logic

The publishing IEDs must provide the following PD/LN.DO.Attributes in the GOOSE message Datasets:

IED Name	IED internal signal description	Source IED Name/Published GOOSE Data Object
Feeder F1-1	O/C Start	Fdr1-1/PTOC.Str (True)
Feeder F1-2	O/C Start	Fdr1-2/PTOC.Str (True)
Feeder F1-3	O/C Start	Fdr1-3/PTOC.Str (True)
Feeder F1-4	O/C Start	Fdr1-4/PTOC.Str (True)
Incomer S1	O/C Start	FdrS1/PTOC.Str (True)

Table 7-26: Publisher GOOSE Table for Blocking Non-Directional Logic

The subscribing IEDs must have the following PD/LN.DO.Attributes available from the subscribed GOOSE message Datasets:

IED Name	Source IED Name/Subscribed GOOSE Data Object	Subscribed IED signal description	Function using the subscribed signal(s)
Incomer S1 (Fdr)	Fdr1-1/PTOC.Str (True)	O/C Start	Fast Busbar Trip (PTRC)
Incomer S1 (Fdr)	Fdr1-2/PTOC.Str (True)	O/C Start	Fast Busbar Trip (PTRC)
Incomer S1 (Fdr)	Fdr1-3/PTOC.Str (True)	O/C Start	Fast Busbar Trip (PTRC)
Incomer S1 (Fdr)	Fdr1-4/PTOC.Str (True)	O/C Start	Fast Busbar Trip (PTRC)

Table 7-27: Subscriber GOOSE Table for Blocking Non-Directional Logic

All outgoing feeder relays publish a GOOSE message containing “o/c start” change of state information. The incoming device subscribes to the “o/c start” data in GOOSE messages from all outgoing feeders to block the fast busbar trip.

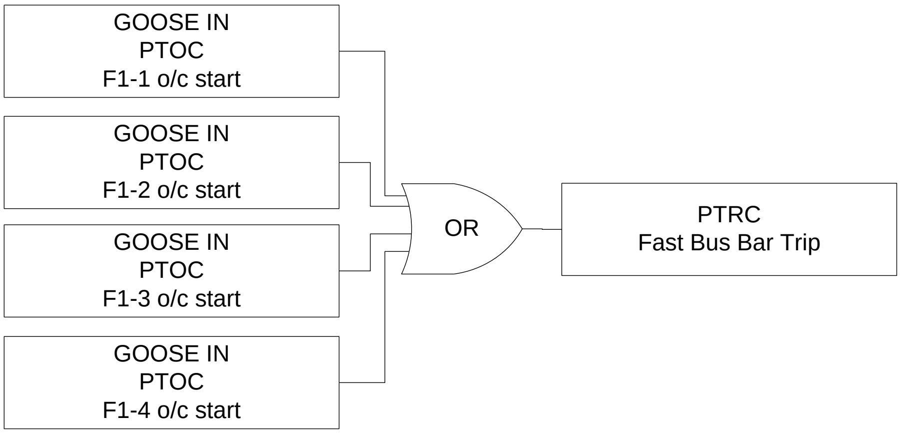

Figure 7-55: Blocking Non-Directional Scheme Logic Implemented in the Incoming Feeder

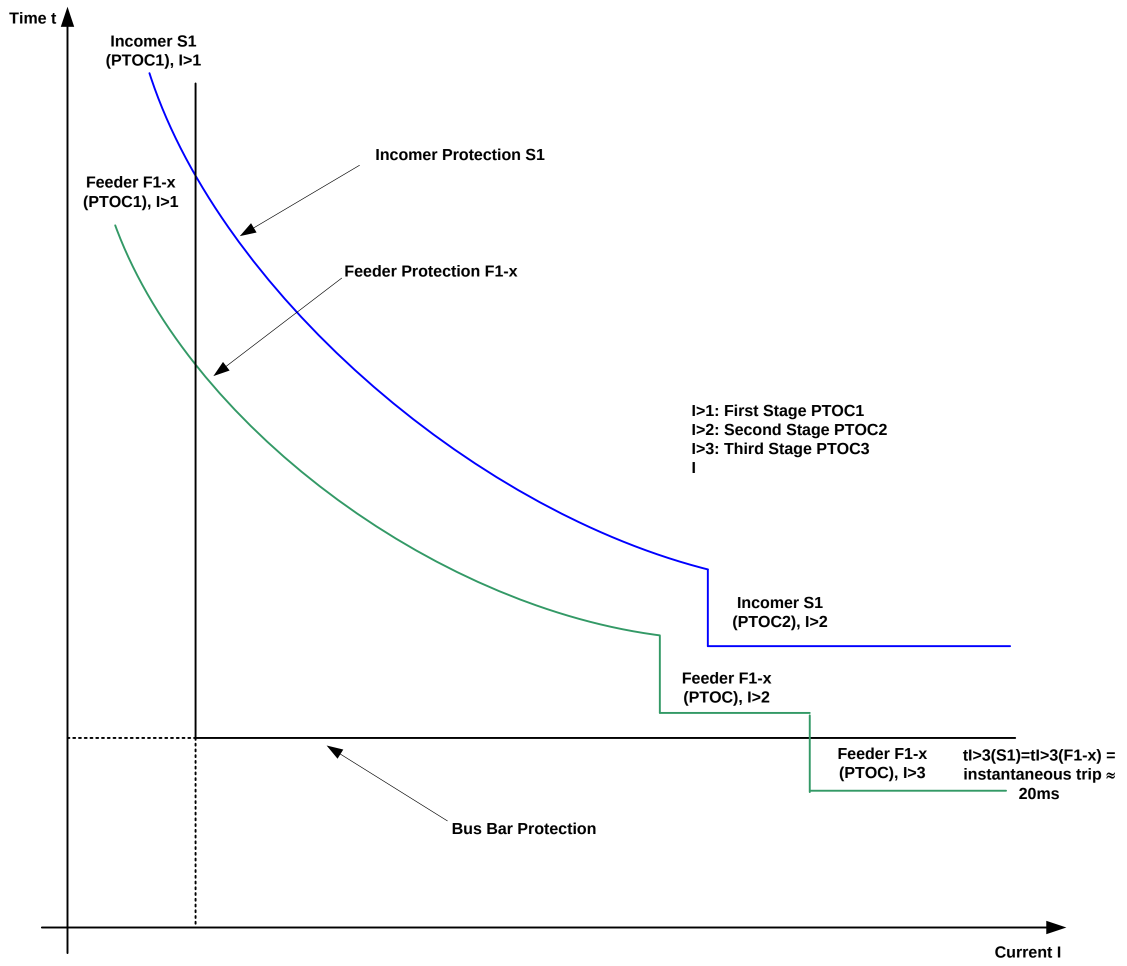

Figure 7-56: Tripping Characteristic

7.11 Feeder Interlocking and Substation Interlocking

7.11.1 Introduction

Switchgear interlocking prevents from switchgear mal-operation in switching stations.

Switchgear interlocking is normally divided into the following groups:

a) Bay interlocking: based on switch positions in the own bay

b) Inter-bay interlocking: based on switch positions in the own bay and other station bays

Bay- and inter-bay interlocking is based on the evaluation of the switch positions in the own bay and other bays of the station. The individual interlocking conditions for the switches could be defined using Boolean logic as for example. The interlocking conditions depend on the specific station configuration. According to the current switch positions the interlocking allows or prevents switching execution.

Inter-bay interlocking is classically achieved by means of a substation automation system (SAS). All feeder and bay IEDs report the switch positions of their bay to the substation controller. The interlocking conditions are defined and evaluated in the substation controller.

GOOSE messages allow transmitting the switch positions of different bays directly between the bay IEDs. Therefore the inter-bay interlocking can be defined and evaluated in the bay IEDs instead of the substation controller.

7.11.2 Example of the switching conditions for a double busbar with bus coupler

As shown in Figure 7-57, a double busbar with a bus coupler (BC) is used as an example and the following switching conditions are considered:

For feeder bay 1A:

Switch, Switching direction	Interlocking condition
QA1 open	Always allowed
QA1 close	allowed if: both disconnectors of the bay are not in intermediate position
QB1 open / close	allowed if: QA1 = open **AND** ((QB2 = open) **OR** (bus coupling = closed))
QB2 open / close	allowed if: QA1 = open **AND** ((QB1 = open) **OR** (bus coupling = closed))

Table 7-28: Example of interlocking conditions for the feeder bay switches

For the bus coupler bay:

Switch, Switching direction	Interlocking condition
QA1 open	not allowed if: ((feeder 1A: QB1 = closed) **AND** (feeder 1A: QB2 = closed)) **OR** ((feeder 2A: QB1 = closed) **AND** (feeder 2A: QB2 = closed))
QA1 close	allowed if: both disconnectors of the bay are not in intermediate position
QB1 open / close	allowed if: QA1 = open
QB2 open / close	allowed if: QA1 = open

Table 7-29: Example of interlocking conditions for the bus coupler bay switches

7.11.3 Description of the Signal Interactions

For being able to execute the above described conditions in the bay IEDs, the following signals are conventionally wired:

a) Auxiliary contacts of the bus coupler CB and the bus coupler disconnectors to both feeder IEDs

b) Auxiliary contacts of the feeder disconnectors to the bus coupler IED

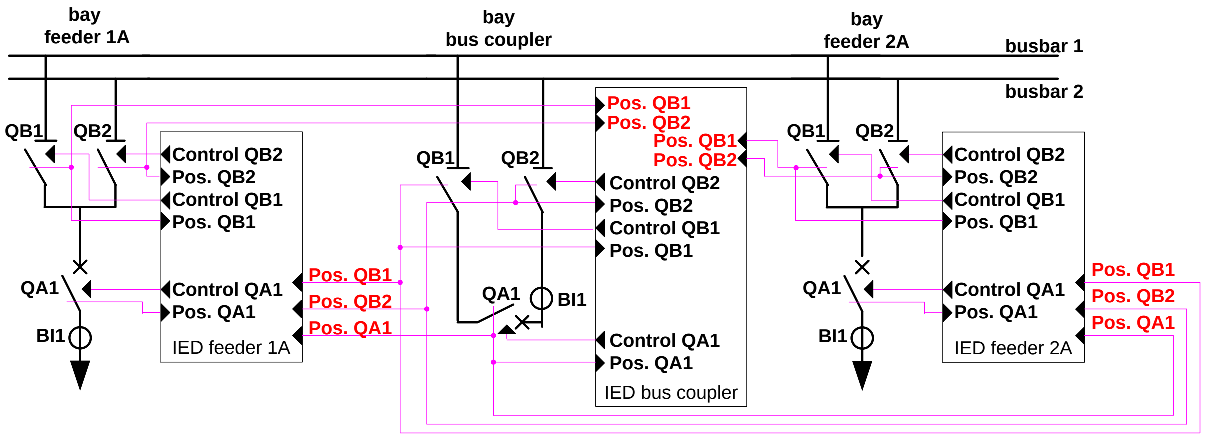

Figure 7-57: Substation interlocking scheme

7.11.4 Use of IEC GOOSE Message

The auxiliary contacts wired between different bays can be replaced by GOOSE messages. The auxiliary contacts of the switches in the own bay are conventionally acquired by the respective bay IED. With IED internal Boolean logic, the publisher GOOSE messages given in the Table 7-30 are built from the acquired switch positions.

E.g. the publisher GOOSE message “both disconnectors closed” of IED feeder 1A is obtained via the following IED internal Boolean logic:

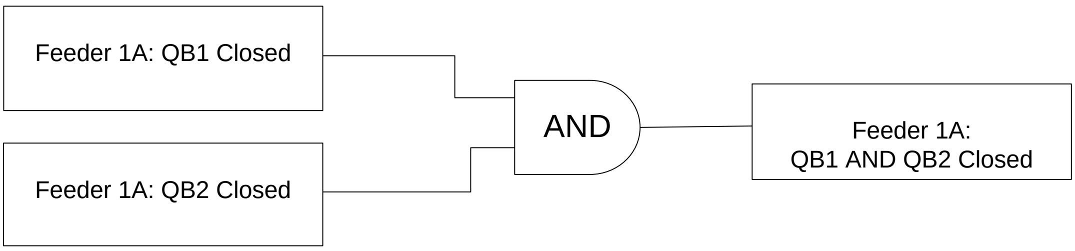

Figure 7-58: Feeder 1A IED internal logic for publisher GOOSE signal

Open and close operations of the bay switches may remain conventionally wired, as shown in Figure 7-59.

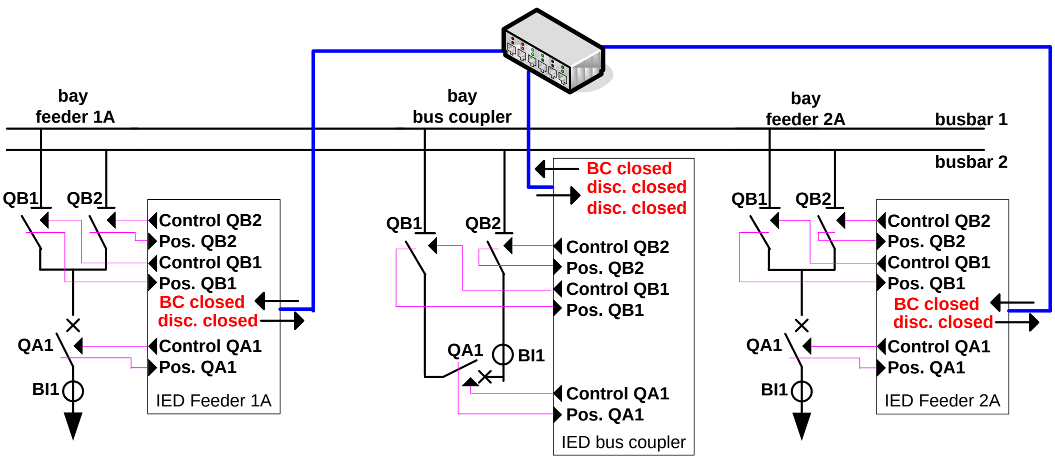

Figure 7-59: Substation interlocking scheme using GOOSE messages

The publishing IEDs must provide the following PD/LN.DO.Attributes in the GOOSE message Datasets:

IED Name	IED Signal	Publisher	Subscriber
Feeder 1A	both disconnectors closed (internal IED logic)	X	
Feeder 1A	bus coupling closed (internal IED logic)		X
Feeder 2A	both disconnectors closed (internal IED logic)	X	
Feeder 2A	bus coupling closed (internal IED logic)		X
Bus coupler	bus coupling closed (internal IED logic)	X	
Bus coupler	Feeder 1A both disconnectors closed (internal IED logic)		X
Bus coupler	Feeder 2A both disconnectors closed (internal IED logic)		X

Table 7-30: Subscriber / Publisher GOOSE Table for a substation interlocking scheme

IED Feeder 1A and 2A publish GOOSE messages containing the information that both disconnectors QB1 and QB2 in one feeder are closed. Both feeder IEDs subscribe to the information that the bus coupler is closed (all three switches QA1 and QB1 and QB2 are closed). The bus coupler IED publishes and describes to the respective information.

7.12 Substation Control Lockout or Control Uniqueness

7.12.1 Introduction

To ensure that only one primary switch at a time can be operated, the so-called reservation or substation control lockout can be used. This mechanism gives additional safety for substation interlocking use.

In this scheme, IEDs need to know the reservation state of all controllable primary equipment to ensure that two or more controllable switches are not operated at the same time resulting in wrong switch positions and substation malfunction. The reason for having this type of scheme implemented with IEC 6185 is that it can be multiple clients capable to do operations to primary equipment e.g. SCADA/Gateway, IEDs (Protection IED, Breaker Control IED) and Substation Automation Systems (HMI).

7.12.2 Description of the Signal Interactions

Reservation based upon the selected state. The selection based reservation uses the selection data of the other IEDs to determine whether another operation is in progress or not. When a control select request is received by an IED from any client, it checks that no other IEDs send a reservation signal prior to accepting the control command. Reservation is freed when primary equipment is operated or after a timeout delay has expired.

7.12.3 Use of IEC GOOSE Message

The selected primary switch state (stSeld) is published when the control mode for the controllable object is Select-Before-Operate or Select-Before-Operate-with-enhanced-security, e.g. CSWI.Pos.stSeld.

If any other IEDs controllable object is in a selected state, then the new select request is rejected and additional control blocking information is sent to the client which made the control selection, and it is able to resume control sequence after the first one is over.

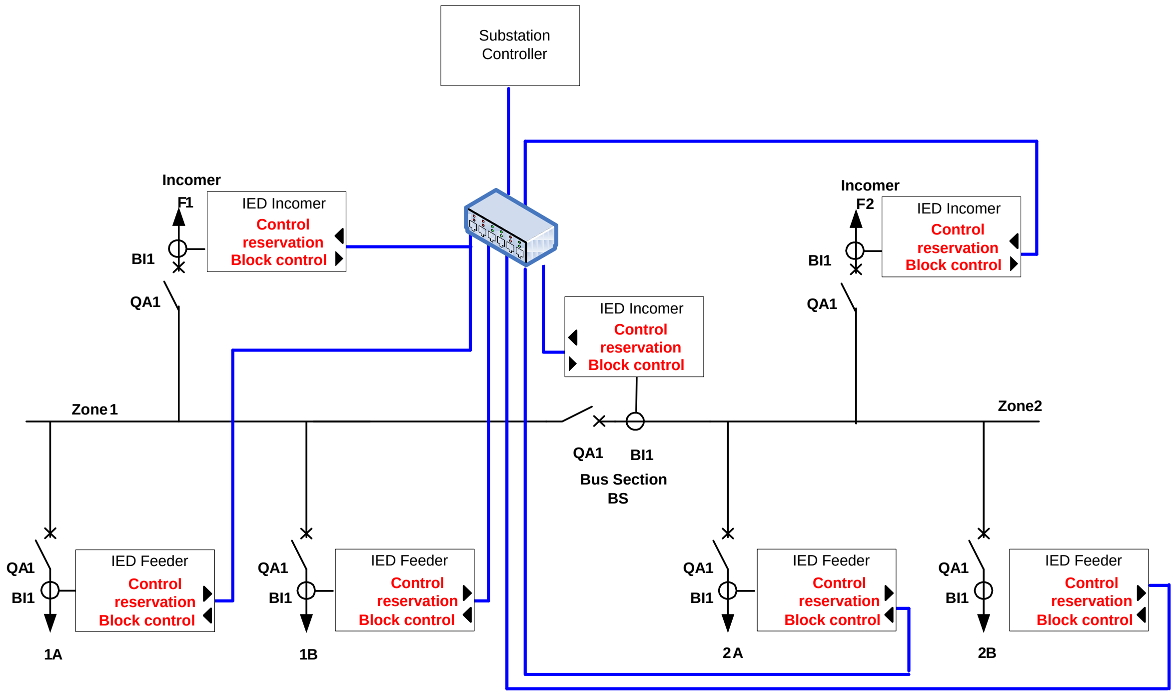

Figure 7-60: Ethernet Architecture for Substation Control Lockout

The following GOOSE messages have to be defined:

IED Name	IED Signal	Publisher	Subscriber
Feeder 1A, 1B, 2A, 2B Incomer F1, F2	Control Reservation (CSWI)	X	
Feeder 1A, 1B, 2A, 2B Incomer F1, F2	Control Block (CILO)		X

Table 7-31: Subscriber / Publisher GOOSE Table for Substation Control Lockout

In the subscribing devices the following logic is required:

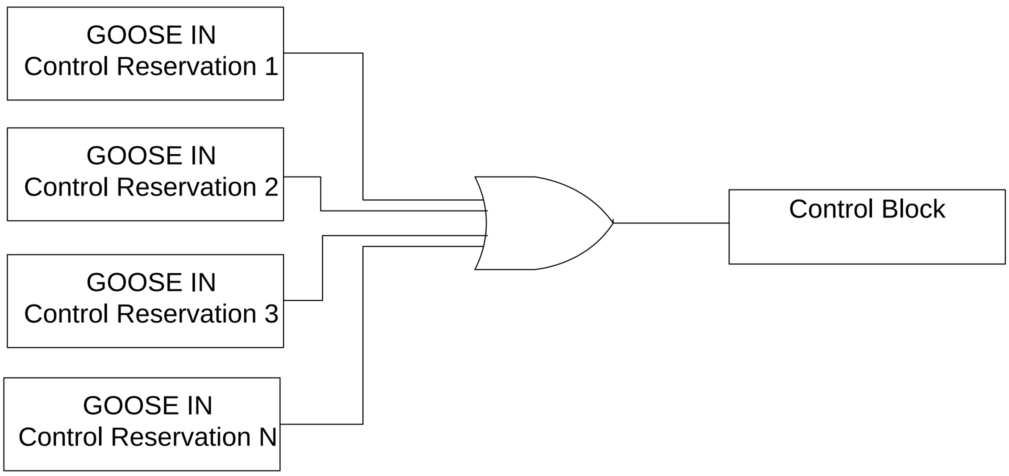

Figure 7-61: Control Block Logic

If the reservation is valid only for a specific part of the switchyard, e.g. a busbar zone or a voltage level, and then the receiving IED has to consider just the relevant selection signals from the incoming GOOSE messages.

7.13 Under Frequency Load Shedding – UFLS:

7.13.1 Introduction

UFLS involves a multi-stage under frequency measurement that ultimately leads to tripping of pre-defined feeders in an attempt to reduce system load and therefore allow the generation sources to recover. Some feeders may be excluded from the UFLS due to the high importance of avoiding loss of supply (e.g. hospitals).

The Feeder IED is 'allocated' to a particular Stage operation. This allocation is often negotiated in commercial agreements between the utility and the consumer(s) for each feeder as loads that can be switched off by the utility without penalty to the utility. The commercial arrangement may involve consideration of being a 'first off' feeder in every case of an under frequency vs. a 'last off' feeder if the frequency drop is severe.

Basic arrangements would involve each Stage operation based on successively lower frequency. However it is also feasible that within one Stage, particular feeders may be arranged to have a longer time delay before tripping in order to minimise the number of feeders that are tripped even for the frequency falling below that Stage set point. Hence stages may be frequency and time allocated. This discussion does not distinguish any difference for time allocation, this being the value of the PTUF.OpDlTmms Data Object.

The restoration sequence generally follows the reverse order and may also be time allocated based on the PTUF.RsDlTmms Data Object.

Note: Similar principles can be applied to other 'stage' based functions e.g. Under Voltage schemes.

7.13.2 Description of the Signal Interactions

Generally, one IED is arranged to measure the frequency on the bus, the incomer to the bus, or perhaps even on the transformer LV. This may be one of several functions the IED provides but must be suitably accurate and responsive. Several individual set point stages with time delayed output are provided as the frequency falls. These outputs are provided to each of the IEDs associated with each Feeder.

The Feeder IEDs will trip their feeder if a under frequency stage operation signal is received which corresponds with the Stage allocation for that feeder e.g. Feeder 4 may be allocated to trip for Stage 2 UFLS only. If the frequency has fallen below Stage 1, those feeders will trip according to their time delay. If the frequency falls below Stage 2, Feeder 4 will trip after the associated time delay. By definition any particular Stage trip would have been preceded or result in the higher Stage operating after its time delay unless other scheme logic is involved to select only feeders according to the band in which the under frequency has occurred.

7.13.3 Use of IEC GOOSE Message

PTUF Logical Nodes would be set for each frequency set point with corresponding operation outputs available for inclusion in a GOOSE DataSet e.g. the four-stage UFLS requirement shown below.

Frequency Measuring IED Data Object and example set points	Frequency	Stage1PTUF1.Op	Stage2PTUF2.Op	Stage3PTUF3.Op	Stage4PTUF4.Op	Dataset
	F>49.8 Hz	False	False	False	False	0000
Stage1PTUF1.StrVal = 49.8	49.6<F<49.8	True	False	False	False	1000
Stage2PTUF2.StrVal = 49.6	49.4<F<49.6	True	True	False	False	1100
Stage3PTUF3.StrVal = 49.4	49.2<F<49.4	True	True	True	False	1110
Stage4PTUF4.StrVal = 49.2	F<49.2	True	True	True	True	1111

Table 7-32: UFLS Conditions and GOOSE Data Set

Each Feeder IED must subscribe to the GOOSE containing this Dataset.

Each Feeder must now be assigned to operate on a selected Stage operation (or not at all). This Stage allocation will be referred to herein as the ‘StageAlloc’ parameter although this has no inherent IEC 61850 semantic or definition and could therefore be any user-specific name. StageAlloc defines which element in the Dataset to which it responds, where “?” means that particular value as 1 or 0 is of no direct interest.

- StageAlloc = 0 means the feeder will **not** trip for any under frequency condition
- StageAlloc = 1 means it will only trip for Dataset containing “1???”
- StageAlloc = 2 means it will only trip for Dataset containing “?1??”
- StageAlloc = 3 means it will only trip for Dataset containing “??1?”
- StageAlloc = 4 means it will only trip for Dataset containing “???1”

Some enhanced security logic may be afforded with a prerequisite that the higher level Stage must also have operated in order for the particular stage trip to also operate. This may also require consideration of what time delays may be involved for each Stage and what happens when a severe under frequency occurs instantaneously versus slowly falling over a long period.

It may be required to set the StageAlloc value by physical means and/or via commands. In some cases physical means are required by switches and or links in order that the setting is made physically on site with less likelihood of inadvertent change or tampering due to the contractual implications of tripping a feeder incorrectly.

The following arrangement shows the use of GGIO to collect the physical inputs and represent the status in a Dataset. It would be preferable for improved semantics in engineering, where IEDs support the capability, to rename the GGIO under a private Name Space according to IEC 61850 7-3 Ed2 cl 7.2.

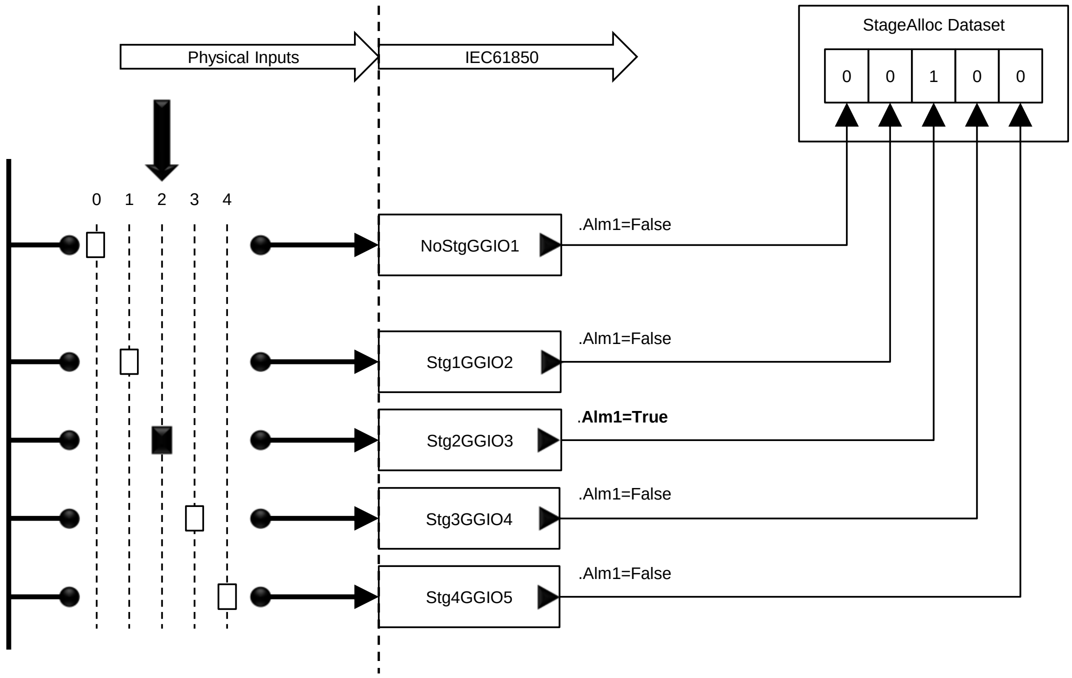

Figure 7-62: UFLS Stage Allocation Dataset – individual GGIO

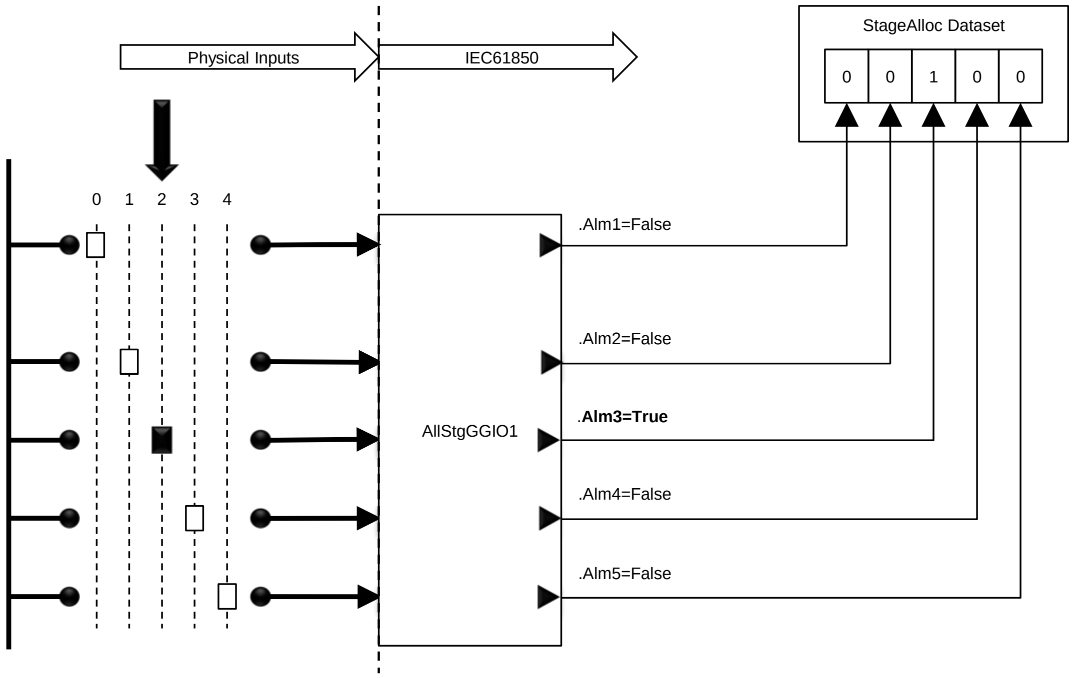

Figure 7-63: UFLS Stage Allocation Dataset – single GGIO

Depending on the IED implementation, it is also possible to use the GGIO.SPSCO or GGIO.ISCSO outputs based on ACSI SetDataValues command from a client application in order to then create the StageAlloc Dataset.

The publishing IEDs must provide the following PD/LN.DO.Attributes in the GOOSE message Datasets:

IED Name	IED internal signal description	Source IED Name/Published GOOSE Data Object (based on individual GGIO scheme)
Stage Alloc F1 (SAF1)	F1 Stage =1/2/3/4	SAF1/Stg1GGIO2.alm1 SAF1/Stg2GGIO3.alm1 SAF1/Stg3GGIO4.alm1 SAF1/Stg4GGIO5.alm1
Stage Alloc F2 (SAF2)	F2 Stage =1/2/3/4	SAF2/Stg1GGIO2.alm1 SAF2/Stg2GGIO3.alm1 SAF2/Stg3GGIO4.alm1 SAF2/Stg4GGIO5.alm1
Stage Alloc F3 (SAF3)	F3 Stage =1/2/3/4	SAF3/Stg1GGIO2.alm1 SAF3/Stg2GGIO3.alm1 SAF3/Stg3GGIO4.alm1 SAF3/Stg4GGIO5.alm1
Stage Alloc F4 (SAF4)	F4 Stage =1/2/3/4	SAF4/Stg1GGIO2.alm1 SAF4/Stg2GGIO3.alm1 SAF4/Stg3GGIO4.alm1 SAF4/Stg4GGIO5.alm1

Table 7-33: Publisher GOOSE Table

The next step presented in following four different schemes is to use logic combining the individual under frequency Stage Operation Dataset and the Stage Allocation Dataset values, which then are used as inputs to the PTRC in order to trip the required feeder circuit breakers. The requirement to use Boolean logic currently sits outside of the scope of IEC 61850 since the purpose of IEC 61850 is for the configuration of functions for the purpose of communication. Presently logic is considered a ‘local’ issue and not specifically involved in the communication requirements of an IED, however some investigations are proceeding.

7.13.4 UFLS using Boolean Logic Elements

Note in the following diagram, although only shown for Feeder 4 IED, each feeder IED must subscribe to its own StageAlloc Dataset as described above, and each feeder IED must also subscribe to the UFLS Stage Operation Dataset.

Note: In this scheme, the time delay for the load shedding on each stage is the PTUF.OpDlTmms setting.

The blue lines indicate a positive under frequency indication message path for a Stage 2 under frequency condition resulting in Feeder 4 trip.

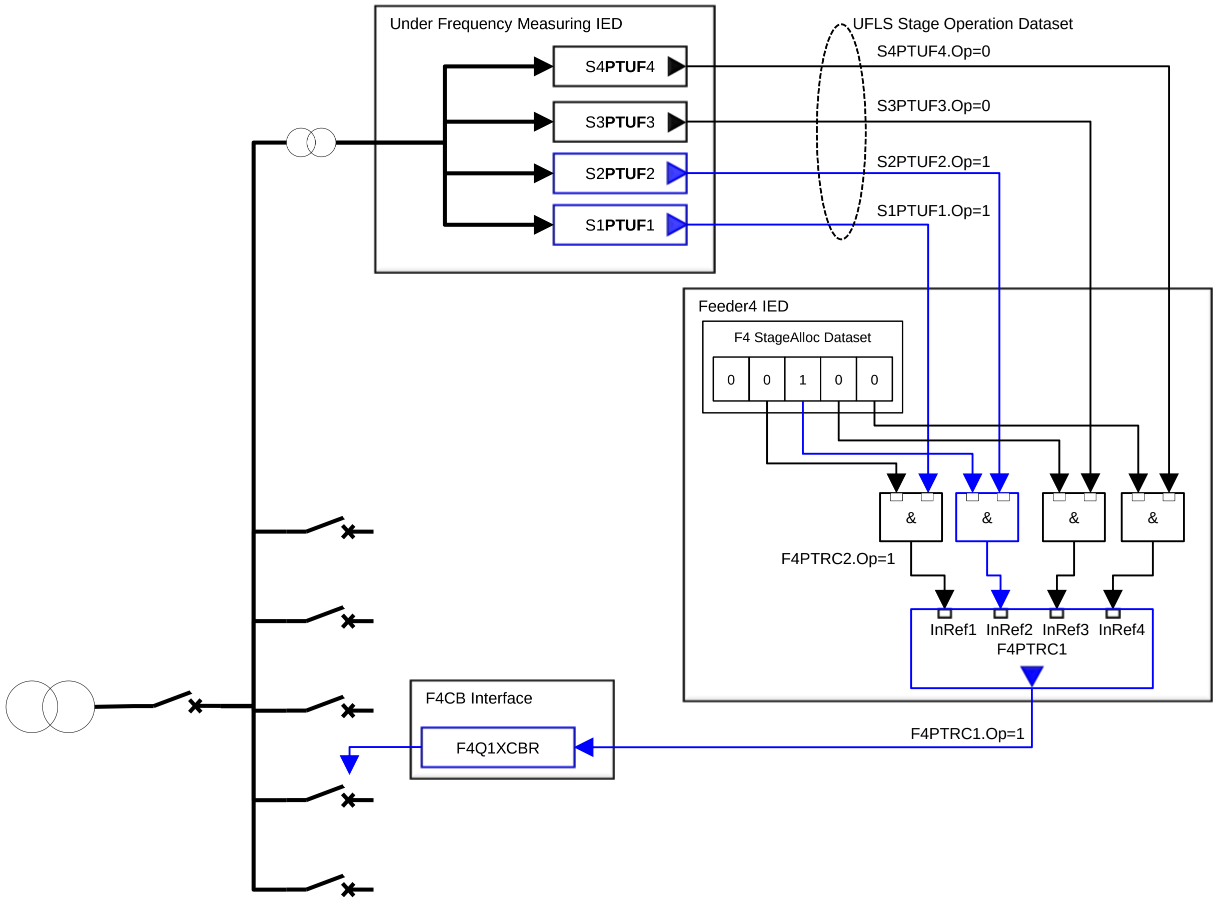

Figure 7-64: UFLS with Boolean Logic

The publishing IEDs must provide the following PD/LN.DO.Attributes in the GOOSE message Datasets:

IED Name	IED internal signal description	Source IED Name/Published GOOSE Data Object (based on individual GGIO scheme)
Frequency IED (UFLS)	Under frequency operation (after time delay)	UFLS/PTUF1.Op UFLS/PTUF2.Op UFLS/PTUF3.Op UFLS/PTUF4.Op
Feeder1 IED (F1)	Stage UFLS Operated	F1/PTRC1.Op
Feeder2 IED (F2)	Stage UFLS Operated	F2/PTRC1.Op
Feeder3 IED (F3)	Stage UFLS Operated	F3/PTRC1.Op
Feeder4 IED (F4)	Stage UFLS Operated	F4/PTRC1.Op

Table 7-34: Publisher GOOSE Table

The subscribing IEDs must have the following PD/LN.DO.Attributes available from the subscribed GOOSE message Datasets:

IED Name	Source IED Name/Subscribed GOOSE Data Object	Subscribed IED signal description	Function using the subscribed signal(s)
Feeder1 IED (F1)	SAF1/Stg1GGIO2.alm1 SAF1/Stg2GGIO3.alm1 SAF1/Stg3GGIO4.alm1 SAF1/Stg4GGIO5.alm1 UFLS/PTUF1.Op UFLS/PTUF2.Op UFLS/PTUF3.Op UFLS/PTUF4.Op	Feeder Stage control	Logic
Feeder2 IED (F2)	SAF2/Stg1GGIO2.alm1 SAF2/Stg2GGIO3.alm1 SAF2/Stg3GGIO4.alm1 SAF2/Stg4GGIO5.alm1 UFLS/PTUF1.Op UFLS/PTUF2.Op UFLS/PTUF3.Op UFLS/PTUF4.Op	Feeder Stage control	Logic
Feeder3 IED (F3)	SAF3/Stg1GGIO2.alm1 SAF3/Stg2GGIO3.alm1 SAF3/Stg3GGIO4.alm1 SAF3/Stg4GGIO5.alm1 UFLS/PTUF1.Op UFLS/PTUF2.Op UFLS/PTUF3.Op UFLS/PTUF4.Op	Feeder Stage control	Logic
Feeder4 IED (F4)	SAF4/Stg1GGIO2.alm1 SAF4/Stg2GGIO3.alm1 SAF4/Stg3GGIO4.alm1 SAF4/Stg4GGIO5.alm1 UFLS/PTUF1.Op UFLS/PTUF2.Op UFLS/PTUF3.Op UFLS/PTUF4.Op	Feeder Stage control	Logic
Feeder1 CB Interface (F1CB)	F1PTRC1.Op	CB Trip	XCBR
Feeder2 CB Interface (F2CB)	F2PTRC1.Op	CB Trip	XCBR
Feeder3 CB Interface (F3CB)	F3PTRC1.Op	CB Trip	XCBR
Feeder4 CB Interface (F4CB)	F4PTRC1.Op	CB Trip	XCBR

Table 7-35: Subscriber GOOSE Table

As shown in Figure 7-65, these two signals are input to an OR gate mapped to the PTRC output.

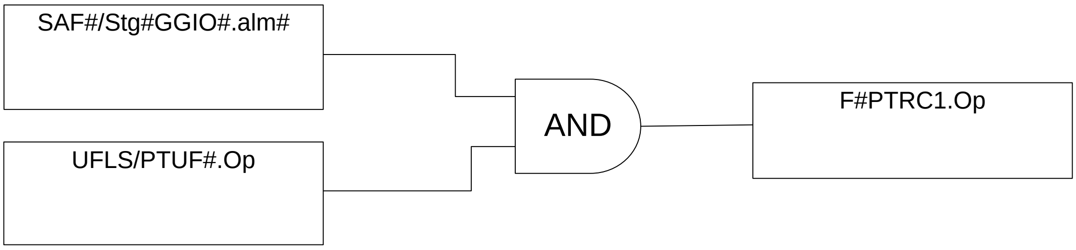

Figure 7-65: UFLS Operation Boolean Logic

7.13.5 <u>UFLS using IEC 61850 InRef/BlkRef “logic”</u>

In order to consider elimination of the Boolean Logic elements it is necessary to consider under frequency in the reverse context.

Under frequency has <u>not occurred</u> if the frequency is above a setting. LNs only have a “.Op” Data Object as by definition PTUF.Op = 0 means it has not operated. There is not a DO available that would give PTUF.NotOp = 1.

However the over frequency LN PTOF does provide the result PTOF.Op = 1 if there is no under frequency. Consideration must be given to the drop-off/pick-up ratio for the IED in order to retain the fundamental premise that PTOF.Op = 0 when the frequency falls below the required threshold.

The blue lines indicate a positive under frequency indication message path for a Stage 2 under frequency condition resulting in Feeder 4 trip. The red lines indicate the active blocking signals.

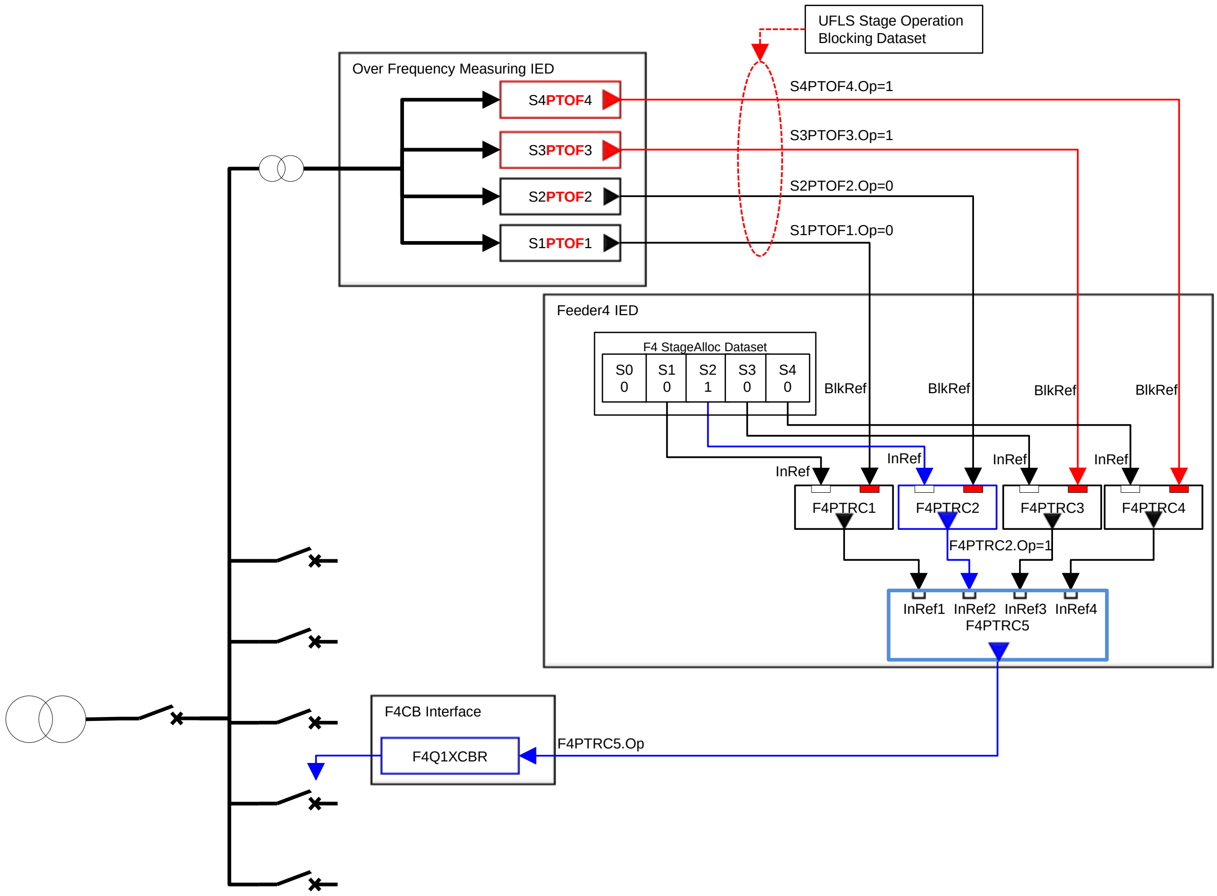

Figure 7-66: UFLS using IEC 61850 InRef/BlkRef "Logic"

The "StageAlloc" Dataset is used as the InRef signal to the stage PTRCs. As Feeder 4 is allocated to Stage 2, F4PTRC2 is 'primed' to operate. The respective Stage will not trip if the frequency is above the Stage setting in the over frequency measuring IED.

Note for a Stage 2 under frequency condition, the Stage 1 and Stage 2 PTOF.Op have reset to a value of 0 since the frequency has fallen below the over frequency setting. Stage 3 and Stage 4 PTOF.Op = 1 since the frequency remains above their over frequency setting.

Although S1PTOF1.Op=0, and hence the block to F4PTRC1 has been removed, F4PTRC1 will not operate since the "StageAlloc" input to InRef1 on F4PTRC1 = 0.

The Stage 2 trip of Feeder 4 via F4PRTC2 will occur because S2PTOF2.Op=0, and hence the block to F4PTRC2 has been removed with the "StageAlloc" input to InRef1 of F4PTRC2 = 1 causing the operation of F4PTRC2.

Note: In this scheme, the time delay for the operation of the shedding sequence on each stage is the PTOF.RsDlTmms setting

The diagram shows a cascaded F4PTRC5 which is used to operate if any of the individual Stage PTRC operate. It is equally feasible for the four stage PTRC.Op signals to be published in a GOOSE Dataset and the CB Interface IED then subscribes and interprets any of those elements in the Dataset having a value of 1 as a requirement for the XCBR to trip the CB.

The publishing IEDs must provide the following PD/LN.DO.Attributes in the GOOSE message Datasets:

IED Name	IED internal signal description	Source IED Name/Published GOOSE Data Object (based on individual GGIO scheme)
Frequency IED (UFLS)	Over frequency operation (reset time delay)	UFLS/PTOF1.Op UFLS/PTOF2.Op UFLS/PTOF3.Op UFLS/PTOF4.Op
Feeder1 IED (F1)	Stage UFLS Operated	F1/PTRC1.Op F1/PTRC2.Op F1/PTRC3.Op F1/PTRC4.Op F1/PTRC5.Op
Feeder2 IED (F2)	Stage UFLS Operated	F2/PTRC1.Op F2/PTRC2.Op F2/PTRC3.Op F2/PTRC4.Op F2/PTRC5.Op
Feeder3 IED (F3)	Stage UFLS Operated	F3/PTRC1.Op F3/PTRC2.Op F3/PTRC3.Op F3/PTRC4.Op F3/PTRC5.Op
Feeder4 IED (F4)	Stage UFLS Operated	F4/PTRC1.Op F4/PTRC2.Op F4/PTRC3.Op F4/PTRC4.Op F4/PTRC5.Op

Table 7-36: Publisher GOOSE Table - IEC 61850 InRef/BlkRef

The subscribing IEDs must have the following PD/LN.DO.Attributes available from the subscribed GOOSE message Datasets:

IED Name	Source IED Name/Subscribed GOOSE Data Object	Subscribed IED signal description	Function using the subscribed signal(s)
Feeder1 IED (F1)	SAF1/Stg1GGIO2.alm1 SAF1/Stg2GGIO3.alm1 SAF1/Stg3GGIO4.alm1 SAF1/Stg4GGIO5.alm1 UFLS/PTOF1.Op UFLS/PTOF2.Op UFLS/PTOF3.Op UFLS/PTOF4.Op	Feeder1 Stage 1 Feeder1 Stage 2 Feeder1 Stage 2 Feeder1 Stage 3 Stage 1 Block Stage 2 Block Stage 3 Block Stage 4 Block	F1PTRC1 F1PTRC2 F1PTRC3 F1PTRC4 F1PTRC1 F1PTRC2 F1PTRC3 F1PTRC4
Feeder2 IED (F2)	SAF2/Stg1GGIO2.alm1 SAF2/Stg2GGIO3.alm1 SAF2/Stg3GGIO4.alm1 SAF2/Stg4GGIO5.alm1 UFLS/PTOF1.Op UFLS/PTOF2.Op UFLS/PTOF3.Op UFLS/PTOF4.Op	Feeder2 Stage 1 Feeder2 Stage 2 Feeder2 Stage 2 Feeder2 Stage 3 Stage 1 Block Stage 2 Block Stage 3 Block Stage 4 Block	F2PTRC1 F2PTRC2 F2PTRC3 F2PTRC4 F2PTRC1 F2PTRC2 F2PTRC3 F2PTRC4
Feeder3 IED (F3)	SAF3/Stg1GGIO2.alm1 SAF3/Stg2GGIO3.alm1 SAF3/Stg3GGIO4.alm1 SAF3/Stg4GGIO5.alm1 UFLS/PTOF1.Op UFLS/PTOF2.Op UFLS/PTOF3.Op UFLS/PTOF4.Op	Feeder3 Stage 1 Feeder3 Stage 2 Feeder3 Stage 2 Feeder3 Stage 3 Stage 1 Block Stage 2 Block Stage 3 Block Stage 4 Block	F3PTRC1 F3PTRC2 F3PTRC3 F3PTRC4 F3PTRC1 F3PTRC2 F3PTRC3 F3PTRC4
Feeder4 IED (F4)	SAF4/Stg1GGIO2.alm1 SAF4/Stg2GGIO3.alm1 SAF4/Stg3GGIO4.alm1 SAF4/Stg4GGIO5.alm1 UFLS/PTOF1.Op UFLS/PTOF2.Op UFLS/PTOF3.Op UFLS/PTOF4.Op	Feeder4 Stage 1 Feeder4 Stage 2 Feeder4 Stage 2 Feeder4 Stage 3 Stage 1 Block Stage 2 Block Stage 3 Block Stage 4 Block	F4PTRC1 F4PTRC2 F4PTRC3 F4PTRC4 F4PTRC1 F4PTRC2 F4PTRC3 F4PTRC4
Feeder1 IED (F1)	F1PTRC1.Op F1PTRC2.Op F1PTRC3.Op F1PTRC4.Op	Stage Trip	F1PTRC5
Feeder2 IED (F2)	F2PTRC1.Op F2PTRC2.Op F2PTRC3.Op F2PTRC4.Op	Stage Trip	F2PTRC5
Feeder3 IED (F3)	F3PTRC1.Op F3PTRC2.Op F3PTRC3.Op F3PTRC4.Op	Stage Trip	F3PTRC5
Feeder4 IED (F4)	F4PTRC1.Op F4PTRC2.Op F4PTRC3.Op F4PTRC4.Op	Stage Trip	F4PTRC5

IED Name	Source IED Name/Subscribed GOOSE Data Object	Subscribed IED signal description	Function using the subscribed signal(s)
Feeder1 CB Interface (F1CB)	F1PTRC5.Op	CB Trip	F1XCBR
Feeder2 CB Interface (F2CB)	F2PTRC5.Op	CB Trip	F2XCBR
Feeder3 CB Interface (F3CB)	F3PTRC5.Op	CB Trip	F3XCBR
Feeder4 CB Interface (F4CB)	F4PTRC5.Op	CB Trip	F4XCBR

Table 7-37: Subscriber GOOSE Table – IEC 61850 InRef/BlkRef

7.13.6 Master/Follower UFLS

Due to the significant impact of tripping any feeder has on the connected loads, it is often a requirement to provide a Master/Follower scheme in order to have a “two-out-of-two” security enhancement.

Wire based schemes are effectively implemented with two contacts in series. Modelling of this in logic is clearly an AND gate function. However it is preferable to avoid the use of Boolean logic as discussed above. The use of IEC 61850 InRef and BlkRef “logic” to control schemes without Boolean logic gates is possible in two different mechanisms which are equally valid depending on the chosen IED capabilities.

7.13.6.1 Master/Follower UFLS with Measurement Stage Blocking

Applying the similar methodology as the previous example, this scheme would be seen as shown in Figure 7-67.

The blue lines indicate a positive under frequency indication message path for a Stage 2 under frequency condition resulting in Feeder 4 trip. The solid red lines indicate the active blocking signals (status = 1), the dotted red lines indicate inactive blocking signals (status = 0).

The Master PTOF IED is operating as a block input to the individual stages of the follower IED in the same manner as PTOF is used in the scheme described in Clause 7.13.5. When the frequency falls below the Master PTOF.strVal setting, the block is removed and the individual stages are allowed to operate as required.

The Follower IED contains all the individual Stage PTUF elements. Provided the BlkRef from the Master PTOF to each has been removed (MasterPTOF.Op=0), these individual Stages will operate as the frequency falls with the respective PTUF.Op changing from 0 to 1.

Note that this scheme has some inherent security with the Master controlling the scheme based over frequency (e.g. MasterPTOF.strVal = 49.9) whilst the individual Stages operate on the basis of under frequency (PTUF.strVal).

Each Feeder IED has its own StageAlloc DataSet as discussed in previous schemes discussed above. However since the individual PTRC are receiving signals implying a trip is required for a particular stage, the StageAlloc Data set must be used to block all other stages except the stage to which that feeder is allocated, i.e. Stage 2 is set on Feeder 4 causing Stage 1, 3 and 4 PTRC to be blocked. Thus when S2PTUF.Op = 1, F4PTRC2 is able to provide the F4PTRC2.Op = 1 output.

There is an additional requirement that if the feeder is to be excluded from the UFLS scheme, all the PTRC for that feeder must be blocked and therefore there is an additional StageAlloc element associated with being set to no stage whatsoever (Stage 0).

Clearly the Under Frequency Measurement IED with the Stage PTUF elements must support BlkRef inputs to the PTUF LNs.

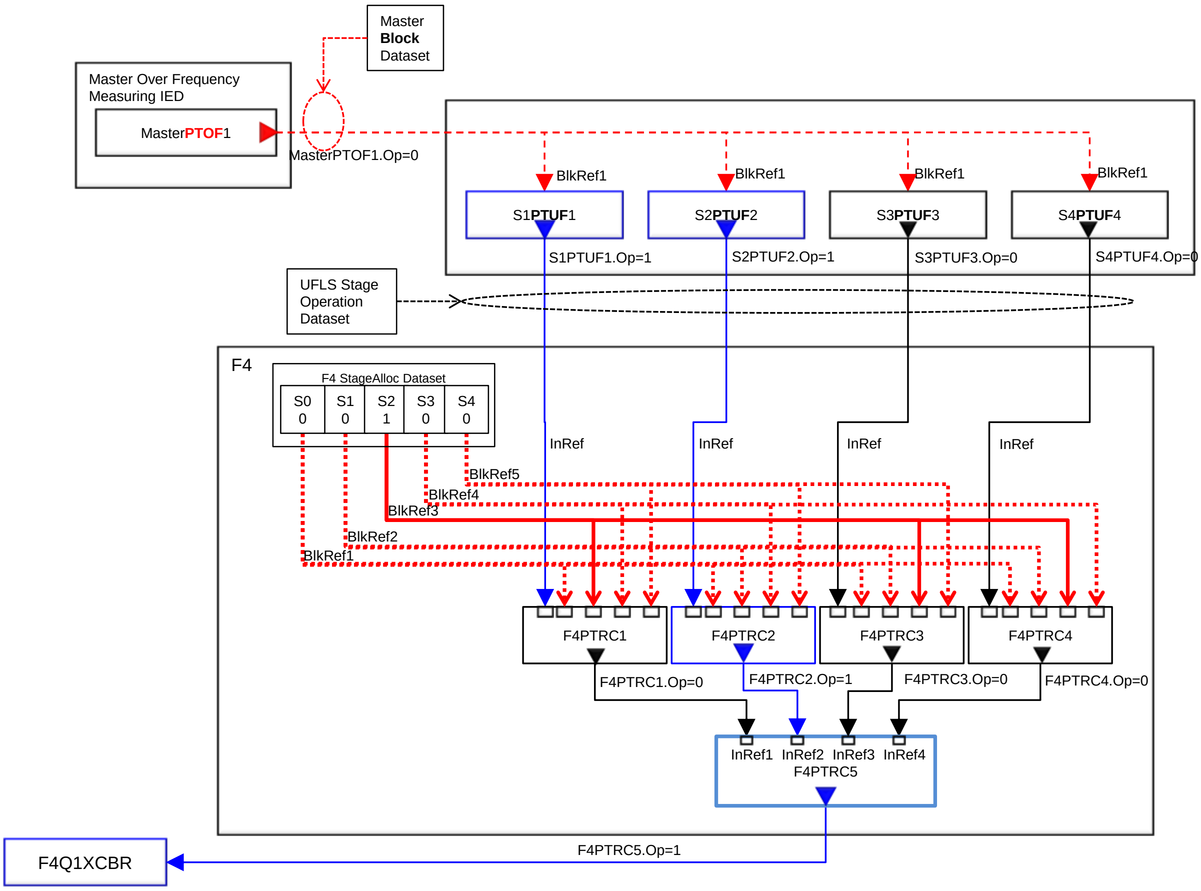

Figure 7-67: Master/Follower UFLS with Measurement Stage Blocking

The publishing IEDs must provide the following PD/LN.DO.Attributes in the GOOSE message Datasets:

IED Name	IED internal signal description	Source IED Name/Published GOOSE Data Object (based on individual GGIO scheme)
Master IED (Master)	Master over frequency block (reset time delay)	Master/PTOF1.Op
Frequency IED (UFLS)	Under frequency operation (operate time delay)	UFLS/PTUF1.Op UFLS/PTUF2.Op UFLS/PTUF3.Op UFLS/PTUF4.Op
Feeder1 IED (F1)	Stage UFLS Operated	F1/PTRC1.Op F1/PTRC2.Op F1/PTRC3.Op F1/PTRC4.Op F1/PTRC5.Op
Feeder2 IED (F2)	Stage UFLS Operated	F2/PTRC1.Op F2/PTRC2.Op F2/PTRC3.Op F2/PTRC4.Op F2/PTRC5.Op
Feeder3 IED (F3)	Stage UFLS Operated	F3/PTRC1.Op F3/PTRC2.Op F3/PTRC3.Op F3/PTRC4.Op F3/PTRC5.Op
Feeder4 IED (F4)	Stage UFLS Operated	F4/PTRC1.Op F4/PTRC2.Op F4/PTRC3.Op F4/PTRC4.Op F4/PTRC5.Op

Table 7-38: Publisher GOOSE Table – Master Measurement Stage Blocking

The subscribing IEDs must have the following PD/LN.DO.Attributes available from the subscribed GOOSE message Datasets:

IED Name	Source IED Name/Subscribed GOOSE Data Object	Subscribed IED signal description	Function using the subscribed signal(s)
Frequency IED (UFLS)	Master/PTOF1.Op	UFLS block	S1PTUF1 S2PTUF2 S3PTUF3 S4PTUF4
Feeder1 IED (F1)	SAF1/Stg1GGIO2.alm1 SAF1/Stg2GGIO3.alm1 SAF1/Stg3GGIO4.alm1 SAF1/Stg4GGIO5.alm1 UFLS/PTUF1.Op UFLS/PTUF2.Op UFLS/PTUF3.Op UFLS/PTUF4.Op	Feeder1 Stage 1 Feeder1 Stage 2 Feeder1 Stage 2 Feeder1 Stage 3 Stage 1 Block Stage 2 Block Stage 3 Block Stage 4 Block	F1PTRC1 F1PTRC2 F1PTRC3 F1PTRC4 F1PTRC1 F1PTRC2 F1PTRC3 F1PTRC4
Feeder2 IED (F2)	SAF2/Stg1GGIO2.alm1 SAF2/Stg2GGIO3.alm1 SAF2/Stg3GGIO4.alm1 SAF2/Stg4GGIO5.alm1 UFLS/PTUF1.Op UFLS/PTUF2.Op UFLS/PTUF3.Op UFLS/PTUF4.Op	Feeder2 Stage 1 Feeder2 Stage 2 Feeder2 Stage 2 Feeder2 Stage 3 Stage 1 Block Stage 2 Block Stage 3 Block Stage 4 Block	F2PTRC1 F2PTRC2 F2PTRC3 F2PTRC4 F2PTRC1 F2PTRC2 F2PTRC3 F2PTRC4
Feeder3 IED (F3)	SAF3/Stg1GGIO2.alm1 SAF3/Stg2GGIO3.alm1 SAF3/Stg3GGIO4.alm1 SAF3/Stg4GGIO5.alm1 UFLS/PTUF1.Op UFLS/PTUF2.Op UFLS/PTUF3.Op UFLS/PTUF4.Op	Feeder3 Stage 1 Feeder3 Stage 2 Feeder3 Stage 2 Feeder3 Stage 3 Stage 1 Block Stage 2 Block Stage 3 Block Stage 4 Block	F3PTRC1 F3PTRC2 F3PTRC3 F3PTRC4 F3PTRC1 F3PTRC2 F3PTRC3 F3PTRC4
Feeder4 IED (F4)	SAF4/Stg1GGIO2.alm1 SAF4/Stg2GGIO3.alm1 SAF4/Stg3GGIO4.alm1 SAF4/Stg4GGIO5.alm1 UFLS/PTUF1.Op UFLS/PTUF2.Op UFLS/PTUF3.Op UFLS/PTUF4.Op	Feeder4 Stage 1 Feeder4 Stage 2 Feeder4 Stage 2 Feeder4 Stage 3 Stage 1 Block Stage 2 Block Stage 3 Block Stage 4 Block	F4PTRC1 F4PTRC2 F4PTRC3 F4PTRC4 F4PTRC1 F4PTRC2 F4PTRC3 F4PTRC4
Feeder1 IED (F1)	F1PTRC1.Op F1PTRC2.Op F1PTRC3.Op F1PTRC4.Op	Stage Trip	F1PTRC5
Feeder2 IED (F2)	F2PTRC1.Op F2PTRC2.Op F2PTRC3.Op F2PTRC4.Op	Stage Trip	F2PTRC5
Feeder3 IED (F3)	F3PTRC1.Op F3PTRC2.Op F3PTRC3.Op F3PTRC4.Op	Stage Trip	F3PTRC5

IED Name	Source IED Name/Subscribed GOOSE Data Object	Subscribed IED signal description	Function using the subscribed signal(s)
Feeder4 IED (F4)	F4PTRC1.Op F4PTRC2.Op F4PTRC3.Op F4PTRC4.Op	Stage Trip	F4PTRC5
Feeder1 CB Interface (F1CB)	F1PTRC5.Op	CB Trip	F1XCBR
Feeder2 CB Interface (F2CB)	F2PTRC5.Op	CB Trip	F2XCBR
Feeder3 CB Interface (F3CB)	F3PTRC5.Op	CB Trip	F3XCBR
Feeder4 CB Interface (F4CB)	F4PTRC5.Op	CB Trip	F4XCBR

Table 7-39: Subscriber GOOSE Table – Master Measurement Stage Blocking

7.13.6.2 Master/Follower UFLS with Trip Blocking

The blue lines indicate a positive under frequency indication message path for a Stage 2 under frequency condition resulting in Feeder 4 trip. The solid red lines indicate the active blocking signals (status = 1), the dotted red lines indicate inactive blocking signals (status = 0).

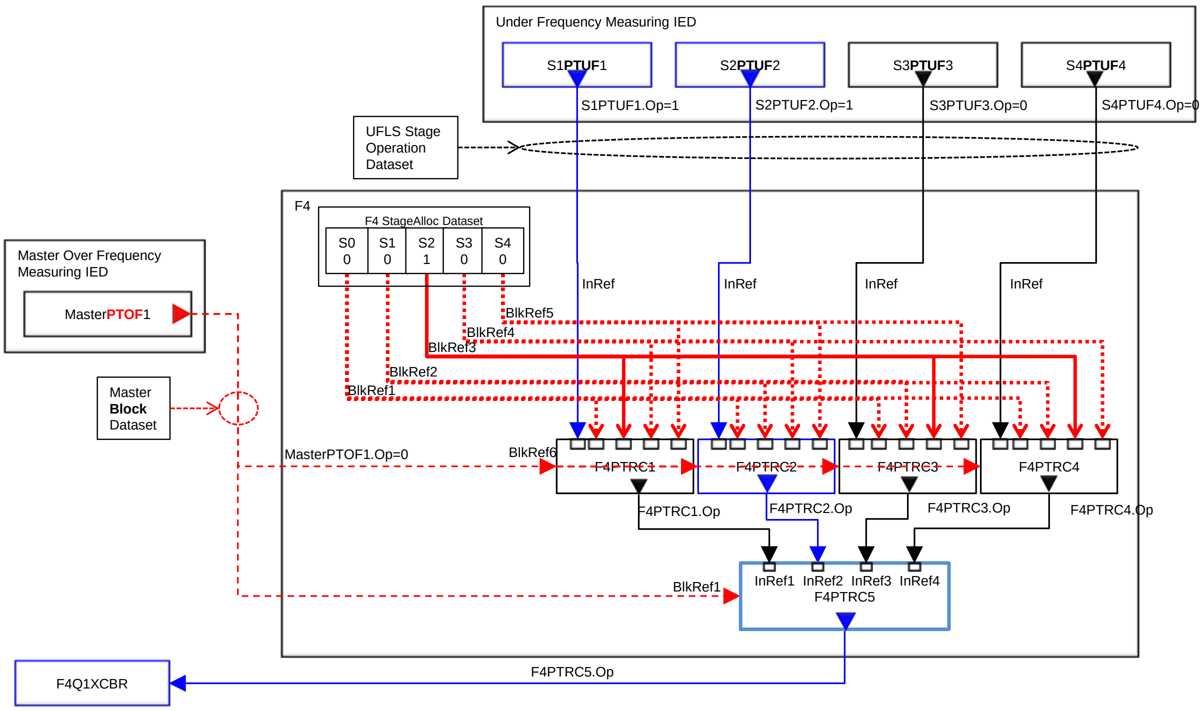

Figure 7-68: Master/Follower UFLS with Trip Blocking

The publishing IEDs must provide the following PD/LN.DO.Attributes in the GOOSE message Datasets:

IED Name	IED internal signal description	Source IED Name/Published GOOSE Data Object (based on individual GGIO scheme)
Master IED (Master)	Master over frequency block (reset time delay)	Master/PTOF1.Op
Frequency IED (UFLS)	Under frequency operation (operate time delay)	UFLS/PTUF1.Op UFLS/PTUF2.Op UFLS/PTUF3.Op UFLS/PTUF4.Op
Feeder1 IED (F1)	Stage UFLS Operated	F1/PTRC1.Op F1/PTRC2.Op F1/PTRC3.Op F1/PTRC4.Op F1/PTRC5.Op
Feeder2 IED (F2)	Stage UFLS Operated	F2/PTRC1.Op F2/PTRC2.Op F2/PTRC3.Op F2/PTRC4.Op F2/PTRC5.Op
Feeder3 IED (F3)	Stage UFLS Operated	F3/PTRC1.Op F3/PTRC2.Op F3/PTRC3.Op F3/PTRC4.Op F3/PTRC5.Op
Feeder4 IED (F4)	Stage UFLS Operated	F4/PTRC1.Op F4/PTRC2.Op F4/PTRC3.Op F4/PTRC4.Op F4/PTRC5.Op

Table 7-40: Publisher GOOSE Table – Master Trip Blocking

The subscribing IEDs must have the following PD/LN.DO.Attributes available from the subscribed GOOSE message Datasets:

IED Name	Source IED Name/Subscribed GOOSE Data Object	Subscribed IED signal description	Function using the subscribed signal(s)
Frequency IED (UFLS)	Master/PTOF1.Op	UFLS block	F1PTRC5 F2PTRC5 F3PTRC5 F4PTRC5
Feeder1 IED (F1)	SAF1/Stg1GGIO2.alm1 SAF1/Stg2GGIO3.alm1 SAF1/Stg3GGIO4.alm1 SAF1/Stg4GGIO5.alm1 UFLS/PTUF1.Op UFLS/PTUF2.Op UFLS/PTUF3.Op UFLS/PTUF4.Op	Feeder1 Stage 1 Feeder1 Stage 2 Feeder1 Stage 2 Feeder1 Stage 3 Stage 1 Block Stage 2 Block Stage 3 Block Stage 4 Block	F1PTRC1 F1PTRC2 F1PTRC3 F1PTRC4 F1PTRC1 F1PTRC2 F1PTRC3 F1PTRC4
Feeder2 IED (F2)	SAF2/Stg1GGIO2.alm1 SAF2/Stg2GGIO3.alm1 SAF2/Stg3GGIO4.alm1 SAF2/Stg4GGIO5.alm1 UFLS/PTUF1.Op UFLS/PTUF2.Op UFLS/PTUF3.Op UFLS/PTUF4.Op	Feeder2 Stage 1 Feeder2 Stage 2 Feeder2 Stage 2 Feeder2 Stage 3 Stage 1 Block Stage 2 Block Stage 3 Block Stage 4 Block	F2PTRC1 F2PTRC2 F2PTRC3 F2PTRC4 F2PTRC1 F2PTRC2 F2PTRC3 F2PTRC4
Feeder3 IED (F3)	SAF3/Stg1GGIO2.alm1 SAF3/Stg2GGIO3.alm1 SAF3/Stg3GGIO4.alm1 SAF3/Stg4GGIO5.alm1 UFLS/PTUF1.Op UFLS/PTUF2.Op UFLS/PTUF3.Op UFLS/PTUF4.Op	Feeder3 Stage 1 Feeder3 Stage 2 Feeder3 Stage 2 Feeder3 Stage 3 Stage 1 Block Stage 2 Block Stage 3 Block Stage 4 Block	F3PTRC1 F3PTRC2 F3PTRC3 F3PTRC4 F3PTRC1 F3PTRC2 F3PTRC3 F3PTRC4
Feeder4 IED (F4)	SAF4/Stg1GGIO2.alm1 SAF4/Stg2GGIO3.alm1 SAF4/Stg3GGIO4.alm1 SAF4/Stg4GGIO5.alm1 UFLS/PTUF1.Op UFLS/PTUF2.Op UFLS/PTUF3.Op UFLS/PTUF4.Op	Feeder4 Stage 1 Feeder4 Stage 2 Feeder4 Stage 2 Feeder4 Stage 3 Stage 1 Block Stage 2 Block Stage 3 Block Stage 4 Block	F4PTRC1 F4PTRC2 F4PTRC3 F4PTRC4 F4PTRC1 F4PTRC2 F4PTRC3 F4PTRC4
Feeder1 IED (F1)	F1PTRC1.Op F1PTRC2.Op F1PTRC3.Op F1PTRC4.Op	Stage Trip	F1PTRC5
Feeder2 IED (F2)	F2PTRC1.Op F2PTRC2.Op F2PTRC3.Op F2PTRC4.Op	Stage Trip	F2PTRC5
Feeder3 IED (F3)	F3PTRC1.Op F3PTRC2.Op F3PTRC3.Op F3PTRC4.Op	Stage Trip	F3PTRC5

IED Name	Source IED Name/Subscribed GOOSE Data Object	Subscribed IED signal description	Function using the subscribed signal(s)
Feeder4 IED (F4)	F4PTRC1.Op F4PTRC2.Op F4PTRC3.Op F4PTRC4.Op	Stage Trip	F4PTRC5
Feeder1 CB Interface (F1CB)	F1PTRC5.Op	CB Trip	F1XCBR
Feeder2 CB Interface (F2CB)	F2PTRC5.Op	CB Trip	F2XCBR
Feeder3 CB Interface (F3CB)	F3PTRC5.Op	CB Trip	F3XCBR
Feeder4 CB Interface (F4CB)	F4PTRC5.Op	CB Trip	F4XCBR

Table 7-41: Subscriber GOOSE Table – Master Trip Blocking

7.13.7 Summary of 4-stages UFLS IED Requirements

Scheme	Clause	Master IED	Stage IED	Feeder IED
No Master with Boolean Logic	7.13.4	n/a	PTUF No Logic	1 x PTRC Boolean Logic
No Master with BlkRef/InRef	7.13.5	n/a	PTOF No Logic	4/5 x PTRC InRef/BlkRef
Master/Follower with Measurement Blocking	7.13.6.1	PTOF	PTUF BlkRef	4/5 x PTRC InRef/BlkRef
Master/Follower with Trip Blocking	7.13.6.2	PTOF	PTUF	4/5 x PTRC InRef/BlkRef

Table 7-42: 4-Stage UFLS Summary Scheme Requirements

7.14 Electromechanical Device Interface with IEC 61850 Semantics

Many substations will need to integrate legacy devices into the IEC 61850 system. Whilst GGIO is the generic Logical Node, its definition in IEC 61850 Part 7-4 Ed2 specifically precludes its use where the function can be represented by a specific Logical Node.

However the IED vendors have generally will not know what is connected to a particular physical input or output to the IED and hence they can only provide the IED with GGIO assigned to those I/O.

7.14.1 Electromechanical Protection Function Integration

In one application the GGIO could ultimately be mapped to the IED input which receives its signal from the transformer neutral electromechanical earth fault relay necessitating tripping of the HV breaker and initiation of the HV breaker CB Fail scheme via the SAS LAN as per Figure 7-69. In this application it would be ideal if that GGIO input could be renamed as PTOC to provide the semantics of PTOC.Op to be used in the SCL engineering process. Note that the PTOC instance is not a full PTOC as it has no controls or settings able to be applied via the SAS. (Note TISSUE 880 Part 7-4, Edition 2).

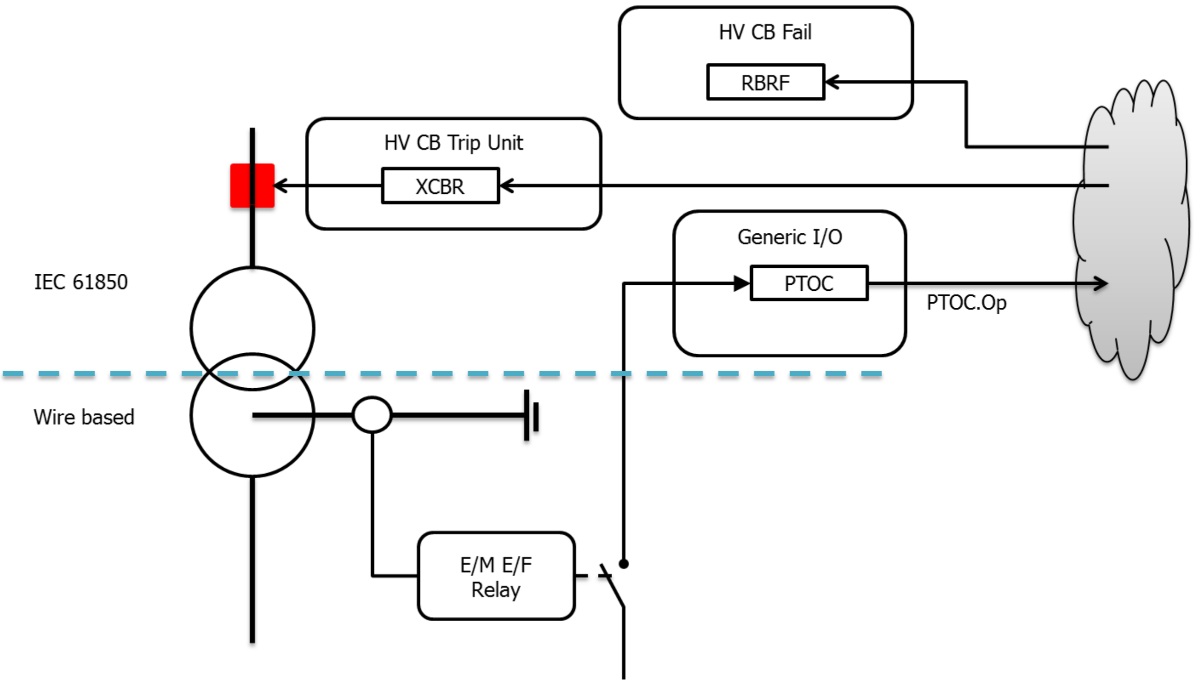

Figure 7-69: Input from Electromechanical Earth Fault Relay Represented as PTOC

Similarly, an electromechanical High Impedance Differential relay can be integrated into the SAS for tripping of all the zone circuit breakers using IEC 61850 by using a GGIO (preferably renamed as PDIF).The use of IEC 61850 provides the opportunity to establish Process Bus applications with significant benefits due to the significant impact of reducing engineering, installation and commissioning effort of thousands of wires between the primary and secondary equipment..

7.14.2 Process Bus for Conventional Primary plant

There is much discussion in the industry regarding the possibilities and emerging realities of Process Bus solutions. In most cases these discussions are in the context of replacing wound core "conventional" CT/VT 1A/110V signals.

Most of the discussions centre on the use of Low Power Instrument Transformers (LPIT – previously referred to as Non-Conventional Instrument Transformers) such as optical CTs or Rogowski coils. Whilst these are well proven technologies since the early 1980's, many remain sceptical about the choice of LPIT. However this does not preclude the use of IEC 61850 9-2 Sampled Value messaging with conventional wound core CT/VT to eliminate extensive yard wiring engineering, installation and commissioning. Stand Alone Merging Units (SAMU) are available for conventional CT/VT inputs which can be installed near the base of the CT/VTs and then connected into the SAS IEC 61850 LAN as shown in Figure 7-70.

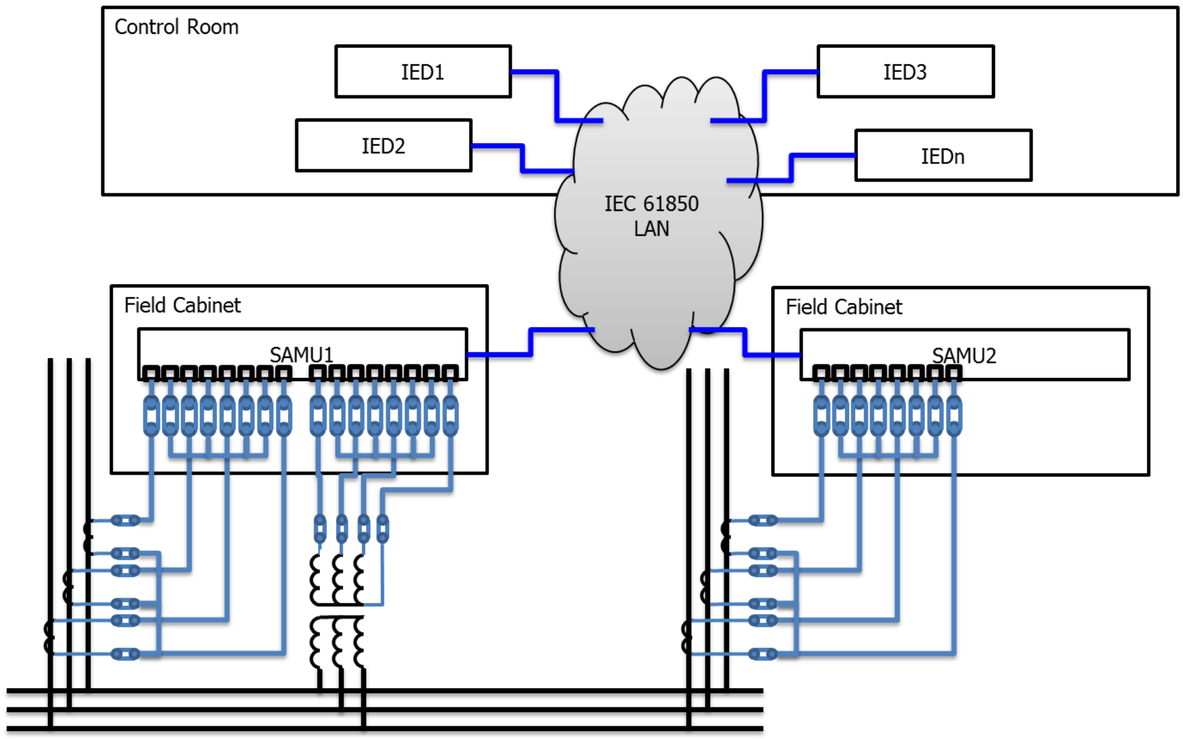

Figure 7-70: Process Bus Implementation for Conventional CT/VT

However Process Bus is not just the CT/VT Sampled Values defined in IEC 61850 9-2 (and the guideline 9-2LE). Process Bus is the section of the LAN which allows communication between the bay and/or station level IEDs to the primary plant. Process Bus therefore also includes LAN connections to Circuit Breakers, Transformers, Reactive Plant (Capacitor banks, reactors, SVC etc.) and any monitoring or controls for pumps, fans, lights etc. This includes operation status (open/closed, on/off, tap position indication), operational control (open/close, switch on/off, raise/lower) and condition monitoring.

Primary plant tends to have much longer life spans that the secondary equipment (refer CIGRE Technical Brochure 246, 2004: "The Automation of existing Substations – why and how" Chapter 1). As such, in many secondary system refurbishments, primary plant /layout augmentations it may be difficult to replace the primary plant with more modern intelligent plant with direct IEC 61850 support. However in these instances it is feasible to use a general purpose I/O unit nominally with GGIO Logical Nodes. Ideally these GGIO should be able to be renamed for example as XCBR in the case of establishing "an intelligent CB" functionality. The I/O unit can be located next to the conventional CB operating mechanism requiring only short direct wire connections between the I/O unit and the CB whilst allowing connection of the I/O unit as an IED connected to the Process Bus as shown in Figure 7-71. Similarly other functions such as Tap Position Indication, fan/pump controls and even lighting can be integrated into the SAS IEC 61850 LAN.

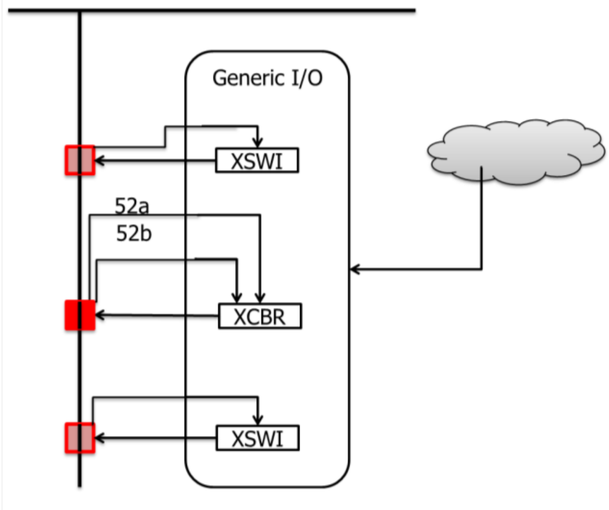

Figure 7-71: Process Bus Implementation for Conventional CB

7.14.3 <u>Integration of Functions Not Specified in IEC 61850</u>

In other circumstances, the IED GGIO could be simply a door open/closed indication (physical security alarm) or controls for the lighting in the yard as per Figure 7-72.

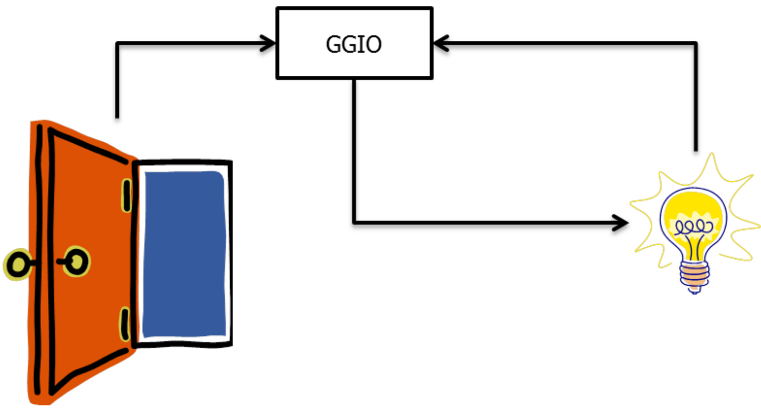

Figure 7-72: Use of GGIO for non-LN defined I/O

However even where the use of GGIO is in accord with the allowable use defined in IEC 61850 7-4, the semantics of GGIO can be quite frustrating when there are dozens of GGIO instance in every IED. It is therefore again useful to be able to rename the GGIO with a suitable semantic, noting that this can only be in the context of a semantic not already defined in the LNs available in the Standard. This can be achieved using 'private' Logical Node definitions under a project or utility-specific namespace (refer IEC 61850 7-1 Ed2 Clause 14.3.2). Hence in the above example, the door GGIO could be modelled as "KDOR" and the light as "KLIT" thus providing semantics in the SCL files. (Note TISSUE 900 Part 7-4 Ed 2).

8 NEW PROTECTION SCHEMES BASED ON BOTH IEC 61850-8-1 AND IEC 61850-9-2 (PROCESS BUS)

8.1 General Description

In the case of distributed architecture, the analogue signals that are usually hardwired from the secondary of the instrument transformers into the analogue inputs of the IED are replaced by an Ethernet message that contains one or more sets of samples from a Merging Unit connected to the instrument transformers.

The instrument transformers can be either conventional or non-conventional. The Merging Units are defined as interface units that accept multiple analogue CT/VT and binary inputs and produces multiple time-synchronized, serial, unidirectional, multi-drop digital point-to-point outputs to provide data communication via the logical interfaces. Two modes of sending sampled values between a merging unit and a device that uses the data are defined by IEC 61850. For protection applications, the merging units send 80 samples per cycle and for measurement applications, 256 samples per cycle. The information exchange for sampled values is also based on a publisher/subscriber mechanism. The publisher writes the values in a local buffer at the sending side, while the subscriber reads the values from a local buffer at the receiving side. A time stamp is added to the values, so that the subscriber can check the timeliness of the values and use them to align the samples for further processing.

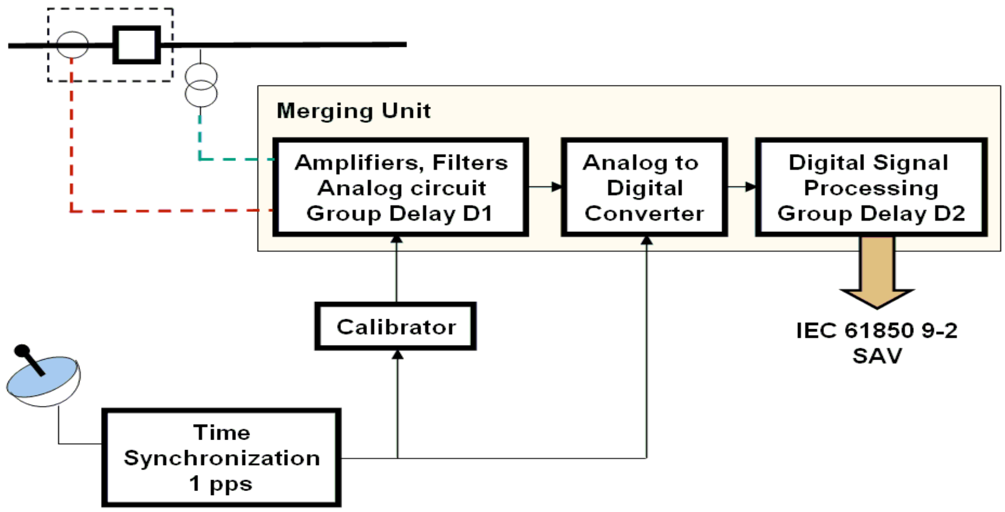

Figure 8-1: Simplified Block Diagram of a Merging Unit

Figure 8-1 shows a simplified block diagram of a merging unit including amplifiers, filters, analogue to digital converter and DSP signal processing. The merging unit is synchronized using e.g. 1 PPS signal from a GPS receiver or some other means with sufficient accuracy. If this time delay is not compensated, it will be seen as a phase shift that will affect all functions using the sampled analogue values.

8.2 Differential busbar protection

The high-speed bus protection function is based on current and voltage samples as well as breaker or switch status information available from the merging units as shown in Figure 8-2 connected to different primary equipment (lines, feeders, transformers, etc.) in the substation.

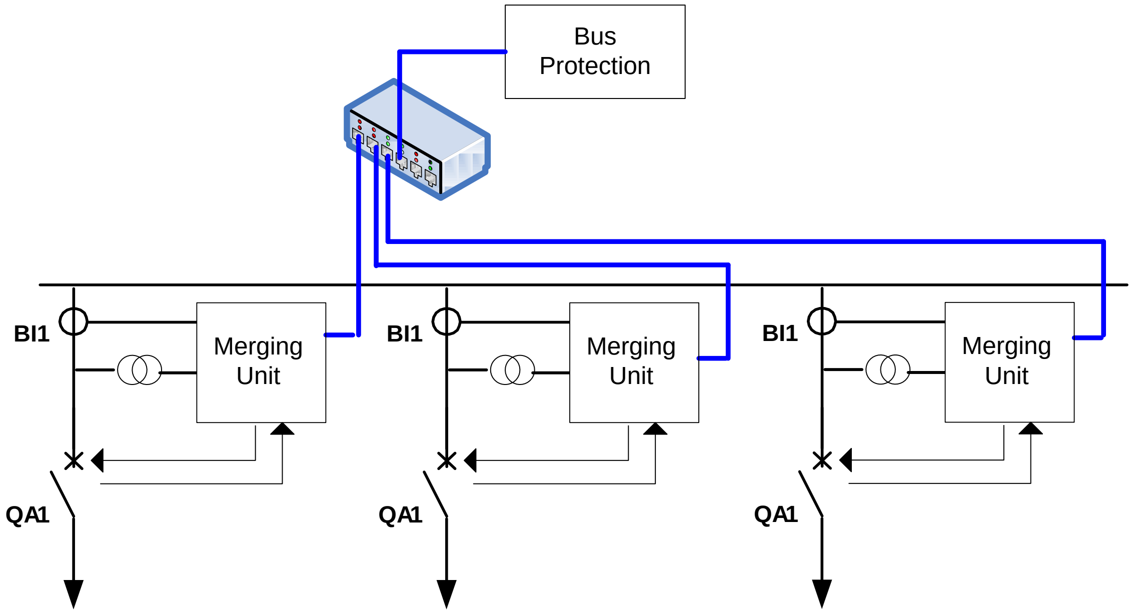

Figure 8-2: High-Speed Bus Protection

The status of the breakers or switches is used to determine the zones of protection for each bus, or bus segment. All merging units are time-synchronized from the Synchronization Unit. The sampled analogue values from the individual merging units are multicast and available to the central bus protection unit through an Ethernet switch. The Ethernet link between the switch and the bus protection unit can be 100 Mb/sec, 1 Gb/sec or higher depending on the available technology and the number of merging units it has to interface with.

The central bus relay runs all the protection algorithms (bus differential, check zone, voltage protection, etc.), takes the decision to trip and generates the Intertrip GOOSE message to the merging units.

The central bus protection unit will receive from multiple merging units through its Ethernet port multiple sets of sampled current and voltage values and breaker status information and continuously update a multi-cycle buffer where the samples for a period of time defined by a setting will be stored. With each set of samples available, the bus protection runs the bus differential algorithms based on the magnitude of the current samples on a per phase basis. The zone of protection will be based on the known configuration of the substation bus and the received indication of change of state of breaker or switches available from the merging units.

8.3 Synchronism Check without Bus VTs

8.3.1 Introduction

Bus-bar VTs can be used as part of synchronizing schemes as the length and complexity of secondary wiring required to use only feeder VTs can be considered to be prohibitive. However, the passing of sampled value voltages using a process bus provides the opportunity to remove the need to install bus-bar VTs. The necessary information can be provided directly to the check-sync element from a circuit already connected to the bus-bar as well as from the isolated feeder that is to be connected.

8.3.2 Description of the Signal Interactions

Consider the example of a bus-bar that is used to interconnect three separate feeders (for simplicity only a single bus section is used). Conventionally, each incoming feeder will have a VT installed and all are connected to the check-sync relay (IED). A separate bus VT will also be installed and connected. Within the IED, logic will be provided to select the appropriate feeder voltage when requested either manually or remotely (via the substation RTU or SCADA) for synchronization. This simplified scheme is shown diagrammatically in Figure 8-3.

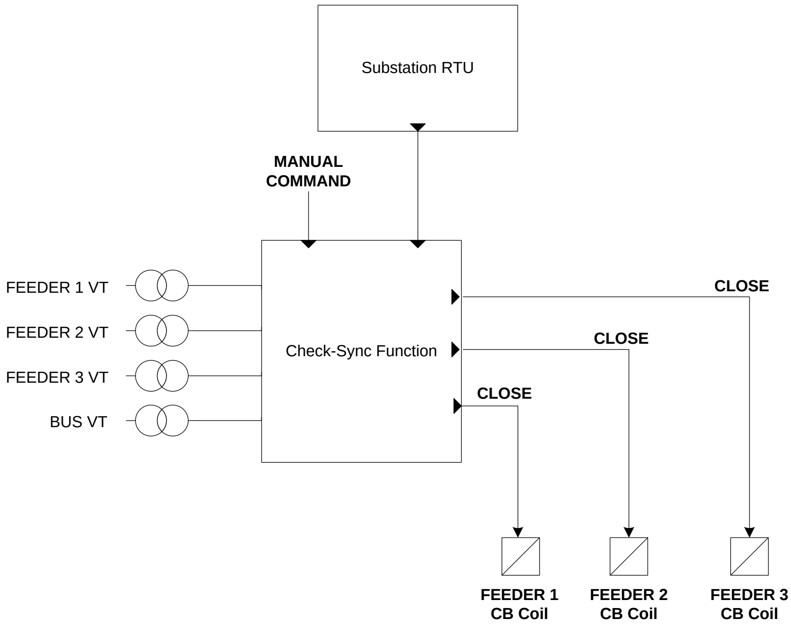

Figure 8-3: Busbar synchronisation scheme using analogue wiring including a bus VT.

8.3.3 Use of IEC GOOSE Message

Alternatively, sampled values can be used to pass voltages for synchronization and circuit breaker close commands can be implemented using GOOSE messages. **Figure 8-4** below provides details of the necessary process bus, voltage transformer merging units, sample synchronization source, check-sync IED and CB IEDs to implement such a scheme. A local hardwired command is still included, although the remote synchronization request from the substation RTU is now made using a GOOSE message.

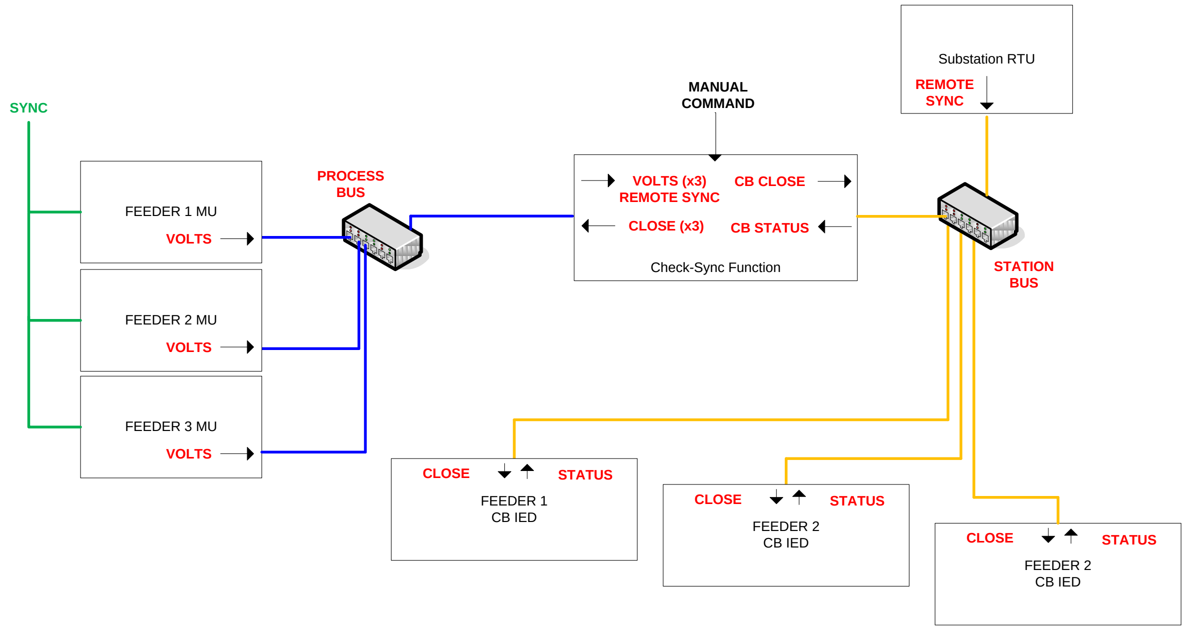

Figure 8-4: Busbar synchronization scheme using IEC sampled values and GOOSE messages

All the devices used in the IEC 61850 based bus-bar synchronization scheme are connected with full duplex Ethernet link to one or more switches depending on the communication topologies (dual ring, redundancy, etc.). A suitable synchronization source is provided for all merging units.

The following tables detail the nature of the sampled values and GOOSE messages to be defined within this scheme.

IED Name	Logical Nodes	Publisher	Subscriber
MU Feeder 1	Va, Vb, Vc	X	
MU Feeder 2	Va, Vb, Vc	X	
MU Feeder 3	Va, Vb, Vc	X	
Synchro Check IED	Va,b,c from F1, F2, F3		X

Table 8-1: Samples Analogue Values Table for Busbar synchronisation scheme

IED Name	Relay Signal	Publisher	Subscriber
RTU	REMOTE_SYNC	X	
Check Sync IED	REMOTE_SYNC		X
Check Sync IED	C1_CB_CLOSE	X	
Check Sync IED	C2_CB_CLOSE	X	
Check Sync IED	C3_CB_CLOSE	X	
Check Sync IED	C1_CB_STATUS		X
Check Sync IED	C2_CB_STATUS		X
Check Sync IED	C3_CB_STATUS		X
FEEDER 1 CB IED	C1_CB_CLOSE		X
FEEDER 2 CB IED	C2_CB_CLOSE		X
FEEDER 3 CB IED	C3_CB_CLOSE		X
FEEDER 1 CB IED	C1_CB_STATUS	X	
FEEDER 2 CB IED	C2_CB_STATUS	X	
FEEDER 3 CB IED	C3_CB_STATUS	X	

Table 8-2: Subscriber / Publisher GOOSE Table for Busbar synchronisation scheme

The following logic is required within the sync-check IED:

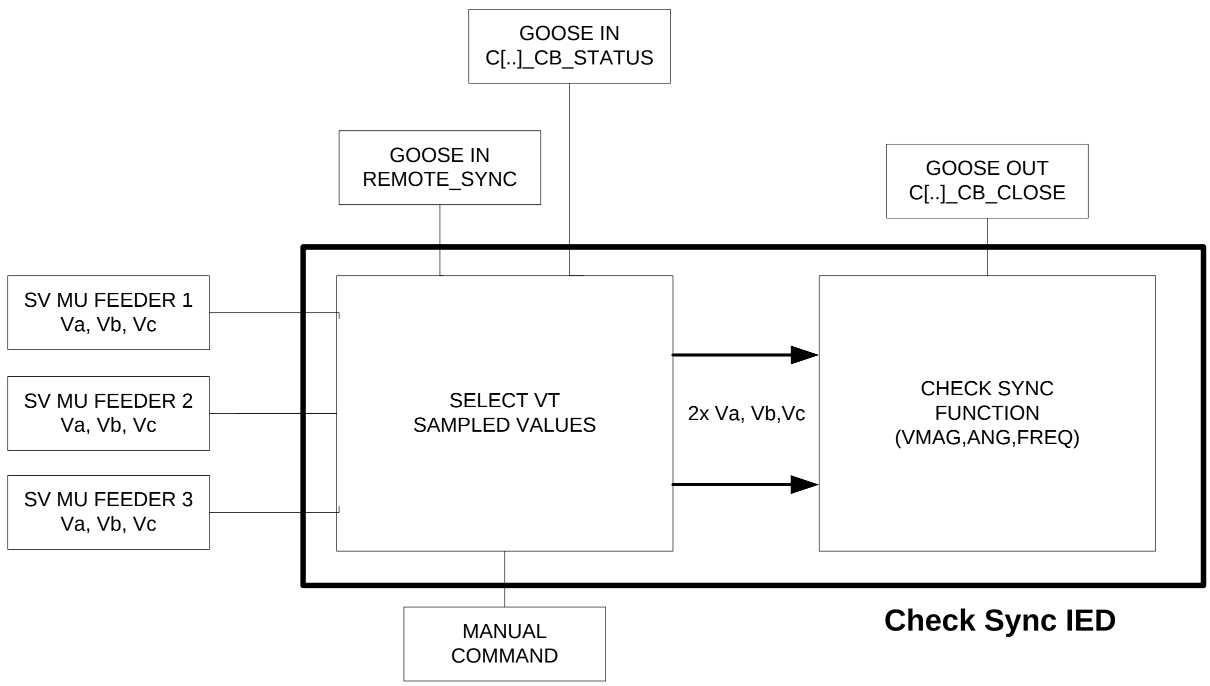

Figure 8-5: Logic to be implemented into the Check Sync IED

8.4 Adaptive Protection Scheme: Tap Changer / Transformer Protection

8.4.1 Introduction

The sensitivity of differential protection applied to transformers can be improved if ratio corrections applied to current vectors are adapted to reflect the current tap position. It is suggested that GOOSE messages are used to pass formation relating to changes in tap position from the tap changer IED to the differential protection IED.

8.4.2 Use of IEC GOOSE Message

To implement such a scheme, the current tap position needs to be sent to the differential relay when it is changed by the tap changer relay using an analogue GOOSE message. Upon receipt of this information, the protection IED can make the necessary ratio correction based on a lookup table of tap positions. A simple scheme is outlined in Figure 8-6**:** (current measurements and circuit breaker trips have been omitted).

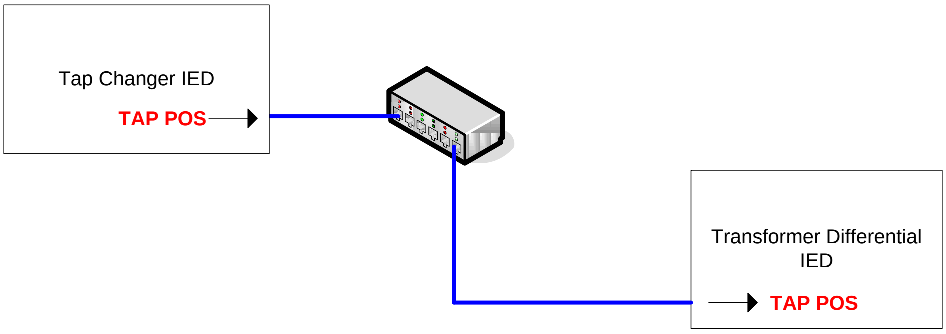

Figure 8-6: Tap changer adaptation using IEC sampled values and GOOSE messages

All the devices used in the adaptive transformer differential protection scheme are connected with full duplex Ethernet link to one or more switches depending on the communication topologies (dual ring, redundancy, etc.).

Table 8-3 details the nature of the GOOSE messages to be defined within this scheme.

IED Name	Relay Signal	Publisher	Subscriber
Tap Changer	TAP_POS	X	
Transformer Diff Protn	TAP_POS		X

Table 8-3: Subscriber / Publisher GOOSE Table for Tap changer adaptation

8.5 Zero sequence mutual compensation for distance relay

8.5.1 <u>Introduction</u>

When there are outgoing lines from the substation that are located in parallel for a sufficiently long distance, the impedance measurement of the distance relays will lose accuracy in earth-faults due to the fact that there is a mutual impedance of these two lines that makes this error in measurement. In order to compensate for this error, the zero sequence current of the parallel line shall be brought to the distance relay of the other feeder.

8.5.2 <u>Description of the Signal Interactions</u>

Consider the parallel lines Line A and Line B from the substation. The distance relay of Line A feeder will need the zero sequence current input from Line B and the distance relay of Line B feeder will need the zero sequence current input from Line A in order to calculate the impedance correctly taking into account the needed compensation of the mutual inter-coupling between lines A and B.

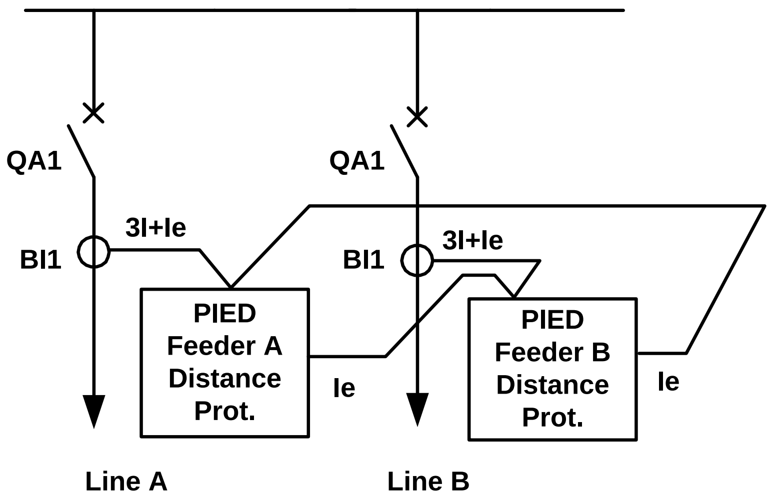

Figure 8-7: Zero sequence mutual compensation

8.5.3 Use of IEC GOOSE Message

Both current inputs between distance relays of Line A and Line B can be replaced with sample value GOOSE messages.

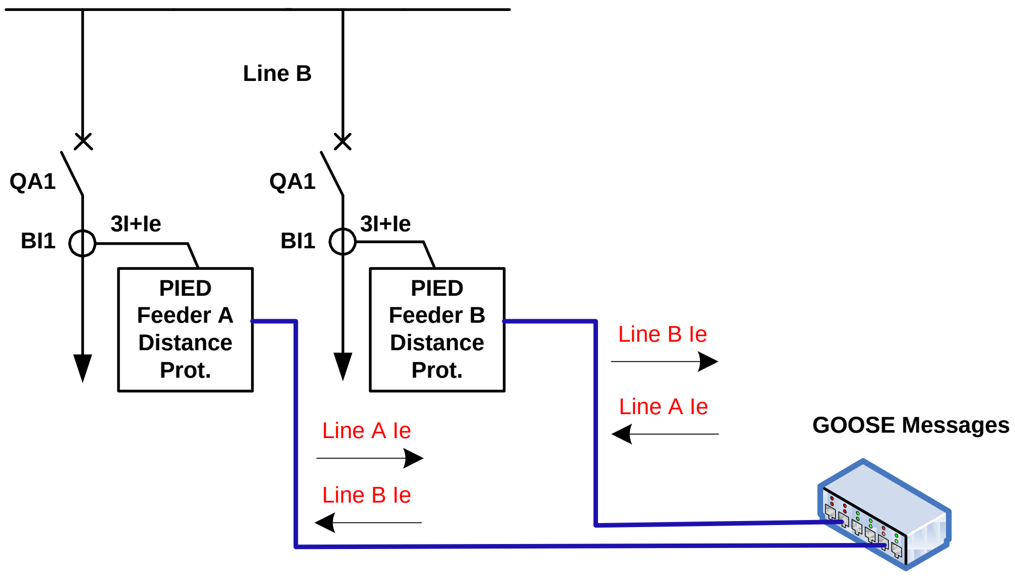

Figure 8-8: Zero sequence mutual compensation using IEC sampled values and GOOSE messages

The following GOOSE messages have to be defined as follows:

IED Name	Signal	Publisher	Subscriber
Line A PDIS	Line A Ie SAV	X	
Line B PDIS	Line A Ie SAV		X
Line B PDIS	Line B Ie SAV	X	
Line A PDIS	Line B Ie SAV		X

Table 8-4: Subscriber / Publisher GOOSE Table for Zero sequence mutual compensation

The distance relay PDIS of Line A publishes SAV GOOSE messages containing Line A zero sequence current (Ie) data stream and the distance relay PDIS of Line B subscribes to this stream of GOOSE message data. For Line B zero sequence current (Ie) data, the signalling process is the same, but in opposite direction.

8.6 Transformer differential protection

8.6.1 <u>Introduction</u>

Transformers are generally provided with a differential protection relay. This measures all ingoing and outgoing currents of the transformer. Based on the simultaneously measured currents, it makes a decision whether there is a fault inside its protection zone or outside of it.

8.6.2 <u>Description of the Signal Interactions</u>

The transformer differential relay will need the three phase currents from both HV and LV side of the transformer. Depending on the grounding method and protection philosophy, transformer neutral point current is included in the transformer differential relay.

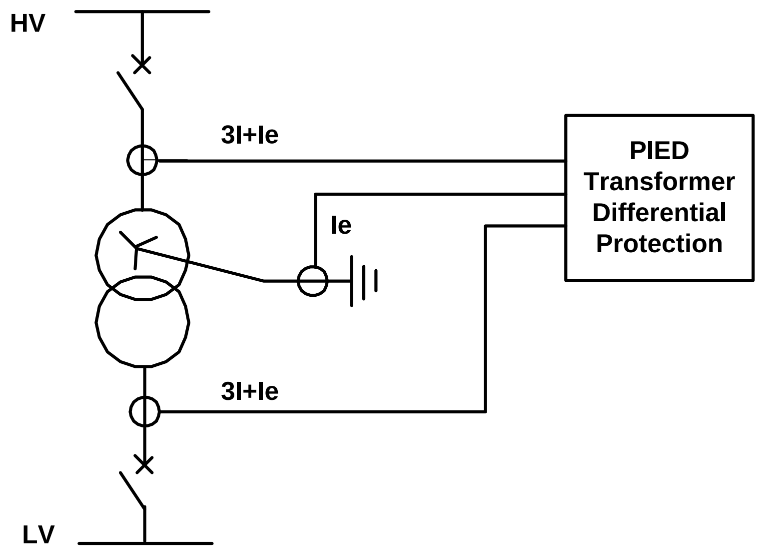

Figure 8-9: Transformer differential protection

8.6.3 <u>Use of IEC GOOSE Message</u>

The current inputs from LV side and neutral point can be replaced with sample value GOOSE messages, if the protection philosophy allows it.

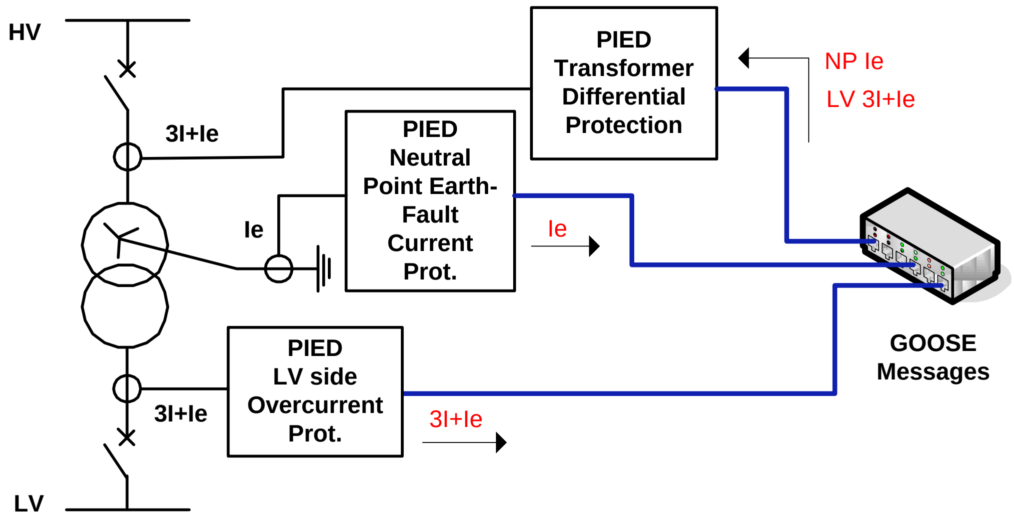

Figure 8-10: Transformer differential protection using IEC sampled values and GOOSE messages

The following GOOSE messages have to be defined as follows:

IED Name	Signal	Publisher	Subscriber
LV PTOC	LV IL1 SAV	X	
HV PDIF	LV IL1 SAV		X
LV PTOC	LV IL2 SAV	X	
HV PDIF	LV IL2 SAV		X
LV PTOC	LV IL3 SAV	X	
HV PDIF	LV IL3 SAV		X
NP PTOC	NP IE SAV	X	
HV PDIF	NP IE SAV		X

Table 8-5: Subscriber / Publisher GOOSE Table for Transformer differential protection

The back-up definite time 3-phase overcurrent protection relay on the low voltage side of the transformer LV PTOC publishes SAV GOOSE messages containing the three phase currents (IL1, IL2, IL3) data stream and the transformer main protection differential relay on the high voltage side of the transformer HV PDIF subscribes to this stream of GOOSE message data. Any neutral point earth-fault current relay publishes SAV GOOSE messages containing the neutral current (IE) data stream and the transformer main protection differential relay on the high voltage side of the transformer HV PDIF subscribes to this stream of GOOSE message data.

However, use of GOOSE messages as shown above isn't possible, if the LV overcurrent relay is supposed to be a back-up relay to the current differential relay, as they share the same physical circuits. I.e., if the LV PTOC relay fails, so does the transformer differential protection.

8.7 Generator Protection

The functions that form the protection for a generator are generally self-contained (i.e. their zone of coverage is that of the machine and any associated step-up transformer) and are thus ideal for integration within a single IED. Consequently, the applications of GOOSE messaging are likely to be found in the provision of circuit breaker trip circuits with the natural extension to include station control systems. Hardwired signalling from protection relays to auxiliary equipment automation systems could also be similarly replaced with GOOSE equivalents (e.g. standby diesel generator starting for essential site supplies).

8.7.1 Example: Equipment Temperature Monitoring

8.7.1.1 Introduction

One specific example of GOOSE messages would be to make use of their capability to contain analogue values to transfer temperature information from RTDs located around the generator to improve the accuracy of a thermal replica model. Problems commonly arise with interference on traditional wiring where long cable runs are required through harsh environments back to the unit's relay room. The use of a remote RTD unit close to the generator and the subsequent sending of digital measurements over the LAN will greatly reduce the likelihood of errors being introduced.

8.7.1.2 Description of the Signal Interactions

Existing implementations of this function would require the hardwiring of analogue circuits from the RTDs located at various locations around the generator. Operator alarms and unit trips will be initiated by the IED when necessary based on the thermal model. Figure 8-11 provides an illustration of a conventional hardwired approach.

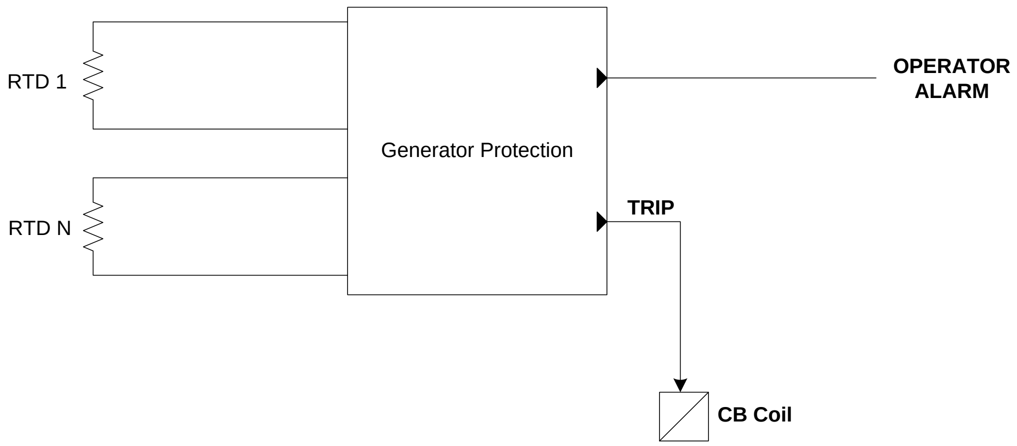

Figure 8-11: Machine temperature monitoring scheme using analogue wiring.

8.7.1.3 Use of IEC GOOSE Message

Figure 8-12 below highlights the structure of a scheme intended to supply a number of temperatures with the GOOSE messages being broadcast either at regular predetermined time intervals or when locally measured temperatures change by a set amount. The latter method being potentially justified by the relatively long thermal time constants associated with the machine. A suitable remote RTD unit will be installed at a marshalling cubicle close to the machine.

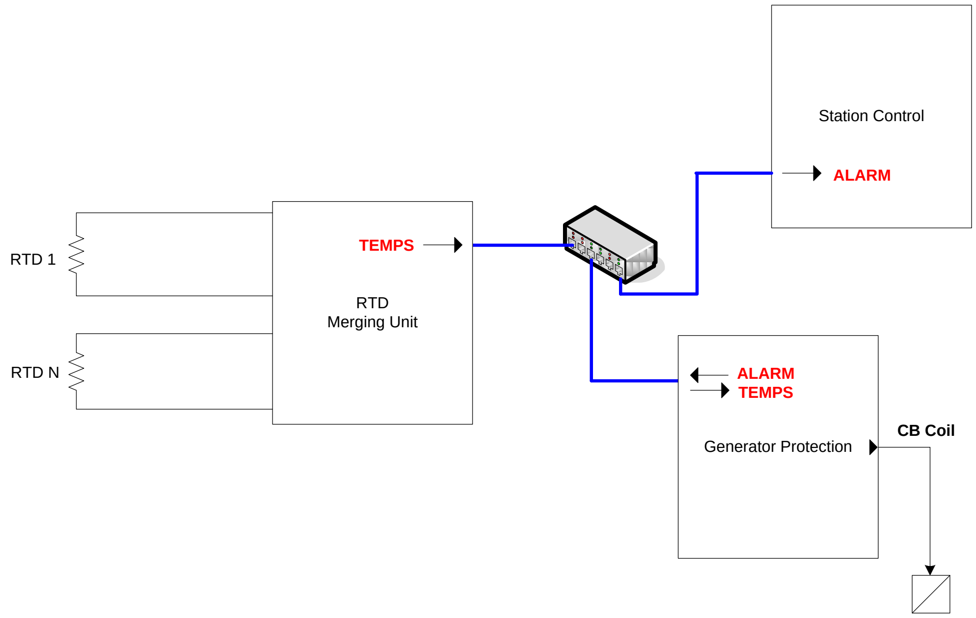

Figure 8-12: Machine temperature monitoring scheme using analogue GOOSE messages.

All the devices used in the IEC 61850 based generator temperature monitoring scheme are connected with full duplex Ethernet link to one or more switches depending on the communication topologies (dual ring, redundancy, etc.).

Table 8-6 details the nature of the SAV and GOOSE messages to be defined within this scheme:

IED Name	IED Signal	Publisher	Subscriber
Remote RTD Unit	T_1 (TTMP)	X	
Remote RTD Unit	T_N (TTMP)	X	
Generator Protection	T_1 (STMP)		X
Generator Protection	T_N (STMP)		X
Generator Protection	ALARM (STMP)	X	
Generator Protection	TRIP (STMP)	X	
Station Control System	ALARM (IHMI)		X
Station Control System	TRIP (IHMI)		X

Table 8-6: Subscriber / Publisher GOOSE Table for Machine temperature monitoring scheme

9 REQUIREMENTS NEEDED FOR IEC 61850 IMPLEMENTATION

9.1 GOOSE Communication and Processing Flow

9.1.1 Introduction

The use of GOOSE messages provides high-speed communication mechanisms between IEDs, thus enabling the implementation of substation level protection, interlocking or distributed control systems. The GOOSE service model defined in the standard provides a possibility for a fast and reliable exchange of data between IEDs.

9.1.2 GOOSE Publishing

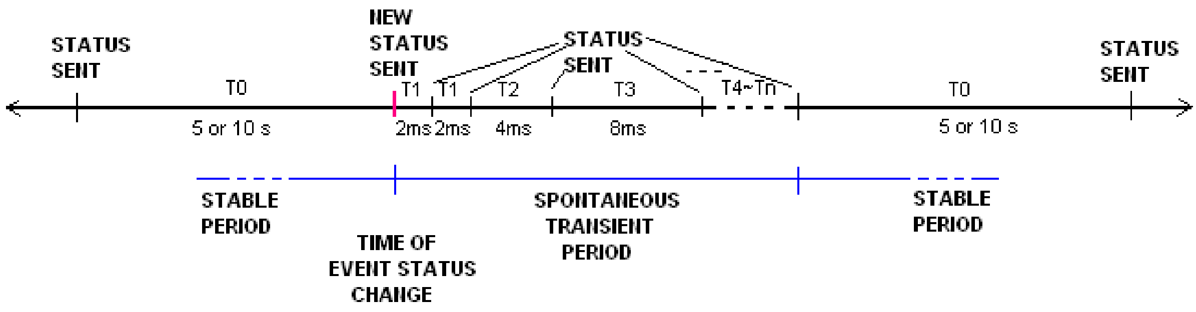

Figure 9-1: Example of time intervals of GOOSE messages

Figure 9-1 illustrates example message repeat intervals on the publisher side (the specific intervals used by any GOOSE publisher may be configurable). A published GOOSE message may contain multiple data objects or attributes. If no attribute value has changed from the previous message it will be published after a relatively long time interval of T0 (for example, 1 to 10 seconds). When any value contained in the data set changes, the updated message will be published with no intentional time delay. Then, the next time interval will be the minimum set time T1 (for example 1 or 2 milliseconds), and then increase to T2 (for example with a time interval twice of T1), and so on, according to the configured repetition mechanism.

Each GOOSE message carries StNum and SqNum parameters (shown in the standard section 15.2.3.1, part 7-2, Ed1). StNum indicates the change of a GoCB data set value. SqNum indicates the message sequence for the same data values. Any new data change in the data set will cause the GOOSE publisher to increment StNum, reset SqNum and change the repeat time interval to T1.

Figure 9-2 shows an example of PTOC.Op status as an element of a GOOSE message for a fault and subsequent clearance. The fast repetition cycle commences when the PTOC.OP changes from 0 to 1 as well as when it resets from 1 to 0 when the fault is cleared. The occurrence of the fault and operation of the PTOC is therefore evident by both the 0-to-1 transition repetition cycle and the 1-to-0 cycle.

Note that if the fault is cleared within 80 milliseconds of the PTOC operation, there will be five GOOSE messages sent in that time frame with the dataset element PTOC.Op=1.

If a PTRC LN is used with a pulse duration set to one second (PTRC.TrPlsTmms = 1 second), eight GOOSE messages will have been sent with PTRC.Tr=1 prior to reset.

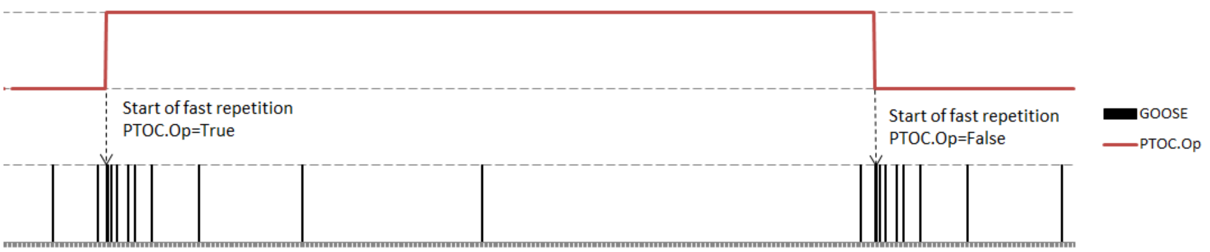

Figure 9-2: GOOSE repetition at each event

By establishing a proper relationship between the fast repetition of messages following a change of data set value and cyclic stable repetition intervals, the GOOSE message flow in the network can be decreased while achieving high speed and reliability levels. Clearly though, the total network or IED bandwidth requirement is relatively inconsequential compared to other traffic such as Sample Values with the Ethernet frame header and footers potentially representing far more bandwidth requirement than the Dataset itself. However with the potential for thousands of GOOSE in a total system, such bandwidth calculations must be carried out. The concept of GOOSE flooding is not as severe as might initially seem since GOOSE messages are happening continuously. The so call flooding can occur if the system is configured with too many Datasets with elements that would change state for a single or series of events that would result in many fast repletion cycles commencing almost concurrently. Good GOOSE message policy and eliminating multiple IEDs initiating multiple GOOSE for the same status change can alleviate flooding considerably.

9.1.3 GOOSE Subscribing and Processing

The subscriber needs a mechanism to deal with the GOOSE messages. Besides the data content in the GOOSE message, it also contains additional information, such as the two parameters of StNum and SqNum. Based on these two parameters, the subscriber can be aware if the current GOOSE message contains new data or not, which can help it to filter GOOSE messages, saving time and processing resources for the subscriber.

Special attention needs to be paid to the processing of GOOSE messages in which the Test bit value is true; however, this is not clearly interpreted in Ed 1 of the standard. It has to be well understood by the user what is its implementation and configuration is in a specific IED.

9.2 GOOSE performance

9.2.1 Introduction

One of the important differences between IEC 61850 and other communication protocols is the introduction of high-speed peer-to-peer communications defined as IEC GOOSE. These messages are used for the exchange of a wide range of possible common data organized by a DATA-SET.

The peer-to-peer communications in an integrated substation protection and control system are based on what is defined as a GSE. This is a Generic Substation Event (GSE) and it is based upon the asynchronous reporting of an IED’s functional elements status to other peer devices enrolled to receive it during the configuration stages of the substation integration process. It is used to replace the hard wired control signal exchange between IED’s, as seen in the previous sections, for interlocking and protection purposes and, consequently, is ***mission sensitive, time critical and must be highly reliable***.

The associated IEDs, receiving the message, use the contained information to determine the appropriate response for the given state change. The decision of the appropriate action to

GSE messages and the action to take, should a message time out due to a communication failure, is determined by local intelligence in the IED receiving the GSE message.

Considering the importance of the functions performed using GSE messages, IEC 61850 defines very strict performance requirements. The idea is that the implementation of high-speed peer-to-peer communications should be *equal to or better than what is achievable by existing technology*. Thus the total peer-to-peer transfer time should be less than 4ms.

For GOOSE messaging, the transfer time means the complete transmission of a message including necessary handling at both ends. The time counts from the moment the sender puts the data content on top of its transmission stack up to the moment the receiver extracts the data from its transmission stack, as shown in Figure 9-3.

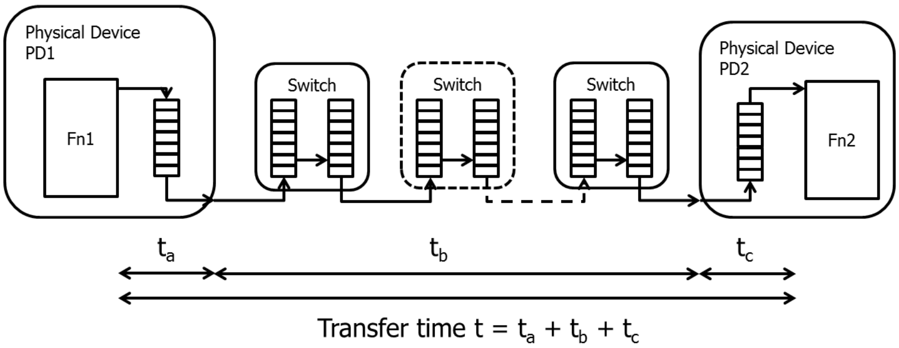

Figure 9-3: Function-to-Function Transfer Time Latency

Note t_b includes all the network transmission and processing times of the Ethernet switches. If too many switches are between publisher and subscriber, performance requirements may be hard to satisfy and hence network topology and equipment selection must be properly engineered.

Another key requirement for the GSE messages is very high reliability. Since the messages are not confirmed, but multicast, and considering the importance of these messages, there has to be a mechanism to ensure that the subscribing IED's will receive the message and operate as expected. To achieve a high level of reliability, messages will be repeated as long as the state persists. To maximize dependability and security, a message will have a time-to-live, which will be known as "hold time". After the hold time expires, the message (status) will expire, unless the same status message is repeated or a new message is received prior to the expiration of the hold time. The repeat time for the initial GSE message will be short and subsequent messages have an increase in repeat and hold times until a maximum is reached. The GSE message contains information that will allow the receiving IED to know that a message has been missed, a status has changed and the time since the last status change.

GOOSE data exchange is based on a Publisher/Subscriber mechanism using multicast. The GOOSE messages are repeated until there is a new change of state. The time between the consecutive transmissions of GOOSE messages immediately after the change of state are very short (a few milliseconds), followed by an increase in repeat and hold times of subsequent messages until a maximum is reached.

In the case where legacy devices exist, these devices do not support GOOSE messages. This function could be performed by the gateway. In this case, the gateway will continuously poll the legacy devices for status changes, and will form and send the appropriate GOOSE messages to the network. One GOOSE message is sent for each individual logical device in the gateway, i.e. there will be one GOOSE message for each legacy IED.

If a GOOSE message has to be processed by a legacy device, the gateway will subscribe to this message, and after processing it, will send a control signal to the appropriate legacy IED for further action. This approach allows the interface of legacy devices with IEC 61850 compliant devices on the substation LAN. However, since the messages between the legacy and the IEC 61850 IED will always go through the gateway, it will be affected by its characteristics and will always be slower than the pure peer-to-peer communications between IEC 61850 IEDs. The control system designer has to evaluate the degradation in performance and determine if this is acceptable. If not, the legacy IEDs have to be replaced by IEC 61850 compliant IEDs.

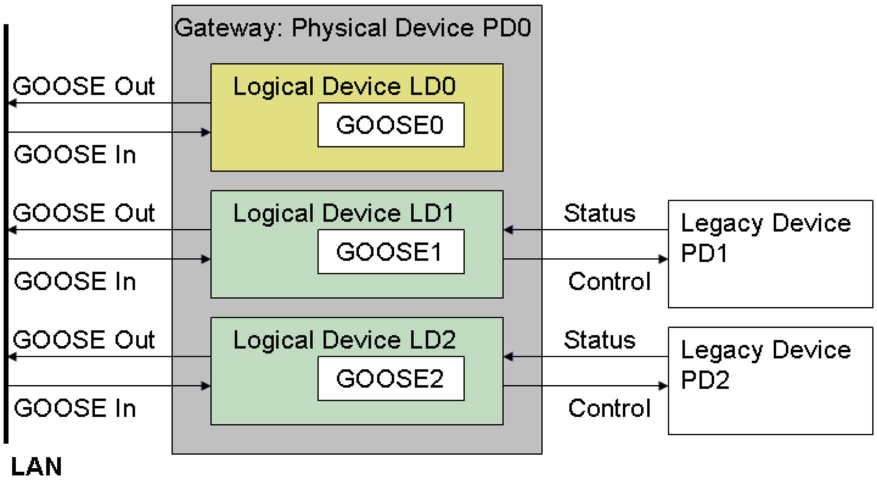

Figure 9-4: Legacy IED GOOSE interface

9.2.2 <u>Comparison between the performance of hard wired and GOOSE based accelerated schemes</u>

Numerous tests performed by different relay manufacturers and test companies show that GOOSE based distributed applications consistently outperform hard wired schemes with the same functionality. This may look strange at the beginning, but as can be seen from the careful analysis of the factors that determine the overall operating time of a distributed protection function, it is what should be expected.

If we consider that the breaker tripping and the communications exchange between the two ends of the protected line is performed in the same manner by the IEDs in both cases, we will have to analyse the time from the operation of the directional element in the sending relay and the resulting detection of the operation of the opto input of the teleprotection IED at the sending end of the line, as well as the time from the receiving of the accelerating signal and the resulting detection of it by the relay at the receiving end.

In the conventional hard wired scheme this will include the operating time of two output relays (each about 3 ms) plus the two detections of the energization of opto inputs (depending on the availability or lack of filtering and the scanning of the opto inputs this time for each can be from 2 to 8 ms).

If we assume an average time of opto input with filtering of about 5 ms, the total time at each end for the hard wired interface between the relay and teleprotection IED will be about 8 ms, giving us a total of about 16 ms for both ends.

If we look at the time between the directional element output and the communication device detection of the GOOSE message, according to IEC 61850 it should be less than 4 ms at each end of the line, giving us a total of about 8 ms for both ends. When we compare the two solutions, we see that the GOOSE based scheme will be about 8 ms (half a cycle at 60 Hz) faster than the hard wired equivalent.

Note:

It should be noted that the operating time of any GOOSE signal must be checked and measured to ensure that the implemented protection scheme based on IEC 61850 meets the expected requirements and specified performance.

9.3 Topology requirements

9.3.1 Introduction

Parts 8-1 and 9-2 of the IEC 61850 Standard specify exchanging time-critical and non-time-critical data through local-area networks (LAN) using ISO/IEC 8802-3 frames over 10/100TX or 100FX physical media. Ethernet based technology is flexible and with its devices is able to connect via different communication systems. Communication links are possible between different substations located in different geographical locations over a Wide Area Network (WAN). The Standard does not define how the physical network is built for Ethernet based station or process bus and in this chapter a few simple examples are given.

Modern Ethernet systems are switched networks where network devices such as Ethernet switches have knowledge of connected devices and therefore are able to route the unicast messages (in IEC 61850 typically reports and controls) in a Point-To-Point manner without distributing the traffic to all nodes in network. GOOSE and SAV are based on Ethernet Multicast messages and these types of messages are forwarded within a subnet simultaneously to all its nodes.

Redundancy of communication in IEC 61850 based systems is not required by the standard, but it is often used as it increases the availability of the applications themselves, and so may also be specified by the customer or end user. It especially improves the safety when using GOOSE services between IEDs, as failures in communication links are not tolerated when using GOOSE for protection purposes. Even though the first edition of the standard does not include any selected technology, the second edition does reference IEC 62439 that serves to reference and define some different methods of redundancy.

9.3.2 Station Bus Topologies

9.3.2.1 Star Topology

Star Network is the basic Ethernet topology in today’s switched networks. All devices are connected with single point-to-point links to switch and network devices routes the traffic between IEDs in substation. This type of topology is straightforward as it uses only standard Ethernet functionality and it does not necessarily need any configuration.

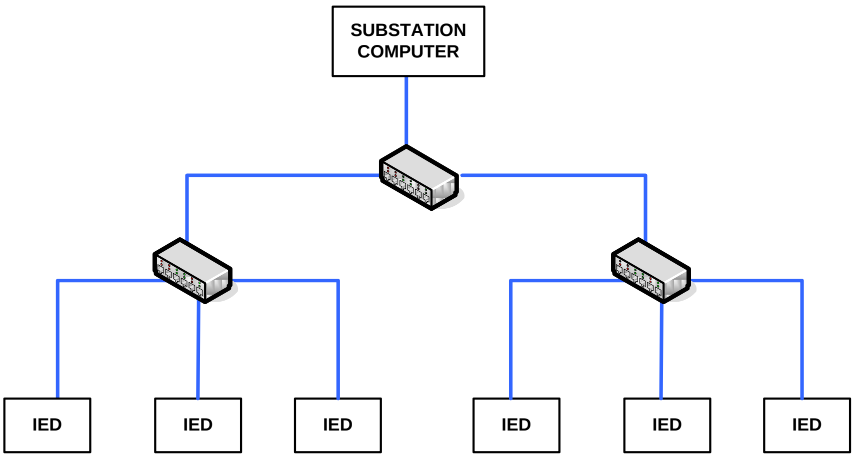

Figure 9-5: Star Network

If a substation is large and consists of several IEDs and switches, the backbone connections between Ethernet switches can be made redundant using a mesh or ring. IEDs have one link to Ethernet station bus. In this topology, switches typically require management possibilities and support of redundancy protocol, e.g. RSTP, to be able to handle loops in network.

RSTP is an IEEE standard, and is referenced from IEC 62439. In RSTP when communication is interrupted between switches, an alternative path is established to link switches in the network. However recovery times from communication failures could be between hundreds of milliseconds to several seconds, and therefore may not be suitable for fast distributed automation applications.

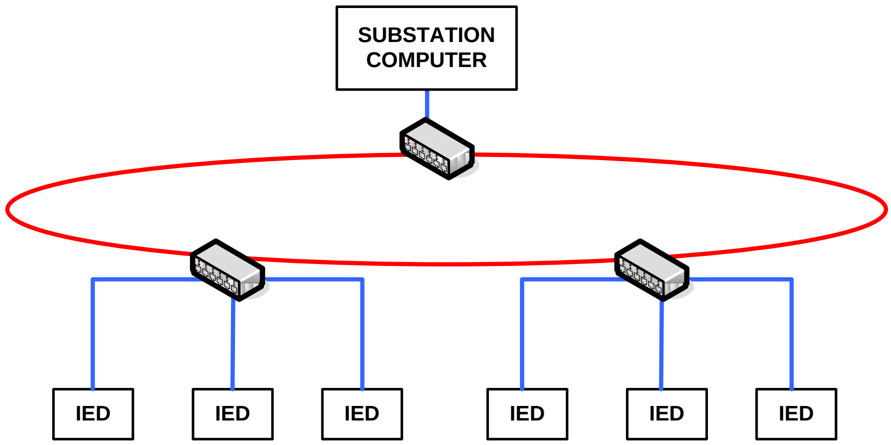

Figure 9-6: Star Network with additional network backbone redundancy

9.3.2.2 Loop Topologies

This is a network topology in which each device acts as a repeater with two communication ports, one for data input and the other for data output. The devices are then daisy-chained to form the loop. Management functions and a redundancy protocol e.g. RSTP are needed to manage the network loop and reroute paths in disturbance situations. IEDs need to be able to forward Ethernet traffic from one port to another if the traffic is not dedicated to it. The loop topology requires an Ethernet switch to logically open one point in the network, to inhibit the circulating of Ethernet messaging in network.

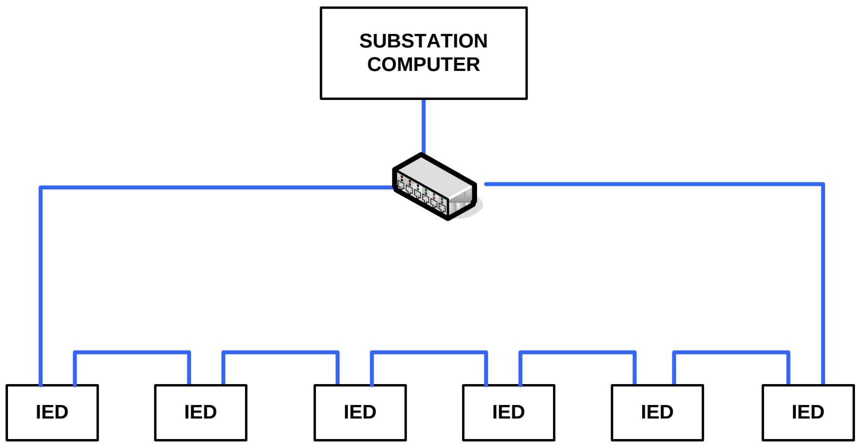

Figure 9-7: Loop Topology

9.3.2.3 Redundant Ring Topology

The redundant ring topology among switches and IEDs is a network topology which uses a redundant ring to communicate between network nodes. IEDs with a single Ethernet port may be connected to switches on the ring, or IEDs with suitable redundant Ethernet ports may be connected directly onto the ring.

Today's redundant ring implementations are proprietary, but in the future, redundant rings can be implemented conforming to the HSR method defined in IEC 62439 in order to provide both recovery times suitable for fast distributed automation applications and interoperability between different vendors' equipment.

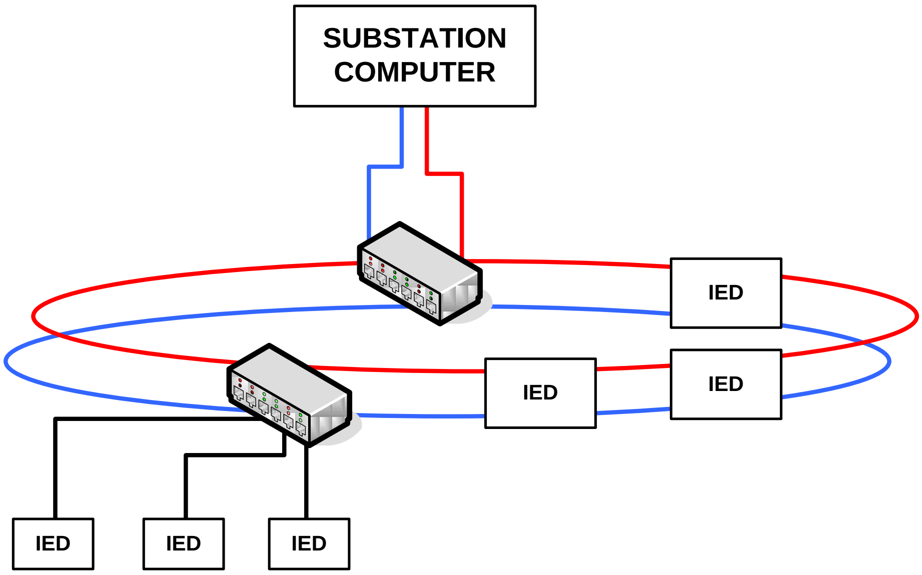

Figure 9-8: Redundant Ring Topology

9.3.2.4 Redundant Star Topology

Redundant Star topology is basically doubled star topology where every IED has point-to-point connections to different backbone networks. This type of network also requires double amounts of Ethernet switches for redundant paths. Redundancy logic must be implemented in all IEDs connected to station bus.

Today's redundant star implementations are proprietary, but in the future, redundant stars can be implemented conforming to the PRP method defined in IEC 62439 in order to provide both recovery times suitable for fast distributed automation applications and interoperability between different vendors' equipment.

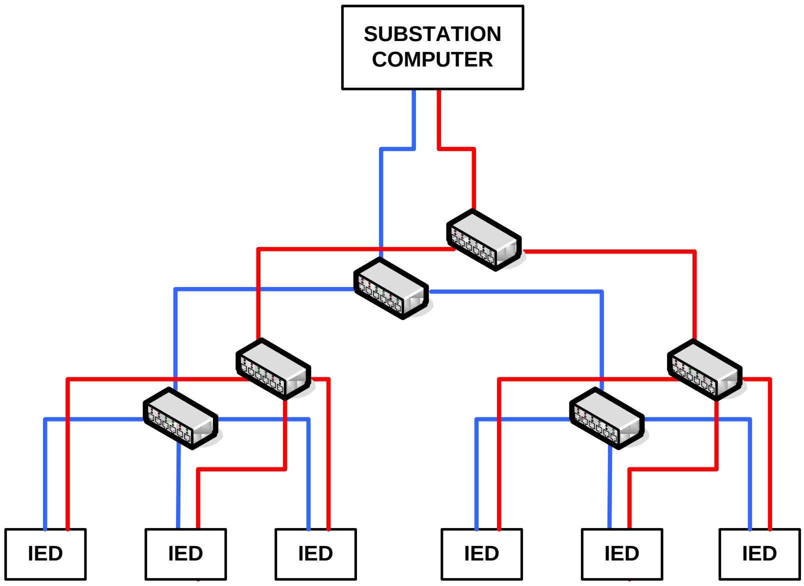

Figure 9-9: Redundant Star Network

9.3.2.5 Switch on loop with IEDs connected to 2 adjacent switches

This type of IED connection is the same as for redundant star. Additionally, in both redundancy networks the backbone is redundant forming loop between Ethernet switches. In this topology switches typically require management possibilities and support of redundancy protocol, e.g. RSTP, to be able to handle loops in network. Redundancy logic must also be implemented in all IEDs connected to station bus.

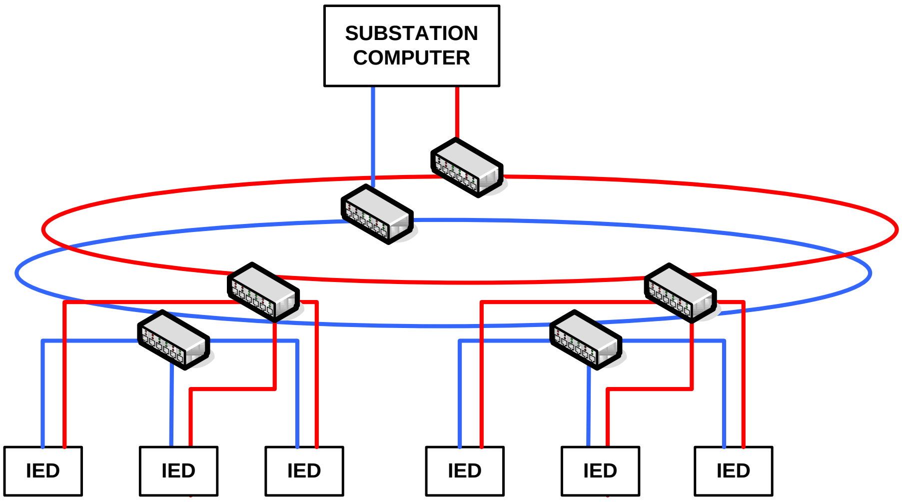

Figure 9-10: Redundant star connection of IEDs with loop between switches

The new IEC 62439 gives some performance comparison between the different redundancy methods / protocols. While designing an IEC 61850 based protection scheme, such considerations should be taken into account to ensure the required performance of the protection scheme.

Protocol	Solution	Frame loss	Redundancy protocol	End node attachment	Network topology	Recovery time fault or repair
IP	IP routing	Yes	Within the network	Single	Single meshed	>30 s typical not deterministic
STP	IEEE 802.1D:1998	Yes	Within the network	Single	Single meshed	>20 s typical not deterministic
RSTP	IEEE 802.1D:2004	Yes	Within the network	Single	Single meshed	>2 s typical not deterministic
CRP	IEC 62439, Clause 7	Yes	In the end nodes	Single and double	Connected, doubly meshed	1 s worst case for 512 end nodes
MRP	IEC 62439, Clause 5	Yes	Within the network	Single	Ring	200 ms worst case for 50 switches
BRP	IEC 62439, Clause 8	Yes	In the end nodes	Double	Connected, doubly meshed	4,8 ms worst case for 500 end nodes
PRP	IEC 62439, Clause 6	No	In the end nodes	Double	Independent double meshed	0 s

Table 9-1: IEC 62439 Standard

9.3.3 Process Bus Topologies

Typically in today's systems the process bus is separated from the station bus. As the process bus is also based on Ethernet technology, any of the topologies mentioned in this chapter could be used. Issues to be considered carefully for the process bus include reliability and availability, time synchronization, and testing. The process bus may have a different topology to the station bus.

Process bus traffic could also be sent in the same physical network as station bus traffic, thus forming a single unified network for all substation data.

9.3.4 Bumpless Topologies

In some applications, a more important consideration to redundancy is so called "bumpless" communication where a particular function will be assured to receive the required messages by virtue of the messages being sent by two physically different paths and the receiver acting on the first message received. Hence failure of one path will still permit reception of the same message by the alternate path.

Bumpless solutions are generally regarded as highly important for critical real-time signals where loss of messages for any period of time may be catastrophic. This particularly applies to functions such as:

- Sampled Values as essential for correct and timely protection function operation
- GOOSE for protection function operation (Pxxx.Op, RBRF.OpEx) essential to be received by the Circuit breaker XCBR

Clearly failure of a communications link or switch in a star topology will cause loss of communication to all IEDs 'below' that switch. This may cause catastrophic disruption to functions operating above or below the failed section.

Ring RSTP systems operate with one section of the ring 'switched-off' in normal operation in order pt prevent "infinite looping" of messages. When a failure is detected, the ring is reconfigured in a cascade process from one switch to another to effect closing of the ring at the previously switched off section. This reconfiguration can take several milliseconds per switch and hence recovery of effective communication may take 100's of milliseconds during which time the IEDs and functions are “blind”. Even the recovery of communication may be catastrophic for some functions which ‘recover’ in advance of others as the ‘direction’ of communication reverses around the ring.

Two bumpless solutions have emerged which prevents loss of any signal due to a single network failure as described in the following sections.

9.3.4.1 High –availability Seamless Redundancy (HSR)

HSR operates as a single ring, with each IED having two communication ports. Each message is sent out on both ports simultaneously and travel around the ring in different directions. All other IEDs must support HSR with dual ports in order that all messages are passed along. The receiving IED will receive both messages via its two ports and will act on the basis of the first message received. Note alarms can be generated if two identical messages are not received, but the function will continue to operate, noting that one path may be longer than the other for some functions. Where IEDs only provide a single port, these can stil be integrated to the HSR ring using a Redundancy ‘Red’ Box.

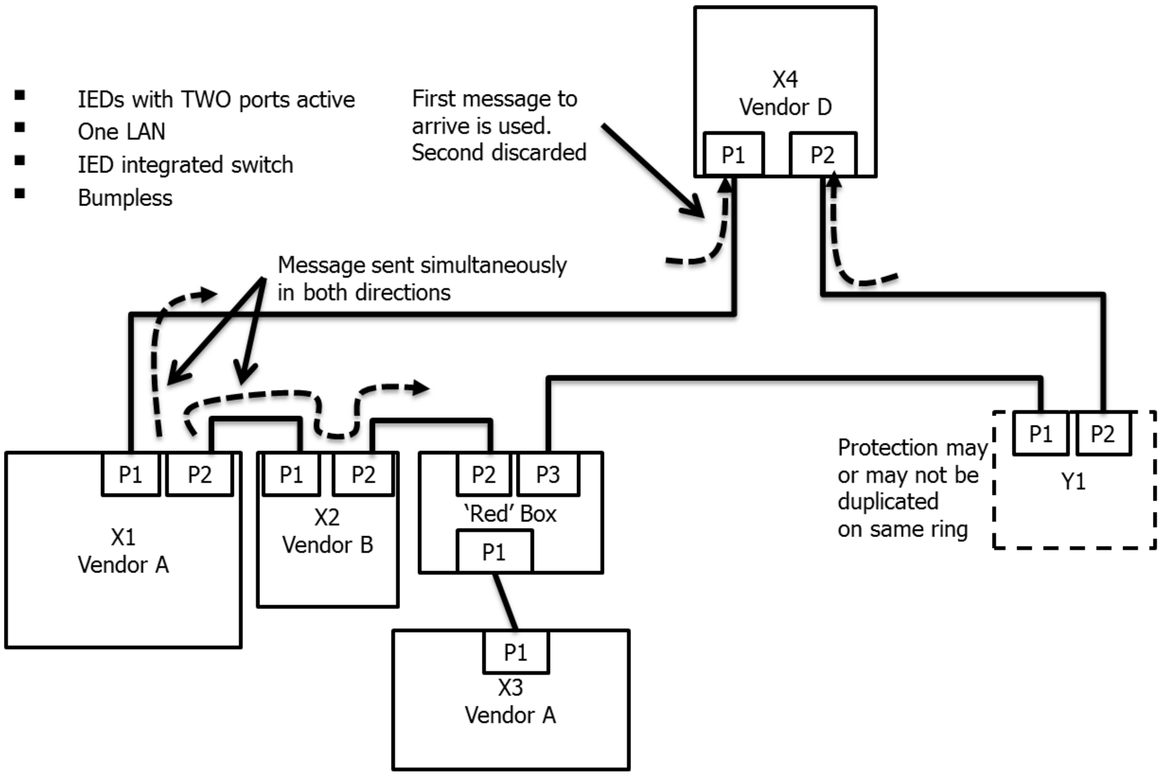

Figure 9-11: HSR Network Operation

9.3.4.2 Parallel Redundancy Protocol (PRP)

PRP also requires the IED to have two separate ports but these are connected to two separate networks. The separate networks themselves could each individually be star, ring or even HSR (although HSR on both sides would require four ports). In the same manner as HSR, the messages are sent by the IED on both ports simultaneously. The receiving IED can then receive both messages and act on the first received and also raise alarms if both messages are not received without loss of operational functionality. Note, that only the IEDs with functions requiring bumpless messages to be sent/received need the dual LAN connections thus minimising requirements for multiple ports on all IEDS. Note some functions may require interconnection of the two LANs if certain signals are only available on one LAN. Redundancy ‘Red’ Boxes may be required for IEDs that must also be connected to both LANs.

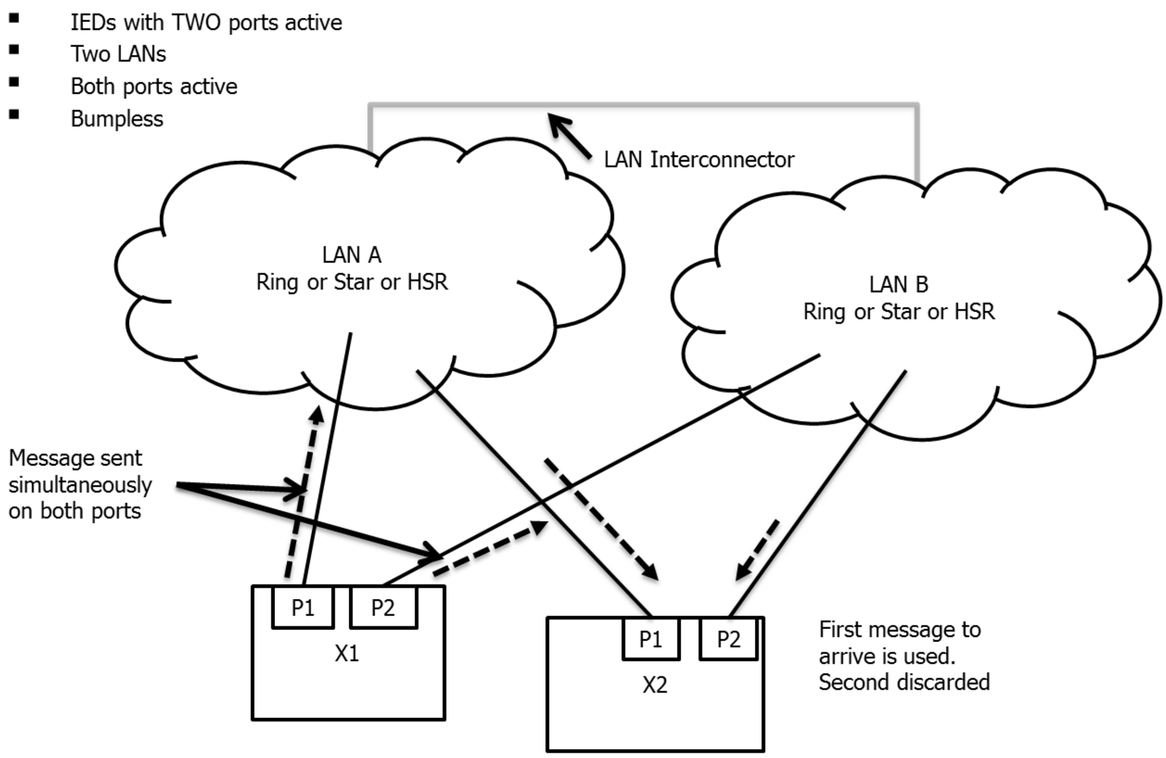

Figure 9-12: HSR Network Operation

Whilst bumpless seems to be the obvious choice for reliability, considerable configuration complexity and LAN duplication cost is added to the system as well as the IEDs must have multiple ports with mechanisms for handling duplicate messages. The process and tools required for fault finding HSR and PR must also be considered since functionally the system appears to be working. In addition, operational and routine maintenance of the substation may require some bays and hence some sections of the networks to be out of service which then obviates the security of dual paths providing the essential bumpless characteristic for the bays that remain in service.

HSR and PRP also require consideration of the potential for common modes of failure, or rather common modes of non-bumpless operation during maintenance or failure, affecting both of the duplicated protection systems and protection related IEDs (Merging Units, protection functions, circuit breaker interfaces) connected to the same networks.

“Traditional” protection philosophies have dealt with failure of devices through the physically segregated independent duplication of the protection scheme. Full duplication means that each system can be kept as simple as possible whilst the overall functionality of protecting the power system with no common mode of failure (to reasonable levels e.g. to the exclusion of widespread damage to the facility). The power system will remain fully protected to the required critical fault clearance times even if either of the systems is partially or totally out of service for any reason, including failure or maintenance.

HSR and PRP may therefore be an expensive and complicated reliability solution affecting configuration; operation and maintenance compared to ‘traditional’ physically segregated independent duplication of systems.

9.4 Principle of Quality function

9.4.1 Principle of Data Quality Handling

Two of the many advantages in IEC 61850 are its GOOSE messaging (8-1) and multicast sampled analogue values (9-2). With GOOSE and SAV functionality it is possible for IEDs to exchange data in a fast way. The IEC 61850 standard defines a quality value associated with each data value. The additional quality information enables protection and control systems to be more safe and supervised. In conventional signal wires, IEDs are not able to process quality information.

Quality information affects the processing of the received data. Applications must consider following situations:

a) What if the IED receives a data change but its data quality is not valid or the data is corrupted or missing?

b) How to handle data when the associated quality has the Test bit set.

c) How to handle data when the associated quality has the Operator Blocked bit set.

IEC 61850 Standard does not state whether quality attribute should be sent together with the data value in messages. This is however highly recommended and used in practice. Following data type definition is used for quality attribute in IEC 61850-7-3. Quality information consists of different identifiers; Validity, detail quality, Source, Test and Operator Blocked. It is not mandatory for IED to support all possible quality information as it is application and implementation specific. Then default values are applied (Validity=good, validity detail bits=false, Source=process, Test and Operator Blocked=false).

Quality Identifier	Value
Validity	good | invalid | reserved | questionable
overflow	true | false
outOfRange	true | false
badReference	true | false
oscillatory	true | false
failure	true | false
oldData	true | false
inconsistent	true | false
inaccurate	true | false
Source	process | substituted
Test	true | false
OperatorBlocked	true | false

Table 9-2: Standard part 7-3 describes the details of different Quality attribute identifiers.

9.4.2 Quality Validity Handling with GOOSE

Generally it does not matter whether IEDs use conventional wires or GOOSE to exchange data. IED applications must work in both normal and disturbance situations in a fail safe manner. E.g. from application point of view it should not matter if the signal wire or Ethernet cable fails and same rules must apply in both cases. IEC 61850 Quality attribute gives additional application resolution for different functionality compared with hardwired signal connections.

From an IED application point of view, how to handle received invalid or questionable data is left outside of standard and is thus implementation specific. Different approaches might exist, e.g. last received good value might be used or a default input value is used for the application. This is an advantage compared with conventional wiring where the signal state becomes false if the input is no more energized or is disconnected from the IED. For example in the case of distribution bus blocking scheme (reference to section 7.10.1), when an IED on an outgoing feeder sends the protection start signal with invalid quality state in a GOOSE message, the blocking is not activated to ensure working protection in a fail-safe manner since the incoming feeder IED cannot trust the received data. Quality attributes may be used further in the application.

9.4.3 GOOSE Message Validity Handling

An additional item in parallel to quality attribute usage is handling of loss of communication situations or when GOOSE message or configuration does not match to expected one. Question is how the subscribing IED needs to react in those situations.

IEC 61850 gives possibility to detect loss of communication and react in those situations as the GOOSE service describes a heartbeat cycle mechanism where publisher IED must resend previous state-change message. Re-send cycle time is configured in Maxtime property of the IEC 61850 configuration. This way the receiver IED can check if its peer IED is alive and healthy. If the receiver IED misses GOOSE frames from peer IED for longer than the GOOSE keep-alive time (typically 2 times the Maxtime in 61850 configuration), the peer IED data must be marked invalid or questionable.

GOOSE message gives additional possibility to check the GOOSE system configuration as every message has configuration revision information and it must match to the configuration revision in the receiver side. If configuration mismatches are noticed, the subscribing IED must mark the subscribed data inputs as invalid.

Publisher IED can also raise a Needs Commissioning flag in the GOOSE message if the GOOSE configuration has no dataset defined or the dataset is too large. In this case the receiving IED should also mark the received data as invalid.

9.4.4 GOOSE Test and Blocked Quality Handling

When GOOSE is used there must be a possibility to test GOOSE signals between IEDs. This is achieved with Test and Operator Blocked logical node modes. In blocked mode, outputs to process are not activated. In IEC 61850 applications the user activates Test or Test/Blocked mode in logical node Mod data object by changing the value locally or controlling from client. Edition 2 of the IEC 61850 standard specifies that for GOOSE, both sender and receiver IEDs must be in Test mode for test signals to be processed as normal by the receiver IED. In Test and Blocked modes, received data with good quality data is also processed as valid.

9.4.5 GOOSE Quality Handling Overview

The following table information is taken from standard part 7-4 and it gives a picture how different IEDs logical node operation modes affect process outputs, LN data outputs and GOOSE inputs.

LN Mode	On	Blocked	Test	Test/Blocked	Off
Function active	Yes	Yes	Yes	Yes	No
Process Output	Yes	No	Yes	No	No
Data Output	Value and q are relevant	Value is frozen q=operatorBlocked	Value is relevant, q=test	Value is relevant q=operatorBlocked + test	Value is irrelevant, q=invalid
Incoming data with q=good	Processed as valid	Processed as valid	Processed as valid	Processed as valid	Not processed
Incoming data with q=operatorBlocked	Processed as blocked	Processed as blocked	Processed as blocked	Processed as blocked	Not processed
Incoming data with q=test	Processed as invalid	Processed as invalid	Processed as valid	Processed as valid	Not processed
Incoming data with q=test + operatorBlocked	Processed as invalid	Processed as invalid	Processed as blocked	Processed as blocked	Not processed
Incoming data with q=invalid	Processed as invalid	Processed as invalid	Processed as invalid	Processed as invalid	Not processed

Table 9-3: GOOSE quality handling mechanism (Table A.1, Part 7-4, Edition 2)

If the LN mode of the receiver IED is in Test mode, the IED outputs to process are active and this must be considered when testing signals, e.g. it may be required for the IED to be de-attached from the trip circuit. If the LN mode of the receiver IED is in Test/Blocked mode, outputs are not activated but application data values are updated in the receiver IED according to the received input value.

Quality identifier Source is not applicable for subscribing IED application, as both possible values Process and Substituted must be processed in same way.

9.5 Required engineering tools

Engineering tools include tools that allow the integration of documentation generated from the conception of an installation during the engineering stage (plans, manuals, etc.) for the duration of its life. These tools should also integrate intermediate stages of modifications and extensions, and also facilitate the commissioning and maintenance of protection and control systems.

Basically, engineering tools should cover the following issues:

a) Integration of protection and control systems' information

b) Integration of electrical, electromechanical and civil systems

c) Protection logic and settings management

d) Control logic and settings management

e) Configuration, execution and documentation of commissioning and maintenance tests

f) Integration with protection management systems

g) SCADA configurations management

Therefore, several types of tools may be considered for the management of the configuration of the IEDs of a given substation. An initial classification of the type of tool could be:

a) **Standard Tools**: These are tools for modifying any function of the IED that has been modelled as an IEC 61850 function. These tools are, or are based on, SCL editors and MMS clients.

a) **Proprietary Tools**: These are tools provided by each vendor and are required for editing the proprietary part of a device configuration. Ideally, the objective should be to reduce the need of these proprietary tools to a minimum.

Moreover, and depending on the different needs of modification, we may distinguish between three fundamental types of tools:

a) **Parameterization Tools**: These are tools for "online" change and change management, basically the IED settings.

b) **Configuration Tools**: These are tools for the implementation and management of "offline" changes. They can also be classified in two types:

    - System level: These can be used for the complete engineering of one or several substations. This type of tool works with and outputs SCD files.
    - IED level: Simpler tools, optimized to facilitate maintenance and oriented to modifications at the IED level. This type of tool can import ICD and SCD files and outputs CID files. This may be the same tool as for parameterization of the IED.

c) **Testing Tools**: These are tools for both control and protection maintenance personnel and engineering personnel, and facilitate the tests on the IED, client and server, allowing simulating equipment and performing automations. This type of tools can be divided into:

    - Oriented towards IED testing: These are tools that allow automating the tests of the functionality of the IEDs. This may include:
        - Analysis e.g. spying and monitoring
        - Performance evaluation
        - Simulation
    - Oriented towards Client testing: These are server emulation tools that allow testing the behaviour of station level clients, such as station computers and gateways.

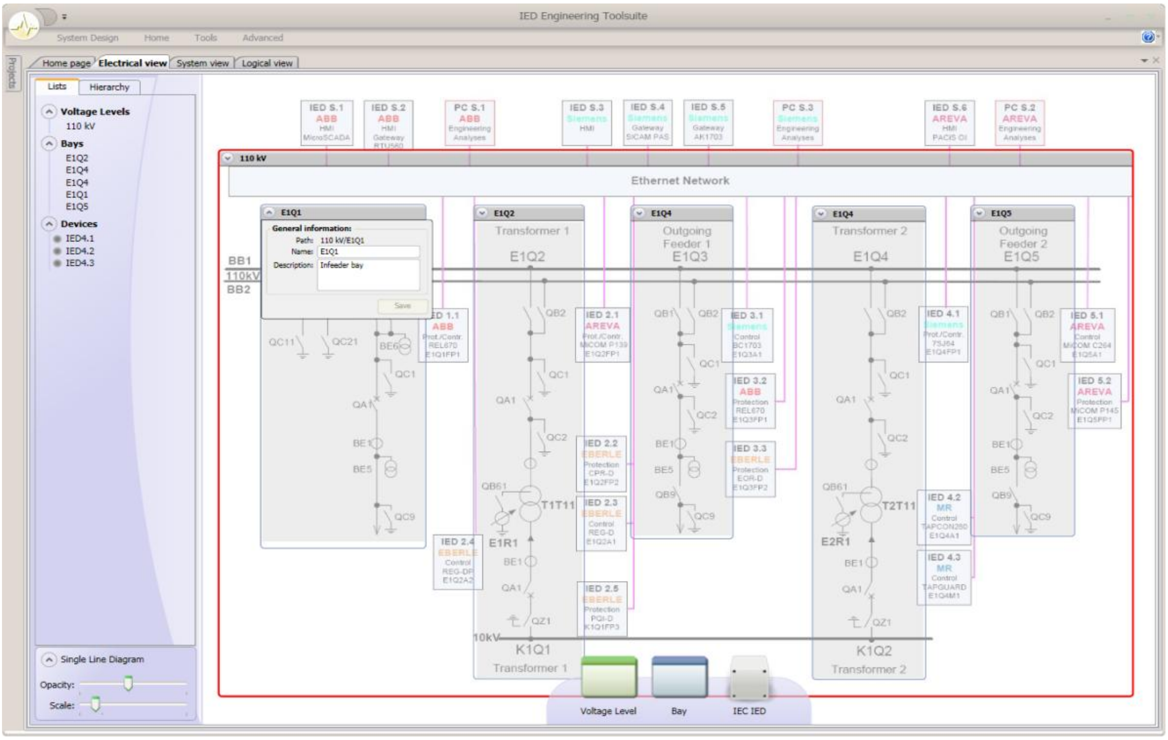

Figure 9-13: Example of Engineering Tool Suite

10 TESTING AND MAINTENANCE

10.1 Testing

10.1.1 Introduction

The IEC 61850 standard for communication networks and systems allows the development of high-speed peer-to-peer communications based distributed protection applications that result in significant changes in the ways protection functions are implemented. This replacement of functions implemented in a single device with equivalents using exchange of analogue and status information over the substation local area network (LAN) requires new technology also for their testing.

In order to properly define the methods for testing of complex IEC 61850 substation automation systems it is important to properly define what a system definition is and to consider what existing methods for system testing are known. Complex systems are not specific to only the electric power systems domain. They exist in industry, communications, computing and many other fields. Software development can be considered the development of complex systems that exchange information between different functional modules. Modern substation automation systems in reality are complex distributed software applications based on exchange of information over the substation local area network. That is why there are significant similarities between the testing of complex software tools and substation automation systems.

IEC 61850 defines a system as “The logical system is a union of all communicating application-functions performing some overall task like “management of a substation”, via logical nodes. The physical system is composed of all devices hosting these functions and the interconnecting physical communication network. The boundary of a system is given by its logical or physical interfaces. Within the scope of the IEC 61850 series, ‘system’ always refers to the Substation Automation System (SAS), unless otherwise noted”.

This is not very far from an abstract definition of a system as a group of interacting, interrelated or independent elements forming a complex whole. Each component of a system is interacting or related to at least one other component/element. Any object which has no relationship with any other element of the system is obviously not a component of that system.

Depending on the complexity of the system, its components can be simple functional elements, subsystems or a combination of the two. A subsystem is then defined as a set of elements, which is a system itself, and also a part of the whole system.

In the substation protection and automation domain we can consider different functions performed by the system as subsystems. The system can contain one or many functions that can have several layers of one or many sub-functions and at the bottom – a sub-function can contain one or many functional elements (logical nodes in IEC 61850).

10.1.2 System Testing

System testing is testing conducted on a complete, integrated substation automation system, subsystem or distributed function. Its goal is to evaluate the system's compliance with its specified requirements.

During commissioning or maintenance testing, it is reasonable to consider that the individual functional elements are operating properly, especially if there are no alarms in any of the IEDs that are included in the system test. In this case a top-down approach is suitable, since we are interested in the overall performance of the tested system function and not in the behaviour of the components of the system. This fits the ‘Black Box’ approach, which means that we take an external perspective of the test object (sometimes referred to as the Device Under Test – DUT) to derive the test cases and analyse the results.

10.1.3 Functional Testing

Functional testing of any function or sub-function requires the test designer to select a set of valid and invalid inputs and determine the correct expected output for each test condition defined in the test plan.

The purpose of functional element testing is to determine if the tested element has the expected behaviour under different realistic test conditions. The functional elements in system testing are considered units, i.e. the smallest testable parts of any system.

System testing looks at the overall performance of the system from an external observer point of view. Bottom-up or top-down testing methods can be used depending on the type of test performed. In all cases, it is important to clearly identify the system or function boundary that will define the requirements for simulation by the test system and monitoring the behaviour of the tested function.

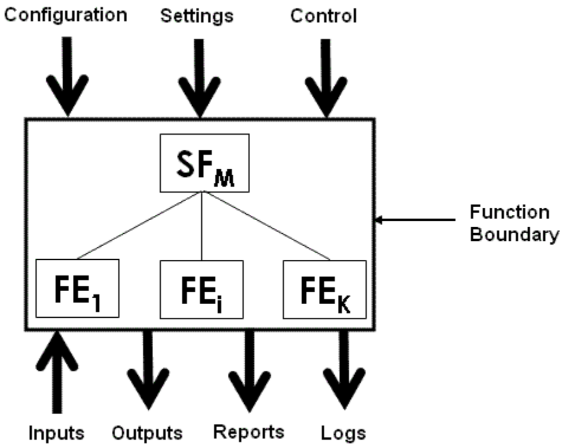

Figure 10-1: Function Boundary Definition

In **Figure 10-1** above, SF indicates a sub-function that contains K functional elements. The functional elements are the smallest component in the system that can be defined with a function boundary, interface and behaviour, i.e. can be tested.

All the above described principles can be used in the testing of IEC 61850 based substation protection and automation systems.

10.1.4 IEC 61850 System Types

Two typical types of IEC 61850 based substation automation systems can be defined based on the interface with the primary substation equipment:

a) with partial implementation of IEC 61850
b) with full implementation of IEC 61850
c) The acceptance of IEC 61850 at the initial stages after the publishing of the standard is related predominantly to the use of the high-speed peer-to-peer communications using GOOSE messages. Client-Server interaction between the substation level applications and the IEDs are also used. This requires only the use of IEC 61850-8-1 communication.
d) With partial implementation the interface with the process is identical to the conventional substations, i.e. hardwired connections between instrument transformers and the analogue inputs of the IEDs, auxiliary contacts of the breakers

and the IED opto inputs, as well as IED binary outputs and the process control (for example breaker trip coils or transformer tap changers).

e) The interface between the devices in the substation is based on communications messages exchange over the substation local area network.

f) A full implementation of IEC 61850 in a substation protection and automation system indicates the use of both IEC 61850-8-1 and IEC 61850-9-2 communications. The interface between all devices in the system in this case is based on communications, with the use of copper cables being limited to DC or AC power, secondary of the instrument transformers and the merging units, as well as breaker auxiliary contacts and trip coils and the secondary devices in the substation.

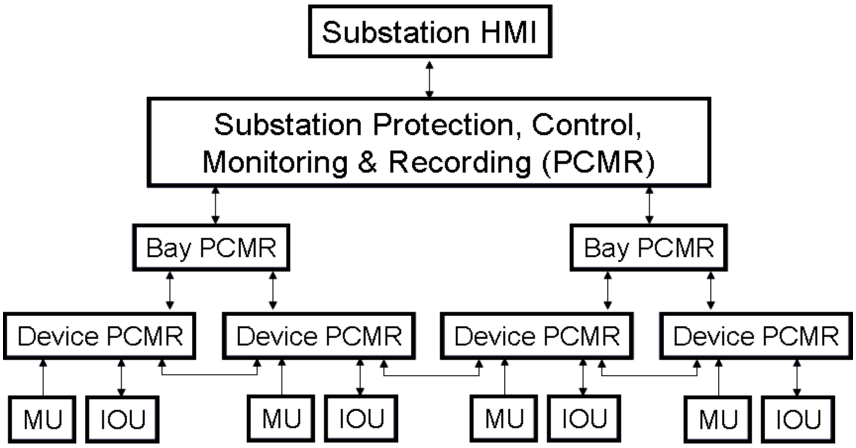

Figure 10-2: Full Implementation Architecture

Analysing the system in Figure 10-2, it is clear that the requirements for testing will change significantly depending on where the system boundary is considered to be. Some of the more typical cases are discussed below.

10.1.5 Testing of IEC 61850 Systems

The method for testing of both types of systems is proposed based on the following order of system components tests:

a) Testing of IEC 61850 standard compliance of the individual components of the system

b) Testing of Merging Units

c) Testing of IEC 61850 compliant IEDs

d) Testing of bay level distributed applications

e) Testing of substation level distributed applications

It is assumed that all components of the system have already passed conformance testing, i.e. that IEC 61850 with all its models and services is properly implemented.

10.1.6 IEC 61850 Test System Components

A test system designed for IEDs or distributed applications based on IEC 61850 have multiple components that are needed for the testing of the individual functions, as well as a complete application. A simplified block diagram of such a system is shown in Figure 10-3.

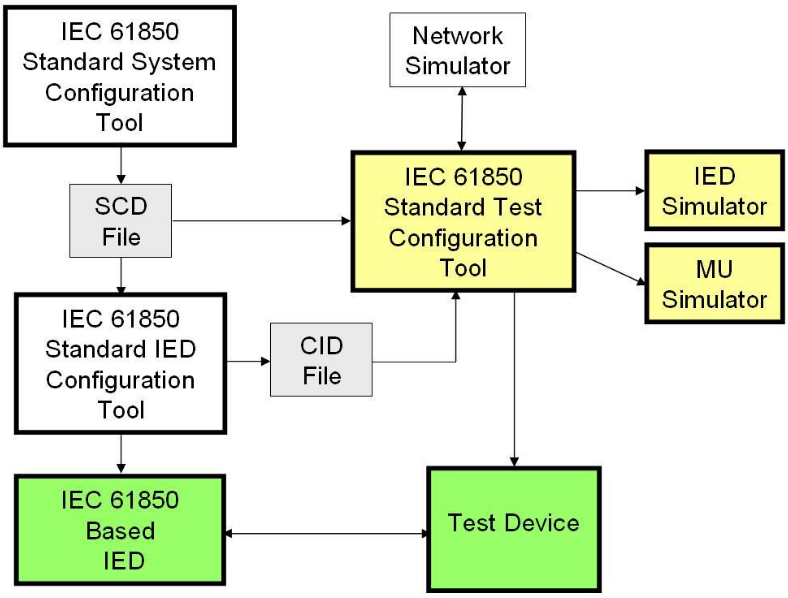

Figure 10-3: Test System / Configuration Tool, simplified Block Diagram

Test Configuration Tool takes advantage of one of the key components of the IEC 61850 standard – the Substation Configuration Language. The Test Configuration Tool is used to create the files required for configuration of different components of the test system.

Depending on the Systems Integrator’s engineering process, either the SCD file, or the collections of CID files are imported into the Test Configuration Tool. The TCT analyses these files to identify the communication configuration and substation description sections for all the IEDs. This information is then used to configure the set of tests to be performed.

The generic capability of any IEC 61850 compliant IED is available in the IED Capability Description file which has a filename extension of .ICD and the IED name within the file is “TEMPLATE”. This file is not a specific configured instance of any of the IEDs for the project e.g. it will not have communication parameters set such as IP address other than the factory default. The ICD does however identify what any of those IEDs are able to provide as they are instantiated in the system as configured versions of the ICD.

As the individual instances of the ICD file are created in the SAS system, corresponding to the number of physical IEDs,, the IED name in these instances is changed from “TEMPLATE” to the project specific name e.g. “feeder 1” and its specific configuration for the project established. The communication section of the file contains the current address of the IED. The substation section related to this IED may be present and then shall have name values assigned according to the project specific names. Depending on the engineering process and tools used, these instances are available in the System Configuration Description file (with an filename extension .SCD), or individual files for each physical IED as the Configured IED Description file (with an filename extension .CID)

The IED Configuration Tool is then used to configure the IED for its instantiation within a substation automation system (SAS) project..

Power System Simulation Tool generates the current and voltage waveforms. The specifics of each simulated test condition are determined by the complete, as well as the configured functionality of the tested device or application.

The simulation tool requirements will also be different depending on the type of function being tested. For example, if the tested function is based on RMS values or phasor measurements, the simulation tool may include a sequence of steps with the analogue values in each of the steps defined as Phasors with their magnitude and phase angle. Based on these configuration parameters the simulation tool will generate the sine waveforms to be applied as analogue signals or in a digital format to the tested components or systems.

If the tested functions are designed to detect transient conditions or operate based on sub-cycle set of samples from the waveform, an electromagnetic transient simulation will be more appropriate.

Virtual Merging Unit simulator: While under conventional testing the waveforms generated by the simulation tool will be applied to the tested device as current and voltage analogue signals, a Virtual Merging Unit will send sampled measured values as defined in IEC 61850 over the Ethernet network used for the testing.

The Virtual Merging Unit simulator should support sampling rates as agreed in IEC 61850-9-2LE. For protection applications the simulator should send 80 samples / cycle in 80 messages/cycle. Each message contains one sample of the three phase currents and voltages (WYE class).

Virtual IED simulator that is used to represent components of the system that is not available at the time of testing, for example during factory acceptance testing. During the testing this module send GOOSE messages that the function or Sub-function under test uses as inputs that determine its behaviour under the test conditions applied.

The fifth component of the testing system is a tool that can simulate network traffic, remote and local operator or system engineer.

Test Evaluation Tool that includes the monitoring functions used to evaluate the performance of the tested elements within a distributed sampled analogue value based system. Such evaluation tool requires multiple evaluation sub-modules that are targeted towards the specifics of the function being tested. They might be based on monitoring the sampled measured values from a tested merging unit, GOOSE messages from a tested IED, as well as reports or waveform records from the tested device.

Reporting Tool that will generate the test reports based on a user defined format and the outputs from the simulation and evaluation tools.

10.1.7 Functional testing of IEC 61850-9-2 Based Merging Units

Since Merging Units are an essential component of any IEC 61850 process bus based application, they have to be tested to ensure that they provide the required sampled measured values. The currents and voltages applied to the Merging Unit will be based on current and voltage waveforms produced from the network simulator in order to simulate different system conditions, such as high current faults or low current minimum load conditions.

At the same time the Test Evaluation tool will need to receive the sampled analogue values from the tested merging unit and compare the individual sampled values from the Merging Unit with the samples coming from the network simulator. The testing of Merging Units will require first of all a very accurate time synchronization of both the test device and the tested MU.

It is necessary to analyse the phase (time) and magnitude differences of the individual samples and compare these to the calibration specifications of the MU. Proper documentation and reporting is required in the same manner as meter testing is performed today.

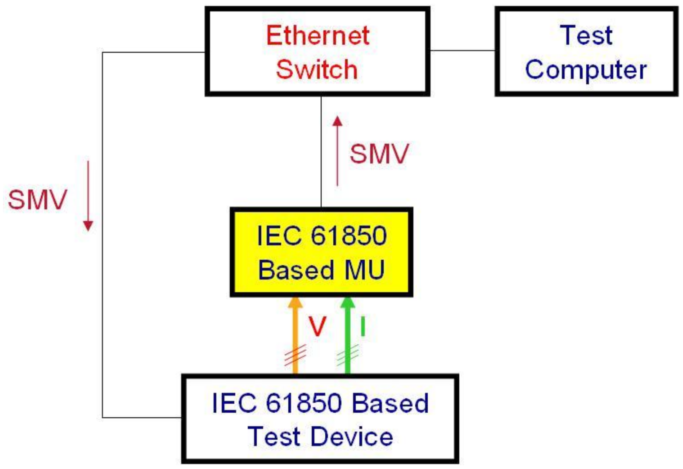

Figure 10-4: Testing of Merging Units

10.1.8 <u>Functional testing of IEC 61850 GOOSE Based IEDs</u>

The testing of different functions in IEDs that are based on publishing and subscription of GOOSE messages can be achieved in a way similar to the testing of conventional hardwired devices. The difference is that in this case there may be no hard wiring between the test device and the tested IED for status signals. The test devices needs to be configured as a GOOSE publisher to simulate different signals required by the test object for the testing, as well as it needs to be a GOOSE subscriber in order to receive messages from the test object and evaluate its performance. In many cases it is recommended to simulate and monitor also hardwired signals (as shown in Figure 10-5) and compare the performance of the test object using both interface methods.

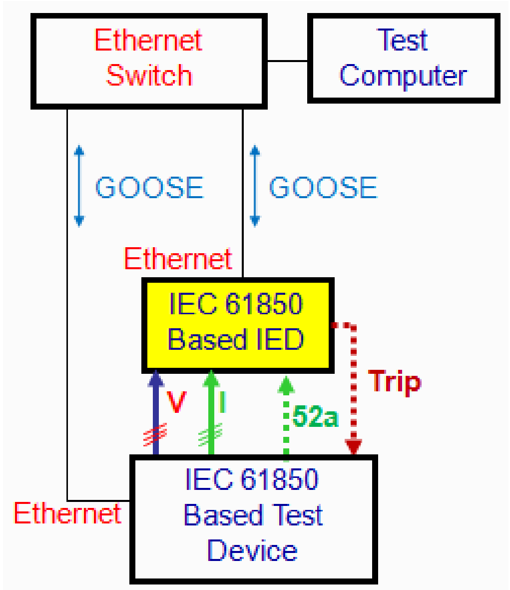

Figure 10-5: GOOSE Based Testing

10.1.9 <u>Functional testing of IEC 61850-9-2 Based IEDs</u>

The testing of different functions in IEDs that are based on sampled measured values can be achieved in a couple of different ways depending on the requirements of the specific test. One approach is acceptable when testing the IED only, while another can be used if the testing includes the complete MU/IED system. The difference is that in the first case there is no hard wiring between the test device and the tested IED – i.e. the test system can be communications based only.

The key component of this module is the Merging Unit simulator described earlier in the Technical Brochure. It will have to take the waveforms generated from the Network Simulator and then format them in the required 80 samples/cycle and multicast the individual sampled values to the LAN 80 times per cycle (e.g. 80 messages/cycle).

The testing of different types of functions available in the IED will be similar to what was described earlier for the hybrid device. This applies to both the configuration and analysis modules of the test system.

The test system needs to subscribe to and monitor the GOOSE messages received from the tested IED that represent the operation of the tested functional elements in order to determine if the devices operated as required. If the tested device has relay outputs as well, they will have to be wired into the test device and their operation (time tag) will be compared with the received GOOSE messages to determine if the performance of communications based solutions is analogous to the hard-wired case.

The test system may also retrieve the waveform records from the tested device and again compare them with the original waveforms from the simulation tool.

Figure 10-6 shows the system configuration for hybrid testing of IEDs that have relay outputs and at the same time support GOOSE messages.

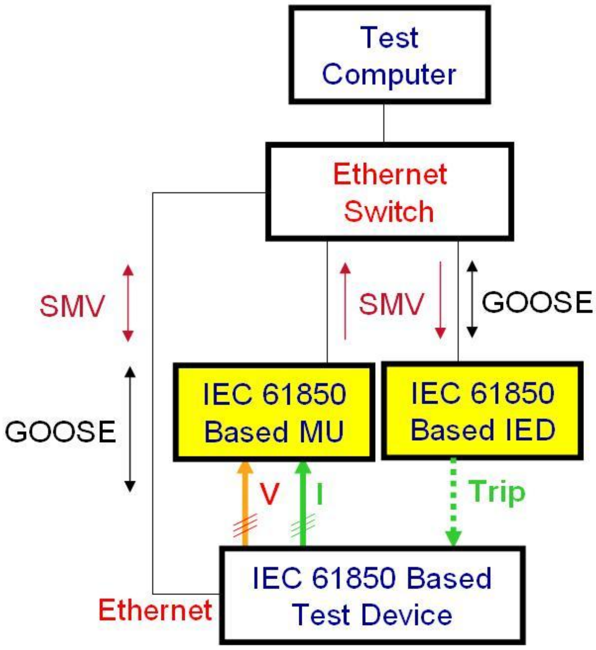

Figure 10-6: Testing of IED with Process Bus and Hardwired Interface

10.1.10 <u>Functional testing of Distributed Applications</u>

The testing of distributed bay and substation level functions that are based on communications only will be similar functionally to the testing of individual IEDs. The main difference is that in this case there will be multiple test devices with virtual simulators or analogue outputs. The simulation of the substation and system environment required for the functional testing of bay and system level functions will require the simulation of multiple merging units (IEC 61850 9-2 interface) and other IEDs (IEC 61850 8-1 interface).

The evaluation of the performance of the distributed functions is based on the subscription of the test system components to the GOOSE messages from the different IEDs participating in the tested distributed applications. If these devices also have relay outputs hardwired to the test devices, their operation will have to be monitored as well in order to evaluate the performance of the tested system and if necessary compare the communications based to hardwired solutions A simplified block diagram of this test system is shown in Figure 10-7.

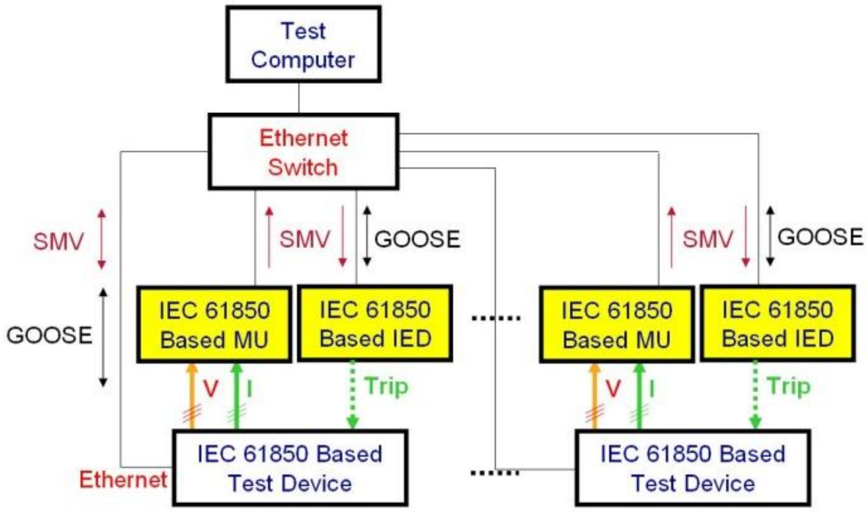

Figure 10-7: Bay or System Level Distributed Application Testing

10.1.11 IEC 61850 Testing Related Features

The methods for testing described in the previous sections of the Technical Brochure are predominantly used for type, acceptance, commissioning, factory and site acceptance testing. In order to support the testing of IEC 61850 system components in energized substations, Edition 1 of the standard already had many different features that could be used for testing. These features included:

a) The possibility to put a function or a functional element (logical nodes or logical devices) in a test mode

b) The possibility to characterize a GOOSE message as a message being sent for test purpose

c) The possibility to characterize a service of the control model as being sent for test purpose

d) The possibility to flag any value sent from a server in the quality as a value for test purpose

However, Edition 1 was not very specific on how to use these features. As a consequence, they were not supported by all vendors since interoperability could not be guaranteed.

This has been improved with Edition 2. Besides more detailed specifications on how to use the existing features, additional features have been added.

10.1.11.1 Test mode of a function

A logical node or a logical device can be put in test mode using the data object Mod of the LN or of LLN0. The behaviour is explained in Figure 10-8 and Figure 10-9. A command to operate can be either initiated by a control operation or by a GOOSE message that is interpreted by the subscriber as a command. If the command is initiated with the test flag set to FALSE, it will only be executed if the function (LN or logical device) is "ON". If the device is set to test more, it will not execute the command (Figure 10-8).

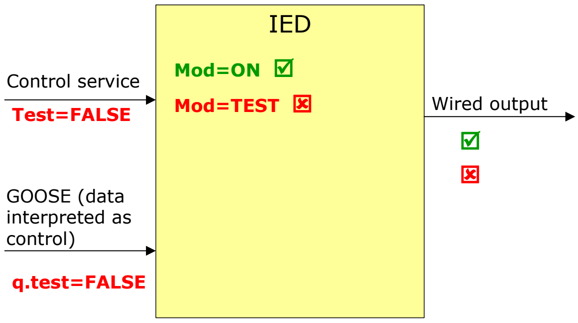

Figure 10-8: Command with Test = FALSE

If the command is initiated with the test flag set to TRUE, it will not be executed, if the function is "ON". If the function is "TEST", the command will be executed and a wired output (e.g. a trip signal to a breaker) will be generated. If the function is set to "TEST-BLOCKED", the command will be processed; all the reactions (e.g. sending a command confirmation) will be produced, but no wired output to the process will be activated (Figure 10-9). The mode "TEST-BLOCKED" is particularly useful while performing tests with a device connected to the process.

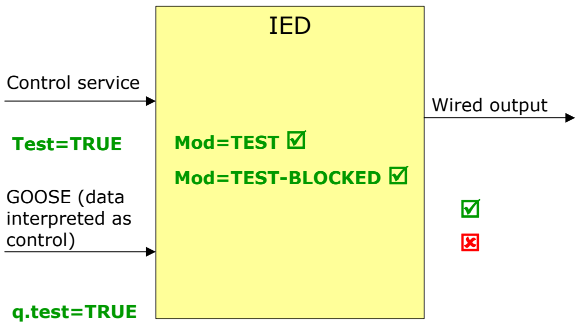

Figure 10-9: Command with Test = TRUE

10.1.11.2 Simulation of messages

Another feature that has been added to Edition 2 is the possibility, to subscribe to GOOSE messages or sampled value messages from simulation or test equipment. The approach is explained in Figure 10-10. GOOSE or sampled value messages have a flag indicating if the message is the original message or if it is a message produced by a simulation. On the other side, the IED has in the logical node LPHD (the logical node for the physical device or IED) a data object defining, if the IED shall receive the original GOOSE or sampled value messages or simulated ones. If the data object Sim is set to TRUE, the IED will receive for all GOOSE messages it is subscribing the ones with the simulation flag set to TRUE. If for a specific GOOSE message no simulated message exists, it will continue to receive the original message. That feature can only be activated for the whole IED, since the IED shall receive either the simulated message or the original message. Receiving both messages at the same time would create a different load situation and therefore create wrong test results.

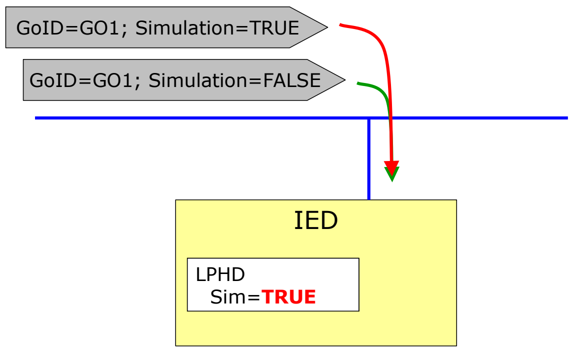

Figure 10-10: Simulation of a GOOSE Message

10.1.11.3 Mirroring control information

A third feature that has been added is the mirroring of control information. This supports the possibility, to test and measure the performance of a control operation while the device is connected to the system.

A control command is applied to a controllable data object. As soon as a command has been received, the device shall activate the data attribute opRcvd. The device shall then process the command. If the command is accepted, the data attribute opOk shall be activated with the same timing (e.g. pulse length) of the wired output. The data attribute tOpOk shall be the time stamp of the wired output and opOk.

These data attributes are produced independently if the wired output is produced or not – the wired output shall not be produced if the function is in mode TEST-BLOCKED. They allow therefore an evaluation of the function including the performance without producing an output.

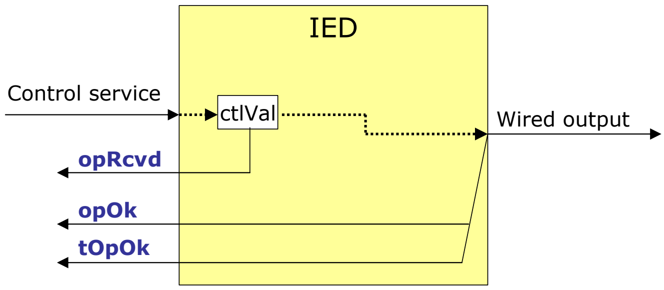

Figure 10-11: Mirroring of Control Information

10.1.11.4 Isolating and testing a device in the system

Combining the mechanisms described in the previous sections, it is possible to test a device that is connected to the system. We will explain that with a short example.

Let's assume we want to test the performance of a main 1 protection that receives sampled values from a merging unit. In the LN LPHD of the main 1 protection relay, the data object Sim shall be set to TRUE, the logical device for the protection function shall be set to the mode "TEST" and the logical node XCBR as interface to the circuit breaker shall be set to the mode "TEST-BLOCKED". A test device shall send sampled values with the same identification as the ones normally received by the protection relay but with the Simulation flag set to TRUE.

The protection device will now receive the sampled values from the test device and will initiate a trip. The XCBR will receive and process that trip; however no output will be generated. The output can be verified through the data attribute XCBR.Pos.opOk and the timing can be measured through the data attribute XCBR.Pos.tOpOk.

10.1.11.5 Advanced simulation possibilities

Finally, enhanced simulation possibilities that can be used for functional testing have been added. The concept is explained in Figure 10-12. As described earlier, with Edition 2, the possibility do describe references to inputs of a logical node has been added. This is done through multiple instances of data objects **InRef** of the CDC ORG. That data object has two data attributes providing object references: one as a reference to the object normally used as input; the other one as a reference to a data object used for testing. By activating the data attribute **tstEna**, the function realized in the LN shall use the data object referred to by the test reference as input instead of the data object used for normal operation.

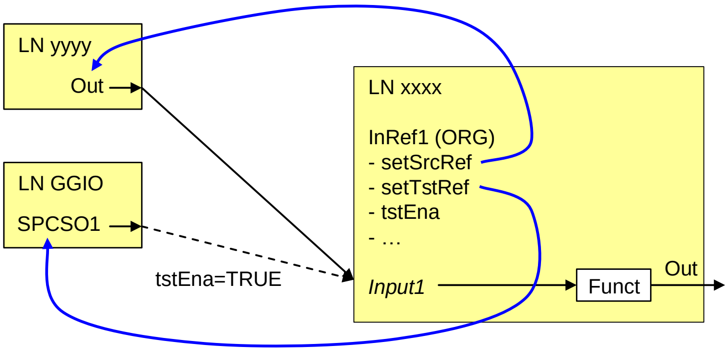

Figure 10-12: Simulated Inputs

Using this feature, it is possible, as an example, to test a logic function such as an interlocking function. Instead of taking the real position indications of the different switches as inputs, the logical node (in that case CILO), can be set to use inputs from e.g. a logical node GGIO. A test application can now easily modify the different data objects of the LN GGIO to simulate the test patterns that shall be verified. That logical node can be external (the data objects being received through GOOSE messages) or it can be implemented in the IED itself for testing support.

Note that while that method allows a detailed functional testing with individually simulated inputs, it may not necessarily be used for performance testing. Since individual inputs are switched, that may change the situation concerning the GOOSE messages to be subscribed in order to receive the new inputs and therefore, the dynamic behaviour may be changed.

10.1.11.6 Service tracking

While tracking of events in the application process was already possible in Edition 1, by logging or reporting of function related data that was not the case for events in the communication.

For that purpose, the concept of service tracking has been added to Edition 2. For that purpose, a data object instance has been defined for each kind of service, which mirrors the values of the service parameters. That data object can be included in a dataset for logging or reporting.

10.1.11.7 Edition 2 of IEC 61850

The Edition 2 of IEC 61850 will introduce many new features that will further enhance the power of the standard. There are new features that should make the life of the end user easier – assuming the features are supported by future products. It is expected, that interoperability between engineering tools will be improved something that is urgently needed. New features supporting functional and system testing should facilitate the ways an

IEC 61850 based installation needs to be tested – during commissioning, in case of problems but as well for routine testing.

At the same time, the backward compatibility should exist to a large extent thus safeguarding the investments already made.

10.2 Operator Controls, Isolation and Test Point

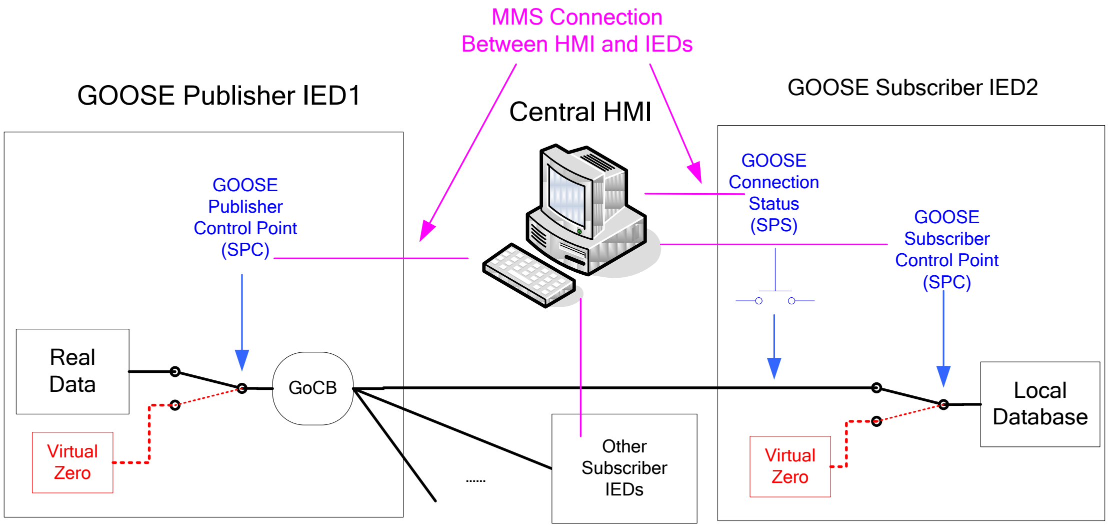

Figure 10-13: Control Point in GOOSE Connection

Where GOOSE messages are implemented, there is a need to check each GOOSE message during the internal system validation, Factory Acceptance Test and Site Acceptance Test.

To check the validity of the GOOSE messages and its related function, and knowing that GOOSE messages are virtual input or output signals in comparison with hardwired copper signals, a new mechanism must be included for technicians to test, change and monitor the status of each GOOSE message in a convenient way.

For example, a GOOSE message is exchanged between two IEDs: IED1 being the Publisher and IED2 being the Subscriber. The related GOOSE message is controlled by a GoCB in the Publisher side IED1. The parameter of “GoEna” in Publisher is applied to control the GoCB function such as sending GOOSE messages or not.

The “GoEna” in the GoCBs has been always “Enabled”. One solution is like that, for each GOOSE message, the Publisher and the Subscriber message are both implemented with a Single CONTROL Point (SPC) to permit/block the sending or receiving of a GOOSE message.

In the Subscriber side, the connection form Publisher may be lost because of some physical or unknown reasons, while the loss of communication may be easily detected in the Subscriber side, and a SPS (Single Point Status) can be used to identify the status change for the communication from the Publisher. If the GOOSE connection fails, a warning report will be sent to the HMI via MMS communication to get the corresponding attention.

During maintenance or routine tests, on one hand, the status of the related GOOSE message between Publisher and Subscriber is always expected to be active, while on the other hand, we may expect the data sent by the Publisher being testing data. An SPC is used in the Publisher IED1 to implement the control function which means that when the control point is enabled, IED1 will send real data in the GOOSE connection, otherwise it will send virtual zero. And in Subscriber IED2 side, a similar SPC can be applied to permit itself to receive the real data from the GOOSE message. So if the control point is disabled, the subscriber IED2 will discard all data received, the data in processing will be replaced by virtual zero, which will be in need of the test logic function in Subscriber side.

10.2.1 In Service Operation and Test Mechanisms

There are several typical tasks that operators may be required to do in a substation for which appropriate facilities must be provided. These include:

a) Control the system operating mode: e.g. Setting Group selection, Function enable/disable, Switch on/off ...

b) Isolate devices and functions

c) Test functions, devices and systems

d) Replace devices

e) Install new devices

Wire based systems essentially involved breaking the electrical circuit of a particular signal by opening links in order to isolate the function.

Communication based IEDs cannot simply be disconnected from the system by removal of the LAN connection. As a system thousands of messages are being exchanged between the IEDs and are therefore expected to always be occurring. Isolation of IEC 61850 based functions is therefor e not only about controlling the types of signals it send and its response mode to signals it receives, but more importantly controlling the operating modes of tens (hundreds) of other IEDs for the messages they send to and receive from the DUT.

The mechanism by which technicians can initiate the control of the IEDs to isolate a function is critical with several core requirements given that the use of these facilities to operate and test the system may be in the middle of the night when specialist IEC 61850 technical support may not be available. The IEDs and the HMI are complex devices for which it is unreasonable, and with high risks, to expect field operators to pick their way through the maze. Operator friendly facilities are required to provide the equivalent functionality of links for isolation purposes and connection of test equipment.

There many prime requirements for any operation and test facility that are taken for granted with wire based systems simply because they have been in common use for so long, are included almost by default in ‘standard designs’ and hence not given much thought as to what the criteria is for appropriate mechanisms. However considering the nature of all the wire based facilities, the following items can be identified as key requirements for the operation and test interfaces.

a) Front access (keep humans out of the physical wiring and terminal side)

b) Operational control does not require anything more than items commonly found in tool kits

c) Can be integrated and coherent in hybrid wire & LAN based systems

d) Clear individual labelling

e) Single function control

f) Ease of control (avoid menus on different IEDs by different vendors)

g) Direct feedback indicators

h) Controls clearly related to and located at the specific panel

i) Not IED vendor specific

a) Same in every panel in every substation regardless of particular IEDs and HMI in the substation

b) Standard for inclusion by all system integrators allowing standard design and procedures)

c) Must not compromise system security including cyber security

d) Must itself be secure from bugs and cyber attack

e) Prevent unauthorised equipment and PCs using the access points to communicate with the system

f) Support Role Based Access Control

g) Prevent procedural sequence errors

a) Itself must be easy to maintain and replace without difficulty or system downtime (hot swappable)

b) Must be benign on the system when not in use i.e. not interfere with the fundamental operation of the SAS

c) be safe to use without hazard to personnel

d) prevent inadvertent disruption of the SAS during connection/disconnection of equipment

e) Automate critical sequencing to eliminate human error

Amongst all of these requirements, cyber–security and physical-security of the LAN must be maintained. It is unacceptable to provide connection points to the LAN that are not controlled by some form of Role Based Access Control and the prevention of inadvertent disconnection of the wrong LAN cable when removing test equipment or laptops, or indeed the possibility of disconnecting one cable in order to obtain a port where test equipment or laptops can be connected instead..

In principle, the test equipment and/or laptops could be connected at any point to the LAN and operate any IED anywhere on the LAN. However in most cases, either for ease of testing activity and/or the requirement for testing of hybrid schemes with mix of wire based signals and GOOSE, it is usually preferable to connect the test equipment and laptops relatively close if not at the particular panel as shown in Figure 10-14.

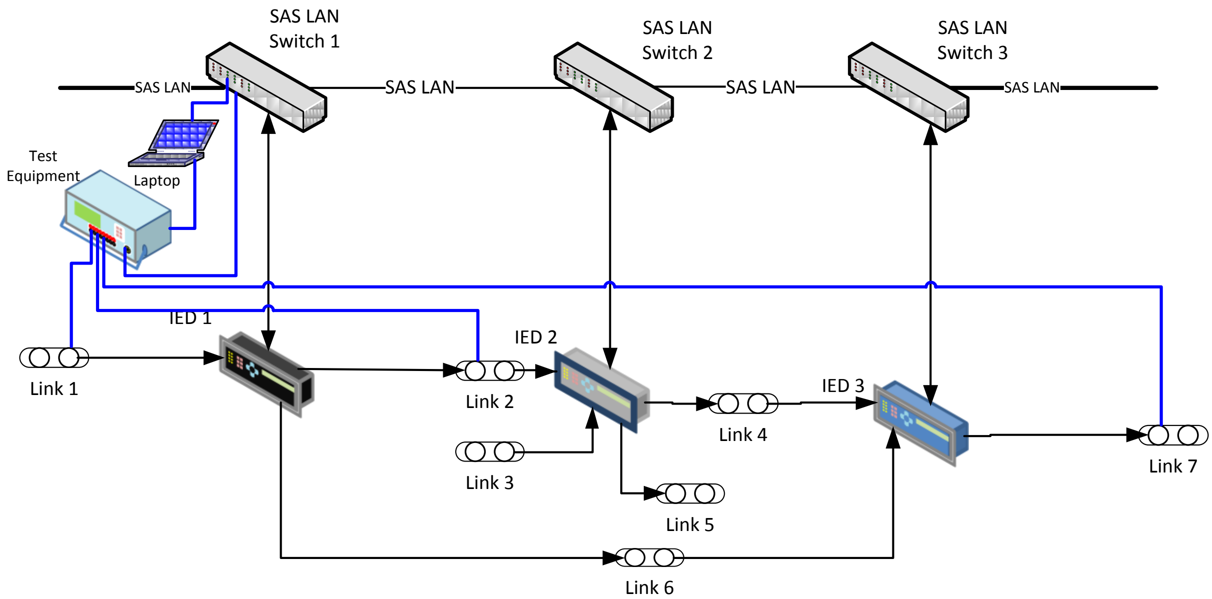

Figure 10-14: Connections for Testing a Hybrid Wire-Virtual System

10.2.2 <u>Substation HMI based control point.</u>

One solution is total monitoring and control from a central HMI of all the GOOSE Connection Status (SPS) and Control Points (SPC).

This requires the HMI platform and configuration must be in communication with all the IEDs in a client/server arrangement and a subscriber to all GOOSE messages in order to verify all messages are properly managed for the “virtual isolations” required. The configuration of the screens and controls must consider all possible test scenarios across the entire substation and how each IED must respond to any test configuration. This is complex for protection and SCADA systems, but will have ‘orders of magnitude’ more complexity with various automation mechanisms and condition monitoring equipment being added to the overall LAN.

Perhaps the most complex issue for any system isolation and/or test procedure is the sequencing of the mode control of all IEDs in the system. These must all be established in the HMI system for all the possible and particular operation or test scenarios.

Furthermore, the programming of the HMI system must consider that over the life of the substation, the substation HMI is likely to undergo several replacements with different generations of hardware, operating system and software. Above all, operators must have consistent operating and isolation procedures available to them in every substation.

However HMI’s are generally considered as equipment that is assumed to be inoperative at critical times. This may be due to failure, of the hardware, hardware stolen/disconnected. Equally the HMI screens and capabilities tend to be platform and software dependant which may not be readily available to replace throughout the life of the substation.

Clearly the substation HMI may provide a point of control of the system, however the physical connection of test equipment and laptops to the LAN must also be considered independent of the overall SAS mode control mechanism. Hence the location of the HMI relative to the equipment being controlled is also a vital factor in usability, especially with IEDs located at the far end of the control room, or indeed in other buildings, or for tasks being undertaken in the yard.

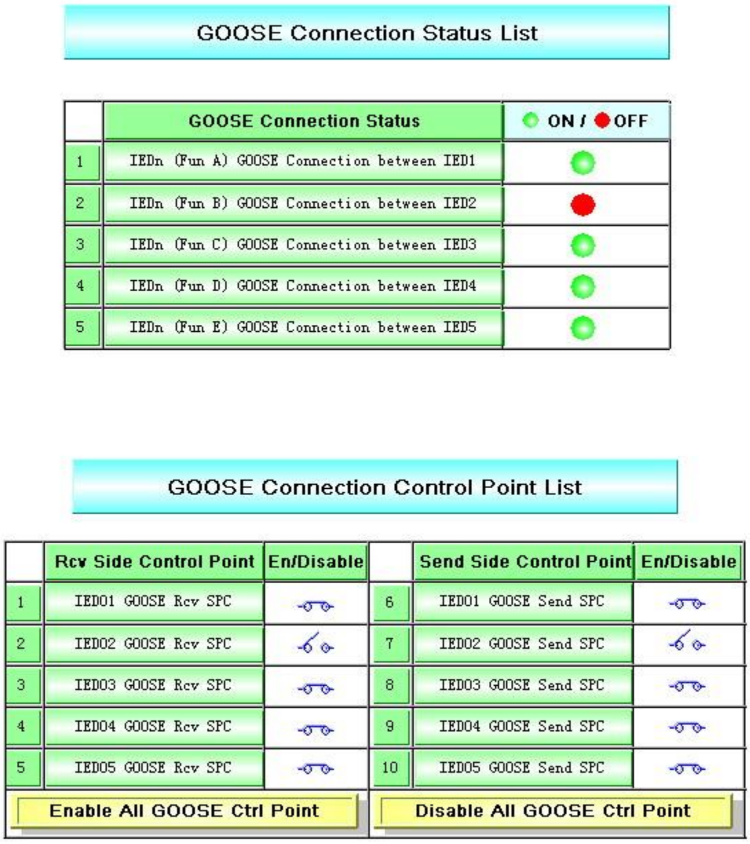

Figure 10-15: Examples of HMI of GOOSE Connection Status & Control List

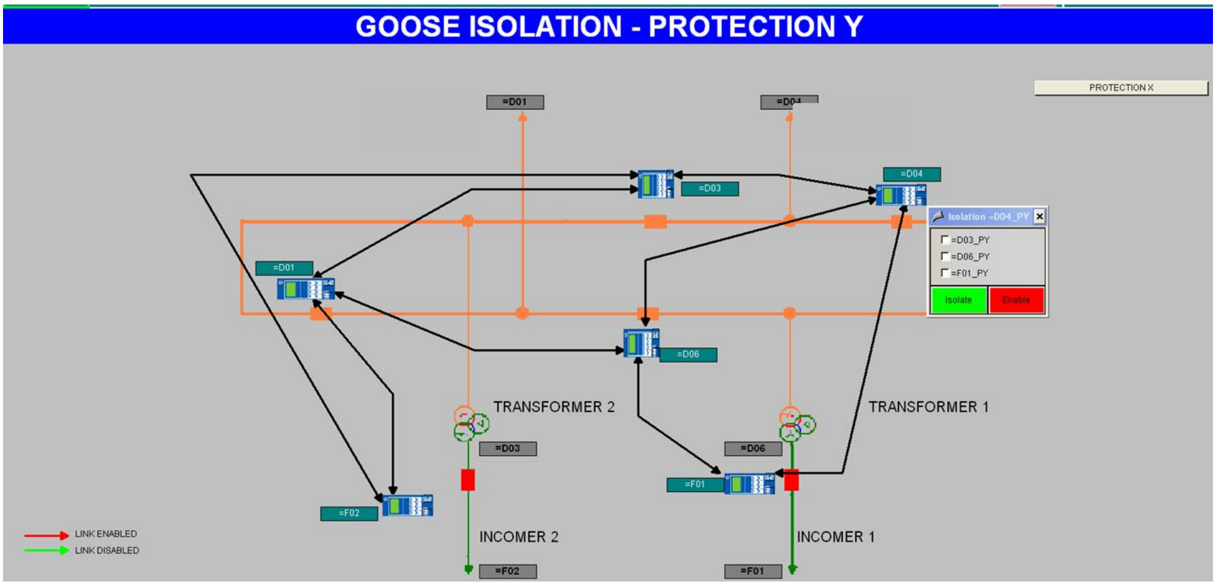

Figure 10-16: Example of HMI screen for Graphical Selection & Control of GOOSE

10.2.3 <u>IED based control point.</u>

An alternative approach is to use the IEDs themselves with via their front-plate operator controls.

However IEDs have a various combinations and capabilities of:

a) Indicators,

b) Buttons and

c) Menus.

These are inevitably different from each vendor, or even different on different types of IED within a particular vendor's IED series. Uniform procedures based on particular numbers of buttons/indicators/menu-trees are difficult to establish particularly if the technicians haven't attended that particular substation for several years and are unfamiliar with those specific IEDs.

Furthermore consideration must be given to the scenario of the IED itself failing. This is particularly significant as virtual systems generally require control of the operating mode of all the other IEDs in the system for the particular operating condition or test sequence being undertaken. If the failed IED is responsible for this configuration there is a high risk which cannot be accepted that the system may not easily be able to be put in a safe and appropriate configuration for the planned activity.

An enhancement of this approach is to provide switches, push buttons and links as inputs to the IED thus providing a visual similarity of the 'air-gap' physical isolations used in full wire based schemes. However given the vast numbers of such physical facilities, this becomes an impractical burden and obviates the benefits of eliminating wire based engineering and fit out.

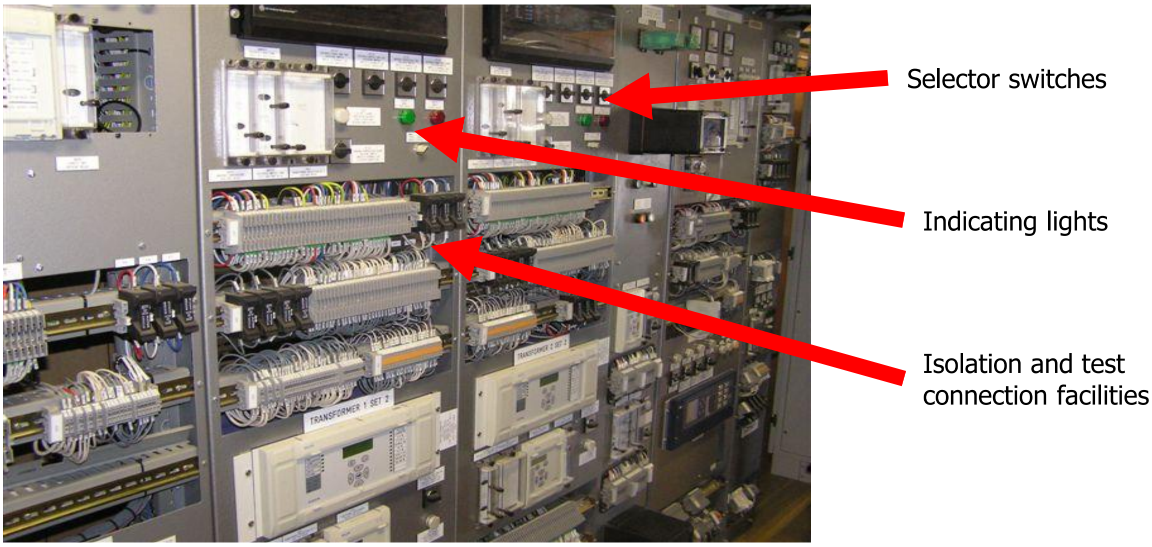

Figure 10-17: Extensive physical isolation mechanisms must not be replicated in virtual systems

Never the less, the configuration of the individual IED must include all the sequencing and logic necessary to control and verify all the other IEDs mode of operation. Such configuration is a proprietary function outside the scope of IEC 61850 itself and hence must be re-engineered for every new type of IED added to the system.

10.2.4 Independent Operation and Test Interface IED.

The fundamental principle of independent isolation of a function suggests a similar mechanism should be considered in light of the requirements outlined in section 10.2.1.

Patents (e.g. http://www.freepatentsonline.com/y2012/0136500.html, but lodged around the world) have been created for IEDs as independent, dedicated Operation and Test Interface (OTI). Such solutions provide integrated facilities that allow

a) standardisation of procedures substation and utility wide,
b) pre-engineered isolation sequencing and verification,
c) control of connection of test equipment and laptops maintaining cyber security,
d) RBAC,
e) location relative to the work location allowing,
f) benign to normal SAS operation and therefore hot swappable in case of own failure
g) LAN connection point physically separate to the secured LAN equipment and cables

11 CONCLUSION

The aim of the Technical Brochure is to provide guidance on the considerations associated with implementing any protection scheme, specifically noted herein or other schemes as they are needed. It is certainly not the aim of the Standard itself to provide standardised implementations of schemes, nor of the IEDs, therefore neither does this Technical Brochure.

This Technical Brochure describes several protection schemes and how the familiar wire-based solutions can be converted into functional IEC 61850 based solutions. The typical IEC 61850 messages required for these schemes are also shown, although should not be taken as the complete message or dataset requirements.

That is not to say however, that these solutions are the only solutions for a particular application. In some cases innovative alternatives are provided highlighting speed of operation, failure modes, re-engineering requirements or even minimising proprietary logic requirements. Other solutions may also exist and must have appropriate engineering assessment OF the System AS a System satisfying the requirements of being:

- “designed to work”,
- “designed for system modification (augmentation and/or enhancement)”
- “designed for operation”,
- “designed for maintenance”,
- “designed for graceful failure degradation”, and
- “designed for IED replacement”.

IEC 61850 is a complete engineering paradigm shift from the 100-years of ‘good industry practice’ that has evolved in wire-based and protocol-based engineering. Whilst certain specific applications are described herein, the whole concept of applying IEC 61850 is about doing traditional and new things in a new way – restrictions of the “old thinking” does not necessarily apply, but neither should the experience of “old thinking” be discarded.

The Technical Brochure therefore firstly describes the fundamentals of IEC 61850 and the general considerations associated with developing the IEC 61850 solutions and implementations.

There is an essential fundamental requirement to understand the purpose and implications of the Standard. The engineering community must not allow themselves to be misled or confused as to the Standards purpose. Incorrect understanding, expectation and application of this complex Standard will simply lead to frustration, disappointment and lack of trust in using the Standard. No doubts there are areas for improvement, and hence the TISSUE process exists as well as opportunity to participate in the activities of IEC TC57 WG10 directly.

Engineering of critical real-time functions should not be solely on the basis of reading a few pages of the Standard, a few guideline documents and attending a 2-day fundamentals training course, although these are the best starting points perhaps in the reverse order. Wire-based engineering is not approached in this manner, nor should IEC 61850 engineering. Well trained and well developed expertise is essential for such an expansive Standard, for which no apology is made given the complexity and variability of the systems it must support and problems it addresses.

The purpose of the Standard is to provide, at the risk of any summary description, first and foremost:

> *A defined engineering process with defined tools for different roles at different stages, with defined files to exchange engineering information between the tools using defined data models and defined communication services for the configuration of the IEDs and functions to communicate interoperably over industry standard protocols and networks.*

None of this could be achieved if the Standard was “just a protocol”.

Nor does this mean, in fact specifically excludes, ‘blind’ IED interchangeability.

Applying the standard to any system engineering and implementation requires that protection specialists, and others, must acquire new technical knowledge and skills. Specific competency development programs must be worked through to train utility staff in the concepts jargon, processes and detail of the Standard. Associated with this is training on the complex tools necessary for them to be able to configure, test and commission these new protection schemes based on IEC 61850. Engineering, testing and commissioning tools for Protection & Control staff must continue to evolve as easy-to-use to provide the ability to realise the real added value of the standard.

Ultimately the success of an IEC 61850 implementation starts with specification of requirements, whether this is the system as a whole, the functions to be provided, or the IEDs that need to be procured to satisfy all of that. If it doesn’t work the way it was expected, the first point to check is the completeness and depth of the specification. This may be contrary to the recent philosophies of “functional or concept” specifications such as “*build a substation*” or “*all IEDs shall comply to IEC 61850*”. In simple terms if you haven’t specified what you want in detail, then don’t be surprised if you don’t get it. Equally if you don’t specify what you don’t want, don’t be surprised that you might get what you don’t want.

The extent of this Technical Brochure is therefore not to prescribe the detail of the procurement specification of a system, scheme or any particular IEDs. This document solely describes examples of potential protection applications and the IEC 61850 elements that would constitute a potential implementation.

The IEC 61850 standard is of potentially large benefit to Protection and Control Engineers and their organisations. The standard gives some new possibilities for re-designing and developing existing protection schemes based on IEC 61850 (using GOOSE signals and Sampled Values SV), as well as developing new solutions and alternative applications for some protection schemes.

Instead of massive numbers of cabling, the signalling between substation IEDs can be realized using digital communication over an Ethernet Local Area Network. This can give both cost and effort savings for utilities, certainly in the aspect of the time and cost to install, test and commission the wire-based schemes.

The most significant part of that saving is not so much in the cost of the wires themselves, although not insignificant, but rather the many man-months of engineering effort required for the thousands of wires, terminations, links etc. in any facility. This effort currently involves many disparate formats of specification and design information which is manually transposed and converted from one form to another, ultimately into specific wires, and then necessitates extensive testing and re-testing of the physical implementation.

The move to an integrated virtual specification and implementation provides the significant benefit of Reusable, and therefore Reliable, Engineering. Specifications and designs do not need to be re-created from scratch at each augmentation, refurbishment or replacement. However this will only be achieved where appropriate engineering tools have been used according the SCL defined in Part 6, Applications using Station Bus are already common place. Applications involving Process Bus to high voltage switchyard will lead to further engineering life cycle cost savings associated with thousands of wires and hundreds of links at various locations between the primary plant and the secondary equipment. Further benefits can be obtained by the options that IEC 61850 Process Bus will support for Low Power Instrument Transformers (LPIT: Optical or Rogowski) with less environmental impact and risk of explosion due to the reduction of the number of oil filled HV devices.

Other benefits also include some simplifications of protection schemes as the Local Area Network can be used in a more optimized way for signalling between substation IEDs. This may help to economically justify some improvements in substation protections such as adding new functions and more redundancy to reduce the risk of critical failures, provide graceful degradation and increase system availability that would not be feasible in wire-based schemes.

Using a LAN network, some IEDs may easily share the same measurement messages from primary plant thus reducing the number of CT cores. The use of Sampled Values instead of copper cables for the analogue interface also leads to significant improvements in the flexibility and safety of the protection and control systems for example associated with open circuit CTs. LPIT give further benefits in higher accuracy, wider dynamic range, immune from transients and no effective saturation.

Implementations of IEC 61850 based protection schemes offers some significant advantages over conventional hard wired schemes. The continuous repetition of GOOSE messages by the protection and communications devices and the streaming of Sampled Values from the merging units provide reliable indication about the status of the interface and communication path function-to-function. Such reliability and failure detection simply cannot be achieved in wire based schemes for each and every signal, and is often only detected through scheduled testing or more catastrophically when the scheme fails to operate.

The analysis of the different factors that determine the overall operating time of the protection scheme show that GOOSE based implementations are faster than the conventional wire-based solutions.

To-date, implementations have tended to be predominantly based on vendors’ tools designed to support the application of their own devices. There are limited numbers of mature third party tools available on the market, despite the fact the engineering process expenditure world-wide is in the billions of any currency per year. Short sighted thinking considers a good tool in terms of the low licence cost rather than the dramatic reduction of engineering time and effort (tens of per cent) by using a “good” functional tool. Whilst this Technical Brochure explore the requirements of good” tools, they must support efficient engineering of systems in a multi-vendor environment, particularly given the variability of the “nuances”, interpretations and indeed implemented options of any particular vendor ..

The engineering, testing and commissioning efforts required to implement the standard in a substation are significant and should not be underestimated. However the benefit of savings tens of per cent of the total cost and engineering time of the substation and slashing several tens of per cent off the subsequent cost and time to engineer of refurbishments [41] through Reusable Reliable Engineering is an impressive payback on the investment.

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

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[16] IEC 60050-441 IEV Switchgear, control gear and fuses

[17] IEC 60050-448 IEV Power system protection

[18] IEC 60050-605 IEV Generation, transmission and distribution of electricity – Substations

[19] IEC 60044-1 Ed. 1.2 2003-02

[20] ANSI C57.13-1993

[21] IEC 60044-2 Ed. 1.2 2003-02

[22] IEC 62439-3 (FDIS): High availability automation networks - Part 3: Parallel Redundancy Protocol (PRP) and High-availability Seamless Redundancy (HSR)

[23] IEC 62351-6: Power systems management and associated information exchange - Data and communications security - Part 6: Security for IEC 61850

12.2 CIGRE & Other publications

[24] CIGRE Brochure 326, “The introduction of IEC 61850 and its impact on protection and automation within substations”. SC B5 WG B5.11, 2007.

[25] CIGRE Brochure 401, “Functional Testing of IEC 61850 Based Systems”. SC B5 WG B5.32, 2009.

[26] CIGRE SPECIAL REPORT 8 FOR GROUP B5 Protection and Automation, CIGRE 2008 session.

[27] CIGRE Paper B5-106 Process communication in switchgear according to IEC 61850 – architectures and application examples, CIGRE 2008 session.

[28] ISA 99WG01, “Security for Industrial and Automation Control Systems – Terminology, Concepts and Models,” Standard ISA-99.01.01,2007.

[29] CIGRE Brochure 427 “The Impact of Implementing Cyber Security Requirements using IEC 61850” SC B5 WG B5.38 2010

[30] Security assessment of the transmission control protocol (TCP), CPNI technical note, February 2009.

[31] Cryptographic Key Management for SCADA Systems, Issues and Perspectives. L. Piètre-Cambacédè, P. Sitbon. International Journal of Security and Applications, July 2008.

[32] Functional Testing of IEC 61850 Based Systems - Christoph Brunner, Alexander Apostolov, 2011

[33] CIGRE Brochure 419 “Treatment of Information Security for Electric Power Utilities (EPUs)” SC D2 WG D2.22 2010

[34] CIGRE (AU) Paper 37 “Experiences of IEC 61850 Engineering – Designing good systems the right way”. SEAPAC 2011

[35] CIGRE (AU) Paper 38 “IEC 61850 Edition 2 – what does it mean for the end user?”. SEAPAC 2011

[36] CIGRE (AU) Paper 39 “Experiences in organizational development and specifying IEC 61850 systems”. SEAPAC 2011

[37] CIGRE Brochure 246, “The Automation Of New And Existing Substations: Why And How?”. SC B5 WG B5.07, 2004.

[38] CIGRE Contribution 2012_B3_PS1_03_DOC_AU_Hughes SC B3 PS1 Hughes 2012.

[39] Patent: Operation & Test Interface http://www.freepatentsonline.com/y2012/0136500.html

[40] CIGRE Brochure 466, “Engineering Guidelines for IEC 61850 Based Digital SAS”. SC B5 WG B5.12, 2011.

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13 APPENDIX

13.1 Questionnaire

See next page

Survey WG B5.36

"Applications for Protection Schemes Based on IEC 61850"

1. What types of existing hardwired protection and control schemes that utilise signalling with other local devices are used within your company's substations?

(Where appropriate please indicate voltage levels)

a) Line protection:

		Tick	*kV*
1)	Circuit Breaker (CB) failure initiation	[___]	[___]
2)	CB back trip signal	[___]	[___]
3)	Auto-reclose (AR) initiation	[___]	[___]
4)	AR for a mesh corner	[___]	[___]
5)	AR for two CBs (breaker and half, master / slave mode)	[___]	[___]
6)	Stub bus protection	[___]	[___]
7)	Check sync using bus VT	[___]	[___]
8)	Check Synch using only line VT	[___]	[___]
9)	Direct aided trip (permissive & blocking schemes)	[___]	[___]
10)	Direct aided trip (direct intertrip)	[___]	[___]
11)	Directional comparison scheme (Directional earth fault protection, etc.)	[___]	[___]
12)	Echo mode (weak infeed)	[___]	[___]
13)	Mutual zero sequence compensation for parallel lines	[___]	[___]
14)	Backup protection (overcurrent, ground fault protection, etc.)	[___]	[___]
15)	Other (please specify): ________________________________		[___]

b) Bus protection:

		Tick	*kV*
1)	Current differential	[___]	[___]
2)	Two out of two logic (external check zone, voltage criteria)	[___]	[___]
3)	CB failure protection (trip through bus protection)	[___]	[___]
4)	Directional blocking	[___]	[___]
5)	End fault protection (fault between line CT & CB)	[___]	[___]
6)	Backup protection (overcurrent, ground fault protection, etc.)	[___]	[___]
7)	Other (please specify): ________________________________		[___]

Survey WG B5.36

"Applications for Protection Schemes Based on IEC 61850"

c)	Transformer and reactor protection:	*Tick*	*kV*
1)	Overcurrent & overload	[___]	[___]
2)	CB failure protection	[___]	[___]
3)	Current differential	[___]	[___]
4)	Direct intertrip	[___]	[___]
5)	On-load tap changer relay	[___]	[___]
6)	Other (please specify): ________________________________		[___]

d)	Generator protection:	*Tick*	*kV*
1)	Current differential	[___]	[___]
2)	Group current differential	[___]	[___]
3)	Voltage control (line drop compensation)	[___]	[___]
4)	Backup protection (overcurrent, ground fault protection, etc.)	[___]	[___]
5)	Other (please specify): ________________________________		[___]

e)	Distribution feeder:	*Tick*	*kV*
1)	Blocking schemes (directional or overcurrent initiated)	[___]	[___]
2)	AR scheme	[___]	[___]
3)	Special AR for line and cable circuits	[___]	[___]
4)	CB failure initiation	[___]	[___]
5)	Intertrips	[___]	[___]
6)	Fast transfer trip	[___]	[___]
7)	Other (please specify): ________________________________		[___]

f)	General:	*Tick*	*kV*
1)	Overload scheme	[___]	[___]
2)	Load shedding (centralized, distributed)	[___]	[___]
3)	Automatic load restoration (centralized, distributed)	[___]	[___]
4)	Isolator/CB pole discrepancy	[___]	[___]
5)	Isolator/CB open/close status position	[___]	[___]
6)	CB trip signal: use of two trip coils	[___]	[___]
7)	CB trip signal: use of two substation batteries	[___]	[___]
8)	Control interlocking (CB and switch control)	[___]	[___]
9)	Stand-alone Disturbance Recorder	[___]	[___]
10)	Other (please specify): ________________________________		[___]

Survey WG B5.36

"Applications for Protection Schemes Based on IEC 61850"

2. Which of the hardwired protection and control schemes listed above currently make use of redundancy in their design?

(Please also indicate the voltage level where such redundancy is required.)

____

____

____

3. Have you implemented any of the above schemes using IEC 61850?

Y [___] or N [___]

(If yes, please indicate below.)

a) Line protection:	*YES*	*NO*
1) Circuit Breaker (CB) failure initiation	[___]	[___]
2) CB back trip signal	[___]	[___]
3) Auto-reclose (AR) initiation	[___]	[___]
4) AR for a mesh corner	[___]	[___]
5) AR for two CB (breaker and half, etc.)	[___]	[___]
6) Stub bus protection	[___]	[___]
7) Check sync using bus VT	[___]	[___]
8) Check Synch using only line VT	[___]	[___]
9) Direct aided trip (permissive & blocking schemes)	[___]	[___]
10) Direct aided trip (direct intertrip)	[___]	[___]
11) Directional comparison scheme (Directional earth fault protection, etc.)	[___]	[___]
12) Echo mode (weak infeed)	[___]	[___]
13) Mutual zero sequence compensation for parallel lines	[___]	[___]
14) Other (please specify): ________________________________		[___]

b) Bus protection:	*YES*	*NO*
1) Current differential	[___]	[___]
2) Two out of two logic (external check zone, voltage criteria)	[___]	[___]
3) CB failure protection (trip through bus protection)	[___]	[___]
4) Directional blocking	[___]	[___]
5) End fault protection (fault between line CT & CB)	[___]	[___]
6) Other (please specify): ________________________________		[___]

Survey WG B5.36

“Applications for Protection Schemes Based on IEC 61850”

		YES	*NO*
c)	Transformer and reactor protection:		
	1) Overcurrent & overload	[___]	[___]
	2) CB failure protection	[___]	[___]
	3) Current differential	[___]	[___]
	4) Direct intertrip	[___]	[___]
	5) On-load tap changer relay	[___]	[___]
	6) Other (please specify): ______________________________		[___]

		YES	*NO*
d)	Generator protection:		
	1) Current differential	[___]	[___]
	2) Group current differential	[___]	[___]
	3) Voltage control (line drop compensation)	[___]	[___]
	4) Other (please specify): ______________________________		[___]

		YES	*NO*
e)	Distribution feeder:		
	1) Blocking schemes (directional or overcurrent initiated)	[___]	[___]
	2) AR scheme	[___]	[___]
	3) Special AR for line and cable circuits	[___]	[___]
	4) CB failure initiation	[___]	[___]
	5) Intertrips	[___]	[___]
	6) Fast transfer trip	[___]	[___]
	7) Other (please specify): ______________________________		[___]

		YES	*NO*
f)	General:		
	1) Overload scheme	[___]	[___]
	2) Load shedding (centralized, distributed)	[___]	[___]
	3) Automatic load restoration (centralized, distributed)	[___]	[___]
	4) Isolator/CB pole discrepancy	[___]	[___]
	5) Isolator/CB open/close status position	[___]	[___]
	6) CB trip signal: use of two trip coils	[___]	[___]
	7) CB trip signal: use of two substation batteries	[___]	[___]
	8) Control interlocking (CB and switch control)	[___]	[___]
	9) Other (please specify): ______________________________		[___]

Survey WG B5.36

"Applications for Protection Schemes Based on IEC 61850"

4. **For which of the IEC 61850 implemented schemes listed above would you consider the addition of redundancy in their design?**

(Please indicate why.)

____

____

____

5. **Are there any new protection schemes that you would consider implementing due to the availability of the hardware and software functionality associated with IEC 61850?**

a) within the substation

b) between substations

c) between the substation and control centre

(Please indicate which schemes.)

____

____

____

____

____

____

____

____

____

6. **Would the use of IEC 61850 improve the reliability or availability of protection schemes?**

Y [___] or N [___]

(Please indicate why.)

____

____

____

Survey WG B5.36

"Applications for Protection Schemes Based on IEC 61850"

7. Have you experienced any problems when implementing IEC 61850 schemes?

		Tick
a)	Engineering (including tools)	[___]
b)	Commissioning and testing	[___]
c)	Operation	[___]
d)	Maintenance	[___]
e)	Training	[___]
f)	Performance	[___]
g)	Interoperability (multi-vendor)	[___]
h)	Other (please specify): ________________________________	

(Please clarify any problems highlighted above.)

____

____

____

Survey WG B5.36

“Applications for Protection Schemes Based on IEC 61850”

8. What advantages or disadvantages do you expect from using IEC 61850?

a) Costs

____

____

b) Availability

____

____

c) Reliability

____

____

d) Engineering

____

____

e) Commissioning and testing

____

____

f) Maintenance and diagnostics

____

____

g) Training

____

____

h) Extendibility

____

____

i) Performance

____

____

j) Others (please specify): ______________________________

____

____

Survey WG B5.36

"Applications for Protection Schemes Based on IEC 61850"

9. Has your company estimated the cost benefits of using IEC 61850-8-1 station bus? Specifically:

(Defined as a percentage of <u>secondary system</u> costs.)

- Existing substation retrofit — *Tick*
  - a) No [___]
  - b) 0-5% [___]
  - c) 5-10% [___]
  - d) >10% [___]

- Green field (new) substation — *Tick*
  - a) No [___]
  - b) 0-5% [___]
  - c) 5-10% [___]
  - d) >10% [___]

10. Has your company estimated the cost benefits of using IEC 61850-9-2 process bus? Specifically:

(Defined as a percentage of <u>substation</u> costs.)

- Existing substation retrofit — *Tick*
  - a) No [___]
  - b) 0-5% [___]
  - c) 5-10% [___]
  - d) >10% [___]

- Green field (new) substation — *Tick*
  - a) No [___]
  - b) 0-5% [___]
  - c) 5-10% [___]
  - d) >10% [___]

Survey WG B5.36

"Applications for Protection Schemes Based on IEC 61850"

11. Do you currently include IEC 61850 in your substation specifications?

	Tick
a) Yes, mandatory	[___]
b) Yes, but only for IEC GOOSE messages (SCADA legacy protocol remains the same)	[___]
c) No, but accepted	[___]
d) No, preference given legacy SCADA protocols	[___]

(Please specify protocol name and use of serial link or TCP/IP: ______________________)

12. If you do not currently use IEC 61850, do you have plans for its implementation within:

	Tick
a) 2-3 years	[___]
b) 4-5 years	[___]
c) No current plans	[___]

13. If you already use or you plan to use IEC 61850, would you implement:

	Tick
a) IEC 61850-8-1 station bus only	[___]
b) IEC 61850-9-2 process bus only	[___]
c) Both	[___]

14. Are you planning to use IEC 61850 for distribution?

	Tick
a) IEC 61850-8-1 station bus only	[___]
b) IEC 61850-9-2 process bus only	[___]
c) Both	[___]

Survey WG B5.36

"Applications for Protection Schemes Based on IEC 61850"

15. **Is it your company policy to use equipment from different vendors within the same substation?**

	Tick
a) Yes	[___]
b) Yes (mandatory)	[___]
c) No	[___]

(Please indicate why.)

____

____

____

16. **Do you foresee that your company will use equipment from different vendors if IEC 61850 is implemented?**

Y [___] or N [___]

(Please indicate why.)

____

____

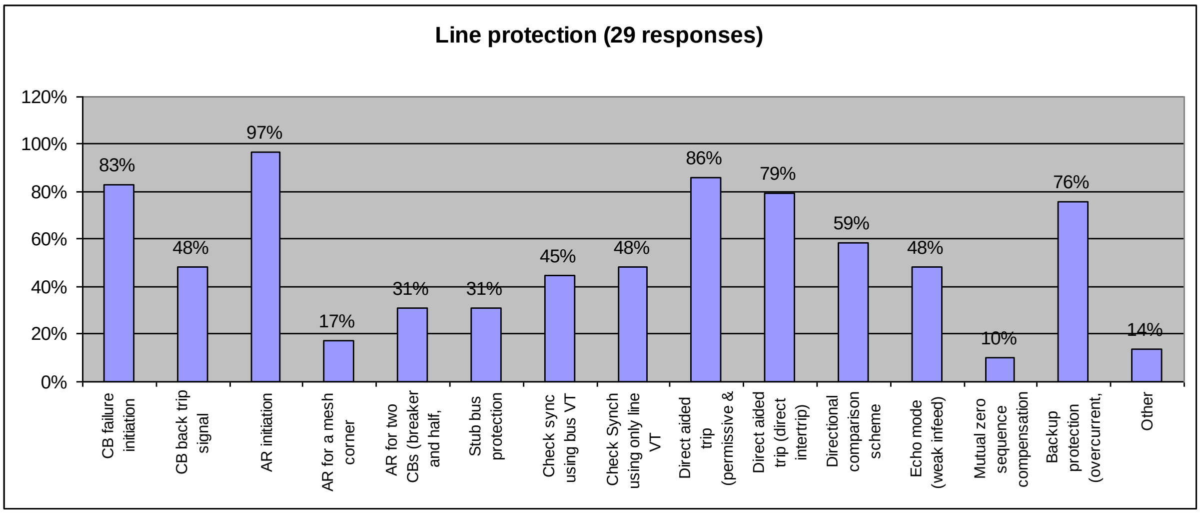
____

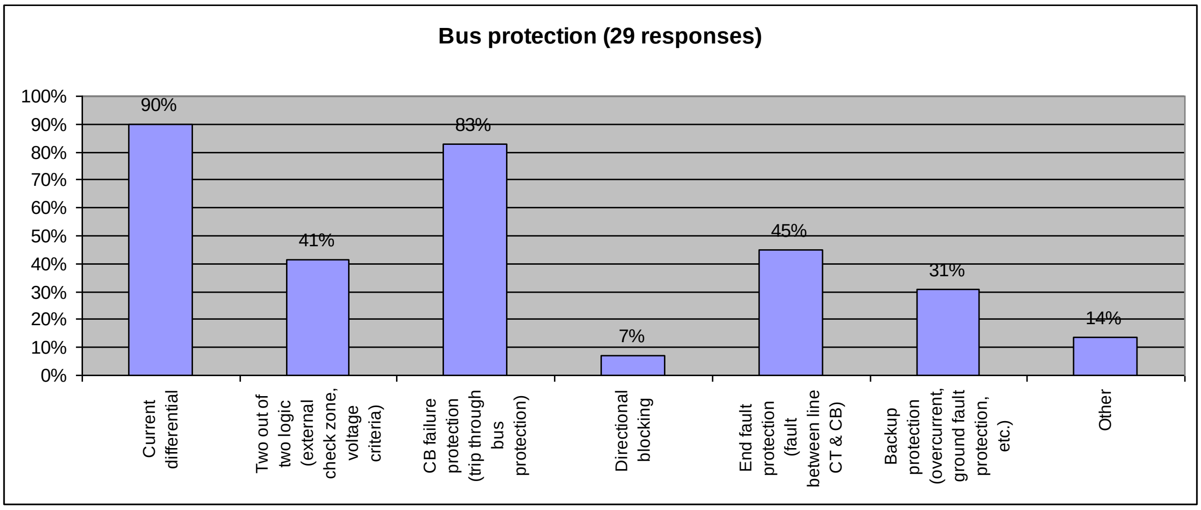
13.2 Results and Analysis

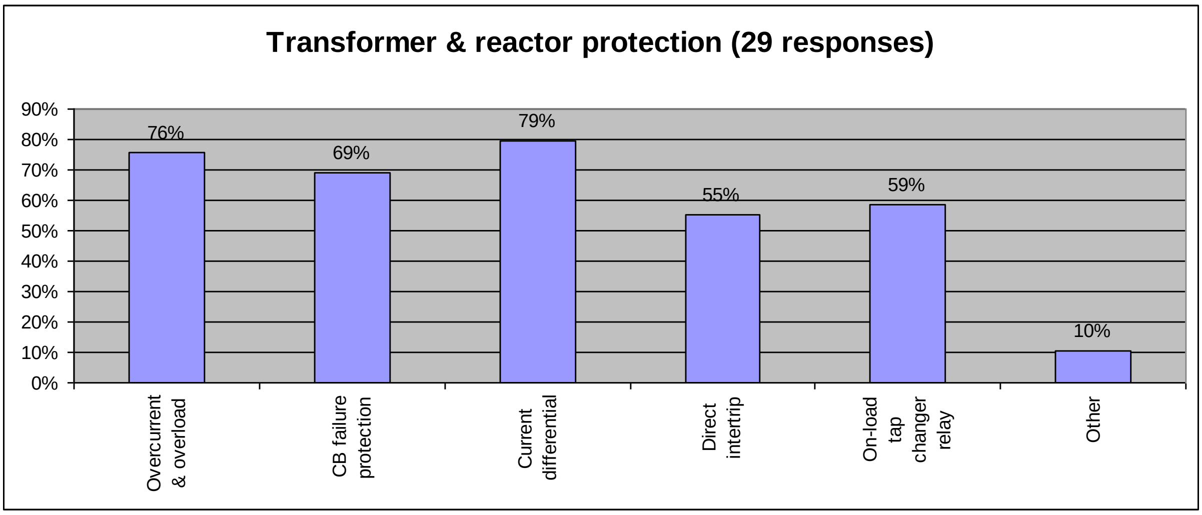
29 responses received from Austria, Australia, Brazil, Canada, China, Finland, France, Germany, Greece, India, Israel, Japan, Norway, Portugal, Saudi Arabia, South Africa, Spain, Sweden and UK.

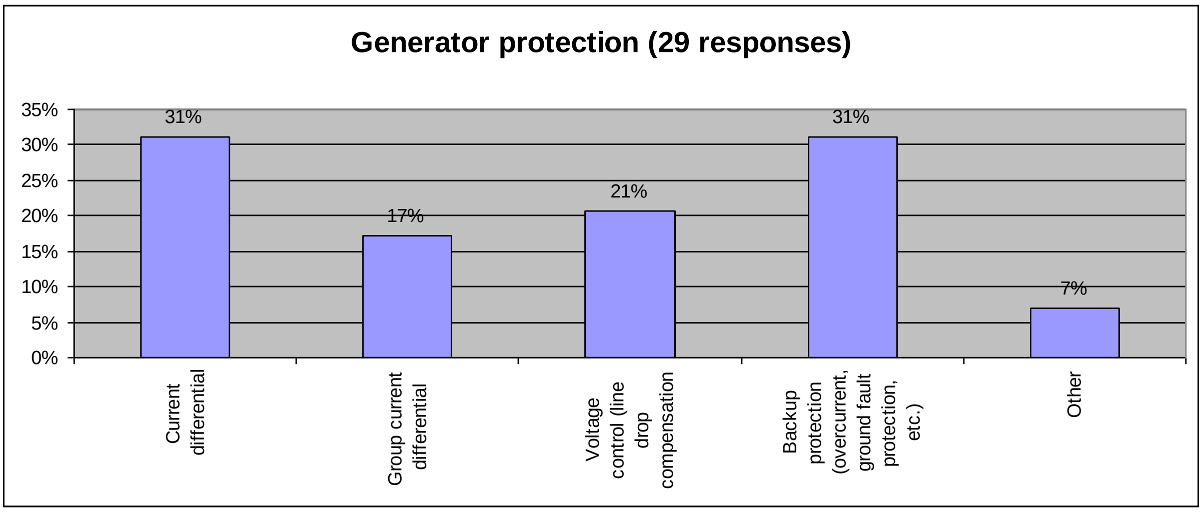
No response received from: Argentina, Belgium, Egypt, Romania, Italy, Iran, Ireland, Malaysia, Netherlands, Poland, Switzerland, Slovenia, South Korea, USA and Yugoslavia.

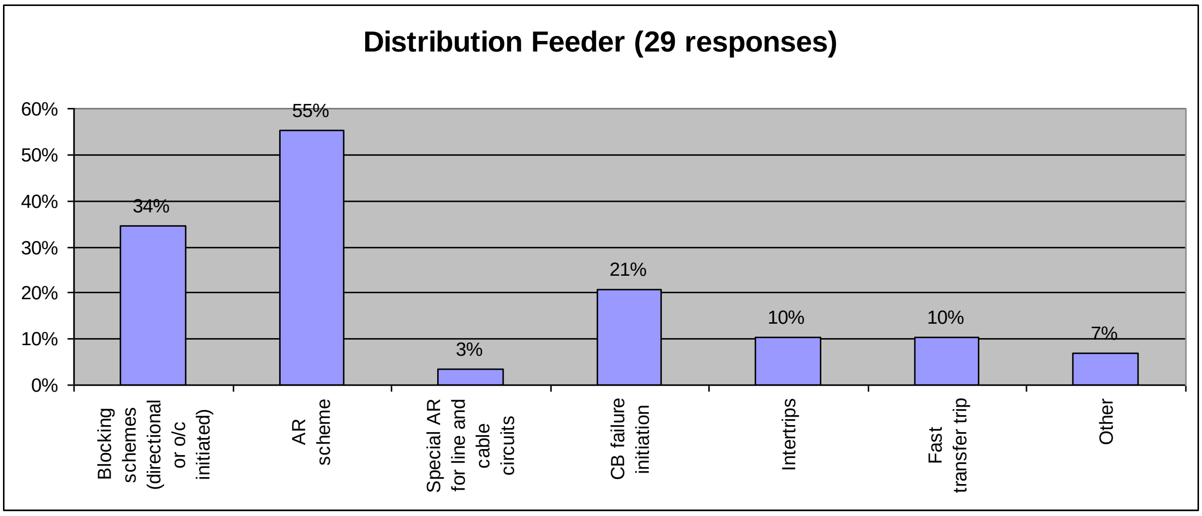
Q1. What type of existing hardwired protection and control schemes that utilize signalling with other local devices are used within your company's substations:

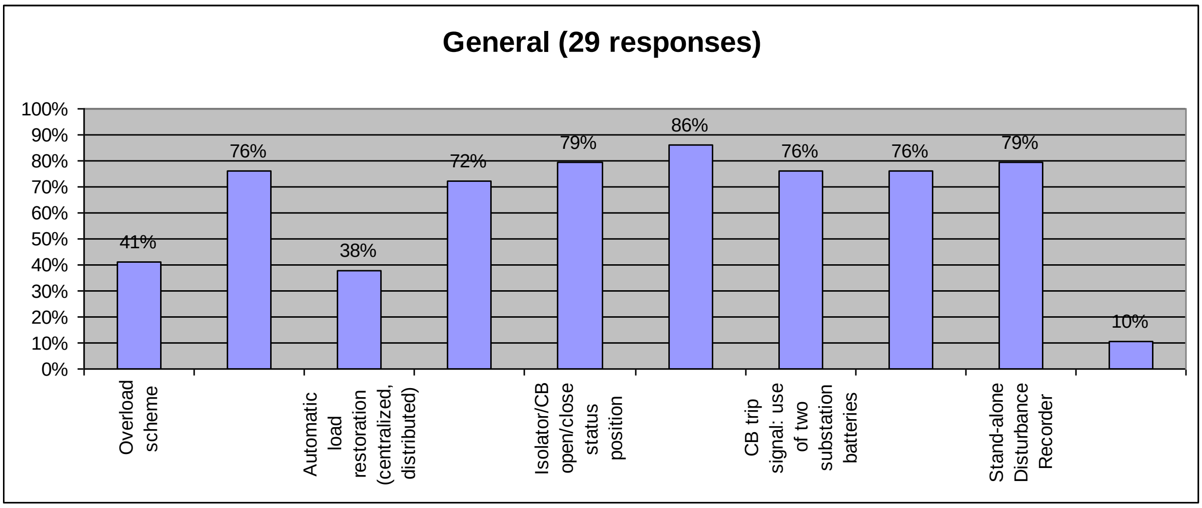





Transformer & reactor protection (29 responses)
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
76%
69%
79%
55%
59%
10%
Overcurrent & overload
CB failure protection
Current differential
Direct intertrip
On-load tap changer relay
Other


Generator protection (29 responses)
35%
30%
25%
20%
15%
10%
5%
0%
31%
17%
21%
31%
7%
Current differential
Group current differential
Voltage control (line drop compensation
Backup protection (overcurrent, ground fault protection, etc.)
Other


Distribution Feeder (29 responses)
60%
50%
40%
30%
20%
10%
0%
34%
55%
3%
21%
10%
10%
7%
Blocking schemes (directional or o/c initiated)
AR scheme
Special AR for line and cable circuits
CB failure initiation
Intertrips
Fast transfer trip
Other



Q2. Which of the hardwired protection and control schemes listed above currently make use of redundancy in their design?

a) POTT

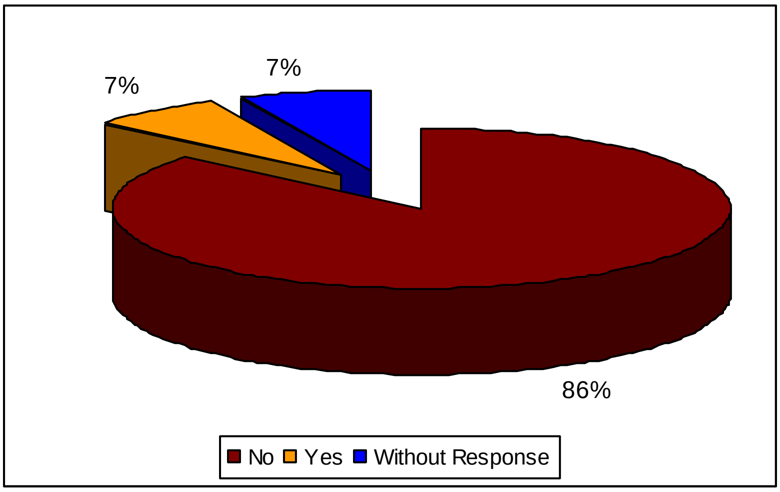
b) SPS

c) Line / Bus / Transformer / Reactor / Stub-Bus

d) DC Supply

e) Trip Circuit

Q3. Have you implemented any of the above schemes using IEC 61850?



Interests for CB Failure Initiation, AR Initiation, AR Scheme, Bus Differential Protection, Two-Of-Two Logic for Bus Protection, Backup O/C protection, Blocking Scheme, Load shedding, Automatic Restoration, Isolator/CB status position, Control Interlocking, Standalone Distance Recorder.

Q4. For which of the IEC 61850 implemented schemes listed above would you consider the addition of redundancy in their design?

a) Control Interlocking, Line/ Transformer / Reactor / Bus relay,

b) AR Initiation Trip, Direct Aided Trip, etc.

c) Mainly independent of the implementation of IEC 61850

Q5. Are there any new protection schemes that you would consider implementing due to the availability of the hardware and software functionality associated with IEC 61850?

a) within the substation

1. Check sync using on line VT
2. Reserve or additional backup bus protection using directional blocking scheme
3. Interlocking control
4. Use of IEC 61850 for both MV and HV s/s

b) between substations

1. Line protection to compensate the influence of the infeed
2. Direct Aided Trip

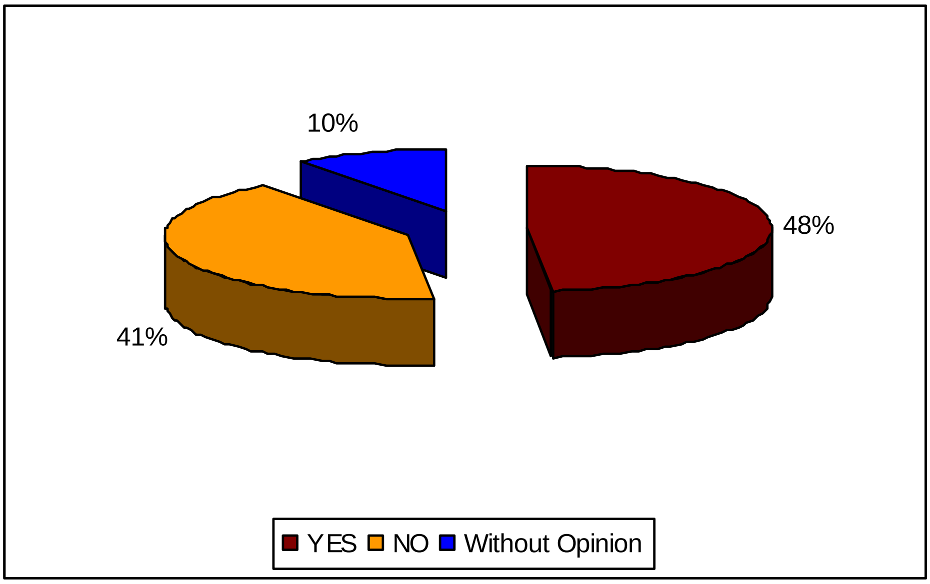
c) between the substation and control centre

1. Implementation of SIPS, WACS and WAPS

Q6. Would the use of IEC 61850 improve the reliability or availability of protection schemes?

- Brings new information sharing and exchanging, Concerns regarding reliability could be released after long term experience, No more needs for protocol converter, GOOSE message are monitored (copper wired signals are not!), More easy to design and maintain, can facilitate the error tracing and engineering !

- No influence, Interoperability ?, Needs for more skilled personal and tools for error tracing and repair, GOOSE message not compatible with existing test and maintenance procedures (isolation of the GOOSE message



WG Response:

The response to this question showed that a small majority of users are of the opinion that this is indeed the case. However, it is also significant to note that the sum of negative responses with those without opinion make up the majority of the returns. Given the relative infancy of the technology and the inherent industry inertia this result is not entirely to be unexpected.

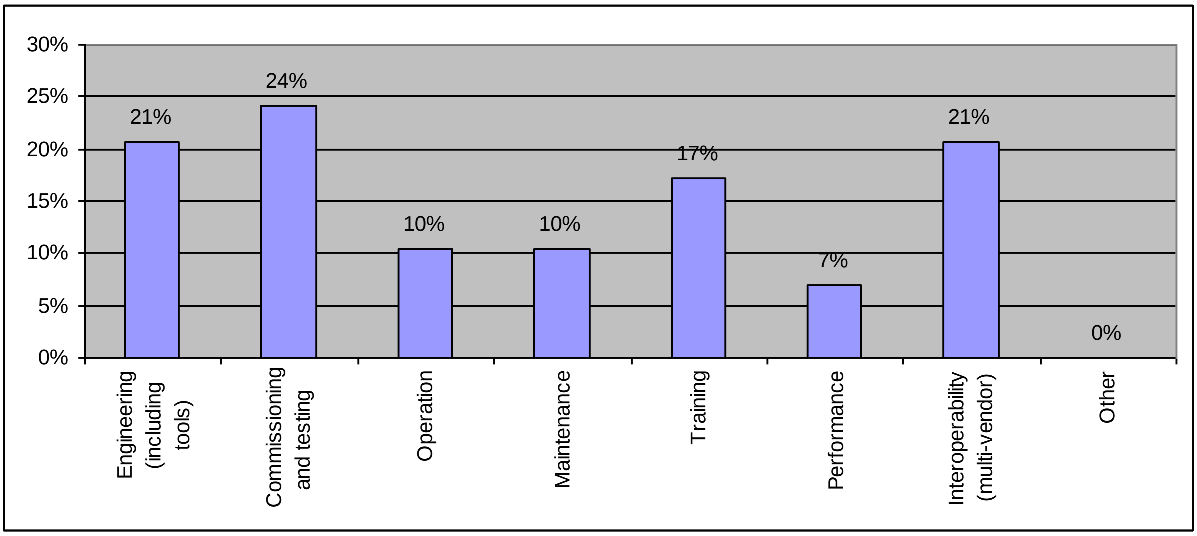
Amongst those that agreed with the statement, a number highlighted that commonly voiced concerns are likely to be alleviated as industry gains a greater level of experience with the application of the standard. This would be similar to any emerging technology and, of course, a parallel can be drawn with the initial adoption of digital relaying.

It is also the case that the removal of certain devices (such as protocol converters between proprietary systems) may act to improve the reliability of schemes. The availability of schemes may also be improved by the easy monitoring of GOOSE messages which represents a major improvement over copper wiring where supervision is not always applied or practical to implement.

Conversely, those who provided a negative response commented on the need for improved toolsets for error tracing and repair as part of the commissioning or maintenance processes. This is indeed an important issue and many product vendors are actively working in this area.

Q7. Have you experience problems when implementing IEC 61850 schemes?

Different types of IEC 6150 services implemented by vendors, Tools and devices are not matured yet, Skills of the personal slow down its implementation, Engineering looks complicated, needs to use different configuration tools.



WG response

The results from the survey clearly show the impact of the early stages of development and implementation of IEC 61850 by IED vendors and software tools developers. At the same time the lack of knowledge of the standard in utilities is further complication the acceptance of IEC 61850 and especially the use of GOOSE messages for protection functions.

Q8. What advantages or disadvantages do you expect using IEC 61850?

Costs:

- ⊕ Less wiring, bay standardization, overall cost reduction during lifetime of the s/s (engineering, installation, maintenance)
- ⊖ Network and IEDs price, redundancy, engineering/ commissioning/testing in first project at least, difficulty to extend and change (?)

Availability:

- ⊕ Redundant remote control and bay to bay connection, more easy to use different type of manufacturer, overall LAN is supervised but more components, remote access will be improved, GOOSE messages are supervised
- ⊖ Depends of the network architecture

Reliability:

- ⊕ Common language, Monitoring, Interoperability
- ⊖ LAN components, availability of the technology, Depends of the system architecture

Engineering:

- ⊕ Integration time, same tools, same language, Simpler and easier to document
- ⊖ Availability of all IEDs IEC 61850 compliant, maturity of the tools, high degree of expertise required for the engineers

Commissioning and testing:

- ⊕ Will be more convenient and faster, standardization, live testing can be made without outage

- ⊖ Tools needs to mature, required new knowledge for commissioning techs or engineers, new tools required for IEC 61850-9-2/NCIT, Difficulty to isolate the feeder

Maintenance:

- ⊕ Will be easier by long term in comparison with hardwired signals, remote access via LAN, reduce maintenance, signal monitoring, improve self-monitoring, maintenance simplified due to interoperability and hopefully one day, Future interchangeability ?!
- ⊖ IT security, requires more skilled personal, harder to isolate for maintenance and testing

Training:

- ⊕ … (Easier to find young protection engineers!)

- ⊖ Knowledge is mainly by vendors, training will become more complex, Difficulty to find personal with the right skills within the company

Extendibility:

- ⊕ More convenient as done mainly with s/w, easier even when done by another vendor,
- ⊖ Version management, availability of smart tools to manage change and regression tests

Performance:

- ⊕ Speed, Use of IEC 61850 native IEDs, faster than hardwired signals,
- ⊖ Lifetime of LAN components, GOOSE signal reliability, some IEDs are till using IEC 61850 internal/external gateway,

Others:

- ⊕ …
- ⊖ Clarity of the AC/DC schematics when GOOSE messages are used, model conformity

WG response

The results from the survey show a good understanding of some of the benefits of the use of IEC 61850 and specifically GOOSE messages. However, the responses related to the disadvantages in many cases indicate that some issues that are common to hardwired and communication based systems are considered only as IEC 61850 drawbacks. Also some of the disadvantages are due to the lack of proper tools and not a problem of the standard. The insufficient knowledge of the details of IEC 61850 by the utilities personnel is also contributing to the perception that there are significant disadvantages in its use.

Q9. Has your company estimated the costs benefits of using IEC 61850-8-1 station bus?

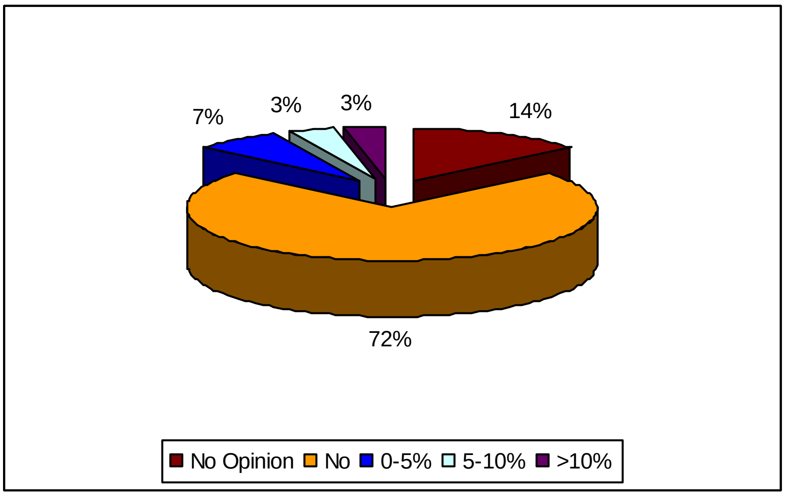


Figure 13-1: Existing Substation

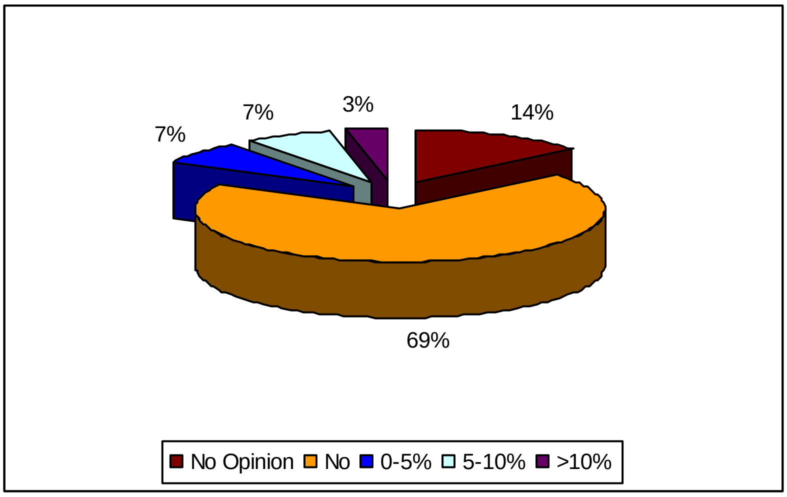


Figure 13-2: Green Substation

Q10. Has your company estimated the costs benefits of using IEC 61850-9-2 process bus?

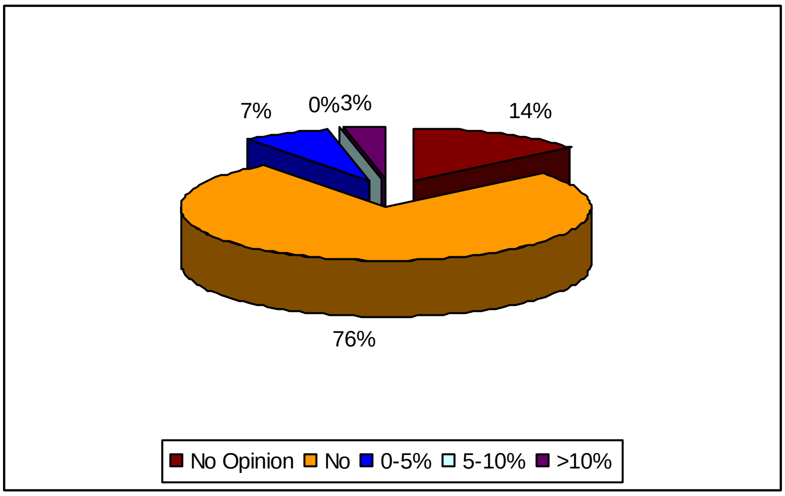


Figure 13-3: Existing Substation

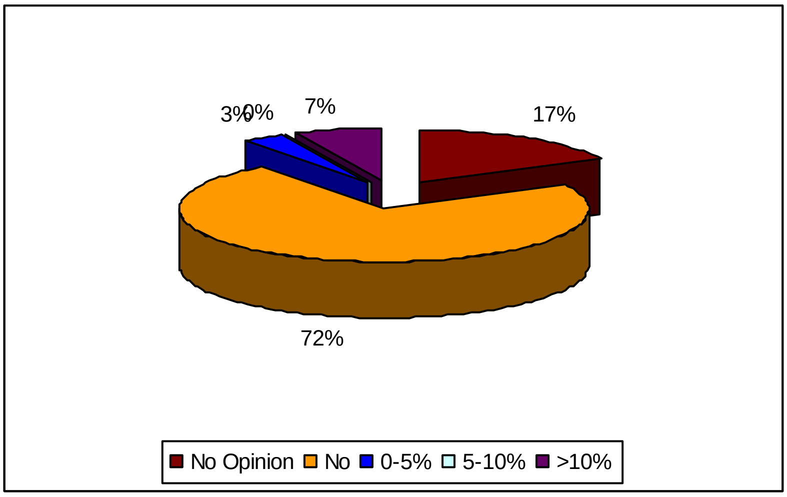
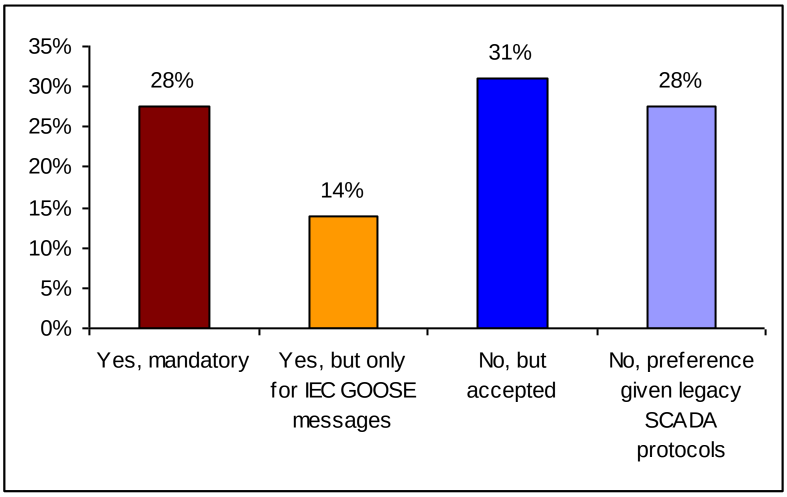
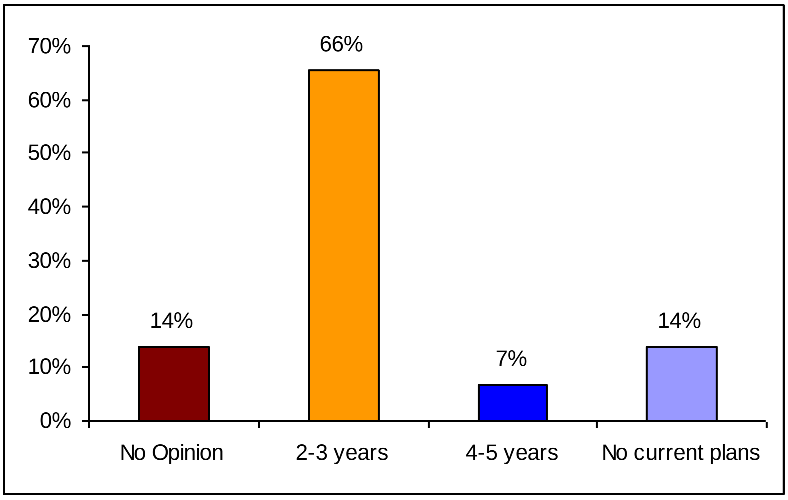


Figure 13-4: Green Substation

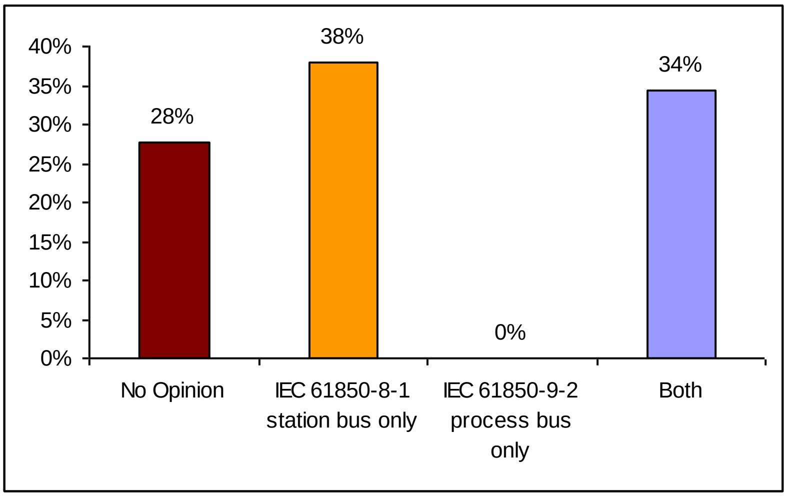
Q11. Do you currently include IEC 61850 in your substation spec?



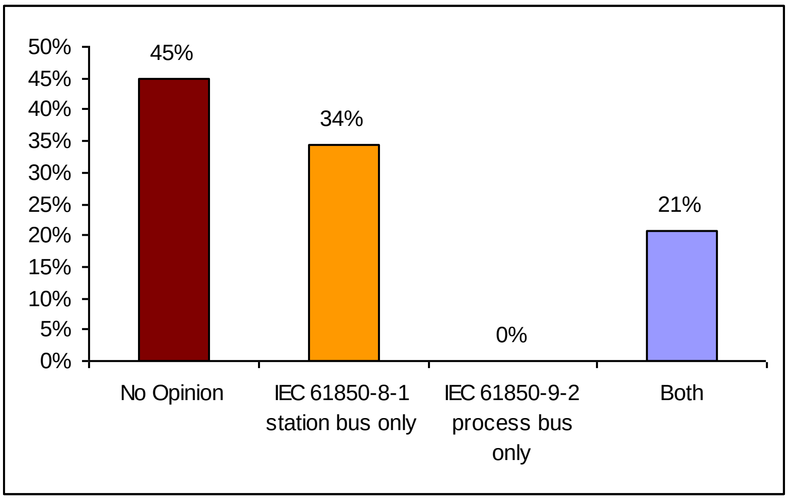
Q12. If you do not currently use IEC 61850, do you plan for its implementation within?



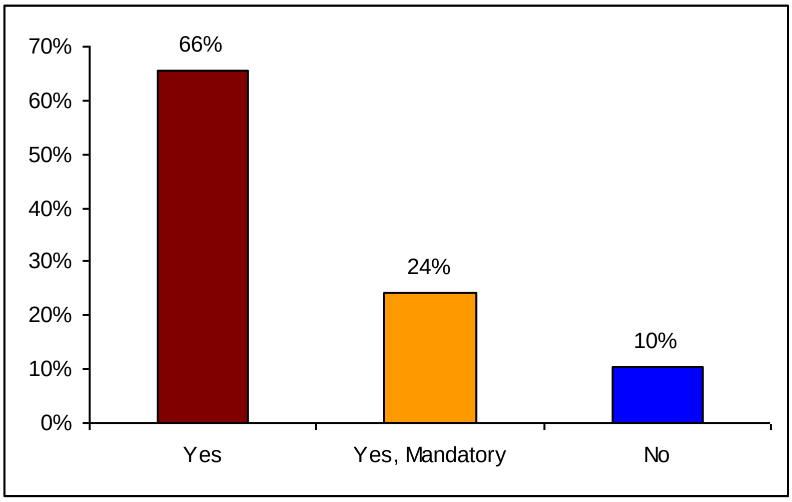
Q13. If you already use or you plan to use IEC 61850, would you implement:



Q14. Are you planning to use IEC 61850 for distribution?



Q15. Is it company point's policy to use equipment from different vendors within the same substations?



Q16. Do you foresee that your company will use equipment from different vendors if IEC 61850 is implemented?