

Relion 650 SERIES

Line differential protection RED650

Version 2.2 IEC

Application manual





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Conformity

This product complies with the directive of the Council of the European Communities on the approximation of the laws of the Member States relating to electromagnetic compatibility (EMC Directive 2004/108/EC) and concerning electrical equipment for use within specified voltage limits (Low-voltage directive 2006/95/EC). This conformity is the result of tests conducted by Hitachi Energy in accordance with the product standard EN 60255-26 for the EMC directive, and with the product standards EN 60255-1 and EN 60255-27 for the low voltage directive. The product is designed in accordance with the international standards of the IEC 60255 series.

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Section 1 Introduction

1.1 This manual

The application manual contains application descriptions and setting guidelines sorted per function. The manual can be used to find out when and for what purpose a typical protection function can be used. The manual can also provide assistance for calculating settings.

1.2 Intended audience

This manual addresses the protection and control engineer responsible for planning, pre-engineering and engineering.

The protection and control engineer must be experienced in electrical power engineering and have knowledge of related technology, such as protection schemes and communication principles.

1.3 Product documentation

1.3.1 Product documentation set

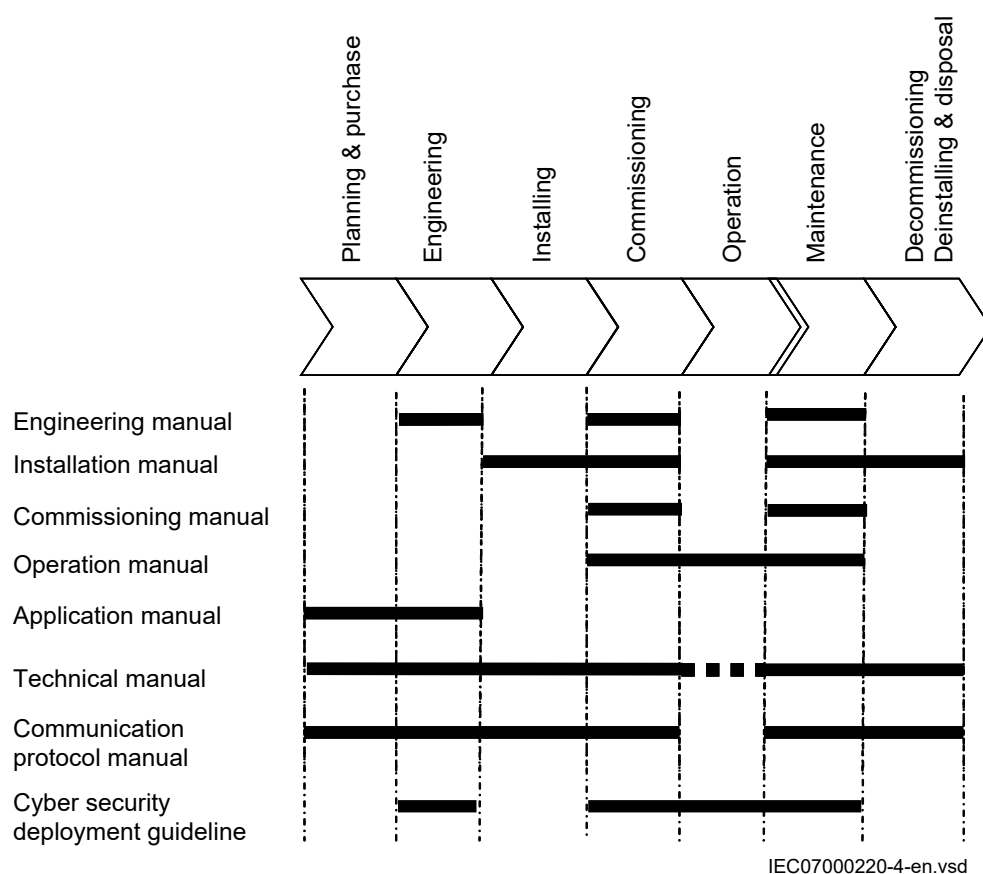


Figure 1: The intended use of manuals throughout the product lifecycle

The engineering manual contains instructions on how to engineer the IEDs using the various tools available within the PCM600 software. The manual provides instructions on how to set up a PCM600 project and insert IEDs to the project structure. The manual also recommends a sequence for the engineering of protection and control functions, as well as communication engineering for IEC 61850.

The installation manual contains instructions on how to install the IED. The manual provides procedures for mechanical and electrical installation. The chapters are organized in the chronological order in which the IED should be installed.

The commissioning manual contains instructions on how to commission the IED. The manual can also be used by system engineers and maintenance personnel for assistance during the testing phase. The manual provides procedures for the checking of external circuitry and energizing the IED, parameter setting and configuration as well as verifying settings by secondary injection. The manual describes the process of testing an IED in a station which is not in service. The chapters are organized in the chronological order in which the IED should be commissioned. The relevant procedures may be followed also during the service and maintenance activities.

The operation manual contains instructions on how to operate the IED once it has been commissioned. The manual provides instructions for the monitoring, controlling and setting of the IED. The manual also describes how to identify disturbances and how to view calculated and measured power grid data to determine the cause of a fault.

The application manual contains application descriptions and setting guidelines sorted per function. The manual can be used to find out when and for what purpose a typical protection function can be used. The manual can also provide assistance for calculating settings.

The technical manual contains operation principle descriptions, and lists function blocks, logic diagrams, input and output signals, setting parameters and technical data, sorted per function. The manual can be used as a technical reference during the engineering phase, installation and commissioning phase, and during normal service.

The communication protocol manual describes the communication protocols supported by the IED. The manual concentrates on the vendor-specific implementations.

The point list manual describes the outlook and properties of the data points specific to the IED. The manual should be used in conjunction with the corresponding communication protocol manual.

The cyber security deployment guideline describes the process for handling cyber security when communicating with the IED. Certification, Authorization with role based access control, and product engineering for cyber security related events are described and sorted by function. The guideline can be used as a technical reference during the engineering phase, installation and commissioning phase, and during normal service.

1.3.2 Document revision history

Document revision	Date	Product revision	History
-	2017-05	2.2.0	First release for product version 2.2
A	2017-10	2.2.1	Ethernet ports with RJ45 connector added. enhancements/ updates made to GENPDIF, ZMFPDIS and ZMFCPDIS.
B	2018-03	2.2.1	Document enhancements and corrections
C	2019-05	2.2.1	PTP enhancements and corrections
D			Document not released
E	2020-09	2.2.4	Added new functions ALGOS, ALSVS and IEC 61850SIM. Added APC5 apparatus control function. Included instances for functions LDRGFC, OOSPAM, BRCPTOC, STBPTOC, LOVPTUV, DELVSPVC, DELISPVC, DELSPVC and DELSPVC. Removed instances for functions SCILO, SCSWI, XLNPROXY, GOOSEXLNRCV.
F			Document not released
Table continues on next page			

Document revision	Date	Product revision	History
G	2021-06	2.2.5	Functions FLTMMXU, BRPTOC, LMBRFLO, HOLDMINMAX, INT_REAL, CONST_INT, INTSEL, LIMITER, ABS, POL_REC, RAD_DEG, CONST_REAL, REALSEL, STOREINT, STOREREAL, DEG_RAD and RSTP added. Updates/enhancements made to functions ZMFPDIS, OC4PTOC, DRPRDRE, EF4PTOC, STBPTOC, BRCPTOC, SXSXI and SXCBI.
H	2022-07	2.2.5.4	Introduced RIA600, which is a software implementation of the IED LHMI panel.
J			Document not released
K	2023-06	2.2.6	SNMP support, IEC 61850 Ed2.1, new variants of single mode SFP added. Functions C1RADR, GOOSEACRCV, SNMPSERVERCONF, and SNMPUSERCONF added. Functions LDRGFC, INTERRSIG, SETGRPS, TERMINALID, ZMFPDIS, OC4PTOC, EF4PTOC, LCPTTR, LFPTTR, BRCPTOC, SCSXI, SXSXI, VSGAPC, SMPPTRC, BTIGAPC, IB16, ITBGAPC, CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU, SSCBI, SPGAPC, SP16GAPC, MVGAPC, IEC61850-8-1, LD0LLN0, AP_1, FLTMMXU, LMBRFLO, LDCMTRN, and AP_FRONT updated.

1.3.3 Related documents

Documents related to RED650	Document numbers
Application manual	1MRK505393-UEN
Commissioning manual	1MRK505395-UEN
Product guide	1MRK505396-BEN
Technical manual	1MRK505394-UEN
Type test certificate	1MRK505396-TEN

650 series manuals	Document numbers
Operation manual	1MRK500128-UEN
Engineering manual	1MRK511420-UEN
Installation manual	1MRK514027-UEN
Communication protocol manual, DNP3	1MRK511413-UUS
Communication protocol manual, IEC 60870-5-103	1MRK511416-UEN
Communication protocol manual, IEC 61850 Edition 1	1MRK511414-UEN
Communication protocol manual, IEC 61850 Edition 2	1MRK511415-UEN
Communication protocol manual, LON	1MRK511417-UEN
Communication protocol manual, SPA	1MRK511418-UEN
Point list manual, DNP3	1MRK511419-UUS
Accessories guide	IEC: 1MRK514012-UEN
Cyber security deployment guideline	1MRK511421-UEN
Connection and Installation components	1MRK513003-BEN
Test system, COMBITEST	1MRK512001-BEN
Application guide, Communication set-up	1MRK505382-UEN

1.4 Document symbols and conventions

1.4.1 Symbols



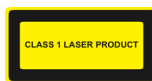
The electrical warning icon indicates the presence of a hazard which could result in electrical shock.



The warning icon indicates the presence of a hazard which could result in personal injury.



The caution hot surface icon indicates important information or warning about the temperature of product surfaces.



Class 1 Laser product. Take adequate measures to protect the eyes and do not view directly with optical instruments.



The caution icon indicates important information or warning related to the concept discussed in the text. It might indicate the presence of a hazard which could result in corruption of software or damage to equipment or property.



The information icon alerts the reader of important facts and conditions.



The tip icon indicates advice on, for example, how to design your project or how to use a certain function.

Although warning hazards are related to personal injury, it is necessary to understand that under certain operational conditions, operation of damaged equipment may result in degraded process performance leading to personal injury or death. It is important that the user fully complies with all warning and cautionary notices.

1.4.2 Document conventions

- Abbreviations and acronyms in this manual are spelled out in the glossary. The glossary also contains definitions of important terms.
- Push button navigation in the LHMI menu structure is presented by using the push button icons. For example, to navigate between the options, use  and .
- HMI menu paths are presented in bold. For example, select **Main menu/Settings**.
- LHMI messages are shown in Courier font. For example, to save the changes in non-volatile memory, select Yes and press .
- Parameter names are shown in italics. For example, the function can be enabled and disabled with the *Operation* setting.
- Each function block symbol shows the available input/output signal.

- the character ^ in front of an input/output signal name indicates that the signal name may be customized using the PCM600 software.
- the character * after an input signal name indicates that the signal must be connected to another function block in the application configuration to achieve a valid application configuration.
- Dimensions are provided both in inches and millimeters. If it is not specifically mentioned then the dimension is in millimeters.

1.5 IEC 61850 Edition 1, Edition 2, and Edition 2.1 mapping

Function block names are used in **ACT** and **PST** to identify functions. Respective function block names of Edition 1, Edition 2, and Edition 2.1 logical nodes are shown in the table below.

Table 1: IEC 61850 Edition 1, Edition 2, and Edition 2.1 mapping

Function block name	Edition 1 logical nodes	Edition 2 and Edition 2.1 logical nodes
-	-	ALGOS
-	-	ALSVS
AGSAL	AGSAL SECLLN0	AGSAL
ALMCALH	ALMCALH	ALMCALH
ALTIM	-	ALTIM
ALTMS	-	ALTMS
ALTRK	-	ALTRK
BRCPTOC	BRCPTOC	BRCPTOC
BRPTOC	BRPTOC	BRPTOC
BTIGAPC	B16IFCVI	BTIGAPC
CCPDSC	CCRPLD	CCPDSC
CCRBRF	CCRBRF	CCRBRF
CCSSPVC	CCSRDIF	CCSSPVC
CMMXU	CMMXU	CMMXU
CMSQI	CMSQI	CMSQI
CVMMXN	CVMMXN	CVMMXN
DELISPVC	DELISPVC	DELISPVC
DELSPVC	DELSPVC	DELSPVC
DELVSPVC	DELVSPVC	DELVSPVC
DPGAPC	DPGGIO	DPGAPC
DRPRDRE	DRPRDRE	DRPRDRE
ECPSCH	ECPSCH	ECPSCH
ECRWPSCH	ECRWPSCH	ECRWPSCH
EF4PTOC	EF4LLN0 EF4PTRC EF4RDIR GEN4PHAR PH1PTOC	EF4PTRC EF4RDIR GEN4PHAR PH1PTOC
EFPIOC	EFPIOC	EFPIOC
ETPMATR	ETPMATR	ETPMATR
FLTMMXU	FLTMMXU	FLTMMXU
FUFSPVC	SDDRFUF	FUFSPVC
GUPPDUP	GUPPDUP	GUPPDUP PH1PTRC
Table continues on next page		

Function block name	Edition 1 logical nodes	Edition 2 and Edition 2.1 logical nodes
GOPPDOP	GOPPDOP	GOPPDOP PH1PTRC
INDCALH	INDCALH	INDCALH
ITBGAPC	IB16FCVB	ITBGAPC
L4UFCNT	L4UFCNT	L4UFCNT
LCPTTR	LCPTTR	LCPTTR
LD0LLN0	LLN0	LLN0
LDLPSCH	LDLPDIF	LDLPSCH
LDRGFC	STSGGIO	LDRGFC LLDLPTRC PHPTUC PHPTUV SVABPTOC SVBCPTOC SVCAPTOC ZSPTOC
LFPTTR	LFPTTR	LFPTTR
LMBRFLO	LMBRFLO	LMBRFLO
LOVPTUV	LOVPTUV	LOVPTUV
LPHD	LPHD	LPHD
LT3CPDIF	LT3CPDIF	LT3CGAPC LT3CPDIF LT3CPHAR LT3CPTRC
MVGAPC	MVGGIO	MVGAPC
OC4PTOC	OC4LLN0 GEN4PHAR PH3PTOC PH3PTRC	GEN4PHAR PH3PTOC PH3PTRC
OOSPPAM	OOSPPAM	OOSPPAM OOSPTRC
OV2PTOV	GEN2LLN0 OV2PTOV PH1PTRC	OV2PTOV PH1PTRC
PCFCNT	PCGGIO	PCFCNT
PHPIOC	PHPIOC	PHPIOC
PSLPSCH	PSLPSCH	PSLPSCH
QCBAY	QCBAY	BAY/LLN0
QCRSV	QCRSV	QCRSV
RCHLCCH	RCHLCCH	RCHLCCH
ROV2PTOV	GEN2LLN0 PH1PTRC ROV2PTOV	PH1PTRC ROV2PTOV
SAPFRC	SAPFRC	SAPFRC
SAPTUF	SAPTUF	SAPTUF
SAPTOF	SAPTOF	SAPTOF
SCHLCCH	SCHLCCH	SCHLCCH
SDEPSDE	SDEPSDE	SDEPSDE SDEPTOC SDEPTOV SDEPTRC
Table continues on next page		

Function block name	Edition 1 logical nodes	Edition 2 and Edition 2.1 logical nodes
SESRSYN	RSY1LLN0 AUT1RSYN MAN1RSYN SYNRSYN	AUT1RSYN MAN1RSYN SYNRSYN
SLGAPC	SLGGIO	SLGAPC
SMBRREC	SMBRREC	SMBRREC
SMPPTRC	SMPPTRC	SMPPTRC
SP16GAPC	SP16GGIO	SP16GAPC
SPC8GAPC	SPC8GGIO	SPC8GAPC
SPGAPC	SPGGIO	SPGAPC
SSCBR	SSCBR	SSCBR
SSIMG	SSIMG	SSIMG
SSIML	SSIML	SSIML
STBPTOC	STBPTOC	STBPTOC
SXCBR	SXCBR	SXCBR
SXSWI	SXSWI	SXSWI
TEIGAPC	TEIGGIO	TEIGAPC
TEILGAPC	TEILGGIO	TEILGAPC
TMAGAPC	TMAGGIO	TMAGAPC
UV2PTUV	GEN2LLN0 PH1PTRC UV2PTUV	PH1PTRC UV2PTUV
VDCPTOV	VDCPTOV	VDCPTOV
VMMXU	VMMXU	VMMXU
VMSQI	VMSQI	VMSQI
VNMMXU	VNMMXU	VNMMXU
VSGAPC	VSGGIO	VSGAPC
VRPVOC	VRLLN0 PH1PTRC PH1PTUV VRPVOC	PH1PTRC PH1PTUV VRPVOC
WRNCALH	WRNCALH	WRNCALH
ZCLCPSCH	ZCLCPLAL	ZCLCPSCH
ZCPSCH	ZCPSCH	ZCPSCH
ZCRWPSCH	ZCRWPSCH	ZCRWPSCH
ZCVPSOF	ZCVPSOF	ZCVPSOF
ZMFPDIS	ZMFLLN0 PSFPDIS ZMFPDIS ZMFPTRC ZMMMIXU	PSFPDIS PSFPDIS ZMFPDIS ZMFPTRC ZMMMIXU
ZMRPSB	ZMRPSB	ZMRPSB

Section 2 Application

2.1 General IED application

RED650 is used for the protection, control and monitoring of overhead lines and cables in solidly or impedance earthed networks. It is suitable for the protection of heavily loaded lines and multi-terminal lines where the requirement for fast one- and/or three-phase tripping is wanted. Back-up protection and apparatus control for 1 circuit breaker is included.

The phase segregated current differential protection provides an excellent sensitivity for high resistive faults and gives a secure phase selection. The availability of six stabilized current inputs per phase allows use on multi-breaker arrangements in two or three terminal applications. The communication between the IEDs involved in the differential scheme is based on the IEEE C37.94 standard and can be made redundant for improved reliability. Charging current compensation allows high sensitivity, even on long overhead lines and cables.

The full scheme distance protection provides protection of power lines with high sensitivity and low requirements on remote end communication. The 6 zones have fully independent measuring and setting ranges which gives high flexibility for all types of lines. Load encroachment and adaptive reach compensation are included.

The multi-shot autoreclose includes priority features for double-breaker arrangements. It co-operates with the synchrocheck function with high-speed or delayed reclosing.

Breaker failure, high set instantaneous phase and earth overcurrent, four step directional or non-directional delayed phase and earth overcurrent and two step undervoltage protection are included and configured as back-up protection.

The impedance protection and the directional overcurrent protection can communicate with a remote end in any teleprotection communication scheme. The advanced logic capability, where the user logic is prepared with a graphical tool, allows special applications. Communication for teleprotection schemes can be realized over the differential protection communication link.

The IED can be used in applications with the IEC 61850-9-2LE process bus with up to eight Merging Units (MU). Each MU has eight analogue channels, four current and four voltages. Conventional input transformer module and Merging Unit channels can be mixed freely in your application.

The power swing detection function is used to detect power swings and initiate block of all distance protection zones. The occurrence of earth-fault currents during a power swing inhibits the function to allow fault clearance. A complementary power swing logic provides the possibility for selective tripping of faults on power lines during system oscillations (power swings or pole slips) when the distance protection function should normally be blocked.

Disturbance recording and fault locator are available to allow independent post-fault analysis after primary disturbances.

One pre-configured package has been defined for the following application:

- Single breaker, 2/3 line ends, 1/3 phase tripping (A11)

The package is configured and ready for direct use. Analog and control circuits have been pre-defined and other signals need to be applied as required for each application. The pre-configured IED can be changed and adapted to suit specific applications with the application configuration tool.

IED supports COMTRADE1999 and COMTRADE2013 formats which can be selected in Parameter Setting Tool (PST) of PCM600 or via LHMI.

Forcing of binary inputs and outputs is a convenient way to test wiring in substations as well as testing configuration logic in the IEDs. Basically it means that all binary inputs and outputs on the IED I/O modules (BOM, BIM and IOM) can be forced to arbitrary values.

Central Account Management is an authentication infrastructure that offers a secure solution for enforcing access control to IEDs and other systems within a substation. This incorporates management of user accounts, roles and certificates and the distribution of such, a procedure completely transparent to the user.

The Flexible Product Naming allows the customer to use an IED-vendor independent IEC 61850 model of the IED. This customer model will be used as the IEC 61850 data model, but all other aspects of the IED will remain unchanged (e.g., names on the local HMI and names in the tools). This offers significant flexibility to adapt the IED to the customers' system and standard solution.



The following tables list all the functions available in the IED. Those functions that are not exposed to the user or do not need to be configured are not described in this manual.

Table 2: Example of quantities

2	= number of basic instances
0-3	= option quantities
3-A03	= optional function included in packages A03 (refer to ordering details)
C30	=1/2 CB application. For the pre-configured variants

2.2 Main protection functions

IEC 61850 or function name	ANSI	Function description	Line Differential
			RED650 (A11)
Differential protection			
LT3CPDIF	87LT	Line differential protection for 3 CT sets, 2-3 line ends, in-zone transformer	1
LDLPSCH	87L	Line differential protection logic	1
LDRGFC	11REL	Additional security logic for differential protection	1
Impedance protection			
ZMFPDIS	21	Distance protection, quad and mho characteristic	1
ZMRPSB	68	Power swing detection, blocking	1
PSLPSCH		Power swing logic	1
OOSPPAM	78	Out-of-step protection	1
ZCVPSOF		Automatic switch onto fault logic, voltage and current based	1

2.3 Back-up protection functions

IEC 61850 or function name	ANSI	Function description	Line Differential
			RED650 (A11)
Current protection			
PHPIOC	50	Instantaneous phase overcurrent protection	1
OC4PTOC	51 ₆₇ ¹⁾	Directional phase overcurrent protection, four steps	1
EFPIOC	50N	Instantaneous residual overcurrent protection	1
EF4PTOC	51N _{67N} ²⁾	Directional residual overcurrent protection, four steps	1
LCPTTR	26	Thermal overload protection, one time constant, Celsius	1
LFPTTR	26	Thermal overload protection, one time constant, Fahrenheit	1
Table continues on next page			

IEC 61850 or function name	ANSI	Function description	Line Differential
			RED650 (A11)
CCRBRF	50BF	Breaker failure protection	1
STBPTOC	50STB	Stub protection	1
CCPDSC	52PD	Pole discordance protection	1
BRCPTOC	46	Broken conductor check	1
BRPTOC	50	Overcurrent protection with binary release	1
Voltage protection			
UV2PTUV	27	Two step undervoltage protection	1
OV2PTOV	59	Two step overvoltage protection	1
ROV2PTOV	59N	Residual overvoltage protection, two steps	1
VDCPTDV	87V	Voltage differential protection	1
LOVPTUV	27	Loss of voltage check	1
Frequency protection			
SAPTUF	81	Underfrequency protection	1
SAPTOF	81	Overfrequency protection	1
SAPFRC	81	Rate-of-change of frequency protection	1

- 1) 67 requires voltage
2) 67N requires voltage

2.4 Control and monitoring functions

IEC 61850 or function name	ANSI	Function description	Line Differential
			RED650 (A11)
Control			
SESRSYN	25	Synchrocheck, energizing check and synchronizing	1
SMBRREC	79	Autorecloser	1
APC5		Control functionality for a single bay, max 5 objects (1CB), including interlocking (see Table 3)	1
QCBAY		Bay control	1
LOCREM		Handling of local/remote switch positions	1
LOCREMCTRL		LHMI control of the permitted source to operate (PSTO)	1
SXCBBR		Circuit breaker	3
SLGAPC		Logic rotating switch for function selection and LHMI presentation	15
VSGAPC		Selector mini switch	30
DPGAPC		Generic communication function for Double Point indication	16
SPC8GAPC		Single point generic control function, 8 signals	5
AUTOBITS		Automation bits, command function for DNP3.0	3
SINGLECMD		Single command, 16 inputs	8
I103CMD		Function commands for IEC 60870-5-103	1
I103GENCMD		Function commands for IEC 60870-5-103, generic	50
I103POSCMD		IED commands with position and select for IEC 60870-5-103	50
I103POSCMDV		IED direct commands with position for IEC 60870-5-103	50
I103IEDCMD		IED commands for IEC 60870-5-103	1
I103USRCMD		Function commands user defined for IEC 60870-5-103	4
Secondary system supervision			
Table continues on next page			

IEC 61850 or function name	ANSI	Function description	Line Differential RED650 (A11)
CCSSPVC	87	Current circuit supervision	1
FUFSPVC		Fuse failure supervision	1
DELVSPVC	7V_78V	Voltage delta supervision	4
DELISPCVC	7I	Current delta supervision	4
DELSPCVC	78	Real delta supervision, real	4
Logic			
SMPPTRC	94	Tripping logic	6
SMAGAPC		General start matrix block	6
STARTCOMB		Start combinator	32
TAGAPC		Trip matrix logic	12
ALMCALH		Logic for group alarm	5
WRNCALH		Logic for group warning	5
INDCALH		Logic for group indication	5
AND, GATE, INV, LLD, OR, PULSETIMER, RSMEMORY, SRMEMORY, TIMERSET, XOR		Basic configurable logic blocks (see Table 4)	40-420
FXDSIGN		Fixed signal function block	1
B16I		Boolean to integer conversion, 16 bit	18
BTIGAPC		Boolean to integer conversion with logical node representation, 16 bit	16
IB16		Integer to Boolean 16 conversion	24
ITBGAPC		Integer to boolean conversion with logical node representation, 16 bit	16
TEIGAPC		Elapsed time integrator with limit transgression and overflow supervision	12
INTCOMP		Comparator for integer inputs	30
REALCOMP		Comparator for real inputs	30
HOLDMINMAX		Hold minimum and maximum of input	20
INT_REAL		Converter integer to real	20
CONST_INT		Definable constant for logic functions	10
INTSEL		Analog input selector for integer values	5
LIMITER		Definable limiter	20
ABS		Absolute value	20
POL_REC		Polar to rectangular converter	20
RAD_DEG		Radians to degree angle converter	20
CONST_REAL		Definable constant for logic functions	10
REALSEL		Analog input selector for real values	5
STOREINT		Store value for integer inputs	10
STOREREAL		Store value for real inputs	10
DEG_RAD		Degree to radians angle converter	20
Monitoring			
CVMMXN		Power system measurement	6
CMMXU		Current measurement	10
VMMXU		Voltage measurement phase-phase	6
CMSQI		Current sequence measurement	6
VMSQI		Voltage sequence measurement	6
VNMMXU		Voltage measurement phase-earth	6
Table continues on next page			

IEC 61850 or function name	ANSI	Function description	Line Differential RED650 (A11)
AISVBAS		General service value presentation of analog inputs	1
SSIMG	63	Insulation supervision for gas medium	21
SSIML	71	Insulation supervision for liquid medium	3
SSCBR		Circuit breaker condition monitoring	3
EVENT		Event function	20
DRPRDRE, A1RADR- A3RADR, B1RBDR- B2RBDR, C1RADR		Disturbance report	1
SPGAPC		Generic communication function for single point indication, 1 input	128
SP16GAPC		Generic communication function for single point indication, 16 inputs	16
MVGAPC		Generic communication function for measured values	24
BINSTATREP		Logical signal status report	3
RANGE_XP		Measured value expander block	66
I103MEAS		Measurands for IEC 60870-5-103	1
I103MEASUSR		Measurands user defined signals for IEC 60870-5-103	3
I103AR		Function status auto-recloser for IEC 60870-5-103	1
I103EF		Function status earth-fault for IEC 60870-5-103	1
I103FLTPROT		Function status fault protection for IEC 60870-5-103	1
I103IED		IED status for IEC 60870-5-103	1
I103SUPERV		Supervision status for IEC 60870-5-103	1
I103USRDEF		Status for user defined signals for IEC 60870-5-103	20
L4UFCNT		Event counter with limit supervision	30
TEILGAPC		Running hour meter	6
FLTMMXU		Fault current and voltage monitoring	1
LMBRFLO		Fault locator	1
Metering			
PCFCNT		Pulse-counter logic	16
ETPMATR		Function for energy calculation and demand handling	6

Table 3: Number of function instances in APC5

Function name	Function description	Total number of instances
SCILO	Interlocking	5
BB_ES		2
ABC_LINE		1
AB_TRAFO		1
SCSWI	Switch controller	5
SXSWI	Circuit switch	4
QCRSV	Reservation function block for apparatus control	2
RESIN1		1
RESIN2		59
Table continues on next page		

Function name	Function description	Total number of instances
POS_EVAL	Evaluation of position indication	5
XLNPROXY	Proxy for signals from switching device via GOOSE	7
GOOSEXLNRCV	GOOSE function block to receive a switching device	7

Table 4: Total number of instances for basic configurable logic blocks

Basic configurable logic block	Total number of instances
AND	280
GATE	40
INV	420
LLD	40
OR	307
PULSETIMER	40
RSMEMORY	40
SRMEMORY	40
TIMERSET	60
XOR	40

2.5 Communication

IEC 61850 or function name	ANSI	Function description	Line Differential
			RED650 (A11)
Station communication			
LONSPA, SPA		SPA communication protocol	1
ADE		LON communication protocol	1
HORZCOMM		Network variables via LON	1
PROTOCOL		Operation selection between SPA and IEC 60870-5-103 for SLM	1
RS485PROT		Operation selection for RS485	1
RS485GEN		RS485	1
DNPGEN		DNP3.0 communication general protocol	1
CHSERRS485		DNP3.0 for EIA-485 communication protocol	1
CH1TCP, CH2TCP, CH3TCP, CH4TCP		DNP3.0 for TCP/IP communication protocol	1
CHSEROPT		DNP3.0 for TCP/IP and EIA-485 communication protocol	1
MSTSER		DNP3.0 serial master	1
MST1TCP, MST2TCP, MST3TCP, MST4TCP		DNP3.0 for TCP/IP communication protocol	1
DNPFREC		DNP3.0 fault records for TCP/IP and EIA-485 communication protocol	1
IEC 61850-8-1		IEC 61850	1
IEC 61850SIM		IEC 61850 simulation mode	1
GOOSEINTLKRCV		Horizontal communication via GOOSE for interlocking	59
GOOSEBINRCV		GOOSE binary receive	16
GOOSEDPRCV		GOOSE function block to receive a double point value	64
GOOSEINTRCV		GOOSE function block to receive an integer value	32
Table continues on next page			

IEC 61850 or function name	ANSI	Function description	Line Differential
			RED650 (A11)
GOOSEMVRVCV		GOOSE function block to receive a measurand value	60
GOOSESPRCV		GOOSE function block to receive a single point value	64
ALGOS		Supervision of GOOSE subscription	100
MULTICMDRCV/ MULTICMDSND		Multiple command receive and send	60/10
OPTICAL103		IEC 60870-5-103 Optical serial communication	1
RS485103		IEC 60870-5-103 serial communication for RS485	1
AGSAL		Generic security application component	1
LD0LLN0		IEC 61850 LD0 LLN0	1
SYSLLN0		IEC 61850 SYS LLN0	1
LPHD		Physical device information	1
PCMACCS		IED configuration protocol	1
SECALARM		Component for mapping security events on protocols such as DNP3 and IEC103	1
FSTACCSNA		Field service tool access via SPA protocol over Ethernet communication	1
FSTACCS		Field service tool access	1
GOOSEACRCV		GOOSE function block to receive a protection activation information	16
		IEC 61850-9-2 Process bus communication, 4 merging units	1-P31
ACTIVLOG		Activity logging	1
ALTRK		Service tracking	1
PRP		IEC 62439-3 Parallel redundancy protocol	1-P23
HSR		IEC 62439-3 High-availability seamless redundancy	1-P24
RSTP		IEC 62439-3 Rapid spanning tree protocol	1-P25
SNMPSEVERCONF		SNMPServerConfiguration	1
SNMPUSERCONF		SNMPUserConfiguration	2
AP_1-AP_4		AccessPoint_ABS1-AccessPoint_ABS4	1
AP_FRONT		Access point front	1
PTP		Precision time protocol	1
ROUTE_1-ROUTE_6		Route_ABS1-Route_ABS6	1
FRONTSTATUS		Access point diagnostic for front Ethernet port	1
SCHLCCH		Access point diagnostic for non-redundant Ethernet port	4
RCHLCCH		Access point diagnostic for redundant Ethernet ports	2
DHCP		DHCP configuration for front access point	1
QUALEXP		IEC 61850 quality expander	32
Remote communication			
BinSignRec1_1 BinSignRec1_2 BinSignReceive2 BinSignTrans1_1 BinSignTrans1_2 BinSignTransm2		Binary signal transfer receive/transmit	3/3/6
LDCMTRN		Transmission of analog data from LDCM	1
LDCMRecBinStat1 LDCMRecBinStat3		Receive binary status from remote LDCM	6/3
LDCMRecBinStat2		Receive binary status from LDCM	3
Scheme communication			
ZCPSCH	85	Scheme communication logic for distance or overcurrent protection	1
ZCRWPSCH	85	Current reversal and weak-end infeed logic for distance protection	1
Table continues on next page			

IEC 61850 or function name	ANSI	Function description	Line Differential
			RED650 (A11)
ZCLCPSCH		Local acceleration logic	1
ECPSCH	85	Scheme communication logic for residual overcurrent protection	1
ECRWPSCH	85	Current reversal and weak-end infeed logic for residual overcurrent protection	1

2.6 Basic IED functions

Table 5: Basic IED functions

IEC 61850 or function name	Description
INTERRSIG SELSUPEVLST	Self supervision with internal event list
TIMESYNCHGEN	Time synchronization module
BININPUT, SYNCHCAN, SYNCHGPS, SYNCHCMPPS, SYNCHLON, SYNCHPPH, SYNCHPPS, SNTP, TIMEZONE	Time synchronization
DSTBEGIN	GPS time synchronization module
DSTENABLE	Enables or disables the use of daylight saving time
DSTEND	GPS time synchronization module
IRIG-B	Time synchronization
SETGRPS	Number of setting groups
ACTVGRP	Active parameter setting group
TESTMODE	Test mode functionality
CHNGLCK	Change lock function
TERMINALID	IED identifiers
PRODINF	Product information
SYSTEMTIME	System time
LONGEN	LON communication
RUNTIME	IED Runtime component
SMBI	Signal matrix for binary inputs
SMBO	Signal matrix for binary outputs
SMAI1 - SMAI12	Signal matrix for analog inputs
3PHSUM	Summation block 3 phase
ATHSTAT	Authority status
ATHCHCK	Authority check
AUTHMAN	Authority management
FTPACCS	FTP access with password
SPACOMMMAP	SPA communication mapping
SPATD	Date and time via SPA protocol
BCSCONF	Basic communication system
GBASVAL	Global base values for settings
PRIMVAL	Primary system values
SAFEFILECOPY	Safe file copy function
Table continues on next page	

IEC 61850 or function name	Description
ALTMS	Time master supervision
ALTIM	Time management
CAMCONFIG	Central account management configuration
CAMSTATUS	Central account management status
TOOLINF	Tools information
COMSTATUS	Protocol diagnostic

Table 6: Local HMI functions

IEC 61850 or function name	Description
LHMICTRL	Local HMI signals
LANGUAGE	Local human machine language
SCREEN	Local HMI Local human machine screen behavior
FNKEYTY1–FNKEYTY5 FNKEYMD1– FNKEYMD5	Parameter setting function for HMI in PCM600
LEDGEN	General LED indication part for LHMI
OPENCLOSE_LED	LHMI LEDs for open and close keys
GRP1_LED1– GRP1_LED15 GRP2_LED1– GRP2_LED15 GRP3_LED1– GRP3_LED15	Basic part for CP HW LED indication module

Section 3 Configuration

3.1 Description of configuration RED650

3.1.1 Introduction

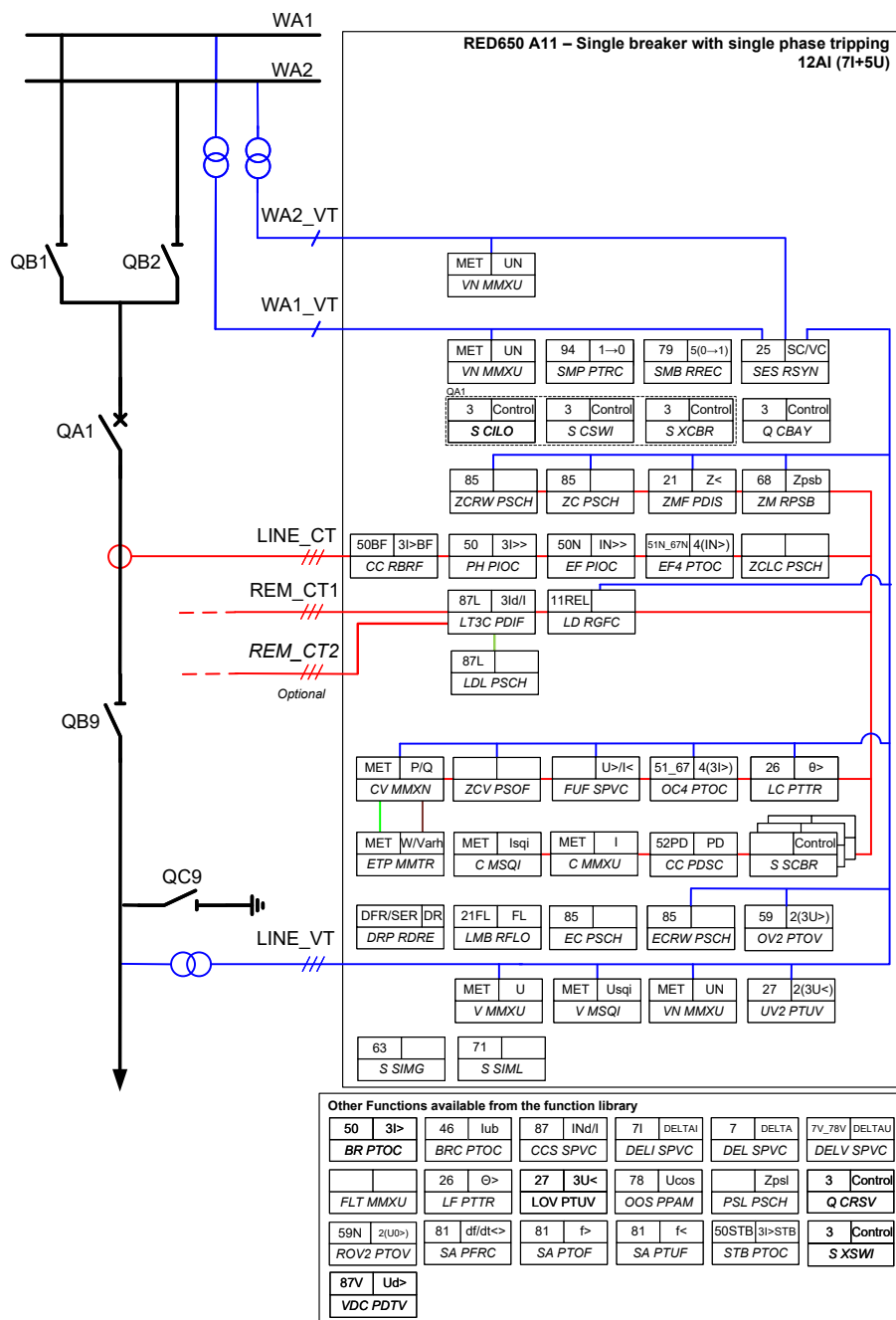
The basic delivery includes one binary input module and one binary output module, which is sufficient for the default configured I/O to trip and close circuit breaker. All IEDs can be reconfigured with the help of the application configuration tool in PCM600. The IED can be adapted to special applications and special logic can be developed, such as logic for automatic opening of disconnectors and closing of ring bays, automatic load transfer from one busbar to the other, and so on.

The basic IED configuration is provided with the signal matrix, single line diagram and the application configuration prepared for the functions included in the product by default. All parameters should be verified by the customer, since these are specific to the system, object or application. Optional functions and optional I/O ordered will not be configured at delivery. It should be noted that the standard only includes one binary input and one binary output module and only the key functions such as tripping are connected to the outputs in the signal matrix tool. The required total I/O must be calculated and specified at ordering.

The configurations are as far as found necessary provided with application comments to explain why the signals have been connected in the special way. On request, ABB is available to support the re-configuration work, either directly or to do the design checking.

3.1.1.1 Description of A11

2 / 3 terminal line differential protection and six zone distance protection with quadrilateral and mho characteristic, for single and three-pole tripping.



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Figure 2: Block diagram for configuration A11

Section 4 Analog inputs

4.1 Introduction

Analog input channels must be configured and set properly in order to get correct measurement results and correct protection operations. For power measuring, all directional and differential functions, the directions of the input currents must be defined in order to reflect the way the current transformers are installed/connected in the field (primary and secondary connections). Measuring and protection algorithms in the IED use primary system quantities. Setting values are in primary quantities as well and it is important to set the data about the connected current and voltage transformers properly.

An AISVBAS reference *PhaseAngleRef* can be defined to facilitate service values reading. This analog channel's phase angle will always be fixed to zero degrees and remaining analog channel's phase angle information will be shown in relation to this analog input. During testing and commissioning of the IED, the reference channel can be changed to facilitate testing and service values reading.



The IED has the ability to receive analog values from primary equipment, that are sampled by Merging units (MU) connected to a process bus, via the IEC 61850-9-2 LE protocol.



The availability of VT inputs depends on the ordered transformer input module (TRM) type.

4.2 Setting guidelines



The available setting parameters related to analog inputs are depending on the actual hardware (TRM) and the logic configuration made in PCM600.



If a second TRM is used, at least one TRM channel must be configured to get the service values. However, the MU physical channel must be configured to get service values from that channel.

4.2.1 Setting of the phase reference channel

All phase angles are calculated in relation to a defined reference. An appropriate analog input channel is selected and used as phase reference. The parameter *PhaseAngleRef* defines the analog channel that is used as phase angle reference.

4.2.1.1 Example

Usually the L1 phase-to-earth voltage connected to the first VT channel number of the transformer input module (TRM) is selected as the phase reference. The first VT channel number depends on the type of transformer input module.

For a TRM with 6 current and 6 voltage inputs the first VT channel is 7. The setting *PhaseAngleRef=7* shall be used if the phase reference voltage is connected to that channel.

4.2.2 Setting of current channels

The direction of a current to the IED is depending on the connection of the CT. Unless indicated otherwise, the main CTs are supposed to be star connected and can be connected with the earthing point to the object or from the object. This information must be set in the IED. The convention of the directionality is defined as follows: A positive value of current, power, and so on means that the quantity has the direction into the object and a negative value means direction out from the object. For directional functions the direction into the object is defined as Forward and the direction out from the object is defined as Reverse. See Figure 3.

A positive value of current, power, and so on (forward) means that the quantity flows towards the object. A negative value of current, power, and so on (reverse) means that the quantity flows away from the object. See Figure 3.

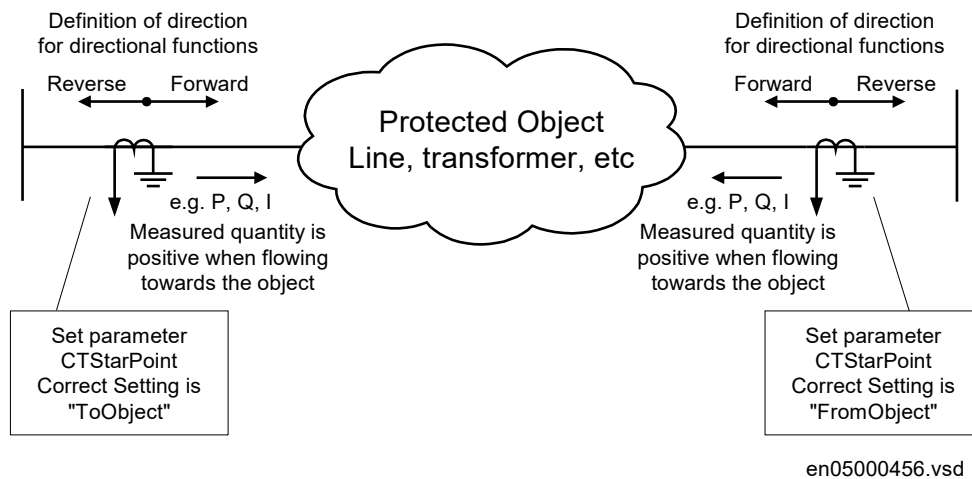


Figure 3: Internal convention of the directionality in the IED

With correct setting of the primary CT direction, *CTStarPoint* set to *FromObject* or *ToObject*, a positive quantities always flowing towards the protected object and a direction defined as Forward always is looking towards the protected object. The following examples show the principle.

4.2.2.1 Example 1

Two IEDs used for protection of two objects.

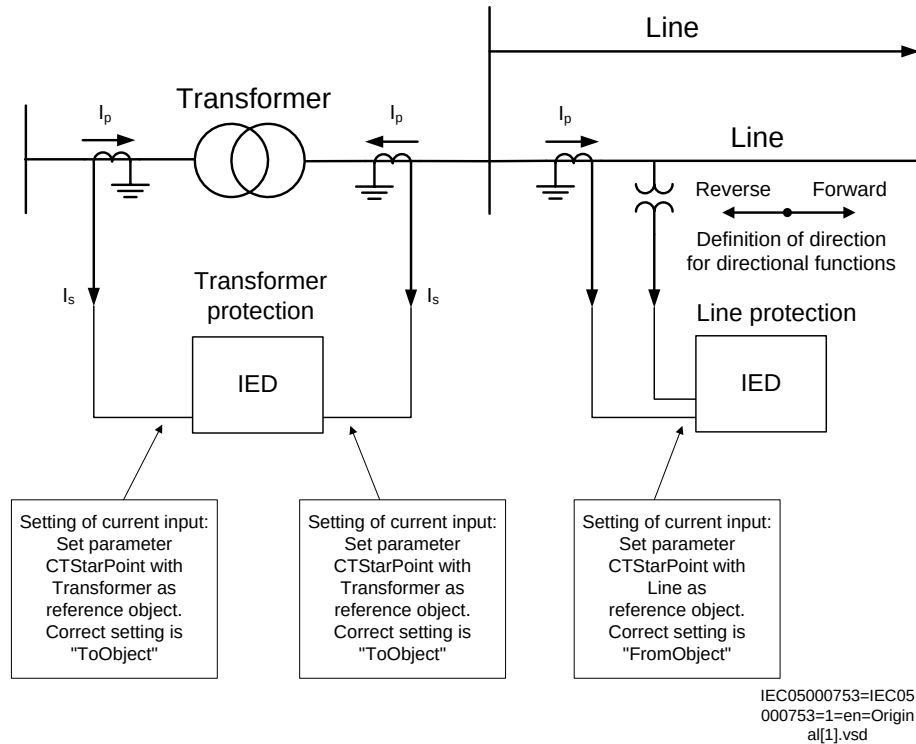


Figure 4: Example how to set CTStarPoint parameters in the IED

Figure 4 shows the normal case where the objects have their own CTs. The settings for CT direction shall be done according to the figure. To protect the line, direction of the directional functions of the line protection shall be set to *Forward*. This means that the protection is looking towards the line.

4.2.2.2 Example 2

Two IEDs used for protection of two objects and sharing a CT.

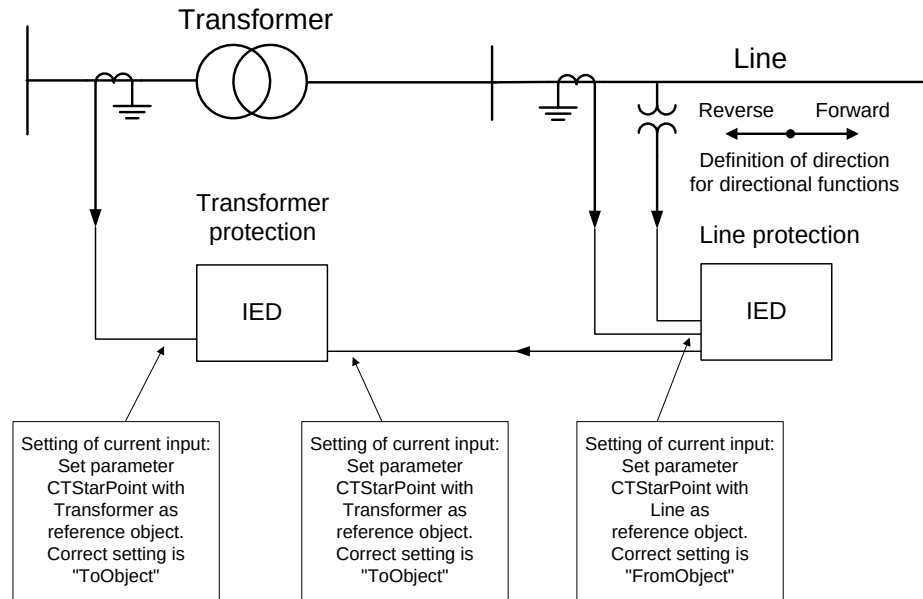


Figure 5: Example how to set CTStarPoint parameters in the IED

This example is similar to example 1, but here the transformer is feeding just one line and the line protection uses the same CT as the transformer protection does. The CT direction is set with different reference objects for the two IEDs though it is the same current from the same CT that is feeding the two IEDs. With these settings, the directional functions of the line protection shall be set to *Forward* to look towards the line.

4.2.2.3 Example 3

One IED used to protect two objects.

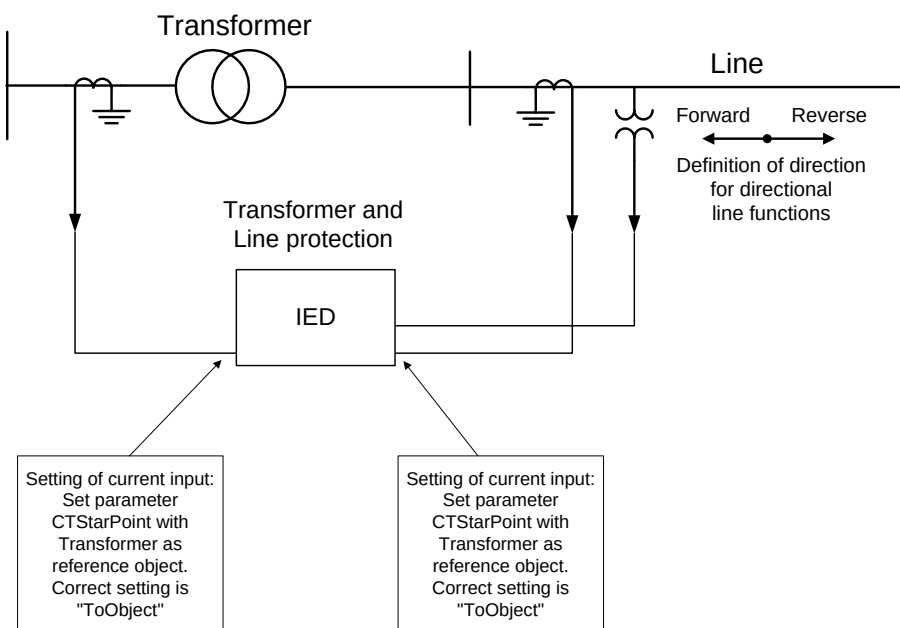


Figure 6: Example how to set CTStarPoint parameters in the IED

In this example, one IED includes both transformer and line protections and the line protection uses the same CT as the transformer protection does. For both current input channels, the CT direction is set with the transformer as reference object. This means that the direction *Forward* for the line protection is towards the transformer. To look towards the line, the direction of the directional functions of the line protection must be set to *Reverse*. The direction *Forward/Reverse* is related to the reference object that is the transformer in this case.

When a function is set to *Reverse* and shall protect an object in reverse direction, it shall be noted that some directional functions are not symmetrical regarding the reach in forward and reverse direction. It is in first hand the reach of the directional criteria that can differ. Normally it is not any limitation but it is advisable to have it in mind and check if it is acceptable for the application in question.

If the IED has sufficient number of analog current inputs, an alternative solution is shown in Figure 7. The same currents are fed to two separate groups of inputs and the line and transformer protection functions are configured to the different inputs. The CT direction for the current channels to the line protection is set with the line as reference object and the directional functions of the line protection shall be set to *Forward* to protect the line.

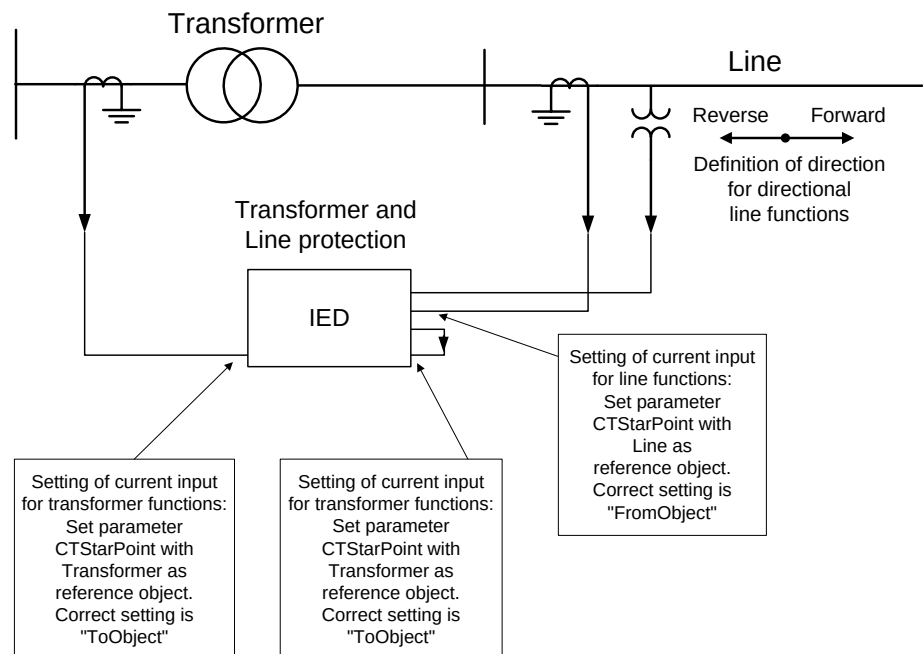
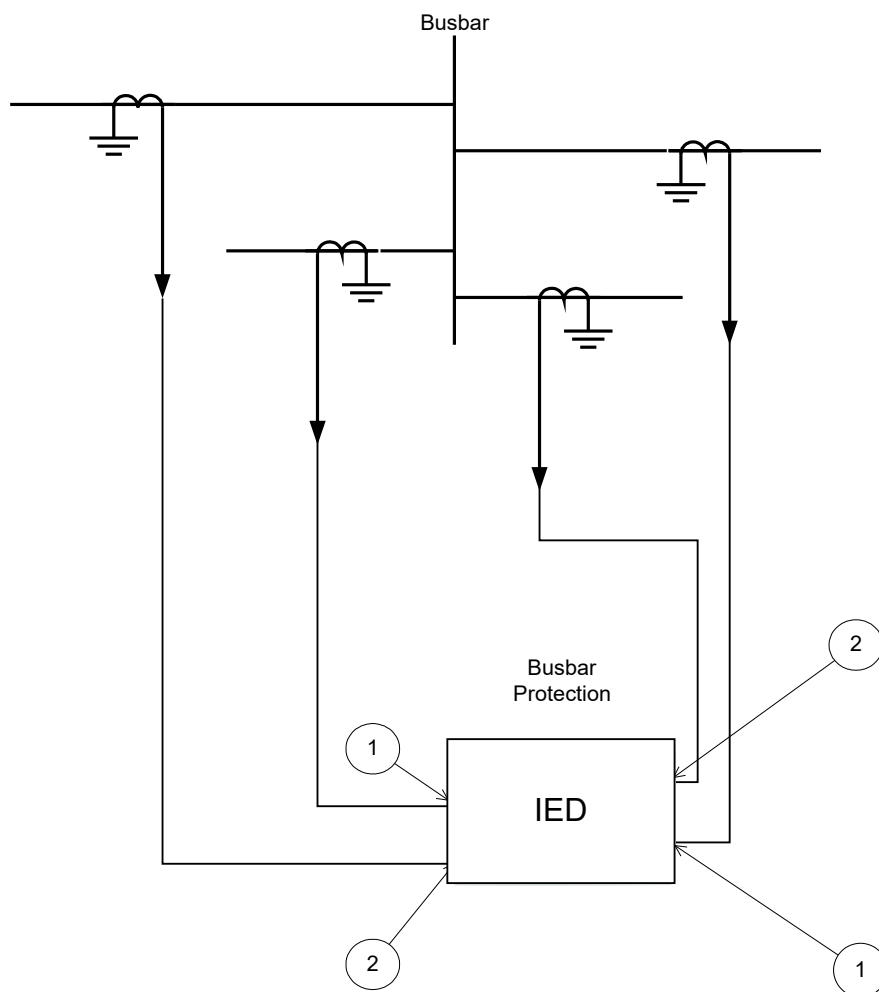


Figure 7: Example how to set CTStarPoint parameters in the IED



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Figure 8:

For busbar protection, it is possible to set the *CTStarPoint* parameters in two ways.

The first solution will be to use busbar as a reference object. In that case for all CT inputs marked with 1 in Figure 8, set *CTStarPoint* = *ToObject*, and for all CT inputs marked with 2 in Figure 8, set *CTStarPoint* = *FromObject*.

The second solution will be to use all connected bays as reference objects. In that case for all CT inputs marked with 1 in Figure 8, set *CTStarPoint* = *FromObject*, and for all CT inputs marked with 2 in Figure 8, set *CTStarPoint* = *ToObject*.

Regardless which one of the above two options is selected, busbar differential protection will behave correctly.

The main CT ratios must also be set. This is done by setting the two parameters *CTsec* and *CTprim* for each current channel. For a 1000/1 A CT, the following settings shall be used:

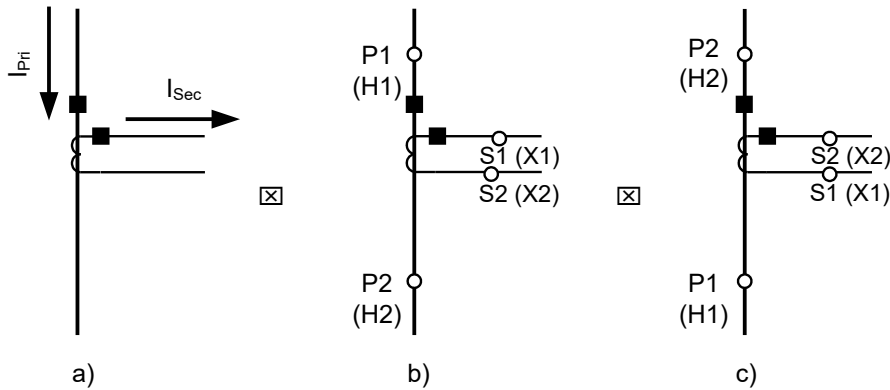
- *CTprim* = 1000 (value in A)
- *CTsec* = 1 (value in A).

4.2.2.4 Examples on how to connect, configure and set CT inputs for most commonly used CT connections

Figure 9 defines the marking of current transformer terminals commonly used around the world:



In the SMAI function block, you have to set if the SMAI block is measuring current or voltage. This is done with the parameter: *AnalogInputType*: Current/Voltage. The *ConnectionType*: phase-phase/phase-earth and *GlobalBaseSel*.



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Figure 9: Commonly used markings of CT terminals

Where:

- a) is symbol and terminal marking used in this document. Terminals marked with a square indicates the primary and secondary winding terminals with the same (that is, positive) polarity
- b) and c) are equivalent symbols and terminal marking used by IEC (ANSI) standard for CTs. Note that for these two cases the CT polarity marking is correct!

It shall be noted that depending on national standard and utility practices, the rated secondary current of a CT has typically one of the following values:

- 1A
- 5A

However, in some cases, the following rated secondary currents are used as well:

- 2A
- 10A

The IED fully supports all of these rated secondary values.

It is recommended to:



- use 1A rated CT input into the IED in order to connect CTs with 1A and 2A secondary rating
- use 5A rated CT input into the IED in order to connect CTs with 5A and 10A secondary rating

4.2.2.5 Example on how to connect a star connected three-phase CT set to the IED

Figure 10 gives an example about the wiring of a star connected two-phase CT set to the IED. It gives an overview of the actions which are needed to make this measurement available to the built-in protection and control functions within the IED as well.



For correct terminal designations, see the connection diagrams valid for the delivered IED.

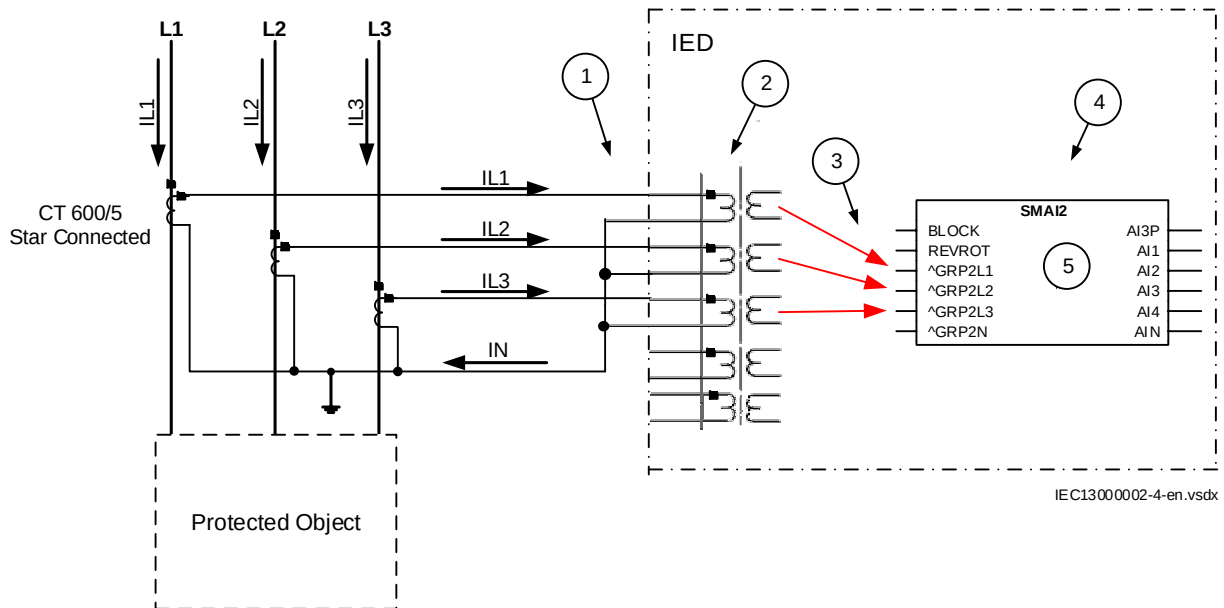


Figure 10: Star connected three-phase CT set with star point towards the protected object

Where:

- 1) The drawing shows how to connect three individual phase currents from a star connected three-phase CT set to the three CT inputs of the IED.
- 2) The current inputs are located in the TRM. It shall be noted that for all these current inputs the following setting values shall be entered for the example shown in Figure 10.

- $CT_{prim}=600A$
- $CT_{sec}=5A$
- $CT_{StarPoint}=ToObject$

Ratio of the first two parameters is only used inside the IED. The third parameter ($CT_{StarPoint}=ToObject$) as set in this example causes no change on the measured currents. In other words, currents are already measured towards the protected object.

Table continues on next page

- 3) These three connections are the links between the three current inputs and the three input channels of the preprocessing function block 4). Depending on the type of functions, which need this current information, more than one preprocessing block might be connected in parallel to the same three physical CT inputs.
- 4) The preprocessing block that has the task to digitally filter the connected analog inputs and calculate:
 - fundamental frequency phasors for all three input channels
 - harmonic content for all three input channels
 - positive, negative and zero sequence quantities by using the fundamental frequency phasors for the first three input channels (channel one taken as reference for sequence quantities)

These calculated values are then available for all built-in protection and control functions within the IED, which are connected to this preprocessing function block. For this application most of the preprocessing settings can be left to the default values.

If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in power plants), then the setting parameters DFTReference shall be set accordingly.

Section SMAI in this manual provides information on adaptive frequency tracking for the signal matrix for analogue inputs (SMAI).

- 5) AI3P in the SMAI function block is a grouped signal which contains all the data about the phases L1, L2, L3 and neutral quantity; in particular the data about fundamental frequency phasors, harmonic content and positive sequence, negative and zero sequence quantities are available. AI1, AI2, AI3, AI4 are the output signals from the SMAI function block which contain the fundamental frequency phasors and the harmonic content of the corresponding input channels of the preprocessing function block. AIN is the signal which contains the fundamental frequency phasors and the harmonic content of the neutral quantity. In this example, GRP2N is not connected so this data is calculated by the preprocessing function block on the basis of the inputs GRPL1, GRPL2 and GRPL3. If GRP2N is connected, the data reflects the measured value of GRP2N.

Another alternative is to have the star point of the three-phase CT set as shown in Figure 11:

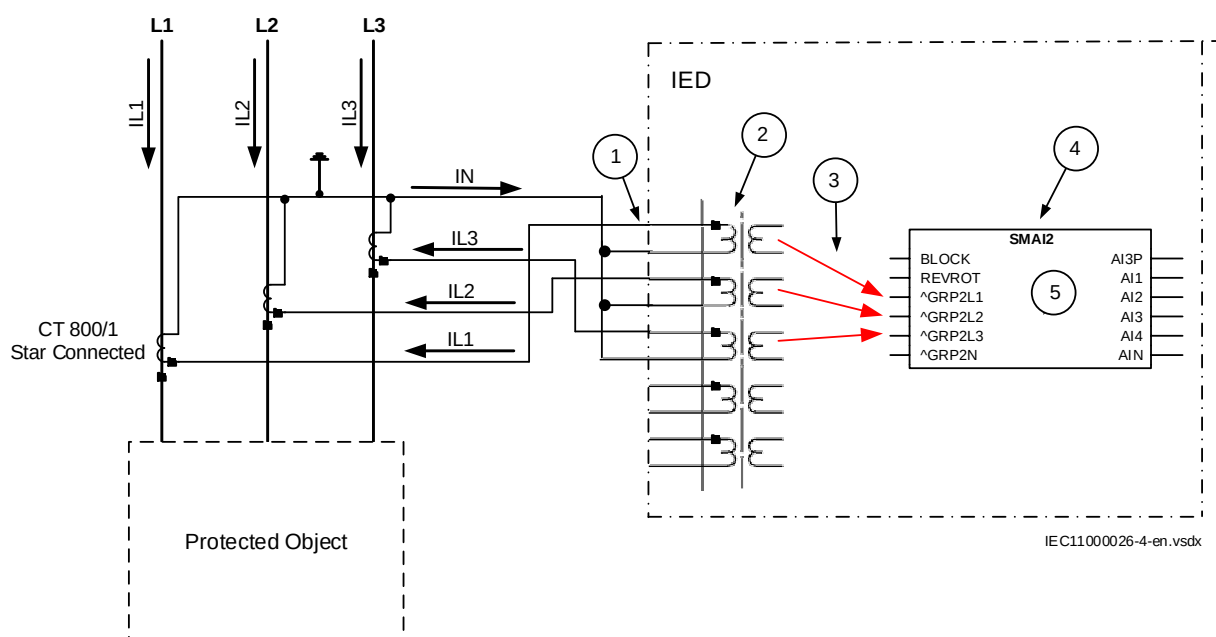


Figure 11: Star connected three-phase CT set with its star point away from the protected object

In the example, everything is done in a similar way as in the above described example (Figure 10). The only difference is the setting of the parameter *CTStarPoint* of the used current inputs on the TRM (item 2 in Figure 11 and 10):

- $CT_{prim}=600A$
- $CT_{sec}=5A$
- $CT_{StarPoint}=FromObject$

The ratio of the first two parameters is only used inside the IED. The third parameter as set in this example will negate the measured currents in order to ensure that the currents are measured towards the protected object within the IED.

A third alternative is to have the residual/neutral current from the three-phase CT set connected to the IED as shown in Figure 11.

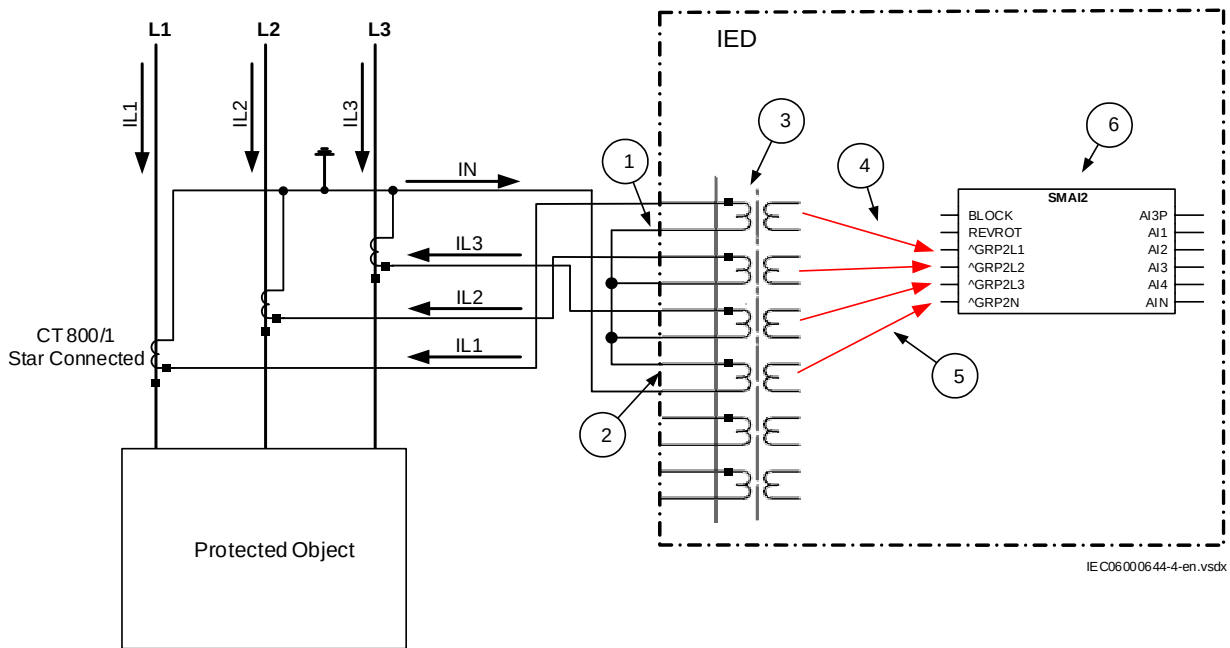


Figure 12: Star connected three-phase CT set with its star point away from the protected object and the residual/neutral current connected to the IED

Where:

- 1) Shows how to connect three individual phase currents from a star connected three-phase CT set to the three CT inputs of the IED.
- 2) Shows how to connect residual/neutral current from the three-phase CT set to the fourth input in the IED. It shall be noted that if this connection is not made, the IED will still calculate this current internally by vectorial summation of the three individual phase currents.
- 3) Is the TRM where these current inputs are located. It shall be noted that for all these current inputs the following setting values shall be entered.
 - $CT_{prim}=800A$
 - $CT_{sec}=1A$
 - $CT_{StarPoint}=FromObject$
 - $ConnectionType=Ph-N$

The ratio of the first two parameters is only used inside the IED. The third parameter as set in this example will have no influence on measured currents (that is, currents are already measured towards the protected object).

- 4) Are three connections made in the Signal Matrix tool (SMT) and Application configuration tool (ACT), which connects these three current inputs to the first three input channels on the preprocessing function block 6). Depending on the type of functions, which need this current information, more than one preprocessing block might be connected in parallel to these three CT inputs.

Table continues on next page

- 5) Is a connection made in the Signal Matrix tool (SMT) and Application configuration tool (ACT), which connects the residual/neutral current input to the fourth input channel of the preprocessing function block 6). Note that this connection in SMT shall not be done if the residual/neutral current is not connected to the IED.
- 6) Is a Preprocessing block that has the task to digitally filter the connected analog inputs and calculate:
- fundamental frequency phasors for all input channels
 - harmonic content for all input channels
 - positive, negative and zero sequence quantities by using the fundamental frequency phasors of the first three input channels (channel one taken as reference for sequence quantities)

These calculated values are then available for all built-in protection and control functions within the IED, which are connected to this preprocessing function block in the configuration tool. For this application, most of the preprocessing settings can be left to the default values.

If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in the generating stations), then the setting parameters DFTRreference shall be set accordingly.

4.2.2.6 Example how to connect delta connected three-phase CT set to the IED

Figure 13 gives an example how to connect a delta connected three-phase CT set to the IED. It gives an overview of the required actions by the user in order to make this measurement available to the built-in protection and control functions in the IED as well.



For correct terminal designations, see the connection diagrams valid for the delivered IED.

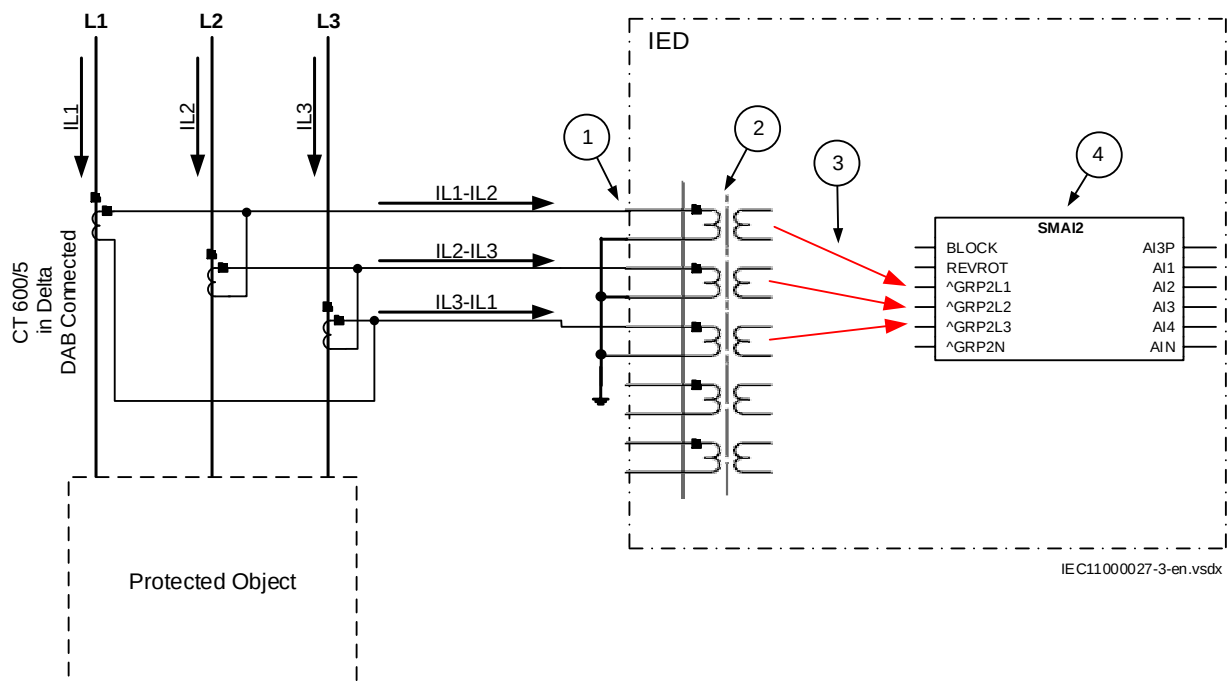


Figure 13: Delta DAB connected three-phase CT set

Where:

- 1) shows how to connect three individual phase currents from a delta connected three-phase CT set to three CT inputs of the IED.
- 2) is the TRM where these current inputs are located. It shall be noted that for all these current inputs the following setting values shall be entered.
 $CT_{prim}=600A$
 $CT_{sec}=5A$
 - $CTStarPoint=ToObject$
 - $ConnectionType=Ph-Ph$
- 3) are three connections made in Signal Matrix Tool (SMT), Application configuration tool (ACT), which connect these three current inputs to first three input channels of the preprocessing function block 4). Depending on the type of functions which need this current information, more then one preprocessing block might be connected in parallel to these three CT inputs.
- 4) is a Preprocessing block that has the task to digitally filter the connected analog inputs and calculate:
 - fundamental frequency phasors for all three input channels
 - harmonic content for all three input channels
 - positive, negative and zero sequence quantities by using the fundamental frequency phasors for the first three input channels (channel one taken as reference for sequence quantities)

These calculated values are then available for all built-in protection and control functions within the IED, which are connected to this preprocessing function block. For this application most of the preprocessing settings can be left to the default values.

If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in the generating stations) then the setting parameters $DFTReference$ shall be set accordingly.

Another alternative is to have the delta connected CT set as shown in Figure 14:

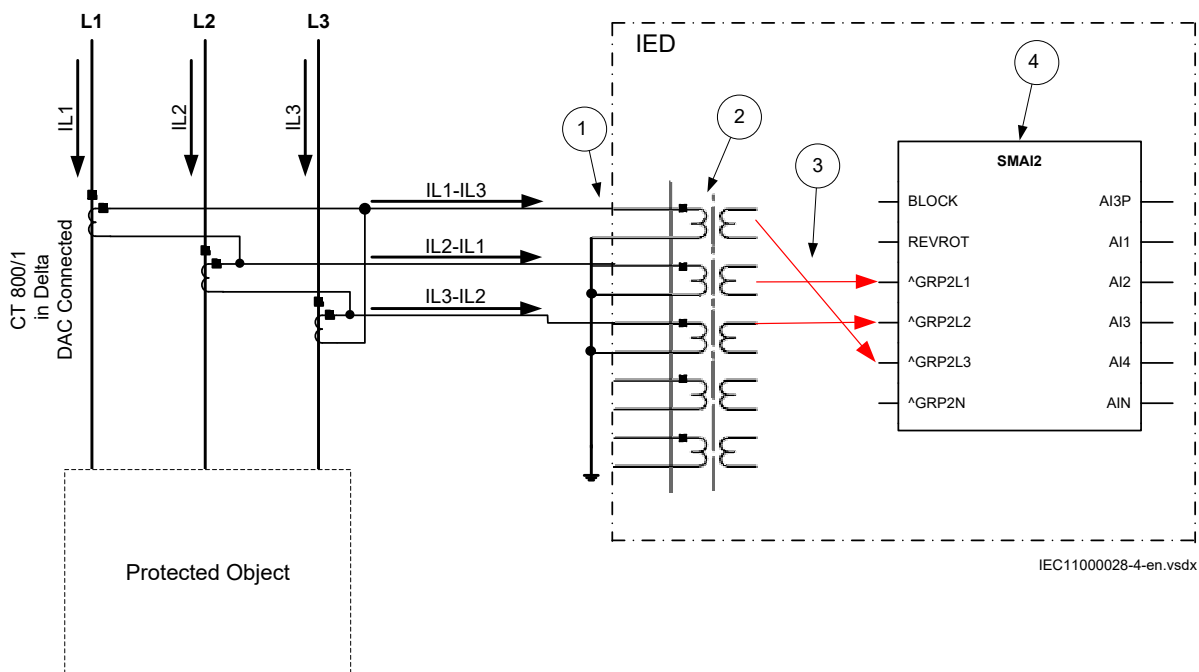


Figure 14: Delta DAC connected three-phase CT set

In this case, everything is done in a similar way as in the above described example, except that for all used current inputs on the TRM the following setting parameters shall be entered:

$$CT_{\text{prim}}=800\text{A}$$

$$CT_{\text{sec}}=1\text{A}$$

- $CT_{\text{StarPoint}}=ToObject$
- $ConnectionType=Ph-Ph$

It is important to notice the references in SMAI. As inputs at *Ph-Ph* are expected to be L1L2, L2L3 respectively L3L1 we need to tilt 180° by setting *ToObject*.

4.2.2.7 Example how to connect single-phase CT to the IED

Figure 15 gives an example how to connect the single-phase CT to the IED. It gives an overview of the required actions by the user in order to make this measurement available to the built-in protection and control functions within the IED as well.



For correct terminal designations, see the connection diagrams valid for the delivered IED.

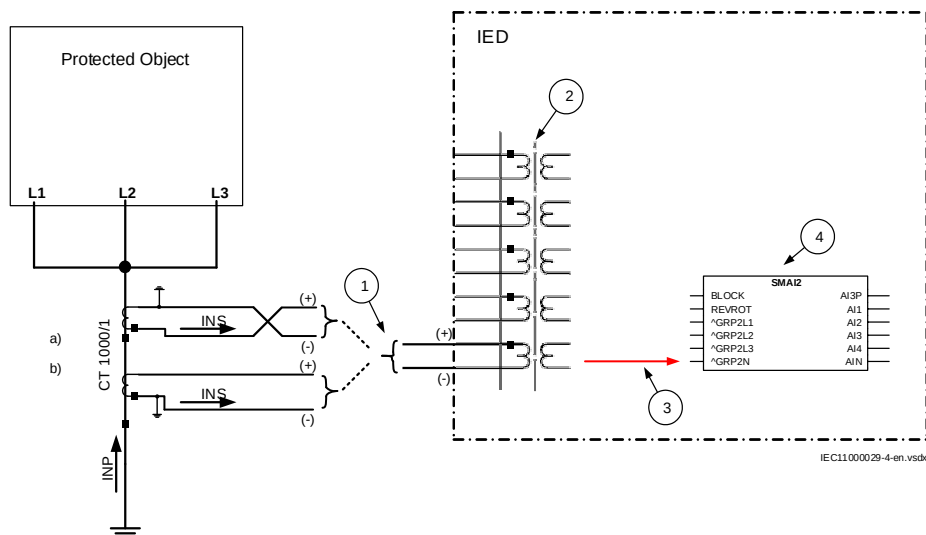


Figure 15: Connections for single-phase CT input

Where:

- 1) shows how to connect single-phase CT input in the IED.
- 2) is TRM where these current inputs are located. It shall be noted that for all these current inputs the following setting values shall be entered.
For connection (a) shown in Figure 15:
 $CT_{prim} = 1000\text{ A}$
 $CT_{sec} = 1\text{ A}$
 $CT_{StarPoint} = ToObject$

For connection (b) shown in Figure 15:
 $CT_{prim} = 1000\text{ A}$
 $CT_{sec} = 1\text{ A}$
 $CT_{StarPoint} = FromObject$
- 3) shows the connection made in SMT tool, which connect this CT input to the fourth input channel of the preprocessing function block 4).
- 4) is a Preprocessing block that has the task to digitally filter the connected analog inputs and calculate values. The calculated values are then available for all built-in protection and control functions within the IED, which are connected to this preprocessing function block.
If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in the power plants) then the setting parameters $DFTReference$ shall be set accordingly.

4.2.3 Relationships between setting parameter Base Current, CT rated primary current and minimum pickup of a protection IED

Note that for all line protection applications (e.g. distance protection or line differential protection) the parameter Base Current (i.e. I_{Base} setting in the IED) used by the relevant protection function, shall always be set equal to the largest rated CT primary current among all CTs involved in the protection scheme. The rated CT primary current value is set as parameter CT_{Prim} under the IED TRM settings.

For all other protection applications (e.g. generator, shunt reactor, shunt capacitor and transformer protection) it is typically desirable to set I_{Base} parameter equal to the rated current of the protected object. However this is only recommended to do if the rated current of the protected object is within the range of 40% to 120% of the selected CT rated primary current. If for any reason (e.g. high maximum short circuit current) the rated current of the protected object is less than 40% of the rated CT primary current, it is strongly recommended to set the parameter I_{Base} in the IED to be equal to the largest rated CT primary current among all CTs involved in the protection scheme and installed on the same voltage level. This will effectively make the protection scheme less sensitive; however, such measures are necessary in order to avoid possible problems with loss of the measurement accuracy in the IED.

Regardless of the applied relationship between the I_{Base} parameter and the rated CT primary current, the corresponding minimum pickup of the function on the CT secondary side must always be verified. It is strongly recommended that the minimum pickup of any instantaneous protection function (e.g. differential, restricted earth fault, distance, instantaneous overcurrent, etc.) shall under no circumstances be less than 4% of the used IED CT input rating (i.e. 1A or 5A). This corresponds to 40mA secondary for IED 1A rated inputs and to 200mA secondary for IED 5A rated inputs used by the function. This shall be individually verified for all current inputs involved in the protection scheme.

Note that exceptions from the above 4% rule may be acceptable for very special applications (e.g. when Multipurpose filter SMAHPAC is involved in the protection scheme).

4.2.4 Setting of voltage channels

As the IED uses primary system quantities, the main VT ratios must be known to the IED. This is done by setting the two parameters VT_{sec} and VT_{prim} for each voltage channel. The phase-to-phase value can be used even if each channel is connected to a phase-to-earth voltage from the VT.

4.2.4.1 Example

Consider a VT with the following data:

$$\frac{132kV}{\sqrt{3}} / \frac{110V}{\sqrt{3}}$$

(Equation 1)

The following setting should be used: $VT_{prim}=132$ (value in kV) $VT_{sec}=110$ (value in V)

4.2.4.2 Examples how to connect, configure and set VT inputs for most commonly used VT connections

Figure 16 defines the marking of voltage transformer terminals commonly used around the world.

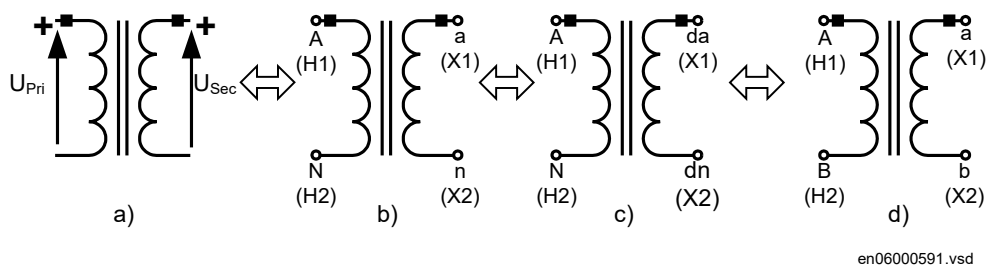


Figure 16: Commonly used markings of VT terminals

Where:

- a) is the symbol and terminal marking used in this document. Terminals marked with a square indicate the primary and secondary winding terminals with the same (positive) polarity
- b) is the equivalent symbol and terminal marking used by IEC (ANSI) standard for phase-to-earth connected VTs
- c) is the equivalent symbol and terminal marking used by IEC (ANSI) standard for open delta connected VTs
- d) is the equivalent symbol and terminal marking used by IEC (ANSI) standard for phase-to-phase connected VTs

It shall be noted that depending on national standard and utility practices the rated secondary voltage of a VT has typically one of the following values:

- 100 V
- 110 V
- 115 V
- 120 V
- 230 V

The IED fully supports all of these values and most of them will be shown in the following examples.

4.2.4.3 Examples on how to connect a three phase-to-earth connected VT to the IED

Figure 17 gives an example on how to connect a three phase-to-earth connected VT to the IED. It gives an overview of required actions by the user in order to make this measurement available to the built-in protection and control functions within the IED.



For correct terminal designations, see the connection diagrams valid for the delivered IED.

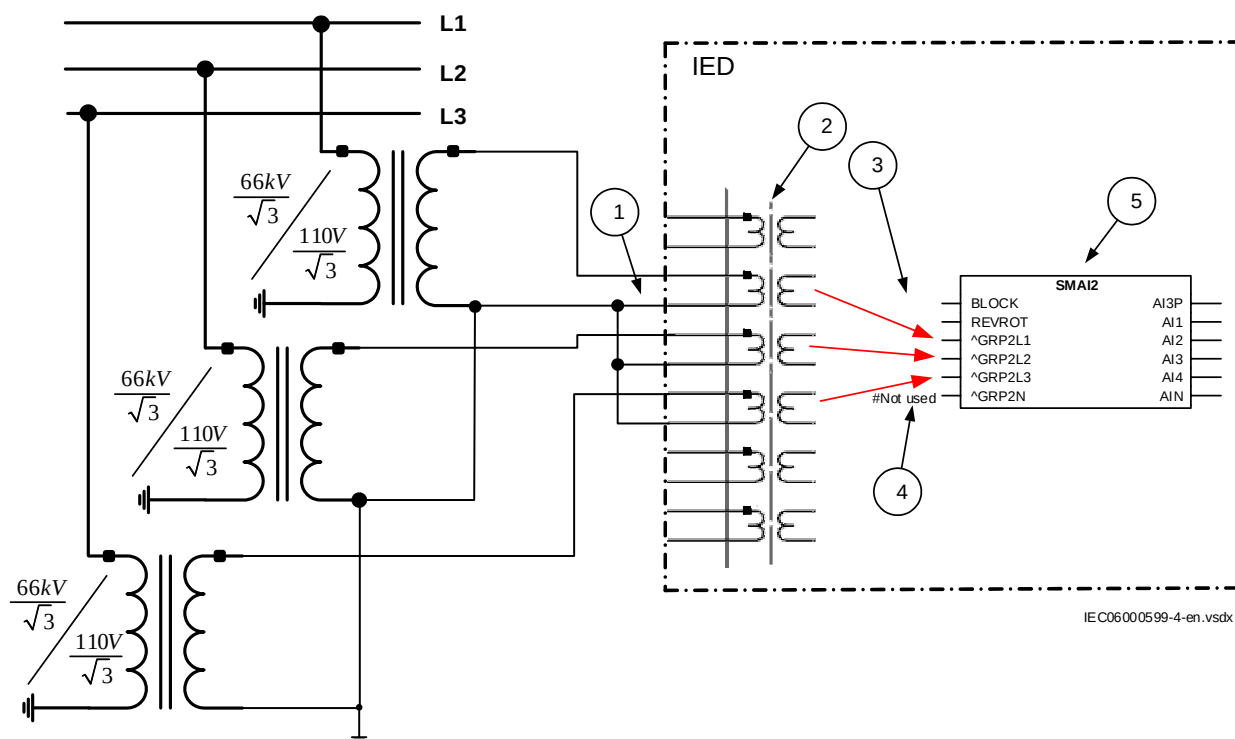


Figure 17: A Three phase-to-earth connected VT

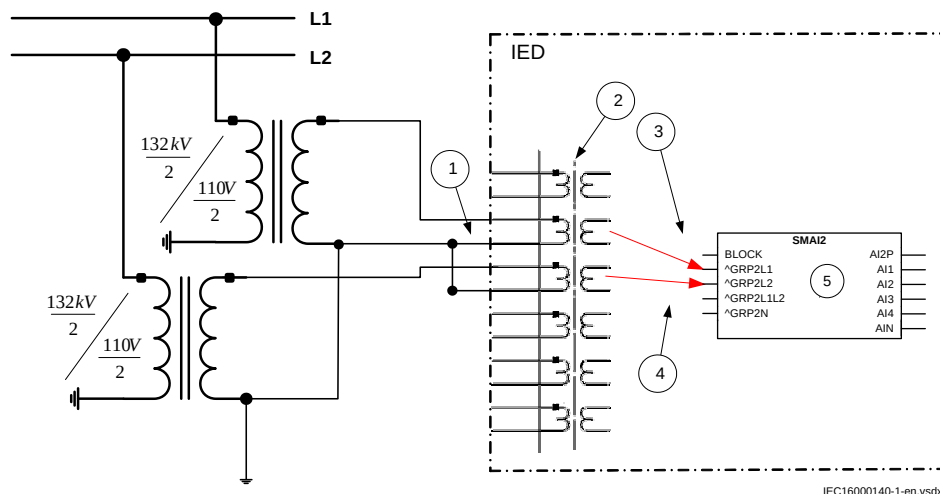


Figure 18: A two phase-to-earth connected VT

Where:

- 1) shows how to connect three secondary phase-to-earth voltages to three VT inputs on the IED
- 2) is the TRM where these three voltage inputs are located. For these three voltage inputs, the following setting values shall be entered:
 $VT_{prim} = 132 \text{ kV}$
 $VT_{sec} = 110 \text{ V}$
 Inside the IED, only the ratio of these two parameters is used. It shall be noted that the ratio of the entered values exactly corresponds to ratio of one individual VT.

$$\frac{66}{110} = \frac{66/\sqrt{3}}{110/\sqrt{3}}$$

(Equation 2)

- 3) are three connections made in Signal Matrix Tool (SMT), which connect these three voltage inputs to first three input channels of the preprocessing function block 5). Depending on the type of functions which need this voltage information, more than one preprocessing block might be connected in parallel to these three VT inputs.
- 4) shows that in this example the fourth (that is, residual) input channel of the preprocessing block is not connected in SMT tool. Thus the preprocessing block will automatically calculate $3U_0$ inside by vectorial sum from the three phase to earth voltages connected to the first three input channels of the same preprocessing block. Alternatively, the fourth input channel can be connected to open delta VT input, as shown in Figure 20.
- 5) is a Preprocessing block that has the task to digitally filter the connected analog inputs and calculate:
 - fundamental frequency phasors for all input channels
 - harmonic content for all input channels
 - positive, negative and zero sequence quantities by using the fundamental frequency phasors for the first three input channels (channel one taken as reference for sequence quantities)

These calculated values are then available for all built-in protection and control functions within the IED, which are connected to this preprocessing function block in the configuration tool. For this application most of the preprocessing settings can be left to the default values. However the following settings shall be set as shown here:

$U_{Base} = 66 \text{ kV}$ (that is, rated Ph-Ph voltage)

If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in the generating stations) then the setting parameters *DFTR* shall be set accordingly.

4.2.4.4 Example on how to connect a phase-to-phase connected VT to the IED

Figure 19 gives an example how to connect a phase-to-phase connected VT to the IED. It gives an overview of the required actions by the user in order to make this measurement available to the built-in protection and control functions within the IED. It shall be noted that this VT connection is only used on lower voltage levels (that is, rated primary voltage below 40 kV).

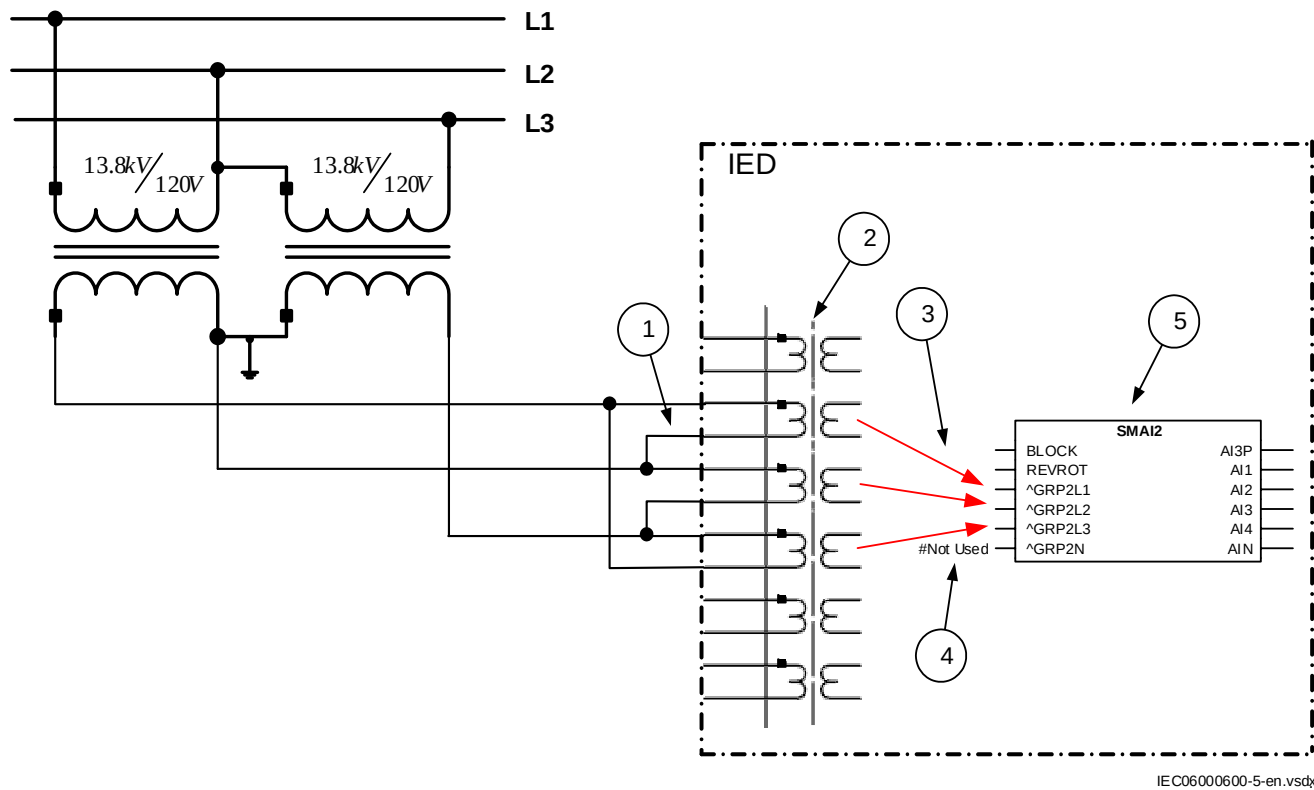


Figure 19: A Two phase-to-phase connected VT

Where:

- 1) shows how to connect the secondary side of a phase-to-phase VT to the VT inputs on the IED
- 2) is the TRM where these three voltage inputs are located. It shall be noted that for these three voltage inputs the following setting values shall be entered:
 $VT_{prim}=13.8 \text{ kV}$
 $VT_{sec}=120 \text{ V}$
 Please note that inside the IED only ratio of these two parameters is used.
- 3) are three connections made in the Signal Matrix tool (SMT), Application configuration tool (ACT), which connects these three voltage inputs to first three input channels of the preprocessing function block 5). Depending on the type of functions, which need this voltage information, more than one preprocessing block might be connected in parallel to these three VT inputs
- 4) shows that in this example the fourth (that is, residual) input channel of the preprocessing block is not connected in SMT. Note. If the parameters U_{L1} , U_{L2} , U_{L3} , U_N should be used the open delta must be connected here.
- 5) Preprocessing block has a task to digitally filter the connected analog inputs and calculate:
 - fundamental frequency phasors for all four input channels
 - harmonic content for all four input channels
 - positive, negative and zero sequence quantities by using the fundamental frequency phasors for the first three input channels (channel one taken as reference for sequence quantities)

These calculated values are then available for all built-in protection and control functions within the IED, which are connected to this preprocessing function block in the configuration tool. For this application most of the preprocessing settings can be left to the default values. However the following settings shall be set as shown here:

$ConnectionType=Ph-Ph$

$U_{Base}=13.8 \text{ kV}$

If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in the generating stations) then the setting parameters $DFTReference$ shall be set accordingly.

4.2.4.5 Example on how to connect an open delta VT to the IED for high impedance earthed or unearthed networks

Figure 20 gives an example about the wiring of an open delta VT to the IED for high impedance earthed or unearthed power systems. It shall be noted that this type of VT connection presents a secondary voltage proportional to $3U_0$ to the IED.

In case of a solid earth fault close to the VT location the primary value of $3U_0$ will be equal to:

$$3U_0 = \sqrt{3} \cdot U_{Ph-Ph} = 3 \cdot U_{Ph-N}$$

(Equation 3)

The primary rated voltage of an open Delta VT is always equal to U_{Ph-E} . Three series connected VT secondary windings gives a secondary voltage equal to three times the individual VT secondary winding rating. Thus the secondary windings of open delta VTs quite often have a secondary rated voltage equal to one third of the rated phase-to-phase VT secondary voltage (110/3V in this particular example).

Figure 20 gives overview of required actions by the user in order to make this measurement available to the built-in protection and control functions within the IED as well.

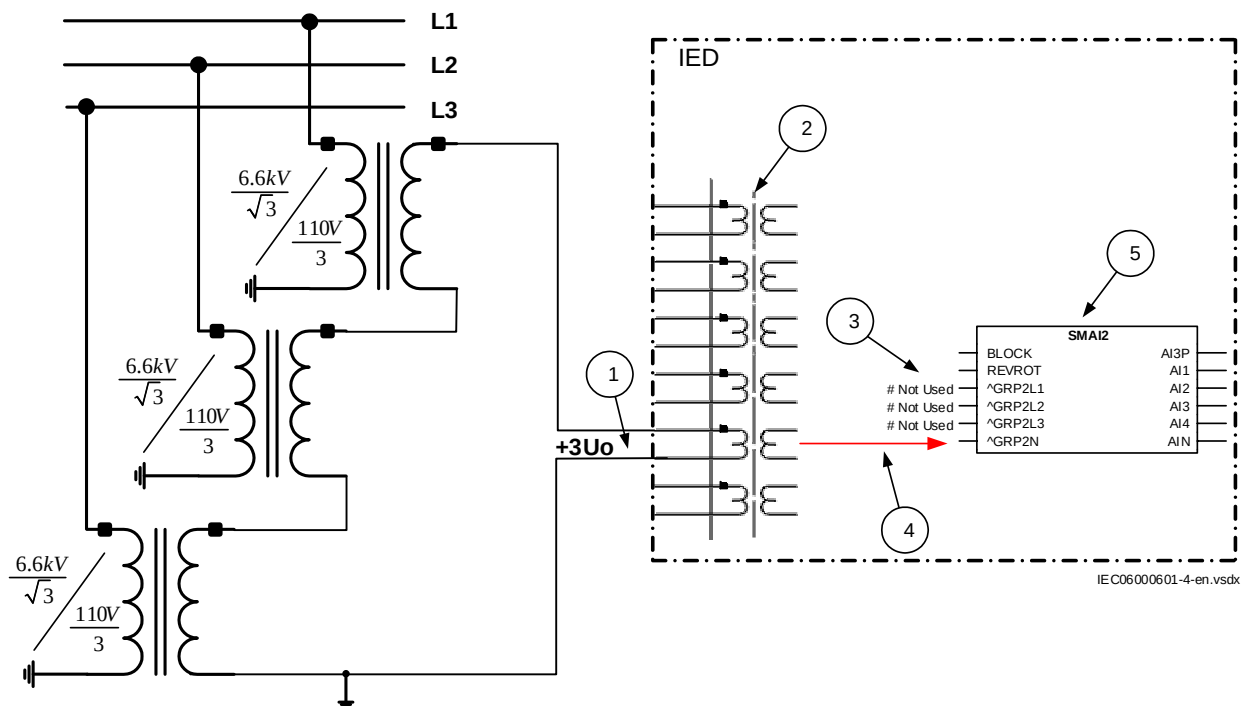


Figure 20: Open delta connected VT in high impedance earthed power system

Where:

- 1) shows how to connect the secondary side of the open delta VT to one VT input on the IED.



+3U₀ shall be connected to the IED

- 2) is the TRM where this voltage input is located. It shall be noted that for this voltage input the following setting values shall be entered:

$$VT_{prim} = \sqrt{3} \cdot 6.6 = 11.43kV$$

(Equation 4)

$$VT_{sec} = 3 \cdot \frac{110}{3} = 110V$$

(Equation 5)

Inside the IED, only the ratio of these two parameters is used. It shall be noted that the ratio of the entered values exactly corresponds to ratio of one individual open delta VT.

$$\frac{\sqrt{3} \cdot 6.6}{110} = \frac{6.6 / \sqrt{3}}{110 / 3}$$

(Equation 6)

- 3) shows that in this example the first three input channel of the preprocessing block is not connected in SMT tool or ACT tool.
- 4) shows the connection made in Signal Matrix Tool (SMT), Application configuration tool (ACT), which connect this voltage input to the fourth input channel of the preprocessing function block 5).
- 5) is a Preprocessing block that has the task to digitally filter the connected analog input and calculate:
- fundamental frequency phasors for all four input channels
 - harmonic content for all four input channels
 - positive, negative and zero sequence quantities by using the fundamental frequency phasors for the first three input channels (channel one taken as reference for sequence quantities)

These calculated values are then available for all built-in protection and control functions within the IED, which are connected to this preprocessing function block in the configuration tool. For this application most of the preprocessing settings can be left to the default values.

If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in the generating stations) then the setting parameters *DFTR* shall be set accordingly.

4.2.4.6 Example how to connect the open delta VT to the IED for low impedance earthed or solidly earthed power systems

Figure 21 gives an example about the connection of an open delta VT to the IED for low impedance earthed or solidly earthed power systems. It shall be noted that this type of VT connection presents secondary voltage proportional to 3U₀ to the IED.

In case of a solid earth fault close to the VT location the primary value of 3U₀ will be equal to:

$$3U_0 = \frac{U_{Ph-Ph}}{\sqrt{3}} = U_{Ph-E}$$

(Equation 7)

The primary rated voltage of such VT is always equal to U_{Ph-E} . Therefore, three series connected VT secondary windings will give the secondary voltage equal only to one individual VT secondary winding rating. Thus the secondary windings of such open delta VTs quite often has a secondary rated voltage close to rated phase-to-phase VT secondary voltage, that is, 115V or $115/\sqrt{3}$ V as in this particular example. Figure 21 gives an overview of the actions which are needed to make this measurement available to the built-in protection and control functions within the IED.

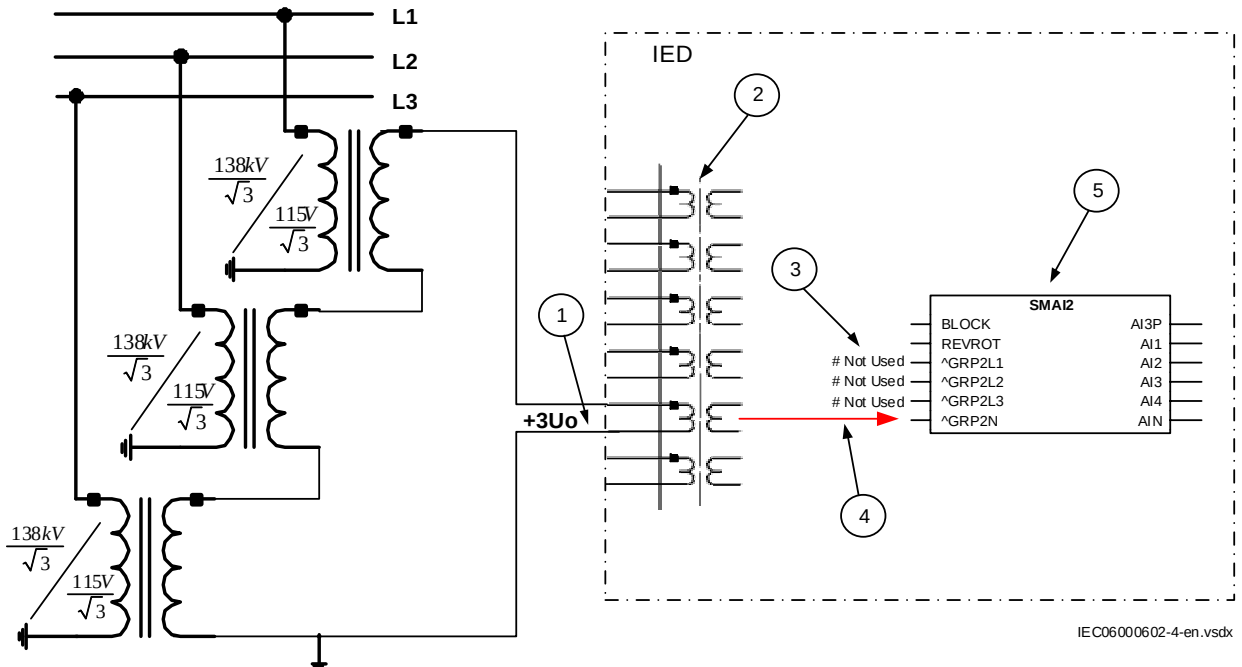


Figure 21: Open delta connected VT in low impedance or solidly earthed power system

Where:

- 1) shows how to connect the secondary side of open delta VT to one VT input in the IED.



+3U₀ shall be connected to the IED.

- 2) is TRM where this voltage input is located. It shall be noted that for this voltage input the following setting values shall be entered:

$$VT_{prim} = \sqrt{3} \cdot \frac{138}{\sqrt{3}} = 138kV$$

(Equation 8)

$$VT_{sec} = \sqrt{3} \cdot \frac{115}{\sqrt{3}} = 115V$$

(Equation 9)

Inside the IED, only the ratio of these two parameters is used. It shall be noted that the ratio of the entered values exactly corresponds to ratio of one individual open delta VT.

$$\frac{138}{115} = \frac{138/\sqrt{3}}{115/\sqrt{3}}$$

(Equation 10)

- 3) shows that in this example the first three input channel of the preprocessing block is not connected in SMT tool.
- 4) shows the connection made in Signal Matrix Tool (SMT), which connect this voltage input to the fourth input channel of the preprocessing function block 4).
- 5) preprocessing block has a task to digitally filter the connected analog inputs and calculate:
 - fundamental frequency phasors for all four input channels
 - harmonic content for all four input channels
 - positive, negative and zero sequence quantities by using the fundamental frequency phasors for the first three input channels (channel one taken as reference for sequence quantities)

These calculated values are then available for all built-in protection and control functions within the IED, which are connected to this preprocessing function block in the configuration tool. For this application most of the preprocessing settings can be left to the default values.

If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in the generating stations) then the setting parameters *DFTReference* shall be set accordingly.

4.2.4.7 Example on how to connect a neutral point VT to the IED

Figure 22 gives an example on how to connect a neutral point VT to the IED. This type of VT connection presents secondary voltage proportional to U₀ to the IED.

In case of a solid earth fault in high impedance earthed or unearthened systems the primary value of U₀ voltage will be equal to:

$$U_0 = \frac{U_{Ph-P_h}}{\sqrt{3}} = U_{Ph-E}$$

(Equation 11)

Figure 22 gives an overview of required actions by the user in order to make this measurement available to the built-in protection and control functions within the IED.

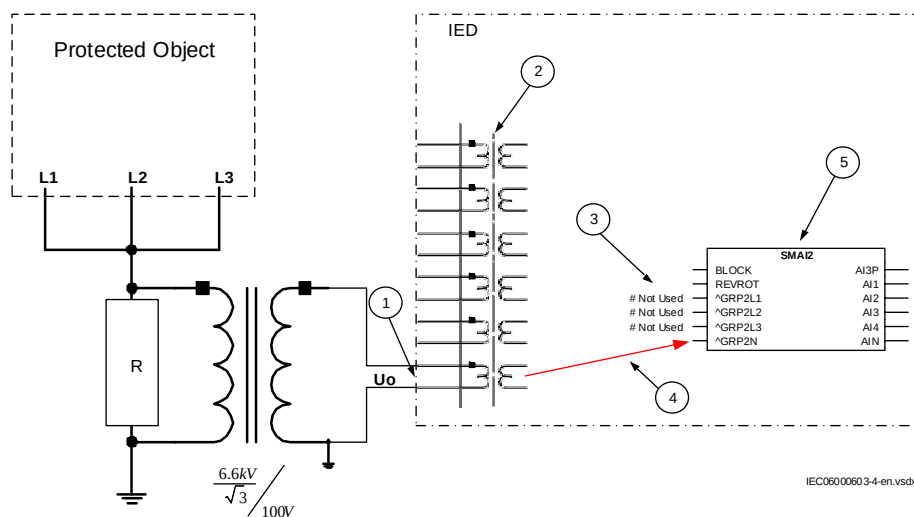


Figure 22: Neutral point connected VT

Where:

- 1) shows how to connect the secondary side of neutral point VT to one VT input in the IED.



U_0 shall be connected to the IED.

- 2) is the TRM or AIM where this voltage input is located. For this voltage input the following setting values shall be entered:

$$VT_{prim} = \frac{6.6}{\sqrt{3}} = 3.81kV$$

(Equation 12)

$$VT_{sec} = 100V$$

(Equation 13)

Inside the IED, only the ratio of these two parameters is used. It shall be noted that the ratio of the entered values exactly corresponds to ratio of the neutral point VT.

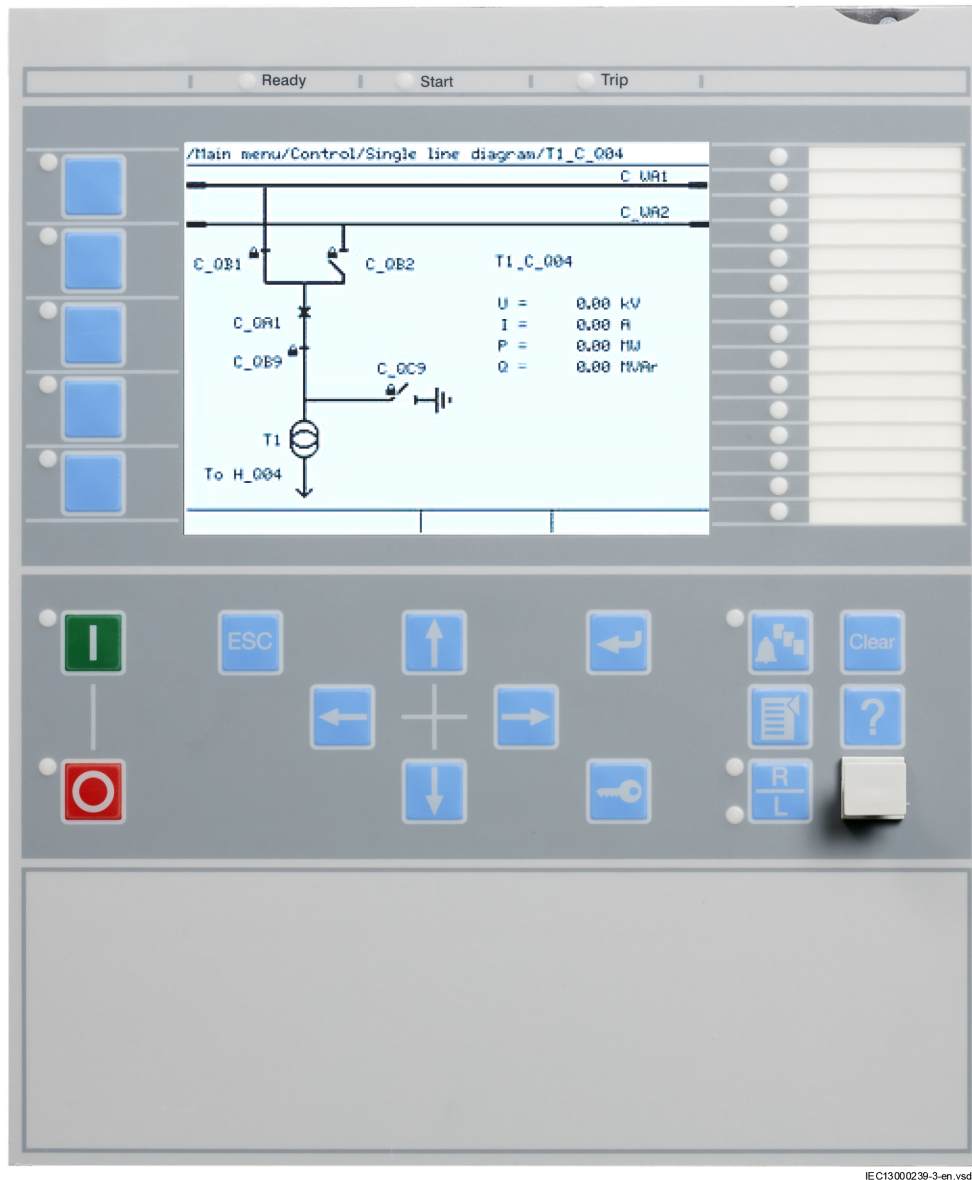
Table continues on next page

- 3) shows that in this example the first three input channels of the preprocessing block is not connected in SMT tool or ACT tool.
- 4) shows the connection made in Signal Matrix Tool (SMT), Application configuration tool (ACT), which connects this voltage input to the fourth input channel of the preprocessing function block 5).
- 5) is a preprocessing block that has the task to digitally filter the connected analog inputs and calculate:
 - fundamental frequency phasors for all four input channels
 - harmonic content for all four input channels
 - positive, negative and zero sequence quantities by using the fundamental frequency phasors for the first three input channels (channel one taken as reference for sequence quantities)

These calculated values are then available for all built-in protection and control functions within the IED, which are connected to this preprocessing function block in the configuration tool. For this application, most of the preprocessing settings can be left to the default values.

If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in the generating stations) then the setting parameters *DFTR* shall be set accordingly.

Section 5 Local HMI



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Figure 23: Local human-machine interface

The LHMI of the IED contains the following elements

- Keypad
- Display (LCD)
- LED indicators
- Communication port for PCM600

The LHMI is used for setting, monitoring and controlling.

5.1 Display

The LHMI includes a graphical monochrome liquid crystal display (LCD) with a resolution of 320 x 240 pixels. The character size can vary. The amount of characters and rows fitting the view depends on the character size and the view that is shown.

The display view is divided into four basic areas.

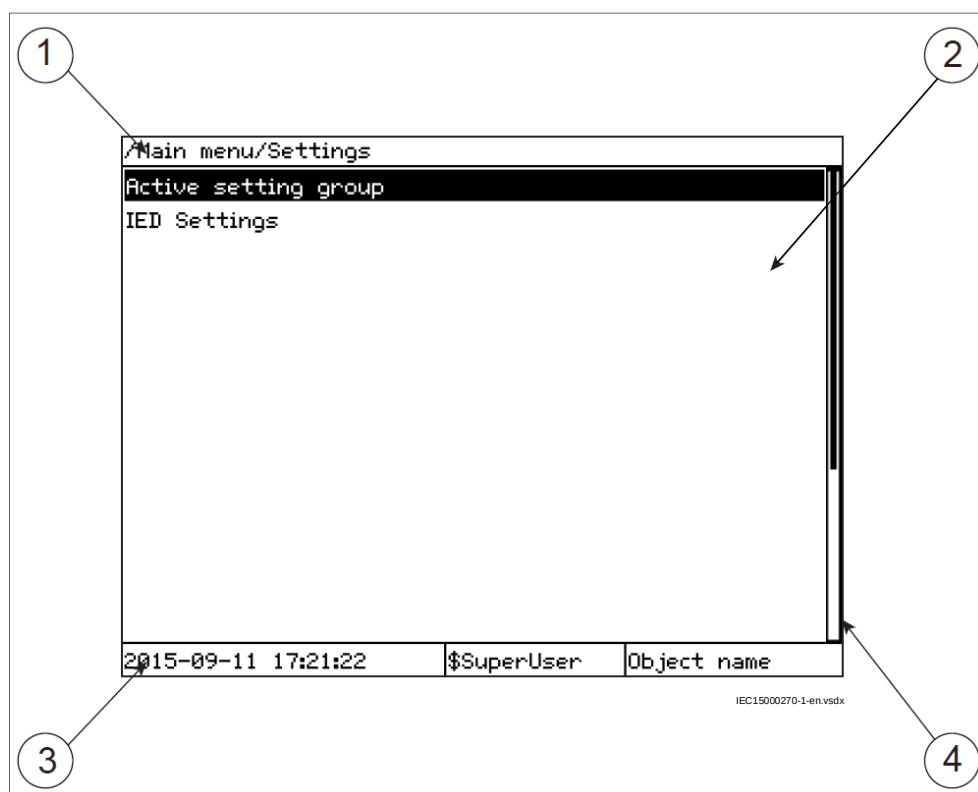


Figure 24: Display layout

- 1 Path
- 2 Content
- 3 Status
- 4 Scroll bar (appears when needed)

The function key button panel shows on request what actions are possible with the function buttons. Each function button has a LED indication that can be used as a feedback signal for the function button control action. The LED is connected to the required signal with PCM600.

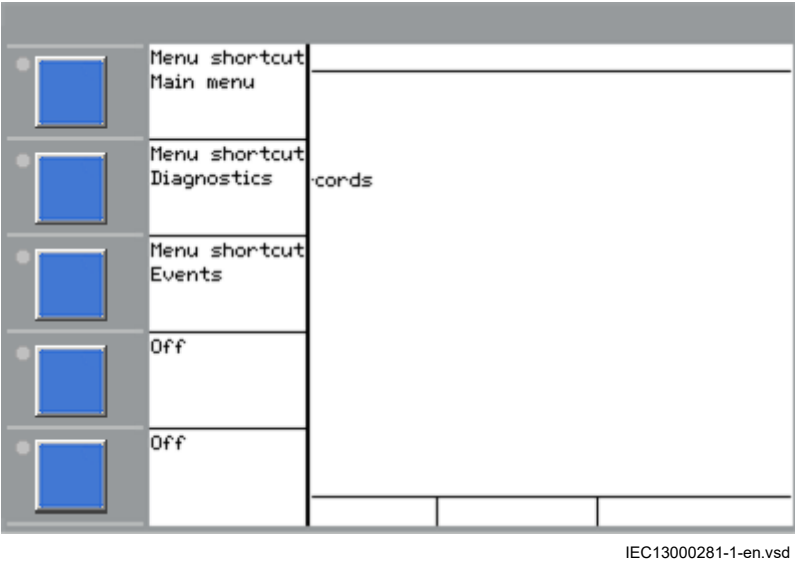


Figure 25: Function button panel

The indication LED panel shows on request the alarm text labels for the indication LEDs. Three indication LED pages are available.

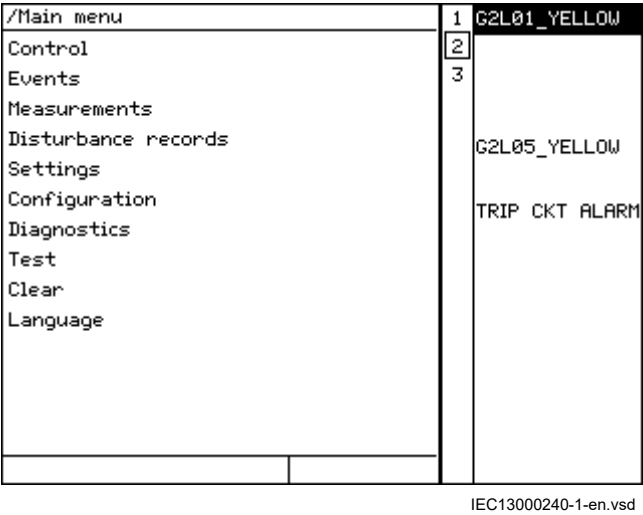


Figure 26: Indication LED panel

The function button and indication LED panels are not visible at the same time. Each panel is shown by pressing one of the function buttons or the Multipage button. Pressing the ESC button clears the panel from the display. Both panels have a dynamic width that depends on the label string length.

5.2 LEDs

The LHMI includes three status LEDs above the display: Ready, Start and Trip.

There are 15 programmable indication LEDs on the front of the LHMI. Each LED can indicate three states with the colors: green, yellow and red. The texts related to each three-color LED are divided into three panels.

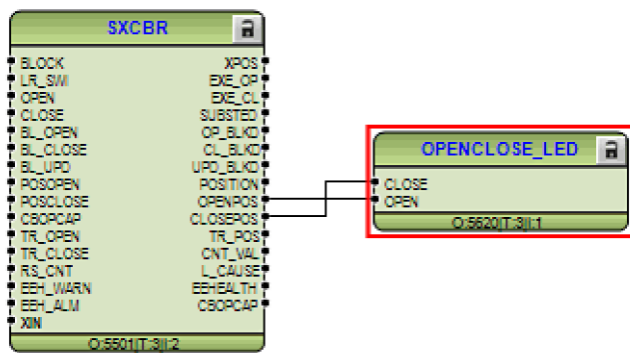
There are 3 separate panels of LEDs available. The 15 physical three-color LEDs in one LED group can indicate 45 different signals. Altogether, 135 signals can be indicated since there are three LED groups. The LEDs are lit according to priority, with red being the highest and green the lowest priority. For example, if on one panel there is an indication that requires the green LED to be lit, and on

another panel there is an indication that requires the red LED to be lit, the red LED takes priority and is lit. The LEDs can be configured with PCM600 and the operation mode can be selected with the LHMI or PCM600.

Information panels for the indication LEDs are shown by pressing the Multipage button. Pressing that button cycles through the three pages. A lit or un-acknowledged LED is indicated with a highlight. Such lines can be selected by using the Up/Down arrow buttons. Pressing the Enter key shows details about the selected LED. Pressing the ESC button exits from information pop-ups as well as from the LED panel as such.

The Multipage button has a LED. This LED is lit whenever any LED on any panel is lit. If there are un-acknowledged indication LEDs, then the Multipage LED blinks. To acknowledge LEDs, press the Clear button to enter the Reset menu (refer to description of this menu for details).

There are two additional LEDs which are next to the control buttons  and . These LEDs can indicate the status of two arbitrary binary signals by configuring the OPENCLOSE_LED function block. For instance, OPENCLOSE_LED can be connected to a circuit breaker to indicate the breaker open/close status on the LEDs.



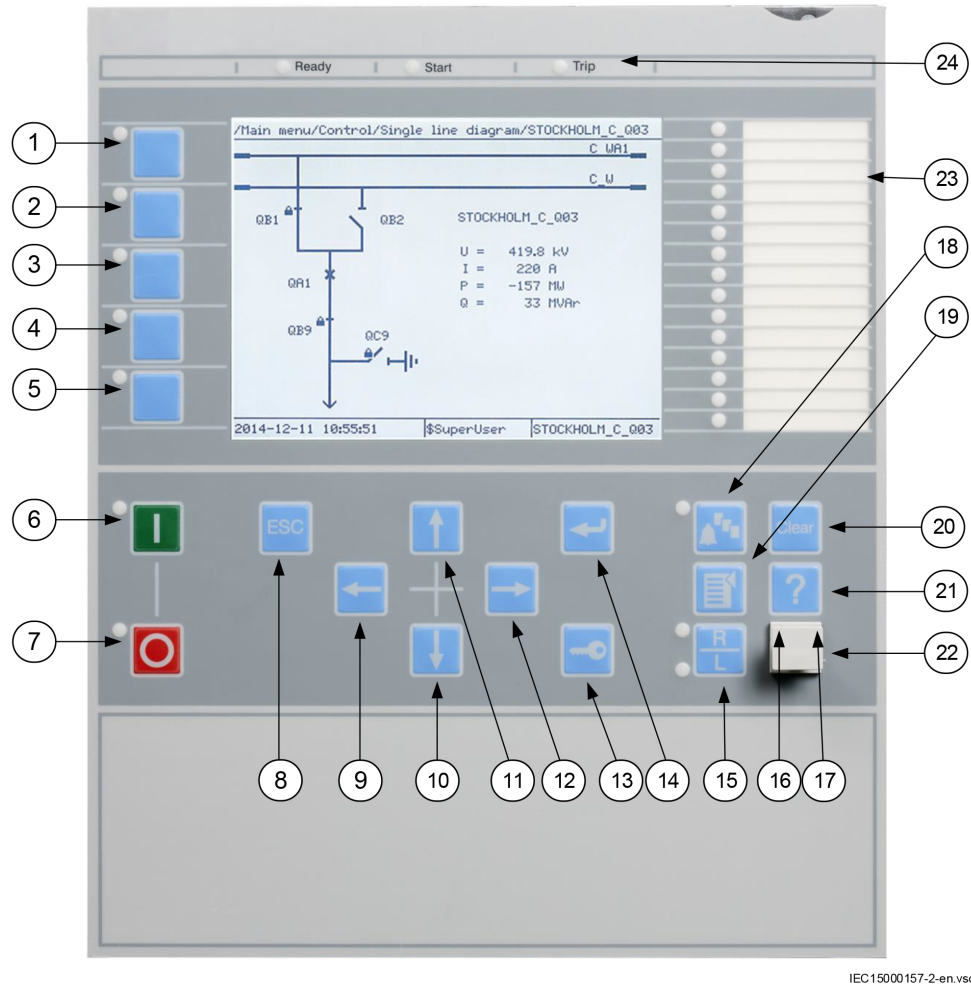
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Figure 27: OPENCLOSE_LED connected to SXCBB

5.3 Keypad

The LHMI keypad contains push-buttons which are used to navigate in different views or menus. The push-buttons are also used to acknowledge alarms, reset indications, provide help and switch between local and remote control mode.

The keypad also contains programmable push-buttons that can be configured either as menu shortcut or control buttons.



IEC15000157-2-en.vsd

Figure 28: LHM keypad with object control, navigation and command push-buttons and RJ-45 communication port

- 1...5 Function button
- 6 Close
- 7 Open
- 8 Escape
- 9 Left
- 10 Down
- 11 Up
- 12 Right
- 13 Key
- 14 Enter
- 15 Remote/Local
- 16 Uplink LED
- 17 Not in use
- 18 Multipage
- 19 Menu
- 20 Clear
- 21 Help
- 22 Communication port
- 23 Programmable indication LEDs

5.4 Local HMI functionality

5.4.1 Protection and alarm indication

Protection indicators

The protection indicator LEDs are Ready, Start and Trip.



The yellow and red status LEDs are configured in the disturbance recorder function, DRPRDRE, by connecting a start or trip signal from the actual function to a BxRBDR binary input function block using the PCM600 and configure the setting to *Off*, *Start* or *Trip* for that particular signal.

Table 7: Ready LED (green)

LED state	Description
OFF	Auxiliary supply voltage is disconnected.
ON	Normal operation.
Flashing/blinking	Internal fault has occurred.

Table 8: Start LED (yellow)

LED state	Description
OFF	Normal operation.
ON	A protection function has started and an indication message is displayed. The start indication is latching and must be reset via communication, LHMI or binary input on the LEDGEN component. To open the reset menu on the LHMI, press  .
Flashing/blinking	When IED is in simulation mode, yellow LED remains flashing/blinking When IED IEC61850 mod value is set other than its normal value, yellow LED remains flashing/blinking The IED is in test mode and protection functions are blocked, or the IEC 61850 protocol is blocking one or more functions. The indication disappears when the IED is no longer in test mode and blocking is removed. The blocking of functions through the IEC 61850 protocol can be reset in Main menu/Test/Reset IEC61850 Mod . The yellow LED changes to either ON or OFF state depending on the state of operation.

Table 9: Trip LED (red)

LED state	Description
OFF	Normal operation.
ON	A protection function has tripped. An indication message is displayed if the auto-indication feature is enabled in the local HMI. The trip indication is latching and must be reset via communication, LHMI or binary input on the LEDGEN component. To open the reset menu on the LHMI, press  .
Flashing/blinking	Configuration mode.

Alarm indicators

The 15 programmable three-color LEDs are used for alarm indication. An individual alarm/status signal, connected to any of the LED function blocks, can be assigned to one of the three LED colors when configuring the LED.

Table 10: Alarm indications

LED state	Description
OFF	Normal operation. All activation signals are OFF.
ON	- Follow-S sequence: The activation signal is ON. - LatchedColl-S sequence: The activation signal is ON, or it is off but the indication has not been acknowledged. - LatchedAck-F-S sequence: The indication has been acknowledged, but the activation signal is still ON. - LatchedAck-S-F sequence: The activation signal is ON, or it is off but the indication has not been acknowledged. - LatchedReset-S sequence: The activation signal is ON, or it is off but the indication has not been acknowledged.
Flashing/ blinking	- Follow-F sequence: The activation signal is ON. - LatchedAck-F-S sequence: The activation signal is ON, or it is off but the indication has not been acknowledged. - LatchedAck-S-F sequence: The indication has been acknowledged, but the activation signal is still ON.

5.4.2 Parameter management

The LHMI is used to access the relay parameters. Three types of parameters can be read and written.

- Numerical values
- String values
- Enumerated values

Numerical values are presented either in integer or in decimal format with minimum and maximum values. Character strings can be edited character by character. Enumerated values have a predefined set of selectable values.

5.4.3 Front communication

The RJ-45 port in the LHMI enables front communication.

- The green uplink LED on the left is lit when the cable is successfully connected to the port.
- The yellow LED is not used; it is always off.

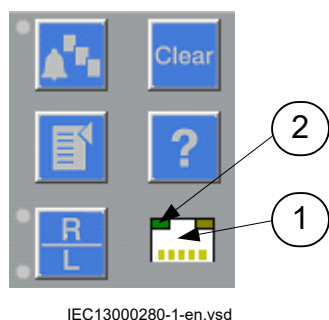


Figure 29: RJ-45 communication port and green indicator LED

- 1 RJ-45 connector
- 2 Green indicator LED

The default IP address for the IED front port is 10.1.150.3 and the corresponding subnetwork mask is 255.255.255.0. It can be set through the local HMI path **Main menu /Configuration/Communication /Ethernet configuration/FRONT port /AP_FRONT**.



Ensure not to change the default IP address of the IED.

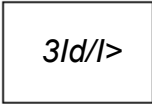


Do not connect the IED front port to a LAN. Connect only a single local PC with PCM600 to the front port. It is only intended for temporary use, such as commissioning and testing.

Section 6 Differential protection

6.1 Line differential protection

6.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Line differential protection 3 CT sets, with in-zone transformers, 2-3 line ends	LT3CPDIF		87LT
Line differential logic	LDLPSCCH	-	87L

6.1.2 Application

Line differential protection can be applied on overhead lines and cables. It is an absolute selective unit protection with a number of advantages. Coordination with other protections is normally simple. All faults on the line, between the line bay CTs, can be cleared instantaneously. The sensitivity can be made high, which is especially important for the ability to detect high resistive earth faults. It is not influenced by possible voltage and/or current inversion, associated with faults in series compensated networks. It is not influenced by fault current reversal at earth faults on parallel lines. As it is phase-segregated, the identification of faulted phases is inherent, and thus the application of single- or two-phase trip and auto-reclosing can be made robust and reliable. Note that if an in-line or shunt power transformer is included in the protected circuit, of the type Dy or Yd, then the protection cannot be phase-segregated. Single-phase automatic re-closing will not be possible.

Line differential protection can be applied on multi-terminal lines with maximum three line ends. Depending on the actual network, reliable fault clearance can often be difficult to achieve with conventional distance protection schemes in these types of applications.



It is recommended to use the same firmware version as well as hardware version for a specific line differential scheme.

With 1½ breaker configurations, normally the line protection is fed from two CTs. Avoiding to add the currents from the two CTs externally before entering the IED is important as this will enable possible bias current from both CTs to be considered in the current differential algorithm, and in that way assuring that the correct restrain will be possible, as shown in figure [30](#).

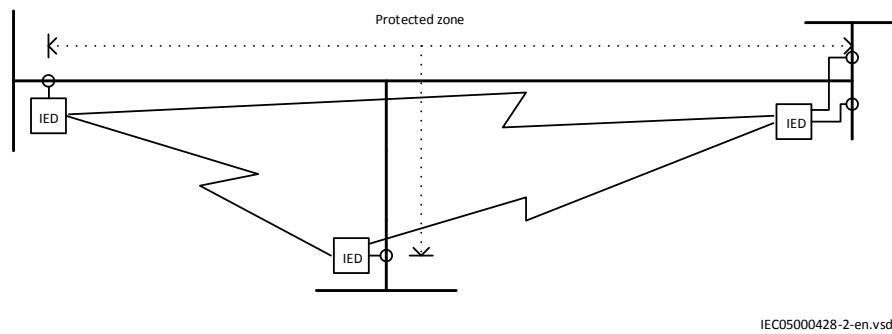


Figure 30: Line protection with 1½ breaker configurations, fed from two CTs

6.1.2.1 Power transformers in the protected zone

Line differential protection can also be applied with in-line power transformers in the protected zone. Such an in-line power transformer can be situated in tap, as shown in Figure 31 or in one end of a two-terminal line. Observe that the currents of the in-line power transformer are measured by the IED on the low voltage side. A one three-winding transformer can be included.

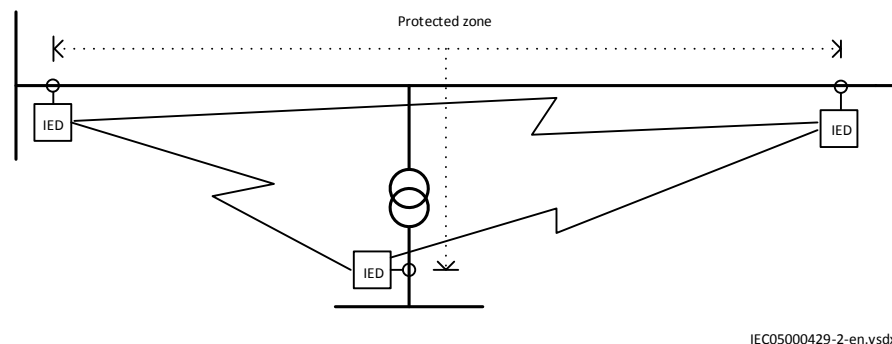


Figure 31: Transformer situated in tap

A current differential protection including power transformers must be compensated for transformer turns ratio and phase shift/vector group. In the line differential function this compensation is made in the software algorithm, which eliminates the need for auxiliary interposing current transformers. Necessary parameters, such as transformer rated voltages and phase shift, must be entered via the Parameter Setting tool or the LHMI.

Another concern with differential protection on power transformers is that a differential protection may operate unwanted due to external earth faults in cases where the zero-sequence current can flow only on one side of the power transformer but not on the other side, as in the case of Yd or Dy phase shift/vector groups. This is the situation when the zero-sequence current cannot be transformed from one side to the other side of the transformer. To make the differential protection insensitive to external earth faults in these situations, the zero-sequence current must be eliminated from the terminal currents so that it does not appear as a differential current. This was previously achieved by means of intermediate current transformers. The elimination of zero-sequence current is done numerically and no auxiliary transformers are necessary. Instead it is necessary to eliminate the zero-sequence current by proper setting of the parameter *ZerSeqCurSubtr*. If the power transformer

is of the type Dyn, where yn-windings currents are measured, then the zero-sequence component will be subtracted when these currents are transformed to the HV-side.

6.1.2.2 Small power transformers in a tap

If there is a line tap with a comparatively small power transformer (say 1-20MVA), line differential protection can be applied without the need of current measurement from the tap. It works such that line differential protection function will be time delayed for small differential currents below a set limit, making coordination with downstream short circuit protection in the tap possible. For differential currents above that limit, the operation will be instantaneous in the normal way. Under the condition that the load current in the tap will be negligible, normal line faults, with a fault current higher than the fault current on the LV side of the transformer, will be cleared instantaneously.

For faults on the LV side of the transformer the function will be time delayed, with the delay characteristic selected, thus providing selectivity to the downstream functions, see figure 32. The scheme will solve the problem with back-up protection for faults on the transformer LV side where many expensive solutions have been applied such as intertripping or a local HV breaker. In many such applications the back-up protection has been lacking due to the complexity in cost implications to arrange it. Refer also to the setting example below.

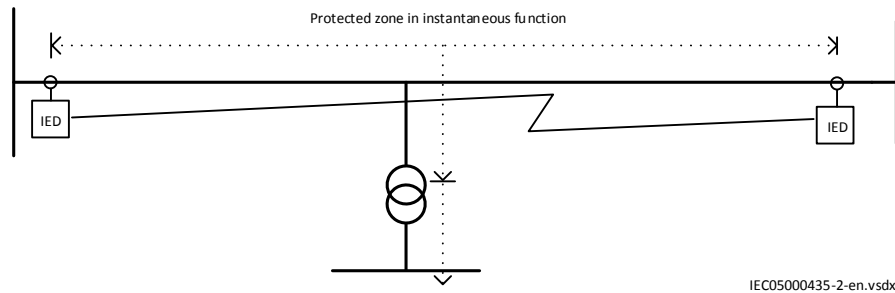


Figure 32: Line tap with a small power transformer, the currents of which are not measured, and consequently contribute to a (false) differential current

6.1.2.3 Charging current compensation

There are capacitances between the line phase conductors and between phase conductors and earth. These capacitances give rise to line charging currents which are seen by the differential protection as “false” differential currents, as shown in figure 33.

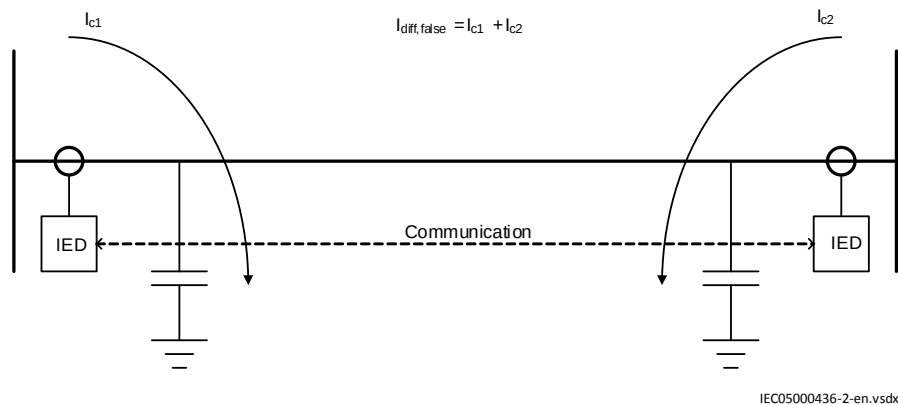


Figure 33: Charging currents

The magnitude of the charging current is dependent of the line capacitance and the system voltage. For earth cables and long overhead lines, the magnitude can be such that it affects the possibility to achieve the wanted sensitivity of the differential protection. To overcome this, a charging current compensation is available in line differential protection. When enabled, this algorithm will measure the fundamental frequency differential current under steady state undisturbed conditions and then subtract it, making the resulting differential current zero (or close to zero). Note that all small pre-fault differential currents are subtracted, no matter what their origin. This action is made separately for each phase.

When a disturbance occurs, values of the pre-fault differential currents are not updated, and the updating process is only resumed 100 ms after normal conditions have been restored. Normal conditions are then considered when there are no start signals, neither internal nor external fault is detected, the power system is symmetrical and so on. If an Open CT condition is detected, the compensation of charging currents is stopped immediately and the charging currents are temporarily memorized by the function. When Open CT signal resets, the process of compensation is resumed with the same charging current as before. The consequence of freezing the pre-fault values during fault conditions in this way will actually introduce a small error in the resulting calculated differential current under fault conditions. However, this will not have any practical negative consequences, while the positive effect of maintaining high sensitivity even with high charging currents will be achieved. To demonstrate this, two cases can be studied, one with a low resistive short circuit, and one with a high resistive short circuit.

The charging current is generated because there is a voltage applied over the line capacitance as seen in figure 33. If an external short circuit with negligible fault resistance occurs close to the line, the voltage in the fault location will be approximately zero. Consequently, zero voltage will also be applied over part of the line capacitance, which in turn will decrease the charging current compared to the pre-fault value. As mentioned above, the value of the pre-fault “false” differential current will be frozen when a fault is detected, and, as a consequence, the value of the subtracted charging current will be too high in this case. However, as it is a low resistive fault, the bias current will be comparatively high, while the charging current and any errors in the approximation of this will be comparatively low. Thus, the overestimated charging current will not jeopardize stability as can be seen from figure 34, showing the characteristic of line differential protection. In this figure, the considered fault will appear in the section well in the restrain area.

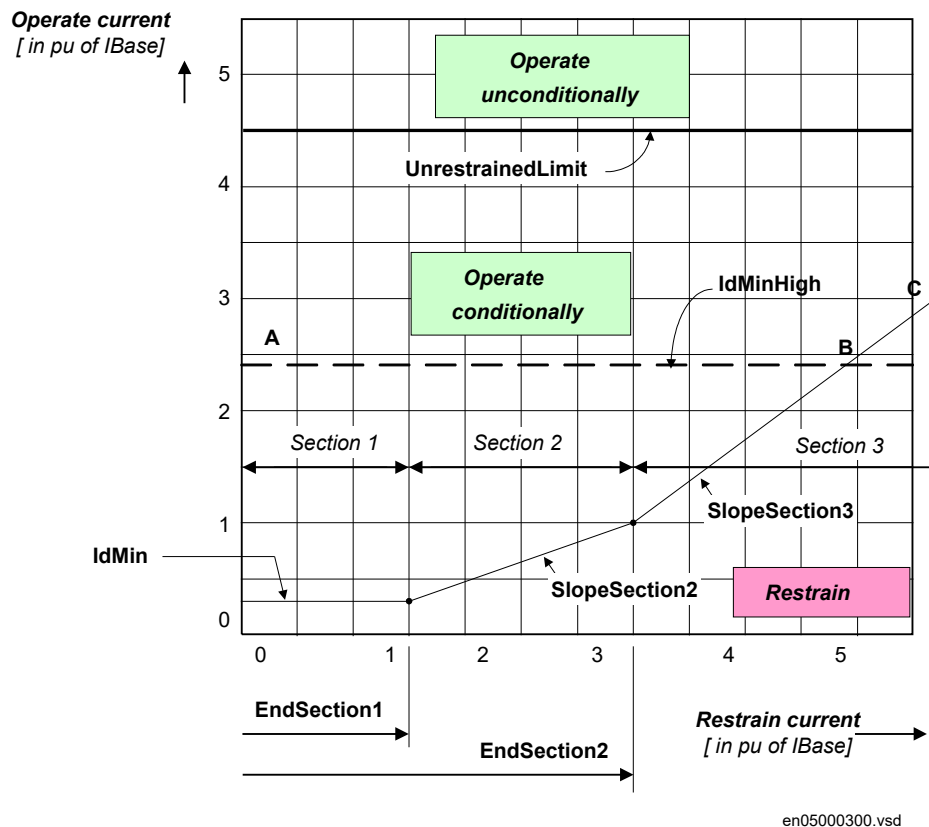


Figure 34: Overestimated charging current

If a high resistive fault is considered, the voltage in the fault location will not be much reduced. Consequently, the value of the pre-fault “false” differential current will be a good estimation of the actual charging current.

Subtracting the pre-fault charging current from the differential current under fault conditions will make it possible to set I_{dmin} mainly without considering the charging current in order to achieve maximum sensitivity. The stability at external faults will not be affected.

6.1.2.4 Time synchronization

Time synchronization of sampled current values is a crucial matter in numerical line differential protections. The synchronization is made with the so called echo method, which can be complemented with IRIG-B time synchronization. In applications with symmetrical communication delay, that is, send and receive times are equal, the echo method is sufficient. When used in networks with asymmetrical transmission times, the optional IRIG-B time synchronization is required.

6.1.2.5 Communication channels for line differential protection

The line differential protection function uses 64 kbit/s communication channels to exchange telegrams between the line differential protection IEDs. These telegrams contain current sample values, time information, trip signals, block signals, alarm signals and 8 binary signals, which can be used for any purpose. Each IED can have a maximum of two communication channels.

On a two terminal line there is a need for one communication channel provided that there is only one CT at each line end (see Figure 35).

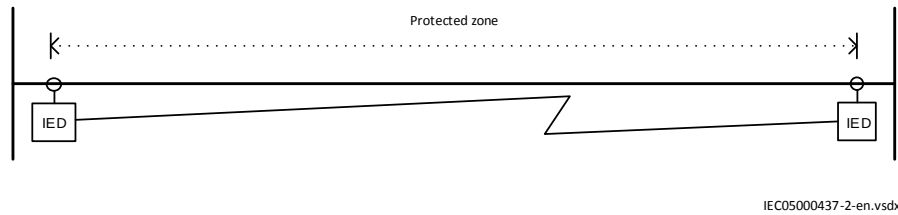


Figure 35: Two-terminal line

In case of $1\frac{1}{2}$ breaker arrangements or ring buses, a line end has two CTs (see Figure 36).

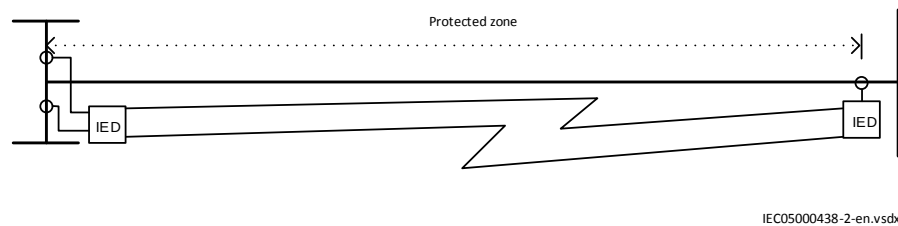


Figure 36: Two-terminal line with $1\frac{1}{2}$ breaker



In Figure 36, both local CTs on the left side are treated as separate ends by the line differential protection function.

Current values from two CTs in double breakers, ring main or $1\frac{1}{2}$ breaker system ends with dual breaker arrangements need to be sent to the remote end. As a 64 kbit/s LDCM only has capacity for one three-phase current (duplex), this implies that two communication channels are needed at both ends, and this is also the normal solution.

To reduce the number of communication channels needed, it is also possible to sum up the two local currents before sending by using a software in the IED. However, this is not recommended as it reduces information about bias currents. Bias current is considered the greatest phase current at any line end, and it is common for all three phases. When sending full information from both local CTs to the remote end, the principle works, but when the two local currents are summed up before sending, information on real phase currents from the two local CTs will not be available at the remote line end.

In 64 kbit mode, the decision on using one communication channel instead of two (as show in Figure 36) must be made case by case. Correct information on bias currents is always available locally while only distorted information is available at the end that receives limited information using only one LDCM.

6.1.2.6 Configuration of analog signals

Currents from the local end enter the IED as analog values via the Analog input modules. These currents are converted to digital values and then forwarded to the line differential protection function in the local IED. From there, they are transmitted to remote IEDs via a Line differential communication module (LDCM). Currents coming from a remote IED are received as digital values via local IED's LDCM, and they are then forwarded to the protection function in the local IED.

LDLPSCH acts as the interface to and from the protection function.

Configuration of this data flow is made in the SMT tool as shown in Figure 37.

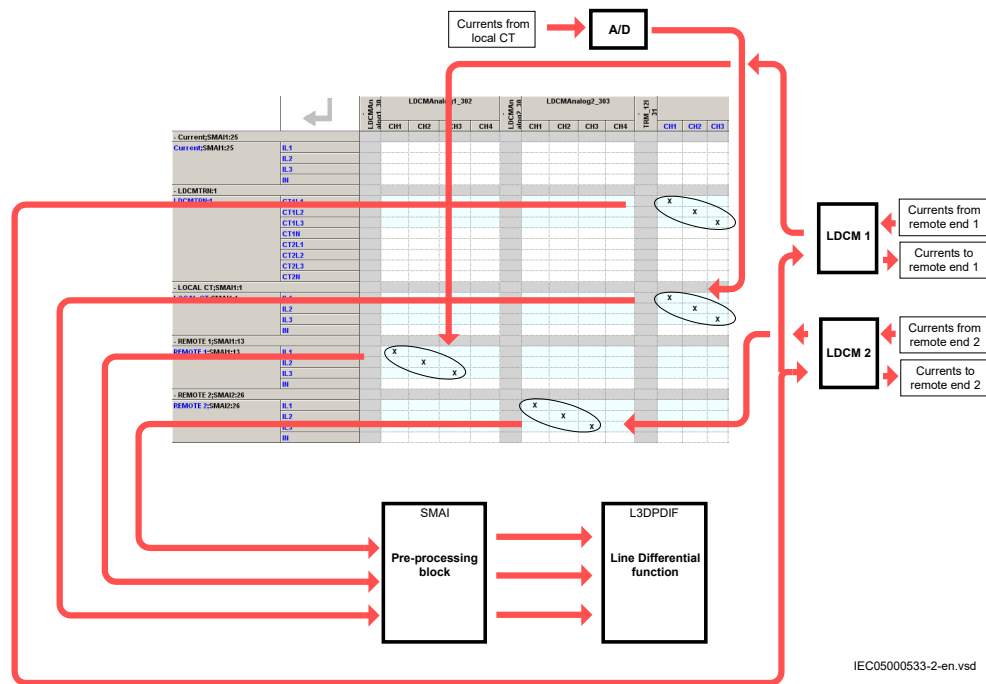


Figure 37: Typical configuration of analog signals for a three-terminal line

Figure 37 shows how one IED in a three-terminal line differential protection can be configured. There are two LDCMs each supporting a duplex connection with a remote line end. Thus, the same local current is configured to both LDCMs, while the received currents from the LDCMs are configured separately to the line differential protection function.

6.1.2.7 Configuration of output signals

There are a number of signals available from the LDCM that can be connected to the virtual binary inputs (SMBI) and used internally in the configuration. The signals appear only in the Signal Matrix Tool (SMT) where they can be mapped to the desired virtual input.

The signal name is found in the Object Properties window by clicking on the input signal number in SMT. Connect the signals to the virtual inputs as desired (see Figure 38)

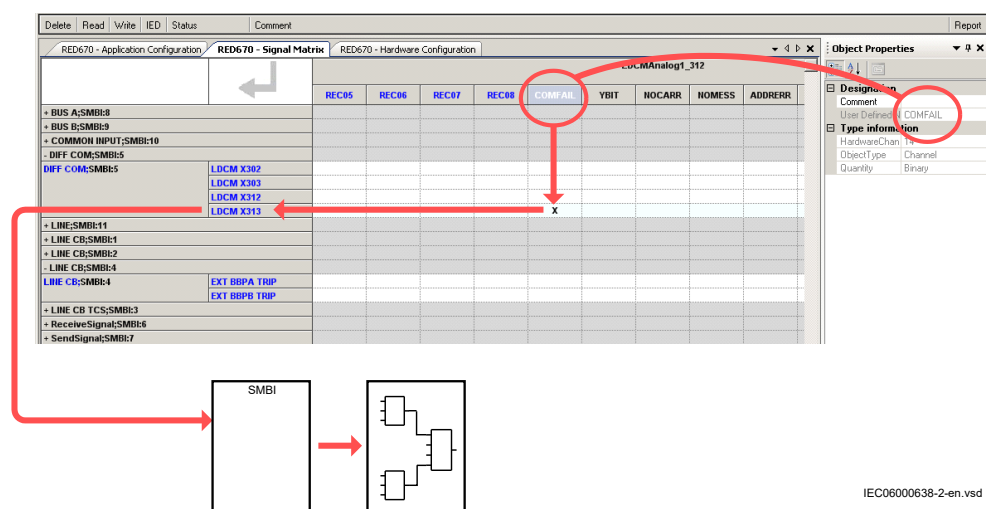


Figure 38: Example of LDCM signals in SMT (example showing 670 device)

6.1.2.8 Open CT detection

Line differential protection has a built-in, advanced open CT detection feature. This feature can block the unwanted operation created by the Line differential protection function in case of an open CT secondary circuit under a normal load condition. However, there is no guarantee that the Open CT algorithm prevents an unwanted disconnection of the protected circuit. The Open CT can be detected in approximately 14 ± 2 ms, and the differential protection might by that time in some cases have already issued a trip command. Nevertheless, the information on an open CT as the reason for trip is still very important. An alarm signal can also be issued to the substation operational personnel to make remedy action once the open CT condition is detected. The open CT algorithm is active under normal load conditions and a little above, i.e. in the range of load current from app. 10 % to app. 150 % rated load. Under normal conditions load is considered to be well described by the bias current. The Open CT detection algorithm is based on the principle that in the phase with an open CT, the current will suddenly drop to zero, while in the other two phases the currents continue as before. The Open CT at each end is enabled 60 seconds after the currents at that end are higher than 3 % rated current of the protected line circuit. An open CT can only be declared if in the phase where an open CT is suspected, exceeds 10 % of the rated current. The Open CT signal disappears when all currents are again normal, or when all three currents become zero.

- Setting parameter *OpenCTEnable* enables and disables this feature.
- Setting parameter *OCTBlockEn* enables and disables the blocking of differential function once an open CT is detected. When *OCTBlockEn* is set to OFF, only an alarm signal is issued.
- Setting parameter *tOCTAlarmDelay* defines the time delay after which the alarm signal is given.
- Setting parameter *tOCTResetDelay* defines the time delay after which the open CT condition resets once the defective CT circuits have been repaired.
- Once the open CT condition has been detected, all the differential protection functions are blocked except the unrestrained (instantaneous) differential protection. However, there is no guarantee that an unwanted disconnection of the protected circuit can always be prevented.
- For applications where the currents from two CTs are summated and sent over LDCM, the output *OPENCT* must be connected to CTFAIL on LDLPSCH logic in order for the Open CT detection to operate properly. Observe that summation of currents shall be avoided where possible.

The outputs of the open CT conditions are *OPENCT* and *OPENCTAL*.

- *OPENCT*: Open CT detected
- *OPENCTAL*: Alarm issued after the setting delay

Outputs (positive integer) for information on the local HMI:

- *OPENCTIN*: Open CT in CT group inputs (1 for input 1 and 2 for input 2)
- *OPENCTPH*: Open CT with phase information (1 for phase L1, 2 for phase L2, 3 for phase L3)

6.1.3 Setting guidelines

Line differential protection receives information about currents from all line terminals and evaluates this information in three different analysis blocks. The results of these analyses are then forwarded to an output logic, where the conditions for trip or no trip are checked.

The three current analyses are:

- Percentage restrained differential analysis
- The 2nd and 5th harmonic analysis (only if there is a power transformer included in the protected circuit)
- Internal/external fault discriminator

6.1.3.1 General settings

IBase set in primary Amp

Set a common *IBase* in Global base for the protected line (circuit). Most current settings for the protection function are then related to the *IBase*. The setting of *IBase* is normally made so that it corresponds to the maximum rated CT in any of the line terminals. For example, if all CTs used in a protected circuit are 1000A/1A, that is, the primary current rating is 1000 A, then *IBase* = 1000 A is a good choice.

NoOfUsedCTs

NoOfUsedCTs indicates to the function the number of three-phase CT sets included in the protected circuit. Note that one IED can process one or two local current terminals of the protected circuit. This is the case, for example, in 1½ breaker configurations in the line bay, where one of the two CT sets will be represented as one separate current terminal. A two-terminal line with 1½ breaker configurations at one line end must consequently have *NoOfUsedCTs* = 3.

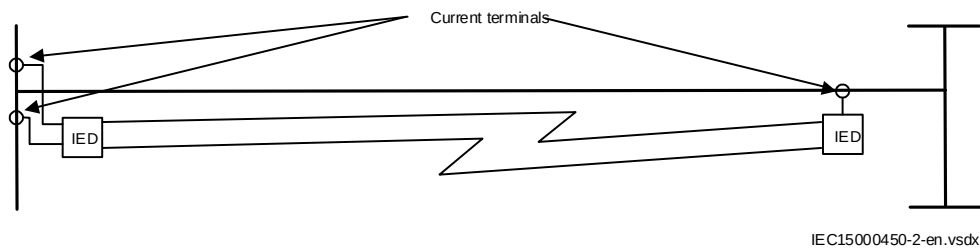


Figure 39: Example when setting *NoOfUsedCTs* = 3 in 1½ breaker configurations

6.1.3.2 Percentage restrained differential operation

Line differential protection is phase-segregated where the operate current is the vector sum of all measured currents taken separately for each phase. The restrain current, on the other hand, is considered the greatest phase current in any line end and it is common for all three phases. Observe that the protection may no more be phase-segregated when there is an in-line power transformer included in the protected circuit. These are usually of the Dy or Yd type and the three phases are related in a complicated way. For example, a single-phase earth fault on the wye side of the power transformer is seen as a two-phase fault on the delta side of the transformer.

Operation: Line differential protection function is switched on or off with this setting. If the parameter *Operation* is set to *Off* this IED is switched over to Slave mode and trip is initiated by the remote end IED.

The characteristic of the restrained differential function is shown in Figure 40. The restrained characteristic is defined by the settings:

1. *IdMin*
2. *EndSection1*
3. *EndSection2*
4. *SlopeSection2*
5. *SlopeSection3*

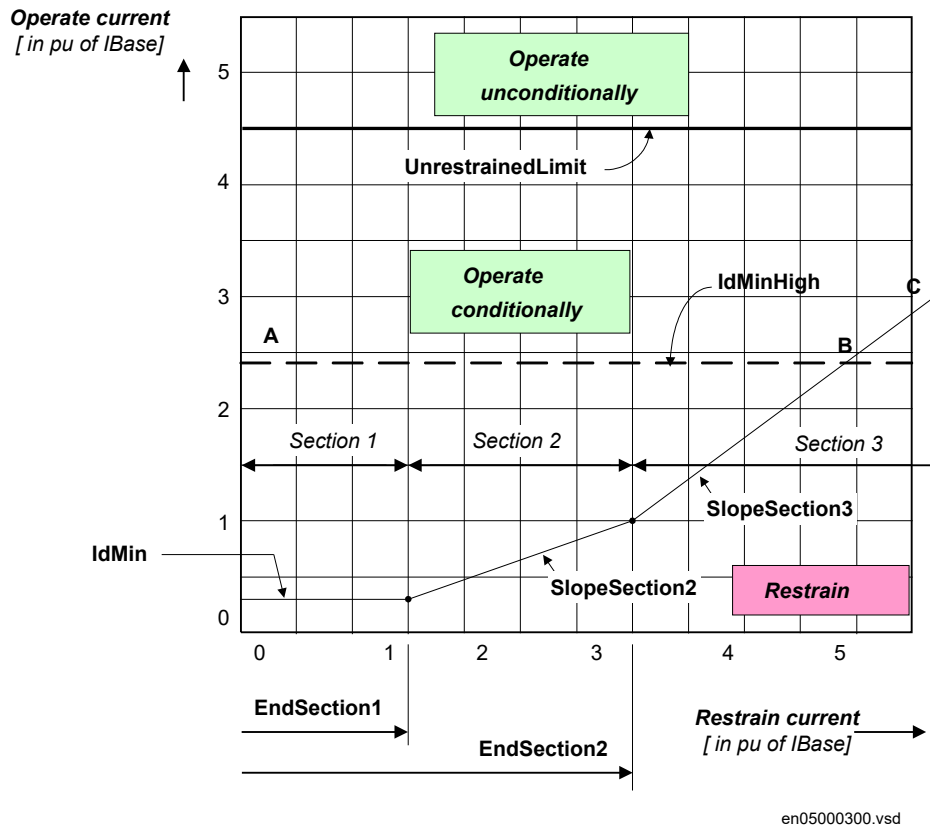


Figure 40: Restrained differential function characteristic (reset ratio 0.95)

where:

$$\text{slope} = \frac{\Delta I_{\text{operate}}}{\Delta I_{\text{restrain}}} \cdot 100\%$$

Line differential protection is phase-segregated where the operate current is the vector sum of all measured currents taken separately for each phase. The restrain current, on the other hand, is considered as the greatest phase current in any line end and it is common for all three phases.

IdMin

This setting is a multiple of *IBase* and must take into account the fundamental frequency line charging current, and whether a power transformer is included in the protected zone or not.

The positive sequence line charging current is calculated according to equation 15.

$$I_{\text{Ch arg e}} = \frac{U}{\sqrt{3} \cdot X_{C1}} = \frac{U}{\sqrt{3} \cdot \frac{1}{2\pi f \cdot C_1}}$$

(Equation 15)

where:

- U is system voltage
- X_{C1} is capacitive positive sequence reactance of the line
- f is system frequency
- C_1 is positive sequence line capacitance

If the charging current compensation is enabled, the setting of I_{dMin} must be: $I_{dMin} \geq 1.2 \times I_{Charge}$, considering some margin in the setting. If the charging current compensation is disabled, the setting of I_{dMin} must be $I_{dMin} \geq 2.5 \times I_{Charge}$. In many cases, the charging current is quite small, which makes the lower limit of the setting range, that is 20% of I_{Base} the practical limit of sensitivity.

When a power transformer is included in the protected zone, the setting of I_{dMin} shall be the highest of recommendations considering charging current as described above and $0.3 \times I_{Base}$.

$I_{dMinHigh}$

The $I_{dMinHigh}$ setting is a multiple of I_{Base} and used to temporarily decrease sensitivity in situations when the line is energized.

Energizing a line can cause transient charging currents to appear. These currents are pure differential currents, but as they are rich in harmonics, they can partly be measured by the differential protection, which in this case measures the Fourier-filtered differential current. Desensitizing the differential protection in this situation by using $I_{dMinHigh}$ instead of I_{dMin} is a safety precaution, and a setting of $1.00 \times I_{Base}$ should be suitable in most cases.

If there is a power transformer included in the protected zone, energizing the line means that the transformer is energized at the same time. If the transformer nominal current is more than 50% of I_{Base} , $I_{dMinHigh}$ is recommended to be set at $2.00 \times I_{Base}$, otherwise it can be kept at $1.00 \times I_{Base}$.

Switching of a transformer inside the protected zone does not normally occur. If the transformer is equipped with a breaker on the HV side, it would most probably not be included in the protected zone. However, tap transformers are sometimes connected with a disconnector on the HV side, and the normal procedure is then to energize the transformer with the disconnector. In such cases, where the tap (shunt) power transformer's power rating is relatively small in comparison to the normal load of the circuit, connecting the tap power transformer to the voltage source, that is, to the protected line circuit, does usually not result in inrush currents high enough to be detected by the differential protection. This is especially the case if the tap power transformer is connected at a junction somewhere towards the middle of the protected line circuit, because the inrush phenomenon is effectively prevented in such cases. If a start signal is nevertheless issued by the differential protection, then the 2nd harmonic will prevent an unwanted trip. Observe that the harmonic inhibit algorithm is active as long as the bias current is below 125% of the base current I_{Base} . (If there is an in-line power transformer included in the protected line circuit, then the harmonic inhibit algorithm is permanently activated, and can only be overridden if an internal fault has been detected.)

$tI_{dMinHigh}$

This setting defines the time that $I_{dMinHigh}$ will be active after the previously dead protected circuit has been connected to the power source. If a power transformer is included in the protection zone, due to long duration of transformer inrush current the parameter should be set to 60 s. Otherwise a setting of 1 s is sufficient.

I_{dUnre}

I_{dUnre} is set as a multiple of I_{Base} . Values of differential currents above the unrestrained limit generate a trip disregarding all other criteria, that is, irrespective of the internal or external fault discriminator and any presence of harmonics. It is intended for fast tripping of internal faults with high fault currents. The recommended setting is 120% of the highest through fault current that can appear on the protected line. Consequently, to set this value properly, the fault current must be calculated in each specific case.

For a short line or a situation with a 1½ breaker bay, the through fault current might be practically the same as the differential current at an internal fault. Extreme unequal CT saturation at external faults could then be a risk of unwanted operation if the unrestrained operation is used. Consequently, if the through fault currents can be of the same order as the maximum differential currents at internal faults, for example, when there is a source of power only on one side (in the branch with the first CT), and only load on the other side (in the branch with the other CT), it is recommended to refrain from using the unrestrained operation, by setting the max value $I_{dUnre} = 50 \times I_{Base}$.

On long lines, the through fault current is often considerably less than the maximum differential current at internal faults, and a suitable setting of the unrestrained level is then easy to calculate.

When a transformer is included in the protected zone, the maximum inrush current must be considered when the unrestrained level is calculated. The inrush current appears from one side of the transformer, while the maximum differential current at internal faults is limited by the source impedances on all sides of the transformer. Observe that if the power transformer is energized via a power line, even a short one, the inrush phenomenon is much less pronounced. The fundamental frequency of the inrush current will not be as high as when the power transformer is connected directly to a source with very low internal impedance.

EndSection1

EndSection1 is set as a multiple of *I_{Base}*. The default value 1.25 is generally recommended. If the conditions are known more in detail, other values can be chosen in order to increase or decrease the sensitivity.

EndSection2

EndSection2 is set as a multiple of *I_{Base}*. The default value 3.00 is generally recommended. If the conditions are known more in detail, other values can be chosen in order to increase or decrease the sensitivity.

SlopeSection2

SlopeSection2 is set as a percentage value: $[\text{delta operate current} / \text{delta restrain current}] \times 100\%$. The default value 40.0 is generally recommended. If the conditions are known more in detail, other values can be chosen in order to increase or decrease the sensitivity.

SlopeSection3

SlopeSection3 is set as a percentage value: $[\text{delta operate current} / \text{delta restrain current}] \times 100\%$. The default value 80.0 is generally recommended. If the conditions are known more in detail, other values can be chosen in order to increase or decrease the sensitivity.

6.1.3.3 The 2nd and 5th harmonic analysis

The 2nd and 5th harmonic block scheme is permanently active only if an in-line power transformer (A or B, alternatively both A and B) is part of the protected circuit. This is a must due to phenomena specific for power transformers, such as inrush and over-excitation. If there is no power transformer included in the protected multi-terminal line circuit, then the 2nd and 5th harmonic block scheme is only active under the following conditions:

- If the bias current is lower than 1.25 times *I_{Base}*.
- Under external fault conditions.
- If *NegSeqDiffEn* = *Off* (the default is *On*)

When the harmonic content is above the set level, the restrained differential operation is blocked. However, if a fault has been classified as internal by the negative sequence fault discriminator, any harmonic restraint is overridden.

I2/I1Ratio

The set value is the ratio of the 2nd harmonic component of the differential current to the fundamental frequency component of the differential current. To obtain this information, the instantaneous differential current must be analyzed.

Transformer inrush currents cause high degrees of the 2nd harmonic in the differential current. The default value of 15% is a reliable value to detect power transformer inrush currents.

CT saturation causes 2nd harmonics of considerable value on the CT secondary side, which contributes to the stabilization of the relay at through fault conditions. It is strongly recommended to maintain a sensitive setting of the *I2/I1Ratio* also when a power transformer is not included in the protected zone.

I5/I1Ratio

The set value is the ratio of the 5th harmonic of the differential current to the fundamental frequency of the differential current. To obtain this information, the instantaneous differential current must be analyzed.

A 20...30% over-excitation of a transformer can cause an increase in the excitation current of 10...100 times the normal value. This excitation current is a true differential current if the transformer is inside the protected zone. It has a high degree of the 5th harmonic, and the default setting of 25% will be suitable in most cases to detect the phenomenon. As CT saturation also causes 5th harmonics on the secondary side, it is recommended to maintain this setting at 25% or lower even if no power transformer is included in the protected zone.

6.1.3.4 Internal/external fault discriminator

NegSeqDiffEn

The negative sequence fault discriminator can be set *On/Off*. It is an important complement to the percentage restrained differential function. As it is directional, it can distinguish between external and internal faults also in difficult conditions, such as CT saturation, and so on. It is strongly recommended that it is always activated (*On*).

NegSeqROA

This is the setting of the relay operate angle of the negative sequence current based internal/external fault discriminator. The directional test is made so that the end with the highest negative sequence current is found. Then, the sum of the negative sequence currents at all other circuit ends is calculated. Finally, the relative phase angle between these two negative sequence currents is determined. See figure 41. Ideally the angle is zero degrees for internal faults and 180 degrees for external faults. However, measuring errors caused by, for example, CT saturation as well as different phase angles of the negative sequence impedances, require a safety margin, expressed as the ROA (Relay Operate Angle). The default value 60 degrees is recommended in most cases. The setting *NegSeqROA* is a compromise between the security and dependability of the differential protection. The value *NegSeqROA* = 60 degrees emphasizes security against dependability. Tests have proven that 60 degrees is a good choice.

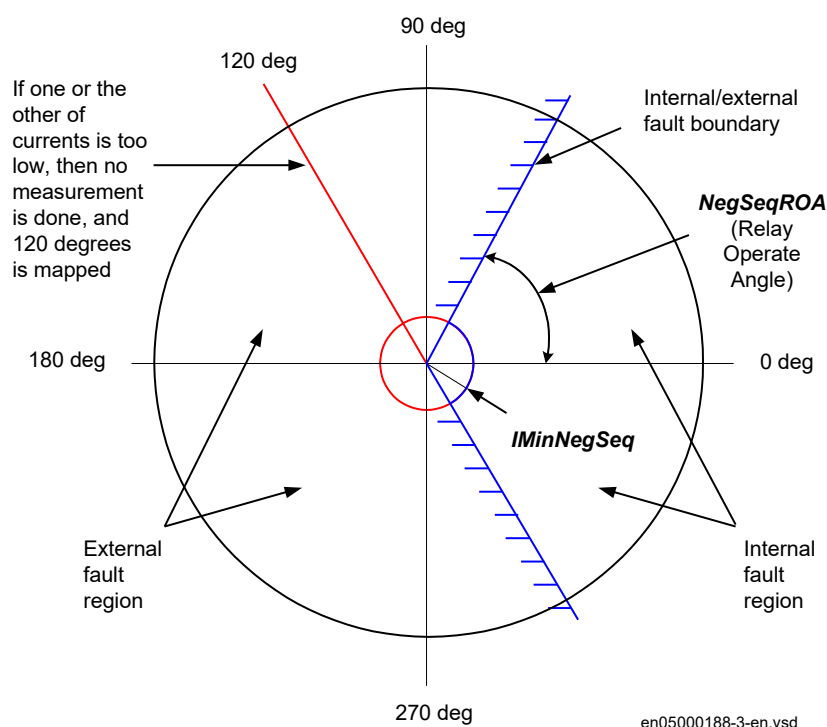


Figure 41: Negative sequence current function Relay Operate Angle (ROA)

IminNegSeq

IminNegSeq is set as a multiple of *IBase*. The local, and the sum of all remote negative sequence currents are compared separately if they are above the set threshold value *IminNegSeq*. If either is below the threshold, no comparison is made. Neither internal nor external fault is declared in this case. The default value $0.04 \times IBase$ can be used if no special considerations, such as extremely weak sources, are taken into account. Observe that internally, whenever the bias current is higher than 1.5 times *IBase*, the actual threshold is equal to the sum of *IminNegSeq* + 0.1 *Ibias*. This is in order to prevent wrong decisions of the internal/external fault discriminator under heavy three-phase external fault conditions with severe CT saturation.

6.1.3.5 Power transformers in the protected zone

One three-winding transformer or two two-winding transformers can be included in the line protection zone. The alternative with one two-winding transformer in the protected zone is shown in Figure 42 and Figure 43.

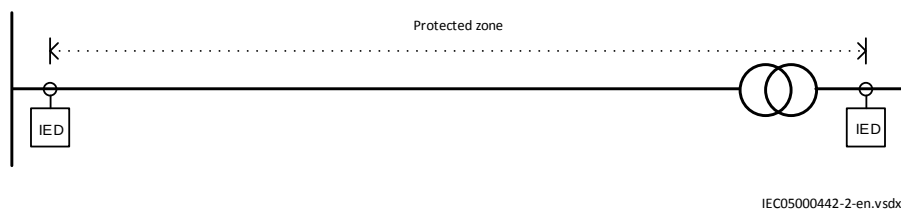


Figure 42: One two-winding transformer in the protected zone

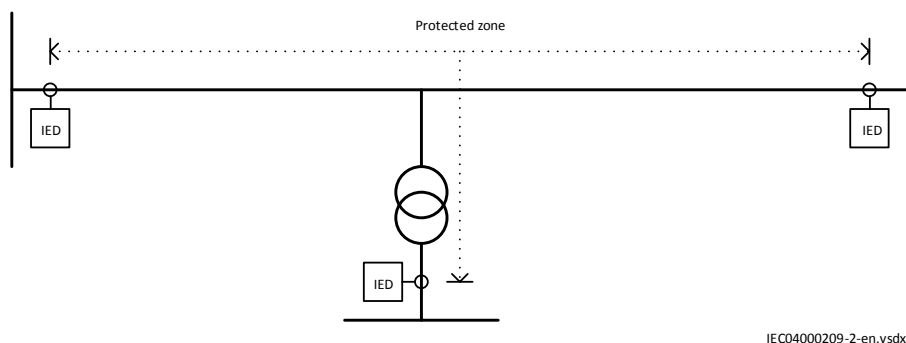
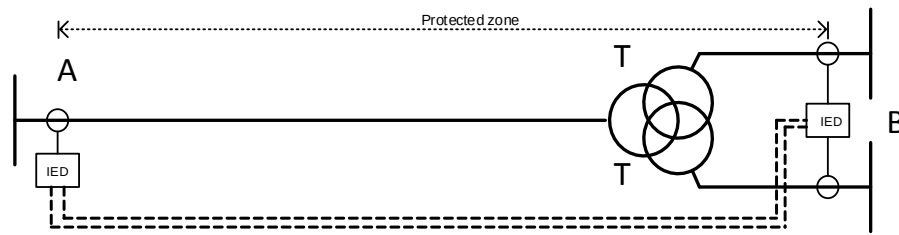


Figure 43: One two-winding transformer in the protected zone

Another alternative is with one three-winding transformer in the protected zone, shown in Figure 44. Observe that in this case, the three-winding power transformer is seen by the differential protection as two separate power transformers, A and B, which have one common winding on the HV side.



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Figure 44: One three-winding transformer in the protected zone

TraAOnInpCh

This parameter is used to indicate that a power transformer is included in the protection zone at current terminal X. This can be either a two-winding transformer or the first secondary winding of a three-winding transformer. The current transformer feeding the IED is located at the low voltage side of the transformer. The parameter is set within the range 0...3, where 0 (zero) is used if no transformer A is included in the protection zone. This is one of the few settings that can be set differently for each separate master IED.

The setting specifies the current input on the differential current function block where the input current must be recalculated, that is, referred to the high voltage side, which is the reference side of the differential protection. The measured current, fed to the input channel determined by the setting *TraAOnInpCh*, will be recalculated to $I \cdot \text{RatVoltW2TraA} / \text{RatVoltW1TraA}$ and shifted counterclockwise by the angle, determined by the product $\text{ClockNumTransA} \times 30$ degrees.

RatVoltW1TraA

The rated voltage (kV) of the primary side (line side = high voltage side) of the power transformer A.

RatVoltW2TraA

The rated voltage (kV) of the secondary side (non-line side = low voltage side) of the power transformer A.

ClockNumTransA

This is the phase shift from primary to secondary side for power transformer A. The phase shift is given in intervals of 30 degrees, where 1 is -30 degrees, 2 is -60 degrees, and so on. The parameter can be set within the range 0...11.

TraBOnInpCh

This parameter is used to indicate that a power transformer is included in the protection zone at current terminal Y. This can be either a two-winding transformer or the second secondary winding of a three-winding transformer. The current transformer feeding the IED is located at the low voltage side of the transformer. The parameter is set within the range 0...3, where zero is used if no transformer B is included in the protection zone.

The setting specifies the current input on the differential current function block where the input current must be recalculated, that is, referred to the high voltage side, which is the reference side of the differential protection. The set input measured current I will be recalculated to $I \times \text{RatVoltW2TraB} / \text{RatVoltW1TraB}$ and shifted counterclockwise by the angle, determined by the product $\text{ClockNumTransB} \times 30$ degrees.

RatVoltW1TraB

The rated voltage (kV) of the primary side (line side = high voltage side) of the power transformer B.

RatVoltW2TraB

The rated voltage (kV) of the secondary side (non-line side = low voltage side) of the power transformer B.

ClockNumTransB

This is the phase shift from primary to secondary side for power transformer B. The phase shift is given in intervals of 30 degrees, where 1 is -30 degrees, 2 is -60 degrees and so on. The parameter can be set within the range 0 – 11.

ZerSeqCurSubtr

The elimination of zero sequence currents in the differential protection can be set *On/Off*. In case of a power transformer in the protected zone, where the zero sequence current cannot be transformed through the transformer, that is, in the great majority of cases, the zero sequence current must be eliminated.

ZerSeqCurSubtr must be set *On* if there is a transformer in the zone. The zero sequence currents are then subtracted from all current terminals.

CrossBlockEn

The possibility of cross-blocking can be set *On/Off*. The meaning of cross-blocking is that the 2nd and 5th harmonic blocking in one phase also blocks the differential function of the other phases. It is recommended to enable the cross-blocking if a power transformer is included in the protection zone, otherwise not.

IMaxAddDelay

IMaxAddDelay is set as a multiple of *IBase*. The current level, under which a possible extra added time delay (of the output trip command), can be applied. The possibility for delayed operation for small differential currents is typically used for lines with a (minor) tapped transformer somewhere in the protected circuit and where no protection terminal of the multi-terminal differential protection is applied at the transformer site. If such a minor tap transformer is equipped with a circuit breaker and its own local protection, then this protection must operate before the line differential protection to achieve selectivity for faults on the low voltage side of the transformer. To ensure selectivity, the current setting must be higher than the greatest fault current for faults at the high voltage side of the transformer.

AddDelay

The possibility of delayed operation for small differential currents can be set *On/Off*.

CurveType

This is the setting of type of delay for low differential currents.

tMinInv

This setting limits the shortest delay when inverse time delay is used. Operation faster than the set value of *tMinInv* is prevented.

If the user-programmable curve is chosen the characteristic of the curve is defined by equation [16](#).

$$t_{op} = k \cdot \left(\frac{a}{\left(\frac{I_{Measured}}{IMaxAddDelay} \right)^p - c} + b \right)$$

(Equation 16)

where:

 t_{op} is operate time

k is time multiplier of the inverse time curve

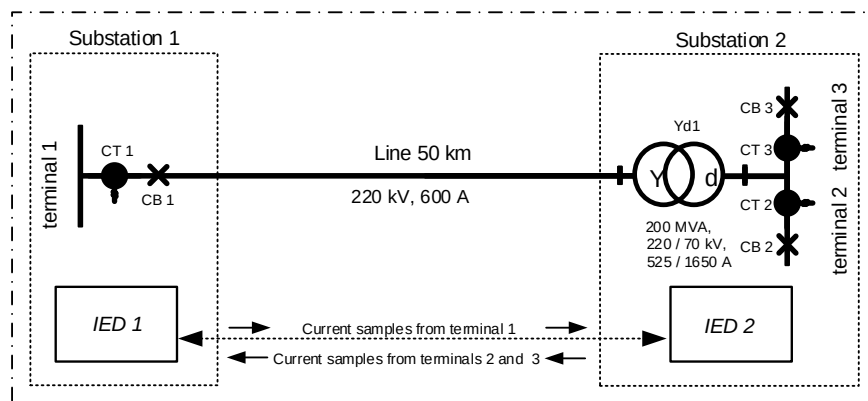
a, b, c, p are settings that will model the inverse time characteristic

6.1.3.6 Settings examples

Setting example with a power transformer in the protected zone

Figure 45 shows a line with a power transformer in the protected zone. Circuit impedances are presented in Figure 46. The protected zone is limited by three current transformers: CT1, CT2 and CT3. IEDs are situated in two separate substations 1 and 2.

The circuit is protected by two terminals 1 and 2. These terminals process the same data except for minor distortion in data that takes place during communication between them. Both terminals operate as masters. If at least one of them indicates an internal fault, the protected circuit is disconnected.



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Figure 45: Line differential protection with a power transformer in the protected zone

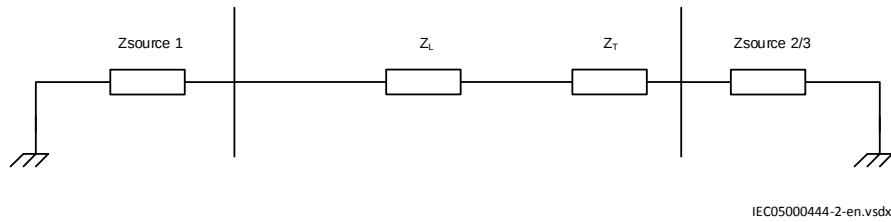


Figure 46: Circuit impedances

where:

Line data is

$$Z_L \approx X_L = 15.0\Omega$$

Transformer data is

$$X\% = 10\% \Rightarrow X_{T220} = \frac{10}{100} \cdot \frac{220^2}{200} = 24.2\Omega$$

Source impedance is

$$Z_{Source1} = 7.0\Omega$$

$$Z_{Source2/3} = 5\Omega \Rightarrow (Z_{Source2/3})_{220} = \left(\frac{220}{70}\right)^2 \cdot 5 = 49.4\Omega$$

Table 11: General settings

Setting	IED 1	IED 2	Description
Operation	On	On	Operation Mode (active)
NoOfTerminals	3	3	Number of current sources/ circuit ends
IBase (Global base)	600 A	600 A	Reference current of the protection in the primary system (note 1) IBase is set in the Global base values function (GBASVAL).
TransfAonInpCh	2	1	Input currents on the input channels are referred to the high voltage side (note 2)
TraAWind1Volt	220 kV	220 kV	Transformer A: Y-side voltage
TraAWind2Volt	70 kV	70 kV	Transformer A: d-side voltage
ClockNumTransA	1	1	LV d-side lags Y-side by 30 degrees
TransfBonInpCh	3	2	Input currents on the input channels are referred to the high voltage side (note 2)
TraBWind1Volt	220 kV	220 kV	Transformer B: Y-side voltage
TraBWind2Volt	70 kV	70 kV	Transformer B: d-side voltage
ClockNumTransB	1	1	LV d-side lags Y-side by 30 degrees
ZerSeqCurSubtr	On	On	Zero-sequence currents are subtracted from differential and bias currents (note 3)

Table 12: Setting group N

Setting	IED 1	IED 2	Description
ChargCurEnable	Off	Off	Charging current not eliminated (default)
IdMin	$0.35 \cdot I_{Base}$	$0.35 \cdot I_{Base}$	Sensitivity in Section 1 of the operate-restrain characteristic
EndSection1	$1.25 \cdot I_{Base}$	$1.25 \cdot I_{Base}$	End of section 1 of the operate-restrain characteristic
EndSection2	$3.00 \cdot I_{Base}$	$3.00 \cdot I_{Base}$	End of section 2 of the operate-restrain characteristic
SlopeSection2	40%	40%	Slope of the operate-restrain characteristic in Section 2
SlopeSection3	80%	80%	Slope of the operate-restrain characteristic in Section 3
IdMinHigh	$2.00 \cdot I_{Base}$	$2.00 \cdot I_{Base}$	Temporarily decreased sensitivity used when the protected circuit is connected to a power source (note 4)
IntervIdMinHig	30.000 s	30.000 s	Time interval when IdMinHig is active (note 5)
Idunre	$5.50 \cdot I_{Base}$	$5.50 \cdot I_{Base}$	Unrestrained operate (differential) current limit (note 6)
CrossBlock	1	1	CrossBlock logic scheme applied (note 7)
I2/I1Ratio	15%	15%	Second to fundamental harmonic ratio limit
I5/I1Ratio	25%	25%	Fifth to fundamental harmonic ratio limit
NegSeqDiff	On	On	Internal/external fault discriminator enabled (default)
IminNegSeq	$0.04 \cdot I_{Base}$	$0.04 \cdot I_{Base}$	Minimum value of the negative-sequence current
NegSeqROA	60.0 deg	60.0 deg	Operate angle (ROA) for Internal/external fault discriminator (default)
AddDelay	Off	Off	Additional delay disabled (default)
ImaxAddDelay	$1.00 \cdot I_{Base}$	$1.00 \cdot I_{Base}$	Not applicable in this case (default)
CurveType	15	15	Not applicable in this case (default)
DefDelay	0.100 s	0.100 s	Not applicable in this case (default)
IDMTtMin	0.010 s	0.010 s	Not applicable in this case (default)
TD	0.00	0.00	Not applicable in this case (default)
Table continues on next page			

Setting	IED 1	IED 2	Description
p	0.02	0.02	Not applicable in this case (default)
a	0.14	0.14	Not applicable in this case (default)
b	1.00	1.00	Not applicable in this case (default)
c	1.00	1.00	Not applicable in this case (default)

Notes:

- 1 *I*Base (set in GBASVAL) is the reference current of the line differential protection given in primary Amperes. CT1 in terminal 1 has a ratio of 600/1 and that is why 600 A is chosen for *I*Base in this example.
- 2 Only one physical power transformer is included in the protected circuit. However, to handle the situation with two CTs on the low-voltage side of the transformer, one more fictitious power transformer is introduced. Thus, transformer A can be thought of as being installed at CT2, and transformer B, which is identical to A, can be thought of as being installed at CT3. Currents measured at CT2 and CT3 are internally separately referred to the high-voltage side of the transformer by the multi-terminal differential algorithm using the same transformation rule. This rule is defined by the power transformer transformation ratio and its type (Yd1 in this example). If an in-line power transformer is included in the protected zone, the protected power lines are usually on the high-voltage side of the in-line power transformer. The differential algorithm always transforms the low-voltage side currents to the high-voltage side.
- 3 Earth faults on the Y-side of the transformer cause a zero sequence current that flows in the Y-winding of the power transformer. This current does not appear outside the transformer on the d-side, and is consequently not measured by CT2 and CT3. Thus, if Y-side earth fault is external to the protected zone, zero sequence current that passes the neutral point of the transformer appears as a false differential current. This can cause an unwanted trip if zero sequence currents are not subtracted from all three fundamental frequency differential currents.
- 4 Energizing the circuit means that the power transformer is energized at the same time. It is assumed that this is always made from the high-voltage side, and the harmonic restraint detects the inrush current and prevents a trip. Setting *IdMinHigh* = 2.00 · *I*Base is justified in this case since the transformer is large.
- 5 The interval when *IdMinHigh* is active is set to 60 s because a power transformer is included in the protected zone. As both IEDs process the same currents, both must have the same value set for *IdMinHigh*.
- 6 The unrestrained operate (differential) current limit should be greater than the highest through fault current. This current appears at a three-phase short circuit on the 33 kV side of the transformer and can be calculated as:

$$I_{Through} = \frac{220}{\sqrt{3} \cdot (7.0 + 15.0 + 24.2)} = 2.75 \text{ kA}$$

(Equation 21)

With a safety margin of 20%:

$$I_{dunre} = \frac{1.2 \cdot I_{Through}}{I_{base}} = \frac{1.2 \cdot 2.75 \text{ kA}}{0.6 \text{ kA}} = \frac{3.30 \text{ kA}}{0.6 \text{ kA}} = 5.50$$

(Equation 22)

- 7 The cross-block logic should always be active when there is a power transformer in the protected zone.

Setting example with a small tap transformer in the protected zone

A typical example is shown in Figure [47](#)

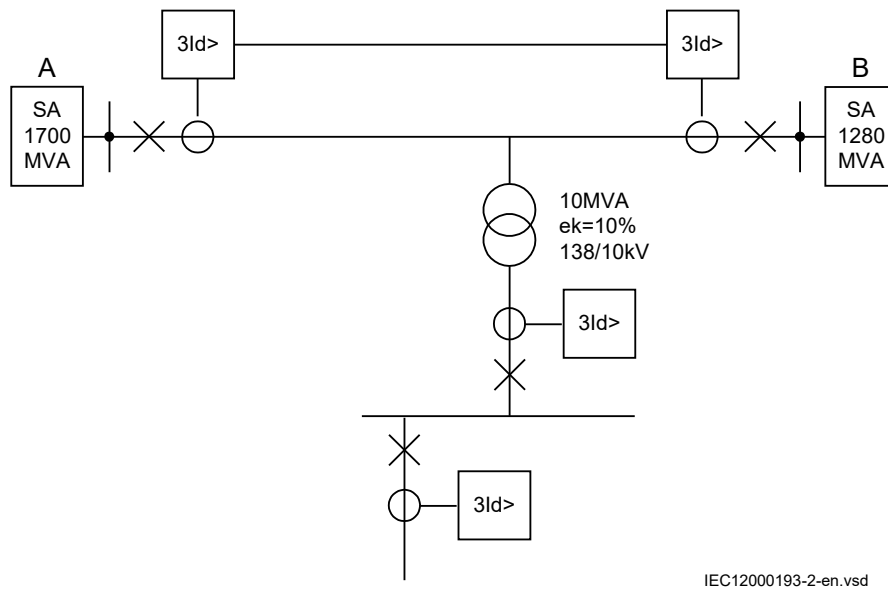


Figure 47: Setting example

Input data to calculation:

- Apparent source power at A side: $S_{sA} = 1700 \text{ MVA}$
- Line impedance from A to tap: $Z_{IA} = 2.8 \Omega$
- Line impedance from tap to B side: $Z_{IB} = 1.2 \Omega$
- Apparent source power at B side: $S_{sB} = 1280 \text{ MVA}$
- Base current of differential current protection: $I_{Base} = 42 \text{ A}$
- Apparent power of transformer: $S_n = 10 \text{ MVA}$
- Short circuit impedance of transformer: $e_k = 10\%$
- Nominal voltage on transformer high voltage winding: $U_n = 138 \text{ kV}$

Fault current on the high voltage (HV) side of the tap transformer is calculated for a three-phase fault on the low voltage (LV) side. 138 kV is chosen as calculation voltage.

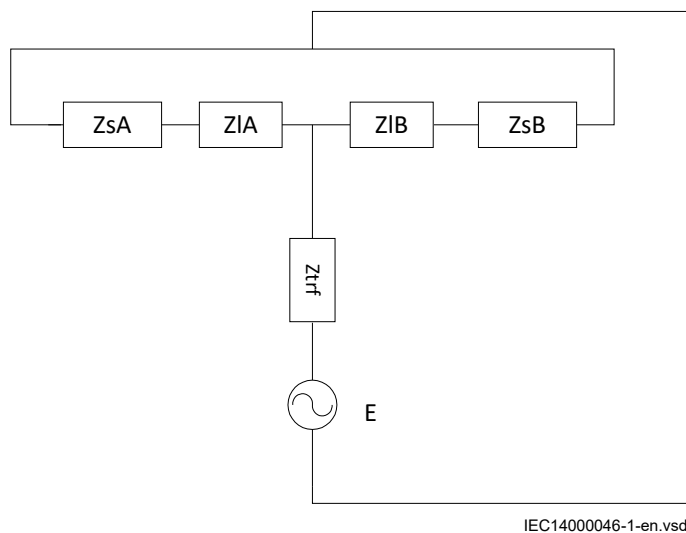


Figure 48: Thevenin equivalent of the tap transformer

Converting the sources into impedances gives:

$$Z_{S_A} = \frac{138^2}{1700} = 11.2 \Omega$$

(Equation 23)

$$Z_{S_B} = \frac{138^2}{1200} = 15.9 \Omega$$

(Equation 24)

Calculating the short circuit impedance of the transformer gives:

$$Z_{trf} = \frac{e_k}{100} \times \frac{U_n^2}{S_n} = 0.1 \times \frac{138^2}{10} = 190.4 \Omega$$

(Equation 25)

Based on the Thevenin equivalent, it is possible to calculate the fault current on the HV side of the transformer:

$$I_{f_{138}} = \frac{138}{\sqrt{3 \times Z_{res}}}$$

(Equation 26)

where:

$$Z_{res} = \frac{(Z_{S_A} + Z_{L_a}) \times (Z_{S_B} + Z_{L_B})}{Z_{S_A} + Z_{L_a} + Z_{S_B} + Z_{L_B}} + Z_{trf} = 198 \Omega$$

(Equation 27)

The numerical value for Z_{res} input in the formula for $I_{f_{138}}$ gives $I_{f_{138}} = 403 \text{ A}$

To avoid unwanted operation of the differential protection for a fault on the LV side of the transformer, *IdMin* must be set to:

$$> 1.2 \times \frac{I_{f_{138}}}{I_{Base}}$$

(Equation 28)

$$IdMin = 1.2 \times \frac{I_{f_{138}}}{I_{Base}} = 11.5$$

(Equation 29)

To allow the differential protection to act as a backup protection for internal faults and faults on the LV side of the transformer, *AddDelay* is set to *On*, and a suitable setting is calculated for *Imax AddDelay*. Differential currents below the set value for *Imax AddDelay* are time delayed. Value two times the rated current of the transformer on the HV side is chosen. The setting is calculated as:

$$ImaxAddDelay = 2 \times \frac{S_n}{\sqrt{3} \times U_n \times I_{Base}} = 2.0$$

(Equation 30)

Table 13: Backup protection example data

Station	Tap transformer 10 MVA		
Type of fault	Three phase fault		
Object	1 = 10 kV Line A	2 = T1 10 kV 50/51	3 = 130 kV 87L (ImaxAddDelay)
Setting	2 MVA	14 MVA	20 MVA
Characteristic	IEC Extr.inverse, k=0.5, A=80, p=2	IEC Norm.inverse k=0.12, A=0.14, p=0.02	IEC Norm.inverse k=0.18, A=0.14, p=0.02
High set stage	14 MVA	----	----

It is important to achieve a proper back-up protection. The short circuit protection on the outgoing bays and on the LV side of the transformer are set according to a prepared selectivity chart. An example in Figure 49 shows that the setting of the short circuit protection on the LV side is 14 MVA, and Normal Inverse has k=0.12 to give back-up to outgoing bays' relays which are extremely inverse and selective to remote fuses.

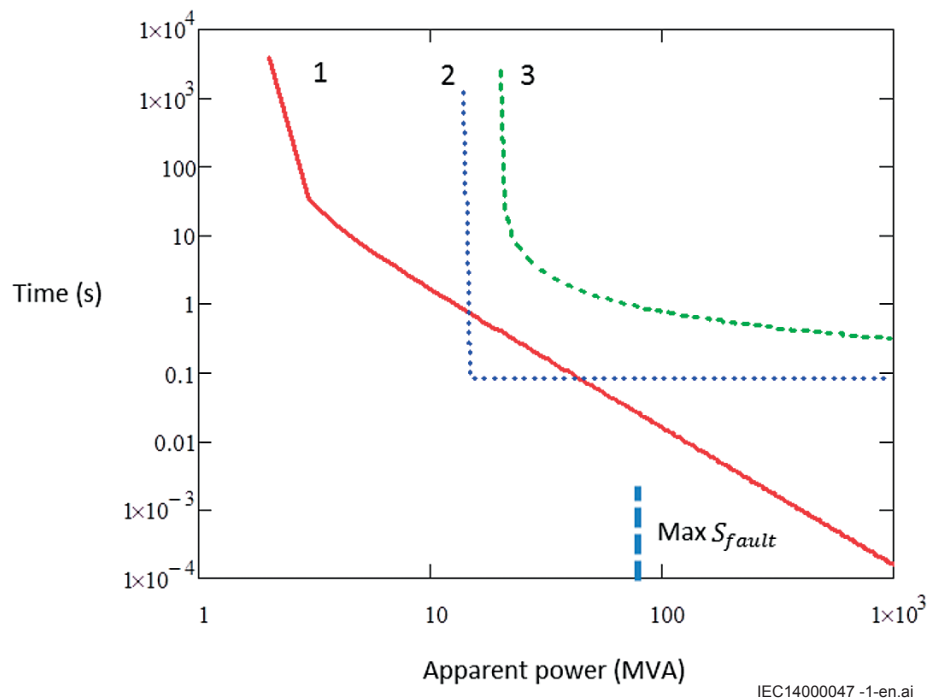


Figure 49: Selectivity chart

Setting example with two transformers in the protected zone (master-slave differential operation)

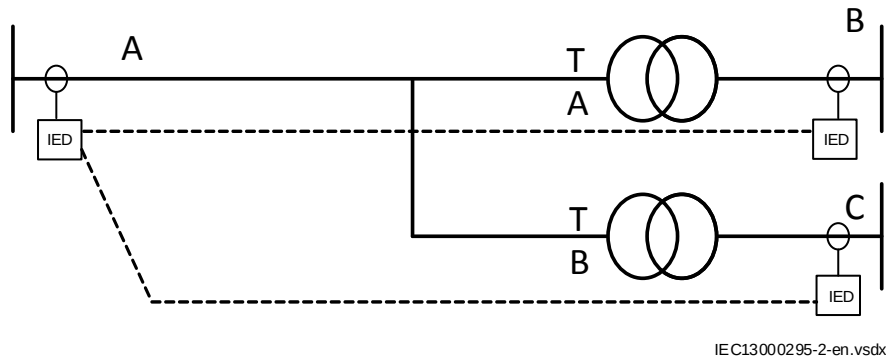


Figure 50: Master- slave differential operation

Setting	Station A	Station B	Station C
PDIF	L3TCPDIF		
NoOfUsedCTs	3		
TraAOnInpCh	2		
TraBOnInpCh	3		

Protection functions in stations B and C operate as slaves (differential function switched off) so currents are sent to protection function in station A, and received on channels 2 and 3. To inform the differential algorithm that currents are coming from the LV sides of the transformers, *TraAOnInpCh* must be set to 2 and *TraBOnInpCh* to 3 (channel1 is reserved for local measurement). This is to ensure that proper turn ratio and vector group correction is done.

Setting example with a three-winding transformer in the protected zone

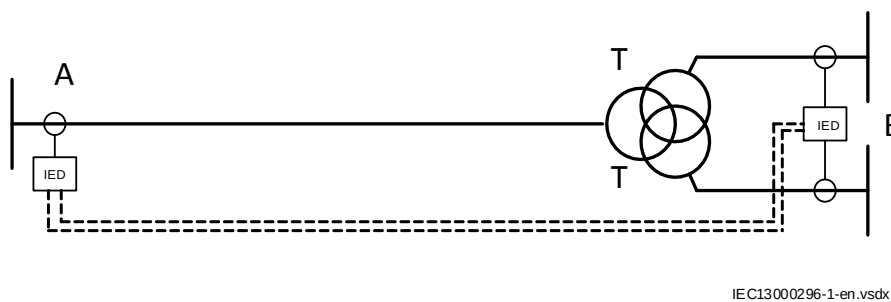


Figure 51: Three-winding transformer in the zone

Settings	Station A	Station B
PDIF	L3TCPDIF	L3TCPDIF
<i>NoOfUsedCTs</i>	3	3
<i>TraAOnInpCh</i>	2	1
<i>TraBOnInpCh</i>	3	2

Currents from the secondary and tertiary windings of the power transformer are connected to one line differential protection IED. Currents for each CT group are sent to the IED at station A by the LDCM. To inform the differential algorithm that currents are coming from the LV sides of the transformers, *TraAOnInpCh* must be set to 2 and *TraBOnInpCh* to 3 (channel1 is reserved for local measurement). This is to ensure that proper turn ratio and vector group correction is done.

6.2 Additional security logic for differential protection LDRGFC

6.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Additional security logic for differential protection	LDRGFC	-	11

6.2.1.1 Function revision history

Document revision	Product revision	History
A	2.2.1	-
B	2.2.1	-
C	2.2.1	-
E	2.2.4	Function cycle time changed from 8 ms to 3 ms
G	2.2.5	-
J	2.2.6	-
K	2.2.6	-

6.2.2 Application

Additional security logic for differential protection LDRGFC can help the security of the protection especially when the communication system is in abnormal status or for example when there is unspecified asymmetry in the communication link. It reduces the probability for mal-operation of the protection. LDRGFC is more sensitive than the main protection logic to always release operation for all faults detected by the differential function. LDRGFC consists of four sub functions:

- Phase-to-phase current variation
- Zero sequence current criterion
- Low voltage criterion
- Low current criterion

Phase-to-phase current variation takes the current samples (IL1–IL2, IL2–IL3, etc.) as input and it calculates the variation using the sampling value based algorithm. Phase-to-phase current variation function is major one to fulfil the objectives of the start up element.

Zero sequence criterion takes the zero sequence current as input. It increases security of protection during high impedance fault conditions.

Low voltage criterion takes the phase voltages and phase to phase voltages as inputs. It increases the security of protection when the three phase fault occurred on the weak end side.

Low current criterion takes the phase currents as inputs and it increases the dependability during the switch onto fault case of an unloaded line.

The differential function can be allowed to trip as no load is fed through the line and protection is not working correctly.

Features:

- Startup element is sensitive enough to detect the abnormal status of the protected system
- Startup element does not influence the operation speed of main protection
- Startup element detects the evolving faults, high impedance faults and three phase fault on weak side
- It is possible to block the each sub function of startup element
- Startup signal has a settable pulse time

The Additional security logic for differential protection LDRGFC is connected as a local criterion to release the tripping from line differential protection. LDRGFC is connected with an AND gate to the trip signals from LDLPDIF function. Figure 52 shows a configuration for three phase tripping, but LDRGFC can be configured with individual release to all phases trip. The START signal can also, through one of the available binary signal transfer channels, be sent to remote end and there connected to input REMSTUP. Normally, the local criterion is sufficient.

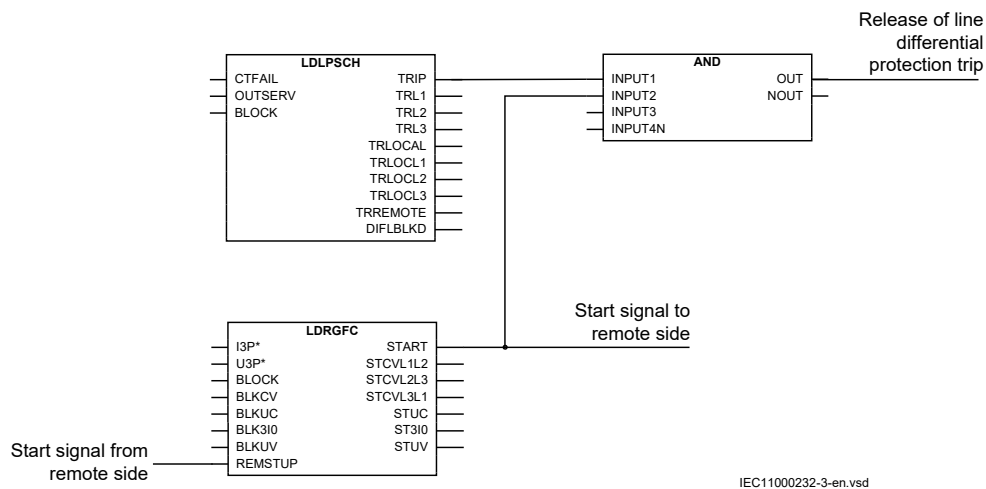


Figure 52: Local release criterion configuration for line differential protection

6.2.3 Setting guidelines

GlobalBaseSel: Selects the global base value group used by the function to define *I*Base, *U*Base and *S*Base. Note that this function will only use *I*Base value.

tStUpReset: Reset delay of the startup signal. The default value is recommended.

Settings for phase-phase current variation subfunction are described below.

OperationCV: *On/Off*, is set *On* in most applications

ICV>: Level of fixed threshold given in % of *I*Base. This setting should be based on fault calculations to find the current increase in case of a fault at the point on the protected line giving the smallest fault current to the protection. The phase current shall be calculated for different types of faults (single phase-to-earth, phase-to-phase to earth, phase-to-phase and three phase short circuits) at different switching states in the network. In case of switching of large objects (shunt capacitor banks, transformers, and so on) large changes in current can occur. The *ICV*> setting should ensure that all multi-phase faults are detected.

tCV: Time delay of phase-to-phase current variation. Default value 0.002 s is recommended

Settings for zero sequence current criterion subfunction are described below.

Operation3I0: *On/Off*, is set *On* for detection of phase-to-earth faults with high sensitivity

3I0> : Level of high zero sequence current detection given in % of *I*Base. This setting should be based on fault calculations to find the zero sequence current in case of a fault at the point on the protected line giving the smallest fault current to the protection. The zero sequence current shall be calculated for different types of faults (single phase-to-earth and phase to phase to earth) at different switching states in the network.

t3I0: Time delay of zero sequence overcurrent criterion. Default value 0.0 s is recommended

Setting for low voltage criterion subfunction are described below.

OperationUV: *On/Off*, is set *On* for detection of faults by means of low phase-to-earth or phase-to-phase voltage

UPhN<: Level of low phase-earth voltage detection, given in % of *U*Base. This setting should be based on fault calculations to find the phase-earth voltage decrease in case of a fault at the most remote point where the differential protection shall be active. The phase-earth voltages shall be calculated for different types of faults (single phase-to-earth and phase to phase to earth) at different switching states in the network. The setting must be higher than the lowest phase-earth voltage during non-faulted operation.

UPhPh<: Level of low phase-phase voltage detection, given in % of *U*Base. This setting should be based on fault calculations to find the phase-phase voltage decrease in case of a fault at the most remote point where the differential protection shall be active. The phase-phase voltages shall be calculated for different types of faults (single phase to earth and phase to phase to earth) at different switching states in the network. The setting must be higher than the lowest phase-phase voltage during non-faulted operation.

tUV: Time delay of undervoltage criterion. Default value 0.0 s is recommended

Settings for low current criterion subfunction are described below.

OperationUC: *On/Off*, is set *On* when tripping is preferred at energizing of the line if differential does not behave correctly.

IUC<: Level of low phase current detection given in % of *I*Base. This setting shall detect open line ends and be below normal minimum load.

tUC: Time delay of undercurrent criterion. Default value is recommended to verify that the line is open.

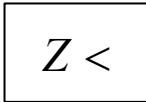
Section 7 Impedance protection

7.1 Distance protection ZMFPDIS

7.1.1 Function revision history

Document revision	Product revision	History
A	2.2.1	Impedance measurement and supervision added (ZMMXU).
B	2.2.1	-
C	2.2.1	-
D	2.2.4	-
E	2.2.4	Zone BU (Backup) is added. Now there are seven zones in total. Zone 2 direction and directional blinders (<i>ArgDir</i> , <i>ArgNegRes</i>) are now settable. Setting <i>tTauDC</i> is added; a parameter for optional fine tuning of performance. Added new setting <i>RStart</i> , which limits the resistive reach of the phase selection outside of the <i>ArgLd</i> sector. Changed setting name <i>XLd</i> to <i>XStart</i> . Added information about grouping of complex values and Dynamic Amplitude deadband monitoring.
F	2.2.5	ORCND input added with corresponding logic that supplements internal phase selection.
L	2.2.6	-
M	2.2.6	Features for some alternative earthing types (Petersén coil/Isolated and Neutral resistance), enabled by connecting to the PPL2PHIZ function. The load compensation of the measuring zones may now be enabled and disabled by a setting. New continuous phase selection based on the voltage symmetrical components replaced the existing one.

7.1.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Distance protection zone	ZMFPDIS		21

7.1.3 Application

The distance protection function in the IED is designed to meet basic requirements for application on transmission and sub-transmission lines (solid earthed systems) although it can also be used on distribution levels.

Sub-transmission networks are being extended and often become more and more complex, consisting of a high number of multi-circuit and/or multi terminal lines of very different lengths. These changes in the network will normally impose more stringent demands on the fault clearing equipment in order to maintain an unchanged or increased security level of the power system.

7.1.3.1 System earthing

The type of system earthing plays an important role when designing the protection system. Some hints with respect to distance protection are highlighted below.

Solidly earthed networks

In solidly earthed systems, the transformer neutrals are connected directly to earth without any impedance between the transformer neutral and earth.

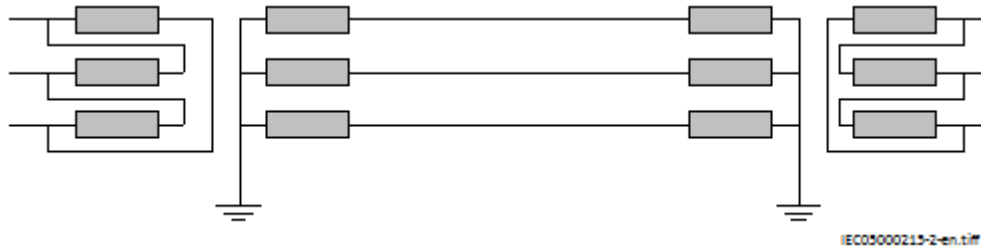


Figure 53: Solidly earthed network

The earth-fault current is as high or even higher than the short-circuit current. The series impedances determine the magnitude of the fault current. The shunt admittance has very limited influence on the earth-fault current. The shunt admittance may, however, have some marginal influence on the earth-fault current in networks with long transmission lines.

The earth-fault current at single phase-to-earth in phase L1 can be calculated as equation 31:

$$3I_0 = \frac{3 \cdot U_{L1}}{Z_1 + Z_2 + Z_0 + 3Z_f} = \frac{U_{L1}}{Z_1 + Z_N + Z_f}$$

(Equation 31)

Where:

- U_{L1} is the phase-to-earth voltage (kV) in the faulty phase before fault
- Z_1 is the positive sequence impedance (Ω /phase)
- Z_2 is the negative sequence impedance (Ω /phase)
- Z_0 is the zero sequence impedance (Ω /phase)
- Z_f is the fault impedance (Ω), often resistive
- Z_N is the earth-return impedance defined as $(Z_0 - Z_1)/3$

The high zero-sequence current in solidly earthed networks makes it possible to use impedance measuring techniques to detect earth faults. However, distance protection has limited possibilities to detect high resistance faults and should therefore always be complemented with other protection function(s) that can carry out the fault clearance in those cases.

Effectively earthed networks

A network is defined as effectively earthed if the earth-fault factor f_e is less than 1.4. The earth-fault factor is defined according to equation 32.

$$f_e = \left| \frac{U_{\max}}{U_{pn}} \right|$$

(Equation 32)

Where:

- $U_{\max}$ is the highest fundamental frequency voltage on one of the healthy phases at single phase-to-earth fault.
- U_{pn} is the phase-to-earth fundamental frequency voltage before fault.

Another definition for effectively earthed network is when the following relationships between the symmetrical components of the network impedances are valid, see equation [33](#) and [34](#).

$$X_0 < 3 \cdot X_1$$

(Equation 33)

$$R_0 \leq R_1$$

(Equation 34)

Where

- R_0 is the resistive zero sequence of the source
- X_0 is the reactive zero sequence of the source
- R_1 is the resistive positive sequence of the source
- X_1 is the reactive positive sequence of the source

The magnitude of the earth-fault current in effectively earthed networks is high enough for impedance measuring elements to detect earth faults. However, in the same way as for solidly earthed networks, distance protection has limited possibilities to detect high resistance faults and should therefore always be complemented with other protection function(s) that can carry out the fault clearance in this case.

High impedance earthed networks

In high impedance networks, the neutral of the system transformers are connected to the earth through high impedance, mostly a reactance in parallel with a high resistor.

This type of network is often operated radially, but can also be found operating as a meshed network.

What is typical for this type of network is that the magnitude of the earth -fault current is very low compared to the short circuit current. The voltage on the healthy phases will get a magnitude of up to $\sqrt{3}$ times the phase voltage during the fault. The zero sequence voltage ($3U_0$) will have the same magnitude in different places in the network due to low voltage drop distribution.

The magnitude of the total fault current can be calculated according to equation [35](#).

$$3I_0 = \sqrt{I_R^2 + (I_L - I_C)^2}$$

(Equation 35)

Where:

- $3I_0$ is the earth-fault current (A)
- I_R is the current through the neutral point resistor (A)
- I_L is the current through the neutral point reactor (A)
- I_C is the total capacitive earth-fault current (A)

The neutral point reactor is normally designed so that it can be tuned to a position where the reactive current balances the capacitive current from the network:

$$\omega L = \frac{1}{3 \cdot \omega \cdot C}$$

(Equation 36)

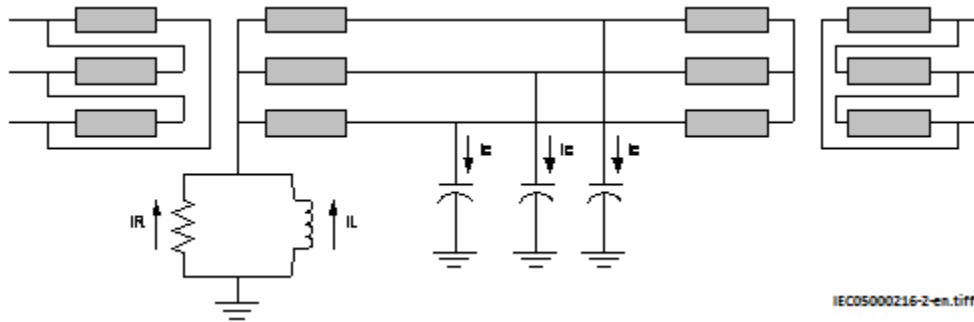


Figure 54: High impedance earthing network

The operation of high impedance earthed networks is different compared to solid earthed networks, where all major faults have to be cleared very fast. In high impedance earthed networks, some system operators do not clear single phase-to-earth faults immediately; they clear the line later when it is more convenient. In case of cross-country faults, many network operators want to selectively clear one of the two earth faults.

In this type of network, there will be very low or no zero-sequence current contributed by the system behind the relay during earthfault. If the earth-faults are identified without the measurement of zero-sequence current, the distance protection will automatically disable the use of zero-sequence current in the load compensation algorithm and direction element. For the reason that earth-fault current might be too low for acceptance, a separate high sensitive earth-fault protection is necessary to carry out the fault clearance for single phase-to-earth-fault. For cross-country faults and when using phase preference, it is necessary to make sure that the distance protection is operating in the phase-to-earth loops independently, whenever possible. See guidelines for setting *INReleasePE*.

7.1.3.2 Fault infeed from remote end

All transmission and most all sub-transmission networks are operated meshed. Typical for this type of network is that fault infeed from remote end will happen when fault occurs on the protected line. The fault current infeed will enlarge the fault impedance seen by the distance protection. This effect is very important to keep in mind when both planning the protection system and making the settings.

With reference to figure 55, the equation for the bus voltage U_A at A side is:

$$\bar{U}_A = \bar{I}_A \cdot p \cdot \bar{Z}_L + (\bar{I}_A + \bar{I}_B) \cdot R_f \quad (\text{Equation 37})$$

If we divide U_A by I_A we get Z present to the IED at A side.

$$\bar{Z}_A = \frac{\bar{U}_A}{\bar{I}_A} = p \cdot \bar{Z}_L + \frac{\bar{I}_A + \bar{I}_B}{\bar{I}_A} \cdot R_f \quad (\text{Equation 38})$$

The infeed factor $(I_A + I_B)/I_A$ can be very high, 10-20 depending on the differences in source impedances at local and remote end.

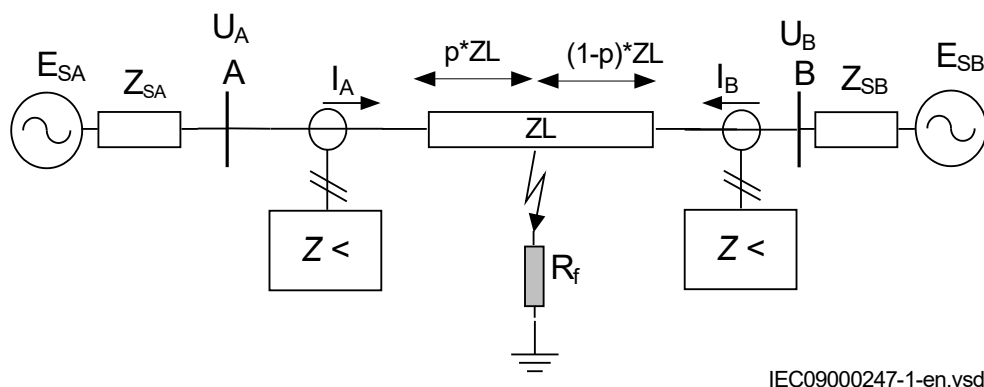


Figure 55: Influence of fault current infeed from remote line end

The effect of fault current infeed from the remote line end is one of the most driving factors to justify complementary protection for distance protection.

When the line is heavily loaded, the distance protection at the exporting end will have a tendency to overreach. To handle this phenomenon, the IED has an adaptive built-in algorithm, which compensates the overreach tendency of zone 1 at the exporting end. No settings are required for this feature.

7.1.3.3 Under-impedance phase selection with load encroachment

In some cases the measured load impedance might enter the set zone characteristic without any fault on the protected line. This phenomenon is called load encroachment and it might occur when an external fault is cleared and high emergency load is transferred onto the protected line. The effect of load encroachment is illustrated on the left in figure 56. A load impedance within the characteristic would cause an unwanted trip. The traditional way of avoiding this situation is to set the distance zone resistive reach with a security margin to the minimum load impedance. The drawback with this approach is that the sensitivity of the protection to detect resistive faults is reduced.

The IED has a built-in feature which shapes the under-impedance starting characteristic according to the characteristic shown in figure 56. The load encroachment algorithm will increase the possibility to detect high fault resistances, especially for phase-to-earth faults at the remote line end. For example, for a given setting of the load angle $ArgLd$, the resistive blinder for the zone measurement can be set according to figure 56 affording higher fault resistance coverage without risk for unwanted operation due to load encroachment. Separate resistive blinder settings are available in forward and reverse direction.

The use of the load encroachment feature is essential for long heavily loaded lines, where there might be a conflict between the necessary emergency load transfer and necessary sensitivity of the distance protection. The function can also preferably be used on heavy loaded, medium long lines. For short lines, the major concern is to get sufficient fault resistance coverage. Load encroachment is not a major problem.

The built-in phase selection is based on current change criteria and has no user defined settings. However, a traditional under-impedance-based phase selector is always working in parallel with it. This under-impedance-based criterion is defined by the two setting parameters $XStart$ and $RStart$, as shown in Figure 56. These two settings are common for both Ph-Ph and Ph-Gnd measurement loops. In order to ensure proper operation of the distance zones the under-impedance based starting element shall be set in such a way to always cover (i.e. be larger than) all used distance zones for both Ph-Ph and Ph-Gnd loops. Consequently, the following settings are recommended:

Parameter $XStart$ shall be set to a value which is at least 20% bigger than the value obtained by formula $(2 \cdot X1FwPEZx + X0FwPEZx)/3$ applied for the longest reaching zone.

Figure 1: Distance Zones. A 2D coordinate system with X (vertical) and F (horizontal) axes. The diagram shows four distance zones defined by lines with slopes $ArgLd$. Key parameters include $RStart$ (horizontal distance from the Y-axis to the start of the zones), $RLdFw$ (vertical distance from the X-axis to the start of the zones), and $XStart$ (vertical distance from the X-axis to the start of the zones). The formula for the vertical distance is given as $\frac{RLdRvFactor}{100} * RLdFw$.

[1]

Table 14: Definition of short and very short line

For very short line applications, the underreaching zone 1 can not be used due to the fact that the voltage drop distribution throughout the line will be too low causing risk for overreaching.

Line differential protection RED650

Application manual

7.1.3.5 Long transmission line application

For long transmission lines, the margin to the load impedance, that is, to avoid load encroachment, will normally be a major concern. It is well known that it is difficult to achieve high sensitivity for phase-to-earth fault at remote line end of long lines when the line is heavily loaded.

What can be recognized as long lines with respect to the performance of distance protection can generally be described as in table 15. Long lines have Source impedance ratio (SIR's) less than 0.5.

Table 15: Definition of long and very long lines

Line category	Un	Un
	110 kV	500 kV
Long lines	77 km - 99 km	350 km - 450 km
Very long lines	> 99 km	> 450 km

The IED's ability to set resistive and reactive reach independent for positive and zero sequence fault loops and individual fault resistance settings for phase-to-phase and phase-to-earth fault together with load encroachment algorithm improves the possibility to detect high resistive faults at the same time as the security is improved (risk for unwanted trip due to load encroachment is eliminated), see figure 56.

7.1.3.6 Parallel line application with mutual coupling

General

Introduction of parallel lines in the network is increasing due to difficulties to get necessary land to build new lines.

Parallel lines introduce an error in the measurement due to the mutual coupling between the parallel lines. The lines need not be of the same voltage level in order to experience mutual coupling, and some coupling exists even for lines that are separated by 100 meters or more. The mutual coupling does influence the zero sequence impedance to the fault point but it does not normally cause voltage inversion.

It can be shown from analytical calculations of line impedances that the mutual impedances for positive and negative sequence are very small (< 1-2%) of the self impedance and it is a common practice to neglect them.

From an application point of view there exists three types of network configurations (classes) that must be considered when making the settings for the protection function.

The different network configuration classes are:

1. Parallel line with common positive and zero sequence network
2. Parallel circuits with common positive but isolated zero sequence network
3. Parallel circuits with positive and zero sequence sources isolated.

One example of class 3 networks could be the mutual coupling between a 400 kV line and rail road overhead lines. This type of mutual coupling is not so common although it exists and is not treated any further in this manual.

For each type of network class, there are three different topologies; the parallel line can be in service, out of service, out of service and earthed in both ends.

The reach of the distance protection zone 1 shall be different depending on the operation condition of the parallel line. This can be handled by the use of different setting groups for handling the cases when the parallel line is in operation and out of service and earthed at both ends.

The distance protection within the IED can compensate for the influence of a zero sequence mutual coupling on the measurement at single phase-to-earth faults in the following ways, by using:

- The possibility of different setting values that influence the earth-return compensation for different distance zones within the same group of setting parameters.
- Different groups of setting parameters for different operating conditions of a protected multi circuit line.

Most multi circuit lines have two parallel operating circuits.

Parallel line applications

This type of networks is defined as those networks where the parallel transmission lines terminate at common nodes at both ends.

The three most common operation modes are:

1. Parallel line in service.
2. Parallel line out of service and earthed.
3. Parallel line out of service and not earthed.

Parallel line in service

This type of application is very common and applies to all normal sub-transmission and transmission networks.

Let us analyze what happens when a fault occurs on the parallel line see figure 57.

From symmetrical components, we can derive the impedance Z at the relay point for normal lines without mutual coupling according to equation 39.

$$\bar{Z} = \frac{\bar{U}_{ph}}{\bar{I}_{ph} + 3\bar{I}_0 \cdot \frac{\bar{Z}_0 - \bar{Z}_1}{3 \cdot \bar{Z}_1}} = \frac{\bar{U}_{ph}}{\bar{I}_{ph} + 3\bar{I}_0 \cdot \bar{K}_N}$$

(Equation 39)

Where:

U_{ph}	is phase to earth voltage at the relay point
I_{ph}	is phase current in the faulty phase
$3I_0$	is earth fault current
Z_1	is positive sequence impedance
Z_0	is zero sequence impedance

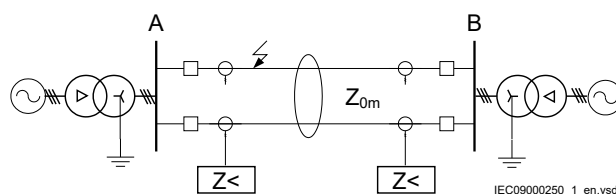


Figure 57: Class 1, parallel line in service

The equivalent circuit of the lines can be simplified, see figure 58.

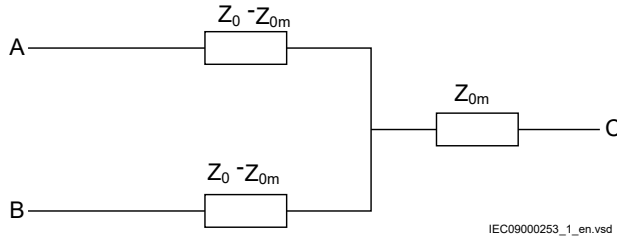


Figure 58: *Equivalent zero sequence impedance circuit of the double-circuit, parallel, operating line with a single phase-to-earth fault at the remote busbar*

When mutual coupling is introduced, the voltage at the relay point A will be changed according to equation 40.

$$U_{ph} = \bar{Z}_{1L} \cdot \left(\bar{I}_{ph} + 3\bar{I}_0 \cdot \frac{\bar{Z}_{0L} - \bar{Z}_{1L}}{3 \cdot \bar{Z}_{1L}} + 3\bar{I}_{0p} \frac{\bar{Z}_{0m}}{3 \cdot \bar{Z}_{1L}} \right)$$

(Equation 40)

By dividing equation 40 by equation 39 and after some simplification we can write the impedance present to the relay at A side as:

$$Z = \bar{Z}_{1L} \left(1 + \frac{3\bar{I}_0 \cdot \bar{K}Nm}{\bar{I}_{ph} + 3\bar{I}_0 \cdot \bar{K}N} \right)$$

(Equation 41)

Where:

$$KNm = Z_{0m} / (3 \cdot Z_{1L})$$

The second part in the parentheses is the error introduced to the measurement of the line impedance.

If the current on the parallel line has negative sign compared to the current on the protected line, that is, the current on the parallel line has an opposite direction compared to the current on the protected line, the distance function will overreach. If the currents have the same direction, the distance protection will underreach.

Maximum overreach will occur if the fault current infeed from remote line end is weak. If considering a single phase-to-earth fault at 'p' unit of the line length from A to B on the parallel line for the case when the fault current infeed from remote line end is zero, the voltage U_A in the faulty phase at A side as in equation 42.

$$\bar{U}_A = p \cdot \bar{Z}_{1L} \left(\bar{I}_{ph} + \bar{K}_N \cdot 3\bar{I}_0 + \bar{K}_{Nm} \cdot 3\bar{I}_{0p} \right)$$

(Equation 42)

One can also notice that the following relationship exists between the zero sequence currents:

$$3\bar{I}_0 \cdot \bar{Z}_{0L} = 3\bar{I}_{0p} \cdot \bar{Z}_{0L} (2 - p)$$

(Equation 43)

Simplification of equation 43, solving it for $3\bar{I}_{0p}$ and substitution of the result into equation 42 gives that the voltage can be drawn as:

$$\overline{U}_A = p \cdot \overline{Z} I_L \left(\overline{I}_{ph} + \overline{K}_N \cdot 3\overline{I}_0 + \overline{K}_{Nm} \cdot \frac{3\overline{I}_0 \cdot p}{2-p} \right)$$

(Equation 44)

If we finally divide equation 44 with equation 39 we can draw the impedance present to the IED as

$$\overline{Z} = p \cdot \overline{Z} I_L \left(\frac{\overline{I}_{ph} + \overline{K}_N \cdot 3\overline{I}_0 + \overline{K}_{Nm} \cdot \frac{3\overline{I}_0 \cdot p}{2-p}}{\overline{I}_{ph} + 3\overline{I}_0 \cdot \overline{K}_N} \right)$$

(Equation 45)

Calculation for a 400 kV line, where we for simplicity have excluded the resistance, gives with $X_{1L}=0.303 \Omega/\text{km}$, $X_{0L}=0.88 \Omega/\text{km}$, zone 1 reach is set to 90% of the line reactance $p=71\%$ that is, the protection is underreaching with approximately 20%.

The zero sequence mutual coupling can reduce the reach of distance protection on the protected circuit when the parallel line is in normal operation. The reduction of the reach is most pronounced with no current infeed in the IED closest to the fault. This reach reduction is normally less than 15%. But when the reach is reduced at one line end, it is proportionally increased at the opposite line end. So this 15% reach reduction does not significantly affect the operation of a permissive underreaching scheme.

Parallel line out of service and earthed

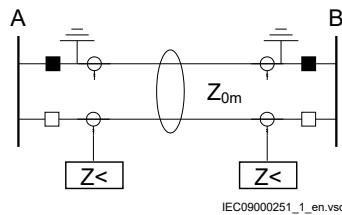


Figure 59: The parallel line is out of service and earthed

When the parallel line is out of service and earthed at both line ends on the bus bar side of the line CTs so that zero sequence current can flow on the parallel line, the equivalent zero sequence circuit of the parallel lines will be according to figure 60.

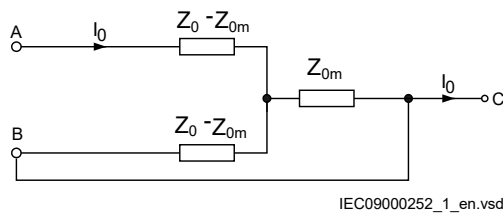


Figure 60: Equivalent zero sequence impedance circuit for the double-circuit line that operates with one circuit disconnected and earthed at both ends

Here the equivalent zero-sequence impedance is equal to $Z_0 - Z_{0m}$ in parallel with $(Z_0 - Z_{0m})/Z_0 - Z_{0m} + Z_{0m}$ which is equal to equation 46.

$$\overline{Z}_E = \frac{\overline{Z}_0^2 - \overline{Z}_{0m}^2}{\overline{Z}_0}$$

(Equation 46)

The influence on the distance measurement will be a considerable overreach, which must be considered when calculating the settings. It is recommended to use a separate setting group for this operation condition since it will reduce the reach considerably when the line is in operation.

All expressions below are proposed for practical use. They assume the value of zero sequence, mutual resistance R_{0m} equals to zero. They consider only the zero sequence, mutual reactance X_{0m} . Calculate the equivalent X_{0E} and R_{0E} zero sequence parameters according to equation 47 and equation 48 for each particular line section and use them for calculating the reach for the underreaching zone.

$$R_{0E} = R_0 \cdot \left(1 + \frac{X_{0m}^2}{R_0^2 + X_0^2} \right)$$

(Equation 47)

$$X_{0E} = X_0 \cdot \left(1 - \frac{X_{0m}^2}{R_0^2 + X_0^2} \right)$$

(Equation 48)

Parallel line out of service and not earthed

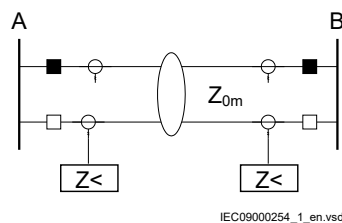


Figure 61: Parallel line is out of service and not earthed

When the parallel line is out of service and not earthed, the zero sequence on that line can only flow through the line admittance to the earth. The line admittance is high which limits the zero-sequence current on the parallel line to very low values. In practice, the equivalent zero-sequence impedance circuit for faults at the remote bus bar can be simplified to the circuit shown in figure 61

The line zero sequence mutual impedance does not influence the measurement of the distance protection in a faulty circuit. This means that the reach of the underreaching distance protection zone is reduced if, due to operating conditions, the equivalent zero sequence impedance is set according to the conditions when the parallel system is out of operation and earthed at both ends.

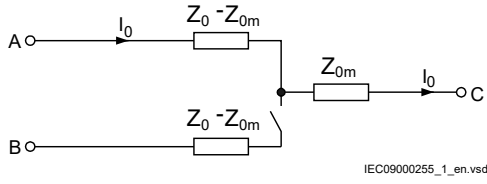


Figure 62: *Equivalent zero-sequence impedance circuit for a double-circuit line with one circuit disconnected and not earthed*

The reduction of the reach is equal to equation 49.

$$\bar{K}_U = \frac{\frac{1}{3} \cdot (2 \cdot \bar{Z}_1 + \bar{Z}_{0E}) + R_f}{\frac{1}{3} \cdot (2 \cdot \bar{Z}_1 + \bar{Z}_0) + R_f} = 1 - \frac{\bar{Z}_{m0}^2}{\bar{Z}_0 \cdot (2 \cdot \bar{Z}_1 + \bar{Z}_0 + 3R_f)}$$

(Equation 49)

This means that the reach is reduced in reactive and resistive directions. If the real and imaginary components of the constant A are equal to equation 50 and equation 51.

$$\text{Re}(\bar{A}) = R_0 \cdot (2 \cdot R_1 + R_0 + 3 \cdot R_f) - X_0 \cdot (X_0 + 2 \cdot X_1)$$

(Equation 50)

$$\text{Im}(\bar{A}) = X_0 \cdot (2 \cdot R_1 + R_0 + 3 \cdot R_f) + R_0 \cdot (2 \cdot X_1 + X_0)$$

(Equation 51)

The real component of the KU factor is equal to equation 52.

$$\text{Re}(\bar{K}_U) = 1 + \frac{\text{Re}(\bar{A}) \cdot X_{m0}^2}{[\text{Re}(\bar{A})]^2 + [\text{Im}(\bar{A})]^2}$$

(Equation 52)

The imaginary component of the same factor is equal to equation 53.

$$\text{Im}(\bar{K}_U) = \frac{\text{Im}(\bar{A}) \cdot X_{m0}^2}{[\text{Re}(\bar{A})]^2 + [\text{Im}(\bar{A})]^2}$$

(Equation 53)

Ensure that the underreaching zones from both line ends will overlap a sufficient amount (at least 10%) in the middle of the protected circuit.

7.1.3.7 Tapped line application

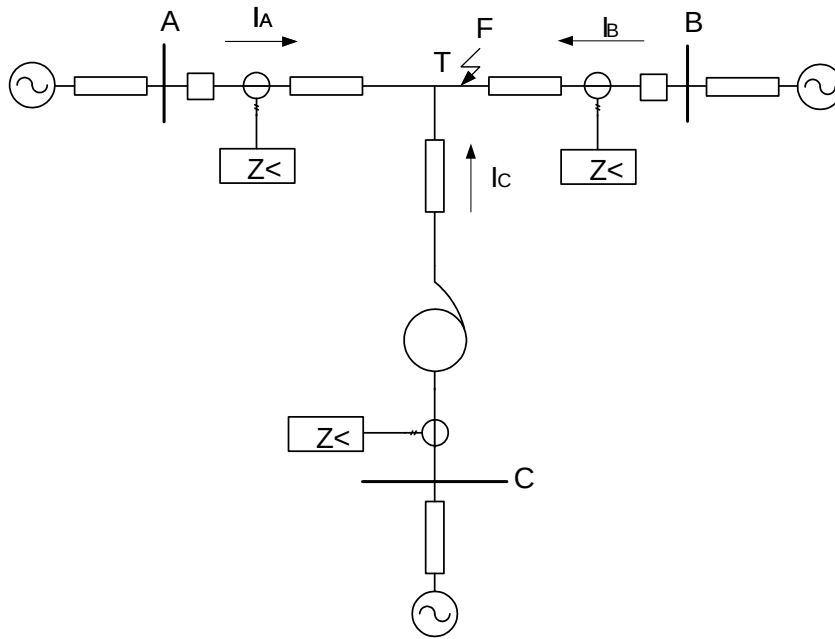


Figure 63: Example of tapped line with Auto transformer

This application gives rise to similar problem that was highlighted in section "[Fault infeed from remote end](#)", that is increased measured impedance due to fault current infeed. For example, for faults between the T point and B station the measured impedance at A and C will be

$$\bar{Z}_A = \bar{Z}_{AT} + \frac{\bar{I}_A + \bar{I}_C}{\bar{I}_A} \cdot \bar{Z}_{TF}$$

(Equation 54)

$$\bar{Z}_C = \bar{Z}_{Tf} + \left(\bar{Z}_{CT} + \frac{\bar{I}_A + \bar{I}_C}{\bar{I}_C} \cdot \bar{Z}_{TF} \right) \cdot \left(\frac{U2}{U1} \right)^2$$

(Equation 55)

Where:

Z_{AT} and Z_{CT}	is the line impedance from the A respective C station to the T point.
I_A and I_C	is fault current from A respective C station for fault between T and B.
$U2/U1$	Transformation ratio for transformation of impedance at U1 side of the transformer to the measuring side U2 (it is assumed that current and voltage distance function is taken from U2 side of the transformer).
Z_{TF}	is the line impedance from the T point to the fault (F).
Z_{Tf}	Transformer impedance

For this example with a fault between T and B, the measured impedance from the T point to the fault will be increased by a factor defined as the sum of the currents from T point to the fault divided by the IED current. For the IED at C, the impedance on the high voltage side U1 has to be transferred to the measuring voltage level by the transformer ratio.

Another complication that might occur depending on the topology is that the current from one end can have a reverse direction for fault on the protected line. For example, for faults at T the current from B might go in reverse direction from B to C depending on the system parameters (see the dotted line in figure 63), given that the distance protection in B to T will measure wrong direction.

In three-end application, depending on the source impedance behind the IEDs, the impedances of the protected object and the fault location, it might be necessary to accept zone 2 trip in one end or sequential trip in one end.

Generally for this type of application it is difficult to select settings of zone 1 that both gives overlapping of the zones with enough sensitivity without interference with other zone 1 settings, that is, without selectivity conflicts. Careful fault calculations are necessary to determine suitable settings and selection of proper scheme communication.

Fault resistance

The performance of distance protection for single phase-to-earth faults is very important, because normally more than 70% of the faults on transmission lines are single phase-to-earth faults. At these faults, the fault resistance is composed of three parts: arc resistance, resistance of a tower construction, and tower-footing resistance. The resistance is also depending on the presence of earth shield conductor at the top of the tower, connecting tower-footing resistance in parallel. The arc resistance can be calculated according to Warrington's formula:

$$R_{arc} = \frac{28707 \cdot L}{I^{1.4}}$$

(Equation 56)

where:

- L represents the length of the arc (in meters). This equation applies for the distance protection zone 1. Consider approximately three times arc foot spacing for the zone 2 and wind speed of approximately 50 km/h
- I is the actual fault current in A.

In practice, the setting of fault resistance for both phase-to-earth *RFPEZx* and phase-to-phase *RFPPZx* should be as high as possible without interfering with the load impedance in order to obtain reliable fault detection.

7.1.4 Setting guidelines

7.1.4.1 General

The settings for Distance measuring zones, quadrilateral characteristic (ZMFPDIS) are done in primary values. The instrument transformer ratio that has been set for the analog input card is used to automatically convert the measured secondary input signals to primary values used in ZMFPDIS .

The following basics must be considered, depending on application, when doing the setting calculations:

- Errors introduced by current and voltage instrument transformers, particularly under transient conditions.
- Inaccuracies in the line zero-sequence impedance data, and their effect on the calculated value of the earth-return compensation factor.
- The effect of infeed between the IED and the fault location, including the influence of different Z_0/Z_1 ratios of the various sources.
- The phase impedance of non transposed lines is not identical for all fault loops. The difference between the impedances for different phase-to-earth loops can be as large as 5-10% of the total line impedance.
- The effect of a load transfer between the IEDs of the protected fault resistance is considerable, the effect must be recognized.
- Zero-sequence mutual coupling from parallel lines.

7.1.4.2 Setting of zone 1

The different errors mentioned earlier usually require a limitation of the underreaching zone (normally zone 1) to 75 - 90% of the protected line.

In case of parallel lines, consider the influence of the mutual coupling according to section ["Parallel line application with mutual coupling"](#) and select the case(s) that are valid in the particular application. By proper setting it is possible to compensate for the cases when the parallel line is in operation, out of service and not earthed and out of service and earthed in both ends. The setting of earth-fault reach should be selected to be <95% also when parallel line is out of service and earthed at both ends (worst case).

7.1.4.3 Setting of overreaching zone

The first overreaching zone (normally zone 2) must detect faults on the whole protected line. Considering the different errors that might influence the measurement in the same way as for zone 1, it is necessary to increase the reach of the overreaching zone to at least 120% of the protected line. The zone 2 reach can be even higher if the fault infeed from adjacent lines at remote end is considerable higher than the fault current at the IED location.

The setting shall generally not exceed 80% of the following impedances:

- The impedance corresponding to the protected line, plus the first zone reach of the shortest adjacent line.
- The impedance corresponding to the protected line, plus the impedance of the maximum number of transformers operating in parallel on the bus at the remote end of the protected line.

Larger overreach than the mentioned 80% can often be acceptable due to fault current infeed from other lines. This requires however analysis by means of fault calculations.

If any of the above gives a zone 2 reach less than 120%, the time delay of zone 2 must be increased by approximately 200ms to avoid unwanted operation in cases when the telecommunication for the short adjacent line at remote end is down during faults. The zone 2 must not be reduced below 120% of the protected line section. The whole line must be covered under all conditions.

The requirement that the zone 2 shall not reach more than 80% of the shortest adjacent line at remote end is highlighted in the example below.

If a fault occurs at point F see figure 64, the IED at point A senses the impedance:

$$\bar{Z}_{AF} = \frac{\bar{V}_A}{\bar{I}_A} = \bar{Z}_{AC} + \frac{\bar{I}_A + \bar{I}_C}{\bar{I}_A} \cdot \bar{Z}_{CF} + \frac{\bar{I}_A + \bar{I}_C + \bar{I}_B}{\bar{I}_A} \cdot R_F = \bar{Z}_{AC} + \left(1 + \frac{\bar{I}_C}{\bar{I}_A}\right) \cdot \bar{Z}_{CF} + \left(1 + \frac{\bar{I}_C + \bar{I}_B}{\bar{I}_A}\right) \cdot R_F \quad (\text{Equation 57})$$

7.1.4.4 Setting of reverse zone

The reverse zone is applicable for purposes of scheme communication logic, current reversal logic, weak-end infeed logic, and so on. The same applies to the back-up protection of the bus bar or power transformers. It is necessary to secure, that it always covers the overreaching zone, used at the remote line IED for the telecommunication purposes.

Consider the possible enlarging factor that might exist due to fault infeed from adjacent lines. Equation 58 can be used to calculate the reach in reverse direction when the zone is used for blocking scheme, weak-end infeed, and so on.

$$Z_{rev} \geq 1.2 \cdot (Z_L - Z_{2rem}) \quad (\text{Equation 58})$$

Where:

Z_L is the protected line impedance

Z_{2rem} is zone 2 setting at remote end of protected line.

In many applications it might be necessary to consider the enlarging factor due to fault current infeed from adjacent lines in the reverse direction in order to obtain certain sensitivity.

7.1.4.5 Setting of zones for parallel line application

Parallel line in service – Setting of zone 1

With reference to section ["Parallel line applications"](#), the zone reach can be set to 85% of the protected line.

However, influence of mutual impedance has to be taken into account.

Parallel line in service – setting of zone 2

Overreaching zones (in general, zones 2 and 3) must overreach the protected circuit in all cases. The greatest reduction of a reach occurs in cases when both parallel circuits are in service with a single phase-to-earth fault located at the end of a protected line. The equivalent zero sequence impedance circuit for this case is equal to the one in figure 58 in section [Parallel line in service](#).

The components of the zero sequence impedance for the overreaching zones must be equal to at least:

$$R_{0E} = R_0 + R_{m0} \quad (\text{Equation 59})$$

$$X_{0E} = X_0 + X_{m0} \quad (\text{Equation 60})$$

Check the reduction of a reach for the overreaching zones due to the effect of the zero sequence mutual coupling. The reach is reduced for a factor:

$$K_0 = 1 - \frac{Z_{0m}}{2 \cdot Z_1 + Z_0 + R_f} \quad (\text{Equation 61})$$

If the denominator in equation 61 is called B and Z_{0m} is simplified to X_{0m} , then the real and imaginary part of the reach reduction factor for the overreaching zones can be written as:

$$\operatorname{Re}(\overline{K}0) = 1 - \frac{X_{0m} \cdot \operatorname{Re}(B)}{\operatorname{Re}(B)^2 + \operatorname{Im}(B)^2}$$

(Equation 62)

$$\operatorname{Im}(\overline{K}0) = \frac{X_{0m} \cdot \operatorname{Im}(B)}{\operatorname{Re}(B)^2 + \operatorname{Im}(B)^2}$$

(Equation 63)

Parallel line is out of service and earthed in both ends

Apply the same measures as in the case with a single set of setting parameters. This means that an underreaching zone must not overreach the end of a protected circuit for the single phase-to-earth faults.

Set the values of the corresponding zone (zero-sequence resistance and reactance) equal to:

$$R_{0E} = R_0 \cdot \left(1 + \frac{X_{m0}^2}{R_0^2 + X_0^2} \right)$$

(Equation 64)

$$X_{0E} = X_0 \cdot \left(1 - \frac{X_{m0}^2}{R_0^2 + X_0^2} \right)$$

(Equation 65)

7.1.4.6 Setting the reach with respect to load

Set separately the expected fault resistance for phase-to-phase faults $RFPPZx$ and for the phase-to-earth faults $RFPEZx$ for each zone. For each distance zone, set all remaining reach setting parameters independently of each other.

The final reach in the resistive direction for phase-to-earth fault loop measurement automatically follows the values of the line-positive and zero-sequence resistance, and at the end of the protected zone is equal to equation [66](#).

$$R = \frac{1}{3} (2 \cdot R_{1Zx} + R_{0Zx}) + RFPEZx$$

(Equation 66)

$$\phi_{loop} = \arctan \left[\frac{2 \cdot X_{1Zx} + X_{0Zx}}{2 \cdot R_{1Zx} + R_{0Zx}} \right]$$

(Equation 67)

Setting of the resistive reach for the underreaching zone 1 should follow the condition to minimize the risk for overreaching:

$$RFPEZx \leq 4.5 \cdot X_{1Zx}$$

(Equation 68)

The fault resistance for phase-to-phase faults is normally quite low compared to the fault resistance for phase-to-earth faults. To minimize the risk for overreaching, limit the setting of the zone1 reach in the resistive direction for phase-to-phase loop measurement based on equation 69.

$$RFPPZ_x \leq 6 \cdot X1Z_x$$

(Equation 69)

The setting XLd is primarily there to define the border between what is considered a fault and what is just normal operation. See figure 65 In this context, the main examples of normal operation are reactive load from reactive power compensation equipment or the capacitive charging of a long high-voltage power line. XLd needs to be set with some margin towards normal apparent reactance; not more than 90% of the said reactance or just as much as is needed from a zone reach point of view.

As with the settings $RLdFw$ and $RLdRv$ [2], XLd is representing a per-phase load impedance of a symmetrical star-coupled representation. For a symmetrical load or three-phase and phase-to-phase faults, this means per-phase, or positive-sequence, impedance. During a phase-to-earth fault, it means the per-loop impedance, including the earth return impedance.

7.1.4.7 Zone reach setting lower than minimum load impedance

Even if the resistive reach of all protection zones is set lower than the lowest expected load impedance and there is no risk for load encroachment, it is still necessary to set $RLdFw$, $RLdRv$ [3] and $ArgLd$ according to the expected load situation, since these settings are used internally in the function as reference points to improve the performance of the phase selection.

The maximum permissible resistive reach for any zone must be checked to ensure that there is a sufficient setting margin between the boundary and the minimum load impedance. The minimum load impedance (Ω /phase) is calculated with equation 70.

$$Z_{loadmin} = \frac{U^2}{S}$$

(Equation 70)

Where:

U the minimum phase-to-phase voltage in kV
S the maximum apparent power in MVA.

The load impedance [Ω /phase] is a function of the minimum operation voltage and the maximum load current:

$$Z_{load} = \frac{U_{min}}{\sqrt{3} \cdot I_{max}}$$

(Equation 71)

Minimum voltage U_{min} and maximum current I_{max} are related to the same operating conditions. Minimum load impedance occurs normally under emergency conditions.



As a safety margin, it is required to avoid load encroachment under three-phase conditions. To guarantee correct, healthy phase IED operation under combined heavy three-phase load and earth faults, both phase-to-phase and phase-to-earth fault operating characteristics should be considered.

[2] $RLdRv = RLdRvFactor \cdot RLdFw$
[3] $RLdRv = RLdRvFactor \cdot RLdFw$

To avoid load encroachment for the phase-to-earth measuring elements, the set resistive reach of any distance protection zone must be less than 80% of the minimum load impedance.

$$RFPEZ_x \leq 0.8 \cdot Z_{load} \quad (\text{Equation 72})$$

Equation 72 is applicable only when the loop characteristic angle for the single phase-to-earth faults is more than three times as large as the maximum expected load-impedance angle. For the case when the loop characteristic angle is less than three times the load-impedance angle, more accurate calculations are necessary according to equation 73.

$$RFPEZ_x \leq 0.8 \cdot Z_{load \min} \cdot \left[\cos \vartheta - \frac{2 \cdot R1Z_x + R0Z_x}{2 \cdot X1Z_x + X0Z_x} \cdot \sin \vartheta \right] \quad (\text{Equation 73})$$

Where:

ϑ is a maximum load-impedance angle, related to the maximum load power.

To avoid load encroachment for the phase-to-phase measuring elements, the set resistive reach of any distance protection zone must be less than 160% of the minimum load impedance.

$$RFPPZ_x \leq 1.6 \cdot Z_{load} \quad (\text{Equation 74})$$

Equation 74 is applicable only when the loop characteristic angle for the phase-to-phase faults is more than three times as large as the maximum expected load-impedance angle. For other cases a more accurate calculations are necessary according to equation 75.

$$RFPPZ_x \leq 1.6 \cdot Z_{load \min} \cdot \left[\cos \vartheta - \frac{R1Z_x}{X1Z_x} \cdot \sin \vartheta \right] \quad (\text{Equation 75})$$

All this is applicable for all measuring zones when no Power swing detection, blocking function ZMRPSB is activated in the IED. Use an additional safety margin of approximately 20% in cases when a ZMRPSB function is activated in the IED, refer to the description of Power swing detection function ZMRPSB.

7.1.4.8 Zone reach setting higher than minimum load impedance

The impedance zones are enabled as soon as the (symmetrical) load impedance crosses the vertical boundaries defined by $RLdFw$ and $RLdRv$ [4] or the lines defined by $ArgLd$. So, it is necessary to consider some margin. It is recommended to set $RLdFw$ and $RLdRv$ to 90% of the per-phase resistance that corresponds to maximum load.

$$RLdFw < 0.9 \cdot R_{load \min} \quad (\text{Equation 76})$$

$$RLdRv < 0.9 \cdot R_{load \min} \quad (\text{Equation 77})$$

The absolute value of the margin to the closest $ArgLd$ line should be of the same order, that is, at least $0.1 \cdot Z_{load \min}$.

[4] $RLdRv = RLdRvFactor \cdot RLdFw$

The load encroachment settings are related to a per-phase load impedance in a symmetrical star-coupled representation. For symmetrical load or three-phase and phase-to-phase faults, this corresponds to the per-phase, or positive-sequence, impedance. For a phase-to-earth fault, it corresponds to the per-loop impedance, including the earth return impedance.

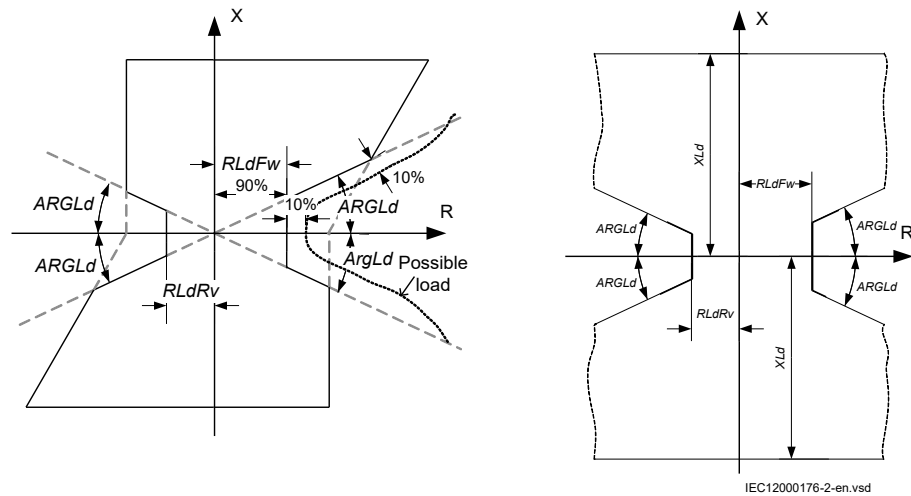


Figure 65: Load impedance limitation with load encroachment

During the initial current change for phase-to-phase and for phase-to-earth faults, operation may be allowed also when the apparent impedance of the load encroachment element is located in the load area. This improves the dependability for fault at the remote end of the line during high load. Although it is not associated to any standard event, there is one potentially hazardous situation that should be considered. Should one phase of a parallel circuit open a single pole, even though there is no fault, and the load current of that phase increase, there is actually no way of distinguish this from a real fault with similar characteristics. Should this accidental event be given precaution, the phase-to-earth reach (RFPEZx) of all instantaneous zones has to be set below the emergency load for the pole-open situation. Again, this is only for the application where there is a risk that one breaker pole would open without a preceding fault. If this never happens, for example when there is no parallel circuit, there is no need to change any phase-to-earth reach according to the pole-open scenario.

7.1.4.9 Other settings

IMinOpPEZx and IMinOpPPZx

The ability for a specific loop and zone to issue a start or a trip is inhibited if the magnitude of the input current for this loop falls below the threshold value defined by these settings. The output of a phase-to-earth loop Ln is blocked if $IL_n < I_{MinOpPE}(Z_x)$. IL_n is the RMS value of the fundamental current in phase n.

The output of a phase-to-phase loop LmLn is blocked if $IL_{mLn} < I_{MinOpPP}(Z_x)$. IL_{mLn} is the RMS value of the vector difference between phase currents Lm and Ln.

Both current limits *IMinOpPEZx* and *IMinOpPPZx* are automatically reduced to 75% of regular set values if the zone is set to operate in reverse direction, that is, *OperationDir* is set to *Reverse*.

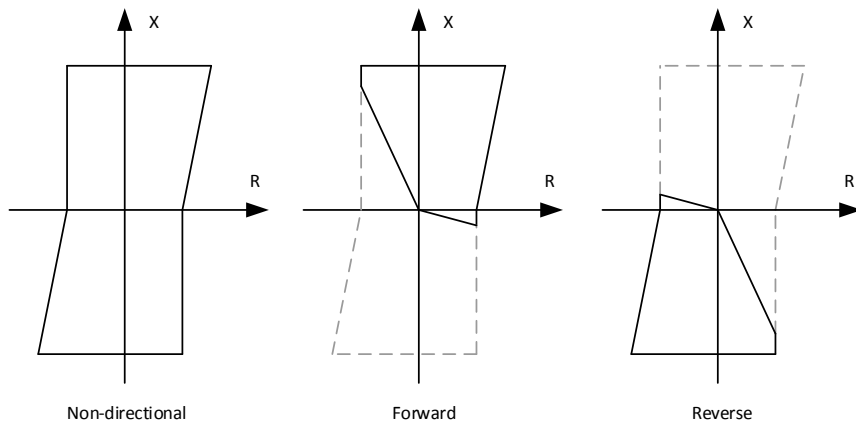
OpModePPZx and OpModePEZx

These settings, two per zone (x=1-5, BU and RV), with options {Off, Quadrilateral, Mho, Offset}, are used to set the operation and characteristic for phase-to-earth and phase-to-phase faults, respectively.

For example, in one zone it is possible to choose Mho characteristic for the three Ph-Ph measuring loops and Quadrilateral characteristic for the three Ph-E measuring loops.

DirModeZx

This setting defines the operating direction for zones Z2 to Z5 and ZBU (the directionality of zones Z1 and ZRV is fixed). The options are *Non-directional*, *Forward* or *Reverse*. The result from respective set value is illustrated in figure 66, where the positive impedance corresponds to the direction out on the protected line.



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Figure 66: Directional operating modes of the distance measuring zones 2 to 5 and BU
tPPZx, *tPEZx*, *TimerModeZx*, *ZoneLinkStart* and *TimerLinksZx*

The logic for the linking of the timer settings can be described with a module diagram. The figure 67 shows only the case when *TimerModeZx* is selected to *Ph-Ph* and *Ph-E*.

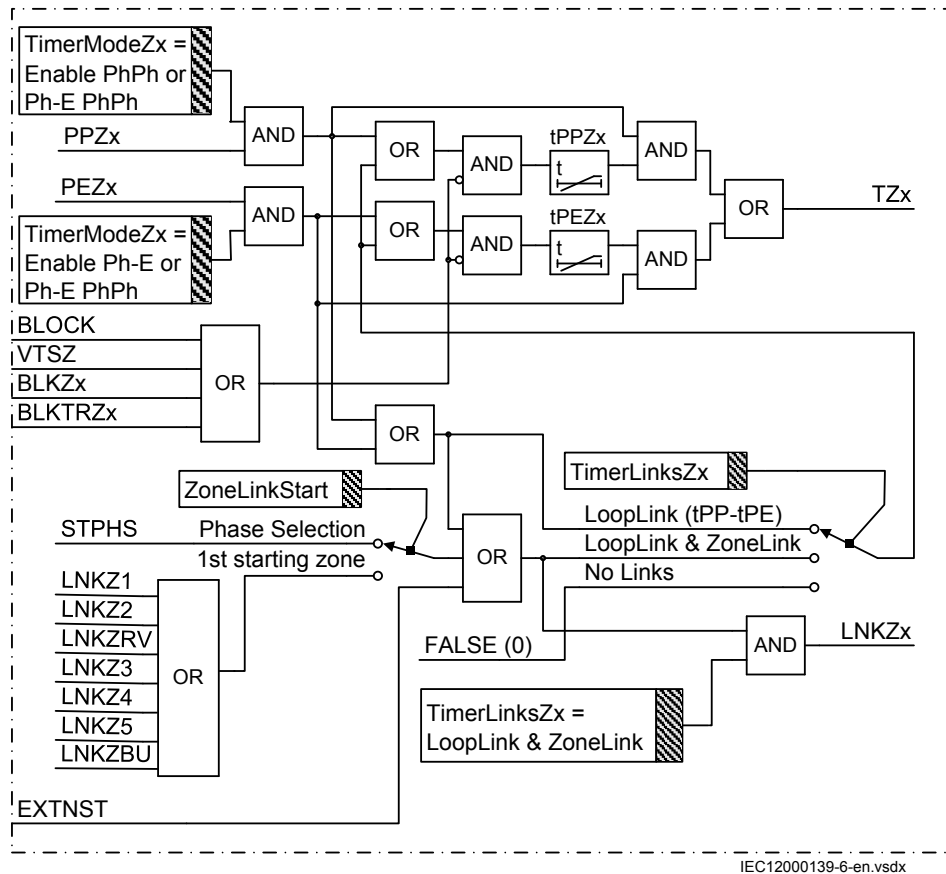


Figure 67: Logic for linking of timers

CVTtype

If possible, the type of capacitive voltage transformer (CVT) used for measurement should be identified. The alternatives are strongly related to the type of ferro-resonance suppression circuit included in the CVT. There are two main choices:

<i>Passive type</i>	For CVTs that use a nonlinear component, like a saturable inductor, to limit overvoltages (caused by ferro-resonance). This component is practically idle during normal load and fault conditions, hence the name "passive." CVTs that have a high resistive burden to mitigate ferro-resonance also fall into this category.
<i>Any</i>	This option is primarily related to the so-called active type CVT, which uses a set of reactive components to form a filter circuit that essentially attenuates frequencies other than the nominal to restrain the ferro-resonance. The name "active" refers to this circuit always being involved during transient conditions, regardless of the voltage level. This option should also be used for the types that do not fall under the other two categories, for example, CVTs with power electronic damping devices, or if the type cannot be identified at all.
<i>None (Magnetic)</i>	This option should be selected if the voltage transformer is fully magnetic.

INReleasePE

This setting opens an opportunity to enable phase-to-earth measurement for phase-to-phase-earth faults. It determines the level of residual current (3I₀) above which phase-to-earth measurement is activated (and phase-to-phase measurement is blocked). The relations are defined with the equation.

$$|3 \cdot I_0| \geq \frac{IN ReleasePE}{100} \cdot I_{ph \max}$$

(Equation 78)

Where:

<i>INReleasePE</i>	the setting for the minimum residual current needed to enable operation in the phase-to-earth fault loops in %
I_{phmax}	the maximum phase current in any of the three phases

By default, this setting is set excessively high to always enable phase-to-phase measurement for phase-to-phase-earth faults. This default setting value must be maintained unless there are very specific reasons to enable phase-to-earth measurement. Even with the default setting value, phase-to-earth measurement is activated whenever appropriate, like in the case of simultaneous faults: two earth faults at the same time, one each on the two circuits of a double line.

One specific situation where the *INReleasePE* setting should be altered is for cross-country faults in high impedance earthed networks, in order to make sure that operation is phase-to-earth. This is particularly important when using phase preference logic, since it is only working per phase, not for phase-to-phase measurement. The limit should be set so that it will be exceeded during a cross-country fault.

OpModeLoadComp

The load compensation is mitigating the effect of load current on the estimated reactance of the fault loop. For heavily loaded lines where the fault resistance can be high, this may be essential for avoiding overreach and partly also underreach.

On the other hand, turning the load compensation off could improve predictability in special situations. Particularly when coordinating with other distance protection functions, which lacks load compensation.

<i>No zone</i>	No zone will have load compensation
<i>Only zone 1</i>	Only Zone 1 will have load compensation
<i>All zones</i>	All zones will have load compensation (default option)

tTauDC

May be used to fine tune the phasor filter characteristic for the exponentially decaying DC component in fault currents, with the aim of improving operate time (in the order of a few milliseconds).

If the additional time is spent to do this, it should preferably be done in connection with extensive testing based on power system simulations, in order to see the overall effect.

If such testing is not feasible, it is best to let the parameter remain at its default value of 999.999 s. This will deliver the operate time and performance presented in the Technical data.

Since the actual time constant may vary depending on where the fault happens, it is best to focus on faults near the reach boundary of one of the zones, where it will have the biggest effect. This would typically be Zone 2, when used in a transfer trip scheme. Always use the maximum value among the considered time constants.

7.1.4.10 ZMMMXU settings

ZZeroDb

Minimum level of impedance in % of range (*ZMax-ZMin*) used as indication of zero impedance (zero point clamping). Measured values below *ZZeroDb* are forced to zero.

ZHiHiLim, *ZHiLim*, *ZLowLim* and *ZLowLowLim*

All measured values are supervised against these four settable limits. It provides the attribute "range" in the data class MV (measured value) with the type ENUMERATED (normal, high, low, high-high and low-low) in ZMFPDIS.ZMMMXU.

ZLimHys

Hysteresis value in % of range ($Z_{Max}-Z_{Min}$), common for all limits. It is used to avoid the frequent update of the value for the attribute "range".

ZMax

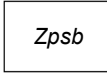
Estimated maximum impedance value. An impedance that is higher than Z_{Max} has the quality attribute as "Out of Range".

ZMin

Estimated minimum impedance value. An impedance that is lower than Z_{Min} has the quality attribute as "Out of Range".

7.2 Power swing detection ZMRPSB

7.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Power swing detection	ZMRPSB		68

7.2.2 Application

7.2.2.1 General

Various changes in power system may cause oscillations of rotating units. The most typical reasons for these oscillations are big changes in load or changes in power system configuration caused by different faults and their clearance. As the rotating masses strive to find a stable operate condition, they oscillate with damped oscillations until they reach the final stability.

The extent of the oscillations depends on the extent of the disturbances and on the natural stability of the system.

The oscillation rate depends also on the inertia of the system and on the total system impedance between different generating units. These oscillations cause changes in phase and amplitude of the voltage difference between the oscillating generating units in the power system, which reflects further on in oscillating power flow between two parts of the system - the power swings from one part to another - and vice versa.

Distance IEDs located in interconnected networks see these power swings as the swinging of the measured impedance in relay points. The measured impedance varies with time along a locus in an impedance plane, see figure 68. This locus can enter the operating characteristic of a distance protection and cause, if no preventive measures have been considered, its unwanted operation.

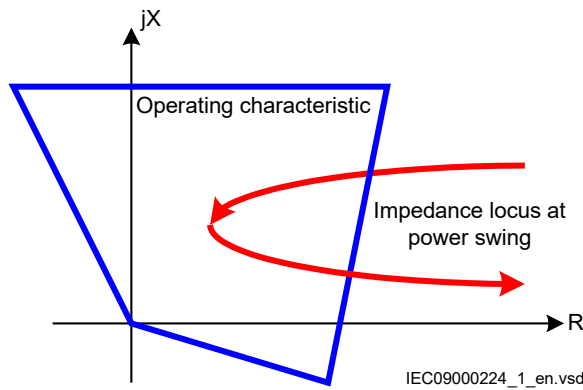


Figure 68: Impedance plane with Power swing detection operating characteristic and impedance locus at power swing

7.2.2.2 Basic characteristics

Power swing detection function (ZMRPSB) reliably detects power swings with periodic time of swinging as low as 200 ms (which means slip frequency as high as 10% of the rated frequency on the 50 Hz basis). It detects the swings under normal system operation conditions as well as during the dead time of a single-pole automatic reclosing cycle.

ZMRPSB function is able to secure selective operation for internal faults during power swing. The operation of the distance protection function remains stable for external faults during the power swing condition, even with the swing (electrical) centre located on the protected power line.

The operating characteristic of the ZMRPSB function is easily adjustable to the selected impedance operating characteristics of the corresponding controlled distance protection zones as well as to the maximum possible load conditions of the protected power lines. See the corresponding description in “Technical reference manual” for the IEDs.

7.2.3 Setting guidelines

Setting guidelines are prepared in the form of a setting example for the protected power line as part of a two-machine system presented in figure 69.

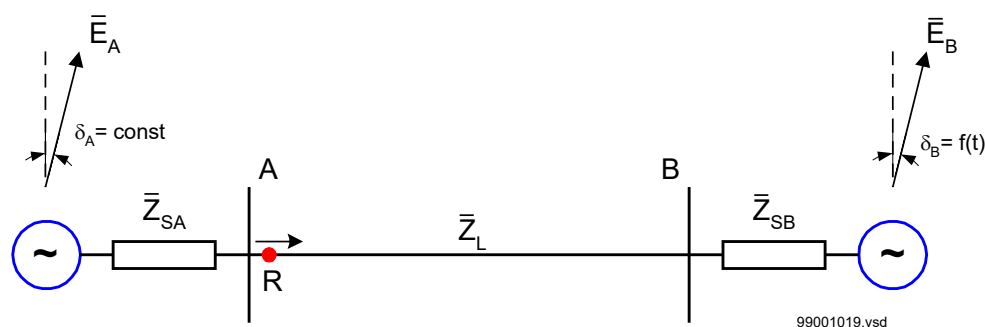


Figure 69: Protected power line as part of a two-machine system

Reduce the power system with protected power line into an equivalent two-machine system with positive sequence source impedances Z_{SA} behind the protective relay R and Z_{SB} behind the remote end bus B. Observe the fact that these impedances cannot be directly calculated from the maximum three-phase short circuit currents for faults on the corresponding busbar. It is necessary to consider separate contributions of different connected circuits.

The required data is as follows:

$U_r = 400kV$	Rated system voltage
$U_{\min} = 380kV$	Minimum expected system voltage under critical system conditions
$f_r = 50Hz$	Rated system frequency
$U_p = \frac{400}{\sqrt{3}}kV$	Rated primary voltage of voltage (or potential) transformers used
$U_s = \frac{0.11}{\sqrt{3}}kV$	Rated secondary voltage of voltage (or potential) transformers used
$I_p = 1200A$	Rated primary current of current transformers used
$I_s = 1A$	Rated secondary current of current transformers used
$\bar{Z}_{L1} = (10.71 + j75.6)\Omega$	Positive sequence line impedance
$\bar{Z}_{SA1} = (1.15 + j43.5)\Omega$	Positive sequence source impedance behind A bus
$\bar{Z}_{SB1} = (5.3 + j35.7)\Omega$	Positive sequence source impedance behind B bus
$S_{\max} = 1000MVA$	Maximum expected load in direction from A to B (with minimum system operating voltage $U_{\min}$)
$\cos(\varphi_{\max}) = 0.95$	Power factor at maximum line loading
$\varphi_{\max} = 25^\circ$	Maximum expected load angle
$f_{si} = 2.5Hz$	Maximum possible initial frequency of power oscillation
$f_{sc} = 7.0Hz$	Maximum possible consecutive frequency of power oscillation

The minimum load impedance at minimum expected system voltage is equal to equation [79](#).

$$|\bar{Z}_{L\min}| = \frac{U_{\min}^2}{S_{\max}} = \frac{380^2}{1000} = 144.4\Omega$$

(Equation 79)

The minimum load resistance $R_{L\min}$ at maximum load and minimum system voltage is equal to equation [80](#).

$$R_{L\min} = |\bar{Z}_{L\min}| \cdot \cos(\varphi_{\max}) = 144.4 \cdot 0.95 = 137.2 \Omega$$

(Equation 80)

The system impedance Z_S is determined as a sum of all impedances in an equivalent two-machine system, see figure 69. Its value is calculated according to equation 81.

$$\bar{Z}_S = \bar{Z}_{SA1} + \bar{Z}_{L1} + \bar{Z}_{SB1} = (17.16 + j154.8) \Omega$$

(Equation 81)

The calculated value of the system impedance is of informative nature and helps in determining the position of the oscillation center, see figure 70, which is for a general case calculated according to equation 82.

$$\bar{Z}_{CO} = \frac{\bar{Z}_S}{1 + \frac{|\bar{E}_B|}{|\bar{E}_A|}} - \bar{Z}_{SA1}$$

(Equation 82)

In particular cases, when

$$|\bar{E}_A| = |\bar{E}_B|$$

(Equation 83)

The center of oscillation resides on the impedance point according to equation 84.

$$\bar{Z}_{CO} = \frac{\bar{Z}_S}{2} - \bar{Z}_{SA1} = (7.43 + j33.9) \Omega$$

(Equation 84)

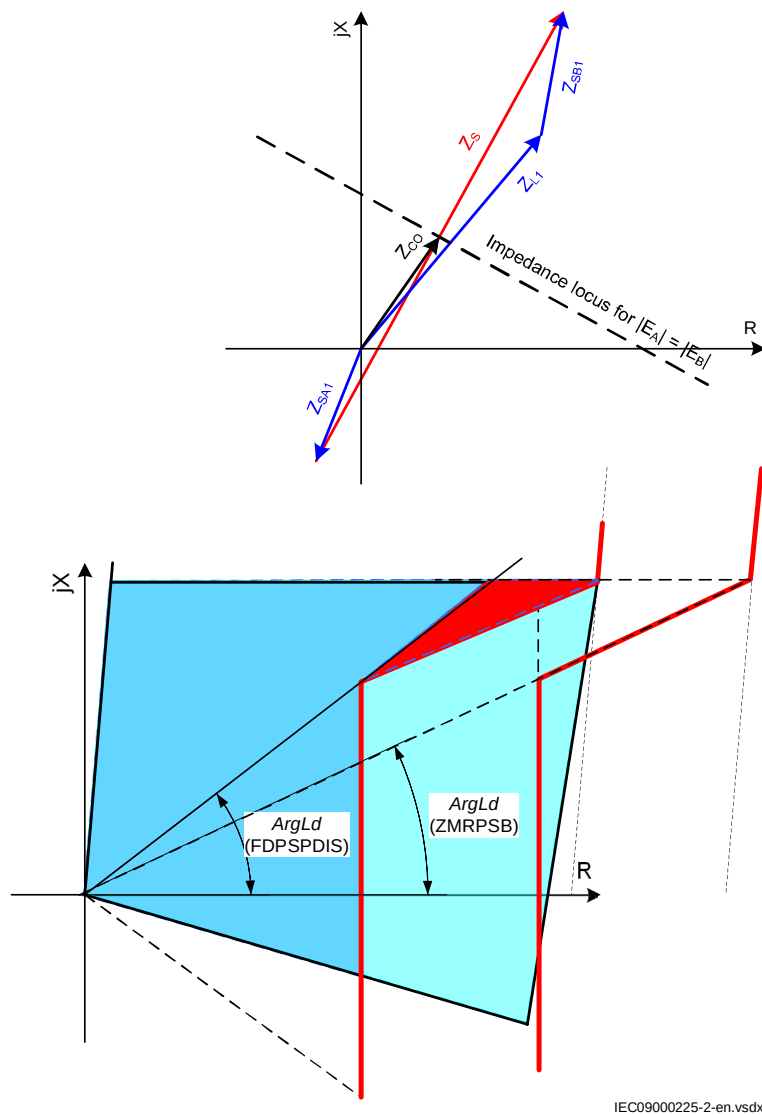


Figure 70: Impedance diagrams with corresponding impedances under consideration

The outer boundary of oscillation detection characteristic in forward direction $RLdOutFw$ should be set with certain safety margin K_L compared to the minimum expected load resistance R_{Lmin} . When the exact value of the minimum load resistance is not known, the following approximations may be considered for lines with a rated voltage of 400 kV:

- $K_L = 0.9$ for lines longer than 150 km
- $K_L = 0.85$ for lines between 80 and 150 km
- $K_L = 0.8$ for lines shorter than 80 km

Multiply the required resistance for the same safety factor K_L with the ratio between actual voltage and 400kV when the rated voltage of the line under consideration is higher than 400kV. The outer boundary $RLdOutFw$ obtains in this particular case its value according to equation 85.

$$RLdOutFw = K_L \cdot R_{Lmin} = 0.9 \cdot 137.2 = 123.5 \Omega$$

(Equation 85)

It is a general recommendation to set the inner boundary $RLdInFw$ of the oscillation detection characteristic to 80% or less of its outer boundary. Take special care during the settings of timers $tP1$ and $tP2$ which is included in the oscillation detection logic. This requires the maximum permitted setting values of factor $kLdRFw = 0.8$. Equation 86 presents the corresponding maximum possible value of $RLdInFw$.

$$RLdInFw = kLdRFw \cdot RLdOutFw = 98.8\Omega$$

(Equation 86)

The load angles, which correspond to external δ_{Out} and internal δ_{In} boundary of proposed oscillation detection characteristic in forward direction, are calculated with sufficient accuracy according to equation 87 and 88 respectively.

$$\delta_{Out} = 2 \cdot \arctan\left(\frac{|\bar{Z}_S|}{2 \cdot RLdOutFw}\right) = 2 \cdot \arctan\left(\frac{155.75}{2 \cdot 123.5}\right) = 64.5^\circ$$

(Equation 87)

$$\delta_{In} = 2 \cdot \arctan\left(\frac{|\bar{Z}_S|}{2 \cdot RLdInFw_{\max}}\right) = 2 \cdot \arctan\left(\frac{155.75}{2 \cdot 98.8}\right) = 76.5^\circ$$

(Equation 88)

The required setting $tP1$ of the initial oscillation detection timer depends on the load angle difference according to equation 89.

$$tP1 = \frac{\delta_{In} - \delta_{Out}}{f_{si} \cdot 360^\circ} = \frac{76.5^\circ - 64.5^\circ}{2.5 \cdot 360^\circ} = 13.3ms$$

(Equation 89)

The general tendency should be to set the $tP1$ time to at least 30 ms, if possible. Since it is not possible to further increase the external load angle δ_{Out} , it is necessary to reduce the inner boundary of the oscillation detection characteristic. The minimum required value is calculated according to the procedure listed in equation 90, 91, 92 and 93.

$$tP1_{\min} = 30ms$$

(Equation 90)

$$\delta_{In-\min} = 360^\circ \cdot f_{si} \cdot tP1_{\min} + \delta_{Out} = 360^\circ \cdot 2.5 \cdot 0.030 + 64.5^\circ = 91.5^\circ$$

(Equation 91)

$$RLdInFw_{\max1} = \frac{|\bar{Z}_S|}{2 \cdot \tan\left(\frac{\delta_{in-\min}}{2}\right)} = \frac{155.75}{2 \cdot \tan\left(\frac{91.5}{2}\right)} = 75.8\Omega$$

(Equation 92)

$$kLdRFw = \frac{RLdInFw_{\max 1}}{RLdOutFw} = \frac{75.8}{123.5} = 0.61$$

(Equation 93)

Also check if this minimum setting satisfies the required speed for detection of consecutive oscillations. This requirement will be satisfied if the proposed setting of $tP2$ time remains higher than 10 ms, see equation 94.

$$tP2_{\max} = \frac{\delta_{In} - \delta_{Out}}{f_{sc} \cdot 360^\circ} = \frac{91.5^\circ - 64.5^\circ}{7 \cdot 360^\circ} = 10.7ms$$

(Equation 94)

The final proposed settings are as follows:

$$RLdOutFw = 123.5\Omega$$

$$kLdRFw = 0.61$$

$$tP1 = 30 \text{ ms}$$

$$tP2 = 10 \text{ ms}$$

Consider $RLdInFw = 75.0\Omega$.



Do not forget to adjust the setting of load encroachment resistance $RLdFw$ in Phase selection with load encroachment (FDPSPDIS or FRPSPDIS) to the value equal to or less than the calculated value $RLdInFw$. It is at the same time necessary to adjust the load angle in FDPSPDIS or FRPSPDIS to follow the condition presented in equation 95.



Index PHS designates correspondence to FDPSPDIS or FRPSPDIS function and index PSD the correspondence to ZMRPSB function.

$$ArgLd_{PHS} \geq \arctan \left[\frac{\tan(ArgLd_{PSD})}{kLdRFw} \right]$$

(Equation 95)

Consider equation 96,

$$ArgLd_{PSD} = \varphi_{\max} = 25^\circ$$

(Equation 96)

then it is necessary to set the load argument in FDPSPDIS or FRPSPDIS function to not less than equation 97.

$$ArgLd_{PHS} \geq \arctan \left[\frac{\tan(ArgLd_{PSD})}{kLdRFw} \right] = \arctan \left[\frac{\tan(25^\circ)}{0.61} \right] = 37.5^\circ$$

(Equation 97)

It is recommended to set the corresponding resistive reach parameters in reverse direction ($RLdOutRv$ and $kLdRRv$) to the same values as in forward direction, unless the system operating

conditions, which dictate motoring and generating types of oscillations, require different values. This decision must be made on basis of possible system contingency studies especially in cases when the direction of transmitted power may change fast in short periods of time. It is recommended to use different setting groups for operating conditions, which are changing only between different periods of year (summer, winter).

System studies should determine the settings for the hold timer tH . The purpose of this timer is to secure continuous output signal from the Power swing detection function (ZMRPSB) during the power swing, even after the transient impedance leaves ZMRPSB operating characteristic and is expected to return within a certain time due to continuous swinging. Consider the minimum possible speed of power swinging in a particular system.

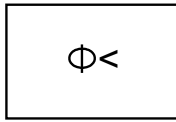
The $tR1$ inhibit timer delays the influence of the detected residual current on the inhibit criteria for ZMRPSB. It prevents operation of the function for short transients in the residual current measured by the IED.

The $tR2$ inhibit timer disables the output START signal from ZMRPSB function, if the measured impedance remains within ZMRPSB operating area for a time longer than the set $tR2$ value. This time delay was usually set to approximately two seconds in older power-swing devices.

The setting of the tEF timer must cover, with sufficient margin, the opening time of a circuit breaker and the dead-time of a single-phase autoreclosing together with the breaker closing time.

7.3 Out-of-step protection OOSPPAM

7.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Out-of-step protection	OOSPPAM		78

7.3.2 Application

Under balanced and stable conditions, a generator operates with a constant rotor (power) angle, delivering an active electrical power to the power system, which is equal to the mechanical input power on the generator axis, minus the small losses in the generator. In the case of a three-phase fault electrically close to the generator, no active power can be delivered. Almost all mechanical power from the turbine is under this condition used to accelerate the moving parts, that is, the rotor and the turbine. If the fault is not cleared quickly, the generator may not remain in synchronism after the fault has been cleared. If the generator loses synchronism (Out-of-step) with the rest of the system, pole slipping occurs. This is characterized by a wild flow of synchronizing power, which reverses in direction twice for every slip cycle.

The out-of-step phenomenon occurs when a phase opposition occurs periodically between different parts of a power system. This is often shown in a simplified way as two equivalent generators connected to each other via an equivalent transmission line and the phase difference between the equivalent generators is 180 electrical degrees.

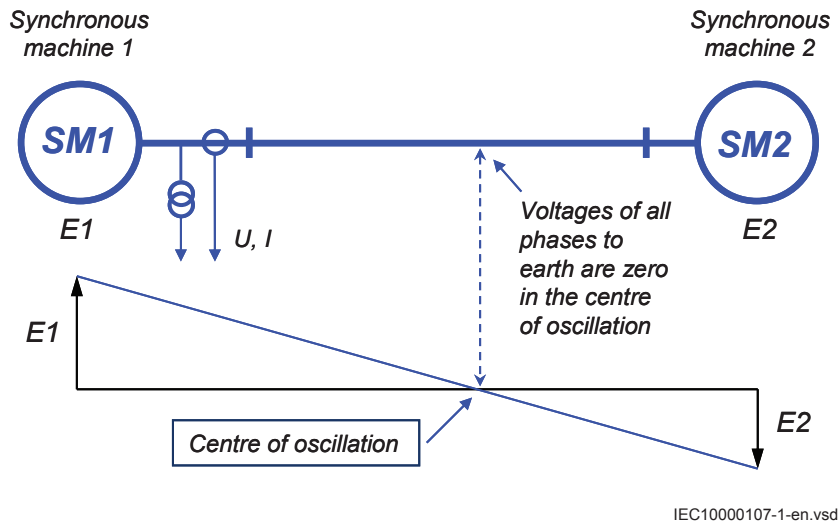
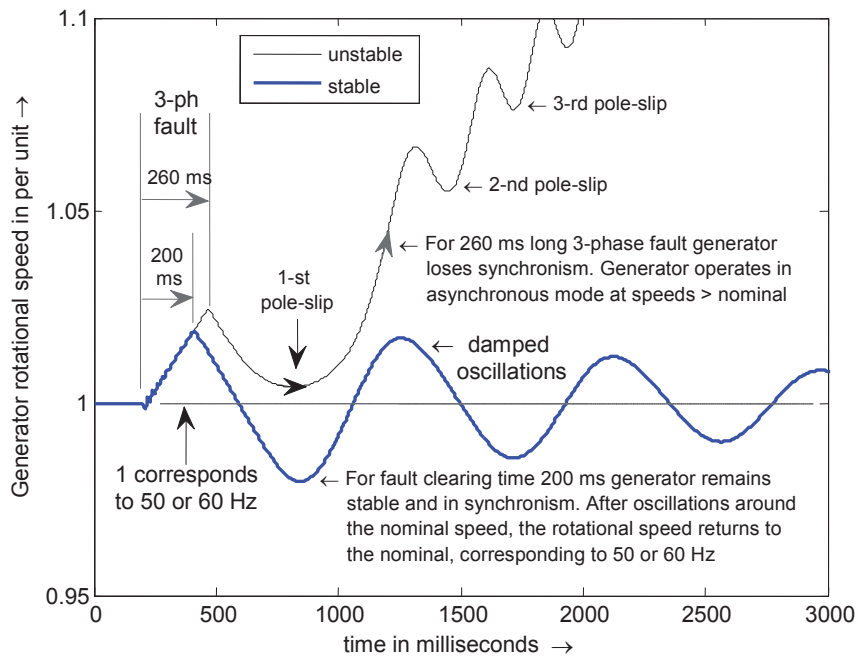


Figure 71: The centre of electromechanical oscillation

The center of the electromechanical oscillation can be in the generator unit (or generator-transformer unit) or outside, somewhere in the power system. When the center of the electromechanical oscillation occurs within the generator it is essential to trip the generator immediately. If the center of the electromechanical oscillation is outside any of the generators in the power system, the power system should be split into two different parts; so each part may have the ability to restore stable operating conditions. This is sometimes called "islanding". The objective of islanding is to prevent an out-of-step condition from spreading to the healthy parts of the power system. For this purpose, uncontrolled tripping of interconnections or generators must be prevented. It is evident that a reasonable strategy for out-of-step relaying as well as, appropriate choice of other protection relays, their locations and settings require detailed stability studies for each particular power system and/or subsystem. On the other hand, if severe swings occur, from which a fast recovery is improbable, an attempt should be made to isolate the affected area from the rest of the system by opening connections at predetermined points. The electrical system parts swinging to each other can be separated with the lines closest to the center of the power swing allowing the two systems to be stable as separated islands. The main problem involved with systemic islanding of the power system is the difficulty, in some cases, of predicting the optimum splitting points, because they depend on the fault location and the pattern of generation and load at the respective time. It is hardly possible to state general rules for out-of-step relaying, because they shall be defined according to the particular design and needs of each electrical network. The reason for the existence of two zones of operation is selectivity, required for successful islanding. If there are several out-of-step relays in the power system, then selectivity between separate relays is obtained by the relay reach (for example zone 1) rather than by time grading.

The out-of-step condition of a generator can be caused by different reasons. Sudden events in an electrical power system such as large changes in load, fault occurrence or slow fault clearance, can cause power oscillations, that are called power swings. In a non-recoverable situation, the power swings become so severe that the synchronism is lost: this condition is called pole slipping.

Undamped oscillations occur in power systems, where generator groups at different locations are not strongly electrically connected and can oscillate against each other. If the connection between the generators is too weak the magnitude of the oscillations may increase until the angular stability is lost. More often, a three-phase short circuit (unsymmetrical faults are much less dangerous in this respect) may occur in the external power grid, electrically close to the generator. If the fault clearing time is too long, the generator accelerates so much, that the synchronism cannot be maintained even if the power system is restored to the pre-fault configuration, see Figure 72.



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Figure 72: *Stable and unstable case. For the fault clearing time $t_{cl} = 200$ ms, the generator remains in synchronism, for $t_{cl} = 260$ ms, the generator loses step.*

A generator out-of-step condition, with successive pole slips, can result in damages to the generator, shaft and turbine.

- Stator windings are under high stress due to electrodynamic forces.
- The current levels during an out-of-step condition can be higher than those during a three-phase fault and, therefore, there is significant torque impact on the generator-turbine shaft.
- In asynchronous operation there is induction of currents in parts of the generator normally not carrying current, thus resulting in increased heating. The consequence can be damages on insulation and iron core of both rotor and stator.

Measurement of the magnitude, direction and rate-of-change of load impedance relative to a generator's terminals provides a convenient and generally reliable means of detecting whether pole-slipping is taking place. The out-of-step protection should protect a generator or motor (or two weakly connected power systems) against pole-slipping with severe consequences for the machines and stability of the power system. In particular it should:

1. Remain stable for normal steady state load.
2. Distinguish between stable and unstable rotor swings.
3. Locate electrical centre of a swing.
4. Detect the first and the subsequent pole-slips.
5. Prevent stress on the circuit breaker.
6. Distinguish between generator and motor out-of-step conditions.
7. Provide information for post-disturbance analysis.

7.3.3 Setting guidelines

The setting example for generator protection application shows how to calculate the most important settings *ForwardR*, *ForwardX*, *ReverseR*, and *ReverseX*.

Table 16: An example how to calculate values for the settings *ForwardR*, *ForwardX*, *ReverseR*, and *ReverseX*

IEC10000117-2-en.vsd				
	Generator	Unit step-up transformer	Single power line	Power system
Data required	$U_{Base} = U_{gen} = 13.8 \text{ kV}$ $I_{Base} = I_{gen} = 8367 \text{ A}$ $X_d' = 0.2960 \text{ pu}$ $R_s = 0.0029 \text{ pu}$	$U_1 = 13.8 \text{ kV}$ $U_2 = 230 \text{ kV}$ $usc = 10\%$ $I_1 = 12\,551 \text{ A}$ $X_t = 0.1000 \text{ pu (transf. ZBase)}$ $R_t = 0.0054 \text{ pu (transf. ZBase)}$	$U_{line} = 230 \text{ kV}$ $X_{line/km} = 0.4289 \text{ } \Omega/\text{km}$ $R_{line/km} = 0.0659 \text{ } \Omega/\text{km}$	$U_{nom} = 230 \text{ kV}$ $SC \text{ level} = 5000 \text{ MVA}$ $SC \text{ current} = 12\,551 \text{ A}$ $\varphi = 84.289^\circ$ $Z_e = 10.5801 \text{ } \Omega$
1-st step in calculation	$Z_{Base} = 0.9522 \text{ } \Omega \text{ (generator)}$ $X_d' = 0.2960 \cdot 0.952 = 0.282 \text{ } \Omega$ $R_s = 0.0029 \cdot 0.952 = 0.003 \text{ } \Omega$	$Z_{Base} (13.8 \text{ kV}) = 0.6348 \text{ } \Omega$ $X_t = 0.100 \cdot 0.6348 = 0.064 \text{ } \Omega$ $R_t = 0.0054 \cdot 0.635 = 0.003 \text{ } \Omega$	$X_{line} = 300 \cdot 0.4289 = 128.7 \text{ } \Omega$ $R_{line} = 300 \cdot 0.0659 = 19.8 \text{ } \Omega$ $(X \text{ and } R \text{ above on } 230 \text{ kV basis})$	$X_e = Z_e \cdot \sin(\varphi) = 10.52 \text{ } \Omega$ $R_e = Z_e \cdot \cos(\varphi) = 1.05 \text{ } \Omega$ $(X_e \text{ and } R_e \text{ on } 230 \text{ kV basis})$
2-nd step in calculation			$X_{line} = 128.7 \cdot (13.8/230)^2 = 0.463 \text{ } \Omega$ $R_{line} = 19.8 \cdot (13.8/230)^2 = 0.071 \text{ } \Omega$ $(X \text{ and } R \text{ referred to } 13.8 \text{ kV})$	$X_e = 10.52 \cdot (13.8/230)^2 = 0.038 \text{ } \Omega$ $R_e = 1.05 \cdot (13.8/230)^2 = 0.004 \text{ } \Omega$ $(X \text{ and } R \text{ referred to } 13.8 \text{ kV})$
3-rd step in calculation	$ForwardX = X_t + X_{line} + X_e = 0.064 + 0.463 + 0.038 = 0.565 \text{ } \Omega$; $ReverseX = X_d' = 0.282 \text{ } \Omega$ (all referred to gen. voltage 13.8 kV) $ForwardR = R_t + R_{line} + R_e = 0.003 + 0.071 + 0.004 = 0.078 \text{ } \Omega$; $ReverseR = R_s = 0.003 \text{ } \Omega$ (all referred to gen. voltage 13.8 kV)			
Final resulted settings	$ForwardX = 0.565/0.9522 \cdot 100 = 59.33 \text{ in } \% Z_{Base}$; $ReverseX = 0.282/0.9522 \cdot 100 = 29.6 \text{ in } \% Z_{Base}$ (all referred to 13.8 kV) $ForwardR = 0.078/0.9522 \cdot 100 = 8.19 \text{ in } \% Z_{Base}$; $ReverseR = 0.003/0.9522 \cdot 100 = 0.29 \text{ in } \% Z_{Base}$ (all referred to 13.8 kV)			

Settings *ForwardR*, *ForwardX*, *ReverseR*, and *ReverseX*.

- A precondition in order to be able to use the Out-of-step protection and construct a suitable lens characteristic is that the power system in which the Out-of-step protection is installed, is modeled as a two-machine equivalent system, or as a single machine – infinite bus equivalent power system. Then the impedances from the position of the Out-of-step protection in the direction of the normal load flow can be taken as forward.
- The settings *ForwardX*, *ForwardR*, *ReverseX* and *ReverseR* must, if possible, take into account, the post-disturbance configuration of the simplified power system. This is not always easy, in particular with islanding. But for the two machine model as in Table 16, the most probable scenario is that only one line is in service after the fault on one power line has been cleared by line protections. The settings *ForwardX*, *ForwardR* must therefore take into account the reactance and resistance of only one power line.
- All the reactances and resistances (*ForwardX*, *ForwardR*, *ReverseX* and *ReverseR*) must be referred to the voltage level where the Out-of-step relay is installed; for the example case shown in Table 16, this is the generator nominal voltage $U_{Base} = 13.8 \text{ kV}$. This affects all the forward reactances and resistances in Table 16.
- All reactances and resistances must be finally expressed in percent of Z_{Base} , where Z_{Base} is for the example shown in Table 16 the base impedance of the generator, $Z_{Base} = 0.9522 \text{ } \Omega$. Observe that the power transformer's base impedance is different, $Z_{Base} = 0.6348 \text{ } \Omega$. Observe that this latter power transformer $Z_{Base} = 0.6348 \text{ } \Omega$ must be used when the power transformer reactance and resistance are transformed.

- For the synchronous machines as the generator in Table 16, the transient reactance X_d' shall be used. This due to the relatively slow electromechanical oscillations under out-of-step conditions.
- Sometimes the equivalent resistance of the generator is difficult to get. A good estimate is 1 percent of transient reactance X_d' . No great error is done if this resistance is set to zero (0).
- Inclination of the Z-line, connecting points SE and RE, against the real (R) axis can be calculated as $\arctan((ReverseX + ForwardX) / (ReverseR + ForwardR))$, and is for the case in Table 16 equal to 84.55 degrees, which is a typical value.

Other settings:

- **ReachZ1:** Determines the reach of the zone 1 in the forward direction. Determines the position of the X-line which delimits zone 1 from zone 2. Set in % of *ForwardX*. In the case shown in Table 16, where the reactance of the unit step-up power transformer is 11.32 % of the total *ForwardX*, the setting *ReachZ1* should be set to *ReachZ1* = 12 %. This means that the generator – unit step-up transformer unit would be in the zone 1. In other words, if the centre of oscillation would be found to be within the zone 1, only a very limited number of pole-slips would be allowed, usually only one.
- **StartAngle:** Angle between the two equivalent rotors induced voltages (that is, the angle between the two internal induced voltages E1 and E2 in an equivalent simplified two-machine system) to get the start signal, in degrees. The width of the lens characteristic is determined by the value of this setting. Whenever the complex impedance Z(R, X) enters the lens, this is a sign of instability. The angle recommended is 110 or 120 degrees, because it is at this rotor angle where problems with dynamic stability usually begin. Power angle 120 degrees is sometimes called “the angle of no return” because if this angle is reached under generator swings, the generator is most likely to lose synchronism. When the complex impedance Z(R, X) enters the lens the start output signal (*START*) is set to 1 (*TRUE*).
- **TripAngle:** The setting *TripAngle* specifies the value of the rotor angle where the trip command is sent to the circuit breaker in order to minimize the stress to which the breaker is exposed when breaking the currents. The range of this value is from 15° to 90°, with higher values suitable for longer breaker opening times. If a breaker opening is initiated at for example 60°, then the circuit breaker opens its contacts closer to 0°, where the currents are smaller. If the breaker opening time *tBreaker* is known, then it is possible to calculate more precisely when opening must be initiated in order to open the circuit breaker contacts as close as possible to 0°, where the currents are smallest. If the breaker opening time *tBreaker* is specified (that is, higher than the default 0.0 s, where 0.0 s means that *tBreaker* is unknown), then this alternative way to determine the moment when a command to open the breaker is sent, is automatically chosen instead of the more approximate method, based on the *TripAngle*.
- **tReset:** Interval of time since the last pole-slip detected, when the Out-of-step protection is reset. If there is no more pole slips detected under the time interval specified by *tReset* since the previous one, the function is reset. All outputs are set to 0 (*FALSE*). If no pole slip at all is detected under interval of time specified by *tReset* since the start signal has been set (for example a stable case with synchronism retained), the function is as well reset, which includes the start output signal (*START*), which is reset to 0 (*FALSE*) after *tReset* interval of time has elapsed. However, the measurements of analogue quantities such as R, X, P, Q, and so on continue without interruptions. Recommended setting of *tReset* is in the range of 6 to 12 seconds.
- **NoOfSlipsZ1:** Maximum number of pole slips with centre of electromechanical oscillation within zone 1 required for a trip. Usually, *NoOfSlipsZ1* = 1.
- **NoOfSlipsZ2:** Maximum number of pole slips with centre of electromechanical oscillation within zone 2 required for a trip. The reason for the existence of two zones of operation is selectivity, required particularly for successful islanding. If there are several pole slip (out-of-step) relays in the power system, then selectivity between relays is obtained by the relay reach (for example zone 1) rather than by time grading. In a system, as in Table 16, the number of allowed pole slips in zone 2 can be the same as in zone 1. Recommended value: *NoOfSlipsZ2* = 2 or 3.
- **Operation:** With the setting *Operation* OOSPPAM function can be set *On/Off*.
- **OperationZ1:** Operation zone 1 *On, Off*. If *OperationZ1* = *Off*, all pole-slips with centre of the electromechanical oscillation within zone 1 are ignored. Default setting = *On*. More likely to be used is the option to extend zone 1 so that zone 1 even covers zone 2. This feature is activated by the input to extend the zone 1 (*EXTZ1*).

- **OperationZ2:** Operation zone 2 On, Off. If *OperationZ1* = Off, all pole-slips with centre of the electromechanical oscillation within zone 2 are ignored. Default setting = On.
- **tBreaker:** Circuit breaker opening time. Use the default value *tBreaker* = 0.000 s if unknown. If the value is known, then a value higher than 0.000 is specified, for example *tBreaker* = 0.040 s: the out-of-step function gives a trip command approximately 0.040 seconds before the currents reach their minimum value. This in order to decrease the stress imposed to the circuit breaker.
- **GlobalBaseSel:** This setting identifies the Global Base Values Group where *UBase* and *IBase* are defined. In particular: *UBase* is the voltage at the point where the Out-of-step protection is connected. If the protection is connected to the generator output terminals, then *UBase* is the nominal (rated) phase to phase voltage of the protected generator. All the resistances and reactances are measured and displayed referred to voltage *Ubase*. Observe that *ReverseX*, *ForwardX*, *ReverseR*, and *ForwardR* must be given referred to *UBase*. *IBase* is the protected generator nominal (rated) current, if the Out-of-step protection belongs to a generator protection scheme.
- **InvertCTCurr:** If the currents fed to the Out-of-step protection are measured on the protected generator neutral side then inversion is not necessary (*InvertCTCurr* = Off), provided that the CT's star point earthing complies with Hitachi Energy recommendations, as it is shown in Table 16. If the currents fed to the Out-of-step protection are measured on the protected generator terminals side, then inversion is necessary (*InvertCTCurr* = On), provided that the CT's star point earthing complies with Hitachi Energy recommendations, as it is shown in Table 16.

7.4 Automatic switch onto fault logic ZCVPSOF

7.4.1 Function revision history

Document revision	Product revision	History
A	2.2.1	-
B	2.2.1	-
C	2.2.1	-
D	2.2.4	Updated technical data for setting parameters <i>tDuration</i> , <i>tDLD</i> and <i>tOperate</i> .
E	2.2.5	-
F	2.2.6	-
G	2.2.6	-

7.4.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Automatic switch onto fault logic	ZCVPSOF	-	-

7.4.3 Application

Automatic switch onto fault logic, voltage- and current-based function ZCVPSOF is a complementary function to impedance measuring functions, but may use the information from such functions.

With ZCVPSOF, a fast trip is achieved for a fault on the whole line when the line is being energized. The ZCVPSOF tripping is generally non-directional to secure a trip at fault situations where directional information cannot be established, for example, due to lack of polarizing voltage when a line potential transformer is used.

Automatic activation based on dead-line detection can only be used when the voltage transformer is situated on the line side of a circuit breaker.

When line side voltage transformers are used, the use of the nondirectional distance zones secures switch onto fault tripping for close-in three-phase short circuits. The use of the nondirectional distance zones also gives a fast fault clearance when energizing a bus from the line with a short circuit fault on the bus.

Other protection functions like time-delayed phase and zero-sequence overcurrent function can be connected to ZCVPSOF to increase the dependability in the scheme.

When the voltage transformers are situated on the bus side, the automatic switch onto fault detection based on dead-line detection is not possible. In such cases the deadline detection is bypassed using the breaker closing status and the switch onto fault logic is activated.

7.4.4 Setting guidelines

The parameters for automatic switch onto fault logic, voltage- and current-based function ZCVPSOF are set via the local HMI or Protection and Control Manager PCM600.

The distance protection zone used for instantaneous trip by ZCVPSOF has to be set to cover the entire protected line with a safety margin of minimum 20%.

Common base IED values for primary current (I_{Base}), primary voltage (U_{Base}) and primary power (S_{Base}) are set in the global base values for settings function GBASVAL.

GlobalBaseSel is used to select GBASVAL for reference of base values.

Operation: The operation of ZCVPSOF is by default set to *On*. The parameter must be set to *Off* if ZCVPSOF is not to be used.

$I_{Ph<}$ is used to set the current level for the detection of a dead line. $I_{Ph<}$ is, by default, set to 20% of I_{Base} . It shall be set with a sufficient margin (15–20%) below the minimum expected load current. In many cases, the minimum load current of a line is close to zero and even can be zero. The operating value must exceed the maximum charging current of an overhead line when only one phase is disconnected (mutual coupling in the other phases).

$U_{Ph<}$ is used to set the voltage level for the detection of a dead line. $U_{Ph<}$ is, by default, set to 70% of U_{Base} . This is a suitable setting in most cases, but it is recommended to check the suitability in the actual application.

AutoInitMode: automatic activating of ZCVPSOF is, by default, set to *DLD disabled*, which means the dead-line logic detection is disabled. If an automatic activation of the dead-line detection is required, the parameter *AutoInitMode* has to be set to either *Voltage*, *Current* or *Current & Voltage*.

When *AutoInitMode* is set to *Voltage*, the dead-line detection logic checks that the three-phase voltages are lower than the set $U_{Ph<}$ level.

When *AutoInitMode* is set to *Current*, the dead-line detection logic checks if the three-phase currents are lower than the set $I_{Ph<}$ level.

When *AutoInitMode* is set to *Current & Voltage*, the dead-line detection logic checks that both three-phase currents and three-phase voltages are lower than the set $I_{Ph<}$ and $U_{Ph<}$ levels.

Otherwise, the logic is activated by an external BC input.

t_{SOTF} : the drop delay of ZCVPSOF is, by default, set to 1.0 seconds, which is suitable for most applications.

tDLD: The time delay for activating ZCVPSOF by the internal dead-line detection is, by default, set to 0.2 seconds. It is suitable in most applications. The delay shall not be set too short to avoid unwanted activations during transients in the system.

Mode: The operation of ZCVPSOF has three modes for defining the criteria for tripping. The setting of *Mode* is, by default, *UILevel*, which means that the tripping criterion is based on the setting of *IPh<* and *UPh<*. The choice of *UILevel* gives a faster and more sensitive operation of the function, which is important for reducing the stress that might occur when energizing onto a fault. However, the voltage recovery can be slow in some systems when energizing the line. Therefore, if the timer *tDuration* is set too short, ZCVPSOF can interpret this as a fault and release a trip.

When *Mode* is set to *Impedance*, the operate criterion is based on the *BC* input (breaker closing), which can be the start of the overreaching zone from the impedance zone measurement or a *tOperate*-delayed *START_DLYD* input. A nondirectional output signal should be used from an overreaching zone. The selection of the *Impedance* mode gives increased security.

When *Mode* is set to *UILvl&Imp*, the condition for tripping is an ORed between *UILevel* and *Impedance*.

tDuration: The setting of the timer for the release of *UILevel* is, by default, 0.02 seconds, which has proven to be suitable in most cases from field experience. If a shorter time delay is to be set, it is necessary to consider the voltage recovery time during line energization.

tOperate: The time delay for the *START_DLYD* input to activate *TRIP* when *Mode* is set to *Impedance* or *UILvl&Imp* is, by default, set to 0.03 seconds.

Section 8 Current protection

8.1 Instantaneous phase overcurrent protection PHPIOC

8.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Instantaneous phase overcurrent protection	PHPIOC	3I>>	50

8.1.2 Application

Long transmission lines often transfer great quantities of electric power from generation to consumption areas. The unbalance of the produced and consumed electric power at each end of the transmission line is very large. This means that a fault on the line can easily endanger the stability of a complete system.

The transient stability of a power system depends mostly on three parameters (at constant amount of transmitted electric power):

- The type of the fault. Three-phase faults are the most dangerous, because no power can be transmitted through the fault point during fault conditions.
- The magnitude of the fault current. A high fault current indicates that the decrease of transmitted power is high.
- The total fault clearing time. The phase angles between the EMFs of the generators on both sides of the transmission line increase over the permitted stability limits if the total fault clearing time, which consists of the protection operating time and the breaker opening time, is too long.

The fault current on long transmission lines depends mostly on the fault position and decreases with the distance from the generation point. For this reason the protection must operate very quickly for faults very close to the generation (and relay) point, for which very high fault currents are characteristic.

The instantaneous phase overcurrent protection PHPIOC can operate in 10 ms for faults characterized by very high currents.

8.1.3 Setting guidelines

The parameters for instantaneous phase overcurrent protection PHPIOC are set via the local HMI or PCM600.

This protection function must operate only in a selective way. So check all system and transient conditions that could cause its unwanted operation.

Only detailed network studies can determine the operating conditions under which the highest possible fault current is expected on the line. In most cases, this current appears during three-phase fault conditions. But also examine single-phase-to-earth and two-phase-to-earth conditions.

Also study transients that could cause a high increase of the line current for short times. A typical example is a transmission line with a power transformer at the remote end, which can cause high

inrush current when connected to the network and can thus also cause the operation of the built-in, instantaneous, overcurrent protection.

Common base IED values for primary current (I_{Base}), primary voltage (U_{Base}) and primary power (S_{Base}) are set in the global base values for settings function GBASVAL.

GlobalBaseSel: To select GBASVAL function for reference of base values.

Operation: Set the protection to *On/Off*.

OpMode: This parameter can be set to *2 out of 3* or *1 out of 3*. The setting controls the minimum number of phase currents that must be larger than the set operate current $IP_{>>}$ for operation. Normally this parameter is set to *1 out of 3* and will thus detect all fault types. If the protection is to be used mainly for multi phase faults, *2 out of 3* should be chosen.

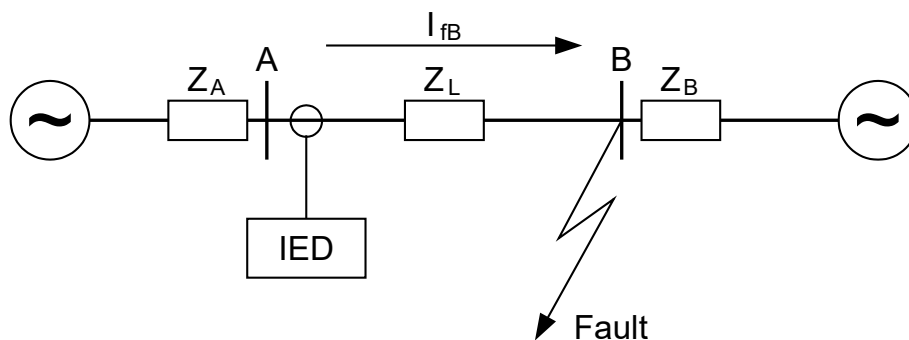
$IP_{>>}$: Set operate current in % of I_B .

$IP_{>>Max}$ and $IP_{>>Min}$ should only be changed if remote setting of operation current level, $IP_{>>}$, is used. The limits are used for decreasing the used range of the $IP_{>>}$ setting. If $IP_{>>}$ is set outside $IP_{>>Max}$ and $IP_{>>Min}$, the closest of the limits to $IP_{>>}$ is used by the function. If $IP_{>>Max}$ is smaller than $IP_{>>Min}$, the limits are swapped.

StValMult: The set operate current can be changed by activation of the binary input ENMULT to the set factor $StValMult$.

8.1.3.1 Meshed network without parallel line

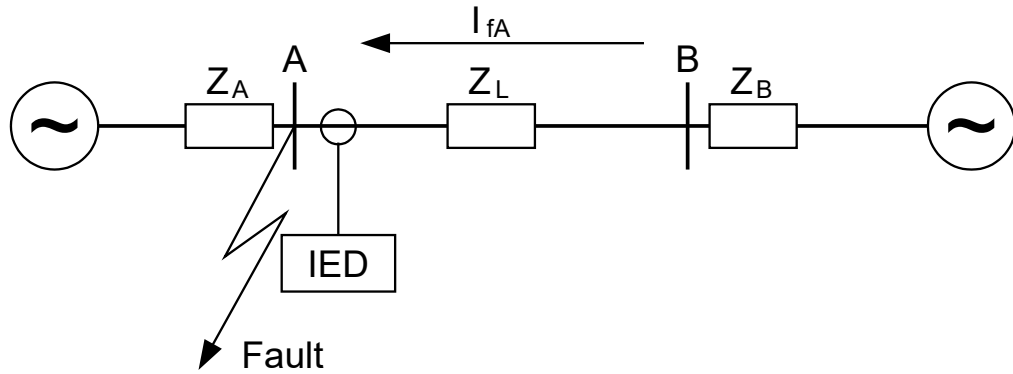
The following fault calculations have to be done for three-phase, single-phase-to-earth and two-phase-to-earth faults. With reference to Figure 73, apply a fault in B and then calculate the current through-fault phase current I_{fB} . The calculation should be done using the minimum source impedance values for Z_A and the maximum source impedance values for Z_B in order to get the maximum through fault current from A to B.



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Figure 73: Through fault current from A to B: I_{fB}

Then a fault in A has to be applied and the through fault current I_{fA} has to be calculated, Figure 74. In order to get the maximum through fault current, the minimum value for Z_B and the maximum value for Z_A have to be considered.



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Figure 74: Through fault current from B to A: I_{fA}

The IED must not trip for any of the two through-fault currents. Hence the minimum theoretical current setting (I_{min}) will be:

$$I_{min} \geq \text{MAX}(I_{fA}, I_{fB})$$

(Equation 98)

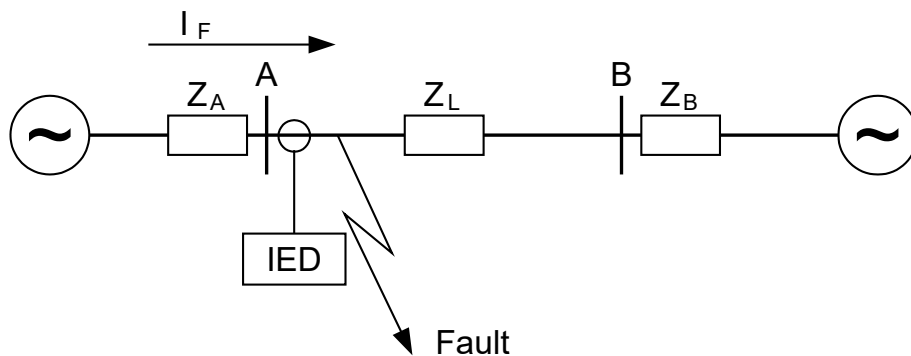
A safety margin of 5% for the maximum protection static inaccuracy and a safety margin of 5% for the maximum possible transient overreach have to be introduced. An additional 20% is suggested due to the inaccuracy of the instrument transformers under transient conditions and inaccuracy in the system data.

The minimum primary setting (I_s) for the instantaneous phase overcurrent protection is then:

$$I_s \geq 1.3 \cdot I_{min}$$

(Equation 99)

The protection function can be used for the specific application only if this setting value is equal to or less than the maximum fault current that the IED has to clear, I_F in Figure 75.



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Figure 75: Fault current: I_F

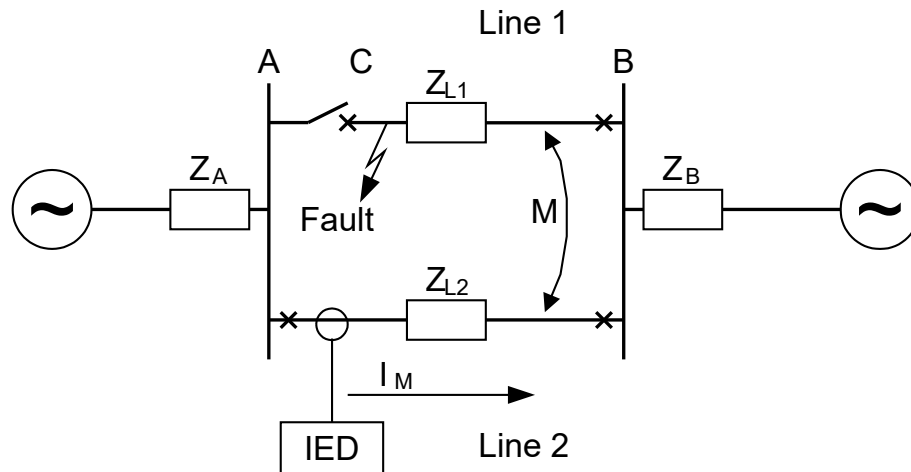
$$IP \gg \frac{I_s}{I_{Base}} \cdot 100$$

(Equation 100)

8.1.3.2 Meshed network with parallel line

In case of parallel lines, the influence of the induced current from the parallel line to the protected line has to be considered. One example is given in Figure 76, where the two lines are connected to the same busbars. In this case the influence of the induced fault current from the faulty line (line 1) to the healthy line (line 2) is considered together with the two through fault currents I_{fA} and I_{fB} mentioned previously. The maximal influence from the parallel line for the IED in Figure 76 will be with a fault at the C point with the C breaker open.

A fault in C has to be applied, and then the maximum current seen from the IED (I_M) on the healthy line (this applies for single-phase-to-earth and two-phase-to-earth faults) is calculated.



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Figure 76: Two parallel lines. Influence from parallel line to the through fault current: I_M

The minimum theoretical current setting for the overcurrent protection function (I_{min}) will be:

$$I_{min} \geq \text{MAX}(I_{fA}, I_{fB}, I_M)$$

(Equation 101)

Where I_{fA} and I_{fB} have been described in the previous paragraph. Considering the safety margins mentioned previously, the minimum setting (I_s) for the instantaneous phase overcurrent protection 3-phase output is then:

$$I_s \geq 1.3 \cdot I_{min}$$

(Equation 102)

The protection function can be used for the specific application only if this setting value is equal or less than the maximum phase fault current that the IED has to clear.

The IED setting value $IP_{>>}$ is given in percentage of the primary base current value, I_{Base} . The value for $IP_{>>}$ is given from this formula:

$$IP_{>>} = \frac{I_s}{I_{Base}} \cdot 100$$

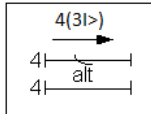
(Equation 103)

8.2 Directional phase overcurrent protection, four steps OC4PTOC

8.2.1 Function revision history

Document revision	Product revision	History
A	2.2.1	-
B	2.2.1	-
C	2.2.1	-
D	2.2.1	-
E	2.2.4	-
F	2.2.5	- The harmonic restraint function changed to freeze the definite and IDMT timers. - The maximum value of the settings <i>IMin1</i>, <i>IMin2</i>, <i>IMin3</i> and <i>IMin4</i> has been decreased to 1000.0 % of IBase.
J	2.2.6	-
K	2.2.6	Minimum value changed to 0.01 for k1,k2,k3 and k4 settings

8.2.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Directional phase overcurrent protection, four steps	OC4PTOC		51_67

8.2.3 Application

Directional phase overcurrent protection, four steps OC4PTOC is used in several applications in the power system. Some applications are:

- Short circuit protection of feeders in distribution and subtransmission systems. Normally these feeders have a radial structure.
- Back-up short circuit protection of transmission lines.
- Back-up short circuit protection of power transformers.
- Short circuit protection of different kinds of equipment connected to the power system such as; shunt capacitor banks, shunt reactors, motors and others.
- Back-up short circuit protection of power generators.

In many applications several steps with different current pickup levels and time delays are needed. OC4PTOC can have up to four different, individually settable steps. The following options are possible:

Non-directional / Directional function: In most applications the non-directional functionality is used. This is mostly the case when no fault current can be fed from the protected object itself. In order to achieve both selectivity and fast fault clearance, the directional function can be necessary.



If VT inputs are not available or not connected, the setting parameter *DirModex* ($x = \text{step } 1, 2, 3 \text{ or } 4$) shall be left to the default value *Non-directional*.

Choice of time delay characteristics: There are several types of time delay characteristics available such as definite time delay and different types of inverse time delay characteristics. The selectivity between different overcurrent protections is normally enabled by co-ordination between the function time delays of the different protections. To enable optimal co-ordination between all overcurrent protections, they should have the same time delay characteristic. Therefore, a wide range of standardized inverse time characteristics are available for IEC and ANSI. It is also possible to tailor make the inverse time characteristic.

Normally, it is required that the phase overcurrent protection shall reset as fast as possible when the current level gets lower than the operation level. In some cases some sort of delayed reset is required. Therefore, different kinds of reset characteristics can be used.

For some protection applications, there can be a need to change the current pick-up level for some time. A typical case is when the protection will measure the current to a large motor. At the start up sequence of a motor the start current can be significantly larger than the rated current of the motor. Therefore, there is a possibility to give a setting of a multiplication factor to the current pick-up level. This multiplication factor is activated from a binary input signal to the function.

Power transformers can have a large inrush current, when being energized. This phenomenon is due to saturation of the transformer magnetic core during parts of the period. There is a risk that inrush current will reach levels above the pick-up current of the phase overcurrent protection. The inrush current has a large 2nd harmonic content. This can be used to avoid unwanted operation of the protection function. Therefore, OC4PTOC has a possibility of 2nd harmonic restrain if the level of 2nd harmonic current reaches a value above a set percent of the fundamental current.

The phase overcurrent protection is often used as a protection for two and three phase short circuits. In some cases, it is not wanted to detect single-phase earth faults by the phase overcurrent protection. This fault type is detected and cleared after operation of earth fault protection. Therefore, it is possible to make a choice how many phases, at minimum, that have to have current above the pick-up level, to enable operation. If set *1 of 3* it is sufficient to have high current in one phase only. If set *2 of 3* or *3 of 3* single-phase earth faults are not detected.

8.2.4 Setting guidelines



When inverse time overcurrent characteristic is selected, the operate time of the stage will be the sum of the inverse time delay and the set definite time delay. Thus, if only the inverse time delay is required, it is important to set the definite time delay for that stage to zero.

The parameters for the directional phase overcurrent protection, four steps OC4PTOC are set via the local HMI or PCM600.

The following settings can be done for OC4PTOC.

Common base IED values for the primary current (*IBase*), primary voltage (*UBase*) and primary power (*SBase*) are set in global base values for settings function GBASVAL.

GlobalBaseSel: Selects the global base value group used by the function to define *IBase*, *UBase* and *SBase*. Note that this function will only use *IBase* value.

MeasType: Selection of discrete Fourier filtered (*DFT*) or true RMS filtered (*RMS*) signals. *RMS* is used when the harmonic contents are to be considered, for example in applications with shunt capacitors.

Operation: The protection can be set to *On* or *Off*.

AngleRCA: Protection characteristic angle set in degrees. If the angle of the fault loop current has the angle RCA, the direction to the fault is forward.

AngleROA: Angle value, given in degrees, to define the angle sector of the directional function, shown in Figure 77.

StartPhSel: Number of phases, with high current, required for operation. The setting possibilities are: 1 out of 3, 2 out of 3 and 3 out of 3. The default setting is 1 out of 3.

IMinOpPhSel: Minimum current setting level for releasing the directional start signals in % of I_B . This setting should be less than the lowest step setting. The default setting is 7% of I_B .

2ndHarmStab: Operate level of 2nd harmonic current restrain set in % of the fundamental current. The setting range is 5 - 100% in steps of 1%. The default setting is 20%.

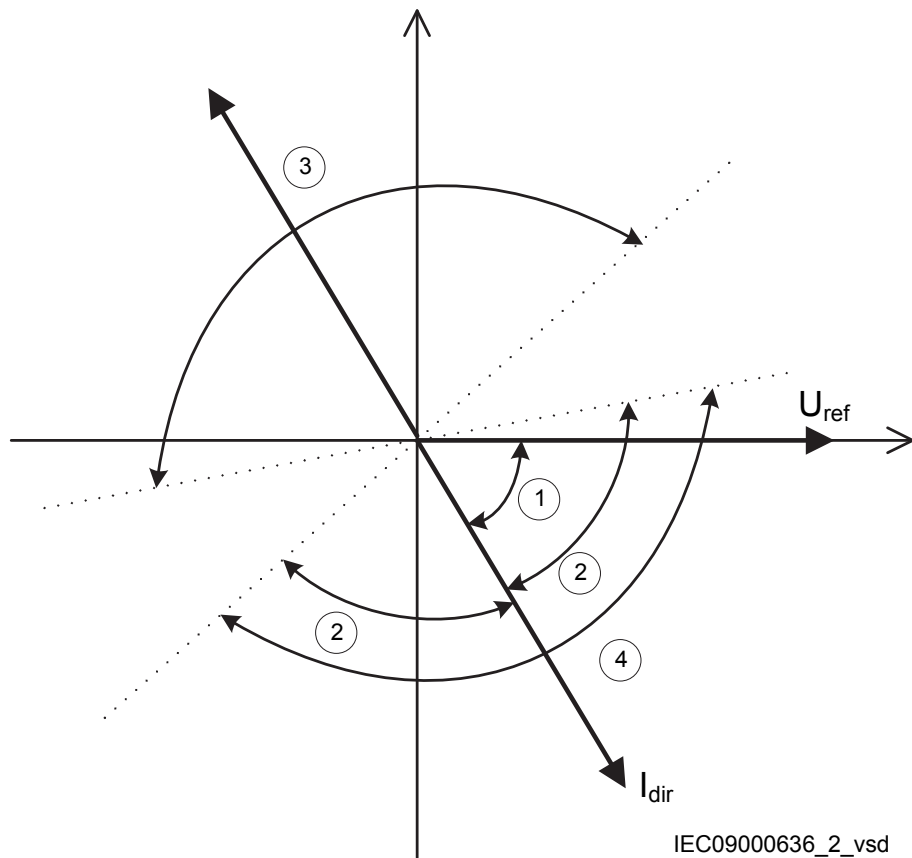


Figure 77: Directional function characteristic

1. RCA = Relay characteristic angle
2. ROA = Relay operating angle
3. Reverse
4. Forward

8.2.4.1 Settings for each step



x means step 1, 2, 3 and 4.

DirModex: The directional mode of step x. Possible settings are *Off/Non-directional/Forward/Reverse*.

Characteristicx: Selection of time characteristic for step x. Definite time delay and different types of inverse time characteristics are available according to Table 17.

Table 17: Inverse time characteristics

Curve name
ANSI Extremely Inverse
ANSI Very Inverse
ANSI Normal Inverse
ANSI Moderately Inverse
ANSI/IEEE Definite time
ANSI Long Time Extremely Inverse
ANSI Long Time Very Inverse
ANSI Long Time Inverse
IEC Normal Inverse
IEC Very Inverse
IEC Inverse
IEC Extremely Inverse
IEC Short Time Inverse
IEC Long Time Inverse
IEC Definite Time
User Programmable
ASEA RI
RXIDG or RD (logarithmic)

The different characteristics are described in *Technical manual*.

I_{x>}: Operate phase current level for step x given in % of *I_B*.

I_{x>Max} and **I_{x>Min}** should only be changed if remote setting of operation current level, **I_{x>}**, is used. The limits are used for decreasing the used range of the **I_{x>}** setting. If **I_{x>}** is set outside **I_{x>Max}** and **I_{x>Min}**, the closest of the limits to **I_{x>}** is used by the function. If **I_{x>Max}** is smaller than **I_{x>Min}**, the limits are swapped.

t_x: Definite time delay for step x. The definite time **t_x** is added to the inverse time when inverse time characteristic is selected. Note that the value set is the time between activation of the start and the trip outputs.

k_x: Time multiplier for inverse time delay for step x.

I_{Minx}: Minimum operate current in % of *I_B* for all inverse time characteristics, below which no operation takes place.

I_{Minx}: Minimum operate current for step x in % of *I_{Base}*. Set **I_{Minx}** below **I_{x>}** for every step to achieve ANSI reset characteristic according to standard. If **I_{Minx}** is set above **I_{x>}** for any step the ANSI reset works as if current is zero when current drops below **I_{Minx}**.

t_{xMin}: Minimum operate time for all inverse time characteristics. At high currents the inverse time characteristic might give a very short operation time. By setting this parameter the operation time of the step can never be shorter than the setting. Setting range: 0.000 - 60.000s in steps of 0.001s.

I_{xMult} : Multiplier for scaling of the current setting value. If a binary input signal ENMULT_x (enableMultiplier) is activated the current operation level is increased by this setting constant. Setting range: 1.0-10.0

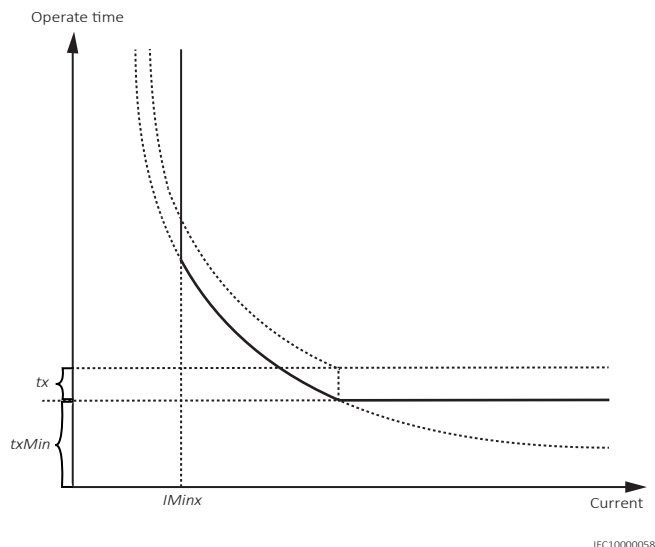


Figure 78: Minimum operate current and operate time for inverse time characteristics

In order to fully comply with the definition of the curve, the setting parameter tx_{Min} shall be set to a value equal to the operating time of the selected inverse curve for twenty times the set current pickup value. Note that the operate time is dependent on the selected time multiplier setting k_x .

ResetTypeCrvx: The reset of the delay timer can be made as shown in Table 18.

Table 18: Reset possibilities

Curve name	Curve index no.
Instantaneous	1
IEC Reset (constant time)	2
ANSI Reset (inverse time)	3

The delay characteristics are described in *Technical manual*. There are some restrictions regarding the choice of the reset delay.

For the definite time delay characteristics, the possible delay time setting instantaneous (1) and IEC (2 = set constant time reset).

For ANSI inverse time characteristics, all three types of reset time characteristics are available: instantaneous (1), IEC (2 = set constant time reset) and ANSI (3 = current dependent reset time).

For IEC inverse time characteristics, the possible delay time settings are instantaneous (1) and IEC (2 = set constant time reset).

For the customer tailor-made inverse time delay characteristics (type 17), all three types of reset time characteristics are available: instantaneous (1), IEC (2 = set constant time reset) and ANSI (3 = current dependent reset time). If the current-dependent type is used, settings pr , tr and cr must be given.

t_{Resetx} : Constant reset time delay in seconds for step x .

t_{PCrvx} , t_{ACrvx} , t_{BCrvx} , t_{CCrvx} : These parameters are used by the customer to create the inverse time characteristic curve. See equation 104 for the time characteristic equation. For more information, refer to *Technical manual*.

$$t[s] = \left(\frac{A}{\left(\frac{i}{i_{n>}} \right)^p - C} + B \right) \cdot IxMult$$

(Equation 104)

$tPRCrvx$, $tTRCrvx$, $tCRCrvx$: These parameters are used by the customer to create the inverse reset time characteristic curve. For more information, refer to *Technical manual*.

HarmRestrinx: Enables freezing of timers of step x from the harmonic restrain function (2nd harmonic). This function should be used when there is a risk of an unwanted trip caused by power transformer inrush currents. It can be set to *Off/On*.

8.2.4.2 Setting example

Directional phase overcurrent protection, four steps can be used in different ways, depending on the application where the protection is used. A general description is given below.

The operating current setting of the inverse time protection, or the lowest current step of the definite time protection, must be defined so that the highest possible load current does not cause protection operation. The protection reset current must also be considered so that a short peak of overcurrent does not cause the operation of a protection even when the overcurrent has ceased. This phenomenon is described in Figure 79.

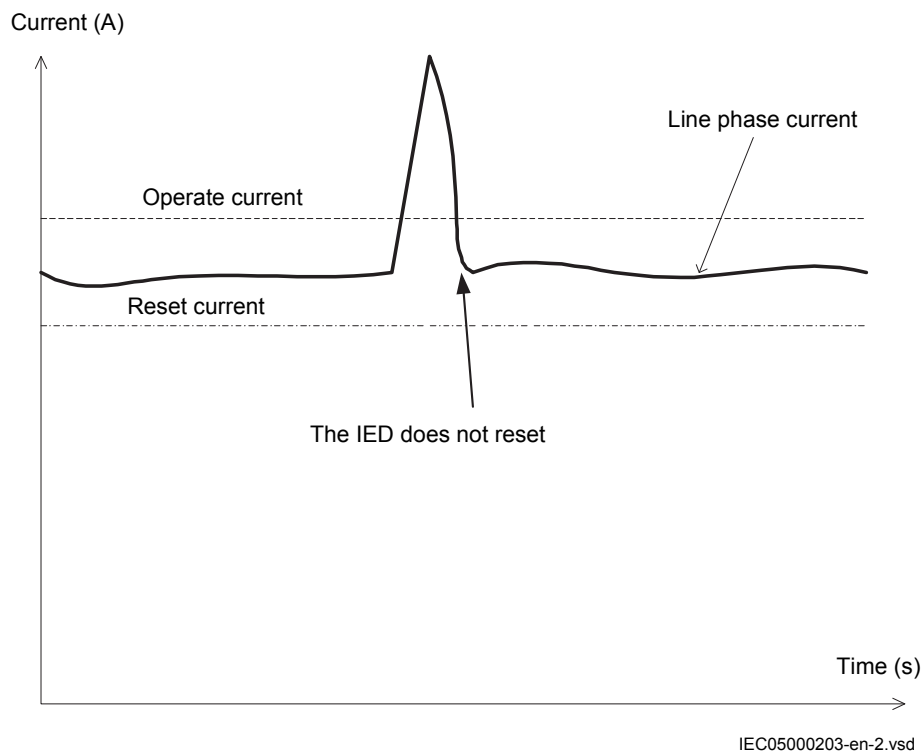


Figure 79: Operate and reset current for an overcurrent protection

The lowest setting value can be written according to Equation 105.

$$I_{pu} \geq 1.2 \cdot \frac{I_{max}}{k}$$

(Equation 105)

where:

1.2 is a safety factor

k is the reset ratio of the protection

I_{max} is the maximum load current

The load current up to the present situation can be found from operation statistics. The current setting must remain valid for several years. In most cases, the setting values are updated once every five years or less often. Investigate the maximum load current that the equipment on the line can withstand. Study components, such as line conductors, current transformers, circuit breakers, and disconnectors. The manufacturer of the equipment normally gives the maximum thermal load current of the equipment.

The maximum load current on the line has to be estimated. There is also a demand that all faults within the zone that the protection shall cover must be detected by the phase overcurrent protection. The minimum fault current I_{scmin} to be detected by the protection must be calculated. Taking this value as a base, the highest pickup current setting can be written according to Equation [106](#).

$$I_{pu} \leq 0.7 \cdot I_{scmin}$$

(Equation 106)

where:

0.7 is a safety factor

I_{scmin} is the smallest fault current to be detected by the overcurrent protection.

As a summary, the operating current shall be chosen within the interval stated in Equation [107](#).

$$1.2 \cdot \frac{I_{max}}{k} \leq I_{pu} \leq 0.7 \cdot I_{scmin}$$

(Equation 107)

The high current function of the overcurrent protection, which only has a short-delay trip time, must be given a current setting so that the protection is selective to other protection functions in the power system. It is desirable to have rapid tripping of faults within a large part of the power system to be protected by the protection (primary protected zone). A fault current calculation gives the largest current of faults, I_{scmax}, at the most remote part of the primary protected zone. The risk of transient overreach must be considered, due to a possible DC component of the short circuit current. The lowest current setting of the fastest stage can be written according to

$$I_{high} \geq 1.2 \cdot k_t \cdot I_{scmax}$$

(Equation 108)

where:

1.2 is a safety factor

k_t is a factor that takes care of the transient overreach due to the DC component of the fault current and can be considered to be less than 1.05I_{scmax} is the largest fault current at a fault at the most remote point of the primary protection zone.

The operate time of the phase overcurrent protection has to be chosen so that the fault time is short enough that the protected equipment will not be destroyed due to thermal overload while, at the

same time, selectivity is assured. For overcurrent protection in a radial fed network, the time setting can be chosen in a graphical way. This is mostly used in the case of inverse time overcurrent protection. Figure 80 shows how the time-versus-current curves are plotted in a diagram. The time setting is chosen to get the shortest fault time with maintained selectivity. Selectivity is assured if the time difference between the curves is larger than a critical time difference.

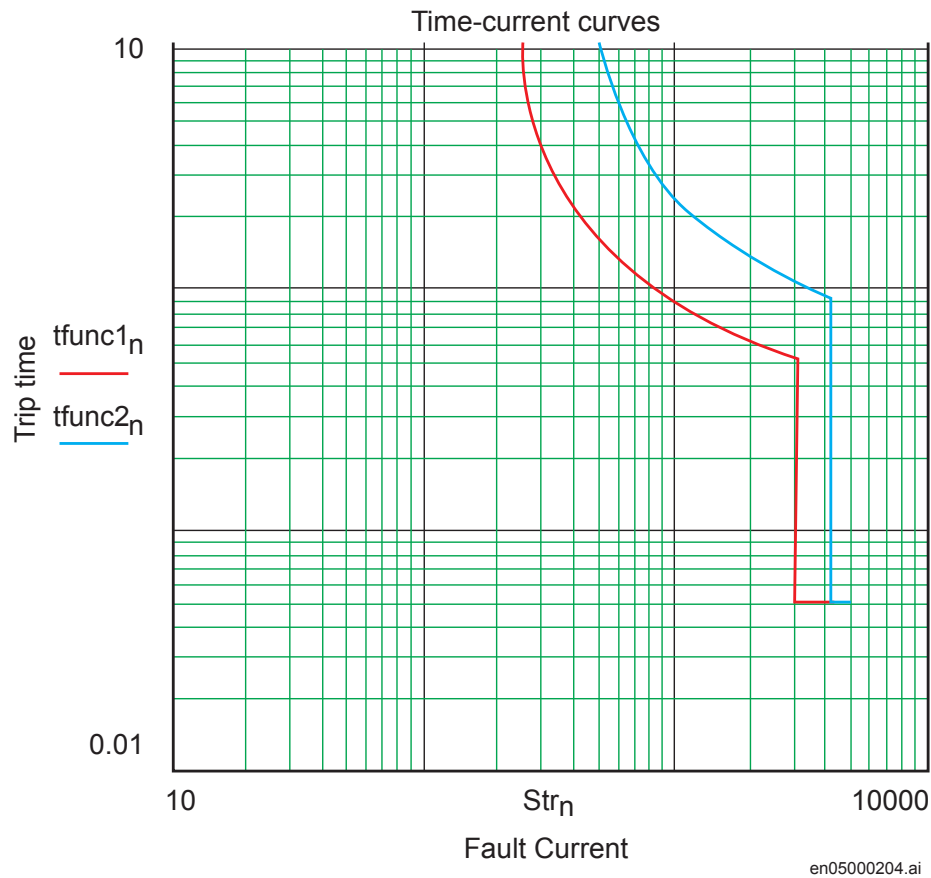


Figure 80: Fault time with maintained selectivity

The operation time can be set individually for each overcurrent protection.

To assure selectivity between different protection functions in the radial network, there has to be a minimum time difference Δt between the time delays of two protections. To determine the shortest possible time difference, the operation time of the protection, the breaker opening time and the protection resetting time must be known. These time delays can vary significantly between different protective equipment. The following time delays can be estimated:

Protection operation time:	15-60 ms
Protection resetting time:	15-60 ms
Breaker opening time:	20-120 ms

Example for time coordination

Assume two substations A and B directly connected to each other via one line, as shown in the Figure 81. Consider a fault located at another line from the station B. The fault current to the overcurrent protection of IED B1 has a magnitude so that the overcurrent protection will start and subsequently trip, and the overcurrent protection of IED A1 must have a delayed operation in order to avoid maloperation. The sequence of events during the fault can be described using a time axis shown in Figure 81.

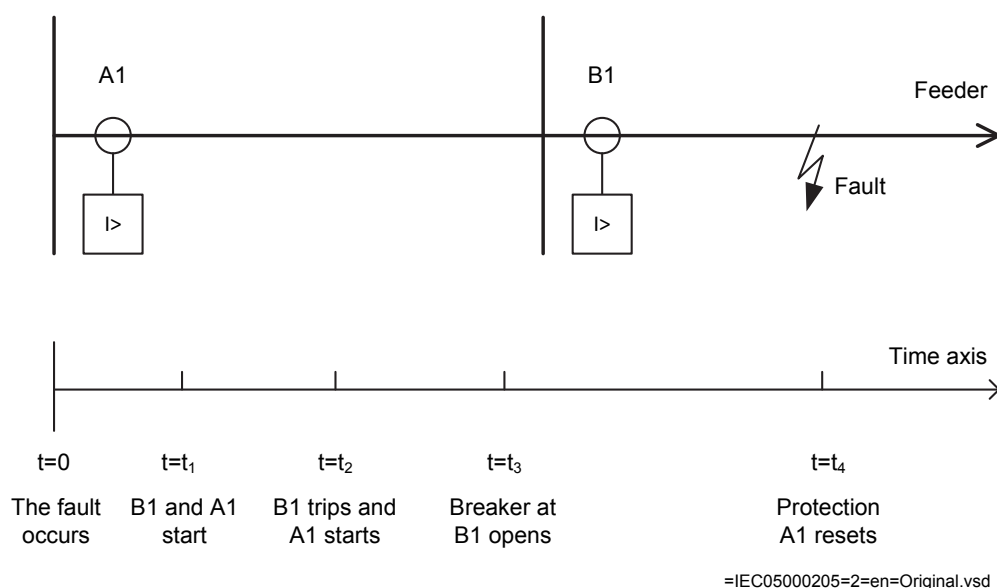


Figure 81: Sequence of events during fault

where:

$t=0$ is when the fault occurs

$t=t_1$ is when protection IED B1 and protection IED A1 start

$t=t_2$ is when the trip signal from the overcurrent protection at IED B1 is sent to the circuit breaker.

$t=t_3$ is when the circuit breaker at IED B1 opens. The circuit breaker opening time is $t_3 - t_2$

$t=t_4$ is when the overcurrent protection at IED A1 resets. The protection resetting time is $t_4 - t_3$.

To ensure that the overcurrent protection at IED A1 is selective to the overcurrent protection at IED B1, the minimum time difference must be larger than the time t_3 . There are uncertainties in the values of protection operation time, breaker opening time and protection resetting time. Therefore a safety margin has to be included. With normal values the needed time difference can be calculated according to Equation 109.

$$\Delta t \geq 40 \text{ ms} + 100 \text{ ms} + 40 \text{ ms} + 40 \text{ ms} = 220 \text{ ms}$$

(Equation 109)

where it is considered that:

the operate time of overcurrent protection B1 is 40 ms

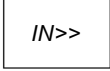
the breaker open time is 100 ms

the resetting time of protection A1 is 40 ms and

the additional margin is 40 ms

8.3 Instantaneous residual overcurrent protection EFPIOC

8.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Instantaneous residual overcurrent protection	EFPIOC		50N

8.3.2 Application

In many applications, when fault current is limited to a defined value by the object impedance, an instantaneous earth-fault protection can provide fast and selective tripping.

The Instantaneous residual overcurrent EFPIOC, which can operate in 15 ms (50 Hz nominal system frequency) for faults characterized by very high currents, is included in the IED.

8.3.3 Setting guidelines

The parameters for the Instantaneous residual overcurrent protection EFPIOC are set via the local HMI or PCM600.

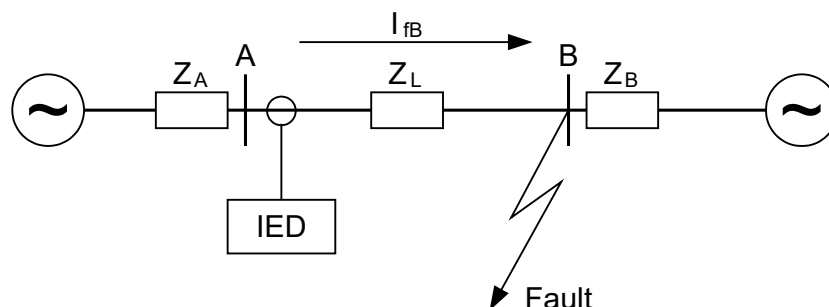
Some guidelines for the choice of setting parameter for EFPIOC is given.

Common base IED values for primary current (I_{Base}), primary voltage (U_{Base}) and primary power (S_{Base}) are set in the global base values for settings function GBASVAL.

GlobalBaseSel: To select GBASVAL function for reference of base values.

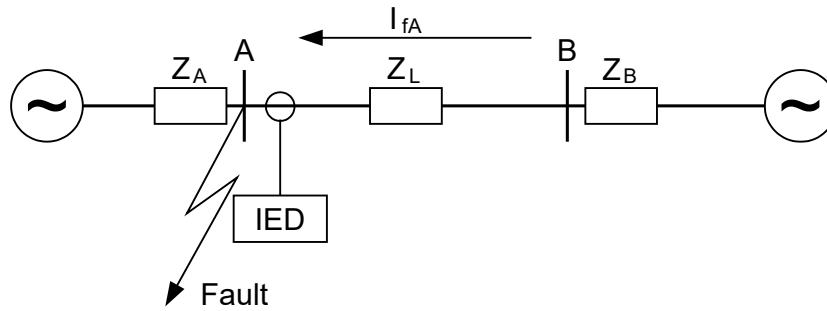
The basic requirement is to assure selectivity, that is EFPIOC shall not be allowed to operate for faults at other objects than the protected object (line).

For a normal line in a meshed system single phase-to-earth faults and phase-to-phase-to-earth faults shall be calculated as shown in Figure 82 and Figure 83. The residual currents ($3I_0$) to the protection are calculated. For a fault at the remote line end this fault current is I_{fB} . In this calculation the operational state with high source impedance Z_A and low source impedance Z_B should be used. For the fault at the home busbar this fault current is I_{fA} . In this calculation the operational state with low source impedance Z_A and high source impedance Z_B should be used.



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Figure 82: Through fault current from A to B: I_{fB}



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Figure 83: Through fault current from B to A: I_{fA}

The function shall not operate for any of the calculated currents to the protection. The minimum theoretical current setting (I_{min}) will be:

$$I_{min} \geq \text{MAX}(I_{fA}, I_{fB})$$

(Equation 110)

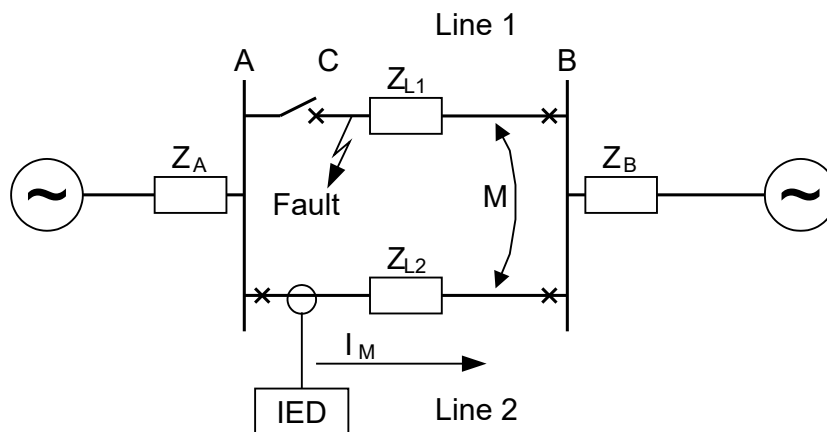
A safety margin of 5% for the maximum static inaccuracy and a safety margin of 5% for maximum possible transient overreach have to be introduced. An additional 20% is suggested due to inaccuracy of instrument transformers under transient conditions and inaccuracy in the system data.

The minimum primary current setting (I_s) is:

$$I_s = 1.3 \times I_{min}$$

(Equation 111)

In case of parallel lines with zero sequence mutual coupling a fault on the parallel line, as shown in Figure 84, should be calculated.



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Figure 84: Two parallel lines. Influence from parallel line to the through fault current: I_M

The minimum theoretical current setting (I_{min}) will in this case be:

$$I_{min} \geq \text{MAX}(I_{fA}, I_{fB}, I_M)$$

(Equation 112)

Where:

I_{fA} and I_{fB} have been described for the single line case.

Considering the safety margins mentioned previously, the minimum setting (I_s) is:

$$I_s = 1.3 \times I_{min}$$

(Equation 113)

The IED setting value $IN>>$ is given in percent of the primary base current value, I_{Base} . The value for $IN>>$ is given by the formula:

$$IN >> = (I_s / I_{Base}) * 100$$

(Equation 114)

Transformer inrush current shall be considered.

The setting of the protection is set as a percentage of the base current (I_{Base}).

Operation: set the protection to *On* or *Off*.

$IN>>$: Set operate current in % of I_B .

$IN>>Max$ and $IN>>Min$ should only be changed if remote setting of operation current level, $IN>>$, is used. The limits are used for decreasing the used range of the $IN>>$ setting. If $IN>>$ is set outside $IN>>Max$ and $IN>>Min$, the closest of the limits to $IN>>$ is used by the function. If $IN>>Max$ is smaller than $IN>>Min$, the limits are swapped.

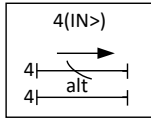
StValMult: The set operate current can be changed by activation of the binary input ENMULT to the set factor **StValMult**.

8.4 Directional residual overcurrent protection, four steps EF4PTOC

8.4.1 Function revision history

Document revision	Product revision	History
A	2.2.1	-
B	2.2.1	-
C	2.2.1	-
D	2.2.4	The phase selection logic is added to allow phase segregated trip. The new phase selections outputs added to this release are PHSELL1, PHSELL2 and PHSELL3. The setting <i>EnPhaseSel</i> is added to enable or disable phase selection. The maximum value changed to 2000.0 % of I_{Base} for I_{Min1} , I_{Min2} , I_{Min3} and I_{Min4} settings.
E	2.2.5	The harmonic restrain function changed to freeze the definite and IDMT timers.
J	2.2.6	-
K	2.2.6	Minimum value changed to 0.01 for k1,k2,k3 and k4 settings

8.4.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Directional residual overcurrent protection, four steps	EF4PTOC		51N_67N

8.4.3 Application

The directional residual overcurrent protection, four steps EF4PTOC is used in several applications in the power system. Some applications are:

- Earth-fault protection of feeders in effectively earthed distribution and subtransmission systems. Normally these feeders have radial structure.
- Back-up earth-fault protection of transmission lines.
- Sensitive earth-fault protection of transmission lines. EF4PTOC can have better sensitivity to detect resistive phase-to-earth-faults compared to distance protection.
- Back-up earth-fault protection of power transformers.
- Earth-fault protection of different kinds of equipment connected to the power system such as shunt capacitor banks, shunt reactors and others.

In many applications, several steps with different current operating levels and time delays are needed. EF4PTOC can have up to four, individual settable steps. The flexibility of each step of EF4PTOC is great. The following options are possible:

Non-directional/Directional function: In some applications the non-directional functionality is used. This is mostly the case when no fault current can be fed from the protected object itself. In order to achieve both selectivity and fast fault clearance, the directional function can be necessary. This can be the case for earth-fault protection in meshed and effectively earthed transmission systems. The directional residual overcurrent protection is also well suited to operate in teleprotection communication schemes, which enables fast clearance of earth faults on transmission lines. The directional function uses the polarizing quantity as decided by setting. Voltage polarizing is the most commonly used, but alternatively current polarizing where currents in transformer neutrals providing the neutral source (ZN) is used to polarize ($IN \cdot ZN$) the function. Dual polarizing, where the sum of both voltage and current components is allowed to polarize can also be selected.

Choice of time characteristics: There are several types of time characteristics available such as definite time delay and different types of inverse time characteristics. The selectivity between different overcurrent protections is normally enabled by co-ordination between the operate time of the different protections. To enable optimal co-ordination all overcurrent protections, to be co-ordinated against each other, should have the same time characteristic. Therefore a wide range of standardized inverse time characteristics are available for IEC and ANSI.

Table 19: Time characteristics

Curve name
ANSI Extremely Inverse
ANSI Very Inverse
ANSI Normal Inverse
ANSI Moderately Inverse
ANSI/IEEE Definite time
ANSI Long Time Extremely Inverse
Table continues on next page

Curve name
ANSI Long Time Very Inverse
ANSI Long Time Inverse
IEC Normal Inverse
IEC Very Inverse
IEC Inverse
IEC Extremely Inverse
IEC Short Time Inverse
IEC Long Time Inverse
IEC Definite Time
User Programmable
ASEA RI
RXIDG or RD (logarithmic)

It is also possible to tailor make the inverse time characteristic.

Normally it is required that EF4PTOC shall reset as fast as possible when the current level gets lower than the operation level. In some cases some sort of delayed reset is required. Therefore different kinds of reset characteristics can be used.

For some protection applications, there can be a need to change the current operating level for some time. Therefore, there is a possibility to give a setting of a multiplication factor *INxMult* to the residual current pick-up level. This multiplication factor is activated from a binary input signal ENMULTx to the function.

Power transformers can have a large inrush current, when being energized. This inrush current can produce residual current component. The phenomenon is due to saturation of the transformer magnetic core during parts of the cycle. There is a risk that inrush current will give a residual current that reaches level above the operating current of the residual overcurrent protection. The inrush current has a large second harmonic content. This can be used to avoid unwanted operation of the protection. Therefore, EF4PTOC has a possibility of second harmonic restrain if the level of 2nd harmonic current reaches a value above a set percent of the fundamental current.

Phase selection element also provides fast and reliable faulty phase identification for phase selective tripping and subsequent reclosing during earth fault. Earth fault protection and Phase selection must always be blocked while the single phase dead time is running.

8.4.4 Setting guidelines



When inverse time over-current characteristic is selected, the operate time of the stage will be the sum of the inverse time delay and the set definite time delay. Thus, if only the inverse time delay is required, it is important to set the definite time delay for that stage to zero.

The parameters for the four step residual over-current protection are set via the local HMI or PCM600. The following settings can be done for the function.

Common base IED values for the primary current (*IBase*), primary voltage (*UBase*) and primary power (*SBase*) are set in global base values for settings function GBASVAL.

GlobalBaseSel: Selects the global base value group used by the function to define *IBase*, *UBase* and *SBase*. Note that this function will only use *IBase* value.

SeqTypeUPol: To select the type of voltage polarising quantity (that is, Zero seq or Neg seq for direction detection).

SeqTypeIPol: To select the type of current polarising quantity (that is, Zero seq or Neg seq for direction detection).

SeqTypeIDir: To select the type of operating current quantity (that is, Zero seq or Neg seq for direction detection).

8.4.4.1 Common settings for all steps

AngleRCA: Relay characteristic angle given in degree. This angle is defined as shown in Figure 85. The angle is defined positive when the residual current lags the reference voltage ($U_{pol} = -3U_0$ or $-3U_2$)

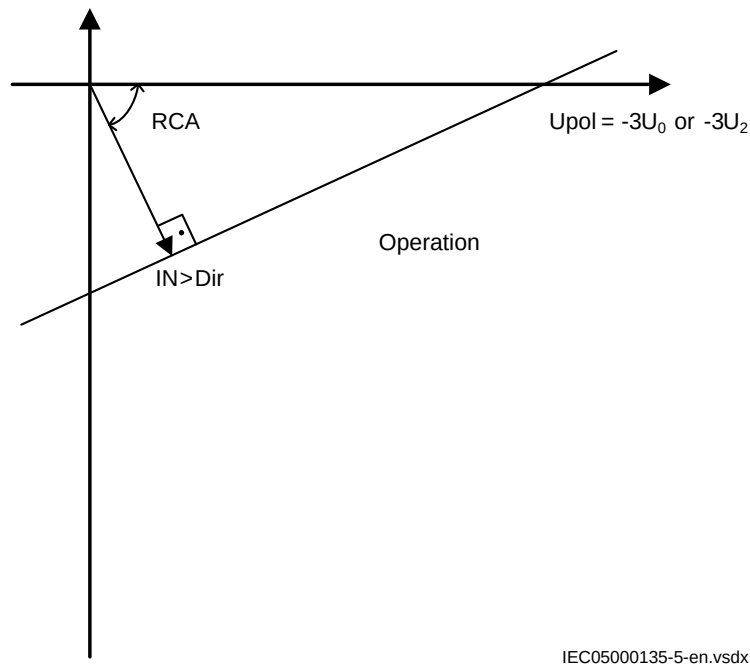


Figure 85: Relay characteristic angle given in degree

In a normal transmission network a normal value of RCA is about 65° . The setting range is -180° to $+180^\circ$.

polMethod: Defines if the directional polarization is from

- Voltage ($3U_0$ or U_2)
- Current ($3I_0 \cdot Z_{Npol}$ or $3I_2 \cdot Z_{Npol}$ where Z_{Npol} is $R_{Npol} + jX_{Npol}$), or
- Both current and voltage, *Dual* (dual polarizing, $(3U_0 + 3I_0 \cdot Z_{Npol})$ or $(U_2 + I_2 \cdot Z_{Npol})$).

Normally voltage polarizing from the internally calculated residual sum or an external open delta is used.

Current polarization is useful when the local source is strong and a high sensitivity is required. In such cases the polarizing voltage ($3U_0$) can be below 1% and it is then necessary to use current polarization or dual polarization. Multiply the required set current (primary) with the minimum impedance (Z_{Npol}) and check that the percentage of the phase-to-earth voltage is definitely higher than 1% (minimum $3U_0 > U_{PolMin}$ setting) as a verification.

RNPOL, *XNPOL*: The zero-sequence source is set in primary ohms as base for the current polarization. The polarizing voltage is then achieved as $3I_0 \cdot Z_{Npol}$. The Z_{Npol} can be defined as $(ZS_1 - ZS_0)/3$,

that is the earth return impedance of the source behind the protection. The maximum earth-fault current at the local source can be used to calculate the value of Z_N as $U/(\sqrt{3} \cdot 3I_0)$. Typically, the minimum Z_{NPol} ($3 \cdot$ zero sequence source) is set. The setting is in primary ohms.

When the dual polarizing method is used, it is important that the setting IN_x or the product $3I_0 \cdot Z_{Npol}$ is not greater than $3U_0$. If so, there is a risk for incorrect operation for faults in the reverse direction.

IPolMin: is the minimum earth-fault current accepted for directional evaluation. For smaller currents than this value, the operation will be blocked. A typical setting is 5-10% of IB .

UPolMin: Minimum polarization (reference) polarizing voltage for the directional function, given in % of $U_{Base}/\sqrt{3}$.

IN>Dir: Operate residual current release level in % of IB for directional comparison scheme. The setting is given in % of IB and must be set below the lowest IN_x setting, set for the directional measurement. The output signals, STFW and STRV can be used in a teleprotection scheme. The appropriate signal should be configured to the communication scheme block.

8.4.4.2 2nd harmonic restrain

If a power transformer is energized there is a risk that the current transformer core will saturate during part of the period, resulting in a transformer inrush current. This will give a declining residual current in the network, as the inrush current is deviating between the phases. There is a risk that the residual over-current function will give an unwanted trip. The inrush current has a relatively large ratio of 2nd harmonic component. This component can be used to create a restrain signal to prevent this unwanted operation.

At current transformer saturation a false residual current can be measured by the protection. Here the 2nd harmonic restrain can prevent unwanted operation as well.

2ndHarmStab: The rate of 2nd harmonic current content for activation of the 2nd harmonic restrain signal. The setting is given in % of the fundamental frequency residual current.

8.4.4.3 Parallel transformer inrush current logic

In case of parallel transformers there is a risk of sympathetic inrush current. If one of the transformers is in operation, and the parallel transformer is switched in, the asymmetric inrush current of the switched-in transformer will cause partial saturation of the transformer already in service. This is called transferred saturation. The 2nd harmonic of the inrush currents of the two transformers will be in phase opposition. The summation of the two currents will thus give a small 2nd harmonic current. The residual fundamental current will however be significant. The inrush current of the transformer in service before the parallel transformer energizing, will be a little delayed compared to the first transformer. Therefore, we will have high 2nd harmonic current initially. After a short period this current will however be small and the normal 2nd harmonic blocking will reset.

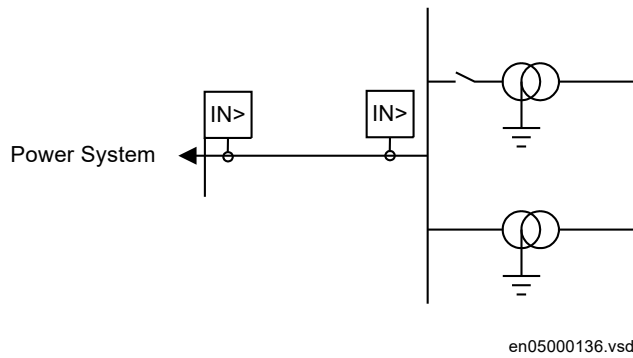


Figure 86: Application for parallel transformer inrush current logic

If the *BlkParTransf* function is activated, the 2nd harmonic restrain signal will latch as long as the residual current measured by the relay is larger than a selected step current level. Assume that step 4 is chosen to be the most sensitive step of the four step residual overcurrent protection function EF4PTOC. The harmonic restrain blocking is enabled for this step. Also the same current setting as this step is chosen for the blocking at parallel transformer energizing.

The settings for the parallel transformer logic are described below.

BlkParTransf: To On blocking at energising of parallel transformers.

UseStartValue: Gives which current level should be used for the activation of the blocking signal. This is given as one of the settings of the steps: Step 1/2/3/4. Normally, the step having the lowest operation current level should be set.

8.4.4.4 Switch onto fault logic

In case of energizing a faulty object there is a risk of having a long fault clearance time, if the fault current is too small to give fast operation of the protection. The switch on to fault function can be activated from auxiliary signals from the circuit breaker, either the close command or the open/close position (change of position).

This logic can be used to issue a fast trip if one breaker pole does not close properly at a manual or automatic closing.

SOTF and under time are similar functions to achieve fast clearance at asymmetrical closing based on requirements from different utilities.

The function is divided into two parts. The SOTF function will give operation from step 2 or 3 during a set time after change in the position of the circuit breaker. The SOTF function has a set time delay. The under time function, which has 2nd harmonic restrain blocking, will give operation from step 4. The 2nd harmonic restrain will prevent unwanted operation in case of transformer inrush current. The under time function has a set time delay.

Below the settings for switch on to fault logics are described.

SOTF: This parameter can be set: *Off/SOTF/Under Time/SOTF+Under Time*.

ActivationSOTF: This setting will select the signal to activate SOTF function; *CB position open/CB position closed/CB close command*.

StepForSOTF: If this parameter is set on step 3, the step 3 start signal will be used as current set level. If set on step 2, the step 2 start signal will be used as current set level.

HarmBlkSOTF: To On/Off harmonic restrain of the Under-time logic.

tSOTF: Time delay for operation of the SOTF function. The setting range is 0.000 - 60.000 s in step of 0.001 s. The default setting is 0.100 s.

t4U: Time interval when the SOTF function is active after breaker closing. The setting range is 0.000 - 60.000 s in step of 0.001 s. The default setting is 1.000 s.

ActUnderTime: Describes the mode to activate the sensitive undertime function. The function can be activated by Circuit breaker position (change) or Circuit breaker command.

tUnderTime: Time delay for operation of the sensitive undertime function. The setting range is 0.000 - 60.000 s in step of 0.001 s. The default setting is 0.300 s.

8.4.4.5 Settings for each step (x = 1, 2, 3 and 4)

Operation: Sets the protection to *On* or *Off*.

DirModex: The directional mode of step x. Possible settings are *Off/Non-directional/Forward/Reverse*.

Characteristicx: Selection of time characteristic for step x. Definite time delay and different types of inverse time characteristics are available.

Inverse time characteristic enables fast fault clearance of high current faults at the same time as selectivity to other inverse time phase overcurrent protections can be assured. This is mainly used in radial fed networks but can also be used in meshed networks. In meshed networks, the settings must be based on network fault calculations.

To assure selectivity between different protections, in the radial network, there has to be a minimum time difference Δt between the time delays of two protections. To determine the shortest possible time difference, the operation time of protections, breaker opening time and protection resetting time must be known. These time delays can vary significantly between different protective equipment. The following time delays can be estimated:

Protection operate time:	15-60 ms
Protection resetting time:	15-60 ms
Breaker opening time:	20-120 ms

The different characteristics are described in the technical reference manual.

tx: Definite time delay for step x. The definite time *tx* is added to the inverse time when inverse time characteristic is selected. Note that the value set is the time between activation of the start and the trip outputs.

INx>: Operate residual current level for step x given in % of *IB*.

INx>Max and ***INx>Min*** should only be changed if remote setting of operation current level, ***INx>***, is used. The limits are used for decreasing the used range of the ***INx>*** setting. If ***INx>*** is set outside ***INx>Max*** and ***INx>Min***, the closest of the limits to ***INx>*** is used by the function. If ***INx>Max*** is smaller than ***INx>Min***, the limits are swapped.

kx: Time multiplier for the dependent (inverse) characteristic for step x.

IMinx: Minimum operate current for step x in % of *IB*. Set ***IMinx*** below ***INx>*** for every step to achieve ANSI reset characteristic according to standard. If ***IMinx*** is set above ***INx>*** for any step, signal will reset at current equals to zero.

txMin: Minimum operating time for inverse time characteristics. At high currents, the inverse time characteristic might give a very short operation time. By setting this parameter, the operation time of the step can never be shorter than the setting.

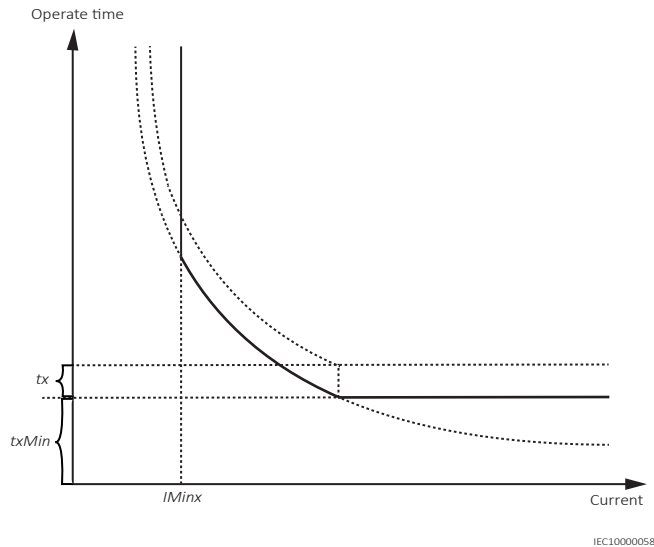


Figure 87: Minimum operate current and operate time for inverse time characteristics

In order to fully comply with the curves definition, the setting parameter *txMin* shall be set to the value which is equal to the operate time of the selected IEC inverse curve for measured current of twenty times the set current pickup value. Note that the operate time value is dependent on the selected setting value for time multiplier *kx*.

INxMult: Multiplier for scaling of the current setting value. If a binary input signal (ENMULTx) is activated, the current operation level is increased by this setting constant.

ResetTypeCrvx: The reset of the delay timer can be made in different ways. The possibilities are described in the technical reference manual.

tResetx: Constant reset time delay in s for step x.

HarmBlockx: To enable freezing of timers of step x from 2nd harmonic restrain function.

tPCrvx, *tACrvx*, *tBCrvx*, *tCCrvx*: Parameters for user programmable of inverse time characteristic curve. The time characteristic equation is according to equation 115:

$$t[s] = \left(\frac{A}{\left(\frac{i}{in} \right)^p - C} + B \right) \cdot k$$

(Equation 115)

Further description can be found in the technical reference manual.

tPRCrvx, *tTRCrvx*, *tCRCrvx*: Parameters for user programmable of inverse reset time characteristic curve. Further description can be found in the technical reference manual.

8.4.4.6 Line application example

Four step residual overcurrent protection can be used in different ways. Below is described one application possibility to be used in meshed and effectively earthed systems.

The protection measures the residual current out on the protected line. The protection function has a directional function where the polarizing voltage (zero-sequence voltage) is the polarizing quantity.

The polarizing voltage and current can be internally generated when a three-phase set of voltage transformers and current transformers are used.

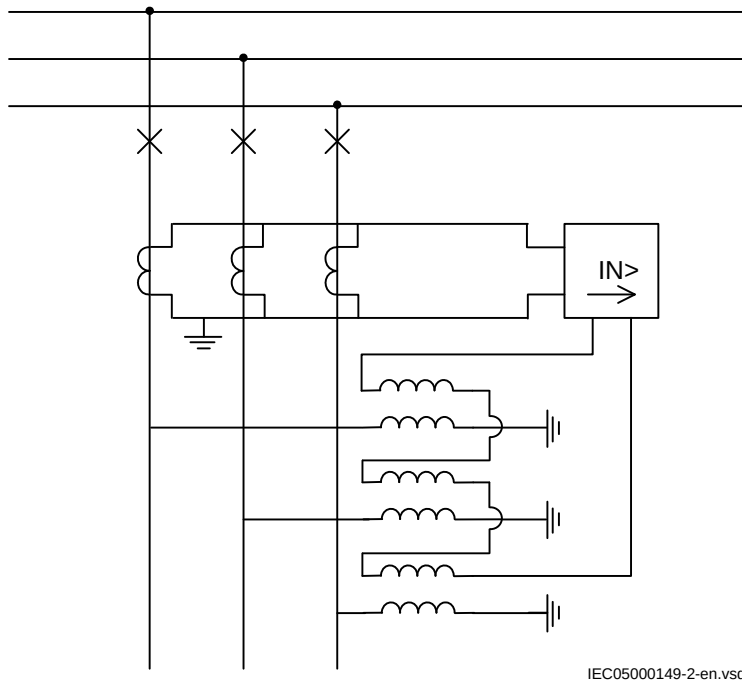


Figure 88: Connection of polarizing voltage from an open delta

The different steps can be described as follows.

Step 1

This step has directional instantaneous function. The requirement is that overreaching of the protected line is not allowed.

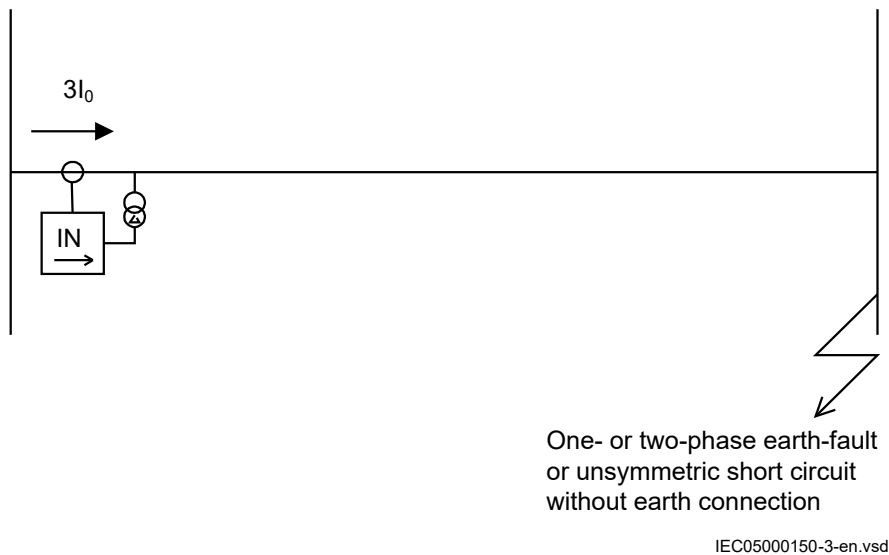


Figure 89: Step 1, first calculation

The residual current out on the line is calculated at a fault on the remote busbar (one- or two-phase-to-earth fault). To assure selectivity it is required that step 1 shall not give a trip at this fault. The requirement can be formulated according to Equation [116](#).

$$I_{step1} \geq 1.2 \cdot 3I_0 \text{ (remote busbar)}$$

(Equation 116)

As a consequence of the distribution of zero sequence current in the power system, the current to the protection might be larger if one line out from the remote busbar is taken out of service, see Figure 90.

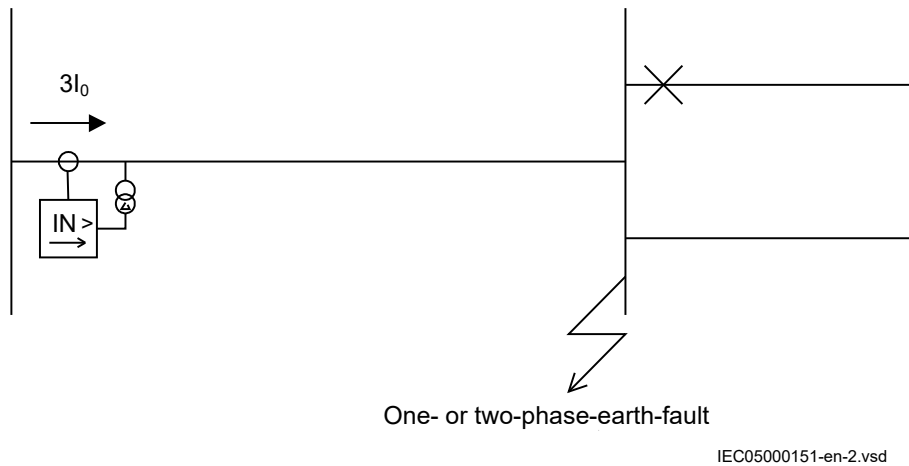


Figure 90: Step 1, second calculation. Remote busbar with, one line taken out of service

The requirement is now according to Equation [117](#).

$$I_{\text{step1}} \geq 1.2 \cdot 3I_0 \text{ (remote busbar with one line out)}$$

(Equation 117)

A higher value of step 1 might be necessary if a big power transformer (Y0/D) at remote bus bar is disconnected.

A special case occurs at double circuit lines, with mutual zero-sequence impedance between the parallel lines, see Figure 91.

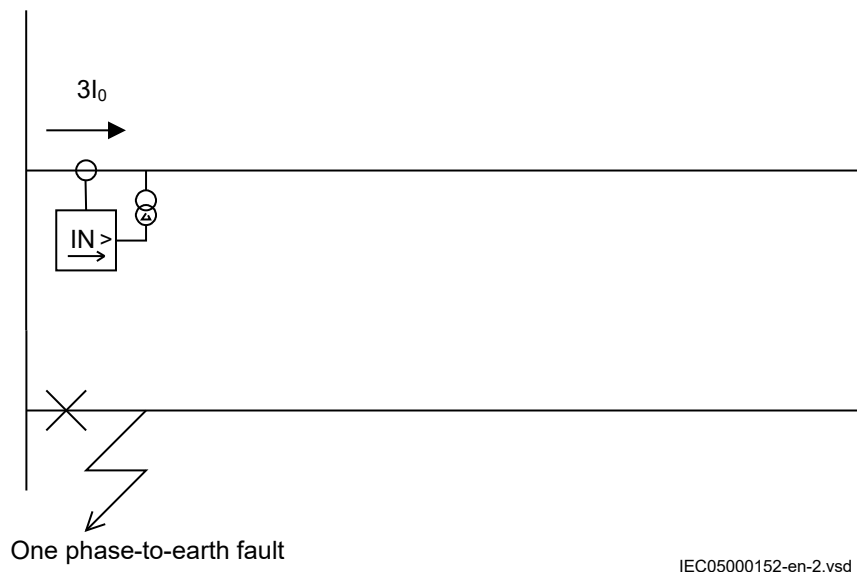


Figure 91: Step 1, third calculation

In this case the residual current out on the line can be larger than in the case of earth fault on the remote busbar.

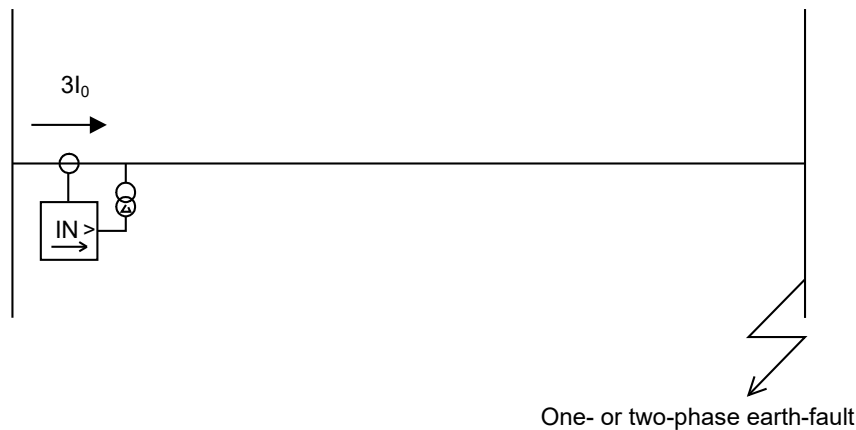
$$I_{\text{step1}} \geq 1.2 \cdot 3I_0$$

(Equation 118)

The current setting for step 1 is chosen as the largest of the above calculated residual currents, measured by the protection.

Step 2

This step has directional function and a short time delay, often about 0.4 s. Step 2 shall securely detect all earth faults on the line, not detected by step 1.



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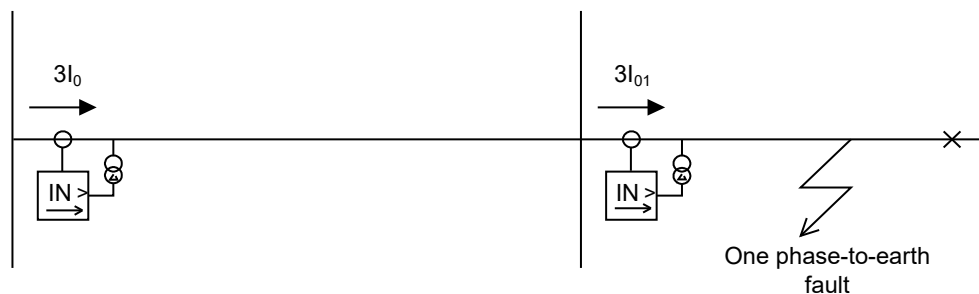
Figure 92: Step 2, check of reach calculation

The residual current, out on the line, is calculated at an operational case with minimal earth-fault current. The requirement that the whole line shall be covered by step 2 can be formulated according to equation 119.

$$I_{\text{step2}} \geq 0.7 \cdot 3I_0 \text{ (at remote busbar)}$$

(Equation 119)

To assure selectivity the current setting must be chosen so that step 2 does not operate at step 2 for faults on the next line from the remote substation. Consider a fault as shown in Figure 93.



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Figure 93: Step 2, selectivity calculation

A second criterion for step 2 is according to equation 120.

$$I_{step2} \geq 1.2 \cdot \frac{3I_0}{3I_{01}} \cdot I_{step1}$$

(Equation 120)

where:

I_{step1} is the current setting for step 1 on the faulted line.

Step 3

This step has directional function and a time delay slightly larger than step 2, often 0.8 s. Step 3 shall enable selective trip of earth faults having higher fault resistance to earth, compared to step 2. The requirement on step 3 is selectivity to other earth-fault protections in the network. One criterion for setting is shown in Figure 94.

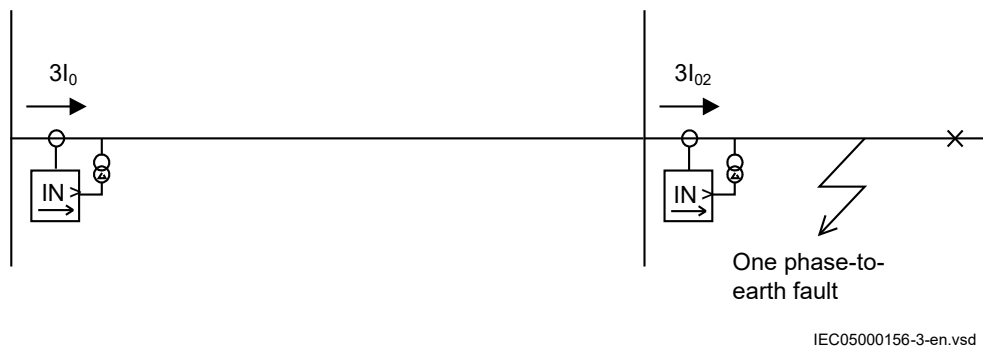


Figure 94: Step 3, Selectivity calculation

$$I_{step3} \geq 1.2 \cdot \frac{3I_0}{3I_{02}} \cdot I_{step2}$$

(Equation 121)

where:

I_{step2} is the chosen current setting for step 2 on the faulted line.

Step 4

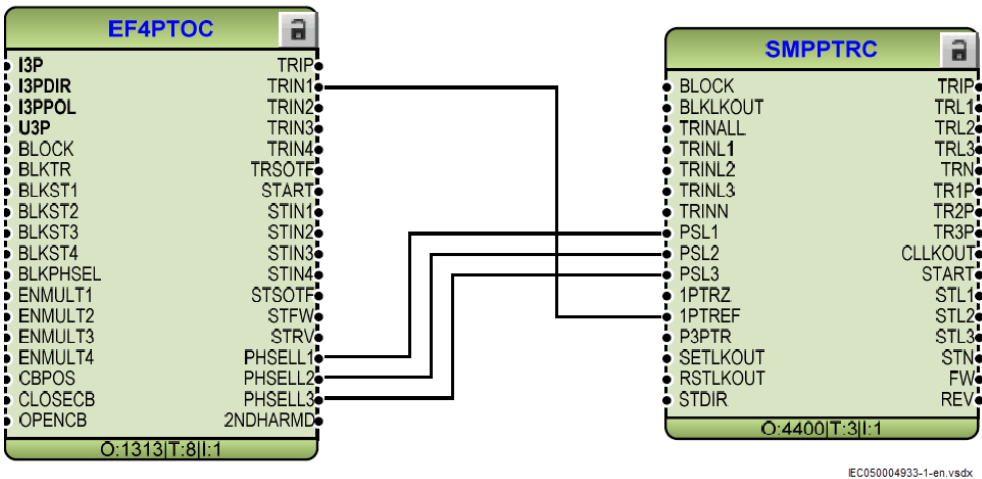
This step normally has non-directional function and a relatively long time delay. The task for step 4 is to detect and initiate trip for earth faults with large fault resistance, for example tree faults. Step 4 shall also detect series faults where one or two poles, of a breaker or other switching device, are open while the other poles are closed.

Both high resistance earth faults and series faults give zero-sequence current flow in the network. Such currents give disturbances on telecommunication systems and current to earth. It is important to clear such faults both concerning personal security as well as risk of fire.

The current setting for step 4 is often set down to about 100 A (primary $3I_0$). In many applications definite time delay in the range 1.2 - 2.0 s is used. In other applications a current dependent inverse time characteristic is used. This enables a higher degree of selectivity also for sensitive earth-fault current protection.

8.4.4.7 Phase selection element

The phase selection feature is controlled by the setting *EnPhaseSel*. The phase selection output PHSELL1, PHSELL2, and PHSELL3 from EF4PTOC shall be connected to phase selection inputs PS1L, PSL2, and PSL3 of the trip logic SMPPTRC, as shown in Figure 95.



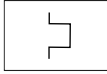
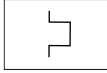
The EF4PTOC function includes four steps with different set values. The input 1PTRZ of SMPPTRC shall be connected to the trip output of the stage(s) from EF4PTOC that are intended for phase selective tripping.

8.5 Thermal overload protection, one time constant, Celsius/Fahrenheit LCPTTR/LFPTTR

8.5.1 Function revision history

Document revision	Product revision	History
A	2.2.1	-
B	2.2.1	-
C	2.2.1	-
D	2.2.4	-
E	2.2.4	-
F	2.2.5	-
G	2.2.5	-
J	2.2.6	-
K	2.2.6	LCPTTR - Default value of the setting Iref changed to 120% of IBase LFPTTR - Default value of the setting Iref changed to 120% of IBase

8.5.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Thermal overload protection, one time constant, Celsius	LCPTTR		26
Thermal overload protection, one time constant, Fahrenheit	LFPTTR		26

8.5.3 Application

Lines and cables in the power system are designed for a certain maximum load current level. If the current exceeds this level the losses will be higher than expected. As a consequence the temperature of the conductors will increase. If the temperature of the lines and cables reaches too high values the equipment might be damaged:

- The sag of overhead lines can reach unacceptable value.
- If the temperature of conductors, for example aluminium conductors, gets too high the material will be destroyed.
- In cables the insulation can be damaged as a consequence of the overtemperature. As a consequence of this phase to phase or phase to earth faults can occur.

In stressed situations in the power system it can be required to overload lines and cables for a limited time. This should be done while managing the risks safely.

The thermal overload protection provides information that makes a temporary overloading of cables and lines possible. The thermal overload protection estimates the conductor temperature continuously, in Celsius or Fahrenheit depending on whether LCPTTR or LFPTTR is chosen. This estimation is made by using a thermal model of the line/cable based on the current measurement.

If the temperature of the protected object reaches a set warning level *AlarmTemp*, a signal ALARM can be given to the operator. This enables actions in the power system to be taken before dangerous temperatures are reached. If the temperature continues to increase to the trip value *TripTemp*, the protection initiates trip of the protected line.

8.5.4 Setting guideline

The parameters for the Thermal overload protection, one time constant, Celsius/Fahrenheit LCPTTR/LFPTTR are set via the local HMI or PCM600.

The following settings can be done for the thermal overload protection.

Operation: Off/On

GlobalBaseSel is used to select a GBASVAL function for reference of base values, primary current (*IBase*), primary voltage (*UBase*) and primary power (*SBase*).

Imult: Enter the number of lines in case the protection function is applied on multiple parallel lines sharing one CT.

I_{Ref}: Reference, steady state current, given in % of *I_{Base}* that will give a steady state (end) temperature rise *T_{Ref}*. It is suggested to set this current to the maximum steady state current allowed for the line/cable under emergency operation (a few hours per year).

T_{Ref}: Reference temperature rise (end temperature) corresponding to the steady state current *I_{Ref}*. From cable manuals current values with corresponding conductor temperature are often given. These values are given for conditions such as earth temperature, ambient air temperature, way of laying of cable and earth thermal resistivity. From manuals for overhead conductor temperatures and corresponding current is given.

Tau: The thermal time constant of the protected circuit given in minutes. Please refer to manufacturers manuals for details.

TripTemp: Temperature value for trip of the protected circuit. For cables, a maximum allowed conductor temperature is often stated to be 90°C (194°F). For overhead lines, the critical temperature for aluminium conductor is about 90 - 100°C (194-212°F). For a copper conductor a normal figure is 70°C (158°F).

AlarmTemp: Temperature level for alarm of the protected circuit. ALARM signal can be used as a warning before the circuit is tripped. Therefore the setting shall be lower than the trip level. It shall at the same time be higher than the maximum conductor temperature at normal operation. For cables this level is often given to 65°C (149°F). Similar values are stated for overhead lines. A suitable setting can be about 15°C (59°F) below the trip value.

RecTemp: Temperature where lockout signal LOCKOUT from the protection is released. When the thermal overload protection trips, a lock-out signal is activated. This signal is intended to block switch in of the protected circuit as long as the conductor temperature is high. The signal is released when the estimated temperature is below the set value. This temperature value should be chosen below the alarm temperature.

8.6 Breaker failure protection CCRBRF

8.6.1 Function revision history

Document revision	Product revision	History
A	2.2.1	<i>I>BlkCBPos</i> setting functionality correction.
B	2.2.1	-
C	2.2.1	-
D	2.2.4	-
E	2.2.5	-
J	2.2.6	-

8.6.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Breaker failure protection, 3-phase activation and output	CCRBRF	<i>3I>BF</i>	50BF

8.6.3 Application

In the design of the fault clearance system the N-1 criterion is often used. This means that a fault needs to be cleared even if any component in the fault clearance system is faulty. One necessary component in the fault clearance system is the circuit breaker.

It is from practical and economical reason not feasible to duplicate the circuit breaker for the protected object. Instead a breaker failure protection is used.

Breaker failure protection CCRBRF will issue a backup trip command to adjacent circuit breakers in case of failure to trip of the “normal” circuit breaker for the protected object. The detection of failure to break the current through the breaker is made either by means of current measurement or as detection of closed status using auxiliary contact.

CCRBRF can also give a retrip command. This means that a second trip signal is sent to the protected object circuit breaker. The retrip function can be used to increase the probability of operation of the breaker, or it can be used to avoid backup trip of many breakers in case of mistakes during relay maintenance and testing.

8.6.4 Setting guidelines

The parameters for Breaker failure protection CCRBRF are set via the local HMI or PCM600.

The following settings can be done for the breaker failure protection.

GlobalBaseSel: Selects the global base value group used by the function to define *IBase*, *UBase* and *SBase*. Note that this function will only use *IBase* value.

Operation: *Off/On* to enable/disable the complete function.

FunctionMode: It defines the way the detection of failure of the breaker is performed. In the *Current* mode, the current measurement is used for the detection. In the *CB Pos* mode, the CB auxiliary contact status is used as an indicator of the failure of the breaker. The mode *Current* or *CB Pos* means that both ways of detections can be activated. The *CB Pos* mode is used in applications where the fault current through the circuit breaker is small. This can be the case for some generator protection application (for example, reverse power protection) or in the case of line ends with weak end infeed.

If TRBU has been given and CBCLDLx still has value one in the *CB Pos* mode or if the CB position part of the *Current* or *CB Pos* mode is active, TRBU and TRRET will internally be reset intentionally after approximately 10 seconds.

This reset is deliberately done in order to make easier power system restoration after operation of the breaker failure protection. Another way of resetting TRBU and TRRET, when the CB position criterion is used, is either to shortly activate BLOCK input or setting CCRBRF to blocked when the IED is in test mode.

StartMode: By this setting it is possible to select how *t1* and *t2* timers are run and consequently how output commands are given from the function:

- **Option 1 - LatchedStart:** “By external start signals which is internally latched”. When function is once started by external *START* signal, the timers *t1* and *t2* will always elapse and then measurement criterion defined by parameter *FunctionMode* will be always checked in order to verify if the appropriate command shall be given out from the function. Timers cannot be stopped by removing the external *START* signal. Function can be started again only when all of the following three timers *t1*, *t2* and fixed timer of 150ms in function internal design has expired and the measurement criterion defined by parameter *FunctionMode* has deactivated, see [Figure 96](#). Note that this option corresponds to the function behavior in previous versions of the 670 Series from version 1.0 up to and including version 2.1.

- Option 2 - FollowStart:** “Follow the external start signal only”.
 The timers $t1$ and $t2$ will run while external *START* signal is present. If they elapse then measurement criterion defined by parameter *FunctionMode* will be checked in order to verify if the appropriate command shall be given out from the function. Timers can be always stopped by resetting the external *START* signal, see [Figure 97](#).
- Option 3- FollowStart&Mode:** “Follow external start signal and selected *FunctionMode*” .
 The timers $t1$ and $t2$ will run while external *START* signal is present and in the same time the measurement criterion defined by parameter *FunctionMode* is active. If they elapse then the appropriate command will be given out from the function. Timers can be stopped by resetting the external *START* signal or if the measurement criterion de-activates, see [Figure 98](#).

When one of the two “follow modes” is used, there is a settable timer $tStartTimeout$ which will block the external *START* input signal when it times-out. This will automatically also reset the $t1$ and $t2$ timers and consequently prevent any backup trip command. At the same time the *STALARM* output from the function will have logical value one. To reset this signal external *START* signal shall be removed. This is done in order to prevent unwanted operation of the breaker failure function for cases where a permanent *START* signal is given by mistake (e.g. due to a fault in the station battery system). Note that any backup trip command will inhibit running of $tStartTimeout$ timer.

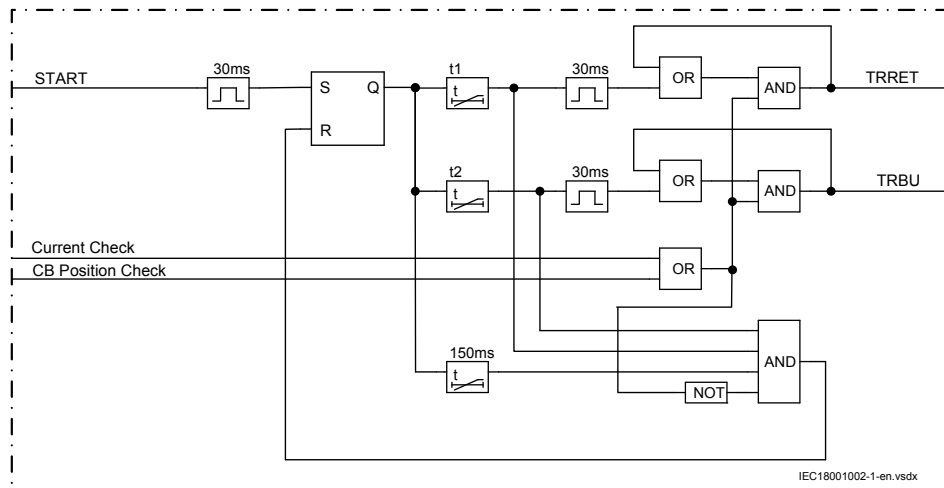


Figure 96: Simplified overall logic for LatchedStart

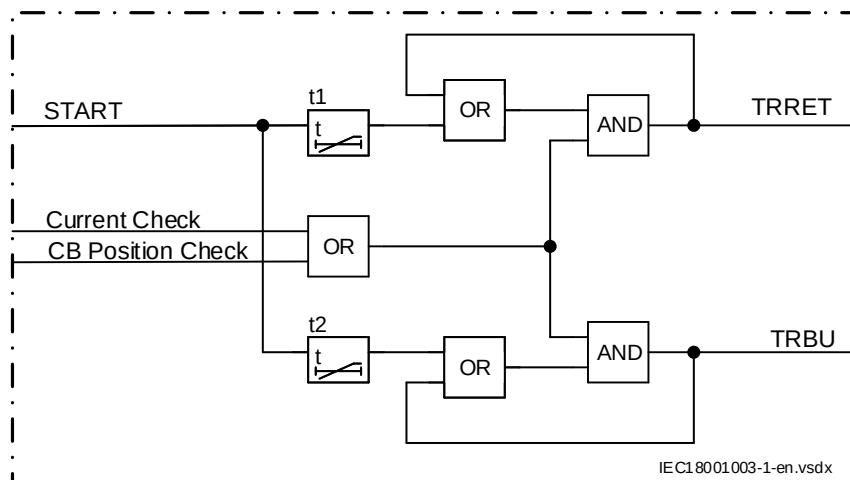


Figure 97: Simplified overall logic for FollowStart

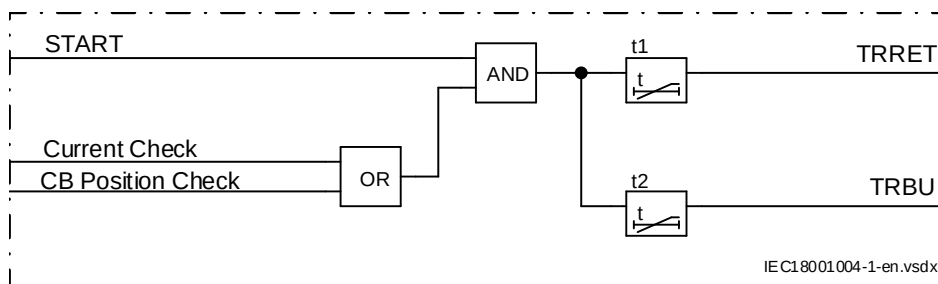


Figure 98: Simplified overall logic for FollowStart&Mode

RetripMode: This setting defines how the retrip function shall operate. Refer to Table 20 for more details.

Table 20: Dependencies between parameters RetripMode and FunctionMode

RetripMode	FunctionMode	Description
Off	N/A	The retrip function is disabled
UseFunctionMode	Current	A phase current should be larger than the set operate level to allow retrip once the $t1$ timer elapses
	CB Pos	retrip is done when the breaker position indicates that breaker is still closed after retrip time has elapsed
	Current or CB Pos	Both the methods are used
Always	N/A	retrip is always given when $t1$ elapses without any further checks

BuTripMode: Defines how many current criterias to be fulfilled in order to detect failure of the breaker. For *Current* operation *2 out of 4* means that at least two currents, of the three-phase currents and the residual current, shall be high to indicate breaker failure. *1 out of 3* means that at least one current of the three-phase currents shall be high to indicate breaker failure. *1 out of 4* means that at least one current of the three phase currents or the residual current shall be high to indicate breaker failure. In most applications *1 out of 3* is sufficient. For *CB Pos* operation *1 out of 3* is always used.

IP>: Current level for detection of breaker failure, set in % of I_{Base} . This parameter should be set so that faults with small fault current can be detected. The setting can be chosen in accordance with the most sensitive protection function to start the breaker failure protection. Default setting is 10% of I_{Base} . Note that this setting shall not be set lower than 4% of I_r , where I_r is rated current of the IED CT input where the function is connected. In principle I_r is either 1A or 5A depending on the ordered IED.

I>BlkCBPos: If the *FunctionMode* is set to *Current* or *CB pos* breaker failure for high current faults are safely detected by the current measurement function. To increase security for low currents the contact based function will be enabled only if the current at the moment of starting is below this set level. The setting can be given within the range 5 – 200% of I_{Base} . It is strongly recommended to set this level above $I_{Ph}>$ set level.

IN>: Residual current level for detection of breaker failure set in % of I_{Base} . In high impedance earthed systems the residual current at phase- to-earth faults are normally much smaller than the short circuit currents. In order to detect breaker failure at single phase-to-earth faults in such systems it is necessary to measure the residual current separately. The *BuTripMode* shall be set *1 out of 4* in such systems. The current setting should be chosen in accordance to the setting of the sensitive earth-fault protection. The setting can be given within the range 2 – 200 % of I_{Base} .

t1: Time delay of the retrip. The setting can be given within the range 0 – 60s in steps of 0.001 s. Typical setting is within range 0 – 50ms.

t_2 : Time delay of the backup trip. The choice of this setting is made as short as possible at the same time as unwanted operation must be avoided. Typical setting is within range 90 – 200ms (also dependent of retrip timer).

Timer t_2 is used when function is started in one phase only (i.e. for single-phase to ground fault on an OHL (Over Head Lines) when single-pole auto-reclosing is used).

The minimum time delay for the backup trip can be estimated as:

$$t_2 \geq t_1 + t_{CB\_open} + t_{BFP\_reset} + t_{margin}$$

(Equation 122)

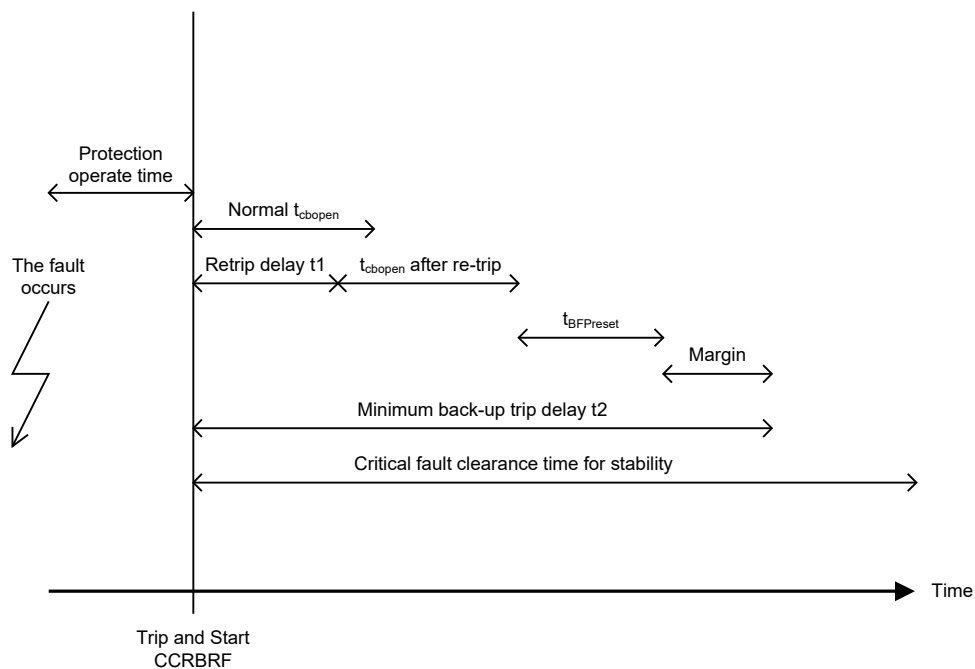
where:

t_{CB_open} is the maximum opening time for the circuit breaker

t_{BFP_reset} is the maximum time for breaker failure protection to detect correct breaker function (the current criteria reset)

t_{margin} is a safety margin

It is often required that the total fault clearance time shall be less than a given critical time. This time is often dependent of the ability of the power system to maintain transient stability in case of a fault close to a power plant.



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Figure 99: Time sequence

t_{2MPH} : Time delay of the backup trip at multi-phase start. The critical fault clearance time is often shorter in case of multi-phase faults, compared to single phase-to-earth faults. Therefore there is a possibility to reduce the backup trip delay for multi-phase faults. Typical setting is 90 – 150 ms.

Note that for a protected object which are always tripped three-phase (e.g. transformers, generators, reactors, cables, etc.) this timer shall always be set to the same value as t_2 timer.

t_3 : Additional time delay to t_2 for a second backup trip TRBU2. In some applications there might be a requirement to have separated backup trip functions, tripping different backup circuit breakers.

*tCBA*alarm: Time delay for alarm in case of indication of faulty circuit breaker. There is a binary input CBFLT from the circuit breaker. This signal is activated when internal supervision in the circuit breaker detect that the circuit breaker is unable to clear fault. This could be the case when gas pressure is low in a SF6 circuit breaker, or others. After the set time an alarm is given, so that actions can be done to repair the circuit breaker. Note that the time delay for backup trip *t2* is bypassed when the CBFLT is active. Typical setting is 2.0 seconds..

tPulse: Trip pulse duration. This setting must be larger than the opening time of circuit breakers to be tripped from the breaker failure protection. Typical setting is 200 ms.

tStartTimeout: When one of the two "Follow Modes" is used, there is a settable timer *tStartTimeout* which will block the external *START* input signal when it times-out. This will automatically also reset the *t1* and *t2* timers and consequently prevent any backup trip command. At the same time the STALARM output from the function will have logical value one. To reset that condition external *START* signal shall be removed. This is done in order to prevent unwanted operation of the breaker failure function for cases where a permanent *START* signal is given by mistake (e.g. due to a fault in the station battery system). Note that any backup trip command will inhibit running of *tStartTimeout* timer.

Table 21: Setting summary for FunctionMode, StartMode, RetripMode and BuTripMode

No.	StartMode	RetripMode	t1 and t2 initiated with	When t1 has elapsed, TRRET will	When t2 or t2MPH has elapsed, TRBU will be given if	t1 and t2 and t2MPH will be stopped (reset) if
FunctionMode = Current						
1	LatchedStart	Off	external START	never be given	current is above set level *)	t1 and (t2 or t2MPH) and 150ms expires and current is below set level *)
2	LatchedStart	UseFunctionMode	external START	be given if current is above set level of IPh>	current is above set level *)	t1 and (t2 or t2MPH) and 150ms expires and current is below set level *)
3	LatchedStart	Always	external START	always be given	current is above set level *)	t1 and (t2 or t2MPH) and 150ms expires and current is below set level *)
4	FollowStart	Off	external START	never be given	current is above set level *)	external START disappears
5	FollowStart	UseFunctionMode	external START	be given if current is above set level of IPh>	current is above set level *)	external START disappears
6	FollowStart	Always	external START	be given if external START is present	current is above set level *)	external START disappears
7	FollowStart&Mode	Off	external START and current above set level	never be given	current is above set level *) and external START present	current is below set level *) or external START disappears
8	FollowStart&Mode	UseFunctionMode	external START and current above set level	be given if current is above set level of IPh> and external START is present	current is above set level *) and external START present	current is below set level *) or external START disappears
9	FollowStart&Mode	Always	external START and current above set level	be given if external START is present	current is above set level *) and external START present	current is below set level *) or external START disappears

*) Set level depends on selected BuTripMode, that is, set level can be either IPh> or IN> or both.

No.	StartMode	RetripMode	t1 and t2 initiated with	When t1 has elapsed, TRRET will	When t2 or t2MPH has elapsed, TRBU will be given if	t1 and t2 and t2MPH will be stopped (reset) if
FunctionMode = CB Pos						
10	LatchedStart	Off	external START	never be given	CBCLDLx input has logical value one	t1 and (t2 or t2MPH) and 150ms expires and CBCLDLx input has logical value zero
11	LatchedStart	UseFunctionMode	external START	be given if CBCLDLx input has logical value one	CBCLDLx input has logical value one	t1 and (t2 or t2MPH) and 150ms expires and CBCLDLx input has logical value zero
12	LatchedStart	Always	external START	always be given	CBCLDLx input has logical value one	t1 and (t2 or t2MPH) and 150ms expires and CBCLDLx input has logical value zero
13	FollowStart	Off	external START	never be given	CBCLDLx input has logical value one	external START disappears
14	FollowStart	UseFunctionMode	external START	be given if CBCLDLx input has logical value one	CBCLDLx input has logical value one	external START disappears
15	FollowStart	Always	external START	if external START is present	CBCLDLx input has logical value one	external START disappears
16	FollowStart&Mode	Off	external START and CBCLDLx input has logical value one	never be given	be given if CBCLDLx input has logical value one and external START is present	CBCLDLx input has logical value zero or external START disappears
17	FollowStart&Mode	UseFunctionMode	external START and CBCLDLx input has logical value one	be given if CBCLDLx input has logical value one and external START is present	be given if CBCLDLx input has logical value one and external START is present	CBCLDLx input has logical value zero or external START disappears
18	FollowStart&Mode	Always	external START and CBCLDLx input has logical value one	be given if external START is present	be given if CBCLDLx input has logical value one and external START is present	CBCLDLx input has logical value zero or external START disappears

No.	StartMode	RetripMode	t1 and t2 initiated with	When t1 has elapsed, TRRET will	When t2 or t2MPH has elapsed, TRBU will be given if	t1 and t2 and t2MPH will be stopped (reset) if
FunctionMode = Current or CB Pos						
19	LatchedStart	Off	external START	never be given	current is above set level *) and higher than I>BlkCBPos or CBCLDLx input has logical value one when current is smaller than I>BlkCBPos	t1 and (t2 or t2MPH) and 150ms expires and current is below set level *) or CBCLDLx input has logical value zero
20	LatchedStart	UseFunctionMode	external START	be given if current is above set level of IPh> and higher than I>BlkCBPos or CBCLDLx input has logical value one when current is smaller than I>BlkCBPos	current is above set level *) and higher than I>BlkCBPos or CBCLDLx input has logical value one when current is smaller than I>BlkCBPos	t1 and (t2 or t2MPH) and 150ms expires and current is below set level *) or CBCLDLx input has logical value zero
21	LatchedStart	Always	external START	always be given	current is above set level *) and higher than I>BlkCBPos or CBCLDLx input has logical value one when current is smaller than I>BlkCBPos	t1 and (t2 or t2MPH) and 150ms expires and current is below set level *) or CBCLDLx input has logical value zero
22	FollowStart	Off	external START	never be given	current is above set level *) and higher than I>BlkCBPos or CBCLDLx input has logical value one when current is smaller than I>BlkCBPos	external START disappears
23	FollowStart	UseFunctionMode	external START	be given if current is above set level of IPh> and higher than I>BlkCBPos or CBCLDLx input has logical value one when current is smaller than I>BlkCBPos	current is above set level *) and higher than I>BlkCBPos or CBCLDLx input has logical value one when current is smaller than I>BlkCBPos	external START disappears
24	FollowStart	Always	external START	be given if external START is present	current is above set level *) and higher than I>BlkCBPos or CBCLDLx input has logical value one when current is smaller than I>BlkCBPos	external START disappears
25	FollowStart&Mode	Off	external START and current above set level	never be given	current is above set level *) and higher than I>BlkCBPos or CBCLDLx input has logical value one when current is smaller than I>BlkCBPos	current is below set level *) or external START disappears
Table continues on next page						

No.	StartMode	RetripMode	t1 and t2 initiated with	When t1 has elapsed, TRRET will	When t2 or t2MPH has elapsed, TRBU will be given if	t1 and t2 and t2MPH will be stopped (reset) if
26	FollowStart&Mode	UseFunctionMode	external START and current above set level	be given if current is above set level of IPh> and higher than I>BlkCBPos or CBCLDLx input has logical value one when current is smaller than I>BlkCBPos	current is above set level *) and higher than I>BlkCBPos or CBCLDLx input has logical value one when current is smaller than I>BlkCBPos	current is below set level *) or external START disappears
27	FollowStart&Mode	Always	external START and current above set level	be given if external START is present	current is above set level *) and higher than I>BlkCBPos or CBCLDLx input has logical value one when current is smaller than I>BlkCBPos	current is below set level *) or external START disappears

*) Set level depends on selected BuTripMode, that is, set level can be either IPh> or IN> or both.

8.7 Stub protection STBPTOC

8.7.1 Function revision history

Document revision	Product revision	History
A	2.2.1	-
B	2.2.1	-
C	2.2.1	-
D	2.2.4	-
E	2.2.5	-
J	2.2.6	-
K	2.2.6	-

8.7.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Stub protection	STBPTOC	3I>STUB	50STB

8.7.3 Application

In a 1½-breaker switchyard, the line protection and the busbar protection normally overlap when a connected object is in service. When an object is taken out of service it is normally required to keep the diagonal of the 1½-breaker switchyard in operation. This is done by opening the disconnector to

the protected object. This will, however, disable the normal object protection (for example the distance protection) of the energized part between the circuit breakers and the open disconnecter.

Stub protection STBPTOC is a simple phase overcurrent protection, fed from the two current transformer groups feeding the object taken out of service. The stub protection is only activated when the disconnector of the object is open. STBPTOC enables fast fault clearance of faults at the section between the CTs and the open disconnector.

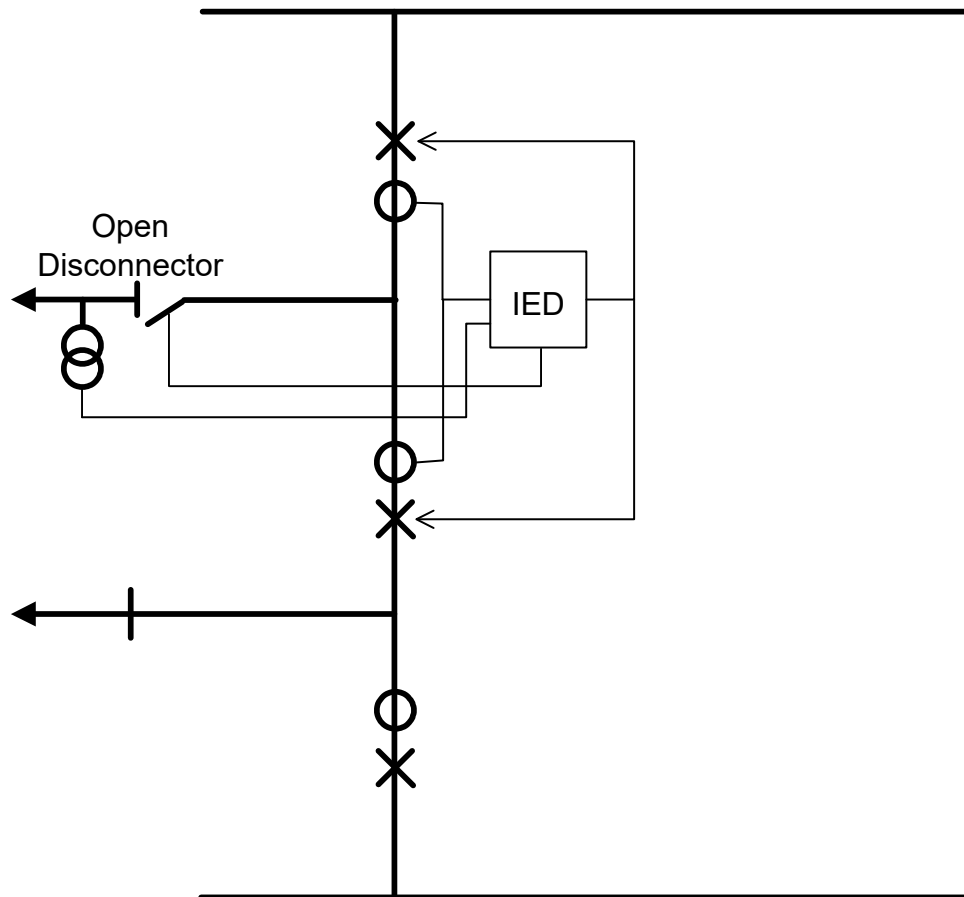


Figure 100: Typical connection for STBPTOC in 1½-breaker arrangement.

8.7.4 Setting guidelines

The parameters for Stub protection STBPTOC are set via the local HMI or PCM600.

The following settings can be done for the stub protection.

GlobalBaseSel: Selects the global base value group used by the function to define *IBase*, *UBase* and *SBase*. Note that this function will only use *IBase* value.

Operation: Off/On

ReleaseMode: This parameter can be set *Release* or *Continuous*. With the *Release* setting the function is only active when a binary release signal RELEASE into the function is activated. This signal is normally taken from an auxiliary contact (normally closed) of the line disconnector and connected to a binary input RELEASE of the IED. With the setting *Continuous* the function is activated independent of presence of any external release signal.

$I_{>}$: Current level for the Stub protection, set in % of I_{Base} . This parameter should be set so that all faults on the stub can be detected. The setting should thus be based on fault calculations.

t : Time delay of the operation. Normally the function shall be instantaneous.

8.8 Pole discordance protection CCPDSC

8.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Pole discordance protection	CCPDSC	<i>PD</i>	52PD

8.8.2 Application

There is a risk that a circuit breaker will get discordance between the poles at circuit breaker operation: closing or opening. One pole can be open and the other two closed, or two poles can be open and one closed. Pole discordance of a circuit breaker will cause unsymmetrical currents in the power system. The consequence of this can be:

- Negative sequence currents that will give stress on rotating machines
- Zero sequence currents that might give unwanted operation of sensitive earth-fault protections in the power system.

It is therefore important to detect situations with pole discordance of circuit breakers. When this is detected the breaker should be tripped directly.

Pole discordance protection CCPDSC will detect situation with deviating positions of the poles of the protected circuit breaker. The protection has two different options to make this detection:

- By connecting the auxiliary contacts in the circuit breaker so that logic is created, a signal can be sent to the protection, indicating pole discordance. This logic can also be realized within the protection itself, by using opened and close signals for each circuit breaker pole, connected to the protection.
- Each phase current through the circuit breaker is measured. If the difference between the phase currents is larger than a *CurrUnsymLevel* this is an indication of pole discordance, and the protection will operate.

8.8.3 Setting guidelines

The parameters for the Pole discordance protection CCPDSC are set via the local HMI or PCM600.

The following settings can be done for the pole discordance protection.

GlobalBaseSel: Selects the global base value group used by the function to define I_{Base} , U_{Base} and S_{Base} . Note that this function will only use I_{Base} value.

Operation: Off or On

tTrip: Time delay of the operation.

ContSel: Operation of the contact based pole discordance protection. Can be set: *Off/PD signal from CB*. If *PD signal from CB* is chosen the logic to detect pole discordance is made in the vicinity to the breaker auxiliary contacts and only one signal is connected to the pole discordance function. If the *Pole pos aux cont.* alternative is chosen each open close signal is connected to the IED and the logic to detect pole discordance is realized within the function itself.

CurrSel: Operation of the current based pole discordance protection. Can be set: *Off/CB oper monitor/Continuous monitor*. In the alternative *CB oper monitor* the function is activated only directly in connection to breaker open or close command (during 200 ms). In the alternative *Continuous monitor* function is continuously activated.

CurrUnsymLevel: Unsymmetrical magnitude of lowest phase current compared to the highest, set in % of the highest phase current. Natural difference between phase currents in 1 1/2 breaker installations must be considered. For circuit breakers in 1 1/2 breaker configured switch yards there might be natural unbalance currents through the breaker. This is due to the existence of low impedance current paths in the switch yard. This phenomenon must be considered in the setting of the parameter.

CurrRelLevel: Current magnitude for release of the function in % of *I_{Base}*.

8.9 Broken conductor check BRCPTOC

8.9.1 Function revision history

Document revision	Product revision	History
A	2.2.1	-
B	2.2.1	-
C	2.2.1	-
D	2.2.4	-
E	2.2.5	A fixed time delay of 50 ms is added before asserting START signal.
F	2.2.6	-
G	2.2.6	Updated Operate time delay range to 0.100 - 60.000 s

8.9.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Broken conductor check	BRCPTOC	-	46

8.9.3 Application

Conventional protection functions can not detect a broken conductor condition. Broken conductor check (BRCPTOC) function, consisting of continuous unsymmetrical current checks on the line where the IED connected will give alarm or trip at detecting broken conductors.

8.9.4 Setting guidelines

Broken conductor check BRCPTOC must be set to detect open phase/s (series faults) with different loads on the line. BRCPTOC must at the same time be set to not operate for maximum asymmetry which can exist due to, for example, untransposed power lines.

All settings are in primary values or percentage.

Set I_{Base} (given in $GlobalBaseSel$) to power line rated current or CT rated current.

Set minimum operating level per phase $IP>$ to typically 10-20% of rated current.

Set the unsymmetrical current, which is relation between the difference of the minimum and maximum phase currents to the maximum phase current to typical $I_{ub>} = 50\%$.



Note that it must be set to avoid problem with asymmetry under minimum operating conditions.

Set the time delay $t_{Oper} = 5 - 60$ seconds and reset time $t_{Reset} = 0.010 - 60.000$ seconds.

8.10 Overcurrent protection with binary release BRPTOC

8.10.1 Function revision history

Document revision	Product revision	History
A	2.2.1	-
B	2.2.1	-
C	2.2.1	-
D	2.2.4	-
E	2.2.5	New function release
M	2.2.6	-
N	2.2.6	-

8.10.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Overcurrent protection with binary release	BRPTOC	3/>	50

8.10.3 Application

Overcurrent protection with binary release (BRPTOC) is a simple, non-directional three-phase overcurrent protection function with definite time delay. A single step is available within the function. The current pickup level and definite time delay can be set independently. It is possible to release the function operation via a binary signal. Several function instances are available.

From the measured three-phase currents, various types of measurement modes such as DFT, Peak, and Peak-to-peak can be selected for the BRPTOC operation.

Peak and Peak-to-Peak measurement mode allow this function to be used as instantaneous over-current protection as well. If required by application, short time delay can also be applied.

BRPTOC can be used for different line and transformer protection applications. If required, it can also be used to supervise on-load tap-changer operation.

8.10.4 Setting guidelines

The parameters for Overcurrent protection with binary release BRPTOC are set via the local HMI or PCM600.

Common base IED values for primary current (I_{Base}), primary voltage (U_{Base}) and primary power (S_{Base}) are set in the global base values for settings function GBASVAL.

GlobalBaseSel: To select GBASVAL function for reference of base values.

MeasType: Selection of discrete Fourier filtered (DFT), Peak filtered or Peak-to-peak filtered signals for BRPTOC operation.

Operation: By using this setting the function can be set *On/Off*.

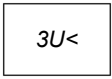
I>: Current start level, set in % of I_{Base} .

tDelay: Time delay of the operation in s.

Section 9 Voltage protection

9.1 Two step undervoltage protection UV2PTUV

9.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Two step undervoltage protection	UV2PTUV		27

9.1.2 Application

Two-step undervoltage protection function (UV2PTUV) is applied to power system elements, such as generators, transformers, motors and power lines in order to detect low voltage conditions. It is used as a supervision and fault detection function for other protection functions as well, to increase the security of a complete protection system. Low voltage conditions are caused by abnormal operation or faults in the power system, such as:

- Malfunctioning of a voltage regulator or wrong settings under manual control (symmetrical voltage decrease)
- Overload (symmetrical voltage decrease)
- Short circuits, often as phase-to-earth faults (unsymmetrical voltage decrease)

UV2PTUV is used in combination with overcurrent protections, either as restraint or in logic "and gates" of the trip signals issued by the two functions. It can also be used to:

- Detect no voltage conditions, for example, before the energization of a HV line or for automatic breaker trip in case of a blackout
- Initiate voltage correction measures, like insertion of shunt capacitor banks to compensate for reactive load and thereby increasing the voltage
- Disconnect apparatuses, like electric motors, which will be damaged when subject to service under low voltage conditions.

The function has a high measuring accuracy and a settable hysteresis to allow applications to control reactive load.

In many cases, UV2PTUV is a useful function in circuits for local or remote automation processes in the power system.

9.1.3 Setting guidelines

All the voltage conditions in the system where UV2PTUV performs its functions should be considered. The same also applies to the associated equipment, its voltage and time characteristic.

There is a very wide application area where general undervoltage functions are used. All voltage-related settings are made as a percentage of the global base value U_{Base} , which normally is set to the primary rated voltage level (phase-to-phase) of the power system or the high voltage equipment under consideration.

The trip time setting for UV2PTUV is normally not critical, since there must be enough time available for the main protection to clear short circuits and earth faults.

Some applications and related setting guidelines for the voltage level are described in the following sections.

9.1.3.1 Equipment protection, such as for motors and generators

The setting must be below the lowest occurring "normal" voltage and above the lowest acceptable voltage for the equipment.

9.1.3.2 Disconnected equipment detection

The setting must be below the lowest occurring "normal" voltage and above the highest occurring voltage, caused by inductive or capacitive coupling, when the equipment is disconnected.

9.1.3.3 Power supply quality

The setting must be below the lowest occurring "normal" voltage and above the lowest acceptable voltage, due to regulation, good practice or other agreements.

9.1.3.4 Voltage instability mitigation

This setting is very much dependent on the power system characteristics, and thorough studies have to be made to find the suitable levels.

9.1.3.5 Backup protection for power system faults

The setting must be below the lowest occurring "normal" voltage and above the highest occurring voltage during the fault conditions under consideration.

9.1.3.6 Settings for two step undervoltage protection

The following settings can be done for Two step undervoltage protection UV2PTUV:

ConnType: Sets whether the measurement shall be phase-to-earth fundamental value, phase-to-phase fundamental value, phase-to-earth RMS value or phase-to-phase RMS value.

Operation: Off or On.

UBase (given in *GlobalBaseSel*): Base voltage phase-to-phase in primary kV. This voltage is used as reference for voltage setting. UV2PTUV will operate if the voltage becomes lower than the set percentage of *UBase*. This setting is used when *ConnType* is set to *PhPh DFT* or *PhPh RMS*. Therefore, always set *UBase* as rated primary phase-to-phase voltage of the protected object. For more information, refer to the *Technical manual*.

The setting parameters described below are identical for the two steps ($n = 1$ or 2). Therefore, the setting parameters are described only once.

Characteristicn: This parameter gives the type of time delay to be used. The setting can be *Definite time*, *Inverse Curve A*, *Inverse Curve B*, *Prog. inv. curve*. The selection is dependent on the protection application.

OpModen: This parameter describes how many of the three measured voltages should be below the set level to give operation for step n. The setting can be *1 out of 3*, *2 out of 3* or *3 out of 3*. In most applications, it is sufficient that one phase voltage is low to give operation. If UV2PTUV shall be insensitive for single phase-to-earth faults, *2 out of 3* can be chosen. In subtransmission and transmission networks the undervoltage function is mainly a system supervision function and 3 out of 3 is selected.

$Un<$: Set operate undervoltage operation value for step n , given as % of the parameter $UBase$. The setting is highly dependent on the protection application. It is essential to consider the minimum voltage at non-faulted situations. Normally, this non-faulted voltage is larger than 90% of the nominal voltage.

tn : time delay of step n , given in s. This setting is dependent on the protection application. In many applications the protection function shall not directly trip when there is a short circuit or earth faults in the system. The time delay must be coordinated to the other short circuit protections.

$tResetn$: Reset time for step n if definite time delay is used, given in s. The default value is 25 ms.

$tnMin$: Minimum operation time for inverse time characteristic for step n , given in s. When using inverse time characteristic for the undervoltage function during very low voltages can give a short operation time. This might lead to unselective tripping. By setting $t1Min$ longer than the operation time for other protections, such unselective tripping can be avoided.

$ResetTypeCrvn$: This parameter for inverse time characteristic can be set to *Instantaneous*, *Frozen time*, *Linearly decreased*. The default setting is *Instantaneous*.

$tIResetn$: Reset time for step n if inverse time delay is used, given in s. The default value is 25 ms.

kn : Time multiplier for inverse time characteristic. This parameter is used for coordination between different inverse time delayed undervoltage protections.

$ACrvn$, $BCrvn$, $CCrvn$, $DCrvn$, $PCrvn$: Parameters to create a programmable under voltage inverse time characteristic. Description of this can be found in the *Technical manual*.

$CrvSatn$: Tuning parameter that is used to compensate for the undesired discontinuity created when the denominator in the equation for the customer programmable curve is equal to zero. For more information, see the *Technical manual*.

$IntBlkSeln$: This parameter can be set to *Off*, *Block of trip*, *Block all*. In case of a low voltage the undervoltage function can be blocked. This function can be used to prevent function when the protected object is switched off. If the parameter is set *Block of trip* or *Block all* unwanted trip is prevented.

$IntBlkStValn$: Voltage level under which the blocking is activated set in % of $UBase$. This setting must be lower than the setting $Un<$. As switch of shall be detected the setting can be very low, that is, about 10%.

$tBlkUVn$: Time delay to block the undervoltage step n when the voltage level is below $IntBlkStValn$, given in s. It is important that this delay is shorter than the operate time delay of the undervoltage protection step.

9.2 Two step overvoltage protection OV2PTOV

9.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Two step overvoltage protection	OV2PTOV	$3U>$	59

9.2.2 Application

Two step overvoltage protection OV2PTOV is applicable in all situations, where reliable detection of high voltage is necessary. OV2PTOV is used for supervision and detection of abnormal conditions, which, in combination with other protection functions, increase the security of a complete protection system.

High overvoltage conditions are caused by abnormal situations in the power system. OV2PTOV is applied to power system elements, such as generators, transformers, motors and power lines in order to detect high voltage conditions. OV2PTOV is used in combination with low current signals, to identify a transmission line, open in the remote end. In addition to that, OV2PTOV is also used to initiate voltage correction measures, like insertion of shunt reactors, to compensate for low load, and thereby decreasing the voltage. The function has a high measuring accuracy and hysteresis setting to allow applications to control reactive load.

OV2PTOV is used to disconnect apparatuses, like electric motors, which will be damaged when subject to service under high voltage conditions. It deals with high voltage conditions at power system frequency, which can be caused by:

1. Different kinds of faults, where a too high voltage appears in a certain power system, like metallic connection to a higher voltage level (broken conductor falling down to a crossing overhead line, transformer flash over fault from the high voltage winding to the low voltage winding and so on).
2. Malfunctioning of a voltage regulator or wrong settings under manual control (symmetrical voltage decrease).
3. Low load compared to the reactive power generation (symmetrical voltage decrease).
4. Earth-faults in high impedance earthed systems causes, beside the high voltage in the neutral, high voltages in the two non-faulted phases, (unsymmetrical voltage increase).

OV2PTOV prevents sensitive equipment from running under conditions that could cause their overheating or stress of insulation material, and, thus, shorten their life time expectancy. In many cases, it is a useful function in circuits for local or remote automation processes in the power system.

9.2.3 Setting guidelines

The parameters for Two step overvoltage protection (OV2PTOV) are set via the local HMI or PCM600.

All the voltage conditions in the system where OV2PTOV performs its functions should be considered. The same also applies to the associated equipment, its voltage and time characteristic.

There are wide applications where general overvoltage functions are used. All voltage related settings are made as a percentage of a settable base primary voltage, which is normally set to the nominal voltage level (phase-to-phase) of the power system or the high voltage equipment under consideration.

The time delay for the OV2PTOV can sometimes be critical and related to the size of the overvoltage - a power system or a high voltage component can withstand smaller overvoltages for some time, but in case of large overvoltages the related equipment should be disconnected more rapidly.

Some applications and related setting guidelines for the voltage level are given below:

The hysteresis is for overvoltage functions very important to prevent that a transient voltage over set level is not "sealed-in" due to a high hysteresis. Typical values should be $\leq 0.5\%$.

9.2.3.1 Equipment protection, such as for motors, generators, reactors and transformers

High voltage will cause overexcitation of the core and deteriorate the winding insulation. The setting has to be well above the highest occurring "normal" voltage and well below the highest acceptable voltage for the equipment.

9.2.3.2 Equipment protection, capacitors

High voltage will deteriorate the dielectricum and the insulation. The setting has to be well above the highest occurring "normal" voltage and well below the highest acceptable voltage for the capacitor.

9.2.3.3 Power supply quality

The setting has to be well above the highest occurring "normal" voltage and below the highest acceptable voltage, due to regulation, good practice or other agreements.

9.2.3.4 High impedance earthed systems

In high impedance earthed systems, earth-faults cause a voltage increase in the non-faulty phases. Two step overvoltage protection (OV2PTOV) is used to detect such faults. The setting must be above the highest occurring "normal" voltage and below the lowest occurring voltage during faults. A metallic single-phase earth-fault causes the non-faulted phase voltages to increase a factor of $\sqrt{3}$.

9.2.3.5 The following settings can be done for the two step overvoltage protection

ConnType: Sets whether the measurement shall be phase-to-earth fundamental value, phase-to-phase fundamental value, phase-to-earth RMS value or phase-to-phase RMS value.

Operation: Off/On.

UBase (given in *GlobalBaseSel*): Base voltage phase to phase in primary kV. This voltage is used as reference for voltage setting. OV2PTOV measures selectively phase-to-earth voltages, or phase-to-phase voltage chosen by the setting *ConnType*. The function will operate if the voltage gets lower than the set percentage of *UBase*. When *ConnType* is set to *PhN DFT* or *PhN RMS* then the IED automatically divides set value for *UBase* by $\sqrt{3}$. When *ConnType* is set to *PhPh DFT* or *PhPh RMS* then set value for *UBase* is used. Therefore, always set *UBase* as rated primary phase-to-phase voltage of the protected object. If phase to neutral (PhN) measurement is selected as setting, the operation of phase-to-earth over voltage is automatically divided by $\sqrt{3}$. This means operation for phase-to-earth voltage over:

$$U > (\%) \cdot U_{Base}(kV) / \sqrt{3}$$

and operation for phase-to-phase voltage over:

$$U > (\%) \cdot U_{Base}(kV)$$

(Equation 124)

The below described setting parameters are identical for the two steps ($n = 1$ or 2). Therefore the setting parameters are described only once.

Characteristicn: This parameter gives the type of time delay to be used. The setting can be *Definite time*, *Inverse Curve A*, *Inverse Curve B*, *Inverse Curve C* or *I/Prog. inv. curve*. The choice is highly dependent of the protection application.

OpModen: This parameter describes how many of the three measured voltages that should be above the set level to give operation. The setting can be *1 out of 3*, *2 out of 3*, *3 out of 3*. In most applications it is sufficient that one phase voltage is high to give operation. If the function shall be insensitive for single phase-to-earth faults *1 out of 3* can be chosen, because the voltage will normally rise in the non-faulted phases at single phase-to-earth faults. In subtransmission and transmission networks the UV function is mainly a system supervision function and 3 out of 3 is selected.

Un>: Set operate overvoltage operation value for step *n*, given as % of *UBase*. The setting is highly dependent of the protection application. Here it is essential to consider the maximum voltage at non-faulted situations. Normally this voltage is less than 110% of nominal voltage.

tn: time delay of step *n*, given in s. The setting is highly dependent of the protection application. In many applications the protection function is used to prevent damages to the protected object. The speed might be important for example in case of protection of transformer that might be overexcited. The time delay must be co-ordinated with other automated actions in the system.

tResetn: Reset time for step *n* if definite time delay is used, given in s. The default value is 25 ms.

tnMin: Minimum operation time for inverse time characteristic for step *n*, given in s. For very high voltages the overvoltage function, using inverse time characteristic, can give very short operation time. This might lead to unselective trip. By setting *t1Min* longer than the operation time for other protections such unselective tripping can be avoided.

ResetTypeCrvn: This parameter for inverse time characteristic can be set: *Instantaneous*, *Frozen time*, *Linearly decreased*. The default setting is *Instantaneous*.

t/Resetn: Reset time for step *n* if inverse time delay is used, given in s. The default value is 25 ms.

kn: Time multiplier for inverse time characteristic. This parameter is used for co-ordination between different inverse time delayed undervoltage protections.

ACrvn, BCrvn, CCrvn, DCrvn, PCrvn: Parameters to set to create programmable under voltage inverse time characteristic. Description of this can be found in the technical reference manual.

CrvSatn: When the denominator in the expression of the programmable curve is equal to zero the time delay will be infinity. There will be an undesired discontinuity. Therefore a tuning parameter *CrvSatn* is set to compensate for this phenomenon. In the voltage interval *Un>* up to *Un>* · (1.0 + *CrvSatn*/100) the used voltage will be: *Un>* · (1.0 + *CrvSatn*/100). If the programmable curve is used, this parameter must be calculated so that:

$$B \cdot \frac{CrvSatn}{100} - C > 0$$

(Equation 125)



If the Programmable inverse curve is chosen for operation and [Equation 125](#) does not satisfy based on the set values, no TRIP signal is issued. However, START signal is set and maintained as long as the measured quantity for operation is above the set start level of step.

HystAbsn: Absolute hysteresis set in % of *UBase*. The setting of this parameter is highly dependent of the application. If the function is used as control for automatic switching of reactive compensation devices the hysteresis must be set smaller than the voltage change after switching of the compensation device.

9.3 Two step residual overvoltage protection ROV2PTOV

9.3.1 Function revision history

Document revision	Product revision	History
A	2.2.1	-
B	2.2.1	-
C	2.2.1	-
D	2.2.1	PTP Enhancement
E	2.2.4	-
J	2.2.6	-
K	2.2.6	-

9.3.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Two step residual overvoltage protection	ROV2PTOV	$2(U_0 >)$	59N

9.3.3 Application

Two step residual overvoltage protection ROV2PTOV is primarily used in high impedance earthed distribution networks, mainly as a backup for the primary earth-fault protection of the feeders and the transformer. To increase the security for different earth-fault related functions, the residual overvoltage signal can be used as a release signal. The residual voltage can be measured either at the transformer neutral or from a voltage transformer open delta connection. The residual voltage can also be calculated internally, based on the measurement of the three phase-to-earth voltages.

In high impedance earthed systems the residual voltage will increase in case of any fault connected to earth. Depending on the type of fault and fault resistance the residual voltage will reach different values. The highest residual voltage, equal to three times the phase-to-earth voltage, is achieved for a single phase-to-earth fault. The residual voltage increases approximately to the same level in the whole system and does not provide any guidance in finding the faulted component. Therefore, ROV2PTOV is often used as a backup protection or as a release signal for the feeder earth-fault protection.

9.3.4 Setting guidelines

All the voltage conditions in the system where ROV2PTOV performs its functions should be considered. The same also applies to the associated equipment, its voltage withstand capability and time characteristic.

All voltage-related settings are made as a percentage of a settable base voltage, which shall be set to the primary nominal voltage (phase-phase) level of the power system or the high-voltage equipment under consideration.

The time delay for ROV2PTOV is seldom critical, since residual voltage is related to earth faults in a high-impedance earthed system, and enough time must normally be given for the primary protection to clear the fault. In some more specific situations, where the residual overvoltage protection is used to protect some specific equipment, the time delay is shorter.

Some applications and related setting guidelines for the residual voltage level are given below.

9.3.4.1 Equipment protection, such as for motors, generators, reactors and transformers Equipment protection for transformers

High residual voltage indicates earth-fault in the system, perhaps in the component to which two step residual overvoltage protection (ROV2PTOV) is connected. For selectivity reasons to the primary protection for the faulted device, ROV2PTOV must trip the component with some time delay. The setting must be above the highest occurring "normal" residual voltage and below the highest acceptable residual voltage for the equipment.

9.3.4.2 Equipment protection, capacitors

High voltage will deteriorate the dielectric and the insulation. Two step residual overvoltage protection (ROV2PTOV) has to be connected to a neutral or open delta winding. The setting must be above the highest occurring "normal" residual voltage and below the highest acceptable residual voltage for the capacitor.

9.3.4.3 Power supply quality

The setting must be above the highest occurring "normal" residual voltage and below the highest acceptable residual voltage, due to regulation, good practice or other agreements.

9.3.4.4 High impedance earthed systems

In high impedance earthed systems, earth faults cause a neutral voltage in the feeding transformer neutral. Two step residual overvoltage protection ROV2PTOV is used to trip the transformer, as a backup protection for the feeder earth-fault protection, and as a backup for the transformer primary earth-fault protection. The setting must be above the highest occurring "normal" residual voltage, and below the lowest occurring residual voltage during the faults under consideration. A metallic single-phase earth fault causes a transformer neutral to reach a voltage equal to the nominal phase-to-earth voltage.

The voltage transformers measuring the phase-to-earth voltages measure zero voltage in the faulty phase. The two healthy phases will measure full phase-to-phase voltage, as the faulty phase will be connected to earth. The residual overvoltage will be three times the phase-to-earth voltage. See figure [101](#).

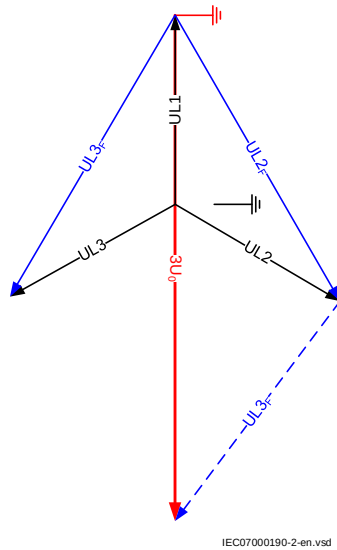


Figure 101: Earth fault in Non-effectively earthed systems

9.3.4.5 Direct earthed system

In direct earthed systems, an earth fault on one phase is indicated by voltage collapse in that phase. The other healthy phase will still have normal phase-to-earth voltage. The residual sum will have the same value as the remaining phase-to-earth voltage, which is shown in Figure 102.

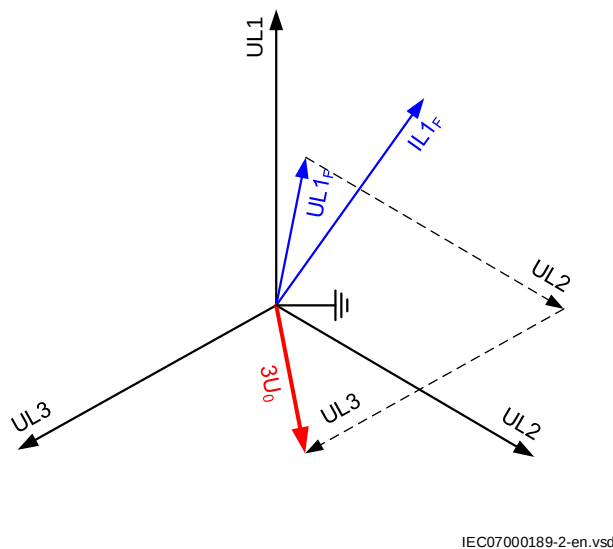


Figure 102: Earth fault in Direct earthed system

9.3.4.6 Settings for two step residual overvoltage protection

Operation: Off or On

U_{Base} (given in *GlobalBaseSel*) is used as voltage reference for the set pickup values. The voltage can be fed to the IED in different ways:

1. The IED is fed from a normal voltage transformer group where the residual voltage is calculated internally from the phase-to-earth voltages within the protection. The setting of the analog input is given as $U_{Base}=U_{ph-ph}$.
2. The IED is fed from a broken delta connection normal voltage transformer group. In an open delta connection the protection is fed by the voltage $3U_0$ (single input). Section *Analog inputs* in the Application manual explains how the analog input needs to be set.
3. The IED is fed from a single voltage transformer connected to the neutral point of a power transformer in the power system. In this connection the protection is fed by the voltage $U_N=U_0$ (single input). Section *Analog inputs* in the *Application manual* explains how the analog input needs to be set.

ROV2PTOV will measure the residual voltage corresponding to the nominal phase-to-earth voltage for a high-impedance earthed system. The measurement will be based on the neutral voltage displacement.

The setting parameters described below are identical for the two steps ($n = \text{step 1 and 2}$). Therefore the setting parameters are described only once.

OperationStepn: To enable/disable operation of step n .

Characteristicn: Selected inverse time characteristic for step n . This parameter gives the type of time delay to be used. The setting can be, *Definite time* or *Inverse curve A* or *Inverse curve B* or *Inverse curve C* or *Prog. inv. curve*. The choice is highly dependent of the protection application.

Un>: Set operate overvoltage operation value for step n , given as % of residual voltage corresponding to U_{Base} :

$$U > (\%) \cdot U_{Base}(kV) / \sqrt{3}$$

(Equation 126)

The setting depends on the required sensitivity of the protection and the type of system earthing. In non-effectively earthed systems, the residual voltage cannot be higher than three times the rated phase-to-earth voltage, which should correspond to 100%.

In effectively earthed systems, this value depends on the ratio Z_0/Z_1 . The required setting to detect high resistive earth faults must be based on network calculations.

tn: time delay of step n , given in s. The setting is highly dependent on the protection application. In many applications, the protection function has the task to prevent damage to the protected object. The speed might be important, for example, in the case of the protection of a transformer that might be overexcited. The time delay must be co-ordinated with other automated actions in the system.

tResetn: Reset time for step n if definite time delay is used, given in s. The default value is 25 ms.

tnMin: Minimum operation time for inverse time characteristic for step n , given in s. For very high voltages the overvoltage function, using inverse time characteristic, can give very short operation time. This might lead to unselective trip. By setting **t1Min** longer than the operation time for other protections such unselective tripping can be avoided.

ResetTypeCrvn: Set reset type curve for step n . This parameter can be set: *Instantaneous*, *Frozen time*, *Linearly decreased*. The default setting is *Instantaneous*.

tIResetn: Reset time for step n if inverse time delay is used, given in s. The default value is 25 ms.

kn: Time multiplier for inverse time characteristic. This parameter is used for co-ordination between different inverse time delayed undervoltage protections.

ACrvn, BCrvn, CCrvn, DCrvn, PCrvn: Parameters for step n , to set to create programmable undervoltage inverse time characteristic. Description of this can be found in the technical reference manual.

CrvSatn: Set tuning parameter for step *n*. When the denominator in the expression of the programmable curve is equal to zero, the time delay will be infinite. There will be an undesired discontinuity. Therefore, a tuning parameter *CrvSatn* is set to compensate for this phenomenon. In the voltage interval $U > U_{set} \cdot (1.0 + CrvSatn/100)$ the used voltage will be: $U_{set} \cdot (1.0 + CrvSatn/100)$. If the programmable curve is used this parameter must be calculated so that:

$$B \cdot \frac{CrvSatn}{100} - C > 0$$

(Equation 127)



If the Programmable inverse curve is chosen for operation and [Equation 127](#) does not satisfy based on the set values, no TRIP signal is issued. However, START signal is set and maintained as long as the measured quantity for operation is above the set start level of step.

HystAbsn: Absolute hysteresis for step *n*, set in % of *UBase*. The setting of this parameter is highly dependent of the application. The hysteresis is used to avoid oscillations of the START output signal. This signal resets when the measured voltage drops below the setting level and leaves the hysteresis area. Make sure that the set value for parameter *HystABSn* is somewhat smaller than the set pickup value. Otherwise there is a risk that step *n* will not reset properly.

9.4 Voltage differential protection VDCPTDV

9.4.1 Function revision history

Document revision	Product revision	History
A	2.2.1	-
B	2.2.1	-
C	2.2.1	-
D	2.2.1	PTP Enhancement
E	2.2.4	-
J	2.2.6	-
K	2.2.6	Function name changed from VDCPTOV to VDCPTDV

9.4.2 Identification

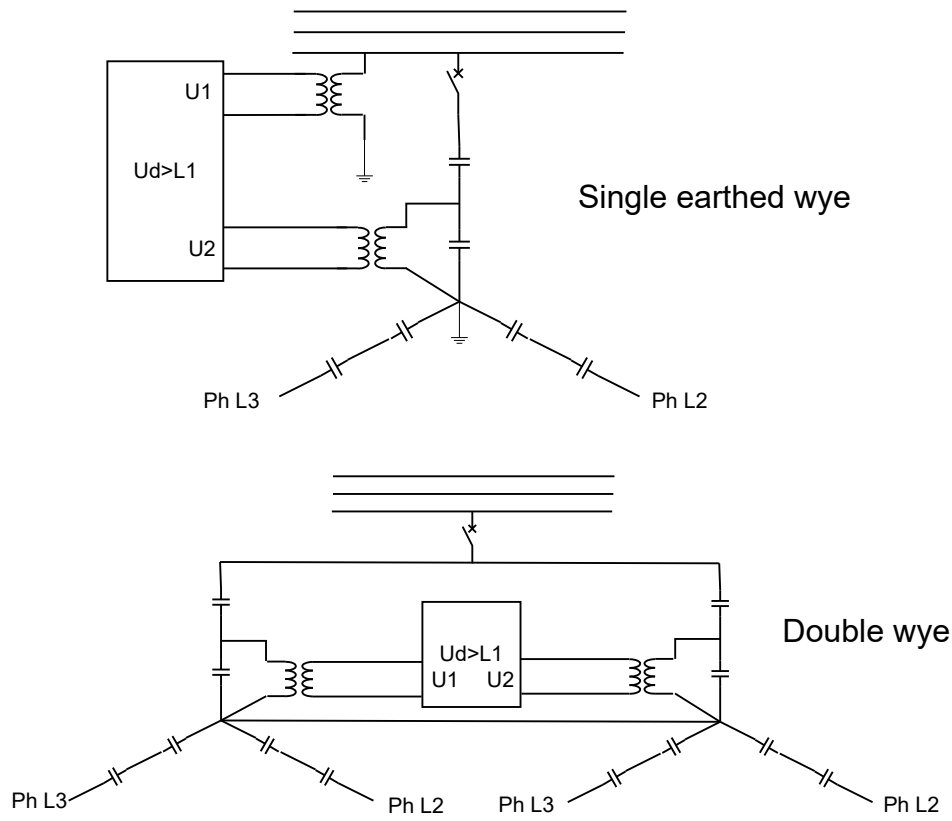
Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Voltage differential protection	VDCPTDV	-	87V

9.4.3 Application

The Voltage differential protection VDCPTDV functions can be used in some different applications.

- Voltage unbalance protection for capacitor banks. The voltage on the bus is supervised with the voltage in the capacitor bank, phase- by phase. Difference indicates a fault, either short-circuited or open element in the capacitor bank. It is mainly used on elements with external fuses but can also be used on elements with internal fuses instead of a current unbalance protection

measuring the current between the neutrals of two half's of the capacitor bank. The function requires voltage transformers in all phases of the capacitor bank. Figure 103 shows some different alternative connections of this function.



IEC06000390_1_en.vsd

Figure 103: Connection of voltage differential protection VDCPTDV function to detect unbalance in capacitor banks (one phase only is shown)

VDCPTDV function has a block input (BLOCK) where a fuse failure supervision (or MCB tripped) can be connected to prevent problems if one fuse in the capacitor bank voltage transformer set has opened and not the other (capacitor voltage is connected to input U2). It will also ensure that a fuse failure alarm is given instead of a Undervoltage or Differential voltage alarm and/or tripping.

The application to supervise the voltage on two voltage transformers in the generator circuit is shown in figure 104.

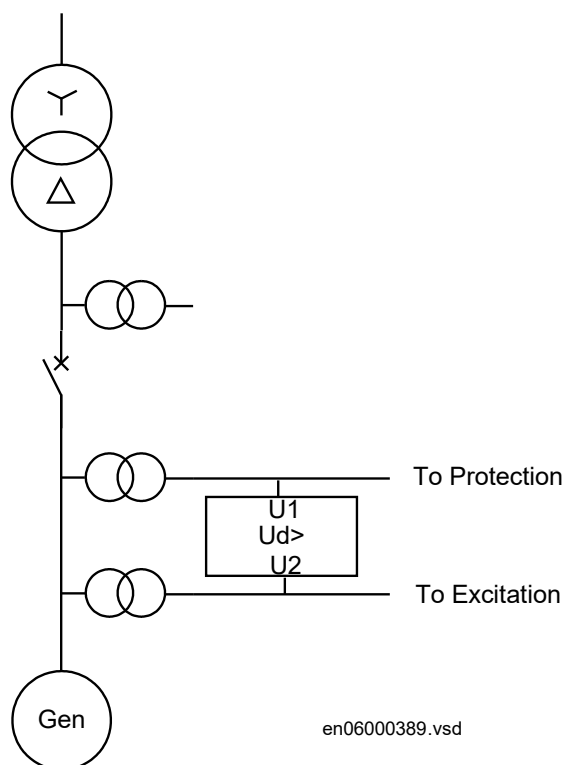


Figure 104: Supervision of fuses on generator circuit voltage transformers

9.4.4 Setting guidelines

The parameters for the voltage differential function are set via the local HMI or PCM600.

The following settings are done for the voltage differential function.

Operation: Off/On

GlobalBaseSel: Selects the global base value group used by the function to define *IBase*, *UBase* and *SBase*. Note that this function will only use *IBase* value.

BlkDiffAtULow: The setting is to block the function when the voltages in the phases are low.

RFLx: Is the setting of the voltage ratio compensation factor where possible differences between the voltages is compensated for. The differences can be due to different voltage transformer ratios, different voltage levels e.g. the voltage measurement inside the capacitor bank can have a different voltage level but the difference can also e.g. be used by voltage drop in the secondary circuits. The setting is normally done at site by evaluating the differential voltage achieved as a service value for each phase. The factor is defined as $U2 \cdot RFLx$ and shall be equal to the $U1$ voltage. Each phase has its own ratio factor.

UDTrip: The voltage differential level required for tripping is set with this parameter. For application on capacitor banks the setting will depend of the capacitor bank voltage and the number of elements per phase in series and parallel. Capacitor banks must be tripped before excessive voltage occurs on the healthy capacitor elements. The setting values required are normally given by the capacitor bank supplier. For other applications it has to be decided case by case. For fuse supervision normally only the alarm level is used.

tTrip: The time delay for tripping is set by this parameter. Normally, the delay does not need to be so short in capacitor bank applications as there is no fault requiring urgent tripping.

tReset: The time delay for reset of tripping level element is set by this parameter. Normally, it can be set to a short delay as faults are permanent when they occur.

For the advanced users following parameters are also available for setting. Default values are here expected to be acceptable.

U1Low: The setting of the undervoltage level for the first voltage input is decided by this parameter. The proposed default setting is 70%.

U2Low: The setting of the undervoltage level for the second voltage input is decided by this parameter. The proposed default setting is 70%.

tBlock: The time delay for blocking of the function at detected undervoltages is set by this parameter.

UDAlarm: The voltage differential level required for alarm is set with this parameter. For application on capacitor banks the setting will depend of the capacitor bank voltage and the number of elements per phase in series and parallel. Normally values required are given by capacitor bank supplier.

For fuse supervision normally only this alarm level is used and a suitable voltage level is 3-5% if the ratio correction factor has been properly evaluated during commissioning.

For other applications it has to be decided case by case.

tAlarm: The time delay for alarm is set by this parameter. Normally, few seconds delay can be used on capacitor banks alarm. For fuse failure supervision (SDDRFUF) the alarm delay can be set to zero.

9.5 Loss of voltage check LOVPTUV

9.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Loss of voltage check	LOVPTUV	-	27

9.5.2 Application

The trip of the circuit breaker at a prolonged loss of voltage at all the three phases is normally used in automatic restoration systems to facilitate the system restoration after a major blackout. Loss of voltage check (LOVPTUV) generates a TRIP signal only if the voltage in all the three phases is low for more than the set time. If the trip to the circuit breaker is not required, LOVPTUV is used for signallization only through an output contact or through the event recording function.

9.5.3 Setting guidelines

Loss of voltage check (LOVPTUV) is in principle independent of the protection functions. It requires to be set to open the circuit breaker in order to allow a simple system restoration following a main voltage loss of a big part of the network and only when the voltage is lost with breakers still closed.

All settings are in primary values or per unit. Set operate level per phase to typically 70% of the global parameter *UBase* level. Set the time delay *tTrip*=5-20 seconds.

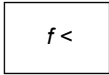
9.5.3.1 Advanced users settings

For advanced users the following parameters need also to be set. Set the length of the trip pulse to typical $tPulse=0.15$ sec. Set the blocking time $tBlock$ to block Loss of voltage check (LOVPTUV), if some but not all voltage are low, to typical 5.0 seconds and set the time delay for enabling the function after restoration $tRestore$ to 3 - 40 seconds.

Section 10 Frequency protection

10.1 Underfrequency protection SAPTUF

10.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Underfrequency protection	SAPTUF		81

10.1.2 Application

Underfrequency protection SAPTUF is applicable in all situations, where reliable detection of low fundamental power system frequency is needed. The power system frequency, and the rate of change of frequency, is a measure of the unbalance between the actual generation and the load demand. Low fundamental frequency in a power system indicates that the available generation is too low to fully supply the power demanded by the load connected to the power grid. SAPTUF detects such situations and provides an output signal, suitable for load shedding, generator boosting, HVDC-set-point change, gas turbine start up and so on. Sometimes shunt reactors are automatically switched in due to low frequency, in order to reduce the power system voltage and hence also reduce the voltage dependent part of the load.

SAPTUF is very sensitive and accurate and is used to alert operators that frequency has slightly deviated from the set-point, and that manual actions might be enough. The underfrequency signal is also used for overexcitation detection. This is especially important for generator step-up transformers, which might be connected to the generator but disconnected from the grid, during a roll-out sequence. If the generator is still energized, the system will experience overexcitation, due to the low frequency.

10.1.3 Setting guidelines

All the frequency and voltage magnitude conditions in the system where SAPTUF performs its functions should be considered. The same also applies to the associated equipment, its frequency and time characteristic.

There are two specific application areas for SAPTUF:

1. to protect equipment against damage due to low frequency, such as generators, transformers, and motors. Overexcitation is also related to low frequency
2. to protect a power system, or a part of a power system, against breakdown, by shedding load, in generation deficit situations.

The under frequency start value is set in Hz. All voltage magnitude related settings are made as a percentage of a global base voltage parameter. The UBase value should be set as a primary phase-to-phase value.

Some applications and related setting guidelines for the frequency level are given below:

Equipment protection, such as for motors and generators

The setting has to be well below the lowest occurring "normal" frequency and well above the lowest acceptable frequency for the equipment.

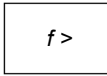
Power system protection, by load shedding

The setting has to be below the lowest occurring "normal" frequency and well above the lowest acceptable frequency for power stations, or sensitive loads. The setting level, the number of levels and the distance between two levels (in time and/or in frequency) depends very much on the characteristics of the power system under consideration. The size of the "largest loss of production" compared to "the size of the power system" is a critical parameter. In large systems, the load shedding can be set at a fairly high frequency level, and the time delay is normally not critical. In smaller systems the frequency start level has to be set at a lower value, and the time delay must be rather short.

The voltage related time delay is used for load shedding. The settings of SAPTUF could be the same all over the power system. The load shedding is then performed firstly in areas with low voltage magnitude, which normally are the most problematic areas, where the load shedding also is most efficient.

10.2 Overfrequency protection SAPTOF

10.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Overfrequency protection	SAPTOF		81

10.2.2 Application

Overfrequency protection function SAPTOF is applicable in all situations, where reliable detection of high fundamental power system frequency is needed. The power system frequency, and rate of change of frequency, is a measure of the unbalance between the actual generation and the load demand. High fundamental frequency in a power system indicates that the available generation is too large compared to the power demanded by the load connected to the power grid. SAPTOF detects such situations and provides an output signal, suitable for generator shedding, HVDC-set-point change and so on. SAPTOF is very sensitive and accurate and can also be used to alert operators that frequency has slightly deviated from the set-point, and that manual actions might be enough.

10.2.3 Setting guidelines

All the frequency and voltage magnitude conditions in the system where SAPTOF performs its functions must be considered. The same also applies to the associated equipment, its frequency and time characteristic.

There are two application areas for SAPTOF:

1. to protect equipment against damage due to high frequency, such as generators, and motors
2. to protect a power system, or a part of a power system, against breakdown, by shedding generation, in over production situations.

The overfrequency start value is set in Hz. All voltage magnitude related settings are made as a percentage of a settable global base voltage parameter *UBase*. The *UBase* value should be set as a primary phase-to-phase value.

Some applications and related setting guidelines for the frequency level are given below:

Equipment protection, such as for motors and generators

The setting has to be well above the highest occurring "normal" frequency and well below the highest acceptable frequency for the equipment.

Power system protection, by generator shedding

The setting must be above the highest occurring "normal" frequency and below the highest acceptable frequency for power stations, or sensitive loads. The setting level, the number of levels and the distance between two levels (in time and/or in frequency) depend very much on the characteristics of the power system under consideration. The size of the "largest loss of load" compared to "the size of the power system" is a critical parameter. In large systems, the generator shedding can be set at a fairly low frequency level, and the time delay is normally not critical. In smaller systems the frequency START level has to be set at a higher value, and the time delay must be rather short.

10.3 Rate-of-change of frequency protection SAPFRC

10.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Rate-of-change of frequency protection	SAPFRC		81

10.3.2 Application

Rate-of-change of frequency protection (SAPFRC) is applicable in all situations, where reliable detection of change of the fundamental power system voltage frequency is needed. SAPFRC can be used both for increasing frequency and for decreasing frequency. SAPFRC provides an output signal, suitable for load shedding or generator shedding, generator boosting, HVDC-set-point change, gas turbine start up and so on. Very often SAPFRC is used in combination with a low frequency signal, especially in smaller power systems, where loss of a fairly large generator will require quick remedial actions to secure the power system integrity. In such situations load shedding actions are required at a rather high frequency level, but in combination with a large negative rate-of-change of frequency the underfrequency protection can be used at a rather high setting.

10.3.3 Setting guidelines

The parameters for Rate-of-change frequency protection SAPFRC are set via the local HMI or through the Protection and Control Manager (PCM600).

All the frequency and voltage magnitude conditions in the system where SAPFRC performs its functions should be considered. The same also applies to the associated equipment, its frequency and time characteristic.

There are two application areas for SAPFRC:

1. to protect equipment against damage due to high or too low frequency, such as generators, transformers, and motors
2. to protect a power system, or a part of a power system, against breakdown by shedding load or generation, in situations where load and generation are not in balance.

SAPFRC is normally used together with an overfrequency or underfrequency function, in small power systems, where a single event can cause a large imbalance between load and generation. In such situations load or generation shedding has to take place very quickly, and there might not be enough time to wait until the frequency signal has reached an abnormal value. Actions are therefore taken at a frequency level closer to the primary nominal level, if the rate-of-change frequency is large (with respect to sign).

The start value for SAPFRC is set in Hz/s. All voltage magnitude related settings are made as a percentage of a settable base voltage, which normally is set to the primary nominal voltage level (phase-phase) of the power system or the high voltage equipment under consideration.

SAPFRC is not instantaneous, since the function needs some time to supply a stable value. It is recommended to have a time delay long enough to take care of signal noise. However, the time, rate-of-change frequency and frequency steps between different actions might be critical, and sometimes a rather short operation time is required, for example, down to 70 ms.

Smaller industrial systems might experience rate-of-change frequency as large as 5 Hz/s, due to a single event. Even large power systems may form small islands with a large imbalance between load and generation, when severe faults (or combinations of faults) are cleared - up to 3 Hz/s has been experienced when a small island was isolated from a large system. For more "normal" severe disturbances in large power systems, rate-of-change of frequency is much less, most often just a fraction of 1.0 Hz/s.

Section 11 Secondary system supervision

11.1 Current circuit supervision CCSSPVC

11.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Current circuit supervision	CCSSPVC	-	87

11.1.2 Application

Open or short circuited current transformer cores can cause unwanted operation of many protection functions such as differential, earth-fault current and negative-sequence current functions. When currents from two independent three-phase sets of CTs, or CT cores, measuring the same primary currents are available, reliable current circuit supervision can be arranged by comparing the currents from the two sets. If an error in any CT circuit is detected, the protection functions concerned can be blocked and an alarm given.

In case of large currents, unequal transient saturation of CT cores with different remanence or different saturation factor may result in differences in the secondary currents from the two CT sets. Unwanted blocking of protection functions during the transient stage must then be avoided.

Current circuit supervision CCSSPVC must be sensitive and have short operate time in order to prevent unwanted tripping from fast-acting, sensitive numerical protections in case of faulty CT secondary circuits.



Open CT circuits creates extremely high voltages in the circuits which is extremely dangerous for the personnel. It can also damage the insulation and cause new problems. The application shall, thus, be done with this in consideration, especially if the protection functions are blocked.

11.1.3 Setting guidelines

GlobalBaseSel: Selects the global base value group used by the function to define *IBase*, *UBase* and *SBase*. Note that this function will only use *IBase* value.

Current circuit supervision CCSSPVC compares the residual current from a three-phase set of current transformer cores with the neutral point current on a separate input taken from another set of cores on the same current transformer.

IMinOp: It must be set as a minimum to twice the residual current in the supervised CT circuits under normal service conditions and rated primary current.

Ip>Block: It is normally set at 150% to block the function during transient conditions.

The FAIL output is connected to the blocking input of the protection function to be blocked at faulty CT secondary circuits.

11.2 Fuse failure supervision FUFSPVC

11.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Fuse failure supervision	FUFSPVC	-	-

11.2.2 Application

Different protection functions within the protection IED, operates on the basis of the measured voltage in the relay point. Examples are:

- impedance protection functions
- undervoltage function
- energizing check function and voltage check for the weak infeed logic

These functions can operate unintentionally if a fault occurs in the secondary circuits between the voltage instrument transformers and the IED.

It is possible to use different measures to prevent such unwanted operations. Miniature circuit breakers in the voltage measuring circuits should be located as close as possible to the voltage instrument transformers, and shall be equipped with auxiliary contacts that are wired to the IEDs. Separate fuse-failure monitoring IEDs or elements within the protection and monitoring devices are another possibilities. These solutions are combined to get the best possible effect in the fuse failure supervision function (FUFSPVC).

FUFSPVC function built into the IED products can operate on the basis of external binary signals from the miniature circuit breaker or from the line disconnector. The first case influences the operation of all voltage-dependent functions while the second one does not affect the impedance measuring functions.

The negative sequence detection algorithm, based on the negative-sequence measuring quantities is recommended for use in isolated or high-impedance earthed networks: a high value of voltage $3U_2$ without the presence of the negative-sequence current $3I_2$ is a condition that is related to a fuse failure event.

The zero sequence detection algorithm, based on the zero sequence measuring quantities is recommended for use in directly or low impedance earthed networks: a high value of voltage $3U_0$ without the presence of the residual current $3I_0$ is a condition that is related to a fuse failure event. In cases where the line can have a weak-infeed of zero sequence current this function shall be avoided.

A criterion based on delta current and delta voltage measurements can be added to the fuse failure supervision function in order to detect a three phase fuse failure. This is beneficial for example during three phase transformer switching.

11.2.3 Setting guidelines

11.2.3.1 General

The negative and zero sequence voltages and currents always exist due to different non-symmetries in the primary system and differences in the current and voltage instrument transformers. The minimum value for the operation of the current and voltage measuring elements must always be set with a safety margin of 10 to 20%, depending on the system operating conditions.

Pay special attention to the dissymmetry of the measuring quantities when the function is used on long untransposed lines, on multicircuit lines and so on.

The settings of negative sequence, zero sequence and delta algorithm are in percent of the base voltage and base current for the function. Common base IED values for primary current (I_{Base}), primary voltage (U_{Base}) and primary power (S_{Base}) are set in Global Base Values $GBASVAL$. The setting $GlobalBaseSel$ is used to select a particular $GBASVAL$ and used its base values.

11.2.3.2 Setting of common parameters

Set the operation mode selector *Operation* to *On* to release the fuse failure function.

The voltage threshold $U_{Sealln}<$ is used to identify low voltage condition in the system. Set $U_{Sealln}<$ below the minimum operating voltage that might occur during emergency conditions. We propose a setting of approximately 70% of U_{Base} .

The drop off time of 200 ms for dead phase detection makes it recommended to always set *Sealln* to *On* since this will secure a fuse failure indication at persistent fuse fail when closing the local breaker when the line is already energized from the other end. When the remote breaker closes the voltage will return except in the phase that has a persistent fuse fail. Since the local breaker is open there is no current and the dead phase indication will persist in the phase with the blown fuse. When the local breaker closes the current will start to flow and the function detects the fuse failure situation. But due to the 200 ms drop off timer the output BLKZ will not be activated until after 200 ms. This means that distance functions are not blocked and due to the “no voltage but current” situation might issue a trip.

The operation mode selector *OpMode* has been introduced for better adaptation to system requirements. The mode selector enables selecting interactions between the negative sequence and zero sequence algorithm. In normal applications, the *OpMode* is set to either *UNsINs* for selecting negative sequence algorithm or *UZsIZs* for zero sequence based algorithm. If system studies or field experiences shows that there is a risk that the fuse failure function will not be activated due to the system conditions, the dependability of the fuse failure function can be increased if the *OpMode* is set to *UZsIZs OR UNsINs* or *OptimZsNs*. In mode *UZsIZs OR UNsINs* both negative and zero sequence based algorithms are activated and working in an OR-condition. Also in mode *OptimZsNs* both negative and zero sequence algorithms are activated and the one that has the highest magnitude of measured negative or zero sequence current will operate. If there is a requirement to increase the security of the fuse failure function *OpMode* can be selected to *UZsIZs AND UNsINs* which gives that both negative and zero sequence algorithms are activated and working in an AND-condition, that is, both algorithms must give condition for block in order to activate the output signals BLKU or BLKZ.

11.2.3.3 Negative sequence based

The relay setting value $3U2>$ is given in percentage of the base voltage U_{Base} and should not be set lower than the value that is calculated according to equation [128](#).

$$3U2 \geq \frac{U_2}{U_{Base}/\sqrt{3}} \cdot 100$$

(Equation 128)

where:

U_2 is the maximal negative sequence voltage during normal operation conditions, plus a margin of 10...20%

U_{Base} is the base voltage for the function according to the setting *GlobalBaseSel*

The setting of the current limit $3I2<$ is in percentage of parameter I_{Base} . The setting of $3I2<$ must be higher than the normal unbalance current that might exist in the system and can be calculated according to equation [129](#).

$$3I2 \leq \frac{I2}{I_{Base}} \cdot 100$$

(Equation 129)

where:

$I2$ is the maximal negative sequence current during normal operating conditions, plus a margin of 10...20%

I_{Base} is the base current for the function according to the setting *GlobalBaseSel*

11.2.3.4 Zero sequence based

The IED setting value $3U0>$ is given in percentage of the base voltage U_{Base} . The setting of $3U0>$ should not be set lower than the value that is calculated according to equation [130](#).

$$3U0 \geq \frac{3U0}{U_{Base} / \sqrt{3}} \cdot 100$$

(Equation 130)

where:

$3U0$ is the maximal zero sequence voltage during normal operation conditions, plus a margin of 10...20%

U_{Base} is the base voltage for the function according to the setting *GlobalBaseSel*

The setting of the current limit $3I0<$ is done in percentage of I_{Base} . The setting of $3I0<$ must be higher than the normal unbalance current that might exist in the system. The setting can be calculated according to equation [131](#).

$$3I0 \leq \frac{3I0}{I_{Base}} \cdot 100$$

(Equation 131)

where:

$3I0<$ is the maximal zero sequence current during normal operating conditions, plus a margin of 10...20%

I_{Base} is the base current for the function according to the setting *GlobalBaseSel*

11.2.3.5 Delta U and delta I

Set the operation mode selector *OpDUDI* to *On* if the delta function shall be in operation.

The setting of $DU>$ should be set high (approximately 60% of U_{Base}) and the current threshold $DI<$ low (approximately 10% of I_{Base}) to avoid unwanted operation due to normal switching conditions in the network. The delta current and delta voltage function shall always be used together with either the negative or zero sequence algorithm. If $U_{Set_{prim}}$ is the primary voltage for operation of dU/dt and $I_{Set_{prim}}$ the primary current for operation of dI/dt , the setting of $DU>$ and $DI<$ will be given according to equation [132](#) and equation [133](#).

$$DU \geq \frac{U_{Set_{prim}}}{U_{Base}} \cdot 100$$

(Equation 132)

$$DI \leq \frac{I_{Set_{prim}}}{I_{Base}} \cdot 100$$

(Equation 133)

The voltage thresholds $UPh>$ is used to identify low voltage condition in the system. Set $UPh>$ below the minimum operating voltage that might occur during emergency conditions. A setting of approximately 70% of $UBase$ is recommended.

The current threshold $IPh>$ shall be set lower than the $IMinOp$ for the distance protection function. A 5...10% lower value is recommended.

11.2.3.6 Dead line detection

The condition for operation of the dead line detection is set by the parameters $IDLD<$ for the current threshold and $UDLD<$ for the voltage threshold.

Set the $IDLD<$ with a sufficient margin below the minimum expected load current. A safety margin of at least 15-20% is recommended. The operate value must however exceed the maximum charging current of an overhead line, when only one phase is disconnected (mutual coupling to the other phases).

Set the $UDLD<$ with a sufficient margin below the minimum expected operating voltage. A safety margin of at least 15% is recommended.

11.3 Voltage based delta supervision DELVSPVC

11.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Voltage based delta supervision	DELVSPVC	—	7V_78V

11.3.2 Application

In a weak grid networks, fault detection and operation of other protection functions is reliably done by delta supervision functionality. In this type of network, a delta based release criteria is used to release the trip signal. The measurement of delta differs from country to country between magnitude, vector or sample based detection.

In this function, a voltage based delta supervision is implemented in a phase segregated design. The delta function has the following features:

- Instantaneous sample based delta detection
- True RMS value based delta detection
- DFT magnitude based delta detection
- Vector shift protection

The Delta detection mode is selected on the basis of application requirements. For example, Instantaneous sample based delta supervision is very fast; the delta is detected in less than a cycle typically. Hence, instantaneous sample based delta supervision can be used for functions that are used as protection enablers or fault detectors

All the other supervision modes like RMS/DFT Mag or Angle requires minimum one cycle for delta detection and can be used for time delay functions.

Angle shift mode

Use of distributed generation (DG) units is increasing due to liberalized markets (deregulation) and the global trend to use more renewable sources of energy. They generate power in the range of 10 kW to 10 MW and most of them are interconnected to the distribution network. They can supply

power into the network as well as to the local loads. It is not common to connect generators directly to the distribution networks and thus the distributed generation can cause some challenges for the protection of distribution networks. From the protection point of view, one of the most challenging issue is islanding.

Islanding is defined as a condition in which a distributed generation unit continues to supply power to a certain part of the distribution network when power from the larger utility main grid is no longer available after opening of a circuit-breaker.

Islanding is also referred as Loss of Mains (LOM) or Loss of Grid (LOG). When LOM occurs, neither the voltage nor the frequency is controlled by the utility supply. Also, these distributed generators are not equipped with voltage and frequency control; therefore, the voltage magnitude of an islanded network may not be kept within the desired limits resulting into undefined voltage magnitudes during islanding situations and frequency instability. Further, uncontrolled frequency represents a high risk for drives and other machines.

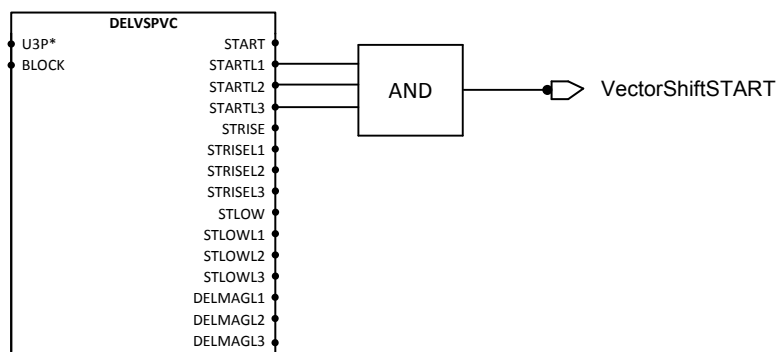
Islanding can occur as a consequence of :

- a fault in the network
- circuit-breaker maloperation
- circuit-breaker opening during maintenance

If the distributed generator continues its operation after the utility supply is disconnected, faults do not clear under certain conditions as the arc is charged by the distributed generators. Moreover, the distributed generators are incompatible with the current reclosing practices. During the reclosing sequence dead time, the generators in the network usually tend to drift out of synchronism with the grid and, reconnecting them without synchronizing may damage the generators introducing high currents and voltages in the neighbouring network.

Due to the technical difficulties mentioned above, protection should be provided, which disconnects the distributed generation once it is electrically isolated from the main grid supply. Various techniques are used for detecting Loss of Mains. However, the present feature of voltage supervision focuses on voltage vector shift.

For islanding based on vector shift protection, the logic shown in Figure 105 should be used to trip the breaker. With this logic, reliable tripping can be ensured as angle shift has been detected in all the three phase voltages.



IEC18000903-1-en.vsdX

Figure 105: DELVSPVC connection diagram

The vector shift detection guarantees fast and reliable detection of mains failure in almost all operational conditions when a distributed generation unit is running in parallel with the mains supply, but in certain cases this may fail.

If the active and reactive power generated by the distributed generation units is nearly balanced (for example, if the power mismatch or unbalance is less than 5...10%) with the active and reactive power consumed by loads, a large enough voltage phase shift may not occur which can be detected by the

vector shift algorithm. This means that the vector shift algorithm has a small non-detection zone (NDZ) which is also dependent on the type of generators, loads, network and start or operate value of the vector shift algorithm.

Other network events like capacitor switching, switching of very large loads in weak network or connection of parallel transformer at HV/MV substation, in which the voltage magnitude is not changed considerably (unlike in faults) can potentially cause maloperation of vector shift algorithm, if very sensitive settings are used.

The vector shift detection also protects synchronous generators from damaging due to islanding or loss-of-mains.

11.3.3 Setting guidelines

Operation: To enable/disable the delta supervision function.

Umin: The minimum start level setting should be set as % of *UBase*. This setting enables the function to start detecting delta. Typical setting is 10% of *UBase*. If the *MeasMode* setting is set as *phase to ground*, this setting is taken as 50% of the set value.

MeasMode: To detect the mode of measurement; *phase to phase* or *phase to ground*.

OpMode: To select the mode of operation. For protection applications, this should be set to *Instantaneous 1 cycle old*. Load supervision can be done using vector shift mode or DFT mag mode.

DeIU>: To detect the start value for instantaneous sample, RMS, DFT mag based delta detection. Set a typical value of 50% of *UBase* to use this function as fault detection.

DeIUang>: This setting is used for angle based delta detection. This setting could be used to detect islanding condition. A typical setting of 8-10 deg. is good to detect a major islanding condition.

DeltaT: This setting defines the number of old cycles data to be used for delta calculation in RMS/DFT Mag and angle mode. Typical value is 2 cycles. This value is not used if *OpMode* is chosen as instantaneous 1 cycle or instantaneous 2 cycle.

tHold: This setting defines the pulse length for supervision start signal. Typical value is 100 ms.

11.4 Current based delta supervision DELISPVC

11.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Current based delta supervision	DELISPVC	—	71 < >

11.4.2 Application

In power system networks, fault detection and operation of other protection functions is reliably done by delta supervision functionality. Single phase networks are an important application of delta supervision. In this type of network, a delta based release criteria is used to release the protection function. The measurement of delta differs from country to country between magnitude, vector or sample based detection.

In this function, a current based delta supervision is implemented in a phase segregated design. The delta function has the following features:

- Instantaneous sample based delta detection (vectorial delta)
- True RMS value based delta detection
- DFT magnitude based delta detection
- 2nd harmonic blocking of delta function
- 3rd harmonic based adaption of starting value

Instantaneous sample based delta supervision is very fast; the delta is detected in less than a cycle typically. This mode can be used for high impedance earth fault detection. All the other supervision modes like RMS/DFT Mag requires minimum one cycle for delta detection.

Therefore, the choice of delta detection mode should be based on the application requirement. Instantaneous sample based delta supervision can be used for functions that are used as protection enabler or fault detector. For time delayed functions, other modes can be used. Current based function can be used for load supervision also in DFT Mag based delta mode.

11.4.3 Setting guidelines

Operation: To enable/disable the delta supervision function.

I_{min}: The minimum start level setting should be set as % of *I_{Base}*. This setting enables the function to start detecting delta. Typical setting is 10% of *I_{Base}*.

MeasMode: To detect the mode of measurement; *phase to phase* or *phase to ground*.

OpMode: To select the mode of operation. For protection applications, this should be set to *Instantaneous 1 cycle old*. Load supervision can be done using DFT mag mode.

Dell>: To detect the start value for instantaneous sample, RMS, DFT mag based delta detection. Set a typical value of 200% of *I_{Base}* to use this function as fault detection.

DeltaT: This setting defines the number of old cycles data to be used for delta calculation in RMS/DFT Mag mode. Typical value is 2 cycles.

tHold: This setting defines the pulse length for supervision start signal. Typical value is 100 ms.

EnaHarm2Blk: This setting should be set to ON, to enable blocking for heavy inrush currents or other sources of 2nd harmonic injections.

Harm2BlkLev: This is the blocking level of 2nd harmonic with respect to the fundamental signal. Typical setting is 15% of fundamental signal.

EnStValAdap: This setting should be set to ENABLE in special networks where settings in the network are adapted with respect to 3rd harmonic level.

Harm3Level: This is the set level of 3rd harmonic with respect to fundamental signal at which the *Dell>* should be modified. Typical setting is 15% of fundamental signal.

StValGrad: To modify the *Dell>* based on 3rd harmonic level. Typical setting is 10% to modify the *Dell>*.

11.5 Delta supervision of real input DELSPVC

11.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Delta supervision of real input	DELSPVC	–	–

11.5.2 Application

Delta supervision of real input DELSPVC is a general processed input delta supervision. It is used to configure any processed inputs such as:

- Power (S)
- Active power (P)
- Reactive power (P)
- Thermal heat content (ϕ)
- Energy

The change over time of these quantities with respect to the old value can be supervised with this function.

11.5.3 Setting guidelines

Operation: To enable/disable the delta supervision function.

MinStVal: The minimum start level of the function. If the input is below this level, the function will be blocked. It should be set depending on the input connected.

De/St>: To set the start value for delta detection.

DeltaT: This setting defines the number of execution cycles of old data to be used for delta calculation. That is, if *DeltaT* setting is set as 6 for a 3 ms function, an 18 ms old value will be used to compare the change against.

tHold: This setting defines the pulse length for the start signal. A typical value of this setting is 100 ms.



Please ensure that the value provided for *De/St>* should be dependent on the input signal connected. For example, in case of temperature, the set value can be in the range of -40 to 200 degrees. If the value monitored is current, then it can be in the range of few hundreds to thousand amperes. Similarly, appropriate value needs to be provided depending on the input as there is a possibility of continuous triggering of the output if the set value is much below the normal range of variation in the input.

Section 12 Control

12.1 Synchrocheck, energizing check, and synchronizing SESRSYN

12.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Synchrocheck, energizing check, and synchronizing	SESRSYN	sc/vc	25

12.1.2 Application

12.1.2.1 Synchronizing

To allow closing of breakers between asynchronous networks, a synchronizing feature is provided. The breaker close command is issued at the optimum time when conditions across the breaker are satisfied in order to avoid stress on the network and its components.

The systems are defined as asynchronous when the frequency difference between bus and line is larger than an adjustable parameter. If the frequency difference is less than this threshold value the system is defined to have a parallel circuit and the synchrocheck function is used.

The synchronizing function measures the difference between the U-Line and the U-Bus. It operates and enables a closing command to the circuit breaker when the calculated closing angle is equal to the measured phase angle and the following conditions are simultaneously fulfilled:

- The voltages U-Line and U-Bus are higher than the set values for *UHighBusSynch* and *UHighLineSynch* of the respective base voltages *GblBaseSelBus* and *GblBaseSelLine*.
- The difference in the voltage is smaller than the set value of *UDiffSynch*.
- The difference in frequency is less than the set value of *FreqDiffMax* and larger than the set value of *FreqDiffMin*. If the frequency is less than *FreqDiffMin* the synchrocheck is used and the value of *FreqDiffMin* must thus be identical to the value *FreqDiffM* resp *FreqDiffA* for synchrocheck function. The bus and line frequencies must also be within a range of ± 5 Hz from the rated frequency. When the synchronizing option is included also for autoreclose there is no reason to have different frequency setting for the manual and automatic reclosing and the frequency difference values for synchronism check should be kept low.
- The frequency rate of change is less than set value for both U-Bus and U-Line.
- The difference in the phase angle is smaller than the set value of *CloseAngleMax*.
- The closing angle is decided by the calculation of slip frequency and required pre-closing time.

The synchronizing function compensates for the measured slip frequency as well as the circuit breaker closing delay. The phase angle advance is calculated continuously. The calculation of the operation pulse sent in advance is using the measured *SlipFrequency* and the set *tBreaker* time. To prevent incorrect closing pulses, a maximum closing angle between bus and line is set with *CloseAngleMax*. To minimize the moment stress when synchronizing near a power station, a narrower limit for the *CloseAngleMax* needs to be used.

When setting the value for *tBreaker* the following should be considered:

- The closing time of contact on a Binary Out Module (BOM) is appr.4ms and on a Static Output Module (SOM) appr. 1ms.
- The operating time of any auxilliary relays in the closing circuit.
- Mechanical closing time of the breaker primary contacts.

The setting *CloseAngleMax* is only a limitation under which which combination of the SlipFrequency and CB closing time the Synchronizing feature is capable to operate.

Theoretically the following equation is valid for the Synchronizing feature:

$$\text{SlipFrequency[Hz]} * t_{\text{Breaker[s]}} < \text{CloseAngleMax[deg]} / 360$$

For example, when *CloseAngleMax* = 30 deg. and *tBreaker* = 0.1 s then the Synchronizing feature can handle up to 0.833 Hz as shown below:

$$\text{SlipFrequency[Hz]} < (30 / 360) / 0.1 = 0.833 \text{ Hz}$$

[Figure 106](#) below shows the dependencies between *tBreaker* and slip frequency for the SYNOK release with *CloseAngleMax* set to 15 or 30 degrees.

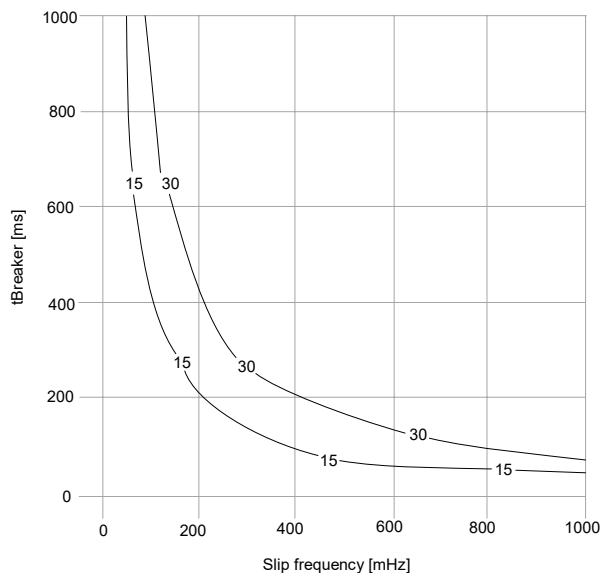


Figure 106: Dependencies between *tBreaker* and Slip frequency with different *CloseAngleMax* values

The reference voltage can be phase-neutral L1, L2, L3 or phase-phase L1-L2, L2-L3, L3-L1 or positive sequence (Require a three phase voltage, that is UL1, UL2 and UL3) . By setting the phases used for SESRSYN, with the settings *SelPhaseBus1*, *SelPhaseBus2*, *SelPhaseLine2* and *SelPhaseLine2*, a compensation is made automatically for the voltage amplitude difference and the phase angle difference caused if different setting values are selected for the two sides of the breaker. If needed an additional phase angle adjustment can be done for selected line voltage with the *PhaseShift* setting.



Some restrictions when using CBConfig selections 1½ bus CB, 1½ bus alt.CB and Tie CB are described in table *Restrictions for CBConfig settings* in the Technical manual. Such restriction are applicable only when a power transformer is connected in the diameter and VT used for synchrocheck function is located on the other side of the transformer.

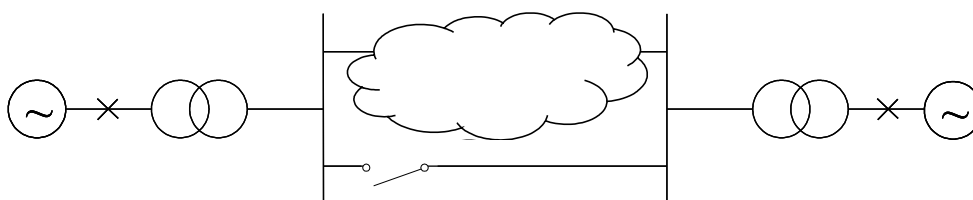
12.1.2.2 Synchrocheck

The main purpose of the synchrocheck function is to provide control over the closing of circuit breakers in power networks in order to prevent closing if conditions for synchronism are not detected. It is also used to prevent the re-connection of two systems, which are divided after islanding and after a three pole reclosing.



Single pole auto-reclosing does not require any synchrocheck since the system is tied together by two phases.

SESRYSYN function block includes both the synchrocheck function and the energizing function to allow closing when one side of the breaker is dead. SESRSYN function also includes a built in voltage selection scheme which allows adoption to various busbar arrangements.



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Figure 107: Two interconnected power systems

Figure 107 shows two interconnected power systems. The cloud means that the interconnection can be further away, that is, a weak connection through other stations. The need for a check of synchronization increases if the meshed system decreases since the risk of the two networks being out of synchronization at manual or automatic closing is greater.

The synchrocheck function measures the conditions across the circuit breaker and compares them to set limits. Output is generated only when all measured conditions are within their set limits simultaneously. The check consists of:

- Live line and live bus.
- Voltage level difference.
- Frequency difference (slip). The bus and line frequency must also be within a range of ± 5 Hz from rated frequency.
- Phase angle difference.

A time delay is available to ensure that the conditions are fulfilled for a minimum period of time.

In very stable power systems the frequency difference is insignificant or zero for manually initiated closing or closing by automatic restoration. In steady conditions a bigger phase angle difference can be allowed as this is sometimes the case in a long and loaded parallel power line. For this application we accept a synchrocheck with a long operation time and high sensitivity regarding the frequency difference. The phase angle difference setting can be set for steady state conditions.

Another example is the operation of a power network that is disturbed by a fault event: after the fault clearance a highspeed auto-reclosing takes place. This can cause a power swing in the net and the phase angle difference may begin to oscillate. Generally, the frequency difference is the time derivative of the phase angle difference and will, typically oscillate between positive and negative values. When the circuit breaker needs to be closed by auto-reclosing after fault-clearance some frequency difference should be tolerated, to a greater extent than in the steady condition mentioned in the case above. But if a big phase angle difference is allowed at the same time, there is some risk that auto-reclosing will take place when the phase angle difference is big and increasing. In this case it should be safer to close when the phase angle difference is smaller.

To fulfill the above requirements the synchrocheck function is provided with duplicate settings, one for steady (Manual) conditions and one for operation under disturbed conditions (Auto).

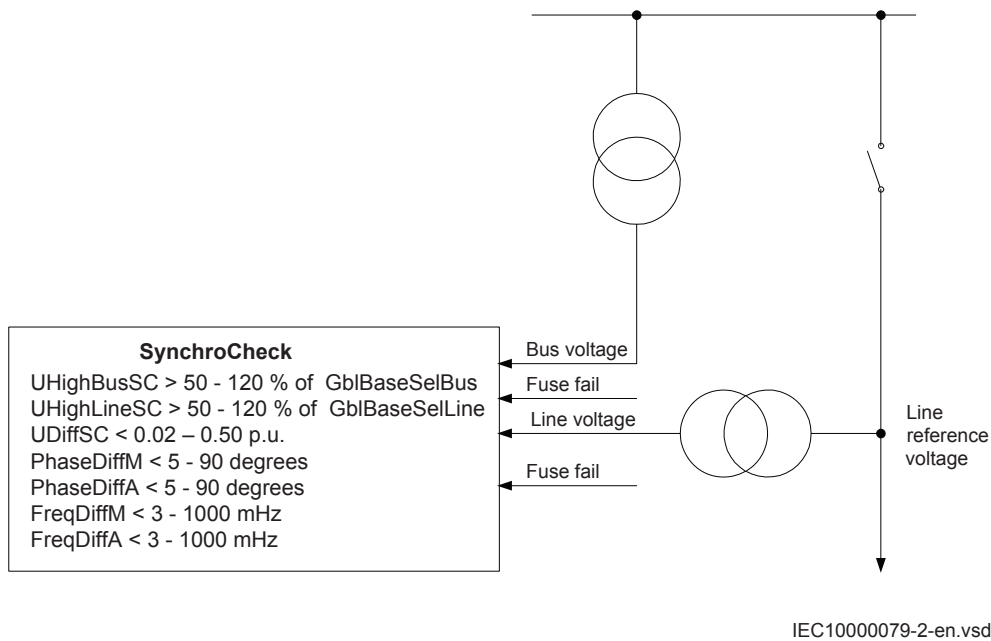


Figure 108: Principle for the synchrocheck function

12.1.2.3 Energizing check

The main purpose of the energizing check function is to facilitate the controlled re-connection of disconnected lines and buses to energized buses and lines.

The energizing check function measures the bus and line voltages and compares them to both high and low threshold values. The output is given only when the actual measured conditions match the set conditions. Figure 109 shows two substations, where one (1) is energized and the other (2) is not energized. The line between CB A and CB B is energized (DLLB) from substation 1 via the circuit breaker A and energization of station 2 is done by CB B energization check device for that breaker DBLL. (or Both).

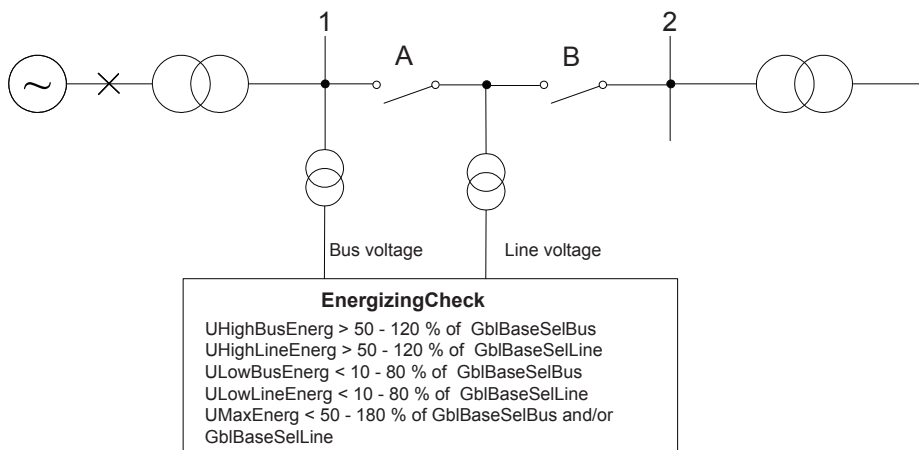


Figure 109: Principle for the energizing check function

The energizing operation can operate in the dead line live bus (DLLB) direction, dead bus live line (DBLL) direction, or in both directions over the circuit breaker. Energizing from different directions can be different for automatic reclosing and manual closing of the circuit breaker. For manual closing

it is also possible to allow closing when both sides of the breaker are dead, Dead Bus Dead Line (DBDL).

The equipment is considered energized (Live) if the voltage is above the set value for *UHighBusEnerg* or *UHighLineEnerg* of the base voltages *GblBaseSelBus* and *GblBaseSelLine*, which are defined in the Global Base Value groups; in a similar way, the equipment is considered non-energized (Dead) if the voltage is below the set value for *ULowBusEnerg* or *ULowLineEnerg* of the respective Global Base Value groups. A disconnected line can have a considerable potential due to factors such as induction from a line running in parallel, or feeding via extinguishing capacitors in the circuit breakers. This voltage can be as high as 50% or more of the base voltage of the line. Normally, for breakers with single breaking elements (<330 kV) the level is well below 30%.

When the energizing direction corresponds to the settings, the situation has to remain constant for a certain period of time before the close signal is permitted. The purpose of the delayed operate time is to ensure that the dead side remains de-energized and that the condition is not due to temporary interference.

12.1.2.4 Voltage selection

The voltage selection function is used for the connection of appropriate voltages to the synchrocheck, synchronizing and energizing check functions. For example, when the IED is used in a double bus arrangement, the voltage that should be selected depends on the status of the breakers and/or disconnectors. By checking the status of the disconnectors auxiliary contacts, the right voltages for the synchronizing, synchrocheck and energizing check functions can be selected.

Available voltage selection types are for single circuit breaker with double busbars. Single circuit breaker with a single busbar do not need any voltage selection function. Neither does a single circuit breaker with double busbars using external voltage selection need any internal voltage selection.

The voltages from busbars and lines must be physically connected to the voltage inputs in the IED and connected, using the PCM software, to each of the SESRSYN functions available in the IED.

12.1.2.5 External fuse failure

Either external fuse failure signals or signals from a tripped fuse (or miniature circuit breaker) are connected to HW binary inputs of the IED; these signals are connected to inputs of SESRSYN function in the application configuration tool of PCM600. The internal fuse failure supervision function can also be used if a three phase voltage is present. The signal BLKU, from the internal fuse failure supervision function, is then used and connected to the fuse supervision inputs of the SESRSYN function block. In case of a fuse failure, the SESRSYN energizing function is blocked.

The UB1OK/UB2OK and UB1FF/UB2FF inputs are related to the busbar voltage and the ULN1OK/ULN2OK and ULN1FF/ULN2FF inputs are related to the line voltage.

External selection of energizing direction

The energizing can be selected by use of the available logic function blocks. Below is an example where the choice of mode is done from a symbol, created in the Graphical Design Editor (GDE) tool on the local HMI, through selector switch function block, but alternatively there can for example, be a physical selector switch on the front of the panel which is connected to a binary to integer function block (B16I).

If the PSTO input is used, connected to the Local-Remote switch on the local HMI, the choice can also be from the station HMI system, typically Hitachi Energy Microscada through IEC 61850–8–1 communication.

The connection example for selection of the manual energizing mode is shown in figure 110. Selected names are just examples but note that the symbol on the local HMI can only show the active position of the virtual selector.

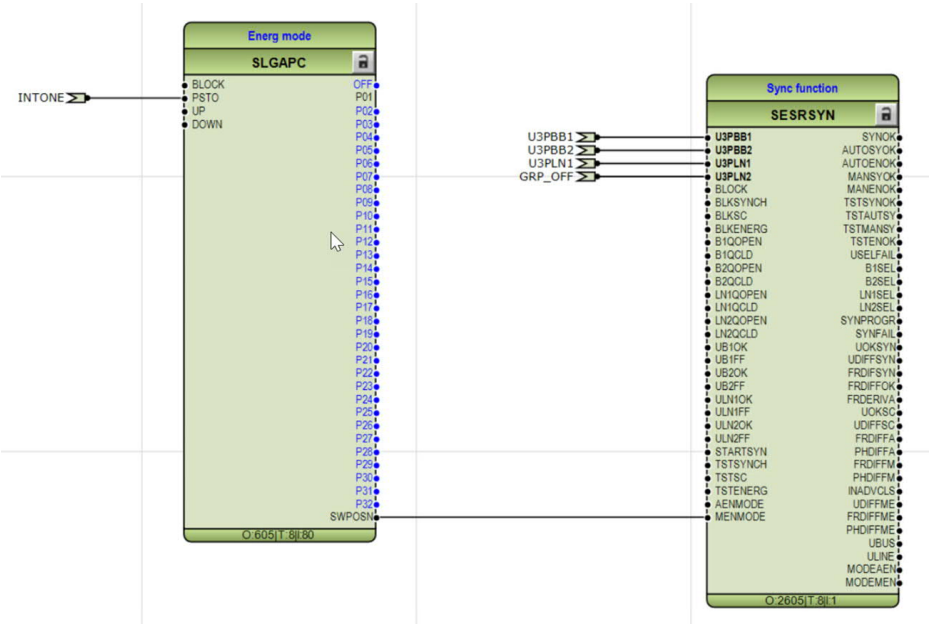


Figure 110: Selection of the energizing direction from a local HMI symbol through a selector switch function block.

12.1.3 Application examples

The synchronizing function block can also be used in some switchyard arrangements, but with different parameter settings. Below are some examples of how different arrangements are connected to the IED analogue inputs and to the function block SESRSYN. One function block is used per circuit breaker.



The input used below in example are typical and can be changed by use of configuration and signal matrix tools.



The SESRSYN and connected SMAI function block instances must have the same cycle time in the application configuration.

12.1.3.1 Single circuit breaker with single busbar

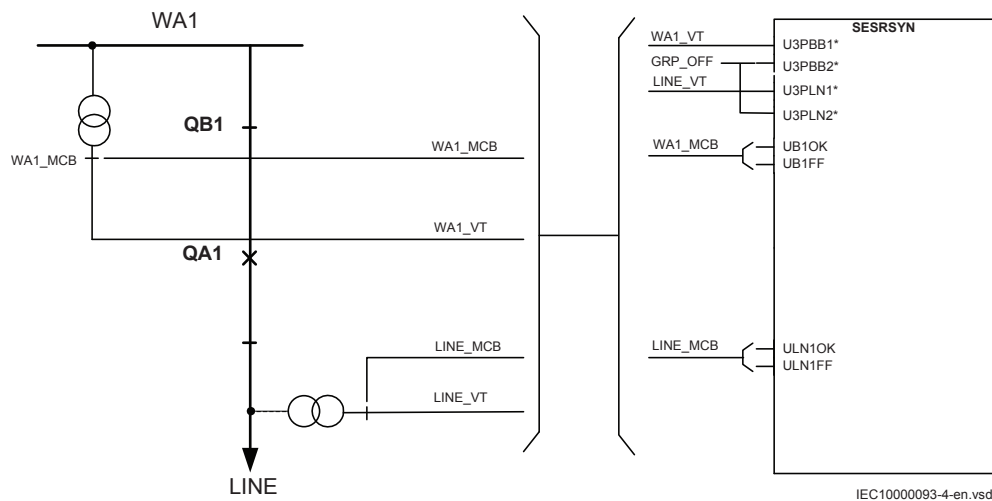


Figure 111: Connection of SESRSYN function block in a single busbar arrangement

Figure 111 illustrates connection principles for a single busbar. For the SESRSYN function there is one voltage transformer on each side of the circuit breaker. The voltage transformer circuit connections are straightforward; no special voltage selection is necessary.

The voltage from busbar VT is connected to U3PBB1 and the voltage from the line VT is connected to U3PLN1. The conditions of the VT fuses shall also be connected as shown above. The voltage selection parameter *CBConfig* is set to *No voltage sel.*

12.1.3.2 Single circuit breaker with double busbar, external voltage selection

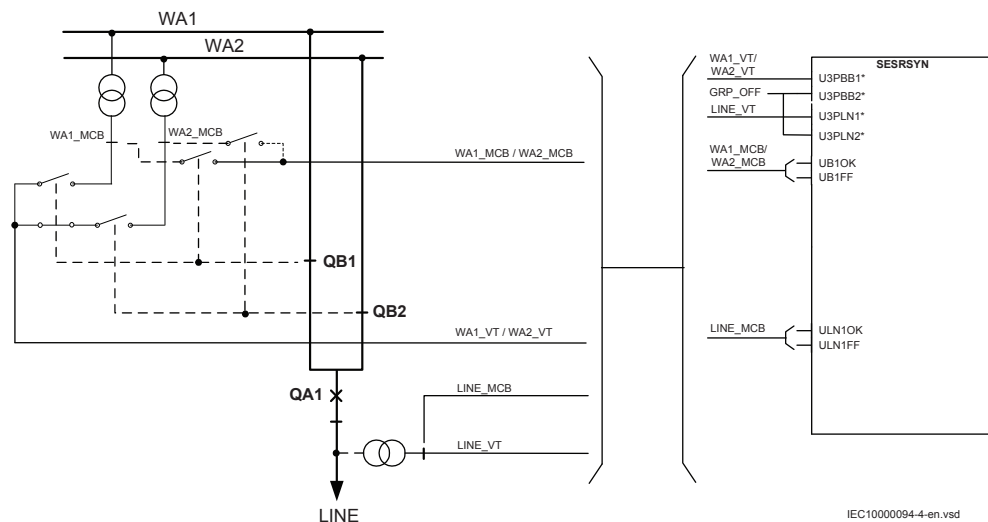


Figure 112: Connection of SESRSYN function block in a single breaker, double busbar arrangement with external voltage selection

In this type of arrangement no internal voltage selection is required. The voltage selection is made by external relays typically connected according to figure 112. Suitable voltage and VT fuse failure supervision from the two busbars are selected based on the position of the busbar disconnectors. This means that the connections to the function block will be the same as for the single busbar arrangement. The voltage selection parameter *CBConfig* is set to *No voltage sel.*

12.1.3.3 Single circuit breaker with double busbar, internal voltage selection

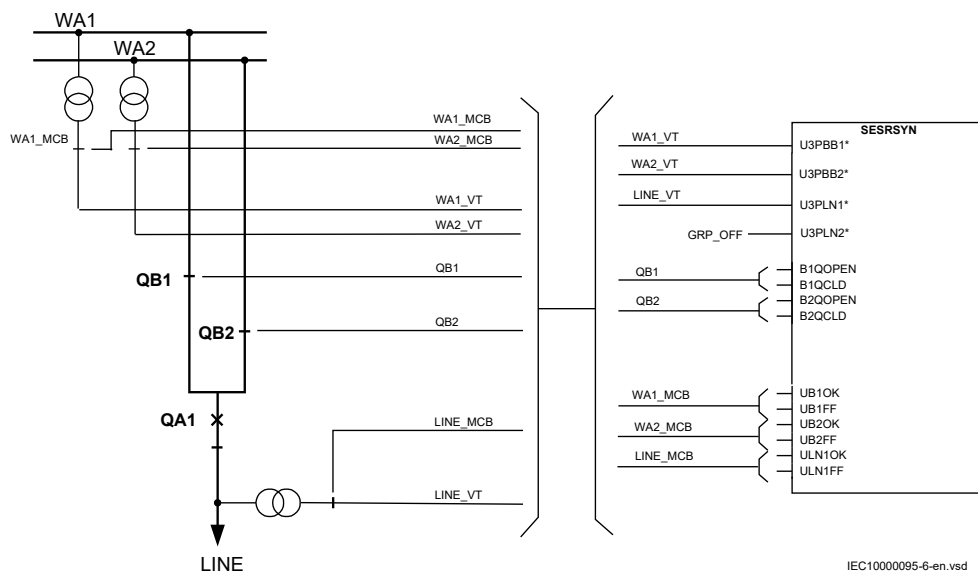


Figure 113: Connection of the SESRSYN function block in a single breaker, double busbar arrangement with internal voltage selection

When internal voltage selection is needed, the voltage transformer circuit connections are made according to figure 113. The voltage from the busbar 1 VT is connected to U3PBB1 and the voltage from busbar 2 is connected to U3PBB2. The voltage from the line VT is connected to U3PLN1. The positions of the disconnectors and VT fuses shall be connected as shown in figure 113. The voltage selection parameter *CBCConfig* is set to *Double bus*.

12.1.4 Setting guidelines

The setting parameters for the Synchronizing, synchrocheck and energizing check function SESRSYN are set via the local HMI (LHMI) or PCM600.

This setting guidelines describes the settings of the SESRSYN function via the LHMI.

Common base IED value for primary voltage (*UBase*) is set in a Global base value function, GBASVAL, found under **Main menu/Configuration/Power system/GlobalBaseValue/GBASVAL_X/UBase**. The SESRSYN function has one setting for the bus reference voltage (*GblBaseSelBus*) and one setting for the line reference voltage (*GblBaseSelLine*) which independently of each other can be set to select one of the twelve GBASVAL functions used for reference of base values. This means that the reference voltage of bus and line can be set to different values. The settings for the SESRSYN function are found under **Main menu/Settings/IED Settings/Control/Synchronizing(25,SC/VC)/SESRSYN(25,SC/VC):X** has been divided into four different setting groups: General, Synchronizing, Synchrocheck and Energizingcheck.

General settings

Operation: The operation mode can be set *On* or *Off*. The setting *Off* disables the whole function.

GblBaseSelBus and *GblBaseSelLine*

These configuration settings are used for selecting one of twelve GBASVAL functions, which then is used as base value reference voltage, for bus and line respectively.

SelPhaseBus1 and *SelPhaseBus2*

Configuration parameters for selecting the measuring phase of the voltage for busbar 1 and 2 respectively, which can be a single-phase (phase-neutral), two-phase (phase-phase) or a positive sequence voltage.

SelPhaseLine1 and SelPhaseLine2

Configuration parameters for selecting the measuring phase of the voltage for line 1 and 2 respectively, which can be a single-phase (phase-neutral), two-phase (phase-phase) or a positive sequence voltage.

CBConfig

This configuration setting is used to define type of voltage selection. Type of voltage selection can be selected as:

- no voltage selection, *No voltage sel.*
- single circuit breaker with double bus, *Double bus*
- 1 1/2 circuit breaker arrangement with the breaker connected to busbar 1, *1 1/2 bus CB*
- 1 1/2 circuit breaker arrangement with the breaker connected to busbar 2, *1 1/2 bus alt. CB*
- 1 1/2 circuit breaker arrangement with the breaker connected to line 1 and 2, *Tie CB*

PhaseShift

To compensate the phase shift between the measured bus voltage and line voltage when, for instance, a power transformer is connected between the bus VT and the line VT location.

Note that this set value is used to cause additional angle shift of the measured line voltage phasor. The measured bus voltage phasor is always taken as is (i.e. without any additional shifting).

Synchronizing settings

OperationSynch

The setting *Off* disables the Synchronizing function. With the setting *On*, the function is in the service mode and the output signal depends on the input conditions.

UHighBusSynch and UHighLineSynch

The voltage level settings shall be chosen in relation to the bus/line network voltage. The threshold voltages *UHighBusSynch* and *UHighLineSynch* have to be set lower than the value where the network is expected to be synchronized. A typical value is 80% of the rated voltage.

UDiffSynch

Setting of the voltage difference between the line voltage and the bus voltage. The difference is set depending on the network configuration and expected voltages in the two networks running asynchronously. A normal setting is 0.10-0.15 p.u.

FreqDiffMin

The setting *FreqDiffMin* is the minimum frequency difference where the systems are defined to be asynchronous. For frequency differences lower than this value, the systems are considered to be in parallel. A typical value for *FreqDiffMin* is 10 mHz. Generally, the value should be low if both synchronizing and synchrocheck functions are provided, and it is better to let the synchronizing function close, as it will close at exactly the right instance if the networks run with a frequency difference.



To avoid overlapping of the synchronizing function and the synchrocheck function the setting *FreqDiffMin* must be set to a higher value than used setting *FreqDiffM*, respective *FreqDiffA* used for synchrocheck.

FreqDiffMax

The setting *FreqDiffMax* is the maximum slip frequency at which synchronizing is accepted. $1/FreqDiffMax$ shows the time for the vector to move 360 degrees, one turn on the synchronoscope, and is called Beat time. A typical value for *FreqDiffMax* is 200-250 mHz, which gives beat times on 4-5 seconds. Higher values should be avoided as the two networks normally are regulated to nominal frequency independent of each other, so the frequency difference shall be small.

FreqRateChange

The maximum allowed rate of change for the frequency.

CloseAngleMax

The setting *CloseAngleMax* is the maximum closing angle between bus and line at which synchronizing is accepted. To minimize the moment stress when synchronizing near a power station, a narrower limit should be used. A typical value is 15 degrees.

tBreaker

The *tBreaker* shall be set to match the closing time for the circuit breaker and should also include the possible auxiliary relays in the closing circuit. It is important to check that no slow logic components are used in the configuration of the IED as there then can be big variations in closing time due to those components. Typical setting is 80-150 ms depending on the breaker closing time.

tClosePulse

The setting for the duration of the breaker close pulse.

tMaxSynch

The setting *tMaxSynch* is set to reset the operation of the synchronizing function if the operation does not take place within this time. The setting must allow for the setting of *FreqDiffMin*, which will decide how long it will take maximum to reach phase equality. At the setting of 10 mHz, the beat time is 100 seconds and the setting would thus need to be at least *tMinSynch* plus 100 seconds. If the network frequencies are expected to be outside the limits from the start, a margin needs to be added. A typical setting is 600 seconds.

tMinSynch

The setting *tMinSynch* is set to limit the minimum time at which the synchronizing closing attempt is given. The synchronizing function will not give a closing command within this time, from when the synchronizing is started, even if a synchronizing condition is fulfilled. A typical setting is 200 ms.

Synchrocheck settings

OperationSC

The *OperationSC* setting *Off* disables the synchrocheck function and sets the outputs AUTOSYOK, MANSYOK, TSTAUTSY and TSTMANSY to low. With the setting *On*, the function is in the service mode and the output signal depends on the input conditions.

UHighBusSC and *UHighLineSC*

The voltage level settings must be chosen in relation to the bus or line network voltage. The threshold voltages *UHighBusSC* and *UHighLineSC* have to be set lower than the value at which the breaker is expected to close with the synchronism check. A typical value can be 80% of the base voltages.

UDiffSC

The setting for voltage difference between line and bus in p.u. This setting in p.u. is defined as $(U_{Bus}/G_{b}/BaseSel_{Bus}) - (U_{Line}/G_{b}/BaseSel_{Line})$. A normal setting is 0,10-0,15 p.u.

FreqDiffM and FreqDiffA

The frequency difference level settings, *FreqDiffM* and *FreqDiffA*, shall be chosen depending on the condition in the network. At steady conditions a low frequency difference setting is needed, where the *FreqDiffM* setting is used. For autoreclosing a bigger frequency difference setting is preferable, where the *FreqDiffA* setting is used. A typical value for *FreqDiffM* can be 10 mHz, and a typical value for *FreqDiffA* can be 100-200 mHz.

PhaseDiffM and PhaseDiffA

The phase angle difference level settings, *PhaseDiffM* and *PhaseDiffA*, shall also be chosen depending on conditions in the network. The phase angle setting must be chosen to allow closing under maximum load condition. A typical maximum value in heavy-loaded networks can be 45 degrees, whereas in most networks the maximum occurring angle is below 25 degrees. The *PhaseDiffM* setting is a limitation to *PhaseDiffA* setting. Fluctuations occurring at high speed autoreclosing limit *PhaseDiffA* setting.

tSCM and tSCA

The purpose of the timer delay settings, *tSCM* and *tSCA*, is to ensure that the synchrocheck conditions remains constant and that the situation is not due to a temporary interference. Should the conditions not persist for the specified time, the delay timer is reset and the procedure is restarted when the conditions are fulfilled again. Circuit breaker closing is thus not permitted until the synchrocheck situation has remained constant throughout the set delay setting time. Manual closing is normally under more stable conditions and a longer operation time delay setting is needed, where the *tSCM* setting is used. During auto-reclosing, a shorter operation time delay setting is preferable, where the *tSCA* setting is used. A typical value for *tSCM* can be 1 second and a typical value for *tSCA* can be 0.1 seconds.

Energizingcheck settings*AutoEnerg and ManEnerg*

Two different settings can be used for automatic and manual closing of the circuit breaker. The settings for each of them are:

- *Off*, the energizing function is disabled.
- *DLLB*, Dead Line Live Bus, the line voltage is below set value of *ULowLineEnerg* and the bus voltage is above set value of *UHighBusEnerg*.
- *DBLL*, Dead Bus Live Line, the bus voltage is below set value of *ULowBusEnerg* and the line voltage is above set value of *UHighLineEnerg*.
- *Both*, energizing can be done in both directions, *DLLB* or *DBLL*.

ManEnergDBDL

If the parameter is set to *On*, manual closing is also enabled when both line voltage and bus voltage are below *ULowLineEnerg* and *ULowBusEnerg* respectively, and *ManEnerg* is set to *DLLB*, *DBLL* or *Both*.

UHighBusEnerg and UHighLineEnerg

The voltage level settings must be chosen in relation to the bus or line network voltage. The threshold voltages *UHighBusEnerg* and *UHighLineEnerg* have to be set lower than the value at which the network is considered to be energized. A typical value can be 80% of the base voltages.

ULowBusEnerg and ULowLineEnerg

The threshold voltages *ULowBusEnerg* and *ULowLineEnerg*, have to be set to a value greater than the value where the network is considered not to be energized. A typical value can be 40% of the base voltages.



A disconnected line can have a considerable potential due to, for instance, induction from a line running in parallel, or by being fed via the extinguishing capacitors in the circuit breakers. This voltage can be as high as 30% or more of the base line voltage.

Because the setting ranges of the threshold voltages *UHighBusEnergy/UHighLineEnergy* and *ULowBusEnergy/ULowLineEnergy* partly overlap each other, the setting conditions may be such that the setting of the non-energized threshold value is higher than that of the energized threshold value. The parameters must therefore be set carefully to avoid overlapping.

UMaxEnergy

To block the closing when the voltage on the live side is above the set value of *UMaxEnergy*.

tAutoEnergy and *tManEnergy*

The purpose of the timer delay settings, *tAutoEnergy* and *tManEnergy*, is to ensure that the dead side remains de-energized and that the condition is not due to a temporary interference. Should the conditions not persist for the specified time, the delay timer is reset and the procedure is restarted when the conditions are fulfilled again. Circuit breaker closing is thus not permitted until the energizing condition has remained constant throughout the set delay setting time.

12.2 Autorecloser for 1 phase, 2 phase and/or 3 phase operation SMBRREC

12.2.1 Identification

Function Description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Autorecloser for 1 phase, 2 phase and/or 3 phase	SMBRREC	5(0 -->1)	79

12.2.2 Application

Automatic reclosing is a well-established method for the restoration of service in a power system after a transient line fault. The majority of line faults are flashovers, which are transient by nature. When the power line is switched off by the operation of line protection and line breakers, the arc de-ionizes and recovers its ability to withstand voltage at a somewhat variable rate. Thus, a certain dead time with a de-energized line is necessary. Line service can then be resumed by automatic reclosing of the line breakers. The dead time selected should be long enough to ensure a high probability of arc de-ionization and successful reclosing.

For individual line breakers, auto reclosing equipment, the required circuit breaker dead time is used to determine the “dead time” setting value. When simultaneous tripping and reclosing at the two line ends occurs, line dead time is approximately equal to the auto recloser “dead time”. If the auto reclosing dead time and line “dead time” differ then, the line will be energized until the breakers at both ends have opened.

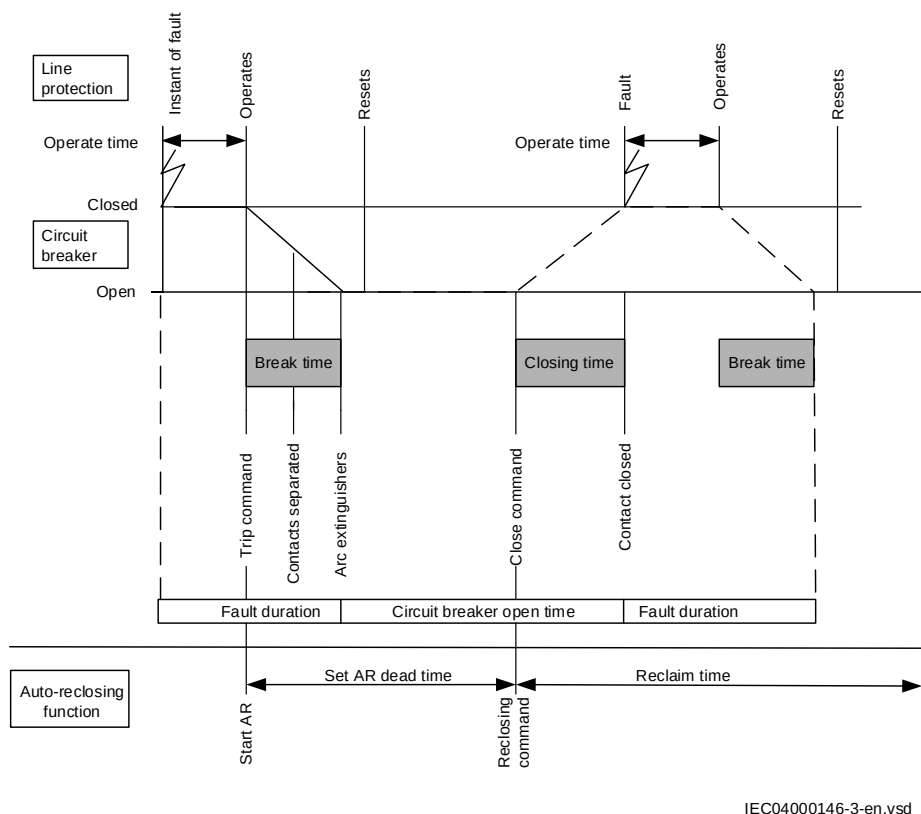


Figure 114: Single-shot automatic reclosing at a permanent fault

Single-phase tripping and single-phase automatic reclosing is a way of limiting the effect of a single-phase line fault on power system operation. Especially at higher voltage levels, the majority of faults are of single-phase type (around 90%). To maintain system stability in power systems with limited meshing or parallel routing single-phase auto reclosing is of particular value. During the single-phase dead time the system is still capable of transmitting load on the two healthy phases and the system is still synchronized. It requires that each circuit breaker pole can be operated individually, which is usually the case for higher transmission voltages.

A somewhat longer dead time may be required for single-phase reclosing compared to high-speed three-phase reclosing. This is due to the influence on the fault arc from the voltage and the current in the non-faulted phases.

To maximize the availability of the power system it is possible to choose single-phase tripping and automatic reclosing during single-phase faults and three-phase tripping and automatic reclosing during multi-phase faults. Three-phase automatic reclosing can be performed with or without the use of synchrocheck.

During the single-phase dead time there is an equivalent "series"-fault in the system resulting in a flow of zero sequence current. It is therefore necessary to coordinate the residual current protections (earth fault protection) with the single-phase tripping and the auto reclosing function. Attention shall also be paid to "pole discordance" that arises when circuit breakers are provided with single-phase operating devices. These breakers need pole discordance protection. They must also be coordinated with the single-phase auto recloser and blocked during the dead time when a normal discordance occurs. Alternatively, they should use a trip time longer than the set single-phase dead time.

For the individual line breakers and auto reclosing equipment, the auto reclosing dead time expression is used. This is the dead time setting for the auto recloser. During simultaneous tripping and reclosing at the two line ends, auto reclosing dead time is approximately equal to the line dead time. Otherwise these two times may differ as one line end might have a slower trip than the other end which means that the line will not be dead until both ends have opened.

If the fault is permanent, the line protection will trip again when reclosing is attempted in order to clear the fault.

It is common to use one automatic reclosing function per line circuit breaker (CB). When one CB per line end is used, then there is one auto-recloser per line end. If auto-reclosers are included in duplicated line protection, which means two auto-reclosers per CB, one should take measures to avoid uncoordinated reclosing commands. In 1 1/2 breaker, double-breaker and ring bus arrangements, two CBs per line end are operated. One auto-recloser per CB is recommended. Arranged in such a way, that sequential reclosing of the two CBs can be arranged with a priority circuit available in the auto-recloser. In case of a permanent fault and unsuccessful reclosing of the first CB, reclosing of the second CB is cancelled and thus the stress on the power system is limited.

The auto-recloser can be selected to perform single-phase and/or three-phase automatic reclosing from several single-shot to multiple-shot reclosing programs. The three-phase auto reclosing dead time can be set to give either High-Speed Automatic Reclosing (HSAR) or Delayed Automatic Reclosing (DAR). These expressions, HSAR and DAR, are mostly used for three-phase auto reclosing as single-phase auto reclosing is always high speed to avoid maintaining the unsymmetrical condition. HSAR usually means a dead time of less than 1 second.

In power transmission systems it is common practice to apply single- and/or three-phase, single-shot auto reclosing. In sub-transmission and distribution systems tripping and auto reclosing are usually three-phase. The mode of automatic reclosing varies however. Single-shot and multi-shot are in use. The first shot can have a short delay, HSAR, or a longer delay, DAR. The second and following reclosing shots have a rather long delay. When multiple shots are used the dead time must harmonize with the breaker duty-cycle capacity.

Automatic reclosing is usually started by the line protection and in particular by instantaneous tripping of such protection. The auto-recloser can be inhibited (blocked) when certain protection functions detecting permanent faults, such as shunt reactor, cable or busbar protection are in operation. Back-up protection zones indicating faults outside the own line are typically connected to inhibit the auto-recloser.

Automatic reclosing should not be attempted when closing a CB and energizing a line onto a fault (SOTF), except when multiple-shots are used where shots 2 etc. will be started at SOTF. Likewise a CB in a multi-breaker busbar arrangement which was not closed when a fault occurred should not be closed by operation of the auto-recloser. Auto reclosing is often combined with a release condition from synchrocheck and dead line or dead busbar check. In order to limit the stress on turbo generator sets from auto reclosing onto a permanent fault, one can arrange to combine auto reclosing with a synchrocheck on line terminals close to such power stations and attempt energizing from the side furthest away from the power station and perform the synchrocheck at the local end if the energizing was successful.

Transmission protection systems are usually sub-divided and provided with two redundant protection IEDs. In such systems it is common to provide auto reclosing in only one of the sub-systems as the requirement is for fault clearance and a failure to reclose because of the auto-recloser being out of service is not considered a major disturbance. If two auto-reclosers are provided on the same breaker, the application must be carefully checked and normally one must be the master and be connected to inhibit the other auto-recloser if it has started. This inhibit can, for example, be done from an auto-recloser for 3-phase operation in progress signal.

When Single and/or three phase auto reclosing is considered, there are a number of cases where the tripping shall be three phase anyway. For example:

- Evolving fault where the fault during the dead-time spreads to another phase. The other two phases must then be tripped and a three phase dead-time and auto reclose initiated
- Permanent fault
- Fault during three-phase dead time
- Auto-recloser out of service or circuit breaker not ready for an auto reclosing cycle

"Prepare three-phase tripping" is then used to switch the tripping to three-phase. This signal is generated by the auto-recloser and connected to the trip function block and also connected outside

the IED through IO when a common auto recloser is provided for two sub-systems. An alternative signal "Prepare 1-phase tripping" is also provided and can be used as an alternative when the autorecloser is shared with another subsystem. This provides a fail safe connection so that even a failure in the IED with the auto recloser will mean that the other sub-system will start a three-phase trip.

A permanent fault will cause the line protection to trip again when it recloses in an attempt to energize the line.

The auto reclosing function allows a number of parameters to be adjusted.

Examples:

- number of auto reclosing shots
- auto reclosing program
- auto reclosing dead times for each shot

12.2.2.1 Auto reclosing operation Off and On

Operation of the automatic recloser can be set to Off and On by a setting parameter or by external control. The setting parameter *Operation* = *Off*, or *On* sets the function to Off or On. With the settings *Operation* = *On* and *ExternalCtrl* = *On*, the control is made by input signal pulses to the inputs On and Off, for example, from a control system or by a control switch.

When the auto recloser is set On, the *SETON* output is set, and the auto recloser becomes operative if other conditions such as circuit breaker is closed and circuit breaker is ready are also fulfilled, the *READY* output is activated (high). Then the auto recloser is ready to accept a start.

12.2.2.2 Start auto reclosing and conditions for start of a reclosing cycle

The usual way to start an auto reclosing cycle, or sequence, is to start it at selective tripping by line protection by applying a signal to the *START* input. Starting signals can be either, general trip signals or, only the conditions for differential, distance protection zone 1 and distance protection aided trip. In some cases also directional earth fault protection aided trip can be connected to start an auto reclose attempt. If general trip is used to start the auto recloser it is important to block it from other functions that should not start an auto reclosing sequence.

In cases where one wants to differentiate three-phase auto reclosing dead time, for different power system configuration or at tripping by different protection stages, one can also use the *STARTHS* input (start high-speed reclosing). When initiating *STARTHS*, the auto reclosing dead time for three-phase shot 1, *t1 3PhHS* is used and the closing is done without checking the synchrocheck condition.

A number of conditions need to be fulfilled for the start to be accepted and a new auto reclosing cycle to be started. They are linked to dedicated inputs. The inputs are:

- *CBREADY*, circuit breaker ready for a reclosing cycle, for example, charged operating gear.
- *CBCLOSED* to ensure that the circuit breaker was closed when the line fault occurred and start was applied.
- No signal at *INHIBIT* input that is, no blocking or inhibit signal present. After the start has been accepted, it is latched in and an internal signal "start" is set. It can be interrupted by certain events, like an "inhibit" signal.

12.2.2.3 Start auto reclosing from circuit breaker open information

If a user wants to initiate auto reclosing from the circuit breaker open position instead of from protection trip signals, the function offers such a possibility. This starting mode is selected with the setting parameter *StartByCBOpen*=*On*. Typically a circuit breaker auxiliary contact of type NO (normally open) is connected to *CBCLOSED* and *START*. When the signal changes from circuit

breaker closed to circuit breaker open an auto reclosing start pulse is generated and latched in the function, subject to the usual checks. The auto reclosing sequence continues then as usual. Signals from manual tripping and other functions, which shall prevent auto reclosing, need to be connected to the *INHIBIT* input.

12.2.2.4 Blocking of the auto recloser

Auto reclose attempts are expected to take place only for faults on the own line. The auto recloser must be blocked by activating the *INHIBIT* input for the following conditions:

- Tripping from delayed distance protection zones
- Tripping from back-up protection functions
- Tripping from breaker failure function
- Intertrip received from remote end circuit breaker failure function
- Busbar protection tripping

Depending of the starting principle (general trip or only instantaneous trip) adopted above the delayed and back-up zones might not be required. Breaker failure trip local and remote must however always be connected.

12.2.2.5 Control of the auto reclosing dead time for shot 1

Up to four different time settings can be used for the first shot, and one extension time. There are separate settings for single-, two- and three-phase auto reclosing dead time, *t1 1Ph*, *t1 2Ph*, *t1 3Ph*. If no particular input signal is applied, and an auto reclosing program with single-phase auto reclosing is selected, the auto reclosing dead time *t1 1Ph* will be used. If one of the *TR2P* or *TR3P* inputs is activated in connection with the start, the auto reclosing dead time for two-phase or three-phase auto reclosing is used. There is also a separate time setting facility for three-phase high-speed auto reclosing without synchrocheck, *t1 3PhHS*, available for use when required. It is activated by the *STARTHS* input.

A time extension delay, *tExtended t1*, can be added to the dead time delay for the first shot. It is intended to come into use if the communication channel for permissive line protection is lost. In a case like this there can be a significant time difference in fault clearance at the two line ends, where a longer auto reclosing dead time can be useful. This time extension is controlled by the setting *Extended t1 = On* and the *PLCLOST* input. If this functionality is used the auto recloser start must also be allowed from distance protection zone 2 time delayed trip. Time extension delay is not possible to add to the three-phase high-speed auto reclosing dead time, *t1 3PhHS*.

12.2.2.6 Long trip signal

In normal circumstances the auto recloser is started with a protection trip command which resets quickly due to fault clearing. The user can set a maximum start pulse duration *tLongStartInh*. This start pulse duration time is controlled by setting *LongStartInhib*.

When start pulse duration signal is longer than set maximum start pulse duration, the auto reclosing sequence interrupts in the same way as for a signal to the *INHIBIT* input.

12.2.2.7 Maximum number of reclosing shots

The maximum number of auto reclosing shots in an auto reclosing cycle is selected by the setting *NoOfShots*. A maximum of five shots can be done. The type of auto reclosing used at the first auto reclosing shot is set by the setting *ARMode*. The first alternative is three-phase auto reclosing. The other alternatives include some single-phase or two-phase auto reclosing. Usually there is no two-phase tripping arranged, and then there will be no two-phase auto reclosing.

The decision for single- and three-phase trip is also made in the tripping logic (SMPTTRC) function block where the setting *3 phase*, *1ph/3Ph* (or *1ph/2ph/3Ph*) is selected.

12.2.2.8 *ARMode* = 3ph, (normal setting for a three-phase shot)

Three-phase auto reclosing, one to five shots according to the *NoOfShots* setting. The prepare three-phase trip PREP3P output is always set (high). A trip operation is made as a three-phase trip for all type of faults. The auto reclosing is as a three-phase auto reclosing as in mode 1/2/3ph described below. All signals, blockings, inhibits, timers, requirements and so on, are the same as in the example described below.

12.2.2.9 *ARMode* = 1/2/3ph

Single-phase, two-phase or three-phase auto reclosing first shot, followed by 3-phase auto reclosing shots, if selected. Here, the auto recloser is assumed to be "On" and "Ready". The circuit breaker is closed and the operation gear ready (operating energy stored). *START* input (or *STARTHS*) is received and sealed-in. The *READY* output is reset (set to false). *ACTIVE* output is set.

- If *TR2P* and *TR3P* inputs are low (i.e. single-phase trip): The timer for single-phase auto reclosing dead time is started and the *1PT1* output (single-phase reclosing in progress) is activated. It can be used to suppress pole disagreement and earth-fault protection trip during the single-phase dead time interval..
- If *TR2P* input is high and *TR3P* input is low (i.e. two-phase trip): The timer for two-phase auto reclosing dead time is started and the *2PT1* output (two-phase reclosing in progress) is activated.
- If *TR3P* input is high (i.e. three-phase trip): The timer for three-phase auto reclosing dead time, *t1 3Ph* or *t1 3PhHS*, is started depending on if *START* or *STARTHS* input has been activated and *3PT1* output (three-phase reclosing shot 1 in progress) is set..

While any of the auto reclosing dead time timers are running, the *INPROGR* output is activated. When the dead time runs out, the respective internal signal is transmitted to the output module for further checks and to issue a breaker closing command.

When a circuit breaker closing command is issued, the prepare three-phase output trip is set. When issuing a circuit breaker closing command the *tReclaim* timer is started. If no tripping takes place during that time, the auto recloser resets to the "Ready" state and the *ACTIVE* output resets. If the first reclosing shot fails, a three-phase trip will be initiated and three-phase reclosing can follow, if selected.

12.2.2.10 *ARMode* = 1/2ph, 1-phase or 2-phase reclosing in the first shot

At single-phase or two-phase tripping, the operation is as in the example described above, program mode 1/2/3ph. If the first reclosing shot fails, a three-phase trip will be issued and three-phase auto reclosing can follow, if selected. In the event of a three-phase trip, *TR3P* input high, the auto recloser will be inhibited and no auto reclosing takes place.

12.2.2.11 *ARMode* = 1ph+1*2ph, 1-phase or 2-phase reclosing in the first shot

At single-phase tripping, the operation is as in the above described example, program mode 1/2/3ph. The single-phase auto reclosing attempt can be followed by three-phase reclosing, if selected. At two-phase trip, a failure of a two-phase auto reclosing attempt will inhibit the auto recloser. No more shots are attempted. If the first trip is a three-phase trip, the auto-reclosing will be inhibited. No more shots are attempted. The expression "1*2ph" should be understood as "Only one shot at two-phase auto reclosing".

12.2.2.12 *ARMode* = 1/2ph + 1*3ph, 1-phase, 2-phase or 3-phase reclosing in the first shot

At single-phase or two-phase tripping, the operation is as in the example described above, program mode 1/2/3ph. If the first reclosing shot fails, a three-phase trip will be issued and three-phase reclosing will follow, if selected. At three-phase trip, a failure of a three-phase auto reclosing attempt

will inhibit the auto recloser. No more shots are attempted. The expression “1*3ph” should be understood as “Only one shot at three-phase auto reclosing”.

12.2.2.13 **ARMode = 1ph + 1*2/3ph, 1-phase, 2-phase or 3-phase reclosing in the first shot**

At single-phase or two-phase tripping, the operation is as in the above described example, program mode 1/2/3ph. If the first reclosing shot fails, a three-phase trip will be issued and three-phase reclosing will follow, if selected. At two-phase or three-phase trip a failure of a two-phase or three-phase auto reclosing attempt will inhibit the auto recloser. No more shots are attempted. The expression “1*2/3ph” should be understood as “Only one shot at two-phase or three-phase auto reclosing”.

Table 22: Type of reclosing shots at different settings of ARMode or integer inputs to MODEINT

MODEINT (integer)	ARMode	Type of fault	1st shot	2nd-5th shot
1	3ph	1ph	3ph	3ph
		2ph	3ph	3ph
		3ph	3ph	3ph
2	1/2/3ph	1ph	1ph	3ph
		2ph	2ph	3ph
		3ph	3ph	3ph
3	1/2ph	1ph	1ph	3ph
		2ph	2ph	3ph
		3ph		
4	1ph + 1*2ph	1ph	1ph	3ph
		2ph	2ph	
		3ph		
5	1/2ph + 1*3ph	1ph	1ph	3ph
		2ph	2ph	3ph
		3ph	3ph	
6	1ph + 1*2/3ph	1ph	1ph	3ph
		2ph	2ph	
		3ph	3ph	

A start of a new auto reclosing cycle during the set “reclaim time” is blocked when the set number of reclosing shots have been reached.

12.2.2.14 **External selection of auto reclosing mode**

The auto reclosing mode can be selected by use of available logic function blocks. Below is an example where the choice of mode, *ARMode=3ph* or *ARMode=1/2/3ph*, is done from a hardware function key at the front of the IED, but alternatively there can for example, be a physical selector switch on the front of the panel which is connected to a binary to integer function block (BTIGAPC).

The connection example for selection of the auto reclosing mode is shown in Figure [115](#).

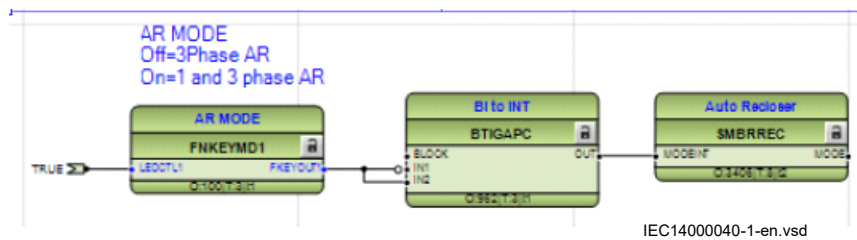


Figure 115: Selection of the auto-reclose mode from a hardware functional key in front of the IED

12.2.2.15 Auto reclosing reclaim timer

The *tReclaim* timer defines the time it takes from issue of the breaker closing command, until the auto recloser resets. Should a new trip occur during this time, it is treated as a continuation of the first fault. The reclaim timer is started when the circuit breaker closing command is given.

12.2.2.16 Pulsing of the circuit breaker closing command and counter

The circuit breaker closing command, *CLOSECB* is given as a pulse with a duration set by the *tPulse* setting. For circuit breakers without an anti-pumping function, close pulse cutting can be used. It is selected by the *CutPulse* setting. In case of a new start pulse (trip), the breaker closing command pulse is then cut (interrupted). The minimum breaker closing command pulse length is always 50ms. At the issue of the breaker closing command, the appropriate auto recloser operation counter is incremented. There is a counter for each type of auto reclosing command and one for the total number of auto reclosing commands.

12.2.2.17 Transient fault

After the breaker closing command the reclaim timer keeps running for the set *tReclaim* time. If no start (trip) occurs within this time, the auto recloser will reset. The circuit breaker remains closed and the operating gear recharges. The *CBCLOSED* and *CBREADY* input signals will be set.

12.2.2.18 Permanent fault and reclosing unsuccessful signal

If a new start occurs, and the number of auto reclosing shots is set to 1, and a new *START* or *TRSOTF* input signal appears, after the circuit breaker closing command, the *UNSUCCL* output (unsuccessful reclosing) is set high. The timer for the first shot can no longer be started. Depending on the set number of auto reclosing shots further shots may be made or the auto reclosing sequence is ended. After reclaim timer time-out the auto recloser resets, but the circuit breaker remains open. The circuit breaker closed information through the *CBCLOSED* input is missing. Thus, the auto recloser is not ready for a new auto reclosing cycle. Normally, the *UNSUCCL* output appears when a new start is received after the last auto reclosing shot has been made and the auto recloser is inhibited. The output signal resets after reclaim time. The “unsuccessful” signal can also be made to depend on the circuit breaker position input. The *UnsucClByCBChk* setting should then be set to *CBCheck*, and the *tUnsucCl* timer should be set too. If the circuit breaker does not respond to the breaker closing command and does not close, but remains open, the *UNSUCCL* output is set high after the set *tUnsucCl* time. The *UNSUCCL* output can for example, be used in multi-breaker arrangement to cancel the auto reclosing for the second circuit breaker, if the first circuit breaker closed onto a persistent fault. It can also be used to generate a lock-out of manual circuit breaker closing until the operator has reset the lock-out, see separate section.

12.2.2.19 Lock-out initiation

In many cases there is a requirement that a lock-out is generated when the auto reclosing attempt fails. This is done with logic connected to the in- and outputs of the auto recloser and connected to

binary I/O as required. Many alternative ways of performing the logic exist depending on whether manual circuit breaker closing is interlocked in the IED, whether an external physical lock-out relay exists and whether the reset is hardwired, or carried out by means of communication. There are also different alternatives regarding what shall generate lock-out. Examples of questions are:

- shall back-up time delayed trip give lock-out (normally yes)
- shall lock-out be generated when closing onto a fault (mostly)
- shall lock-out be generated when the auto recloser is Off at the fault or for example, in single-phase auto recloser mode and the fault was multi-phase (normally not as no closing attempt has been given)
- shall lock-out be generated if the circuit breaker did not have sufficient operating power for an auto reclosing sequence (normally not as no auto closing attempt has been given)

In Figures 116 and 117 the logic shows how a closing lock-out logic can be designed with the lock-out relay as an external relay alternatively with the lock-out created internally with the manual closing going through the synchrocheck function. An example of lock-out logic.

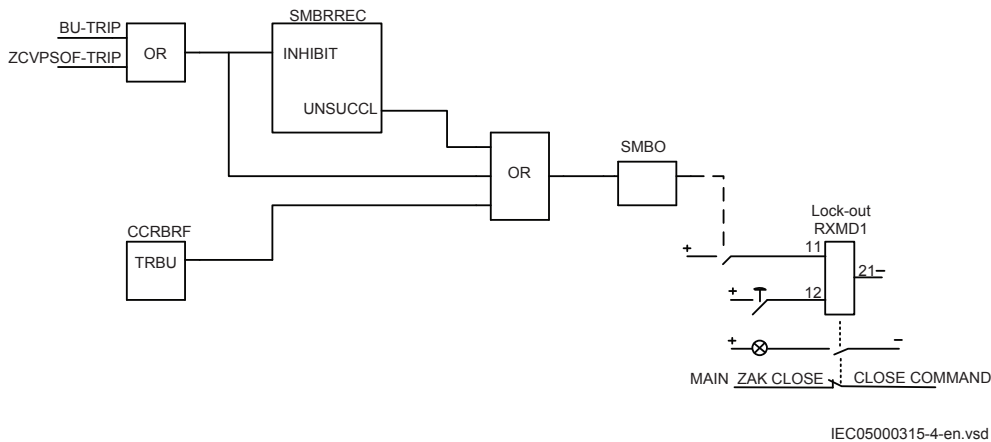


Figure 116: Lock-out arranged with an external lock-out relay

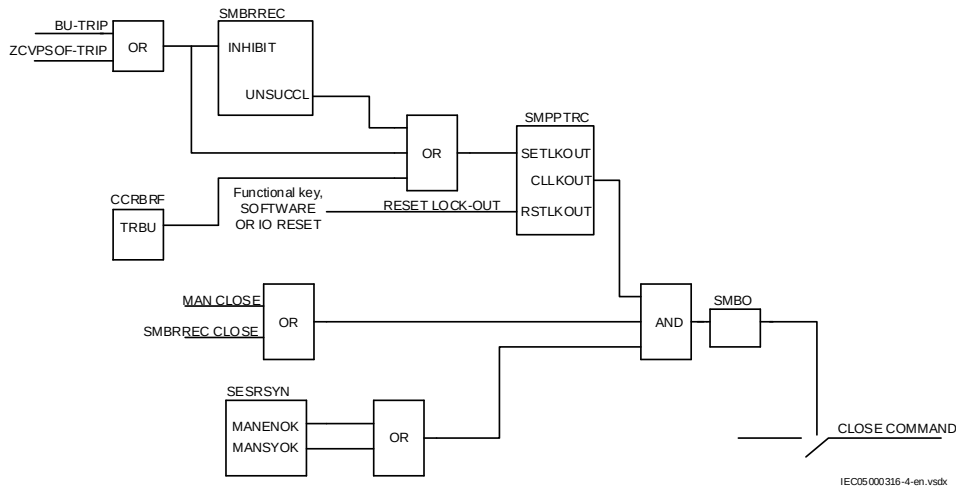


Figure 117: Lock-out arranged with internal logic with manual closing going through in IED

12.2.2.20 Evolving fault

An evolving fault starts as a single-phase fault which leads to single-phase tripping and then the fault spreads to another phase. The second fault is then cleared by three-phase tripping.

The auto recloser will first receive a start signal (*START*) without any three-phase signal (*TR3P*). The auto recloser will start a single-phase auto reclosing sequence, if programmed to do so. At the evolving fault clearance there will be a new *START* signal and three-phase trip information, *TR3P*. The single-phase auto reclosing sequence will then be stopped, and instead the timer, *t1 3Ph*, for three-phase auto reclosing will be started from zero. The sequence will continue as a three-phase auto reclosing sequence, if it is a selected alternative reclosing mode. The second fault which can be single-phase is tripped three-phase because the trip function (SMPPTRC) in the IED has an evolving fault timer which ensures that the second fault is always tripped three-phase. For other types of relays where the relays do not include this function, the *PREP3PH* output (or the inverted *PERMIT1PH* output) is used to prepare the other sub-system for three-phase tripping. This signal will, for evolving fault situations, be activated a short time after the first trip has reset and will thus ensure that new starts (trips) will be three phase.

12.2.2.21 Automatic continuation of the auto reclosing sequence

The auto recloser can be programmed to proceed to the next auto reclosing shots (if multiple shots are selected) even if start signals are not received from protection functions, but the circuit breaker is still not closed. This is done by setting *AutoCont* = *On* and *tAutoContWait* to the required delay for the function to proceed without a new start.

12.2.2.22 Thermal overload protection holding the auto recloser back

If the *THOLHOLD* input (thermal overload protection holding auto reclosing back) is activated, it will keep the auto recloser on a hold until it is reset. There may thus be a considerable delay between start of the auto recloser and the breaker closing command to the circuit breaker. An external logic limiting the time and sending an inhibit to the *INHIBIT* input can be used. The input can also be used to set the auto recloser on hold for a longer or shorter period.

12.2.3 Setting guidelines

12.2.3.1 Configuration

Use the PCM600 configuration tool to configure signals.

Auto recloser function parameters are set via the local HMI or Parameter Setting Tool (PST). Parameter Setting Tool is a part of PCM600.

Recommendations for input signals

Please see Figure [118](#) and default factory configuration for examples.

BLKOFF

Used to unblock the auto recloser when it has been blocked due to activating *BLKON* input or by an unsuccessful auto reclosing attempt if the *BlockByUnsucCI* setting is set to *On*.

BLKON

Used to block the auto recloser, for example, when certain special service conditions arise. When used, blocking must be reset with *BLKOFF*.

CBCLOSED and CBREADY

These binary inputs should pick-up information from the circuit breaker. At three operating gears in the circuit breaker (single pole operated circuit breakers) the connection should be "All poles closed" (series connection of the NO contacts) or "At least one pole open" (parallel connection of NC contacts). The *CBREADY* is a signal meaning that the circuit breaker is ready for an auto reclosing operation, either Close-Open (CO), or Open-Close-Open (OCO). If the available signal is of type

“circuit breaker not charged” or “not ready”, an inverter can be inserted in front of the *CBREADY* input.

INHIBIT

To this input shall be connected signals that interrupt an auto reclosing cycle or prevent a start from being accepted. Such signals can come from protection for a line connected shunt reactor, from transfer trip receive, from back-up protection functions, busbar protection trip or from breaker failure protection. When the circuit breaker open position is set to start the auto recloser, then manual opening must also be connected here. The inhibit is often a combination of signals from external IEDs via the I/O and internal functions. An OR-gate is then used for the combination.

MODEINT

The auto reclosing mode is selected with the *ARMode* setting. As an alternative to the setting, the mode can be selected by connecting an integer, for example from function block B16I, to the *MODEINT* input. The six possible modes are described in table 6 with their corresponding *MODEINT* integer value. When a valid integer is connected to the input *MODEINT* the selected *ARMode* setting will be invalid and the *MODEINT* input value will be used instead. The selected mode is reported as an integer on the *MODE* output.

ON and OFF

These inputs can be connected to binary inputs or to a communication interface block for external control.

PLCLOST

This is intended for line protection permissive signal channel lost (fail) for example, PLC= Power Line Carrier failure. It can be connected, when it is required to prolong the auto reclosing dead time when communication is not working, that is, one line end might trip with a zone2 delay. If this is used the auto recloser must also be started from zone2 time delayed trip.

RESET

Used to reset the auto recloser to start conditions. Possible hold by thermal overload protection will be reset. Circuit breaker position will be checked and time settings will be restarted with their set times.

RSTCOUNT

There is a counter for each type of auto reclosing and one for the total number of circuit breaker close commands issued. All counters are reset with the *RSTCOUNT* input or by an IEC 61850 command.

SKIPHS

The high-speed auto reclosing sequence can be skipped and be replaced by normal auto reclosing sequence by activating *SKIPHS* input before the *STARTHS* high-speed start input is activated. The replacement is done for the 1st shot.

START

The *START* input should be connected to the trip function (SMPPTRC) output, which starts the auto recloser for 1/2/3-phase operation. It can also be connected to a binary input for start from an external contact. A logical OR-gate can be used to combine the number of start sources.



If *StartByCBOpen* is used, the circuit breaker open condition shall also be connected to the *START* input.

STARHHS, Start high-speed auto reclosing

It may be used when one wants to use two different dead times in different protection trip operations. This input starts the dead time $t1\ 3PhHS$. High-speed reclosing shot 1 started by this input is without a synchronization check.

SYNC

This input is connected to the internal synchrocheck function when required or to an external device for synchronism. If neither internal nor external synchronism or energizing check is required, it can be connected to a permanently high source, TRUE. The signal is required for three-phase shots 1-5 to proceed (Note! Not the high-speed step).

THOLHOLD

Signal "Thermal overload protection holding back auto reclosing". It can be connected to a thermal overload protection trip signal which resets only when the thermal content has fallen to an acceptable level, for example, 70%. As long as the signal is high, indicating that the line is hot, the auto reclosing is held back. When the signal resets, a reclosing cycle will continue. Observe that this has a considerable delay. Input can also be used for other purposes if for some reason the auto reclosing shot needs to be halted.

TR2P and TR3P

Signals for two-phase and three-phase trip. They are usually connected to the corresponding output of the trip function block. They control the choice of dead time and the auto reclosing cycle according to the selected program. Signal TR2P needs to be connected only if the trip function block has been selected to give 1ph/2ph/3ph trip and an auto reclosing cycle with two phase reclosing is foreseen.

TRSOTF

This is the signal "Trip by Switch Onto Fault". It is usually connected to the "switch onto fault" output of line protection if multi-shot auto reclosing attempts are used. The input will start the shots two to five.

ZONESTEP

The *ZONESTEP* input is used when coordination between local auto reclosers and down stream auto reclosers is needed. When this input is activated the auto recloser increases its actual shot number by one and enters "reclaim time" status. If a start is received during this reclaim time the auto recloser is proceeding as usual but with the dead time for the increased shot number. Every new increase of the shot number needs a new activation of the *ZONESTEP* input. This functionality is controlled by the setting *ZoneSeqCoord*.

Recommendations for output signals

Please see Figure [118](#) and default factory configuration for examples.

1PT1 and 2PT1

Indicates that single-phase or two-phase auto reclosing is in progress. It is used to temporarily block an earth-fault and/or pole disagreement function during the single-phase or two-phase open interval.

3PT1, 3PT2, 3PT3, 3PT4 and 3PT5

Indicates that three-phase auto reclosing shots one to five are in progress. The signals can be used as an indication of progress or for own logic.

ABORTED

The *ABORTED* output indicates that the auto recloser is inhibited while it is in one of the following internal states:

- **inProgress**: auto recloser is started and dead time is in progress
- **reclaimTimeStarted**: the circuit breaker closing command has started the reclaim timer
- **wait**: an auto recloser, acting as slave, is waiting for a release from the master to proceed with its own reclosing sequence

ACTIVE

Indicates that the auto recloser is active, from start until end of reclaim time.

BLOCKED

Indicates that auto recloser is temporarily or permanently blocked.

CLOSECB

Connect to a binary output for circuit breaker closing command.

COUNT1P, COUNT2P, COUNT3P1, COUNT3P2, COUNT3P3, COUNT3P4 and COUNT3P5

Indicates the number of auto reclosing shots made for respective shot.

COUNTAR

Indicates the total number of auto reclosing shots made.

INHIBOUT

If the *INHIBIT* input is activated it is reported on the *INHIBOUT* output.

INPROGR

Indicates that an auto recloser sequence is in progress, from start until circuit breaker close command.

MODE

When a valid integer is connected to the *MODEINT* input, the selected *ARMode* setting will be invalid and the *MODEINT* input value will be used instead. The selected mode is reported as an integer on the *MODE* output. The six possible modes are described in Table 22 with their corresponding *MODEINT* integer value.

PERMIT1P

Permit single-phase trip is the inverse of *PREP3P*. It can be connected to a binary output relay for connection to external protection or trip relays. In case of a total loss of auxiliary power, the output relay drops and does not allow single-phase trip.

PREP3P

Prepare three-phase trip is usually connected to the trip block to force a coming trip to be a three-phase one. If the auto recloser cannot make a single-phase or two-phase auto reclosing, the tripping should be three-phase.

READY

Indicates that the auto recloser is ready for a new and complete auto reclosing sequence. It can be connected to the zone extension if a line protection should have extended zone reach before auto reclosing.

SETON

Indicates that auto recloser is switched on and operative.

SUCCL

If the circuit breaker closing command is given and the circuit breaker is closed within the set time interval *tUnsucCl*, the *SUCCL* output is activated after the set time interval *tSuccessful*.

SYNCFAIL

The *SYNCFAIL* output indicates that the auto recloser is inhibited because the synchrocheck or energizing check condition has not been fulfilled within the set time interval, *tSync*. Also *ABORTED* output will be activated.

UNSUCCL

Indicates unsuccessful reclosing.

Connection and setting examples

Figure 118 is showing an example of how to connect the auto recloser when used for three-phase auto reclosing and Figure 119 is showing an example of how to connect the auto recloser when used for single-phase, two-phase or three-phase auto reclosing.

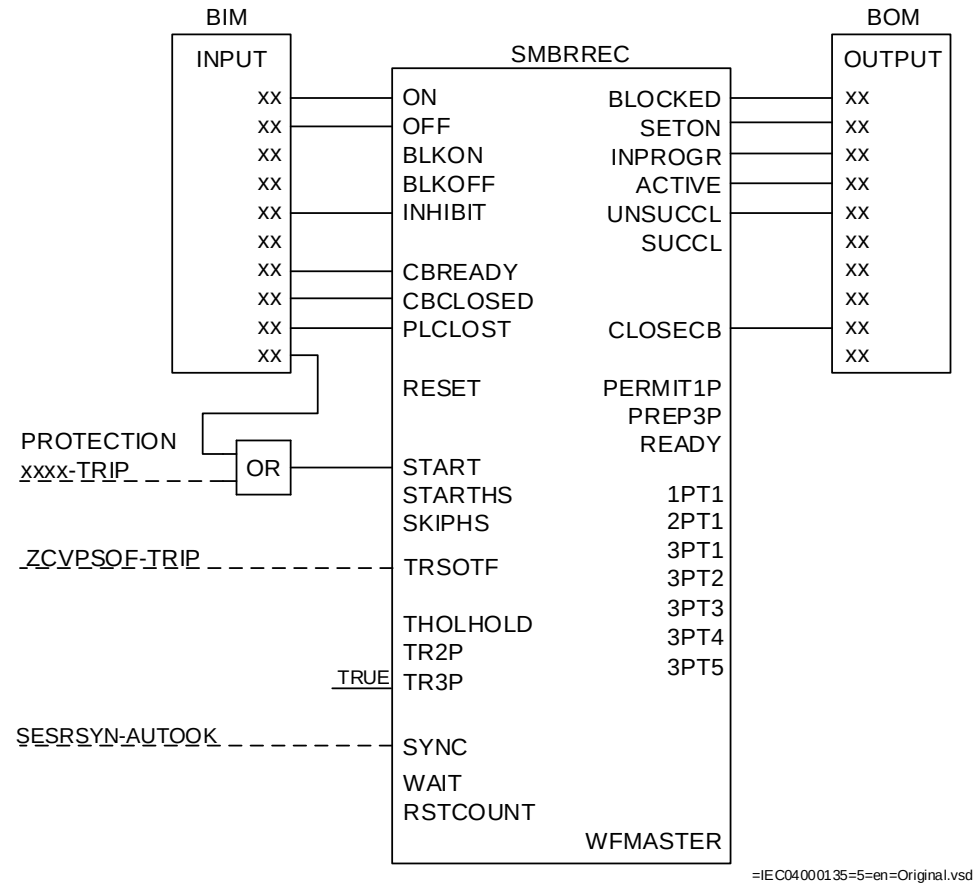


Figure 118: Example of I/O-signal connections at a three-phase auto reclosing sequence

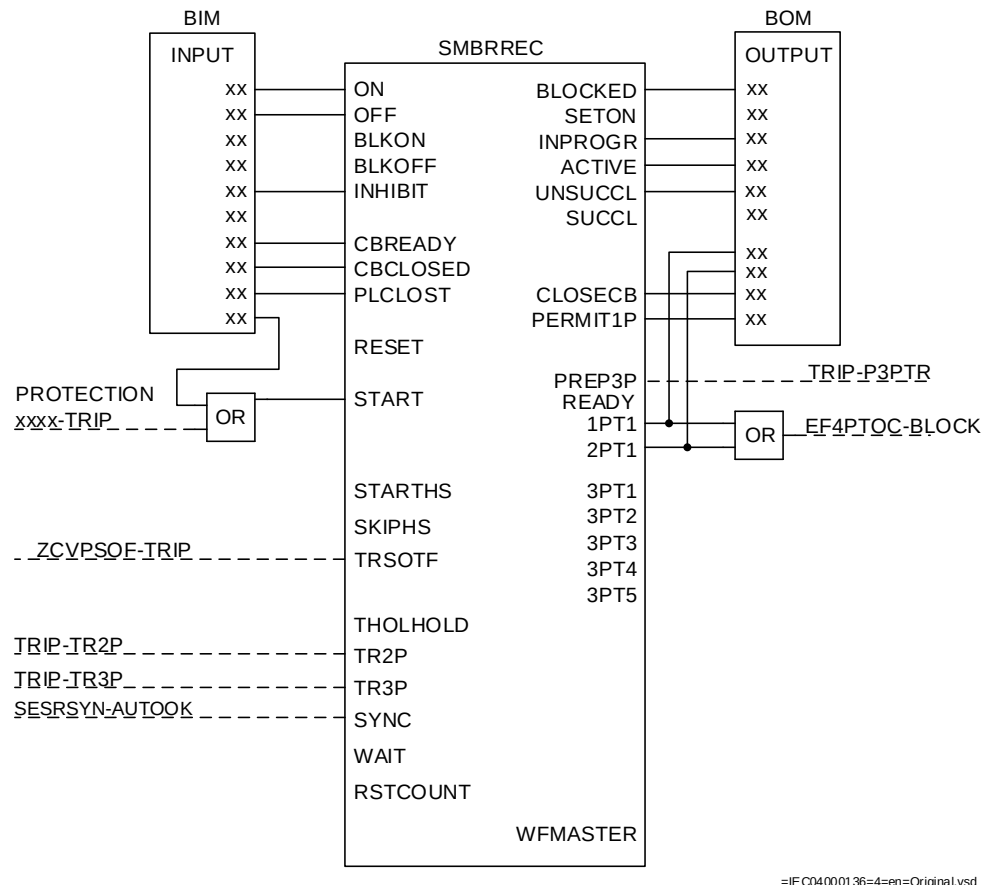


Figure 119: Example of I/O-signal connections for a single-phase, two-phase or three-phase auto reclosing sequence

12.2.3.2 Auto recloser settings

The settings for the auto recloser are set using the local HMI (LHMI) or PCM600.

This setting guideline describes the settings of the auto recloser using the LHMI.

The settings for the auto recloser are found under **Main menu /Settings /IED Settings /Control / AutoRecloser(79,5(0->1)) /SMBRREC(79,5(0->)):X** and have been divided into four different setting groups: General, CircuitBreaker, DeadTime and MasterSlave.

General settings

Operation: The operation of the auto recloser can be switched *On* or *Off*.

ExternalCtrl: This setting makes it possible to switch the auto recloser *On* or *Off* using an external switch via IO or communication ports.

ARMode: There are six different possibilities in the selection of auto reclosing programs. The type of auto reclosing used for different kinds of faults depends on the power system configuration and the users practices and preferences. When the circuit breaker only have three-phase operation, then three-phase auto reclosing has to be chosen. This is usually the case in sub-transmission and distribution lines. Three-phase tripping and reclosing for all types of faults is also widely accepted in completely meshed power systems. In transmission systems with few parallel circuits, single-phase reclosing for single-phase faults is an attractive alternative for maintaining service and system stability.

AutoContinue: Automatic continuation to the next shot if the circuit breaker is not closed within the set time of *tAutoContWait*. The normal setting is *AutoContinue = Off*.

tAutoContWait: This is the length in time the auto recloser waits to see if the circuit breaker is closed when *AutoContinue* is set to *On*. Normally, the setting of *tAutoContWait* can be 2 sec.

StartByCBOpen: The normal setting *Off* is used when the function is started by protection trip signals. If set *On* the start of the auto recloser is controlled by an circuit breaker auxiliary contact.

LongStartInhib: Usually the protection trip command, used as an auto reclosing start signal, resets quickly as the fault is cleared. A prolonged trip command may depend on a circuit breaker failing to clear the fault. A protection trip signal present when the circuit breaker is reclosed will result in a new trip. The user can set a maximum start pulse duration time *tLongStartInh*. This start pulse duration time is controlled by the *LongStartInhib* setting. When the start pulse duration signal is longer than set maximum start pulse duration, the auto reclosing sequence interrupts in the same way as for a signal to the *INHIBIT* input.

tLongStartInh: The user can set a maximum start pulse duration time *tLongStartInh*. At a set time somewhat longer than the auto reclosing dead time, this facility will not influence the auto reclosing. A typical setting of *tLongStartInh* could be close to the auto reclosing dead time.

tInhibit: To ensure reliable interruption and temporary blocking of the auto recloser a resetting time delay *tInhibit* is used. The auto recloser will be blocked this time after the deactivation of the *INHIBIT* input. A typical resetting delay is 5.0 s.

ZoneSeqCoord: The *ZONESTEP* input is used when coordination between local auto reclosers and down stream auto reclosers is needed. When this input is activated the auto recloser increases its actual shot number by one and enters "reclaim time" status. If a start is received during this reclaim time the auto recloser is proceeding as usual but with the dead time for the increased shot number. Every new increase of the shot number needs a new activation of the *ZONESTEP* input. The setting *NoOfShots* limits of course the possibility to increase the shot number. This functionality is controlled by the setting *ZoneSeqCoord*.

CircuitBreaker settings

CBReadyType: The selection depends on the type of performance available from the circuit breaker operating gear. At setting *OCO* (circuit breaker ready for an Open – Close – Open cycle), the condition is checked only at the start of the auto reclosing cycle. The signal will disappear after tripping, but the circuit breaker will still be able to perform the C-O sequence. For the selection *CO* (circuit breaker ready for a Close – Open cycle) the condition is also checked after the set auto reclosing dead time. This selection has a value first of all at multi-shot auto reclosing to ensure that the circuit breaker is ready for a C-O sequence at shot two and further shots. During single-shot auto reclosing, the *OCO* selection can be used. A breaker shall according to its duty cycle always have storing energy for a CO operation after the first trip. (IEC 56 duty cycle is O – 0.3sec – CO – 3min – CO).

FollowCB: The usual setting is *Follow CB = Off*. The setting *On* can be used for delayed auto reclosing with long delay, to cover the case when a circuit breaker is being manually closed during the auto reclosing dead time before the auto recloser has issued its breaker close command.

UnsucClByCBChk: The normal setting is *NoCBCheck* and the auto reclosing unsuccessful event is then decided by a new trip within the reclaim time after the last reclosing shot. If one wants to get the *UNSUCCL* (Reclosing is unsuccessful) signal in the case the circuit breaker does not respond to the circuit breaker close command, one can set *UnsucClByCBCheck = CB Check* and set *tUnsucCl* for instance to 1.0 s.

BlockByUnsucCl: Setting of whether an unsuccessful auto reclosing attempt shall set the auto recloser in blocked status. If used the *BLKOFF* input must be configured to unblock the function after an unsuccessful auto reclosing attempt. Normal setting is *Off*.

CutPulse: In circuit breakers without anti-pumping relays, the setting *CutPulse* = *On* can be used to avoid repeated closing operation when reclosing onto a fault. A new start will then cut the ongoing pulse.

tPulse: The circuit breaker closing command should be long enough to ensure reliable operation of the circuit breaker. The circuit breaker closing command pulse has a duration set by the *tPulse* setting. A typical setting may be *tPulse* = 200 ms. A longer pulse setting may facilitate dynamic indication at testing, for example, in debug mode of the Application Configuration Tool (ACT) in PCM600. In circuit breakers without anti-pumping relays, the setting *CutPulse* = *On* can be used to avoid repeated closing operations when reclosing onto a fault. A new start will then cut the ongoing pulse.

tReclaim: The reclaim time sets the time for resetting the function to its original state, after which a line fault and tripping will be treated as an independent new case with a new auto reclosing cycle. One may consider a nominal CB duty cycle of for instance, O – 0.3sec – CO – 3min – CO. However the 3 minute (180 s) recovery time is usually not critical as fault levels are mostly lower than rated value and the risk of a new fault within a short time is negligible. A typical time may be *tReclaim* = 60 or 180 s dependent on the fault level and circuit breaker duty cycle.

tSync: Maximum wait time for fulfilled synchrocheck conditions. The time window should be coordinated with the operate time and other settings of the synchrocheck function. Attention should also be paid to the possibility of a power swing when reclosing after a line fault. Too short a time may prevent a potentially successful auto reclosing.

tCBClosedMin: A typical setting is 5.0 s. If the circuit breaker has not been closed for at least this minimum time, an auto reclosing start will not be accepted.

tSuccessful: If the circuit breaker closing command is given and the circuit breaker is closed within the set time interval *tUnsucCl*, the *SUCCL* output is activated after the set time interval *tSuccessful*.

tUnsucCl: The reclaim timer, *tReclaim*, is started each time a circuit breaker closing command is given. If no start occurs within this time, the auto recloser will reset. A new start received in “reclaim time” status will reenter the auto recloser to “in progress” status as long as the final shot is not reached. The auto recloser will reset and enter “inactive” status if a new start is given during the final reclaim time. This will also happen if the circuit breaker has not closed within set time interval *tUnsucCl* at the end of the reclaim time. This latter case is controlled by setting *UnsucClByCBChk*. The auto reclosing sequence is considered unsuccessful for both above cases and the *UNSUCCL* output is activated.

DeadTime settings

NoOfShots: In power transmission one shot is mostly used. In most cases one auto reclosing shot is sufficient as the majority of arcing faults will cease after the first auto reclosing shot. In power systems with many other types of faults caused by other phenomena, for example wind, a greater number of auto reclosing attempts (shots) can be motivated.

t1 1Ph, t1 2Ph, t1 3Ph: There are separate settings for the first shot for single-, two- and three-phase auto reclosing dead times.

Single-phase auto reclosing dead time: A typical setting is *t1 1Ph* = 800ms. Due to the influence of energized phases the arc extinction may not be instantaneous. In long lines with high voltage the use of shunt reactors in the form of a star with a neutral reactor improves the arc extinction.

Three-phase auto reclosing dead time: Different local phenomena, such as moisture, salt, pollution, can influence the required dead time. Some users apply Delayed Auto Reclosing (DAR) with delays of 10s or more.

Extended t1: The time extension below is controlled by the *Extended t1* setting.

tExtended t1: A time extension delay, *tExtended t1*, can be added to the dead time delay for the first shot. It is intended to come into use if the communication channel for permissive line protection is

lost. The communication link in a permissive (not strict) line protection scheme, for instance a power line carrier (PLC) link, may not always be available. If lost, it can result in delayed tripping at one end of a line. There is a possibility to extend the auto reclosing dead time in such a case by use of the *PLCLOST* input, and the *tExtended t1* setting. Typical setting in such a case: *Extended t1 = On* and *tExtended t1 = 0.8 s*.

t1 3PhHS: There is also a separate time setting facility for three-phase high-speed auto reclosing, *t1 3PhHS*. This high-speed auto reclosing is activated by the *STARHS* input and is used when auto reclosing is done without the requirement of synchrocheck conditions to be fulfilled. A typical dead time is 400ms.

t2 3Ph, t3 3Ph, t4 3Ph, t5 3Ph: The delay of auto reclosing shot two and possible later shots are usually set at 30s or more. A check that the circuit breaker duty cycle can manage the selected setting must be done. The setting can in some cases be restricted by national regulations. For multiple shots the setting of shots two to five must be longer than the circuit breaker duty cycle time.

MasterSlave settings

Priority: In single circuit breaker applications, one sets *Priority = None*. At sequential reclosing the auto recloser for the first circuit breaker, e.g. near the busbar, is set as master (High) and the auto recloser for the second circuit breaker is set as slave (Low).

tWaitForMaster: The slave should take the duration of the circuit breaker closing time of the master into consideration before sending the circuit breaker closing command. A setting *tWaitForMaster* sets a maximum wait time for the *WAIT* input to reset. If the wait time expires, the auto reclosing cycle of the slave is inhibited. The maximum wait time, *tWaitForMaster* for the second circuit breaker is set longer than the auto reclosing dead time plus a margin for synchrocheck conditions to be fulfilled for the first circuit breaker. Typical setting is 2sec.

tSlaveDeadTime: When activating the *WAIT* input, in the auto recloser set as slave, every dead timer is changed to the value of setting *tSlaveDeadTime* and holds back the auto reclosing operation. When the *WAIT* input is reset at the time of a successful reclosing of the first circuit breaker, the slave is released to continue the auto reclosing sequence after the set *tSlaveDeadTime*. The reason for shortening the time, for the normal dead timers with the value of *tSlaveDeadTime*, is to give the slave permission to react almost immediately when the *WAIT* input resets. The minimum settable time for *tSlaveDeadTime* is 0.1sec because both master and slave should not send the circuit breaker closing command at the same time.

12.3 Apparatus control

12.3.1 Application

The apparatus control is a functionality for control and supervising of circuit breakers, disconnectors, and earthing switches within a bay. Permission to operate is given after evaluation of conditions from other functions such as interlocking, synchrocheck, operator place selection and external or internal blockings.

Figure [120](#) shows from which places the apparatus control function receives commands. The commands to an apparatus can be initiated from the Control Centre (CC), the station HMI or the local HMI on the IED front.

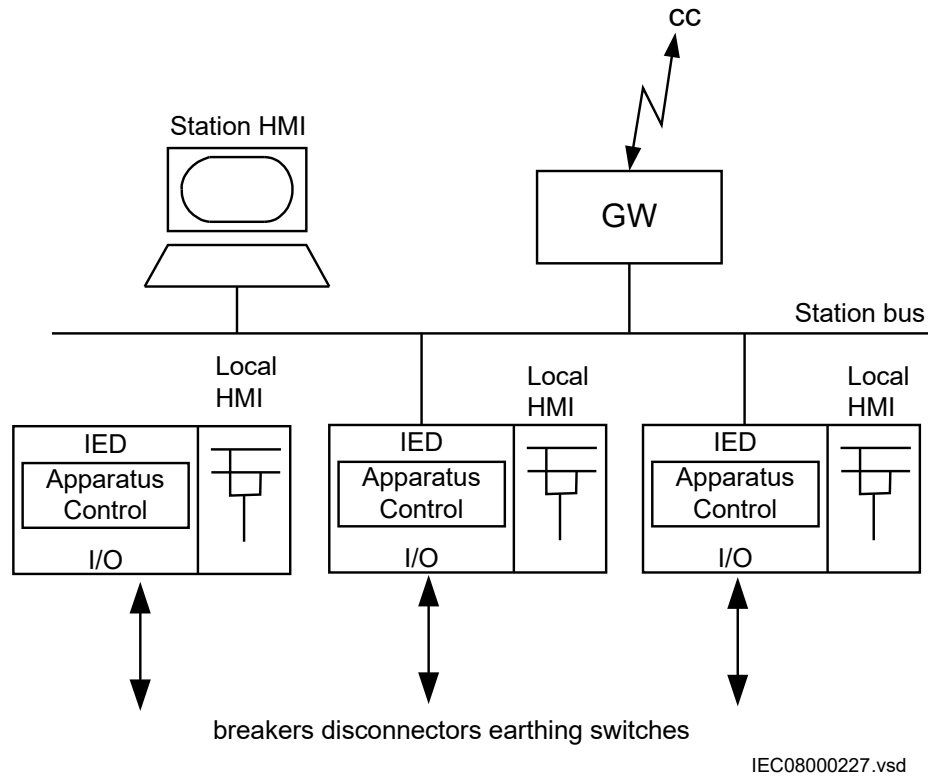


Figure 120: Overview of the apparatus control functions

Features in the apparatus control function:

- Operation of primary apparatuses
- Select-Execute principle to give high security
- Selection and supervision of operator place
- Command supervision
- Block/deblock of operation
- Block/deblock of updating of position indications
- Substitution of position indications
- Overriding of interlocking functions
- Overriding of synchrocheck
- Pole discordance supervision
- Operation counter
- Suppression of mid position

The apparatus control function is realized by means of a number of function blocks designated:

- Switch controller SCSWI
- Circuit breaker SXCBR
- Circuit switch SXSWI
- Bay control QCBAY
- Reservation input RESIN
- Local remote LOCREM
- Local remote LOCREM
- Local remote control LOCREMCTRL

When the circuit breaker or switch is located in a breaker IED, two more functions are added:

- GOOSE receive for switching device GOOSEXLNRCV
- Proxy for signals from switching device via GOOSE XLNPROXY

The extension of the signal flow and the usage of the GOOSE communication are shown in Figure [122](#).

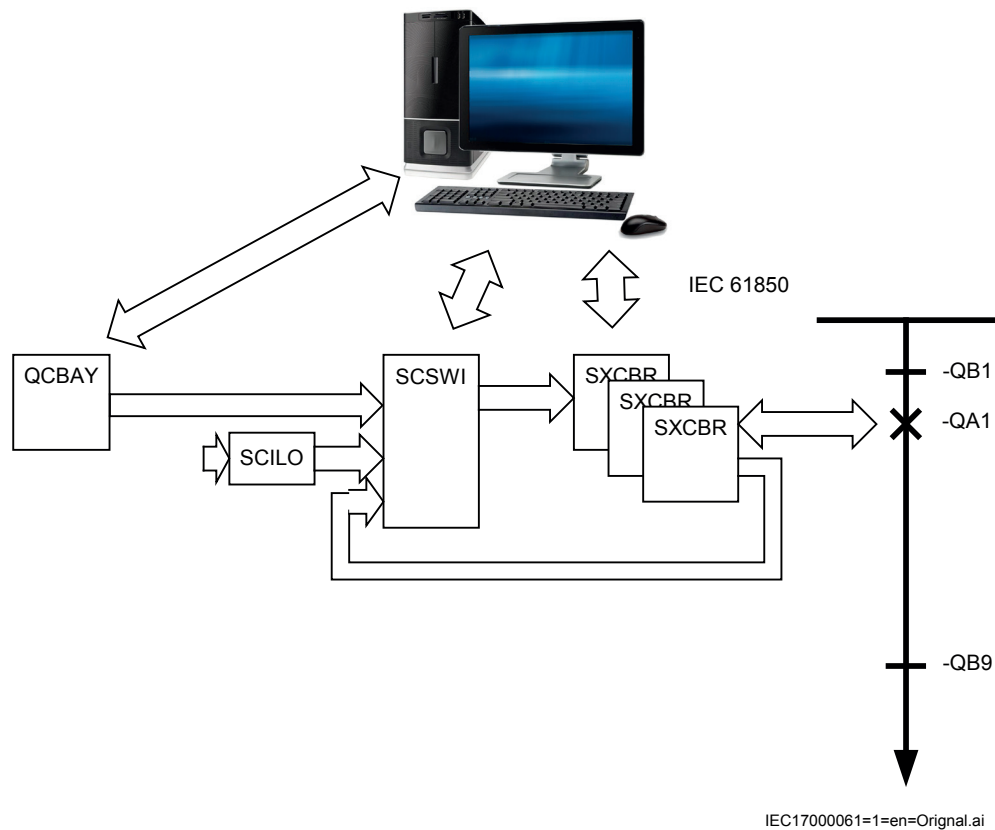


Figure 121: Signal flow between apparatus control function blocks when all functions are situated within the IED

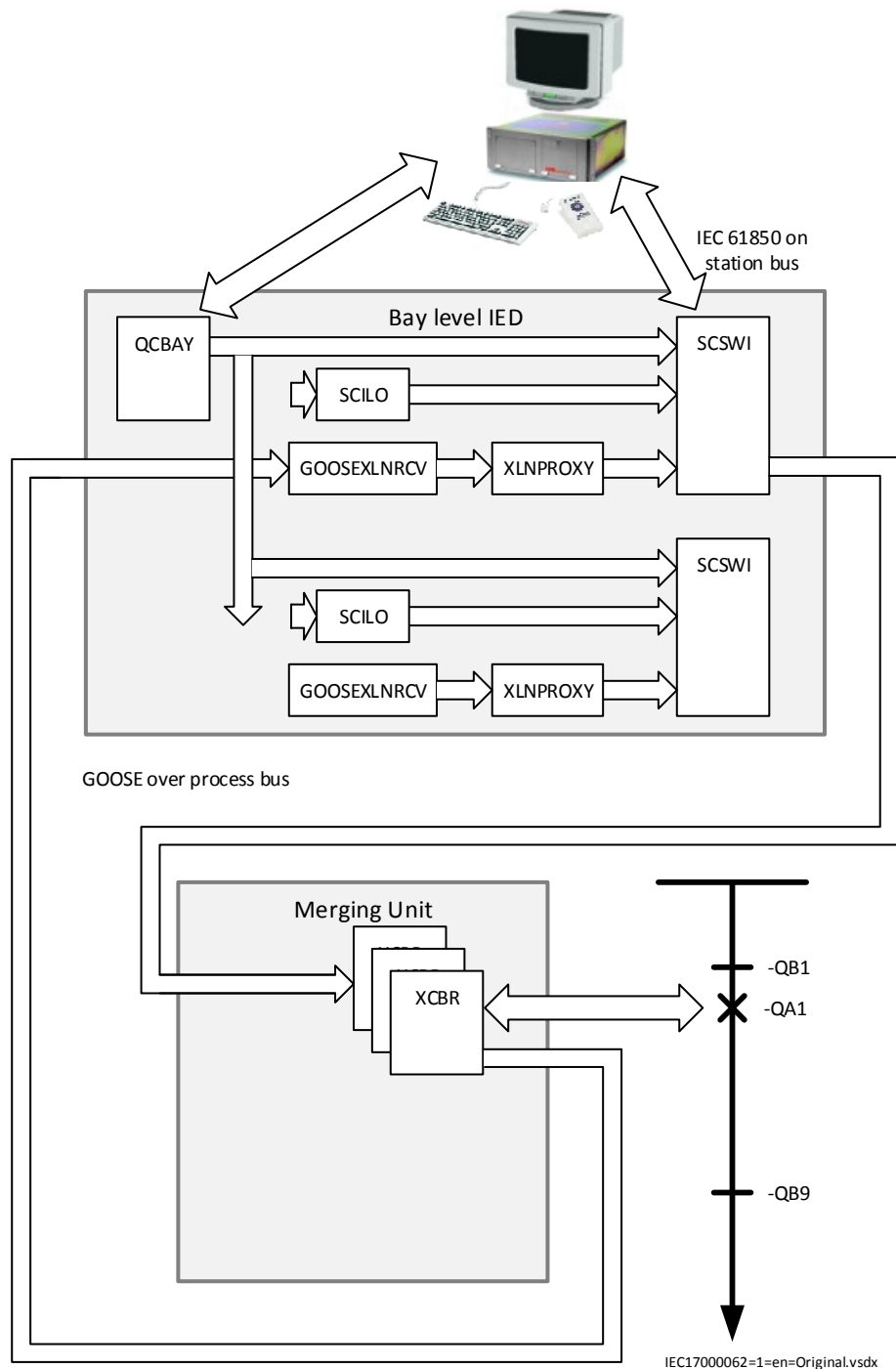


Figure 122: Signal flow between apparatus control functions with XCBR and XSWI located in a breaker IED

Control operation can be performed from the local IED HMI. If users are defined in the IED, then the local/remote switch is under authority control, otherwise the default user can perform control operations from the local IED HMI without logging in. The default position of the local/remote switch is on remote.

Accepted originator categories for PSTO

If the requested command is accepted by the authority control, the value will change. Otherwise the attribute *blocked-by-switching-hierarchy* is set in the *cause* signal. If the PSTO value is changed during a command, then the command is aborted.

The accepted originator categories for each PSTO value are shown in [Table 23](#).

Table 23: Accepted originator categories for each PSTO

Permitted Source To Operate	Originator (orCat)
0 = Off	4,5,6
1 = Local	1,4,5,6
2 = Remote	2,3,4,5,6
3 = Faulty	4,5,6
4 = Not in use	4,5,6
5 = All	1,2,3,4,5,6
6 = Station	2,4,5,6
7 = Remote	3,4,5,6

PSTO = All, then it is no priority between operator places. All operator places are allowed to operate.

According to IEC 61850 standard the *orCat* attribute in originator category are defined in [Table 24](#)

Table 24: orCat attribute according to IEC 61850

Value	Description
0	not-supported
1	bay-control
2	station-control
3	remote-control
4	automatic-bay
5	automatic-station
6	automatic-remote
7	maintenance
8	process

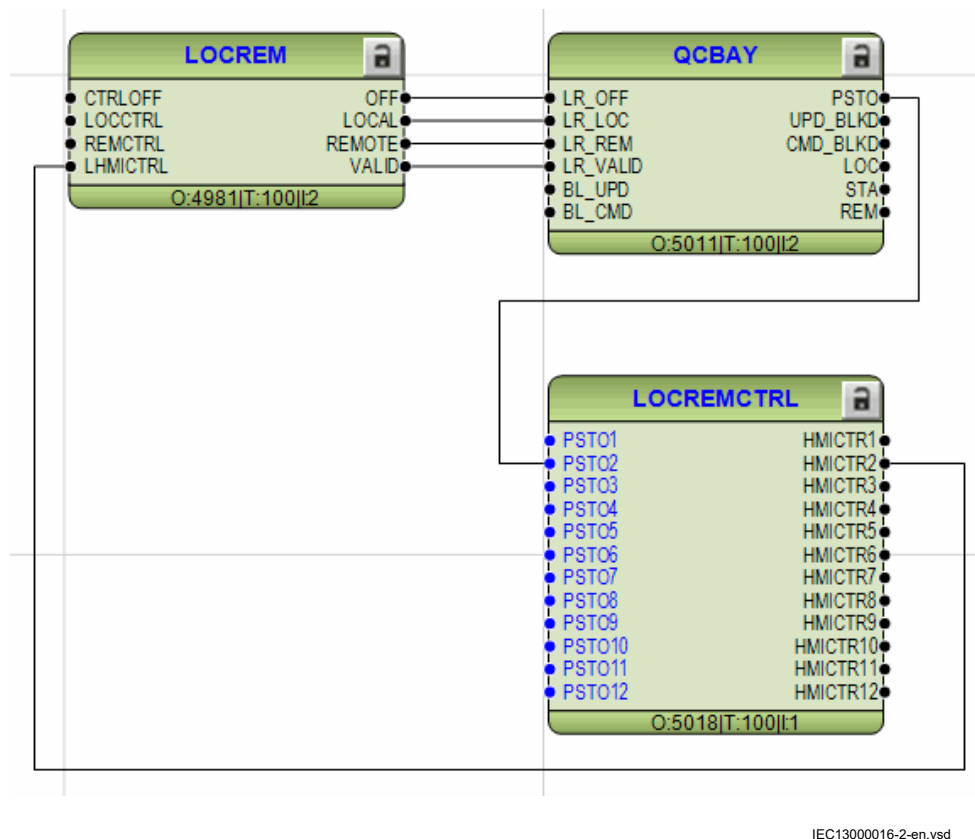
12.3.2 Bay control QCBAY

The Bay control (QCBAY) is used to handle the selection of the operator place per bay. The function gives permission to operate from two main types of locations either from Remote (for example, control centre or station HMI) or from Local (local HMI on the IED) or from all (Local and Remote). The Local/Remote switch position can also be set to Off, which means no operator place selected that is, operation is not possible either from local or from remote.

For IEC 61850-8-1 communication, the Bay Control function can be set to discriminate between commands with orCat station and remote (2 and 3). The selection is then done through the IEC 61850-8-1 edition 2 command LocSta.

QCBAY also provides blocking functions that can be distributed to different apparatuses within the bay. There are two different blocking alternatives:

- Blocking of update of positions
- Blocking of commands



IEC13000016-2-en.vsd

Figure 123: APC - Local remote function block

12.3.3 Switch controller SCSWI

SCSWI may handle and operate on one three-phase device or three one-phase switching devices.

After the selection of an apparatus and before the execution, the switch controller performs the following checks and actions:

- A request initiates to reserve other bays to prevent simultaneous operation.
- Actual position inputs for interlocking information are read and evaluated if the operation is permitted.
- The synchrocheck/synchronizing conditions are read and checked, and performs operation upon positive response.
- The blocking conditions are evaluated
- The position indications are evaluated according to given command and its requested direction (open or closed).

The command sequence is supervised regarding the time between:

- Select and execute.
- Select and until the reservation is granted.
- Execute and the final end position of the apparatus.
- Execute and valid close conditions from the synchrocheck.

At error the command sequence is cancelled.

In the case when there are three one-phase switches (SXCBR/SXSWI) connected to the switch controller function, the switch controller will "merge" the position of the three switches to the resulting three-phase position. In case of a pole discordance situation, that is, the positions of the one-phase switches are not equal for a time longer than a settable time; an error signal will be given.

The switch controller represents the content of the SCSWI logical node (according to IEC 61850) with mandatory functionality.

12.3.4 Switches SXCBR

Switches are functions used to close and interrupt an ac power circuit under normal conditions, or to interrupt the circuit under fault, or emergency conditions. The intention with these functions is to represent the lowest level of a power-switching device with or without short circuit breaking capability, for example, circuit breakers, disconnectors, earthing switches etc.

The purpose of these functions is to provide the actual status of positions and to perform the control operations, that is, pass all the commands to the primary apparatus via output boards and to supervise the switching operation and position.

Switches have the following functionalities:

- Local/Remote switch intended for the switchyard
- Block/deblock for open/close command respectively
- Update block/deblock of position indication
- Substitution of position indication
- Supervision timer that the primary device starts moving after a command
- Supervision of allowed time for intermediate position
- Definition of pulse duration for open/close command respectively

The realizations of these functions are done with SXCBR representing a circuit breaker.

Circuit breaker (SXCBR) can be realized either as three one-phase switches or as one three-phase switch.

The content of this function is represented by the IEC 61850 definitions for the logical node Circuit breaker (SXCBR) with mandatory functionality.

12.3.5 Proxy for signals from switching device via GOOSE XLNPROXY

The purpose of the proxy for signals from switching device via GOOSE (XLNPROXY) is to give the same internal representation of the position status and control response for a switch modeled in a breaker IED as if represented by a SXCBR or SCSWI function.

The command response functionality is dependent on the connection of the execution information, XIN, from the SCSWI function controlling the represented switch. Otherwise, the function only reflects the current status of the switch, such as blocking, selection, position, operating capability and operation counter.

Since different switches are represented differently on IEC 61850, the data that is mandatory to model in IEC 61850 is mandatory inputs and the other useful data for the command and status following is optional. To make it easy to choose which data to use for the XLNPROXY function, their usage is controlled by the connection of each data's signal input and valid input. These connections are usually from the GOOSEXLNRCV function (see Figure 124 and Figure 125). The data to GOOSEXLNRCV is used when using process bus and MU. Signals from MU are sent via GOOSE over the process bus.

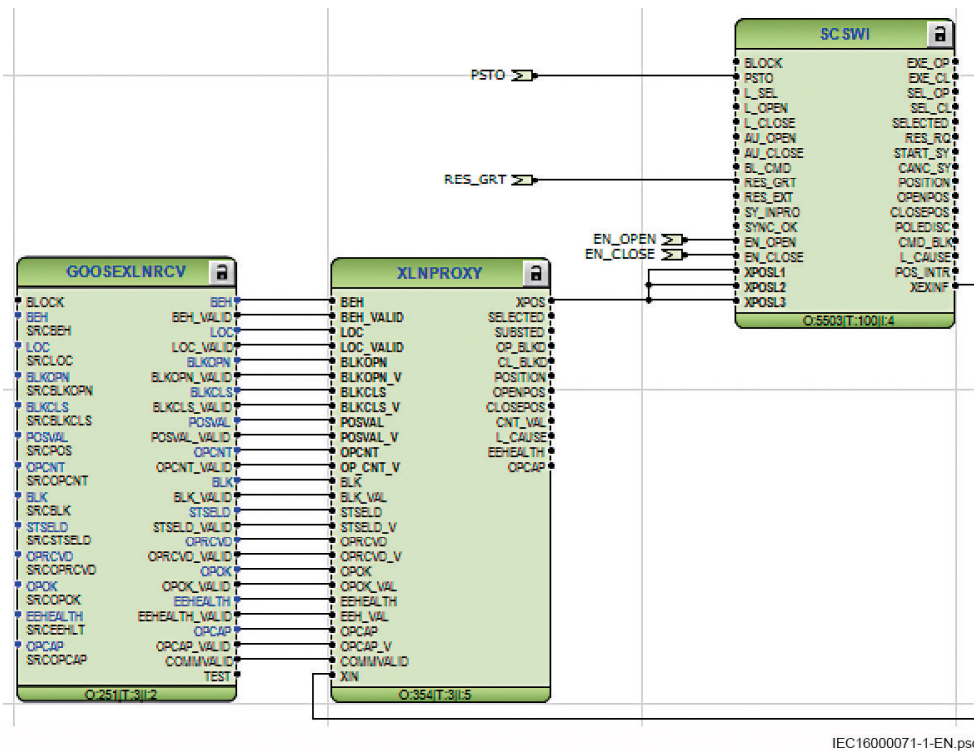


Figure 124: Configuration with XLNPROXY and GOOSEXLNRCV where all the IEC 61850 modelled data is used, including selection

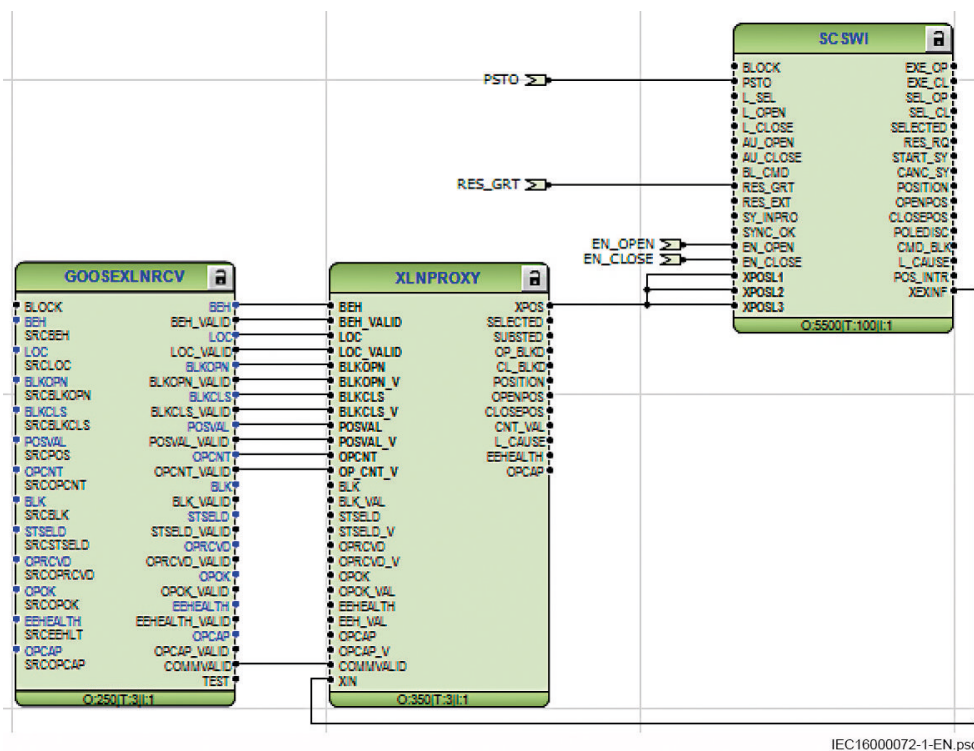


Figure 125: Configuration with XLNPROXY and GOOSEXLNRCV where only the mandatory data in the IEC 61850 modelling is used

All the information from the XLNPROXY to the SCSWI about command following status, causes for failed command and selection status is transferred in the output XPOS. The other outputs may be

used by other functions in the same way as the corresponding outputs of the SXCBB and SXSWI function.

When a command has been issued from the connected SCSWI function, the XLNPROXY function awaits the response on it from the represented switch through the inputs POSVAL and OPOK. While waiting for the switch to start moving, it checks if the switch is blocked for the operation. When the switch has started moving and no blocking condition has been detected, XLNPROXY issues a response to the SCSWI function that the command has started. If OPOK is used, this response is given when XLNPROXY receives the signal. These two LNs are only to be used when having XCBB/ XSWI in a separate IED (IO unit).

If no movement of the switch is registered within the limit $t_{StartMove}$, the command is considered failed, and the cause of the failure is evaluated. In the evaluation, the function checks if the state of the represented switch is indicating that the command is blocked in any way during the command, and gives the appropriate cause to the SCSWI function. This cause is also shown on the output L_CAUSE as indicated in the following table:

Table 25: Possible cause values from XLNPROXY

IEC 61850 ED1	IEC 61850 ED2	Cause Description	Conditions
8	8	Blocked-by-Mode	The BEH input is 5.
2	2	Blocked-by-switching-hierarchy	The LOC input indicates that only local commands are allowed for the breaker IED function.
-24	9	Blocked-for-open-cmd	The BLKOPN is active indicating that the switch is blocked for open commands.
-25	9	Blocked-for-close-cmd	The BLKCLS is active indicating that the switch is blocked for close commands.
9	9	Blocked-by-process	If the Blk input is connected and active indicating that the switch is dynamically blocked. Or if the OPCAP input is connected, it indicates that the operation capability of the switch is not enough to perform the command.
5	5	Position-reached	Switch is already in the intended position.
-33	16	Switch-not-start-moving	Switch did not start moving within $t_{StartMove}$.
-34	4	Persistent-intermediate-state	The switch stopped in intermediate state for longer than $t_{Intermediate}$.
-35	4	Switch-returned-to-init-pos	Switch returned to the initial position.
-32	4	Switch-in-bad-state	Switch is in a bad position.
-33	4	Not-expected-final-position	Switch did not reach the expected final position.



The OPCAP input and output are used for the CBOpCap data of a XCBB respectively SwOpCap for a XSWI. The interpretation for the command following is controlled through the setting *SwitchType*.



The minus values in the table are vendor-specific and only available in Edition 1.

12.3.6 Reservation function (QCRSV and RESIN)

The purpose of the reservation function is primarily to transfer interlocking information between IEDs in a safe way and to prevent double operation in a bay, switchyard part, or complete substation.

For interlocking evaluation in a substation, the position information from switching devices, such as circuit breakers, disconnectors and earthing switches can be required from the same bay or from several other bays. When information is needed from other bays, it is exchanged over the station bus between the distributed IEDs. The problem that arises, even at a high speed of communication, is a

space of time during which the information about the position of the switching devices are uncertain. The interlocking function uses this information for evaluation, which means that also the interlocking conditions are uncertain.

To ensure that the interlocking information is correct at the time of operation, a unique reservation method is available in the IEDs. With this reservation method, the bay that wants the reservation sends a reservation request to other bays and then waits for a reservation granted signal from the other bays. Actual position indications from these bays are then transferred over the station bus for evaluation in the IED. After the evaluation the operation can be executed with high security.

This functionality is realized over the station bus by means of the function blocks QCRSV and RESIN. The application principle is shown in Figure 126.

The function block QCRSV handles the reservation. It sends out either the reservation request to other bays or the acknowledgement if the bay has received a request from another bay.

The other function block RESIN receives the reservation information from other bays. The number of instances is the same as the number of involved bays (up to 60 instances are available). The received signals are either the request for reservation from another bay or the acknowledgment from each bay respectively, which have received a request from this bay. Also the information of valid transmission over the station bus must be received.

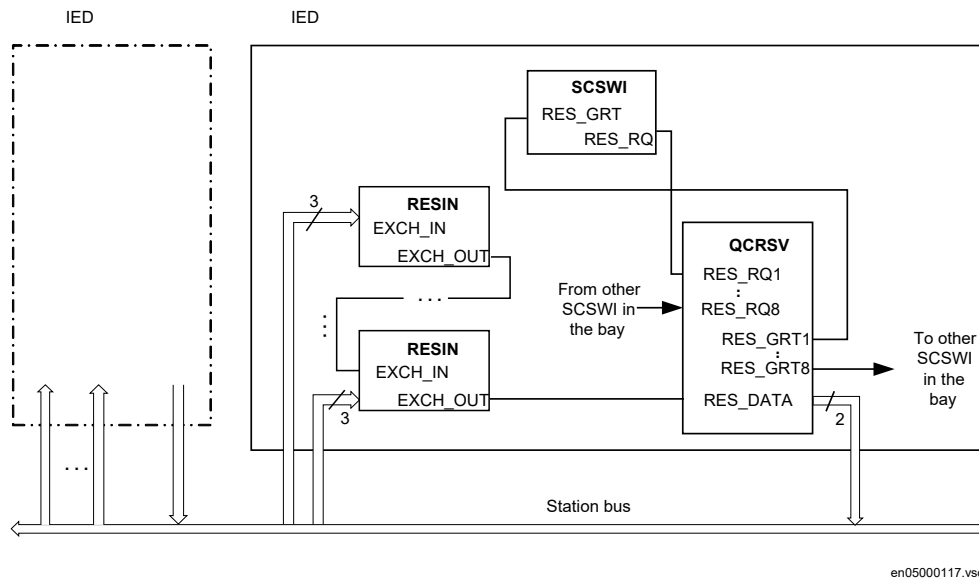


Figure 126: Application principles for reservation over the station bus

The reservation can also be realized with external wiring according to the application example in Figure 127. This solution is realized with external auxiliary relays and extra binary inputs and outputs in each IED, but without use of function blocks QCRSV and RESIN.

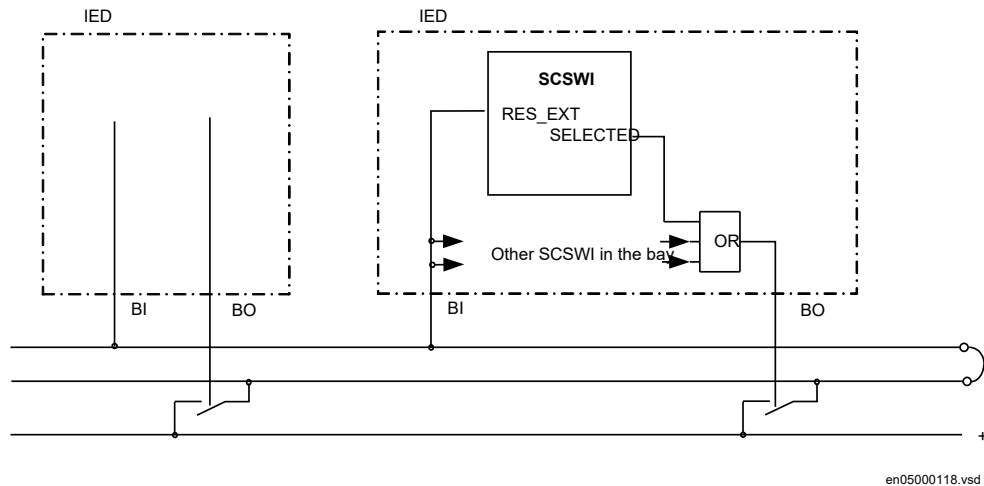


Figure 127: Application principles for reservation with external wiring

The solution in Figure 127 can also be realized over the station bus according to the application example in Figure 128. The solutions in Figure 127 and Figure 128 do not have the same high security compared to the solution in Figure 126, but instead have a higher availability, since no acknowledgment is required.

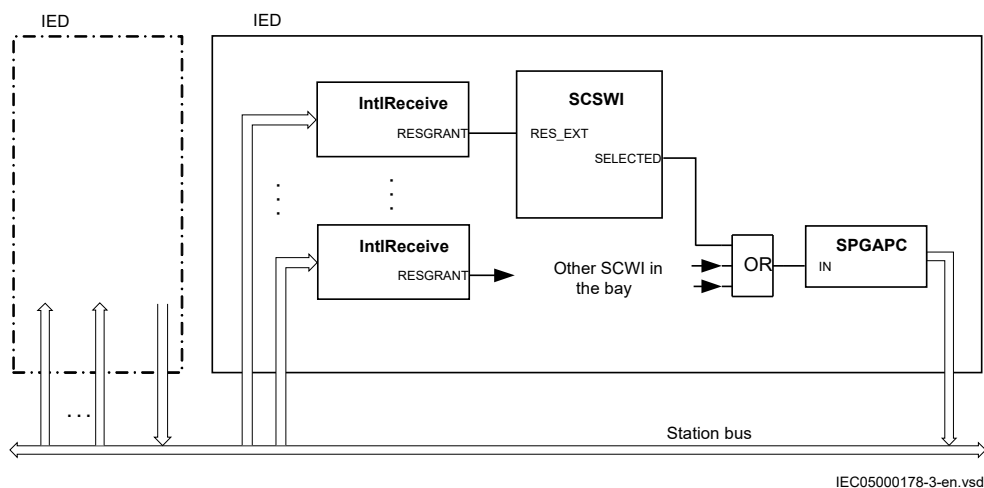


Figure 128: Application principle for an alternative reservation solution

12.3.7 Interaction between modules

A typical bay with apparatus control function consists of a combination of logical nodes or functions that are described here:

- The Switch controller (SCSWI) initializes all operations for one apparatus. It is the command interface of the apparatus. It includes the position reporting as well as the control of the position
- The Circuit breaker (SXCBB) is the process interface to the circuit breaker for the apparatus control function.
- The Bay control (QCBAY) fulfils the bay-level functions for the apparatuses, such as operator place selection and blockings for the complete bay.
- The Protection trip logic (SMPPTRC) connects the "trip" outputs of one or more protection functions to a common "trip" to be transmitted to SXCBB.
- The Autorecloser (SMBRREC) consists of the facilities to automatically close a tripped breaker with respect to a number of configurable conditions.

- The logical node Interlocking (SCILO) provides the information to SCSWI whether it is permitted to operate due to the switchyard topology. The interlocking conditions are evaluated with separate logic and connected to SCILO .
- The Synchrocheck, energizing check, and synchronizing (SESRSYN) calculates and compares the voltage phasor difference from both sides of an open breaker with predefined switching conditions (synchrocheck). Also the case that one side is dead (energizing-check) is included.
- The Generic Automatic Process Control function, GAPC, handles generic commands from the operator to the system.

The overview of the interaction between these functions is shown in Figure 129 below.

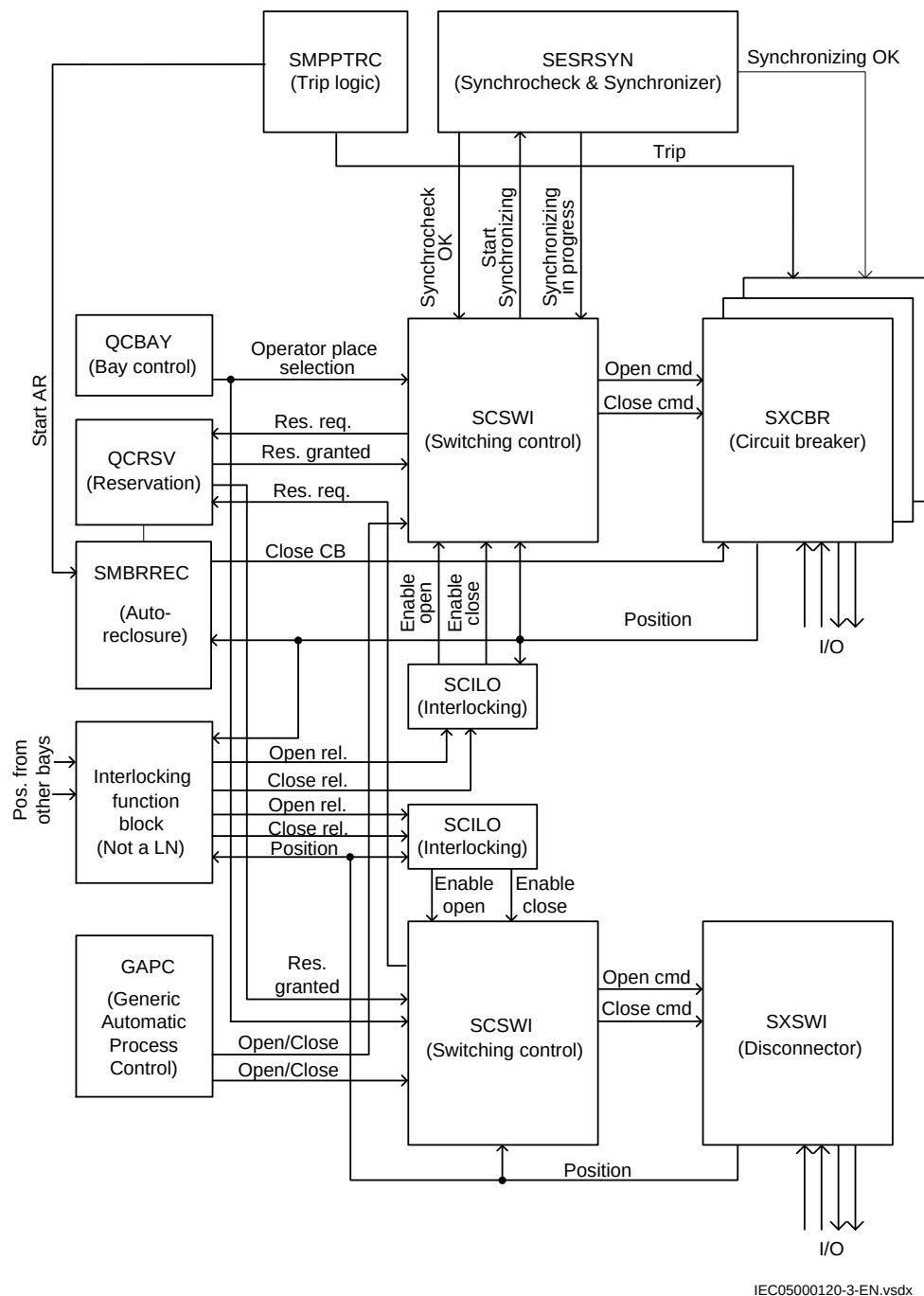


Figure 129: Example overview of the interactions between functions in a typical bay

When the protection trip is routed through the SXCBR function, consideration has to be taken to if the blocking conditions for the breaker should also stop activation from the protection functions. If the trip

is allowed to override the blocking conditions used, the trip signal can be used for inhibiting the blocking signals, such as BL_OPEN and CBOPCAP. An example is as shown in [Figure 130](#).

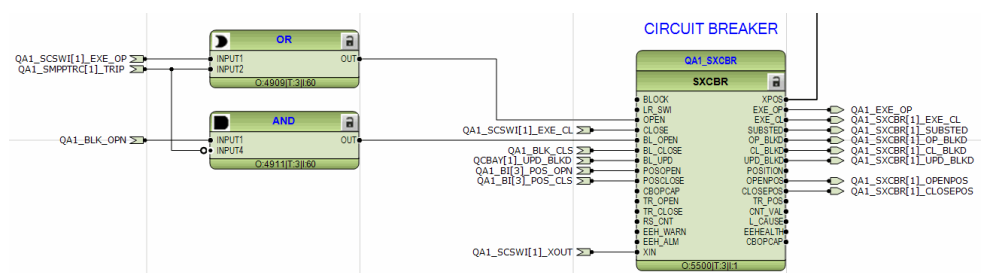


Figure 130: Example of how to allow the TRIP signal from SMPPTRC to override the blocked for open conditions

12.3.8 Setting guidelines

The setting parameters for the apparatus control function are set via the local HMI or PCM600.

12.3.8.1 Bay control (QCBAY)

If the parameter *AllPSTOValid* is set to *No priority*, all originators from local and remote are accepted without any priority.

If the parameter *RemoteIncStation* is set to *Yes*, commands from IEC 61850-8-1 clients at both station and remote level are accepted, when the QCBAY function is in Remote. If set to *No*, the command *LocSta* controls which operator place is accepted when QCBAY is in Remote. If *LocSta* is true, only commands from station level are accepted, otherwise only commands from remote level are accepted.



The parameter *RemoteIncStation* has only effect on the IEC 61850-8-1 communication. Further, when using IEC 61850 edition 1 communication, the parameter should be set to *Yes*, since the command *LocSta* is not defined in IEC 61850-8-1 edition 1.

12.3.8.2 Switch controller (SCSWI)

The parameter *CtlModel* specifies the type of control model according to IEC 61850. The default for control of circuit breakers, disconnectors and earthing switches the control model is set to *SBO Enh* (Select-Before-Operate with enhanced security).

When the operation shall be performed in one step, and no monitoring of the result of the command is desired, the model direct control with normal security is used.

At control with enhanced security there is an additional supervision of the status value by the control object, which means that each command sequence is terminated by a termination response.

The parameter *PosDependent* gives permission to operate depending on the position indication. At *Always permitted*, it is always permitted to operate independent of the value of the position. At *Not perm 00/11* it is not permitted to operate if the position is in bad or intermediate state. At *Not perm cPos*, it is not permitted to operate if the command is to move to the current position. At *Not perm cPos/00/11*, it is not permitted to operate if the command is to move to the current position, or the position is in bad or intermediate state.

tSelect is the maximum allowed time between the select and the execute command signal, that is, the time the operator has to perform the command execution after the selection of the object to operate. When the time has expired, the selected output signal is set to false and a cause-code is given.

The time parameter *tResResponse* is the allowed time from reservation request to the feedback reservation granted from all bays involved in the reservation function. When the time has expired, the control function is reset, and a cause-code is given.

tSynchrocheck is the allowed time for the synchrocheck function to fulfill the close conditions. When the time has expired, the function tries to start the synchronizing function. If *tSynchrocheck* is set to 0, no synchrocheck is done, before starting the synchronizing function.

The timer *tSynchronizing* supervises that the signal synchronizing in progress is obtained in SCSWI after start of the synchronizing function. The start signal for the synchronizing is set if the synchrocheck conditions are not fulfilled. When the time has expired, the control function is reset, and a cause-code is given. If no synchronizing function is included, the time is set to 0, which means no start of the synchronizing function is done, and when *tSynchrocheck* has expired, the control function is reset and a cause-code is given.

tExecutionFB is the maximum time between the execute command signal and the command termination. When the time has expired, the control function is reset and a cause-code is given.

tPoleDiscord is the allowed time to have discrepancy between the poles at control of three one-phase breakers. At discrepancy an output signal is activated to be used for trip or alarm, and during a command, the control function is reset, and a cause-code is given.

SuppressMidPos when *On* suppresses the mid-position during the time *tIntermediate* of the connected switches.

The parameter *InterlockCheck* decides if interlock check should be done at both select and operate, Sel & Op phase, or only at operate, Op phase.

12.3.8.3 Switch (SXCBR)

tStartMove is the supervision time for the apparatus to start moving after a command execution is done from the SCSWI function. When the time has expired, the command supervision is reset, and a cause-code is given.

During the *tIntermediate* time, the position indication is allowed to be in an intermediate (00) state. When the time has expired, the command supervision is reset, and a cause-code is given. The indication of the mid-position at SCSWI is suppressed during this time period when the position changes from open to close or vice-versa if the parameter *SuppressMidPos* is set to *On* in the SCSWI function.

If the parameter *AdaptivePulse* is set to *Adaptive* the command output pulse resets when a new correct end position is reached. If the parameter is set to *Not adaptive* the command output pulse remains active until the timer *tOpenPulsetClosePulse* has elapsed.

tOpenPulse is the output pulse length for an open command. If *AdaptivePulse* is set to *Adaptive*, it is the maximum length of the output pulse for an open command. The default length is set to 200 ms for a circuit breaker (SXCBR).

tClosePulse is the output pulse length for a close command. If *AdaptivePulse* is set to *Adaptive*, it is the maximum length of the output pulse for an open command. The default length is set to 200 ms for a circuit breaker (SXCBR).

12.3.8.4 Proxy for signals from switching device via GOOSE XLNPROXY

The *SwitchType* setting controls the evaluation of the operating capability. If *SwitchType* is set to *Circuit Breaker*, the input OPCAP is interpreted as a breaker operating capability, otherwise it is interpreted as a switch operating capability.

Table 26: Operating capability values for breaker/switches

Value	Breaker operating capability, CbOpCap	Switch operating capability, SwOpCap
1	None	None
2	Open	Open
3	Close – Open	Close
4	Open – Close – Open	Close and Open
5	Close – Open – Close – Open	Larger values handled as 4, both Close and Open
6	Open – Close – Open – Close – Open	
7	more	

tStartMove is the supervision time for the apparatus to start moving after a command execution is done from the SCSWI function. When the time has expired, the command supervision is reset, and a cause-code is given.

During the *tIntermediate* time, the position indication is allowed to be in an intermediate (00) state. When the time has expired, the command supervision is reset, and a cause-code is given. The indication of the mid-position at SCSWI is suppressed during this time period when the position changes from open to close or vice-versa if the parameter *SuppressMidPos* is set to *On* in the SCSWI function.

In most cases, the same value can be used for both *tStartMove* and *tIntermediate* as in the source function. However, *tStartMove* may need to be increased to accommodate for the communication delays, mainly when representing a circuit breaker.

12.3.8.5 Bay Reserve (QCRSV)

The timer *tCancelRes* defines the supervision time for canceling the reservation, when this cannot be done by requesting bay due to for example communication failure.

When the parameter *ParamRequestx* (x=1-8) is set to *Only own bay res.* individually for each apparatus (x) in the bay, only the own bay is reserved, that is, the output for reservation request of other bays (RES_BAYS) will not be activated at selection of apparatus x.

12.3.8.6 Reservation input (RESIN)

With the *FutureUse* parameter set to *Bay future use* the function can handle bays not yet installed in the SA system.

12.4 Logic rotating switch for function selection and LHMI presentation SLGAPC

12.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Logic rotating switch for function selection and LHMI presentation	SLGAPC	-	-

12.4.2 Application

The logic rotating switch for function selection and LHMI presentation function (SLGAPC) (or the selector switch function block, as it is also known) is used to get a selector switch functionality similar with the one provided by a hardware multi-position selector switch. Hardware selector switches are used extensively by utilities, in order to have different functions operating on pre-set values. Hardware switches are however sources for maintenance issues, lower system reliability and extended purchase portfolio. The virtual selector switches eliminate all these problems.

SLGAPC function block has two operating inputs (UP and DOWN), one blocking input (BLOCK) and one operator position input (PSTO).

SLGAPC can be activated both from the local HMI and from external sources (switches) via the IED binary inputs. It also allows the operation from remote (like the station computer). SWPOSN is an integer value output, giving the actual output number. Since the number of positions of the switch can be established by settings (see below), one must be careful in coordinating the settings with the configuration (if one sets the number of positions to x in settings – for example, there will be only the first x outputs available from the block in the configuration). Also the frequency of the (UP or DOWN) pulses should be lower than the setting $tPulse$.

From the local HMI, the selector switch can be operated from Single-line diagram (SLD).

12.4.3 Setting guidelines

The following settings are available for the Logic rotating switch for function selection and LHMI presentation (SLGAPC) function:

Operation: Sets the operation of the function *On* or *Off*.

NrPos: Sets the number of positions in the switch (max. 32).

OutType: *Steady* or *Pulsed*.

tPulse: In case of a pulsed output, it gives the length of the pulse (in seconds).

tDelay: The delay between the UP or DOWN activation signal positive front and the output activation.

StopAtExtremes: Sets the behavior of the switch at the end positions – if set to *Disabled*, when pressing UP while on first position, the switch will jump to the last position; when pressing DOWN at the last position, the switch will jump to the first position; when set to *Enabled*, no jump will be allowed.

12.5 Selector mini switch VSGAPC

12.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Selector mini switch	VSGAPC	-	43

12.5.2 Application

Selector mini switch (VSGAPC) function is a multipurpose function used in the configuration tool in PCM600 for a variety of applications, as a general purpose switch. VSGAPC can be used for both

acquiring an external switch position (through the IPOS1 and the IPOS2 inputs) and represent it through the single line diagram symbols (or use it in the configuration through the outputs POS1 and POS2) as well as, a command function (controlled by the PSTO input), giving switching commands through the CMDPOS12 and CMDPOS21 outputs.

The output POSITION is an integer output, showing the actual position as an integer number 0 – 3, where 0 = MidPos, 1 = Open, 2 = Closed and 3 = Error.

An example where VSGAPC is configured to switch Autorecloser on–off from a button symbol on the local HMI is shown in figure 131. The I and O buttons on the local HMI are normally used for on–off operations of the circuit breaker.

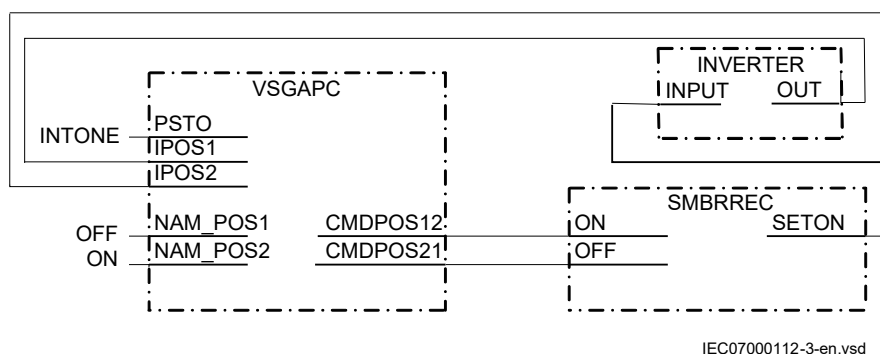


Figure 131: Control of Autorecloser from local HMI through Selector mini switch

VSGAPC is also provided with IEC 61850 communication so it can be controlled from SA system as well.

12.5.3 Setting guidelines

Selector mini switch (VSGAPC) function can generate pulsed or steady commands (by setting the *Mode* parameter). When pulsed commands are generated, the length of the pulse can be set using the *tPulse* parameter. Also, being accessible on the single line diagram (SLD), this function block has two control modes (settable through *CtlModel*): *Dir Norm* and *SBO Enh*.

12.6 Generic communication function for double point indication DPGAPC

12.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Generic communication function for double point indication	DPGAPC	-	-

12.6.2 Application

Generic communication function for double point indication (DPGAPC) function block is used to send double point position indication to other systems, equipment or functions in the substation through IEC 61850-8-1 or other communication protocols. It is especially intended to be used in the interlocking station-wide logics. To be able to get the signals into other systems, equipment or functions, one must use other tools, described in the Engineering manual, and define which function block in which systems, equipment or functions should receive this information.

More specifically, DPGAPC function reports a combined double point position indication output POSITION, by evaluating the value and the timestamp attributes of the inputs OPEN and CLOSE, together with the logical input signal VALID.

When the input signal VALID is active, the values of the OPEN and CLOSE inputs determine the two-bit integer value of the output POSITION. The timestamp of the output POSITION will have the latest updated timestamp of the inputs OPEN and CLOSE.

When the input signal VALID is inactive, DPGAPC function forces the position to intermediated state.

When the value of the input signal VALID changes, the timestamp of the output POSITION will be updated as the time when DPGAPC function detects the change.

Refer to Table 27 for the description of the input-output relationship in terms of the value and the quality attributes.

Table 27: Description of the input-output relationship

VALID	OPEN	CLOSE	POSITION	
			Value	Description
0	-	-	0	Intermediate
1	0	0	0	Intermediate
1	1	0	1	Open
1	0	1	2	Closed
1	1	1	3	Bad State

12.6.3 Setting guidelines

The function does not have any parameters available in the local HMI or PCM600.

12.7 Single point generic control 8 signals SPC8GAPC

12.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Single point generic control 8 signals	SPC8GAPC	-	-

12.7.2 Application

The Single point generic control 8 signals (SPC8GAPC) function block is a collection of 8 single point commands that can be used for direct commands for example reset of LED's or putting IED in "ChangeLock" state from remote. In this way, simple commands can be sent directly to the IED outputs, without confirmation. Confirmation (status) of the result of the commands is supposed to be achieved by other means, such as binary inputs and SPGAPC function blocks.



PSTO is the universal operator place selector for all control functions. Even if PSTO can be configured to allow LOCAL or ALL operator positions, the only functional position usable with the SPC8GAPC function block is REMOTE.

12.7.3 Setting guidelines

The parameters for the single point generic control 8 signals (SPC8GAPC) function are set via the local HMI or PCM600.

Operation: turning the function operation *On/Off*.

There are two settings for every command output (totally 8):

PulseModex: decides if the command signal for output *x* is *Latched* (steady) or *Pulsed*.

tPulsex: if *PulseModex* is set to *Pulsed*, then *tPulsex* will set the length of the pulse (in seconds).

12.8 AutomationBits, command function for DNP3.0 AUTOBITS

12.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
AutomationBits, command function for DNP3	AUTOBITS	-	-

12.8.2 Application

Automation bits, command function for DNP3 (AUTOBITS) is used within PCM600 in order to get into the configuration the commands coming through the DNP3.0 protocol. The AUTOBITS function plays the same role as functions GOOSEBINRCV (for IEC 61850) and MULTICMDRCV (for LON).

AUTOBITS function block have 32 individual outputs which each can be mapped as a Binary Output point in DNP3. The output is operated by a "Object 12" in DNP3. This object contains parameters for control-code, count, on-time and off-time. To operate an AUTOBITS output point, send a control-code of latch-On, latch-Off, pulse-On, pulse-Off, Trip or Close. The remaining parameters are regarded as appropriate. For example, pulse-On, on-time=100, off-time=300, count=5 would give 5 positive 100 ms pulses, 300 ms apart.

For description of the DNP3 protocol implementation, refer to the Communication manual.

12.8.3 Setting guidelines

AUTOBITS function block has one setting, (*Operation*: *On/Off*) enabling or disabling the function. These names will be seen in the DNP3 communication management tool in PCM600.

12.9 Single command, 16 inputs SINGLECMD

12.9.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Single command, 16 inputs	SINGLECMD	-	-

12.9.2 Application

Single command, 16 inputs (SINGLECMD) is a common function and always included in the IED.

The IEDs may be provided with a function to receive commands either from a substation automation system or from the local HMI. That receiving function block has outputs that can be used, for example, to control high voltage apparatuses in switchyards. For local control functions, the local HMI can also be used. Together with the configuration logic circuits, the user can govern pulses or steady output signals for control purposes within the IED or via binary outputs.

Figure 132 shows an application example of how the user can connect SINGLECMD via configuration logic circuit to control a high-voltage apparatus. This type of command control is normally carried out by sending a pulse to the binary outputs of the IED. Figure 132 shows a close operation. An open breaker operation is performed in a similar way but without the synchro-check condition.



This function is only used for SPA and LON communication.

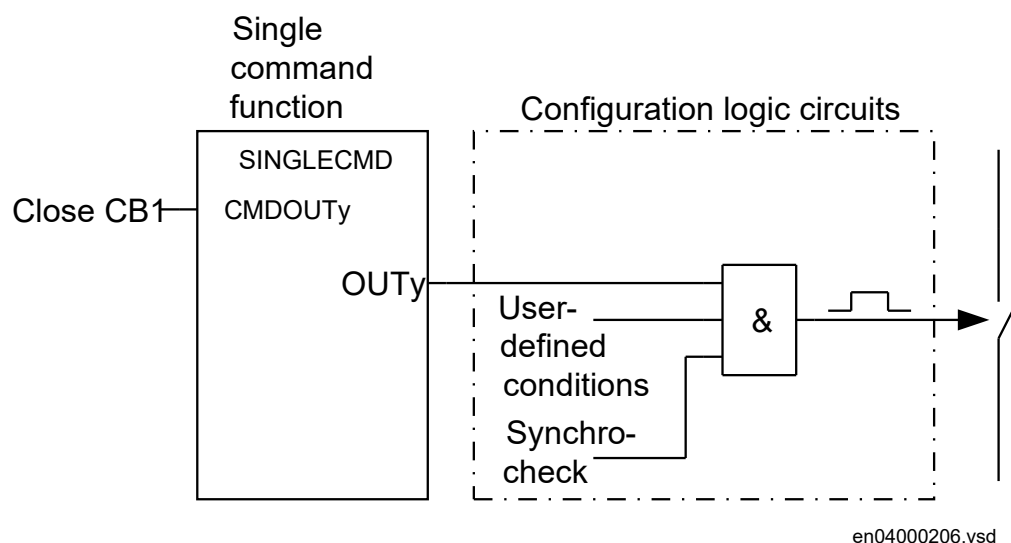


Figure 132: Application example showing a logic diagram for control of a circuit breaker via configuration logic circuits

Figure 133 and figure 134 show other ways to control functions, which require steady On/Off signals. Here, the output is used to control built-in functions or external devices.

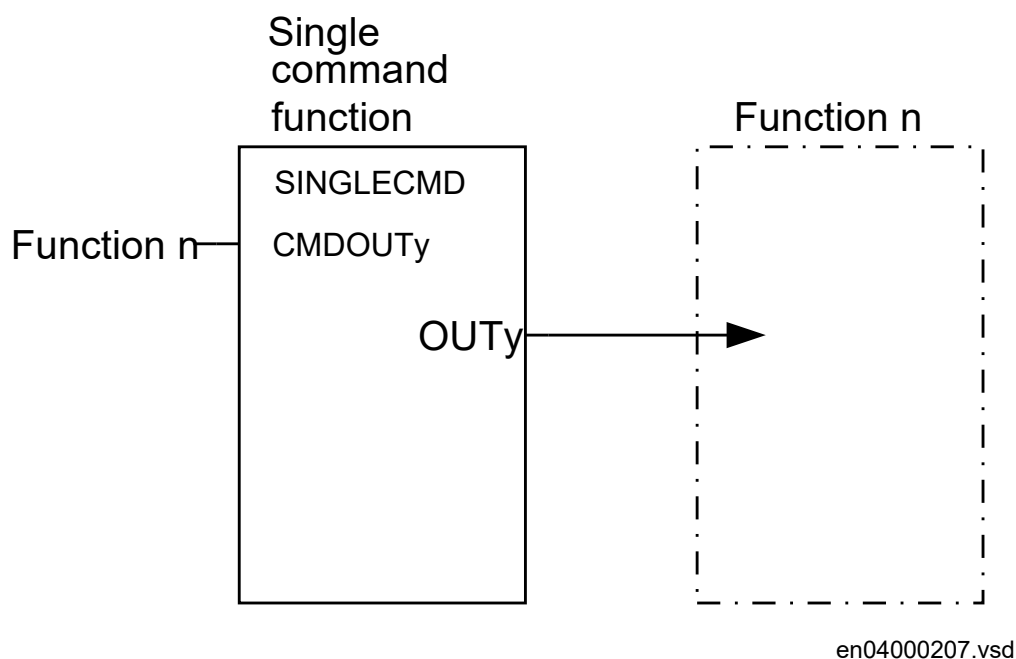


Figure 133: Application example showing a logic diagram for control of built-in functions

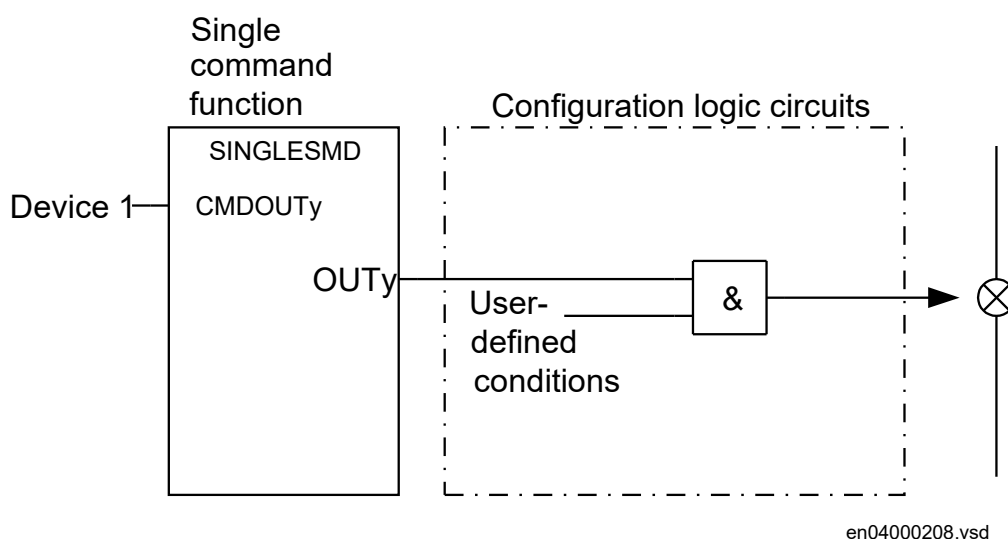


Figure 134: Application example showing a logic diagram for control of external devices via configuration logic circuits

12.9.3 Setting guidelines

The parameters for Single command, 16 inputs (SINGLECMD) are set via the local HMI or PCM600.

Parameters to be set are MODE, common for the whole block, and CMDOUTy which includes the user defined name for each output signal. The MODE input sets the outputs to be one of the types Off, Steady, or Pulse.

- Off, sets all outputs to 0, independent of the values sent from the station level, that is, the operator station or remote-control gateway.
- Steady, sets the outputs to a steady signal 0 or 1, depending on the values sent from the station level.
- Pulse, gives a pulse with 100 ms duration, if a value sent from the station level is changed from 0 to 1. That means the configured logic connected to the command function block may not have a cycle time longer than the cycle time for the command function block.

Section 13 Scheme communication

13.1 Scheme communication logic for distance or overcurrent protection ZCPSCH

13.1.1 Function revision history

Document revision	Product revision	History
B	2.2.1	-
C	2.2.2	-
D	2.2.2	
E	2.2.2	-
F	2.2.3	-
G	2.2.3	-
H	2.2.3	-
J	2.2.4	-
K	2.2.4	-
L	2.2.4	
M	2.2.5	Added separate DOs for teleprotection permissive (<i>TxPrm</i> & <i>RxPrm1</i>), blocking (<i>TxBlk</i> & <i>RxBlk1</i>) and direct trip (<i>TxTr</i> & <i>RxTr1</i>) transmit and receive signals in accordance with 61850 Ed 2.0.
N	2.2.6	-
P	2.2.6	-

13.1.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Scheme communication logic for distance or overcurrent protection	ZCPSCH	-	85

13.1.3 Application

To achieve fast fault clearing for a fault on the part of the line not covered by the instantaneous zone 1, the stepped distance protection function can be supported with logic that uses a communication channel.

One communication channel in each direction, which can transmit an on/off signal is required. The performance and security of this function is directly related to the transmission channel speed and security against false or lost signals. Communication speed, or minimum time delay, is always of utmost importance because the purpose for using communication is to improve the tripping speed of the scheme.

To avoid false signals that could cause false tripping, it is necessary to pay attention to the security of the communication channel. At the same time it is important to pay attention to the communication channel dependability to ensure that proper signals are communicated during power system faults, the time during which the protection schemes must perform their tasks flawlessly.

The logic supports the following communications schemes:

- blocking schemes (blocking and delta blocking)
- permissive schemes (overreaching and underreaching)
- unblocking scheme and direct intertrip

A permissive scheme is inherently faster and has better security against false tripping than a blocking scheme. On the other hand, a permissive scheme depend on a received CR signal for a fast trip, so its dependability is lower than that of a blocking scheme.

13.1.3.1 Blocking schemes

In a blocking scheme a reverse looking zone is used to send a block signal to the remote end to block an overreaching zone.

Since the scheme is sending the blocking signal during conditions where the protected line is healthy, it is common to use the line itself as communication media (PLC). The scheme can be used on all line lengths.

The blocking scheme is very dependable because it will operate for faults anywhere on the protected line if the communication channel is out of service. On the other hand, it is less secure than permissive schemes because it will trip for external faults within the reach of the tripping function if the communication channel is out of service.

Inadequate speed or dependability can cause spurious tripping for external faults. Inadequate security can cause delayed tripping for internal faults.

To secure that the send signal will arrive before the zone used in the communication scheme will trip, the trip is released first after the time delay t_{Coord} has elapsed. The setting of t_{Coord} must be set longer than the maximal transmission time of the channel. A security margin of at least 10 ms should be considered.

The timer $t_{SendMin}$ for prolonging the send signal is proposed to set to zero.

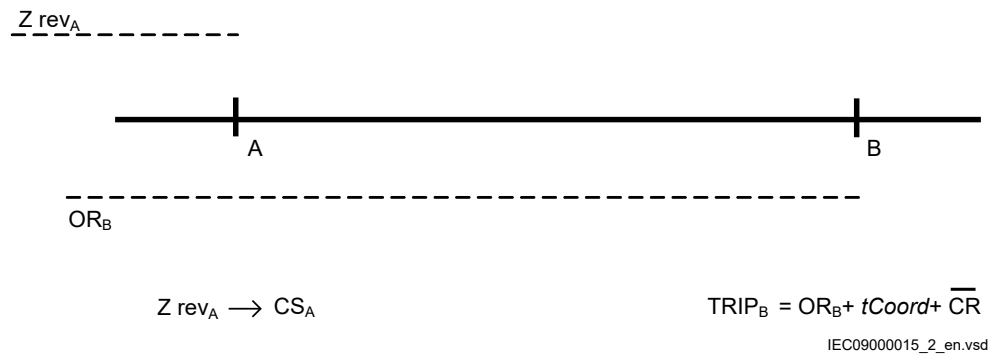


Figure 135: Principle of blocking scheme

OR: Overreaching
CR: Communication signal received
CS: Communication signal send
Z rev_A: Reverse zone

13.1.3.2 Delta blocking scheme

In the delta blocking scheme a fault inception detection element using delta based quantities of voltage and current will send a block signal to the remote end to block an overreaching zone.

The delta based start is very fast and if the transmission channel is fast then there is no need for delaying the operation of remote distance element. If the fault is in forward direction, the sending is inhibited by a forward directed distance (or directional current or directional earth fault) element.

Since the scheme is sending the blocking signal during conditions where the protected line is healthy, it is common to use the line itself as communication media (PLC). The scheme can be used on all line lengths.

The blocking scheme is very dependable because it will operate for faults anywhere on the protected line if the communication channel is out of service. Conversely, it is less secure than permissive schemes because it will trip for external faults within the reach of the tripping function if the communication channel is out of service.

Inadequate speed or dependability can cause spurious tripping for external faults. Inadequate security can cause delayed tripping for internal faults.

Since the blocking signal is initiated by the delta based detection which is very fast the time delay t_{Coord} can be set to zero seconds, except in cases where the transmission channel is slow.

The timer $t_{SendMin}$ for prolonging the send signal is proposed to set to zero.

DeltaBasedDetection (deltaA) _ _ _

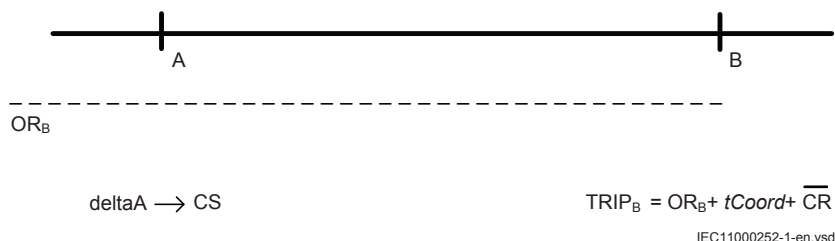


Figure 136: Principle of delta blocking scheme

OR: Overreaching

CR: Communication signal received

CS: Communication signal send

deltaA: Delta based fault inception detection on A side that gets inhibited for forward faults

13.1.3.3 Permissive schemes

In permissive schemes, the permission to trip is sent from the local end to the remote end(s), when the protection at the local end has detected a fault on the protected object. The received signal(s) is combined with an overreaching zone and gives an instantaneous trip if the received signal is present during the time the chosen zone has detected a fault.

Either end may send a permissive (or command) signal to trip to the other end(s), and the teleprotection equipment needs to be able to receive while transmitting.

A general requirement on permissive schemes is that it shall be fast and secure.

If the sending signal(s) is issued by underreaching or overreaching zone, it is divided into a permissive underreach or permissive overreach scheme.

Permissive underreaching scheme

Permissive underreaching scheme is not suitable to use on short line length due to difficulties for distance protection measurement in general to distinguish between internal and external faults in those applications.

The underreaching zones at the local and remote end(s) must overlap in reach to prevent a gap between the protection zones where faults would not be detected. If the underreaching zone do not meet the required sensitivity due to for instance fault infeed from the remote end, a blocking or permissive overreaching scheme should be considered.

The received signal (CR) must be received when the overreaching zone is activated to achieve an instantaneous trip. In some cases, due to the fault current distribution, the overreaching zone can operate only after the fault has been cleared at the terminal nearest to the fault. There is a certain risk that in case of a trip from an independent tripping zone, the zone issuing the send signal (CS) resets before the overreaching zone has started at the remote terminal. To assure a sufficient duration of the received signal (CR), the send signal (CS) can be prolonged by a $t_{SendMin}$ reset timer. The recommended setting of $t_{SendMin}$ is 100 ms.

Since the received communication signal is combined with the output from an overreaching zone, there is less concern about a false signal causing an incorrect trip. Therefore set the timer t_{Coord} to zero.

Failure of the communication channel does not affect the selectivity, but delays tripping at one end(s) for certain fault locations.

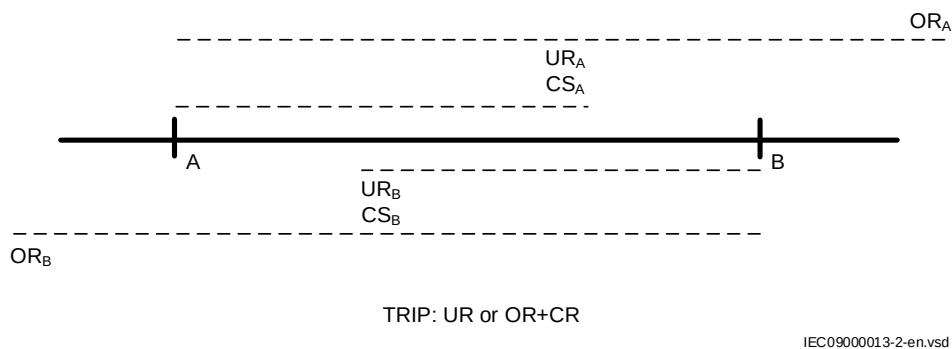


Figure 137: Principle of Permissive underreaching scheme

UR: Underreaching
OR: Overreaching
CR: Communication signal received
CS: Communication signal send

Permissive overreaching scheme

In a permissive overreaching scheme there is an overreaching zone that issues the send signal. At the remote end the received signal together with the start of an overreaching zone will give an instantaneous trip. The scheme can be used for all line lengths.

In permissive overreaching schemes, the communication channel plays an essential roll to obtain fast tripping at both ends. Failure of the communication channel may affect the selectivity and delay the tripping at one end at least, for faults anywhere along the protected circuit.

Teleprotection, operating in permissive overreaching scheme, must consider besides the general requirement of fast and secure operation also consider requirement on the dependability. Inadequate security can cause unwanted tripping for external faults. Inadequate speed or dependability can cause delayed tripping for internal faults or even unwanted operations.

This scheme may use virtually any communication media that is not adversely affected by electrical interference from fault generated noise or by electrical phenomena, such as lightning. Communication media that uses metallic paths are particularly subjected to this type of interference, therefore they must be properly shielded or otherwise designed to provide an adequate communication signal during power system faults.

The send signal (CS) might be issued in parallel both from an overreaching zone and an underreaching, independent tripping zone. The CS signal from the overreaching zone must not be prolonged while the CS signal from zone 1 can be prolonged.

To secure correct operations of current reversal logic in case of parallel lines the send signal CS shall not be prolonged. Set the $tSendMin$ to zero in this case.

There is no need to delay the trip at receipt of the signal, so set the timer $tCoord$ to zero.

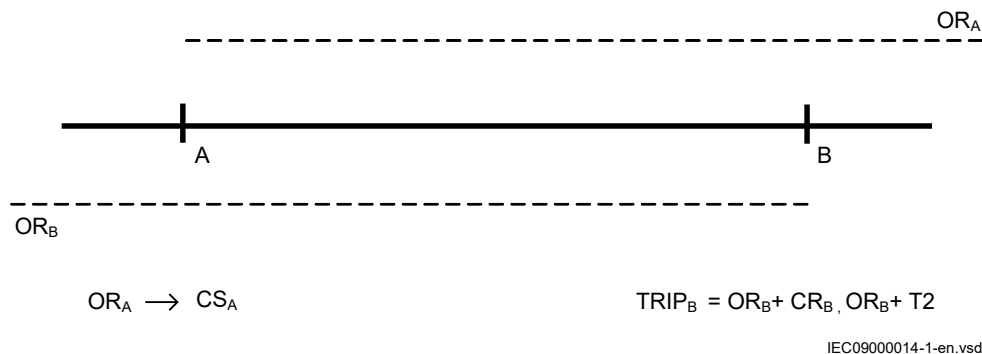


Figure 138: Principle of Permissive overreaching scheme

OR: Overreaching
 CR: Communication signal received
 CS: Communication signal send
 T2: Timer step 2

Unblocking scheme

Metallic communication paths adversely affected by fault generated noise may not be suitable for conventional permissive schemes that rely on a signal transmitted during a protected line fault. With power line carrier for example, the communication signal may be attenuated by the fault, especially when the fault is close to the line end, thereby disabling the communication channel.

To overcome the lower dependability in permissive schemes, an unblocking function can be used. Use this function at older, less reliable, power-line carrier (PLC) communication, where the signal has to be sent through the primary fault. The unblocking function uses a guard signal CRG, which must always be present, even when no CR signal is received. The absence of the CRG signal during the security time is used as a CR signal. This also enables a permissive scheme to operate when the line fault blocks the signal transmission. Set the $tSecurity$ to 35 ms.

13.1.3.4 Intertrip scheme

In some power system applications, there is a need to trip the remote end breaker immediately from local protections. This applies for instance when transformers or reactors are connected to the system without circuit-breakers or for remote tripping following operation of breaker failure protection.

In an intertrip scheme, the send signal is initiated by an underreaching zone or from an external protection (transformer or reactor protection). At the remote end, the received signals initiate a trip without any further protection criteria. To limit the risk for an unwanted trip due to the spurious sending of signals, the timer $tCoord$ should be set to 10-30 ms dependant on the type of communication channel.

The general requirement for teleprotection equipment operating in intertripping applications is that it should be very secure and very dependable, since both inadequate security and dependability may cause unwanted operation. In some applications the equipment shall be able to receive while

transmitting, and commands may be transmitted over longer time period than for other teleprotection systems.

13.1.4 Setting guidelines

The parameters for the scheme communication logic function are set via the local HMI or PCM600.

Configure the zones used for the CS send and for scheme communication tripping by using the ACT configuration tool.

The recommended settings of *tCoord* timer are based on maximal recommended transmission time for analogue channels according to IEC 60834-1. It is recommended to coordinate the proposed settings with actual performance for the teleprotection equipment to get optimized settings.

13.1.4.1 Blocking scheme

Set <i>Operation</i>	= <i>On</i>
Set <i>SchemeType</i>	= <i>Blocking</i>
Set <i>tCoord</i>	= 25 ms (10 ms + maximal transmission time)
Set <i>tSendMin</i>	= 0 s
Set <i>Unblock</i>	= <i>Off</i> (Set to <i>NoRestart</i> if Unblocking scheme with no alarm for loss of guard is to be used. Set to <i>Restart</i> if Unblocking scheme with alarm for loss of guard is to be used)
Set <i>tSecurity</i>	= 0.035 s

13.1.4.2 Delta blocking scheme

Set <i>Operation</i>	= <i>On</i>
Set <i>SchemeType</i>	= <i>DeltaBlocking</i>
Set <i>tCoord</i>	= 0 s
Set <i>tSendMin</i>	= 0 s
Set <i>Unblock</i>	= <i>Off</i> (Set to <i>NoRestart</i> if Unblocking scheme with no alarm for loss of guard is to be used. Set to <i>Restart</i> if Unblocking scheme with alarm for loss of guard is to be used)
Set <i>tSecurity</i>	= 0.035 s
Set <i>DeltaI</i>	= 10 %IB
Set <i>DeltaU</i>	= 5 %UB
Set <i>Delta3I0</i>	= 10 %IB
Set <i>Delta3U0</i>	= 5 %UB

13.1.4.3 Permissive underreaching scheme

Set <i>Operation</i>	= <i>On</i>
Set <i>SchemeType</i>	= <i>Permissive UR</i>
Set <i>tCoord</i>	= 0 ms
Set <i>tSendMin</i>	= 0.1 s
Set <i>Unblock</i>	= <i>Off</i>
Set <i>tSecurity</i>	= 0.035 s

13.1.4.4 Permissive overreaching scheme

Set <i>Operation</i>	= <i>On</i>
Set <i>Scheme type</i>	= <i>Permissive OR</i>
Set <i>tCoord</i>	= 0 ms
Set <i>tSendMin</i>	= 0.1 s (0 s in parallel line applications)
Set <i>Unblock</i>	= <i>Off</i>
Set <i>tSecurity</i>	= 0.035 s

13.1.4.5 Unblocking scheme

Set <i>Unblock</i>	= <i>Restart</i> (Loss of guard signal will give both trip and alarm Choose <i>NoRestart</i> if only trip is required)
Set <i>tSecurity</i>	= 0.035 s

13.1.4.6 Intertrip scheme

Set <i>Operation</i>	= <i>On</i>
Set <i>SchemeType</i>	= <i>Intertrip</i>
Set <i>tCoord</i>	= 50 ms (10 ms + maximal transmission time)
Set <i>tSendMin</i>	= 0.1 s (0 s in parallel line applications)
Set <i>Unblock</i>	= <i>Off</i>
Set <i>tSecurity</i>	= 0.015 s

13.2 Current reversal and Weak-end infeed logic for distance protection 3-phase ZCRWPSCH

13.2.1 Function revision history

Document revision	Product revision	History
B	2.2.1	-
C	2.2.2	-
D	2.2.2	
E	2.2.2	-
F	2.2.3	-
G	2.2.3	-
H	2.2.3	-
J	2.2.4	-
J	2.2.4	-
K	2.2.4	
Table continues on next page		

Document revision	Product revision	History
L	2.2.5	Added DOs for teleprotection permissive ($TxPrm$ & $RxPrm1$) transmit and receive signals in accordance with 61850 Ed 2.0
M	2.2.6	-
N	2.2.6	-

13.2.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Current reversal and weak-end infeed logic for distance protection 3-phase	ZCRWPSCCH	-	85

13.2.3 Application

13.2.3.1 Current reversal logic

To avoid this kind of disturbances, a fault current reversal logic (transient blocking logic) can be used.

The unwanted operations that might occur can be explained by looking into Figure 139 and Figure 140. Initially the protection A2 at A side will detect a fault in forward direction and send a communication signal to the protection B2 at remote end, which is measuring a fault in reverse direction.

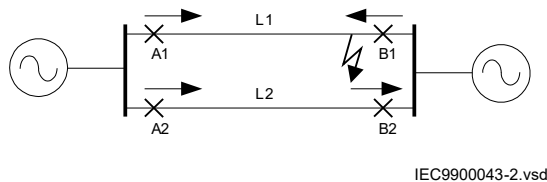


Figure 139: Current distribution for a fault close to B side when all breakers are closed

When the breaker B1 opens for clearing the fault, the fault current through B2 bay will invert. If the communication signal has not reset at the same time as the distance protection function used in the teleprotection scheme has switched on to forward direction, we will have an unwanted operation of breaker B2 at B side.

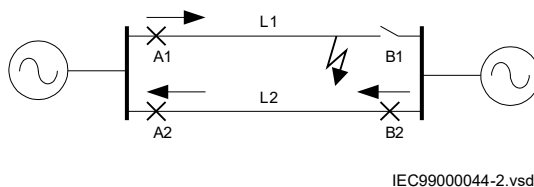


Figure 140: Current distribution for a fault close to B side when breaker B1 has opened

To handle this the send signal CS or CSLn from B2 is held back until the reverse zone IRVLn has reset and the $tDelayRev$ time has been elapsed. To achieve this the reverse zone on the distance

protection shall be connected to input IRV and the output IRVL shall be connected to input BLKCS on the communication function block ZCPSCH.

The function can be blocked by activating the input IRVBLK or the general BLOCK input.

13.2.3.2 Weak-end infeed logic

Permissive communication schemes can only operate when the protection in the remote IED can detect the fault. The detection requires a sufficient minimum fault current, normally $>20\%$ of I_r . The fault current can be too low due to an open breaker or low short-circuit power of the source. To overcome these conditions, weak-end infeed (WEI) echo logic is used. The fault current can also be initially too low due to the fault current distribution. Here, the fault current increases when the breaker opens at the strong terminal, and a sequential tripping is achieved. This requires a detection of the fault by an independent tripping zone 1. To avoid sequential tripping as described, and when zone 1 is not available, weak-end infeed tripping logic is used. The weak end infeed function only works together with permissive overreach communication schemes as the carrier send signal must cover the complete line length.

The WEI function sends back (echoes) the received signal under the condition that no fault has been detected on the weak-end by different fault detection elements (distance protection in forward and reverse direction).

Also, the WEI function can be additionally extended to trip the breaker in the weak side. The trip is achieved when one or more phase voltages are low during an echo function.

In case of single-pole tripping, the phase voltages are used as phase selectors together with the received signal CRLn.

When used with the blocking teleprotection scheme some limitations apply:

- Only the trip part of the function can be used together with the blocking scheme. It is not possible to use the echo function to send the echo signal to the remote line IED. The echo signal would block the operation of the distance protection at the remote line end and in this way prevents the correct operation of a complete protection scheme.
- A separate direct intertrip channel must be arranged from the remote end when a trip or accelerated trip is given there. The intertrip receive signal is connect to input CRL.
- The WEI function shall be set to *WEI=Echo&Trip*. The WEI function block will then give phase selection and trip the local breaker.

Avoid using WEI function at both line ends. It shall only be activated at the weak-end.

13.2.4 Setting guidelines

The parameters for the current reversal logic and the weak-end infeed logic (WEI) function are set via the local HMI or PCM600.

Common base IED values for the primary current (*IBase*), primary voltage (*UBase*) and primary power (*SBase*) are set in global base values for settings function GBASVAL.

GlobalBaseSel: Selects the global base value group used by the function to define *IBase*, *UBase* and *SBase*. Note that this function will only use *IBase* value.

13.2.4.1 Current reversal logic



The forward zone timer must be set longer than the *tDelayRev* set value.

Set *CurrRev* to *On* to activate the function.

Set *tDelayRev* timer of the maximum reset time for the communication equipment that gives the carrier receive (CRL) signal plus 30 ms. A minimum setting of 40 ms is recommended, typical 60 ms.

A long *tDelayRev* setting increases security against unwanted tripping, but delays the fault clearing time in case of a fault from one line that evolves to the other one. The probability of this type of fault is small. Therefore set *tDelayRev* with a good margin.

Set the pick-up delay *tPickUpRev* to <80% of the minimum sum of breaker operate time + communication delay time, but with a minimum of 20 ms.

13.2.4.2 Weak-end infeed logic

Set *WEI* to *Echo*, to activate the weak-end infeed function with only echo function.

Set *WEI* to *Echo&Trip* to obtain echo with trip.

The *tPickUpWEI* is the on-time delay to activate the weak-end infeed function. Set *tPickUpWEI* to 10 ms, a short delay is recommended to avoid that spurious carrier received signals will activate WEI and cause unwanted carrier send (ECHO) signals.



When single phase tripping is required, a detailed study of the voltages during phase-to-phase and phase-to-earth faults should be done, at different fault locations.

13.3 Local acceleration logic ZCLCPSCH

13.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Local acceleration logic	ZCLCPSCH	-	-

13.3.2 Application

The local acceleration logic (ZCLCPSCH) is used in applications where a conventional teleprotection scheme is not available (no communication channel), but where the user still requires fast clearance for faults on the whole line.

The logic can be controlled either by the autorecloser (zone extension) or by the loss-of-load current (loss-of-load acceleration).

The loss-of-load acceleration gives selected overreach zone permission to operate instantaneously after checking the loss-of-load condition. It can not operate for three-phase faults.

13.3.3 Setting guidelines

The parameters for the local acceleration logic functions are set via the local HMI or PCM600.

Set *ZoneExtension* to *On* when the first trip from selected overreaching zone shall be instantaneous and the definitive trip after autoreclosure a normal time-delayed trip.

Set *LossOfLoad* to *On* when the acceleration shall be controlled by loss-of-load in healthy phase(s).

LoadCurr must be set below the current that will flow on the healthy phase when one or two of the other phases are faulty and the breaker has opened at remote end. Calculate the setting according to equation [134](#).

$$LoadCurr = \frac{0.5 \cdot I_{Load\ min}}{I_{Base}}$$

(Equation 134)

where:

*I*_{Loadmin} is the minimum load current on the line during normal operation conditions.

The timer *tLoadOn* is used to increase the security of the loss-of-load function for example to avoid unwanted release due to transient inrush current when energizing the line power transformer. The loss-of-load function will be released after the timer *tLoadOn* has elapsed at the same time as the load current in all three phases are above the setting *LoadCurr*. In normal acceleration applications there is no need for delaying the release, so set the *tLoadOn* to zero.

The drop-out timer *tLoadOff* is used to determine the window for the current release conditions for Loss-of-load. The timer is by default set to 300ms, which is judged to be enough to secure the current release.

The setting of the minimum current detector, *MinCurr*, should be set higher than the unsymmetrical current that might flow on the non faulty line, when the breaker at remote end has opened. At the same time it should be set below the minimum load current transfer during normal operations that the line can be subjected to. By default, *MinCurr* is set to 5% of *I*_{Base}.

The pick-up timer *tLowCurr* determine the window needed for pick-up of the minimum current value used to release the function. The timer is by default set to 200 ms, which is judged to be enough to avoid unwanted release of the function (avoid unwanted trip).

13.4 Scheme communication logic for residual overcurrent protection ECPSCH

13.4.1 Function revision history

Document revision	Product revision	History
B	2.2.1	-
C	2.2.2	-
D	2.2.2	
E	2.2.2	-
F	2.2.3	-
G	2.2.3	-
H	2.2.3	-
J	2.2.4	-
K	2.2.4	-
L	2.2.4	
M	2.2.5	Added separate DOs for teleprotection permissive (<i>TxPrm</i> & <i>RxPrm1</i>), blocking (<i>TxBlk</i> & <i>RxBlk1</i>) and direct trip (<i>TxTr</i> & <i>RxTr1</i>) transmit and receive signals in accordance with 61850 Ed 2.0.
J	2.2.6	-
K	2.2.6	-

13.4.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Scheme communication logic for residual overcurrent protection	ECPSCH	-	85

13.4.3 Application

To achieve fast fault clearance of earth faults on the part of the line not covered by the instantaneous step of the residual overcurrent protection, the directional residual overcurrent protection can be supported with a logic that uses communication channels.

One communication channel is used in each direction, which can transmit an on/off signal if required. The performance and security of this function is directly related to the transmission channel speed and security against false or lost signals.

In the directional scheme, information of the fault current direction must be transmitted to the other line end.

With directional comparison in permissive schemes, a short operate time of the protection including a channel transmission time, can be achieved. This short operate time enables rapid autoreclosing function after the fault clearance.

The communication logic module enables blocking as well as permissive under/overreaching schemes. The logic can also be supported by additional logic for weak-end infeed and current reversal, included in the Current reversal and weak-end infeed logic for residual overcurrent protection (ECRWPSCH) function.

Metallic communication paths adversely affected by fault generated noise may not be suitable for conventional permissive schemes that rely on signal transmitted during a protected line fault. With power line carrier, for example, the communication signal may be attenuated by the fault, especially when the fault is close to the line end, thereby disabling the communication channel.

To overcome the lower dependability in permissive schemes, an unblocking function can be used. Use this function at older, less reliable, power line carrier (PLC) communication, where the signal has to be sent through the primary fault. The unblocking function uses a guard signal CRG, which must always be present, even when no CR signal is received. The absence of the CRG signal during the security time is used as a CR signal. This also enables a permissive scheme to operate when the line fault blocks the signal transmission. Set the *tSecurity* to 35 ms.

13.4.4 Setting guidelines

The parameters for the scheme communication logic for residual overcurrent protection function are set via the local HMI or PCM600.

The following settings can be done for the scheme communication logic for residual overcurrent protection function:

Operation: Off or On.

SchemeType: This parameter can be set to *Off*, *Intertrip*, *Permissive UR*, *Permissive OR* or *Blocking*.

tCoord: Delay time for trip from ECPSCH function. For Permissive under/overreaching schemes, this timer shall be set to at least 20 ms plus maximum reset time of the communication channel as a

security margin. For Blocking scheme, the setting should be > maximum signal transmission time +10 ms.

Unblock: Select *Off* if unblocking scheme with no alarm for loss of guard is used. Set to *Restart* if unblocking scheme with alarm for loss of guard is used.

tSendMin: Time duration, the carrier send signal is prolonged.

tSecurity: The absence of CRG signal for a time duration of *tSecurity* is considered as CR signal.

13.5

Current reversal and weak-end infeed logic for residual overcurrent protection ECRWPSCH

13.5.1

Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Current reversal and weak-end infeed logic for residual overcurrent protection	ECRWPSCH	-	85

13.5.2

Application

13.5.2.1

Fault current reversal logic

Figure 141 and figure 142 show a typical system condition, which can result in a fault current reversal.

Assume that fault is near the B1 breaker. B1 Relay sees the fault in Zone1 and A1 relay identifies the fault in Zone2.

Note that the fault current is reversed in line L2 after the breaker B1 opening.

It can cause an unselective trip on line L2 if the current reversal logic does not block the permissive overreaching scheme in the IED at B2.

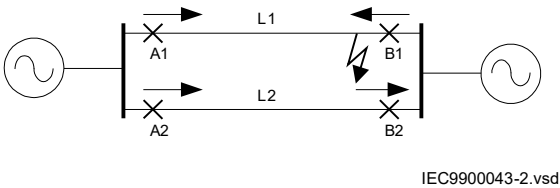


Figure 141: Current distribution for a fault close to B side when all breakers are closed

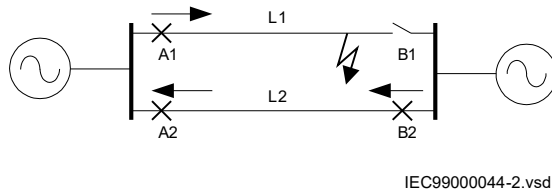


Figure 142: Current distribution for a fault close to B side when breaker at B1 is opened

When the breaker on the parallel line operates, the fault current on the healthy line is reversed. The IED at B2 recognizes the fault in forward direction from reverse direction before breaker operates. As IED at B2 already received permissive signal from A2 and IED at B2 is now detecting the fault as forward fault, it will immediately trip breaker at B2. To ensure that tripping at B2 should not occur, the permissive overreaching function at B2 needs to be blocked by IRVL till the received permissive signal from A2 is reset.

The IED at A2, where the forward direction element was initially activated, must reset before the send signal is initiated from B2. The delayed reset of output signal IRVL also ensures the send signal from IED B2 is held back till the forward direction element is reset in IED A2.

13.5.2.2 Weak-end infeed logic

Figure 143 shows a typical system condition that can result in a missing operation. Note that there is no fault current from node B. This causes that the IED at B cannot detect the fault and trip the breaker in B. To cope with this situation, a selectable weak-end infeed logic is provided for the permissive overreaching scheme.

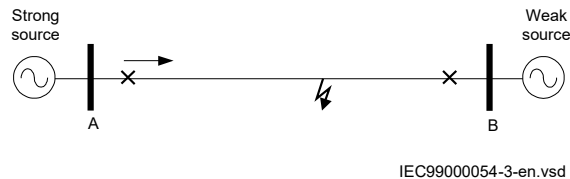


Figure 143: Initial condition for weak-end infeed

13.5.3 Setting guidelines

The parameters for the current reversal and weak-end infeed logic for residual overcurrent protection function are set via the local HMI or PCM600.

Common base IED values for primary current (I_{Base}), primary voltage (U_{Base}) and primary power (S_{Base}) are set in a Global base values for settings function GBASVAL.

GlobalBaseSel: To select a GBASVAL function for reference of base values.

13.5.3.1 Current reversal

The current reversal function is set on or off by setting the parameter *CurrRev* to *On* or *Off*. Time delays shall be set for the timers *tPickUpRev* and *tDelayRev*.

tPickUpRev is chosen shorter (<80%) than the breaker opening time, but minimum 20 ms.

tDelayRev is chosen at a minimum to the sum of protection reset time and the communication reset time. A minimum *tDelayRev* setting of 40 ms is recommended.

The reset time of the directional residual overcurrent protection (EF4PTOC) is typically 25 ms. If other type of residual overcurrent protection is used in the remote line end, its reset time should be used.

The signal propagation time is in the range 3 – 10 ms/km for most types of communication media. In communication networks small additional time delays are added in multiplexers and repeaters. These delays are less than 1 ms per process. It is often stated that the total propagation time is less than 5 ms.

When a signal picks-up or drops out there is a decision time to be added. This decision time is highly dependent on the interface between communication and protection used. In many cases an external interface (teleprotection equipment) is used. This equipment makes a decision and gives a binary signal to the protection device. In case of analog teleprotection equipment typical decision time is in the range 10 – 30 ms. For digital teleprotection equipment this time is in the range 2 – 10 ms.

If the teleprotection equipment is integrated in the protection IED the decision time can be slightly reduced.

The principle time sequence of signaling at current reversal is shown.

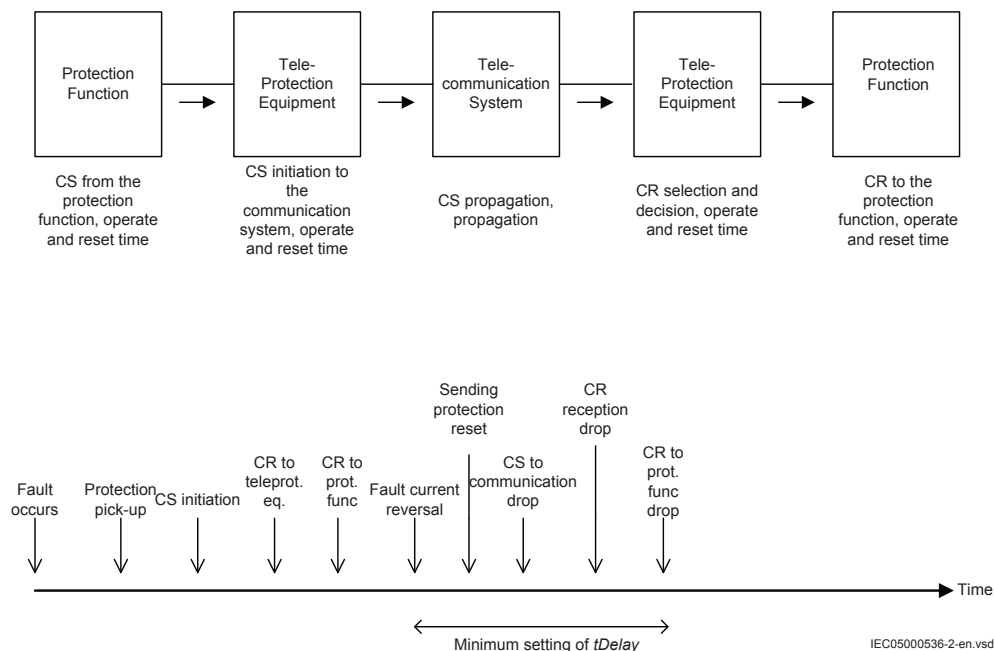


Figure 144: Time sequence of signaling at current reversal

13.5.3.2 Weak-end infeed

The weak-end infeed can be set by setting the parameter *WEI* to *Off*, *Echo* or *Echo & Trip*. Operating zero sequence voltage when parameter *WEI* is set to *Echo & Trip* is set with $3U_0$.

The zero sequence voltage for a fault at the remote line end and appropriate fault resistance is calculated.

To avoid unwanted trip from the weak-end infeed logic (if spurious signals should occur), set the operate value of the broken delta voltage level detector ($3U_0$) higher than the maximum false network frequency residual voltage that can occur during normal service conditions. The recommended minimum setting is two times the false zero-sequence voltage during normal service conditions.

Section 14 Logic

14.1 Tripping logic SMPPTRC

14.1.1 Function revision history

Document revision	Product revision	History
A	2.2.1	STN (Start neutral) output added. IEC 61850 mapping is made for the added output.
B	2.2.1	-
C	2.2.1	-
D	2.2.4	Added TRINN (Trip neutral) input and TRN (trip neutral) outputs. TRINALL (Trip all phases) input is changed from TRIN. IEC 61850 mapping is made for the added output. The block logic is corrected for the lockout functionality.
E	2.2.5	-
J	2.2.6	-
K	2.2.6	Fault current and voltage reporting is added

14.1.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Tripping logic	SMPPTRC	1 -> 0	94

14.1.3 Application

All trip signals from the different protection functions shall be routed through the trip logic. All start signals and directional information can be routed through the trip logic as well. In its simplest form, the trip logic will only link the TRIP signal to a binary output and make sure that the pulse time is long enough.

Tripping logic SMPPTRC offers three different operating modes:

- Three-phase tripping for all fault types (3ph operating mode)
- Single-phase tripping for single-phase faults and three-phase tripping for multi-phase and evolving faults (1ph/3ph operating mode).
- Single-phase tripping for single-phase faults, two-phase tripping for two-phase faults and three-phase tripping for three-phase faults (1ph/2ph/3ph operating mode).

If the OHL is connected to the substation via more than one breaker, one SMPPTRC function block should be used for each breaker. For example when single-phase tripping and autoreclosing is used on the line, both breakers are normally set up for 1/3-phase tripping and 1/3-phase autoreclosing. Alternatively, the breaker chosen as master can have single-phase tripping, while the slave breaker could have three-phase tripping and autoreclosing. In the case of a permanent fault, only one of the breakers has to be operated when the fault is energized a second time. In the event of a transient fault the slave breaker performs a three-phase reclosing onto the non-faulted line.

The same philosophy can be used for two-phase tripping and autoreclosing.

To prevent closing of a circuit breaker after a trip, the function offers a lockout function.

14.1.3.1 Three-phase tripping

Connect the inputs from the protection functions to the input TRINALL. The TMGAPC function block is used to combine up to 32 inputs into one output. Connect the output TRIP to the binary outputs on the IO board.

This signal can also be used for other purposes internally in the IED. An example could be the starting of breaker failure protection. The three outputs TRL1, TRL2, and TRL3 will always be activated at every trip and can be utilized on individual trip outputs if single-phase operating devices are available on the circuit breaker even when a three-phase tripping scheme is selected.

Set the function block to *Program = 3 phase* and set the required length of the trip pulse to for example, $t_{TripMin} = 150ms$.

The typical connection is shown below in [Figure 145](#).

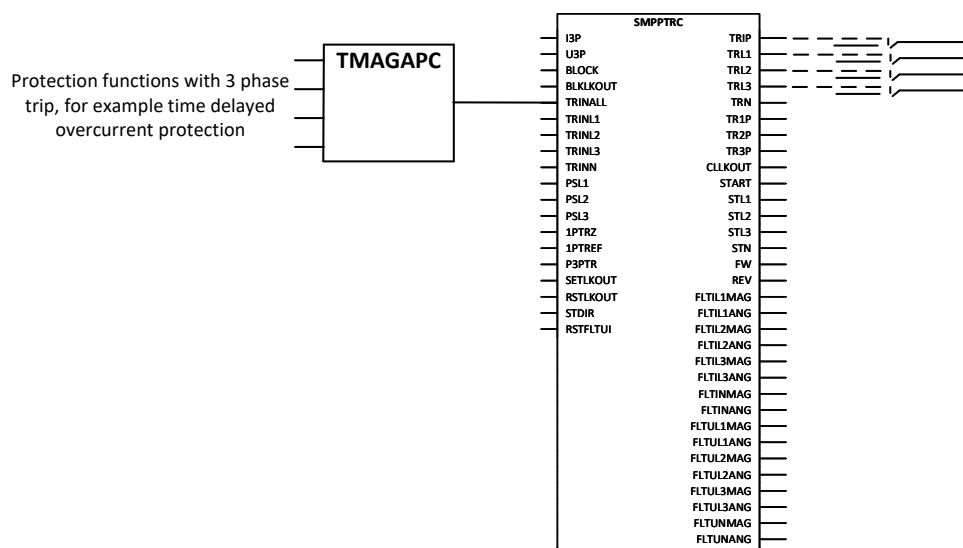


Figure 145: Tripping logic SMPPTRC is used for a simple three-phase tripping application

14.1.3.2 Single- and/or three-phase tripping

The single-/three-phase tripping operation mode will give single-phase tripping for single-phase faults and three-phase tripping for multi-phase fault. This operating mode is always used together with a single-phase autoreclosing scheme.

The single-phase tripping operation mode can include different options and the use of the different inputs in the function block. Inputs TRINL1, TRINL2, and TRINL3 shall be used for trip signals from functions with built-in phase selection logic such as distance or line differential protection functions.

The inputs 1PTRZ and 1PTREF are used for single-phase tripping from functions which do not have built-in phase selection logic:

- 1PTRZ can be connected to the carrier aided trip signal from the distance protection scheme (it means that another distance protection function has seen or detected the fault)
- 1PTREF can be connected to an earth fault function such as EF4PTOC or a carrier aided trip signal from the earth fault protection scheme

These two inputs are combined with the external phase selection logic. Phase selection signals from the external phase selector must be connected to the inputs PSL1, PSL2, and PSL3 to achieve the

tripping on the respective single-phase trip outputs TRL1, TRL2, and TRL3. The output TRIP is a general trip and is always activated independent of which phase is involved. Depending on which phases are involved the outputs TR1P and TR3P will be activated as well.

When single-phase tripping schemes are used, a single-phase autoreclosing attempt is expected to follow. For cases where the autoreclosing is not in service or will not follow for some reason, the input prepare three-phase trip P3PTR must be activated. This input is normally connected to the output PREP3P on the autorecloser function SMBRREC but can also be connected to other signals, for example, an external logic signal. If two circuit breakers are involved, one SMPPTRC block instance and one SMBRREC instance are used for each circuit breaker. This will ensure correct operation and behavior of each circuit breaker.

The output TR3P must be connected to the input TR3P on the SMBRREC function in order to switch SMBRREC to perform a three-phase reclosing. If this signal is not activated, SMBRREC will use single-phase dead time.



If a second line protection is utilizing the same SMBRREC, the three-phase trip signal must be generated as OR conditions from both line protections.

Other back-up functions are connected to the input TRIN as described above for three-phase tripping. A typical connection for a single-phase tripping scheme is shown in figure 146.

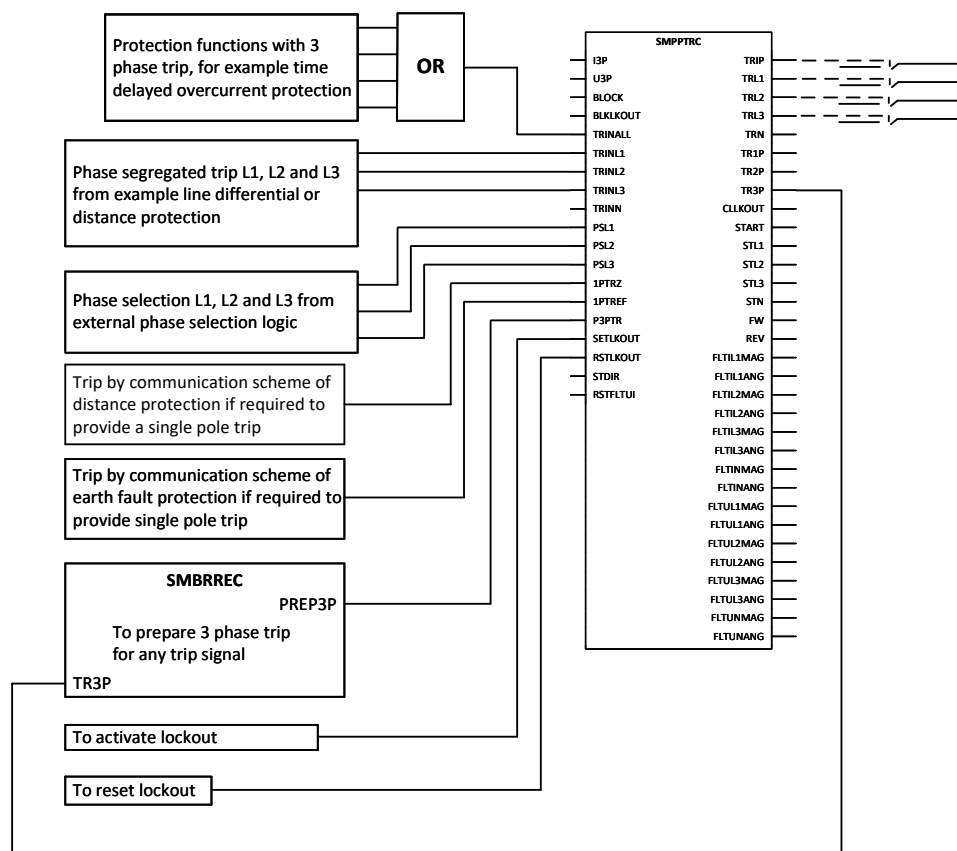


Figure 146: The trip logic function SMPPTRC used for single-phase tripping application

14.1.3.3 Single-, two- or three-phase tripping

The single-/two-/three-phase tripping mode provides single-phase tripping for single-phase faults, two-phase tripping for two-phase faults and three-phase tripping for three-phase faults. The operating mode is always used together with an autoreclosing scheme with setting *ARMode* = 1/2/3 *ph* or *ARMode* = 1/2 *ph*.

The functionality is very similar to the single-phase scheme described above. However, in addition to the connections for single phase SMBRREC must also be informed that the trip is two phases by connecting the output TR2P to the input TR2P in the SMBRREC function.

14.1.3.4 Lock-out

The SMPPTRC function block is provided with possibilities to initiate lockout. The lockout can be set to only activate the circuit breaker lockout output CLLKOUT or to both initiate the circuit breaker lockout output and to maintain the trip signal outputs TRIP, TRL1, TRL2, TRL3, and TR3P (latched).

If external conditions are required to initiate a circuit breaker lockout, it can be achieved by activating input SETLKOUT. The setting *AutoLock* = *Off* means that the internal three-phase trip will not activate lockout so only initiation of the input SETLKOUT will result in lockout. This is normally the case for overhead line protection where most faults are transient. Unsuccessful autoreclosing and back-up zone tripping can in such cases be connected to initiate lockout by activating the input SETLKOUT.

If CLLKOUT is set by an external trip signal from another protection function, that is by activating SETLKOUT input, or internally by a three-phase trip, that is with the setting *AutoLock* = *On* and the setting *TripLockout* = *On*, then also all trip outputs are set latched.

The lockout can manually be reset after checking the primary fault by activating the reset lockout input RSTLKOUT.

The BLKCLKOUT input blocks the circuit breaker lockout output CLLKOUT.

14.1.3.5 Example of directional data

An example how to connect the directional data from different application functions to the trip function is shown in [Figure 147](#):

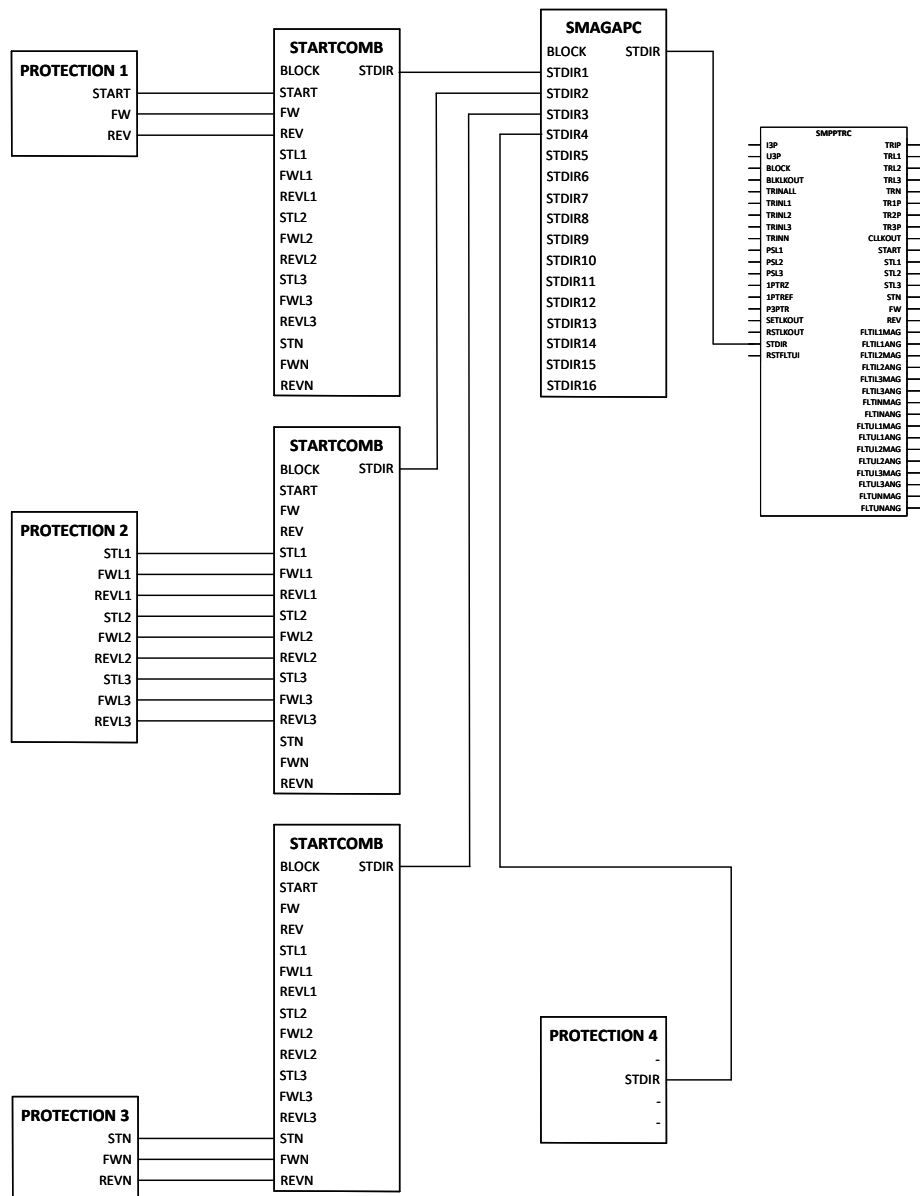


Figure 147: Example of the connection of directional start logic

The Start Matrix (SMAGAPC) merges start and directional output signals from different application functions and creates a common directional output signal (STDIR) to be connected to the trip function (SMPPTRC). Protection functions connect their directional data via the STARTCOMB function to SMAGAPC and then to the SMPPTRC, or directly to SMAGAPC and then to the SMPPTRC.

The trip function (SMPPTRC) splits up the directional data as general output data for *START*, *STL1*, *STL2*, *STL3*, *STN*, *FW* and *REV*.

All start and directional outputs are mapped to the logical node data model of the trip function and provided via the IEC 61850 attributes *dirGeneral*, *dirPhsA*, *dirPhsB*, *dirPhsC*, and *dirNeut*.

Fault current and voltage reporting

The snapshot of each phase current DFT values (FLTILxMAG/FLTILxANG), each phase voltage DFT values (FLTULxMAG/FLTULxANG), neutral current magnitude and angle (FLTINMAG/FLTINANG), and neutral voltage magnitude and angle (FLTUNMAG/FLTUNANG) will be taken at the positive

edge of the TRIP activation. These values also will be stored and reported to IEC 61850, LHMI, and the monitoring tool at the instant of TRIP activation, for example, if the TRIP signal of PHPIOC is connected to the TRINALL signal of the SMPPTRC function. The functionality is shown in [Figure 148](#).

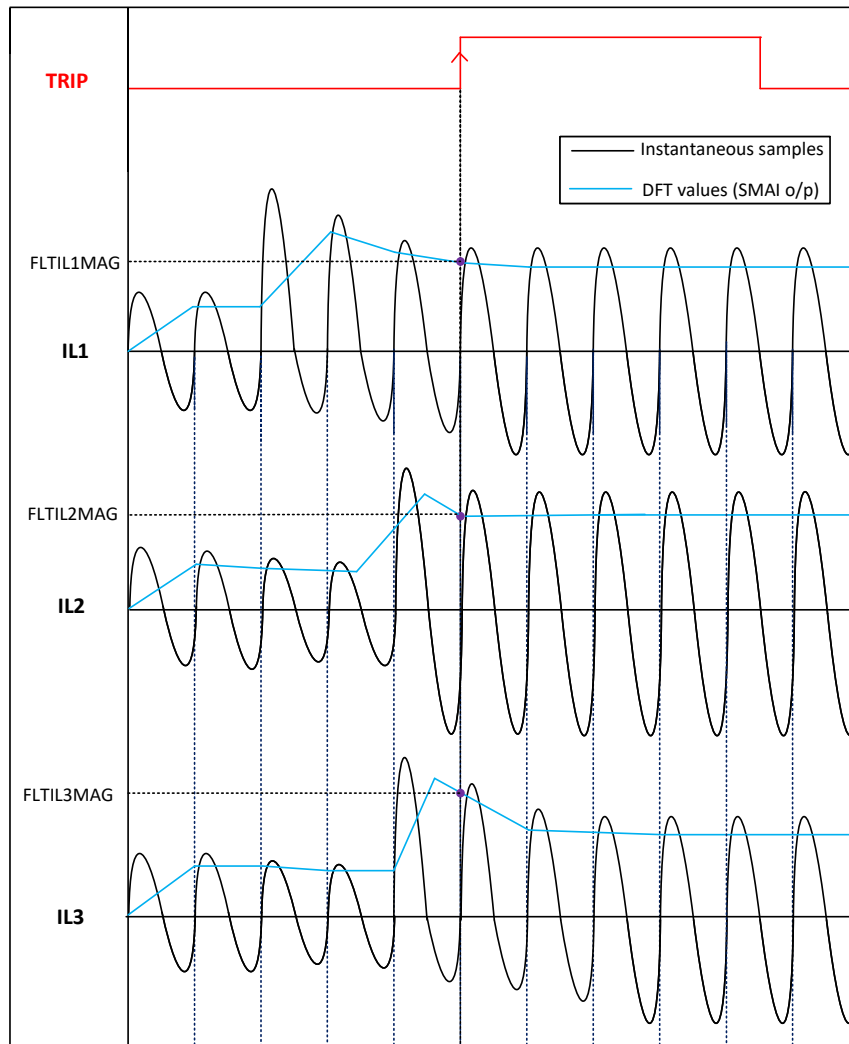


Figure 148: Reporting of fault current

The reported outputs (FLTILxMAG/FLTILxANG, FLTULxMAG/FLTULxANG, FLTINMAG/FLTINANG, and FLTUNMAG/FLTUNANG) show the previous event values until a new positive edge trigger is received by TRINx input.



If the signal RESET is HIGH, SMPPTRC will set all the reported current magnitudes to -1.000A, voltage magnitudes to -0.001kV, current and voltage angles to -1.000deg values respectively.



If the group connections of current and voltage are not connected to SMAI or the signal quality is bad, the SMPPTRC function will set all the reported current magnitudes to -2.000A, voltage magnitudes to -0.002kV, current and voltage angles to -2.000deg values respectively, indicating Invalid data.

14.1.3.6 Blocking of the function block

Total block of the trip function is done by activating the input BLOCK and can be used to disable the outputs of the trip logic in the event of internal failures. Block of lockout output is achieved by activating the input BLKLKOUT.

14.1.4 Setting guidelines

The parameters for the trip function SMPPTRC are set via the local HMI or PCM600.

Operation: Sets the mode of operation. *Off* switches the tripping off. The normal selection is *On*.

Program: Sets the required tripping scheme. Normally *3 phase* or *1ph/3ph* is used.

TripLockout: Sets the scheme for lockout. *Off* only activates the circuit breaker close lockout output. *On* activates the circuit breaker close lockout output and latches the TRIP related outputs. The normal selection is *Off*.

AutoLock: Sets the scheme for lockout. *Off* only activates lockout through the output CLLKOUT. *On* additionally allows lockout activation via the trip inputs. The normal selection is *Off*.

tTripMin: Sets the required minimum duration of the trip pulse. It should be set to ensure that the circuit breaker is opened correctly. The normal setting is *0.150s*.

tWaitForPHS: Sets a duration during which external phase selection must operate in order to get a single phase trip, after any of the inputs 1PTRZ or 1PTREF has been activated. If no phase selection has been achieved, a three-phase trip will be issued after this time has elapsed.

tEvolvingFault: Secures two- or three-pole tripping depending on *Program* selection during evolving faults.

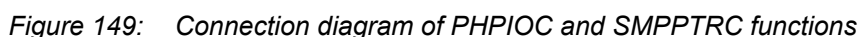
14.1.4.1 Setting example

Consider a line-to-earth fault in phase L2 of a 400 kV, 2000 MVA, 50 Hz system.

Table 28: System details

Name	Value
Rated MVA capacity (<i>SBase</i>)	2000 MVA
Rated voltage (<i>UBase</i>)	400 kV
Rated Current (<i>IBase</i>)	3000 A
System Frequency	50 Hz
VT ratio	400 kV/110 V
CT ratio	3000/1 A

The general setting parameters for PHPIOC and SMPPTRC functions can be set as mentioned in [Table 29](#) and [Table 30](#), respectively, and the connection diagram is shown in [Figure 149](#).



Setting	Description	Default value
<i>Operation</i>	Operation <i>Off/On</i>	<i>On</i>
<i>GlobalBaseSel</i>	Selection of one of the Global Base Value groups	1
<i>OpMode</i>	Select operation mode <i>2 out of 3/1 out of 3</i>	1
<i>StValMult</i>	Multiplier for operate current level	1.0
<i>IP>></i>	Operate phase current level in % of <i>IBase</i>	200
<i>IP>>Min</i>	Minimum used operate phase current level in % of <i>IBase</i> , if <i>IP>></i> is less than <i>IP>>Min</i> , then <i>IP>></i> is set to <i>IP>>Min</i>	5
<i>IP>>Max</i>	Maximum used operate phase current level in % of <i>IBase</i> , if <i>IP>></i> is greater than <i>IP>>Max</i> , then <i>IP>></i> is set to <i>IP>>Max</i>	2500
<i>EnaCurrMult</i>	Enable/disable current multiplier	1

Setting	Description	Default value
<i>CondBlkMode</i>	Conditional blocking mode of function due to analog data quality	0
<i>FltValRepMode</i>	Selection of trigger for fault record 0-Do not report, 1-Report at trip	1
<i>Operation</i>	Operation <i>Off/On</i>	<i>On</i>
<i>Program</i>	Three ph; single or three ph; single, two or three ph trip	1
<i>TripLockout</i>	Latch TRIP output when SETLKOUT input is activated	0
<i>AutoLock</i>	Activate CLLKOUT output when TRIP output is activated	0
<i>tTripMin</i>	Minimum duration of trip output signal	0.15
<i>tWaitForPHS</i>	Secure 3-pole trip when phase selection failed	0.05
<i>tEvolvingFault</i>	Secure 3-pole tripping at evolving faults	2

Line differential protection RED650

Application manual

DFT magnitude and angle (FLTINMAG/FLTINANG), and neutral voltage DFT magnitude and angle (FLTUNMAG/FLTUNANG) are stored at the positive edge of the binary input TRIP.

The SMPPTRC function monitors and reports the following data at the output, considering the default setting parameters mentioned in [Figure 150](#).

tatus/Logic/TripLogic(94,1->0)/SMPPTRC(94,1->0):1/Outputs				tatus/Logic/TripLogic(94,1->0)/SMPPTRC(94,1->0):1/Outputs				tatus/Logic/TripLogic(94,1->0)/SMPPTRC(94,1->0):1/Outputs			
INSTNAME	SMPPTRC			STL1				FLTIL2MAG			
Beh	On			STL2	0			FLTIL2ANG	-121.224	deg	
Blk	0			STL3	0			FLTIL3MAG	3000.000	A	
TRIP	1			STN	0			FLTIL3ANG	120.000	deg	
TRL1	1			FW	0			FLTINMAG	0.000	A	
TRL2	1			REV	0			FLTINANG	90.000	deg	
TRL3	1			FLTIL1MAG	3000.000	A		FLTUL1MAG	209.946	kV	
TRN	0			FLTIL1ANG	0.000	deg		FLTUL1ANG	-30.000	deg	
TR1P	0			FLTIL2MAG	7088.821	A		FLTUL2MAG	209.946	kV	
TR2P	0			FLTIL2ANG	-121.224	deg		FLTUL2ANG	-150.000	deg	
TR3P	1			FLTIL3MAG	3000.000	A		FLTUL3MAG	209.946	kV	
CLLKOUT	0			FLTIL3ANG	120.000	deg		FLTUL3ANG	90.000	deg	
START	0			FLTINMAG	0.000	A		FLTUNMAG	0.000	kV	
STL1	0			FLTINANG	90.000	deg		FLTUNANG	90.000	deg	
2023-02-23 17:15:24	\$SuperUser	Hint available		2023-02-23 17:16:14	\$SuperUser	Hint available		2023-02-23 17:16:56	\$SuperUser	Hint available	

Figure 150: Reported fault data on occurrence of trip event from PHPIOC function

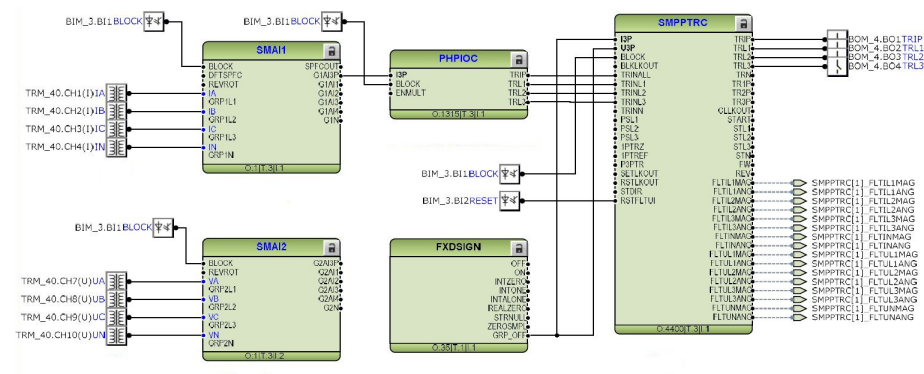


Figure 151: Connection diagram of PHPIOC and SMPPTRC functions for Invalid Data Reporting

tatus/Logic/TripLogic(94,1->0)/SMPPTRC(94,1->0):1/Outputs				tatus/Logic/TripLogic(94,1->0)/SMPPTRC(94,1->0):1/Outputs				tatus/Logic/TripLogic(94,1->0)/SMPPTRC(94,1->0):1/Outputs			
INSTNAME	SMPPTRC			STL1				FLTIL2MAG			
Beh	On			STL2	0			FLTIL2ANG	-1.000	deg	
Blk	0			STL3	0			FLTIL3MAG	-1.000	A	
TRIP	1			STN	0			FLTIL3ANG	-1.000	deg	
TRL1	1			FW	0			FLTINMAG	-1.000	A	
TRL2	1			REV	0			FLTINANG	-1.000	deg	
TRL3	1			FLTIL1MAG	-1.000	A		FLTUL1MAG	-0.001	kV	
TRN	0			FLTIL1ANG	-1.000	deg		FLTUL1ANG	-1.000	deg	
TR1P	0			FLTIL2MAG	-1.000	A		FLTUL2MAG	-0.001	kV	
TR2P	0			FLTIL2ANG	-1.000	deg		FLTUL2ANG	-1.000	deg	
TR3P	1			FLTIL3MAG	-1.000	A		FLTUL3MAG	-0.001	kV	
CLLKOUT	0			FLTIL3ANG	-1.000	deg		FLTUL3ANG	-1.000	deg	
START	0			FLTINMAG	-1.000	A		FLTUNMAG	-0.001	kV	
STL1	0			FLTINANG	-1.000	deg		FLTUNANG	-1.000	deg	
2023-03-21 08:30:04	\$SuperUser	Hint available		2023-03-21 08:31:36	\$SuperUser	Hint available		2023-03-21 08:32:15	\$SuperUser	Object name	

Figure 152: Reported fault data on occurrence of trip event from PHPIOC function for RESET input

..tatus/Logic/TripLogic(94,1->0)/SHPPTRC(94,1->0):1/Outputs			..tatus/Logic/TripLogic(94,1->0)/SHPPTRC(94,1->0):1/Outputs			..tatus/Logic/TripLogic(94,1->0)/SHPPTRC(94,1->0):1/Outputs		
INSTNAME	SHPPTRC		STL1			FLTIL2MAG		
Beh	On		STL2	0		FLTIL2ANG	-2.000	A
Blk	0		STL3	0		FLTIL3MAG	-2.000	A
TRIP	1		STN	0		FLTIL3ANG	-2.000	deg
TRL1	1		FU	0		FLTINMAG	-2.000	A
TRL2	1		REV	0		FLTINANG	-2.000	deg
TRL3	1		FLTIL1MAG	-2.000	A	FLTUL1MAG	-0.002	kV
TRN	0		FLTIL1ANG	-2.000	deg	FLTUL1ANG	-2.000	deg
TR1P	0		FLTIL2MAG	-2.000	A	FLTUL2MAG	-0.002	kV
TR2P	0		FLTIL2ANG	-2.000	deg	FLTUL2ANG	-2.000	deg
TR3P	1		FLTIL3MAG	-2.000	A	FLTUL3MAG	-0.002	kV
CLLKOUT	0		FLTIL3ANG	-2.000	deg	FLTUL3ANG	-2.000	deg
START	0		FLTINMAG	-2.000	A	FLTUNMAG	-0.002	kV
STL1	0		FLTINANG	-2.000	deg	FLTUNANG	-2.000	deg
2023-03-21 10:57:37	\$SuperUser	Object name	2023-03-21 10:58:03	\$SuperUser	Object name	2023-03-21 10:58:25	\$SuperUser	Object name

Figure 153: Reported fault data on occurrence of trip event from PHPIOC function for invalid input

14.2 Trip matrix logic TMAGAPC

14.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Trip matrix logic	TMAGAPC	-	-

14.2.2 Application

The trip matrix logic function has 3 output signals and these outputs can be connected to physical tripping outputs according to the specific application needs for settable pulse or steady output.

14.2.3 Setting guidelines

Operation: Operation of function *On/Off*.

PulseTime: Defines the pulse time when in *Pulsed* mode. When used for direct tripping of circuit breaker(s) the pulse time delay shall be set to approximately 0.150 seconds in order to obtain satisfactory minimum duration of the trip pulse to the circuit breaker trip coils.

OnDelay: Used to prevent output signals to be given for spurious inputs. Normally set to 0 or a low value.

OffDelay: Defines a delay of the reset of the outputs after the activation conditions no longer are fulfilled. It is only used in *Steady* mode. When used for direct tripping of circuit breaker(s) the off delay time shall be set to at least 0.150 seconds in order to obtain a satisfactory minimum duration of the trip pulse to the circuit breaker trip coils.

ModeOutputx: Defines if output signal OUTPUT_x (where x=1-3) is *Steady* or *Pulsed*.

14.3 Logic for group alarm ALMCALH

14.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Logic for group alarm	ALMCALH	-	-

14.3.2 Application

Group alarm logic function ALMCALH is used to route alarm signals to different LEDs and/or output contacts on the IED.

ALMCALH output signal and the physical outputs allows the user to adapt the alarm signal to physical tripping outputs according to the specific application needs.

14.3.3 Setting guidelines

Operation: On or Off

14.4 Logic for group alarm WRNCALH

14.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Logic for group warning	WRNCALH	-	-

14.4.1.1 Application

Group warning logic function WRNCALH is used to route warning signals to LEDs and/or output contacts on the IED.

WRNCALH output signal WARNING and the physical outputs allows the user to adapt the warning signal to physical tripping outputs according to the specific application needs.

14.4.1.2 Setting guidelines

Operation On or Off

14.5 Logic for group indication INDCALH

14.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Logic for group indication	INDCALH	-	-

14.5.1.1 Application

Group indication logic function INDCALH is used to route indication signals to different LEDs and/or output contacts on the IED.

INDCALH output signal IND and the physical outputs allows the user to adapt the indication signal to physical outputs according to the specific application needs.

14.5.1.2 Setting guidelines

Operation: On or Off

14.6 Configurable logic blocks

The configurable logic blocks are available in two categories:

- Configurable logic blocks that do not propagate the time stamp and the quality of signals. They do not have the suffix QT at the end of their function block name, for example, SRMEMORY. These logic blocks are also available as part of an extension logic package with the same number of instances.
- Configurable logic blocks that propagate the time stamp and the quality of signals. They have the suffix QT at the end of their function block name, for example, SRMEMORYQT.

14.6.1 Application

A set of standard logic blocks, like AND, OR etc, and timers are available for adapting the IED configuration to the specific application needs.

14.6.2 Setting guidelines

There are no settings for AND gates, OR gates, inverters or XOR gates.

For normal On/Off delay and pulse timers the time delays and pulse lengths are set from the local HMI or via the PST tool.

Both timers in the same logic block (the one delayed on pick-up and the one delayed on drop-out) always have a common setting value.

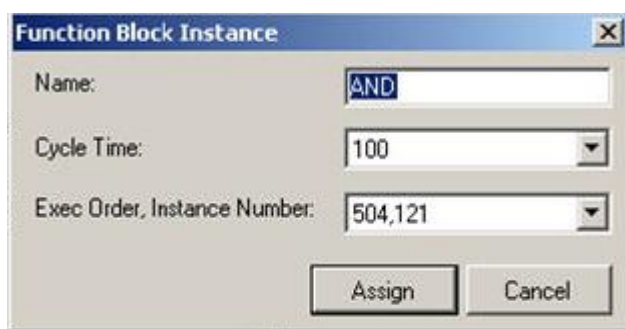
For controllable gates, settable timers and SR flip-flops with memory, the setting parameters are accessible via the local HMI or via the PST tool.

14.6.2.1 Configuration

Logic is configured using the ACT configuration tool in PCM600.

Execution of functions as defined by the configurable logic blocks runs according to a fixed sequence with different cycle times.

For each cycle time, the function block is given an serial execution number. This is shown when using the ACT configuration tool with the designation of the function block and the cycle time, see example below.



IEC09000695_2_en.vsd

Figure 154: Example designation, serial execution number and cycle time for logic function

The execution of different function blocks within the same cycle is determined by the order of their serial execution numbers. Always remember this when connecting two or more logical function blocks in series.



Always be careful when connecting function blocks with a fast cycle time to function blocks with a slow cycle time. Remember to design the logic circuits carefully and always check the execution sequence for different functions. In other cases, additional time delays must be introduced into the logic schemes to prevent errors, for example, race between functions.

14.7 Fixed signal function block FXDSIGN

14.7.1 Application

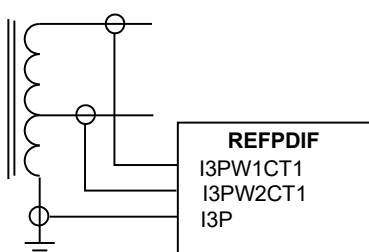
The Fixed signals function (FXDSIGN) has nine pre-set (fixed) output signals that can be used in the configuration of an IED, either for forcing the unused inputs in other function blocks to a certain level/value, or for creating certain logic. Boolean, integer, floating point, string types of signals are available.

One FXDSIGN function block is included in all IEDs.

Example for use of GRP_OFF signal in FXDSIGN

The Restricted earth fault function (REFPDIF) can be used both for auto-transformers and normal transformers.

When used for auto-transformers, information from both windings parts, together with the neutral point current, needs to be available to the function. This means that three inputs are needed.



IEC09000619_3_en.vsd

Figure 155: REFPDIF function inputs for autotransformer application

For normal transformers only one winding and the neutral point is available. This means that only two inputs are used. Since all group connections are mandatory to be connected, the third input needs to be connected to something, which is the GRP_OFF signal in FXDSIGN function block.

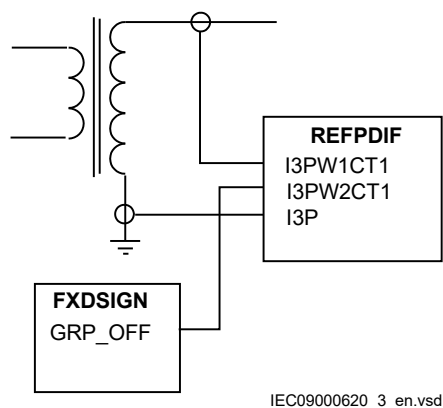


Figure 156: REFDPDIF function inputs for normal transformer application

14.8 Boolean 16 to Integer conversion B16I

14.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Boolean 16 to integer conversion	B16I	-	-

14.8.2 Application

Boolean 16 to integer conversion function B16I is used to transform a set of 16 binary (logical) signals into an integer. It can be used – for example, to connect logical output signals from a function (like distance protection) to integer inputs from another function (like line differential protection). B16I does not have a logical node mapping.

The Boolean 16 to integer conversion function (B16I) will transfer a combination of up to 16 binary inputs IN_x where $1 \leq x \leq 16$ to an integer. Each IN_x represents a value according to the table below from 0 to 32768. This follows the general formula: $IN_x = 2^{x-1}$ where $1 \leq x \leq 16$. The sum of all the values on the activated IN_x will be available on the output OUT as a sum of the values of all the inputs IN_x that are activated. OUT is an integer. When all IN_x where $1 \leq x \leq 16$ are activated that is = Boolean 1 it corresponds to that integer 65535 is available on the output OUT. B16I function is designed for receiving up to 16 booleans input locally. If the BLOCK input is activated, it will freeze the output at the last value.

Values of each of the different OUT_x from function block B16I for $1 \leq x \leq 16$.

The sum of the value on each IN_x corresponds to the integer presented on the output OUT on the function block B16I.

Name of input	Type	Default	Description	Value when activated	Value when deactivated
IN1	BOOLEAN	0	Input 1	1	0
IN2	BOOLEAN	0	Input 2	2	0
IN3	BOOLEAN	0	Input 3	4	0
IN4	BOOLEAN	0	Input 4	8	0
IN5	BOOLEAN	0	Input 5	16	0
Table continues on next page					

Name of input	Type	Default	Description	Value when activated	Value when deactivated
IN6	BOOLEAN	0	Input 6	32	0
IN7	BOOLEAN	0	Input 7	64	0
IN8	BOOLEAN	0	Input 8	128	0
IN9	BOOLEAN	0	Input 9	256	0
IN10	BOOLEAN	0	Input 10	512	0
IN11	BOOLEAN	0	Input 11	1024	0
IN12	BOOLEAN	0	Input 12	2048	0
IN13	BOOLEAN	0	Input 13	4096	0
IN14	BOOLEAN	0	Input 14	8192	0
IN15	BOOLEAN	0	Input 15	16384	0
IN16	BOOLEAN	0	Input 16	32768	0

The sum of the numbers in column “Value when activated” when all IN_x (where 1≤x≤16) are active that is=1; is 65535. 65535 is the highest boolean value that can be converted to an integer by the B16I function block.

14.9 Boolean to integer conversion with logical node representation, 16 bit BTIGAPC

14.9.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Boolean to integer conversion with logical node representation, 16 bit	BTIGAPC	-	-

14.9.2 Application

Boolean to integer conversion with logical node representation, 16 bit (BTIGAPC) is used to transform a set of 16 binary (logical) signals into an integer. BTIGAPC has a logical node mapping in IEC 61850.

The BTIGAPC function will transfer a combination of up to 16 binary inputs IN_x where 1≤x≤16 to an integer. Each IN_x represents a value according to the table below from 0 to 32768. This follows the general formula: $IN_x = 2^{x-1}$ where 1≤x≤16. The sum of all the values on the activated IN_x will be available on the output OUT as a sum of the values of all the inputs IN_x that are activated. OUT is an integer. When all IN_x where 1≤x≤16 are activated that is = Boolean 1 it corresponds to that integer 65535 is available on the output OUT. BTIGAPC function is designed for receiving up to 16 booleans input locally. If the BLOCK input is activated, it will freeze the output at the last value.

Values of each of the different OUT_x from function block BTIGAPC for 1≤x≤16.

The sum of the value on each IN_x corresponds to the integer presented on the output OUT on the function block BTIGAPC.

Name of input	Type	Default	Description	Value when activated	Value when deactivated
IN1	BOOLEAN	0	Input 1	1	0
IN2	BOOLEAN	0	Input 2	2	0
IN3	BOOLEAN	0	Input 3	4	0
IN4	BOOLEAN	0	Input 4	8	0
IN5	BOOLEAN	0	Input 5	16	0
IN6	BOOLEAN	0	Input 6	32	0
IN7	BOOLEAN	0	Input 7	64	0
IN8	BOOLEAN	0	Input 8	128	0
IN9	BOOLEAN	0	Input 9	256	0
IN10	BOOLEAN	0	Input 10	512	0
IN11	BOOLEAN	0	Input 11	1024	0
IN12	BOOLEAN	0	Input 12	2048	0
IN13	BOOLEAN	0	Input 13	4096	0
IN14	BOOLEAN	0	Input 14	8192	0
IN15	BOOLEAN	0	Input 15	16384	0
IN16	BOOLEAN	0	Input 16	32768	0

The sum of the numbers in column “Value when activated” when all INx (where $1 \leq x \leq 16$) are active that is=1; is 65535. 65535 is the highest boolean value that can be converted to an integer by the BTIGAPC function block.

14.10 Integer to Boolean 16 conversion IB16

14.10.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Integer to boolean 16 conversion	IB16	-	-

14.10.2 Application

Integer to boolean 16 conversion function (IB16) is used to transform an integer into a set of 16 binary (logical) signals. It can be used – for example, to connect integer output signals from one function to binary (logical) inputs to another function. IB16 function does not have a logical node mapping.

The Boolean 16 to integer conversion function (IB16) will transfer a combination of up to 16 binary inputs INx where $1 \leq x \leq 16$ to an integer. Each INx represents a value according to the table below from 0 to 32768. This follows the general formula: $INx = 2^{x-1}$ where $1 \leq x \leq 16$. The sum of all the values on the activated INx will be available on the output OUT as a sum of the values of all the inputs INx that are activated. OUT is an integer. When all INx where $1 \leq x \leq 16$ are activated that is = Boolean 1 it corresponds to that integer 65535 is available on the output OUT. IB16 function is designed for receiving up to 16 booleans input locally. If the BLOCK input is activated, it will freeze the output at the last value.

Values of each of the different OUTx from function block IB16 for $1 \leq x \leq 16$.

The sum of the value on each INx corresponds to the integer presented on the output OUT on the function block IB16.

Name of input	Type	Default	Description	Value when activated	Value when deactivated
IN1	BOOLEAN	0	Input 1	1	0
IN2	BOOLEAN	0	Input 2	2	0
IN3	BOOLEAN	0	Input 3	4	0
IN4	BOOLEAN	0	Input 4	8	0
IN5	BOOLEAN	0	Input 5	16	0
IN6	BOOLEAN	0	Input 6	32	0
IN7	BOOLEAN	0	Input 7	64	0
IN8	BOOLEAN	0	Input 8	128	0
IN9	BOOLEAN	0	Input 9	256	0
IN10	BOOLEAN	0	Input 10	512	0
IN11	BOOLEAN	0	Input 11	1024	0
IN12	BOOLEAN	0	Input 12	2048	0
IN13	BOOLEAN	0	Input 13	4096	0
IN14	BOOLEAN	0	Input 14	8192	0
IN15	BOOLEAN	0	Input 15	16384	0
IN16	BOOLEAN	0	Input 16	32768	0

The sum of the numbers in column “Value when activated” when all INx (where $1 \leq x \leq 16$) are active that is $\sum_{x=1}^{16} 2^{x-1}$; is 65535. 65535 is the highest boolean value that can be converted to an integer by the IB16 function block.

14.11 Integer to boolean conversion with logical node representation, 16 bit ITBGAPC

14.11.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Integer to boolean conversion with logical node representation, 16 bit	ITBGAPC	-	-

14.11.2 Application

Integer to boolean conversion with logical node representation, 16 bit function (ITBGAPC) is used to transform an integer into a set of 16 boolean signals. ITBGAPC function can receive an integer from a station computer – for example, over IEC 61850–8–1. This function is very useful when the user wants to generate logical commands (for selector switches or voltage controllers) by inputting an integer number. ITBGAPC function has a logical node mapping in IEC 61850.

The Integer to boolean conversion with logical node representation, 16 bit function (ITBGAPC) will transfer an integer with a value between 0 to 65535 communicated via IEC 61850 and connected to the ITBGAPC function block to a combination of activated outputs OUTx where $1 \leq x \leq 16$.

The values of the different OUTx are according to the Table [31](#).

If the BLOCK input is activated, it freezes the logical outputs at the last value.

Table 31: Output signals

Name of OUTx	Type	Description	Value when activated	Value when deactivated
OUT1	BOOLEAN	Output 1	1	0
OUT2	BOOLEAN	Output 2	2	0
OUT3	BOOLEAN	Output 3	4	0
OUT4	BOOLEAN	Output 4	8	0
OUT5	BOOLEAN	Output 5	16	0
OUT6	BOOLEAN	Output 6	32	0
OUT7	BOOLEAN	Output 7	64	0
OUT8	BOOLEAN	Output 8	128	0
OUT9	BOOLEAN	Output 9	256	0
OUT10	BOOLEAN	Output 10	512	0
OUT11	BOOLEAN	Output 11	1024	0
OUT12	BOOLEAN	Output 12	2048	0
OUT13	BOOLEAN	Output 13	4096	0
OUT14	BOOLEAN	Output 14	8192	0
OUT15	BOOLEAN	Output 15	16384	0
OUT16	BOOLEAN	Output 16	32768	0

The sum of the numbers in column "Value when activated" when all OUTx ($1 \leq x \leq 16$) are active equals 65535. This is the highest integer that can be converted by the ITBGAPC function block.

14.12 Elapsed time integrator with limit transgression and overflow supervision TEIGAPC

14.12.1 Identification

Function Description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Elapsed time integrator	TEIGAPC	-	-

14.12.2 Application

The function TEIGAPC is used for user-defined logics and it can also be used for different purposes internally in the IED. An application example is the integration of elapsed time during the measurement of neutral point voltage or neutral current at earth-fault conditions.

Settable time limits for warning and alarm are provided. The time limit for overflow indication is fixed to 999999.9 seconds.

14.12.3 Setting guidelines

The settings t_{Alarm} and $t_{Warning}$ are user settable limits defined in seconds. The achievable resolution of the settings depends on the level of the values defined.

A resolution of 10 ms can be achieved when the settings are defined within the range

$1.00 \text{ second} \leq t_{Alarm} \leq 99\,999.99 \text{ seconds}$

$1.00 \text{ second} \leq t_{Warning} \leq 99\,999.99 \text{ seconds.}$

If the values are above this range, the resolution becomes lower due to the 32 bit float representation

$99\,999.99 \text{ seconds} < t_{Alarm} \leq 999\,999.0 \text{ seconds}$

$99\,999.99 \text{ seconds} < t_{Warning} \leq 999\,999.0 \text{ seconds}$



Note that t_{Alarm} and $t_{Warning}$ are independent settings, that is, there is no check if $t_{Alarm} > t_{Warning}$.

The limit for the overflow supervision is fixed at 999999.9 seconds.

14.13 Comparator for integer inputs - INTCOMP

14.13.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Comparison of integer values	INTCOMP	Int<=>	

14.13.2 Application

The function gives the possibility to monitor the level of integer values in the system relative to each other or to a fixed value. It is a basic arithmetic function that can be used for monitoring, supervision, interlocking and other logics.

14.13.3 Setting guidelines

For proper operation of comparison the set value should be set within the range of $\pm 2 \times 10^9$.

Setting procedure on the IED:

EnaAbs: To select the comparison type between signed and absolute values.

- **Absolute:** Comparison is performed on absolute values of input and reference values
- **Signed:** Comparison is performed on signed values of input and reference values.

RefSource: To select the reference source between input and setting for comparison.

- **Input REF:** The function will take reference value from input REF
- **Set Value:** The function will take reference value from setting *SetValue*

SetValue: To set the reference value for comparison when setting *RefSource* is selected as *SetValue*.

14.13.4 Setting example

For absolute comparison between inputs:

Set the *EnaAbs* = *Absolute*

Set the *RefSource* = *Input REF*

Similarly for Signed comparison between inputs

Set the *EnaAbs* = *Signed*

Set the *RefSource* = *Input REF*

For absolute comparison between input and setting

Set the *EnaAbs* = *Absolute*

Set the *RefSource* = *Set Value*

SetValue shall be set between -2000000000 to 2000000000

Similarly for signed comparison between input and setting

Set the *EnaAbs* = *Signed*

Set the *RefSource* = *Set Value*

SetValue shall be set between -2000000000 to 2000000000

14.14 Comparator for real inputs - REALCOMP

14.14.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Comparator for real inputs	REALCOMP	Real<=>	

14.14.2 Application

The function gives the possibility to monitor the level of real values in the system relative to each other or to a fixed value. It is a basic arithmetic function that can be used for monitoring, supervision, interlocking and other logics.

14.14.3 Setting guidelines

Setting procedure on the IED:

EnaAbs: To select the comparison type between signed and absolute values.

- *Absolute*: Comparison is performed with absolute values of input and reference.
- *Signed*: Comparison is performed with signed values of input and reference.

RefSource: To select the reference source between input and setting for comparison.

- *Input REF*: The function will take reference value from input REF
- *Set Value*: The function will take reference value from setting *SetValue*

SetValue: To set the reference value for comparison when setting *RefSource* is selected as *Set Value*. If this setting value is less than 0.2% of the set unit then the output INLOW will never pickup.

RefPrefix: To set the unit of the reference value for comparison when setting *RefSource* is selected as *SetValue*. It has 5 unit selections and they are Milli, Unity, Kilo, Mega and Giga.

EqualBandHigh: To set the equal condition high band limit in % of reference value. This high band limit will act as reset limit for INHIGH output when INHIGH.

EqualBandLow: To set the equal condition low band limit in % of reference value. This low band limit will act as reset limit for INLOW output when INLOW.

14.14.4 Setting example

Let us consider a comparison is to be done between current magnitudes in the range of 90 to 110 with nominal rating is 100 and the order is kA.

For the above condition the comparator can be designed with settings as follows,

EnaAbs = Absolute

RefSource = Set Value

SetValue = 100

RefPrefix = Kilo

EqualBandHigh = 5.0 % of reference value

EqualBandLow = 5.0 % of reference value

Operation

The function will set the outputs for the following conditions,

INEQUAL will set when the INPUT is between the ranges of 95 to 105 kA.

INHIGH will set when the INPUT crosses above 105 kA.

INLOW will set when the INPUT crosses below 95 kA.

If the comparison should be done between two current magnitudes then those current signals need to be connected to function inputs, INPUT and REF. Then the settings should be adjusted as below,

EnaAbs = Absolute

RefSource = Input REF

EqualBandHigh = 5.0 % of reference value

EqualBandLow = 5.0 % of reference value.

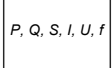
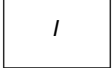
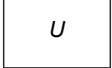
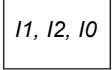
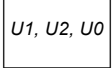
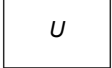
Section 15 Monitoring

15.1 Measurement

15.1.1 Function revision history

Document revision	Product revision	History
A	2.2.1	-
B	2.2.1	-
C	2.2.1	-
D	2.2.1	PTP Enhancement
E	2.2.4	-
J	2.2.6	-
K	2.2.6	-

15.1.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Power system measurements	CVMMXN		-
Phase current measurement	CMMXU		-
Phase-phase voltage measurement	VMMXU		-
Current sequence component measurement	CMSQI		-
Voltage sequence component measurement	VMSQI		-
Phase-neutral voltage measurement	VNMMXU		-

15.1.3 Application

Measurement functions are used for power system measurement, supervision and reporting to the local HMI, monitoring tool within PCM600 or to station level for example, via IEC 61850. The possibility to continuously monitor measured values of active power, reactive power, currents, voltages, frequency, power factor etc. is vital for efficient production, transmission and distribution of electrical energy. It provides to the system operator fast and easy overview of the present status of the power system. Additionally, it can be used during testing and commissioning of protection and control IEDs in order to verify proper operation and connection of instrument transformers (CTs and VTs). During normal service by periodic comparison of the measured value from the IED with other independent meters the proper operation of the IED analog measurement chain can be verified. Finally, it can be used to verify proper direction orientation for distance or directional overcurrent protection function.



The available measured values from an IED are depending on the actual hardware (TRM) and the logic configuration made in PCM600.

All measured values can be supervised with four settable limits that is, low-low limit, low limit, high limit and high-high limit. A zero clamping reduction is also supported, that is, the measured value below a settable limit is forced to zero which reduces the impact of noise in the inputs.

Dead-band supervision can be used to report measured signal value to station level when change in measured value is above set threshold limit or time integral of all changes since the last time value updating exceeds the threshold limit. Measure value can also be based on periodic reporting.

All measurement functions use fundamental frequency phasors (that is, DFT filtering) for internal calculations and for reporting of measured values. However, from the following three measurement functions CMMXU, VMMXU and VNMMXU it is also possible to report the total measured quantity (that is, true RMS filtering). By selecting the RMS mode, the reported value will be in addition to the fundamental magnitude also include harmonics.

Main menu /Measurement /Monitoring /Service values /CVMMXN

The measurement function, CVMMXN, provides the following power system quantities:

- P, Q and S: three phase active, reactive and apparent power
- PF: power factor
- U: phase-to-phase voltage amplitude
- I: phase current amplitude
- F: power system frequency

The measuring functions CMMXU, VMMXU and VNMMXU provide physical quantities:

- I: phase currents (amplitude and angle) (CMMXU)
- U: voltages (phase-to-earth and phase-to-phase voltage, amplitude and angle) (VMMXU, VNMMXU)

Fundamental frequency filtered values (DFT) or true RMS values can be selected as a measurement type in CMMXU, VMMXU and VNMMXU functions.

The CVMMXN function calculates three-phase power quantities by using fundamental frequency phasors (DFT values) of the measured current and voltage signals. The measured power quantities are available either, as instantaneously calculated quantities or, averaged values over a period of time (low pass filtered) depending on the selected settings.

It is possible to calibrate the measuring function above to get better than class 0.5 presentation. This is accomplished by angle and amplitude compensation at 5, 30 and 100% of rated current and at 100% of rated voltage.



The power system quantities provided, depends on the actual hardware, (TRM) and the logic configuration made in PCM600.

The measuring functions CMSQI and VMSQI provide sequence component quantities:

- I: sequence currents (positive, zero, negative sequence, amplitude and angle)
- U: sequence voltages (positive, zero and negative sequence, amplitude and angle).

15.1.4 Zero clamping

Measuring functions CVMMXN, CMMXU, VMMXU and VNMMXU have no interconnections regarding any settings or parameters.

Zero clampings are also handled entirely by *ZeroDb* separately for each function's every output signal. For example, zero clamping of U12 is handled by *UL12ZeroDb* in VMMXU, zero clamping of I1 is handled by *IL1ZeroDb* in CMMXU, and so on.

Example of CVMMXN operation

Outputs seen on the local HMI under **Main menu/Measurements /Monitoring/ Servicevalues(P_Q) /CVMMXN(P_Q)**:

S	Apparent three-phase power
P	Active three-phase power
Q	Reactive three-phase power
PF	Power factor
ILAG	I lagging U
ILEAD	I leading U
U	System mean voltage, calculated according to selected mode
I	System mean current, calculated according to selected mode
F	Frequency

Relevant settings and their values on the local HMI under **Main menu/Settings /IED settings/ Monitoring /Servicevalues(P_Q)/CVMMXN(P_Q)** :

- When system voltage falls below *UGenZeroDB*, values for S, P, Q, PF, ILAG, ILEAD, U and F are forced to zero.
- When system current falls below *IGenZeroDB*, values for S, P, Q, PF, ILAG, ILEAD, U and F are forced to zero.
- When the value of a single signal falls below its set deadband, the value is forced to zero. For example, if the apparent three-phase power falls below *SZeroDb*, the value for S is forced to zero.

15.1.5 Setting guidelines

The available setting parameters of the measurement function CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU are depending on the actual hardware (TRM) and the logic configuration made in PCM600.

The parameters for the Measurement functions CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU are set via the local HMI or PCM600.

GlobalBaseSel: Selects the global base value group used by the function to define *IBase*, *UBase* and *SBase*. Note that this function will only use *IBase* value.

Operation: Off/On. Every function instance (CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU) can be taken in operation (*On*) or out of operation (*Off*).

The following general settings can be set for the **Measurement function** (CVMMXN).

PowAmpFact: Amplitude factor to scale power calculations.

PowAngComp: Angle compensation for phase shift between measured I & U.

Mode: Selection of measured current and voltage. There are 9 different ways of calculating monitored three-phase values depending on the available VT inputs connected to the IED. See parameter group setting table.

k: Low pass filter coefficient for power measurement, U and I.

UGenZeroDb: Minimum level of voltage in % of UBase, used as indication of zero voltage (zero point clamping). If measured value is below *UGenZeroDb* calculated S, P, Q and PF will be zero.

IGenZeroDb: Minimum level of current in % of IBase, used as indication of zero current (zero point clamping). If measured value is below *IGenZeroDb* calculated S, P, Q and PF will be zero.

UAmpCompY: Amplitude compensation to calibrate voltage measurements at Y% of Ur, where Y is equal to 5, 30 or 100.

IampCompY: Amplitude compensation to calibrate current measurements at Y% of Ir, where Y is equal to 5, 30 or 100.

IAngCompY: Angle compensation to calibrate angle measurements at Y% of Ir, where Y is equal to 5, 30 or 100.

The following general settings can be set for the **Phase current measurement** (CMMXU).

IampCompY: Amplitude compensation to calibrate current measurements at Y% of Ir, where Y is equal to 5, 30 or 100.

IAngCompY: Angle compensation to calibrate angle measurements at Y% of Ir, where Y is equal to 5, 30 or 100.

MeasurementType: This default setting is DFT, which gives fundamental frequency amplitude and angle. It can be set as RMS, if true RMS value over one cycle is required.

The following general settings can be set for the **Phase-phase voltage measurement** (VMMXU).

UAmpCompY: Amplitude compensation to calibrate voltage measurements at Y% of Ur, where Y is equal to 5, 30 or 100.

UAngCompY: Angle compensation to calibrate angle measurements at Y% of Ur, where Y is equal to 5, 30 or 100.

MeasurementType: This default setting is DFT, which gives fundamental frequency amplitude and angle. It can be set as RMS, if true RMS value over one cycle is required.

The following general settings can be set for **all monitored quantities** included in the functions (CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU) X in setting names below equals S, P, Q, PF, U, I, F, IL1-3, UL1-3, UL12-31, I1, I2, 3I0, U1, U2 or 3U0.

Xmin: Minimum value for analog signal X set directly in applicable measuring unit. This forms the minimum limit of the range.

Xmax: Maximum value for analog signal X. This forms the maximum limit of the range.

XZeroDb: Zero point clamping. A signal value less than *XZeroDb* is forced to zero.

Observe the related zero point clamping settings in Setting group N for CVMMXN (*UGenZeroDb* and *IGenZeroDb*). If measured value is below *UGenZeroDb* and/or *IGenZeroDb* calculated S, P, Q and PF will be zero and these settings will override *XZeroDb*.

XRepTyp: Reporting type. Cyclic (*Cyclic*), amplitude deadband (*Dead band*), integral deadband (*Int deadband*) or Deadband and xx se cyclic (xx: 5 sec, 30 sec, 1 min). The reporting interval is controlled by the parameter *XDbRepInt*.

XDbRepInt: This setting handles all the reporting types. If setting is deadband in *XRepTyp*, *XDbRepInt* defines the deadband in m% of the measuring range. For cyclic reporting type (*XRepTyp* : *cyclic*), the setting value reporting interval is in seconds. Amplitude deadband is the setting value in m% of measuring range. Integral deadband setting is the integral area, that is, measured value in m% of measuring range multiplied by the time between two measured values.

XHiHiLim: High-high limit. Set as % of *YBase* (Y is *SBase* for S,P,Q *UBase* for Voltage measurement and *IBase* for current measurement).

XHiLim: High limit. Set as % of *YBase* (Y is *SBase* for S,P,Q *UBase* for Voltage measurement and *IBase* for current measurement).

XLowLim: Low limit. Set as % of *YBase* (Y is *SBase* for S,P,Q *UBase* for Voltage measurement and *IBase* for current measurement).

XLowLowLim: Low-low limit. Set as % of *YBase* (Y is *SBase* for S,P,Q *UBase* for Voltage measurement and *IBase* for current measurement).

XLimHyst: Hysteresis value in % of range and is common for all limits.

All phase angles are presented in relation to defined reference channel. The parameter *PhaseAngleRef* defines the reference, see Section [“Analog inputs”](#).

Calibration curves

It is possible to calibrate the functions (CVMMXN, CMMXU, VMMXU and VNMMXU) to get class 0.5 presentations of currents, voltages and powers. This is accomplished by amplitude and angle compensation at 5, 30 and 100% of rated current and voltage. The compensation curve will have the characteristic for amplitude and angle compensation of currents as shown in figure [157](#) (example). The first phase will be used as reference channel and compared with the curve for calculation of factors. The factors will then be used for all related channels.

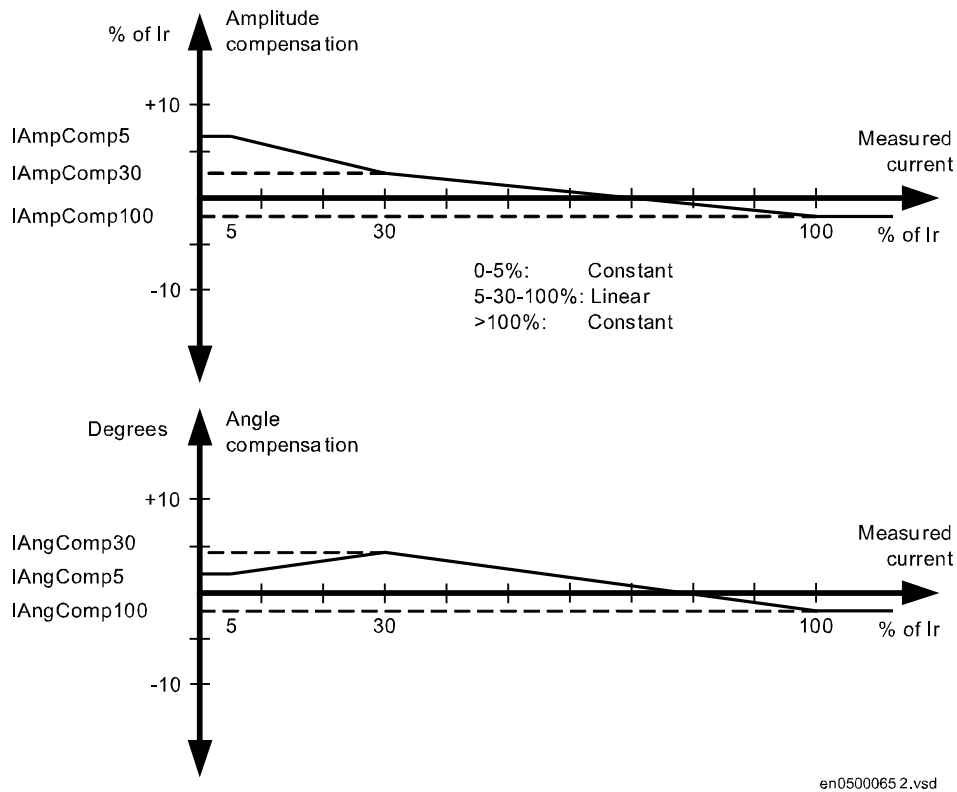


Figure 157: Calibration curves

15.1.5.1 Setting examples

Three setting examples, in connection to Measurement function (CVMMXN), are provided:

- Measurement function (CVMMXN) application for a OHL
- Measurement function (CVMMXN) application on the secondary side of a transformer
- Measurement function (CVMMXN) application for a generator

For each of them detail explanation and final list of selected setting parameters values will be provided.



The available measured values of an IED are depending on the actual hardware (TRM) and the logic configuration made in PCM600.

Measurement function application for a 400kV OHL

Single line diagram for this application is given in figure [158](#):

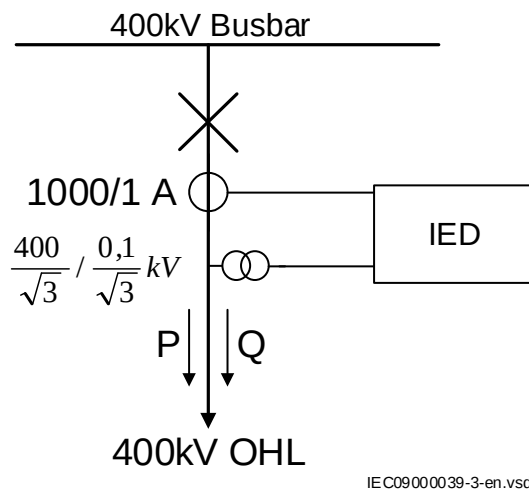


Figure 158: Single line diagram for 400kV OHL application

In order to monitor, supervise and calibrate the active and reactive power as indicated in figure 158 it is necessary to do the following:

1. Set correctly CT and VT data and phase angle reference channel *PhaseAngleRef* (see Section “Setting of the phase reference channel”) using PCM600 for analog input channels
2. Connect, in PCM600, measurement function to three-phase CT and VT inputs
3. Set under General settings parameters for the Measurement function:
 - general settings as shown in table 32.
 - level supervision of active power as shown in table 33.
 - calibration parameters as shown in table 34.

Table 32: General settings parameters for the Measurement function

Setting	Short Description	Selected value	Comments
Operation	Operation Off/On	On	Function must be On
PowAmpFact	Amplitude factor to scale power calculations	1.000	It can be used during commissioning to achieve higher measurement accuracy. Typically no scaling is required
PowAngComp	Angle compensation for phase shift between measured I & U	0.0	It can be used during commissioning to achieve higher measurement accuracy. Typically no angle compensation is required. As well here required direction of P & Q measurement is towards protected object (as per IED internal default direction)
Mode	Selection of measured current and voltage	L1, L2, L3	All three phase-to-earth VT inputs are available
k	Low pass filter coefficient for power measurement, U and I	0.00	Typically no additional filtering is required
UGenZeroDb	Zero point clamping in % of Ubase	25	Set minimum voltage level to 25%. Voltage below 25% will force S, P and Q to zero.
IGenZeroDb	Zero point clamping in % of Ibase	3	Set minimum current level to 3%. Current below 3% will force S, P and Q to zero.
Table continues on next page			

Setting	Short Description	Selected value	Comments
UBase (set in Global base)	Base setting for voltage level in kV	400.00	Set rated OHL phase-to-phase voltage
IBase (set in Global base)	Base setting for current level in A	1000	Set rated primary CT current used for OHL
SBase (set in Global base)	Base Setting for power base in MVA	1000	Set based on rated Power

Table 33: Settings parameters for level supervision

Setting	Short Description	Selected value	Comments
PMin	Minimum value	-100	Minimum expected load
PMax	Maximum value	100	Maximum expected load
PZeroDb	Zero point clamping in 0.001% of range	3000	Set zero point clamping to 60 MW that is, 3% of 200 MW
PRepTyp	Reporting type	db	Select amplitude deadband supervision
PDbRepInt	Cycl: Report interval (s), Db: In 0.001% of range, Int Db: In 0.001% s	2000	Set $\pm\Delta db=40$ MW that is, 2% (larger changes than 40 MW will be reported)
PHiHiLim	High High limit (physical value), % of SBase	60	High alarm limit that is, extreme overload alarm, hence it will be 415 MW.
PHiLim	High limit (physical value), in % of SBase	50	High warning limit that is, overload warning, hence it will be 371 MW.
PLowLim	Low limit (physical value), in % of SBase	-50	Low warning limit -500 MW
PLowLowLim	Low Low limit (physical value), in % of SBase	-60	Low alarm limit -600 MW
PLimHyst	Hysteresis value in % of range (common for all limits)	1	Set $\pm\Delta$ Hysteresis 20 MW that is, 1% of range (2000 MW)

Table 34: Settings for calibration parameters

Setting	Short Description	Selected value	Comments
IAmpComp5	Amplitude factor to calibrate current at 5% of Ir	0.00	
IAmpComp30	Amplitude factor to calibrate current at 30% of Ir	0.00	
IAmpComp100	Amplitude factor to calibrate current at 100% of Ir	0.00	
UAmpComp5	Amplitude factor to calibrate voltage at 5% of Ur	0.00	
UAmpComp30	Amplitude factor to calibrate voltage at 30% of Ur	0.00	
UAmpComp100	Amplitude factor to calibrate voltage at 100% of Ur	0.00	
IAngComp5	Angle calibration for current at 5% of Ir	0.00	
IAngComp30	Angle pre-calibration for current at 30% of Ir	0.00	
IAngComp100	Angle pre-calibration for current at 100% of Ir	0.00	

Measurement function application for a power transformer

Single line diagram for this application is given in figure 159.

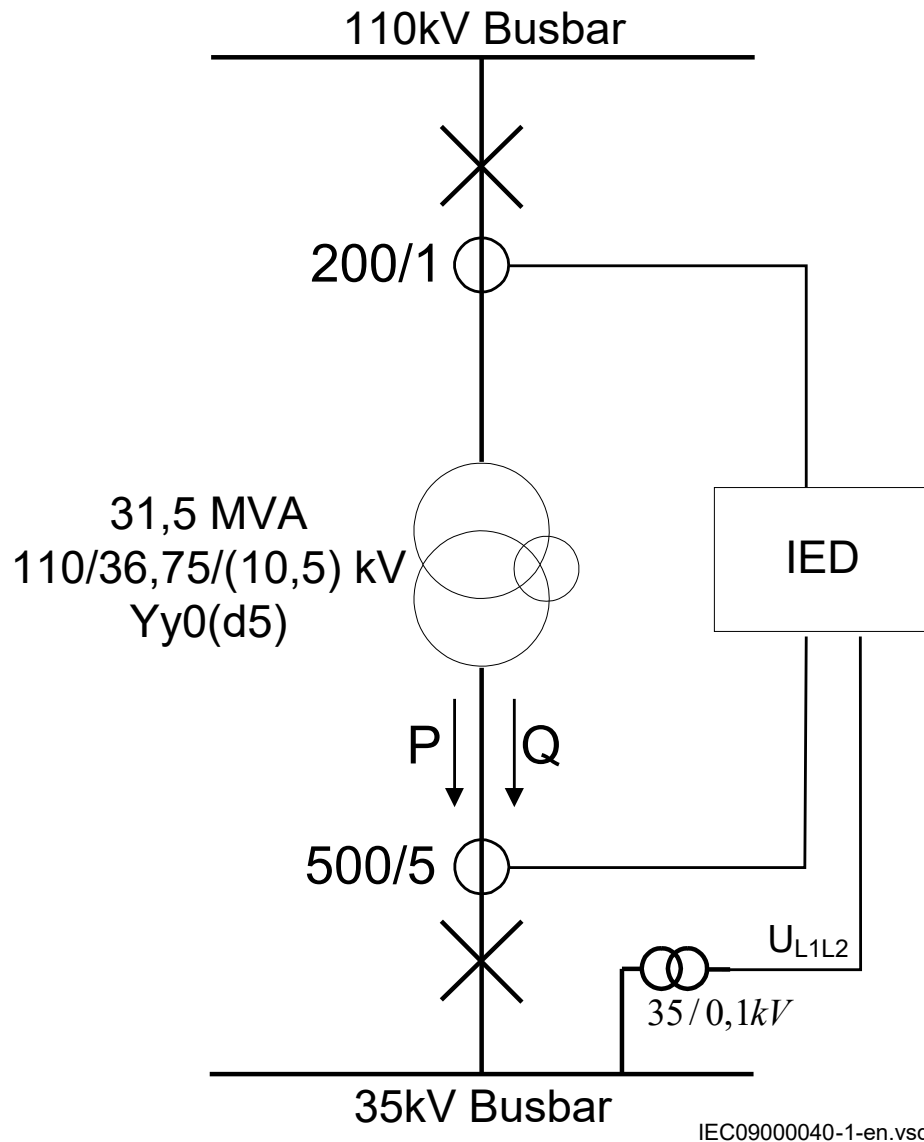


Figure 159: Single line diagram for transformer application

In order to measure the active and reactive power as indicated in figure 159, it is necessary to do the following:

1. Set correctly all CT and VT and phase angle reference channel *PhaseAngleRef* (see Section “Setting of the phase reference channel”) data using PCM600 for analog input channels
2. Connect, in PCM600, measurement function to LV side CT & VT inputs
3. Set the setting parameters for relevant Measurement function as shown in the following table 35:

Table 35: General settings parameters for the Measurement function

Setting	Short description	Selected value	Comment
Operation	Operation Off/On	On	Function must be On
PowAmpFact	Amplitude factor to scale power calculations	1.000	Typically no scaling is required
PowAngComp	Angle compensation for phase shift between measured I & U	180.0	Typically no angle compensation is required. However here the required direction of P & Q measurement is towards busbar (Not per IED internal default direction). Therefore angle compensation have to be used in order to get measurements in alignment with the required direction.
Mode	Selection of measured current and voltage	L1L2	Only UL1L2 phase-to-phase voltage is available
k	Low pass filter coefficient for power measurement, U and I	0.00	Typically no additional filtering is required
UGenZeroDb	Zero point clamping in % of Ubase	25	Set minimum voltage level to 25%
IGenZeroDb	Zero point clamping in % of Ibase	3	Set minimum current level to 3%
UBase (set in Global base)	Base setting for voltage level in kV	35.00	Set LV side rated phase-to-phase voltage
IBase (set in Global base)	Base setting for current level in A	495	Set transformer LV winding rated current
SBase (set in Global base)	Base setting for power in MVA	31.5	Set based on rated power

15.2 Insulation gas monitoring function SSIMG

15.2.1 Function revision history

Document revision	Product revision	History
A	2.2.1	-
B	2.2.2	-
C	2.2.1	-
D	2.2.4	Binary quality inputs SENLVLQ and SENTEMPQ have been added for pressure and temperature sensor signals in order to control alarm and lockout signals. Whenever there is no sensor, the quality of the binary input will be low. If sensor quality is low, then lockout and alarm signals will get reset.
E	2.2.5	-
J	2.2.6	-
K	2.2.6	-

15.2.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Insulation gas monitoring function	SSIMG	-	63

15.2.3 Application

Gas medium supervision (SSIMG) is used for monitoring the circuit breaker condition. Proper arc extinction by the compressed gas in the circuit breaker is very important. When the pressure becomes too low compared to the required value, the circuit breaker operation shall be blocked to minimize the risk of internal failure.

The function can be used with analog or analog and binary signals. The analog sensor values can be fed through GOOSE communication. Binary information based on the gas pressure in the circuit breaker is used as an input signal to the function. The function generates alarms based on the received information. If only binary signals are available, then a generic SP16GAPC function can be used and modeled as SIMG using FPN feature in PCM600.

15.2.4 Setting guidelines

The parameters for Gas medium supervision SSIMG can be set via local HMI or Protection and Control Manager PCM600.

Operation : To disable/enable the operation of gas medium supervision, that is, *Off / On* .

PresAlmLimit : To set the limit for a pressure alarm condition in the circuit breaker.

PresLOLimit : To set the limit for a pressure lockout condition in the circuit breaker.

TempAlarmLimit : To set the limit for a temperature alarm condition in the circuit breaker.

TempLOLimit : To set the limit for a temperature lockout condition in the circuit breaker.

tPressureAlarm : To set the time delay for a pressure alarm indication, given in s.

tPressureLO : To set the time delay for a pressure lockout indication, given in s.

tTempAlarm : To set the time delay for a temperature alarm indication, given in s.

tTempLockOut : To set the time delay for a temperature lockout indication, given in s.

tResetPressAlm : For the pressure alarm indication to reset after a set time delay in s.

tResetPressLO : For the pressure lockout indication to reset after a set time delay in s.

tResetTempLO : For the temperature lockout indication to reset after a set time delay in s.

tResetTempAlm : For the temperature alarm indication to reset after a set time delay in s.

15.3 Insulation liquid monitoring function SSIML

15.3.1 Function revision history

Document revision	Product revision	History
A	2.2.1	-
B	2.2.2	-
C	2.2.1	-
Table continues on next page		

Document revision	Product revision	History
D	2.2.4	Binary quality inputs SENLVLQ and SENTEMPQ have been added for pressure and temperature sensor signals in order to control alarm and lockout signals. Whenever there is no sensor, the quality of the binary input will be low. If sensor quality is low, then lockout and alarm signals will get reset.
E	2.2.5	-
J	2.2.6	-

15.3.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Insulation liquid monitoring function	SSIML	-	71

15.3.3 Application

Liquid medium supervision (SSIML) is used for monitoring the oil insulated device condition. For example, transformers, shunt reactors, and so on. When the level becomes too low compared to the required value, the operation is blocked to minimize the risk of internal failures.

The function can be used with analog or analog and binary signals. The analog sensor values can be fed through GOOSE communication. Binary information based on the oil level in the oil insulated devices are used as input signals to the function. The function generates alarms based on the received information. If only binary signals are available, then a generic SP16GAPC function can be used and modeled as SIML using FPN feature in PCM600.

15.3.4 Setting guidelines

The parameters for Liquid medium supervision SSIML can be set via local HMI or Protection and Control Manager PCM600.

Operation: To disable/enable the operation of liquid medium supervision i.e. *Off/On*.

LevelAlmLimit: To set the limit for a level alarm condition in the oil insulated device.

LevelLOLimit: To set the limit for a level lockout condition in the oil insulated device.

TempAlarmLimit: To set the limit for a temperature alarm condition in the oil insulated device.

TempLOLimit: To set the limit for a temperature lockout condition in the oil insulated device.

tLevelAlarm: To set the time delay for a level alarm indication, given in s.

tLevelLockOut: To set the time delay for a level lockout indication, given in s.

tTempAlarm: To set the time delay for a temperature alarm indication, given in s.

tTempLockOut: To set the time delay for a temperature lockout indication, given in s.

tResetLevelAlm: For the level alarm indication to reset after a set time delay in s.

tResetLevelLO: For the level lockout indication to reset after a set time delay in s.

tResetTempLO: For the temperature lockout indication to reset after a set time delay in s.

tResetTempAlm: For the temperature alarm indication to reset after a set time delay in s.

15.4 Breaker monitoring SSCBR

15.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Breaker monitoring	SSCBR	-	-

15.4.2 Application

The circuit breaker maintenance is usually based on regular time intervals or the number of operations performed. This has some disadvantages because there could be a number of abnormal operations or few operations with high-level currents within the predetermined maintenance interval. Hence, condition-based maintenance scheduling is an optimum solution in assessing the condition of circuit breakers.

Circuit breaker contact operation time

Auxiliary contacts provide information about the mechanical operation, opening time and closing time of a breaker. Detecting an excessive operation time is essential to indicate the need for maintenance of the circuit breaker mechanism. The excessive operation time can be due to problems in the driving mechanism or failures of the contacts.

Circuit breaker status

Monitoring the breaker status ensures proper functioning of the features within the protection relay such as breaker control, breaker failure and autoreclosing. The breaker status is monitored using breaker auxiliary contacts. The breaker status is indicated by the binary outputs. These signals indicate whether the circuit breaker is in an open, closed or error state.

Remaining life of circuit breaker

Every time the breaker operates, the circuit breaker life reduces due to wear. The wear in a breaker depends on the interrupted current. For breaker maintenance or replacement at the right time, the remaining life of the breaker must be estimated. The remaining life of a breaker can be estimated using the maintenance curve provided by the circuit breaker manufacturer.

Circuit breaker manufacturers provide the number of make-break operations possible at various interrupted currents. An example is shown in figure [160](#).

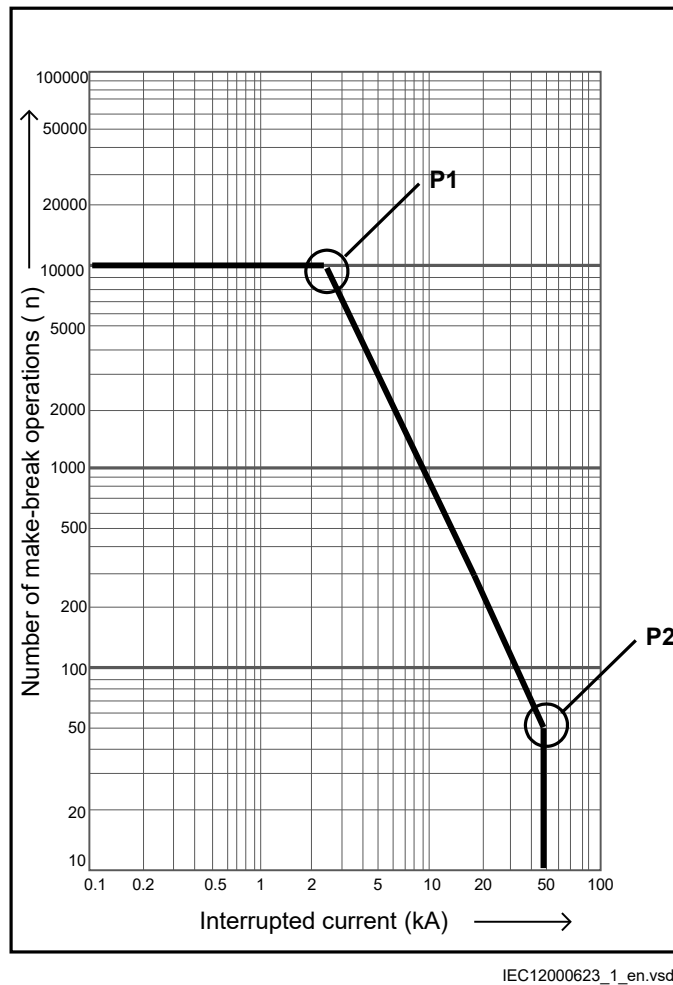


Figure 160: An example for estimating the remaining life of a circuit breaker

Calculation for estimating the remaining life

The graph shows that there are 10000 possible operations at the rated operating current and 900 operations at 10 kA and 50 operations at rated fault current. Therefore, if the interrupted current is 10 kA, one operation is equivalent to $10000/900 = 11$ operations at the rated current. It is assumed that prior to tripping, the remaining life of a breaker is 10000 operations. Remaining life calculation for three different interrupted current conditions is explained below.

- Breaker interrupts at and below the rated operating current, that is, 2 kA, the remaining life of the CB is decreased by 1 operation and therefore, 9999 operations remaining at the rated operating current.
- Breaker interrupts between rated operating current and rated fault current, that is, 10 kA, one operation at 10kA is equivalent to $10000/900 = 11$ operations at the rated current. The remaining life of the CB would be $(10000 - 10) = 9989$ at the rated operating current after one operation at 10 kA.
- Breaker interrupts at and above rated fault current, that is, 50 kA, one operation at 50 kA is equivalent to $10000/50 = 200$ operations at the rated operating current. The remaining life of the CB would become $(10000 - 200) = 9800$ operations at the rated operating current after one operation at 50 kA.

Accumulated contact abrasion

Monitoring the contact erosion and interrupter wear has a direct influence on the required maintenance frequency. Therefore, it is necessary to accurately estimate the erosion of the contacts and condition of interrupters using cumulative summation of I^2t . The factor "y" depends on the type of

circuit breaker. The energy values were accumulated using the current value and exponent factor for CB contact opening duration. When the next CB opening operation is started, the energy is accumulated from the previous value. The accumulated contact abrasion value can be reset to initial accumulation contact abrasion value by using the Reset accumulating contact abrasion input, RSACCMABR.

Circuit breaker operation cycles

Routine breaker maintenance like lubricating breaker mechanism is based on the number of operations. A suitable threshold setting helps in preventive maintenance. This can also be used to indicate the requirement for oil sampling for dielectric testing in case of an oil circuit breaker.

Circuit breaker operation monitoring

By monitoring the activity of the number of operations, it is possible to calculate the number of days the breaker has been inactive. Long periods of inactivity degrade the reliability for the protection system.

Circuit breaker spring charge monitoring

For normal circuit breaker operation, the circuit breaker spring should be charged within a specified time. Detecting a long spring charging time indicates the time for circuit breaker maintenance. The last value of the spring charging time can be given as a service value.

Circuit breaker gas pressure indication

For proper arc extinction by the compressed gas in the circuit breaker, the pressure of the gas must be adequate. Binary input available from the pressure sensor is based on the pressure levels inside the arc chamber. When the pressure becomes too low compared to the required value, the circuit breaker operation is blocked.

Coil open indication

Coil open indicates that opening coil is being operated through manual open command and not from the command from protection function.

15.4.3 Setting guidelines

The breaker monitoring function is used to monitor different parameters of the circuit breaker. The breaker requires maintenance when the number of operations has reached a predefined value. For proper functioning of the circuit breaker, it is also essential to monitor the circuit breaker operation, spring charge indication or breaker wear, travel time, coil open indication, number of operation cycles and accumulated energy during arc extinction.

Since there is no current measurement in SAM600-IO, evaluation of the following parameters are not possible in the circuit breaker condition monitoring function (SSCBR):



- Circuit breaker status
- Remaining life of the circuit breaker
- Contact erosion estimation
- Circuit breaker contact travel time

Ensure that `OPNPOS`, `CLSPOS`, `INVDPOS`, `RMNLIFEALM`, `ACCMABRWRN`, `ACCMABRALM`, `OPTMOPNALM` and `OPTMCLSALM` signals are not used in SAM600-IO.

15.4.3.1 Setting procedure on the IED

The parameters for breaker monitoring (SSCBR) can be set via the local HMI or Protection and Control Manager (PCM600).

Common base IED values for primary current (*IBase*), primary voltage (*UBase*) and primary power (*SBase*) are set in Global base values for settings function GBASVAL.

GlobalBaseSel: To select a GBASVAL function for reference of base values.

Operation: On or Off.

IBase: Base phase current in primary A. This current is used as reference for current settings.

OpTmOpnCor: Correction factor for circuit breaker open operation time.

OpTmClsCor: Correction factor for circuit breaker close operation time.

OpTmOpnAlmLev: Setting of alarm level for open operation time.

OpTmClsAlmLev: Setting of alarm level for close operation time.

OpNumWrnLev: Warning level for number of mechanical operations.

OpNumAlmLev: Alarm level for number of mechanical operations.

CurExponent: Current exponent setting for accumulated contact abrasion calculation. It varies for different types of circuit breakers. This factor ranges from 0.5 to 3.0.

AccmAbrStopCur: RMS current setting below which calculation of accumulated contact abrasion stops. It is given as a percentage of *IBase*.

OpnTmTrvlCor: Correction factor for time difference in auxiliary and main contacts' opening time.

AccmAbrWrnLev: Setting of warning level for accumulated contact abrasion.

AccmAbrAlmLev: Alarm level for accumulated contact abrasion.

SpcTmAlmLev: Alarm level for spring charging time.

tGasPresAlm: Time delay for gas pressure alarm.

tGasPresLO: Time delay for gas pressure lockout.

DirCff: Directional coefficient for circuit breaker life calculation.

RatedOpCur: Rated operating current of the circuit breaker.

RatedFltCur: Rated fault current of the circuit breaker.

OpNumRatedCur: Number of operations possible at rated current.

OpNumFltCur: Number of operations possible at rated fault current.

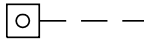
RmnLifeAlmLev: Alarm level for circuit breaker remaining life.

AccmAbrClcMod: Accumulated contact abrasion calculation mode.

OpTmDelay: Time delay between change of status of trip output and start of main contact separation.

15.5 Event function EVENT

15.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Event function	EVENT		-

15.5.2 Application

When using a Substation Automation system with LON or SPA communication, time-tagged events can be sent at change or cyclically from the IED to the station level. These events are created from any available signal in the IED that is connected to the Event function (EVENT). The EVENT function block is used for LON and SPA communication.

Analog, integer and double indication values are also transferred through the EVENT function.

15.5.3 Setting guidelines

The input parameters for the Event function (EVENT) can be set individually via the local HMI (**Main Menu /Settings / IED Settings / Monitoring / Event Function**) or via the Parameter Setting Tool (PST).

EventMask (Ch_1 - 16)

The inputs can be set individually as:

- *NoEvents*
- *OnSet*, at pick-up of the signal
- *OnReset*, at drop-out of the signal
- *OnChange*, at both pick-up and drop-out of the signal
- *AutoDetect*, the EVENT function makes the reporting decision (reporting criteria for integers have no semantic, prefer to be set by the user)

LONChannelMask or SPACHannelMask

Definition of which part of the event function block that shall generate events:

- *Off*
- *Channel 1-8*
- *Channel 9-16*
- *Channel 1-16*

MinRepIntVal (1 - 16)

A time interval between cyclic events can be set individually for each input channel. This can be set between 0 s to 3600 s in steps of 1 s. It should normally be set to 0, that is, no cyclic communication.



It is important to set the time interval for cyclic events in an optimized way to minimize the load on the station bus.

15.6 Disturbance report DRPRDRE

15.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Disturbance report	DRPRDRE	-	-
Disturbance report	A1RADR - A3RADR	-	-
Disturbance report	B1RBDR - B22RBDR	-	-
Disturbance report	C1RADR	-	-

15.6.2 Application

To get fast, complete and reliable information about disturbances in the primary and/or in the secondary system it is very important to gather information on fault currents, voltages and events. It is also important having a continuous event-logging to be able to monitor in an overview perspective. These tasks are accomplished by the disturbance report function DRPRDRE and facilitate a better understanding of the power system behavior and related primary and secondary equipment during and after a disturbance. An analysis of the recorded data provides valuable information that can be used to explain a disturbance, basis for change of IED setting plan, improve existing equipment, and so on. This information can also be used in a longer perspective when planning for and designing new installations, that is, a disturbance recording could be a part of Functional Analysis (FA).

Disturbance report DRPRDRE, always included in the IED, acquires sampled data of all selected analog and binary signals connected to the function blocks that is,

- Maximum 30 external analog signals,
- 10 internal derived analog signals, and
- 352 binary signals

Disturbance report function is a common name for several functions; Indications (IND), Event recorder (ER), Event list (EL), Trip value recorder (TVR), Disturbance recorder (DR) and Fault locator (FL).

Disturbance report function is characterized by great flexibility as far as configuration, starting conditions, recording times, and storage capacity are concerned. Thus, disturbance report is not dependent on the operation of protective functions, and it can record disturbances that were not discovered by protective functions for one reason or another. Disturbance report can be used as an advanced stand-alone disturbance recorder.

Every disturbance report recording is saved in the IED. The same applies to all events, which are continuously saved in a ring-buffer. Local HMI can be used to get information about the recordings, and the disturbance report files may be uploaded in the PCM600 using the Disturbance handling tool, for report reading or further analysis (using WaveWin, that can be found on the PCM600 installation CD). The user can also upload disturbance report files using FTP or MMS (over 61850-8-1) clients.

If the IED is connected to a station bus (IEC 61850-8-1), the disturbance recorder (record made and fault number) and the fault locator information are available. The same information is obtainable if IEC 60870-5-103 is used.

15.6.3 Setting guidelines

The setting parameters for the Disturbance report function DRPRDRE are set via the local HMI or PCM600.

It is possible to handle up to 40 analog and 352 binary signals, either internal signals or signals coming from external inputs. The binary signals are identical in all functions that is, Disturbance

recorder (DR), Event recorder (ER), Indication (IND), Trip value recorder (TVR) and Event list (EL) function.

User-defined names of binary and analog input signals are set using PCM600. The analog and binary signals appear with their user-defined names. The name is used in all related functions (Disturbance recorder (DR), Event recorder (ER), Indication (IND), Trip value recorder (TVR) and Event list (EL)).

Figure 161 shows the relations between Disturbance report, included functions and function blocks. Event list (EL), Event recorder (ER) and Indication (IND) uses information from the binary input function blocks (BxRBDR). Trip value recorder (TVR) uses analog information from the analog input function blocks (AxRADR), which is used by Fault locator (FL) after estimation by Trip Value Recorder (TVR). Disturbance report function acquires information from both AxRADR and BxRBDR.

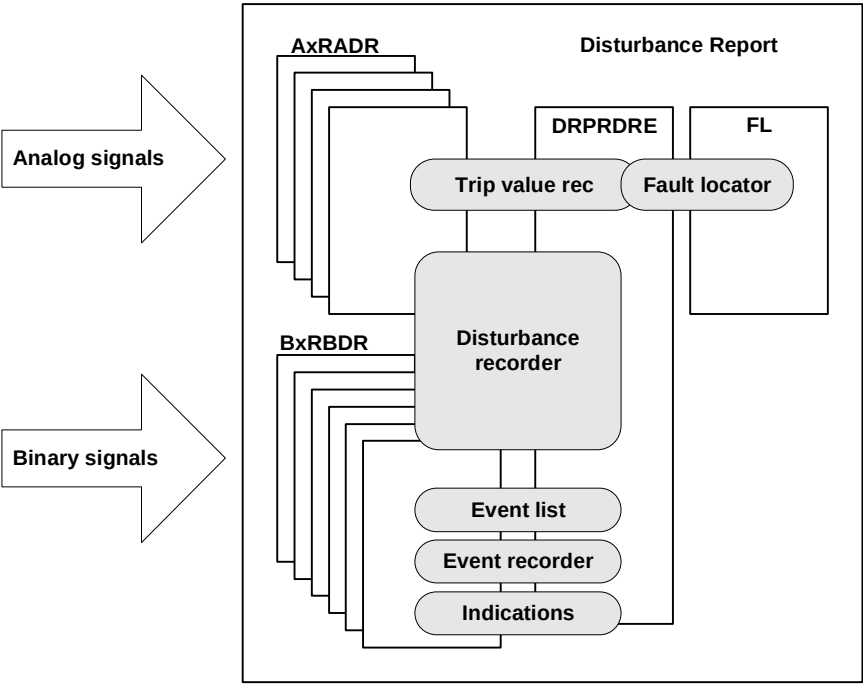


Figure 161: Disturbance report functions and related function blocks

For Disturbance report function there are a number of settings which also influences the sub-functions.

Three LED indications placed above the LCD screen makes it possible to get quick status information about the IED.

Green LED:	
Steady light	In Service
Flashing light	Internal failure
Dark	No power supply
Yellow LED:	
Steady light	Triggered on binary signal N with SetLEDx = Start (or Start and Trip)

Table continues on next page

Flashing light	The IED is in test mode
Red LED:	
Steady light	Triggered on binary signal N with SetLEDx = Trip (or Start and Trip)
Flashing	The IED is in configuration mode

Operation

The operation of Disturbance report function DRPRDRE has to be set *On* or *Off*. If *Off* is selected, note that no disturbance report is registered, and none sub-function will operate (the only general parameter that influences Event list (EL)).

Operation = Off:

- Disturbance reports are not stored.
- LED information (yellow - start, red - trip) is not stored or changed.

Operation = On:

- Disturbance reports are stored, disturbance data can be read from the local HMI and from a PC for example using PCM600.
- LED information (yellow - start, red - trip) is stored.

Every recording will get a number (0 to 999) which is used as identifier (local HMI, disturbance handling tool and IEC 61850). An alternative recording identification is date, time and sequence number. The sequence number is automatically increased by one for each new recording and is reset to zero at midnight. The maximum number of recordings stored in the IED is 200. The oldest recording will be overwritten when a new recording arrives (FIFO).



To be able to delete disturbance records, *Operation* parameter has to be *On*.



The IED flash disk should not be used to store any user files. This causes lack of space for new disturbance recordings.

15.6.3.1 Recording times

The different recording times for Disturbance report are set (the pre-fault time, post-fault time, and limit time). These recording times affect all sub-functions more or less but not the Event list (EL) function.

Prefault recording time (*PreFaultRecT*) is the recording time before the starting point of the disturbance. The setting should be at least 0.1 s to ensure enough samples for the estimation of pre-fault values in the Trip value recorder (TVR) function.

Postfault recording time (*PostFaultRecT*) is the maximum recording time after the disappearance of the trig-signal (does not influence the Trip value recorder (TVR) function).

Recording time limit (*TimeLimit*) is the maximum recording time after trig. The parameter limits the recording time if some triggering condition (fault-time) is very long or permanently set (does not influence the Trip value recorder (TVR) function).

Operation in test mode

If the IED is in test mode and *OpModeTest* = *Off*. Disturbance report function does not save any recordings and no LED information is displayed.

If the IED is in test mode and *OpModeTest* = *On*. Disturbance report function works in normal mode and the status is indicated in the saved recording.

Post Retrigger

Disturbance report function does not automatically respond to any new trig condition during a recording, after all signals set as trigger signals have been reset. However, under certain circumstances the fault condition may reoccur during the post-fault recording, for instance by automatic reclosing to a still faulty power line.

In order to capture the new disturbance it is possible to allow retriggering (*PostRetrig* = *On*) during the post-fault time. In this case a new, complete recording will start and, during a period, run in parallel with the initial recording.

When the retrig parameter is disabled (*PostRetrig* = *Off*), a new recording will not start until the post-fault (*PostFaultrecT* or *TimeLimit*) period is terminated. If a new trig occurs during the post-fault period and lasts longer than the proceeding recording a new complete recording will be started.

Disturbance report function can handle a maximum of 3 simultaneous disturbance recordings.

15.6.3.2 Binary input signals

Up to 352 binary signals can be selected among internal logical and binary input signals. The configuration tool is used to configure the signals.

For each of the 352 signals, it is also possible to select if the signal is to be used as a trigger for the start of the Disturbance report and if the trigger should be activated on positive (1) or negative (0) slope.

OperationN: Disturbance report may trig for binary input N (*On*) or not (*Off*).

TrigLevelN: Trig on positive (*Trig on 1*) or negative (*Trig on 0*) slope for binary input N.

Func103N: Function type number (0-255) for binary input N according to IEC-60870-5-103, that is, 128: Distance protection, 160: overcurrent protection, 176: transformer differential protection and 192: line differential protection.

Info103N: Information number (0-255) for binary input N according to IEC-60870-5-103, that is, 69-71: Trip L1-L3, 78-83: Zone 1-6.

See also description in the chapter IEC 60870-5-103.

15.6.3.3 Analog input signals

Up to 40 analog signals can be selected among internal analog and analog input signals. PCM600 is used to configure the signals.



For retrieving remote data from LDCM module, the Disturbance report function should be connected to a 8 ms SMAI function block if this is the only intended use for the remote data.

The analog trigger of Disturbance report is not affected if analog input M is to be included in the disturbance recording or not (*OperationM* = *On/Off*).

If *OperationM* = *Off*, no waveform (samples) will be recorded and reported in graph. However, Trip value, pre-fault and fault value will be recorded and reported. The input channel can still be used to trig the disturbance recorder.

If *OperationM* = *On*, waveform (samples) will also be recorded and reported in graph.

NomValueM: Nominal value for input M.

OverTrigOpM, UnderTrigOpM: Over or Under trig operation, Disturbance report may trig for high/low level of analog input M (*On*) or not (*Off*).

OverTrigLeM, UnderTrigLeM: Over or under trig level, Trig high/low level relative nominal value for analog input M in percent of nominal value.

15.6.3.4 Sub-function parameters

All functions are in operation as long as Disturbance report is in operation.

Indications

IndicationMaN: Indication mask for binary input N. If set (*Show*), a status change of that particular input, will be fetched and shown in the disturbance summary on local HMI. If not set (*Hide*), status change will not be indicated.

SetLEDN: Set red LED on local HMI in front of the IED if binary input N changes status.

Disturbance recorder

OperationM: Analog channel M is to be recorded by the disturbance recorder (*On*) or not (*Off*).

If *OperationM* = *Off*, no waveform (samples) will be recorded and reported in graph. However, Trip value, pre-fault and fault value will be recorded and reported. The input channel can still be used to trig the disturbance recorder.

If *OperationM* = *On*, waveform (samples) will also be recorded and reported in graph.

Setting information

SetInfoInDrep: Parameter used to enable or disable the settings information in disturbance header.

Event recorder

Event recorder (ER) function has no dedicated parameters.

Trip value recorder

ZeroAngleRef: The parameter defines which analog signal that will be used as phase angle reference for all other analog input signals. This signal will also be used for frequency measurement and the measured frequency is used when calculating trip values. It is suggested to point out a sampled voltage input signal, for example, a line or busbar phase voltage (channel 1-30).

Event list

Event list (EL) (SOE) function has no dedicated parameters.

15.6.3.5 Consideration

The density of recording equipment in power systems is increasing, since the number of modern IEDs, where recorders are included, is increasing. This leads to a vast number of recordings at every single disturbance and a lot of information has to be handled if the recording functions do not have proper settings. The goal is to optimize the settings in each IED to be able to capture just valuable disturbances and to maximize the number that is possible to save in the IED.

The recording time should not be longer than necessary (*PostFaultrecT* and *TimeLimit*).

- Should the function record faults only for the protected object or cover more?
- How long is the longest expected fault clearing time?
- Is it necessary to include reclosure in the recording or should a persistent fault generate a second recording (*PostRetrig*)?

Minimize the number of recordings:

- Binary signals: Use only relevant signals to start the recording that is, protection trip, carrier receive and/or start signals.
- Analog signals: The level triggering should be used with great care, since unfortunate settings will cause enormously number of recordings. If nevertheless analog input triggering is used, chose settings by a sufficient margin from normal operation values. Phase voltages are not recommended for triggering.



There is a risk of flash wear out if the disturbance report triggers too often.

Remember that values of parameters set elsewhere are linked to the information on a report. Such parameters are, for example, station and object identifiers, CT and VT ratios.

15.7 Logical signal status report BINSTATREP

15.7.1 Identification

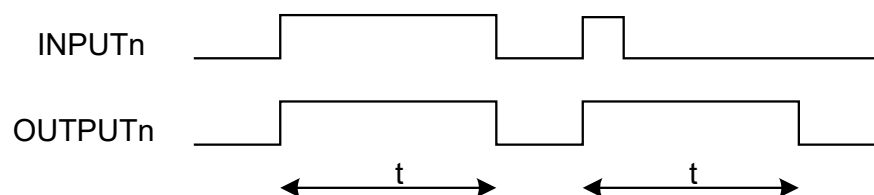
Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Logical signal status report	BINSTATREP	-	-

15.7.2 Application

The Logical signal status report (BINSTATREP) function makes it possible to poll signals from various other function blocks.

BINSTATREP has 16 inputs and 16 outputs. The output status follows the inputs and can be read from the local HMI or via SPA communication.

When an input is set, the respective output is set for a user defined time. If the input signal remains set for a longer period, the output will remain set until the input signal resets.



IEC09000732-1-en.vsd

Figure 162: BINSTATREP logical diagram

15.7.3 Setting guidelines

The pulse time t is the only setting for the Logical signal status report (BINSTATREP). Each output can be set or reset individually, but the pulse time will be the same for all outputs in the entire BINSTATREP function.

15.8 Limit counter L4UFCNT

15.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Limit counter	L4UFCNT		-

15.8.2 Application

Limit counter (L4UFCNT) is intended for applications where positive and/or negative flanks on a binary signal need to be counted.

The limit counter provides four independent limits to be checked against the accumulated counted value. The four limit reach indication outputs can be utilized to initiate proceeding actions. The output indicators remain high until the reset of the function.

It is also possible to initiate the counter from a non-zero value by resetting the function to the wanted initial value provided as a setting.

If applicable, the counter can be set to stop or rollover to zero and continue counting after reaching the maximum count value. The steady overflow output flag indicates the next count after reaching the maximum count value. It is also possible to set the counter to rollover and indicate the overflow as a pulse, which lasts up to the first count after rolling over to zero. In this case, periodic pulses will be generated at multiple overflow of the function.

15.8.3 Setting guidelines

The parameters for Limit counter L4UFCNT are set via the local HMI or PCM600.

15.9 Running hour-meter TEILGAPC

15.9.1 Identification

Function Description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Running hour-meter	TEILGAPC	-	-

15.9.2 Application

The function is used for user-defined logics and it can also be used for different purposes internally in the IED. An application example is to accumulate the total running/energized time of the generator, transformer, reactor, capacitor bank or even line.

Settable time limits for warning and alarm are provided. The time limit for overflow indication is fixed to 99999.9 hours. At overflow the accumulated time resets and the accumulation starts from zero again.

15.9.3 Setting guidelines

The settings *tAlarm* and *tWarning* are user settable limits defined in hours. The achievable resolution of the settings is 0.1 hours (6 minutes).



tAlarm and *tWarning* are independent settings, that is, there is no check if *tAlarm* > *tWarning*.

The limit for the overflow supervision is fixed at 99999.9 hours.

The setting *tAddToTime* is a user settable time parameter in hours.

15.10 Fault current and voltage monitoring function FLTMMXU

15.10.1 Function revision history

Document revision	Product revision	History
A	2.2.1	-
B	2.2.1	-
C	2.2.1	-
D	2.2.1	-
E	2.2.4	-
J	2.2.6	-
K	2.2.6	-

15.10.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Fault current and voltage monitoring function	FLTMMXU	-	-

15.10.3 Application

Fault current and voltage monitoring function (FLTMMXU) is used for monitoring the fault data on occurrence of a fault event. The monitored data available can be used for post fault analysis, for example, switchgear stress for maximum current, doing the root cause analysis of fault event and short circuit analysis of a power system network.

Analyzing the faults on the power lines and transformer substations based on the available monitored data can help in managing the power system for improved performance. When a fault occurs, the binary input TRIGFLTUI of the function can be activated to trigger fault data monitoring, from the trip signal from the SMPPTRC function for example.

The following values are monitored in the function on occurrence of a trip event.

- Maximum peak current of individual phases during trip event (ILxMAXPK, where Lx =phase L1, L2 and L3)
- Maximum RMS current of individual phases during trip event (ILxMAX)
- Maximum RMS current of all phases during trip event (IMAX)
- Fundamental DFT current magnitude and angle of individual phases at the instant of triggering (FLTILxMAG/FLTILxANG)

- Fundamental DFT neutral current magnitude and angle at the instant of triggering (FLTINMAG/FLTINANG)
- Fundamental DFT voltage magnitude and angle of individual phases at the instant of triggering (FLTULxMAG/FLTULxANG)
- Fundamental DFT neutral voltage magnitude and angle at the instant of triggering (FLTINMAG/FLTINANG)

[Figure 163](#) shows the maximum peak and RMS current calculation during a trip event.

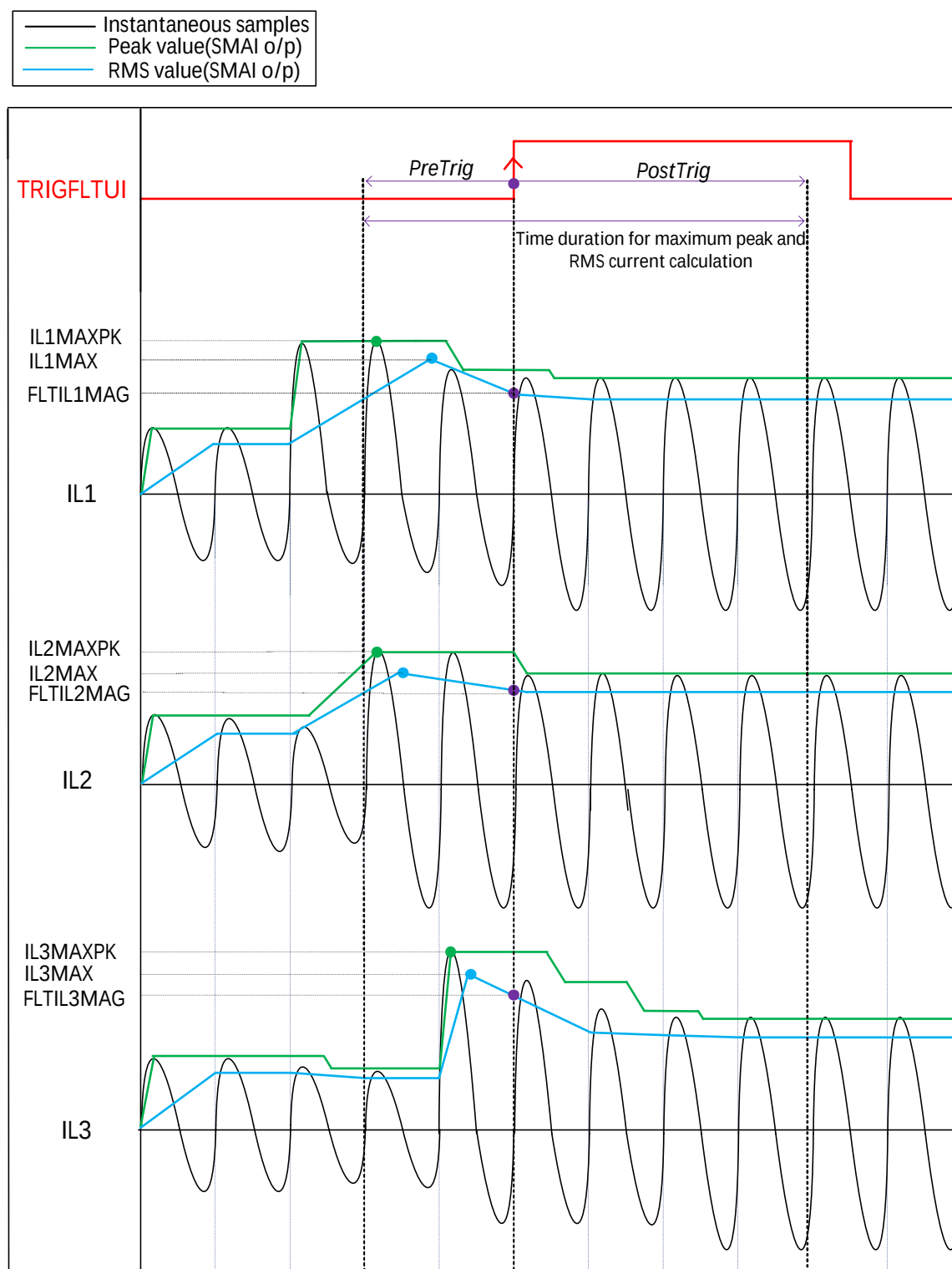


Figure 163: Maximum peak and RMS current calculation

15.10.4 Setting guidelines

The setting parameters for fault current and voltage reporting function FLTMMXU can be set via Protection and Control Manager PCM600.

Operation: To disable/enable the operation of fault current and voltage reporting function, that is, Off/On.

PreTrig: To set the number of power system cycles to be considered for fault event data window prior to positive edge of the binary input TRIGFLTUI.

PostTrig: To set the number of power system cycles to be considered for fault event data window after the positive edge of binary input TRIGFLTUI.

15.10.5 Setting example

Consider a line-to-earth fault in phase L2 of a 11.4 kV, 11.8 MVA, 60 Hz system. The voltage and current signals in the system are shown in [Figure 164](#).

Table 36: System details

Name	Value
Rated MVA capacity (SBase)	11.8
Rated voltage (UBase)	11.4kV
Rated Current (IBase)	600 A
System Frequency	60 Hz
VT ratio	11.4 kV/115V
CT ratio	600/5A

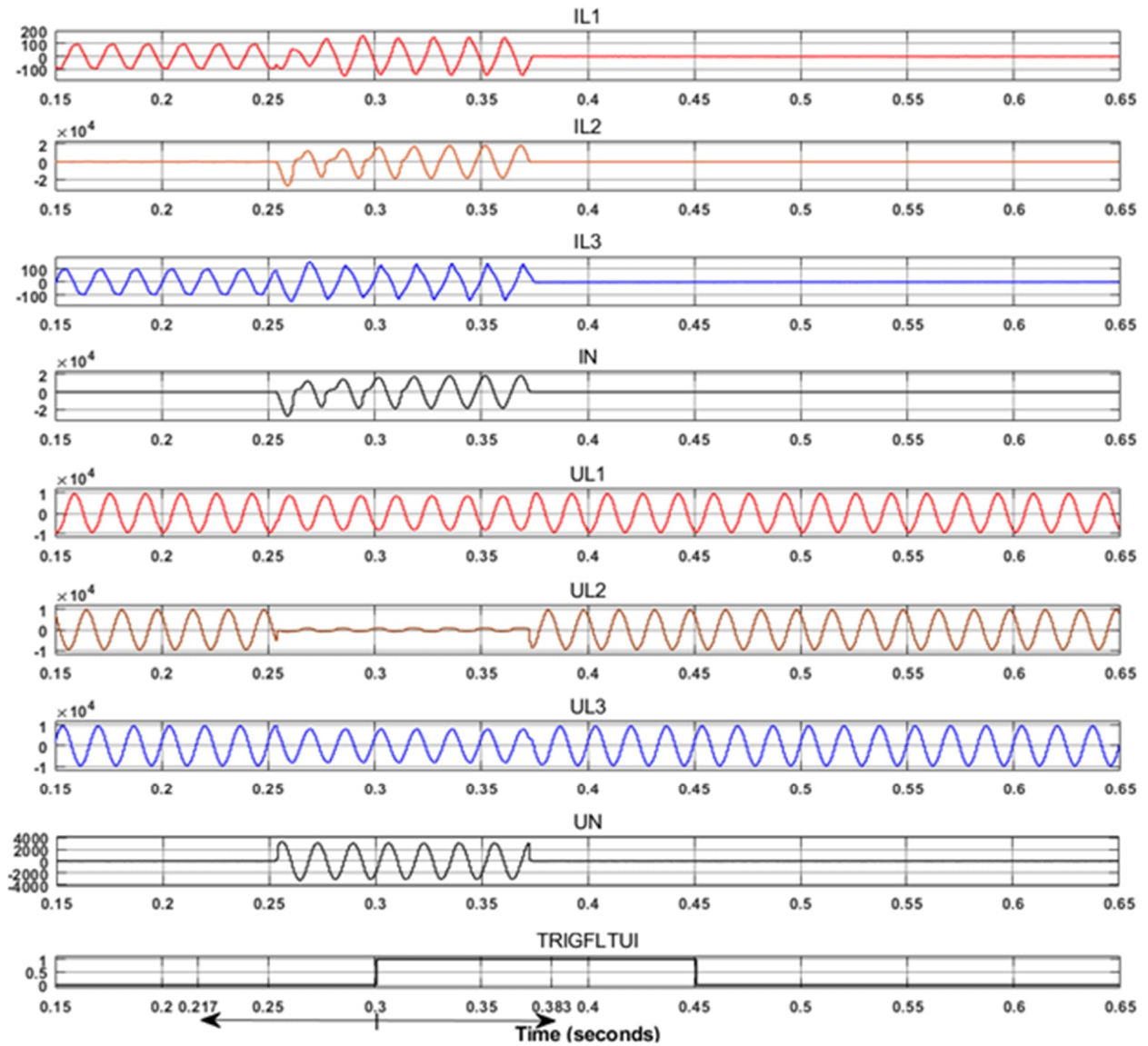


Figure 164: Current and voltage signals in the considered system

The general setting parameters for FLTMMXU, OC4PTOC and SMPPTRC functions can be set as mentioned in [Table 37](#), [Table 38](#) and [Table 39](#) respectively and the connection diagram is shown in [Figure 165](#).

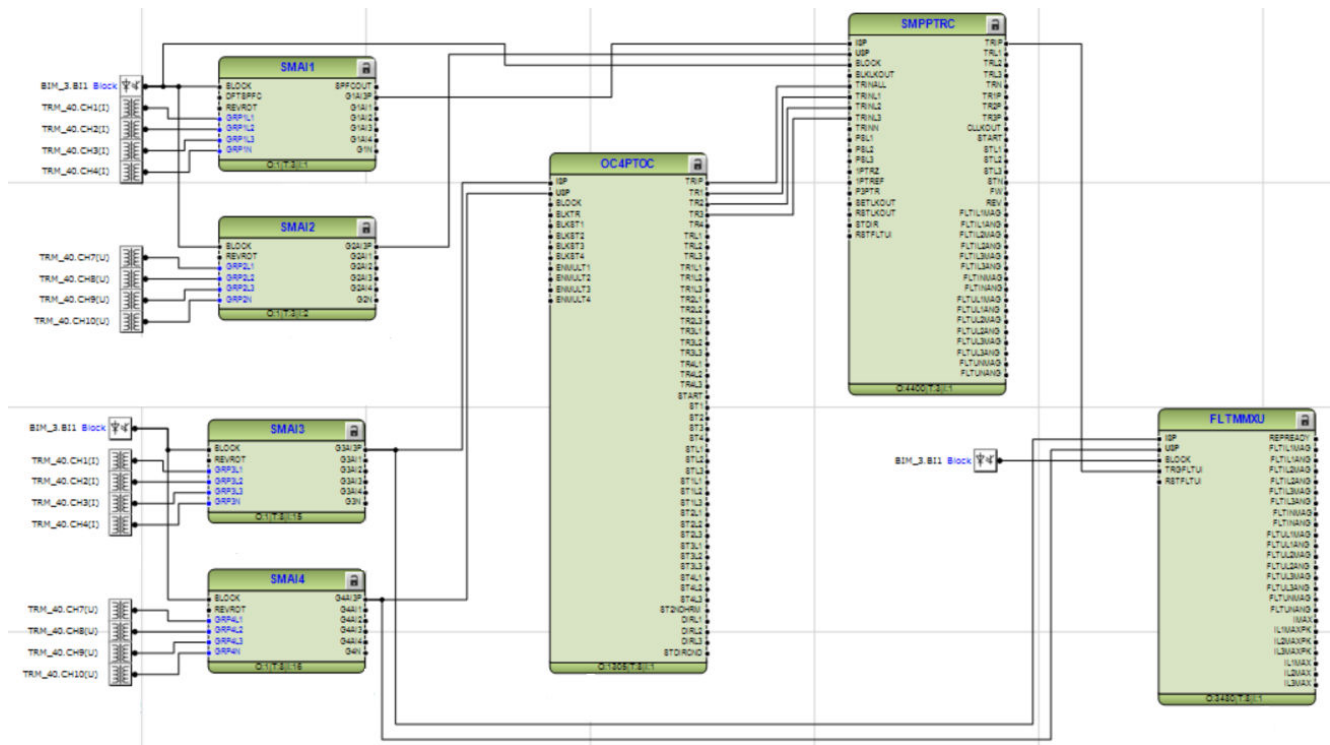


Figure 165: Connection diagram of OC4PTOC, SMPPTRC and FLTMMXU function

Table 37: General setting parameters for the FLTMMXU function

Setting	Default value
Operation	On
PreTrig	5
PostTrig	5

Table 38: General setting parameters for the OC4PTOC function

Name	Description	Value
Operation	Operation Off / On	On
I1	Operating phase current level for step 1 in % of IBase	1500
t1	Definite time delay / additional time delay for IDMT characteristics of step 1	0.030

Table 39: General setting parameters for the SMPPTRC function

Name	Description	Value
Operation	Operation Off / On	On
Program	Three ph; single or three ph; single, two or three ph trip	1ph/3ph
tTripMin	Tswo or three ph trip	0.150

From the positive edge of the binary input TRIGFLTUI, the fault data will be stored for 5 cycles (0.083 s prior to TRIGFLTUI active, based on the setting *PreTrig*) prior to positive edge and 5 cycles (0.083

s post to TRIGFLTUI active, based on the setting *PostTrig*) post positive edge as shown in [Figure 164](#) and is considered as the fault duration for the fault data monitoring.

The directional phase overcurrent protection, four steps (OC4PTOC) has operated, and with the setting parameter *I1* value set as 1500 and *I1* set as 0.030 s, trip signal has become active at 0.3 s. This trip signal has been connected to SMPPTRC and trip from SMPPTRC function is connected to FLTMMXU function for the monitoring of fault data. As the TRIGFLTUI input becomes active at 0.3, the maximum peak current of the individual phases and maximum RMS current of individual phases will be evaluated during the fault duration from 0.217 s to 0.383 s.

Also, the snapshot of each phase current DFT magnitude and angle values (FLTILxMAG/FLTILxANG), each phase voltage DFT magnitude and angle values (FLTULxMAG/FLTULxANG), neutral current DFT magnitude and angle (FLTINMAG/FLTINANG) and neutral voltage DFT magnitude and angle (FLTUNMAG/FLTUNANG) are stored at the positive edge of the binary input TRIGFLTUI.

The FLTMMXU function monitors and reports the following data at the output considering the default setting parameters mentioned in [Figure 166](#).

n status/Monitoring/FaultUIMonitoring/FLTMMXU:1/Outputs					
INSTNAME		FLTMMXU			
Beh	On		FLTUL1MAG	5.728	kV
Bk	0		FLTUL1ANG	-35.488	deg
TRIGTIME	2023-02-15 11:00:07		FLTUL2MAG	6.460	kV
REPREADY	1		FLTUL2ANG	-149.018	deg
TRIGDUR	149.627	ms	FLTUL3MAG	6.708	kV
FLTIL1MAG	536.968	A	FLTUL3ANG	82.511	deg
FLTIL1ANG	-0.000	deg	FLTUNMAG	0.000	kV
FLTIL2MAG	9986.950	A	FLTUNANG	0.000	deg
FLTIL2ANG	-122.731	deg	IMAX	10346.652	A
FLTIL3MAG	561.688	A	IL1MAXPK	848.528	A
FLTIL3ANG	110.802	deg	IL2MAXPK	13576.450	A
FLTINMAG	0.000	A	IL3MAXPK	848.528	A
FLTINANG	0.000	deg	IL1MAX	646.666	A
			IL2MAX	10346.652	A
2023-02-15 11:00:07		\$SuperUser	Object name	2023-02-15 11:01:10	\$SuperUser
					Object name

n status/Monitoring/FaultUIMonitoring/FLTMMXU:1/Outputs					
FLTUNANG		0.000	deg		
IMAX		10346.642	A		
IL1MAXPK		848.528	A		
IL2MAXPK		13576.450	A		
IL3MAXPK		848.528	A		
IL1MAX		646.665	A		
IL2MAX		10346.642	A		
IL3MAX		646.665	A		
IL1		634.503	A		
IL2		8790.178	A		
IL3		612.846	A		
UL1		7.094	kV		
UL3		6.180	kV		
UL2		6.438	kV		
2023-02-15 11:01:38		\$SuperUser	Object name		

Figure 166: Reported fault data on occurrence of trip event from OC4PTOC function



The reference for the angle outputs can be set by *DFTReference* setting parameter in SMAI function. In this example, the fundamental DFT angle of phase L1 voltage is considered as the reference for the angle outputs.

15.11 Fault locator LMBRFLO

15.11.1 Function revision history

Document revision	Product revision	History
A	2.2.1	-
B	2.2.1	-
C	2.2.1	-
D	2.2.4	Added FLINVAL, FLT_DIST, FLT_R, and FLT_LOOP outputs in the ACT function block.
E	2.2.5	-
J	2.2.6	-

15.11.2 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Fault locator	LMBRFLO	-	-

15.11.3 Application

The main objective of line protection and monitoring IEDs is fast, selective and reliable operation for faults on a protected line section. Besides this, information on distance to fault is very important for those involved in operation and maintenance. Reliable information on the fault location greatly decreases the downtime of the protected lines and increases the total availability of a power system.

The fault locator is started with the input CALCDIST to which trip signals indicating in-line faults are connected, typically distance protection zone 1 and accelerating zone or the line differential protection. The disturbance report must also be started for the same faults since the function uses pre- and post-fault information from the trip value recorder function (TVR).

Beside this information the function must be informed about faulted phases for correct loop selection (phase selective outputs from differential protection, distance protection, directional OC protection, and so on). The following loops are used for different types of faults:

- For 3 phase faults: Loop L1 - L2
- For 2 phase faults: The loop between the faulted phases
- For 2 phase-to-earth faults: The loop between the faulted phases
- For phase-to-earth faults: The phase-to-earth loop

LMBRFLO function indicates the distance to fault as a percentage of the line length, in kilometers or miles as selected on the local HMI. *LineLengthUnit* setting is used to select the unit of length either, in *kilometer* or *miles* for the distance to fault. The distance to the fault, which is calculated with a high accuracy, is stored together with the recorded disturbances. This information can be read on the local HMI, uploaded to PCM600 and is available on the station bus according to IEC 61850–8–1.

The distance to fault can be recalculated on the local HMI by using the measuring algorithm for different fault loops or for changed system parameters.

15.11.4 Setting guidelines

The parameters for the Fault locator function are set via the local HMI or PCM600.

The Fault locator algorithm uses phase voltages, phase currents and residual current in observed bay (protected line) and residual current from a parallel bay (line, which is mutual coupled to protected line).

The Fault locator has close connection to the Disturbance report function. All external analog inputs (channel 1-30), connected to the Disturbance report function, are available to the Fault locator and the function uses information calculated by the Trip value recorder. After allocation of analog inputs to the Disturbance report function, the user has to point out which analog inputs to be used by the Fault locator. According to the default settings the first four analog inputs are currents and next three are voltages in the observed bay (no parallel line expected since chosen input is set to zero). Use the Parameter Setting tool within PCM600 for changing analog configuration.

The measured phase voltages can be fine tuned with the parameters *UL1Gain*, *UL2Gain*, and *UL3Gain* to further increase the accuracy of the fault locator.

The list of parameters explains the meaning of the abbreviations. [Figure 167](#) also presents these system parameters graphically. Note, that all impedance values relate to their primary values and to the total length of the protected line.

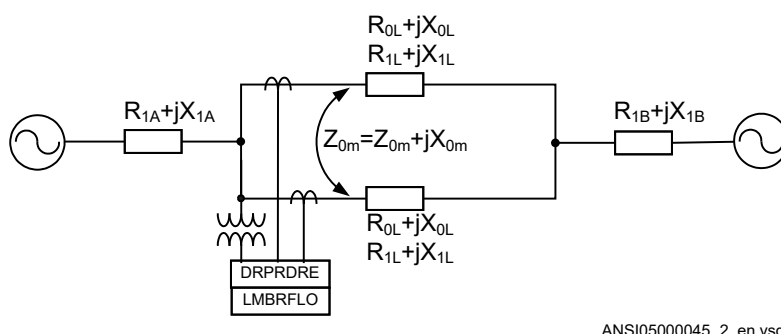


Figure 167: Simplified network configuration with network data, required for settings of the fault location-measuring function

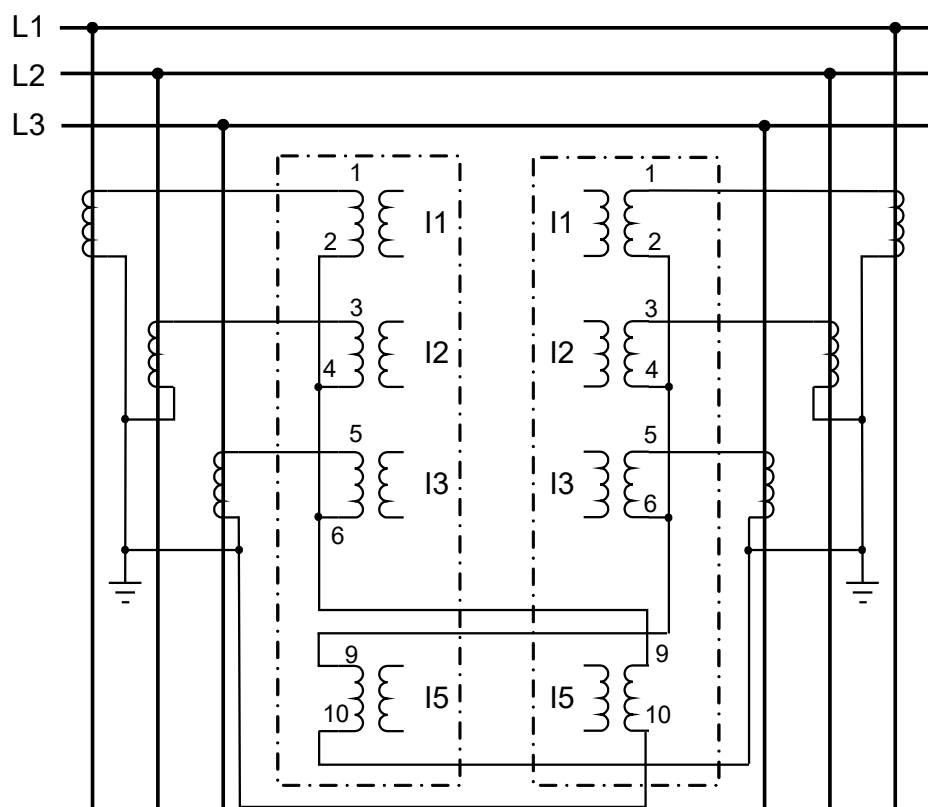
For a single-circuit line (no parallel line), the figures for mutual zero-sequence impedance (X_{0M} , R_{0M}) and analog input are set at zero.

Power system specific parameter settings are not general settings but specific setting included in the setting groups, that is, this makes it possible to change conditions for the Fault locator with short notice by changing setting group.

The source impedance is not constant in the network. However, this has a minor influence on the accuracy of the distance-to-fault calculation, because only the phase angle of the distribution factor has an influence on the accuracy. The phase angle of the distribution factor is normally very low and practically constant, because the positive sequence line impedance, which has an angle close to 90° , dominates it. Always set the source impedance resistance to values other than zero. If the actual values are not known, the values that correspond to the source impedance characteristic angle of 85° give satisfactory results.

15.11.4.1 Connection of analog currents

Connection diagram for analog currents included IN from parallel line shown in [Figure 168](#).



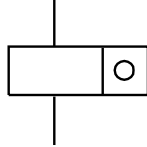
en07000113-1.vsd

Figure 168: Example of connection of parallel line IN for Fault locator LMBRFLO

Section 16 Metering

16.1 Pulse-counter logic PCFCNT

16.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Pulse-counter logic	PCFCNT		-

16.1.2 Application

Pulse-counter logic (PCFCNT) function counts externally generated binary pulses, for instance pulses coming from an external energy meter, for calculation of energy consumption values. The pulses are captured by the binary input module (BIM), and read by the PCFCNT function. The number of pulses in the counter is then reported via the station bus to the substation automation system or read via the station monitoring system as a service value. When using IEC 61850–8–1, a scaled service value is available over the station bus.

The normal use for this function is the counting of energy pulses from external energy meters. An optional number of inputs from an arbitrary input module in IED can be used for this purpose with a frequency of up to 40 Hz. The pulse-counter logic PCFCNT can also be used as a general purpose counter.

16.1.3 Setting guidelines

Parameters that can be set individually for each pulse counter from PCM600:

- *Operation: Off/On*
- *tReporting: 0-3600s*
- *EventMask: NoEvents/ReportEvents*

Configuration of inputs and outputs of PCFCNT is made via PCM600.

On the Binary input module (BIM), the debounce filter default time is set to 5ms, that is, the counter suppresses pulses with a pulse length less than 5 ms. The input oscillation blocking frequency is preset to 40 Hz meaning that the counter detects the input to oscillate if the input frequency is greater than 40 Hz. Oscillation suppression is released at 30 Hz. Block/release values for oscillation can be changed on the local HMI and PCM600 under **Main menu /Configuration //O modules**.



The setting is common for all input channels on BIM, that is, if limit changes are made for inputs not connected to the pulse counter, the setting also influences the inputs on the same board used for pulse counting.

16.2 Function for energy calculation and demand handling ETPMMTR

16.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Function for energy calculation and demand handling	ETPMMTR	W_Varh	-

16.2.2 Application

Energy calculation and demand handling function (ETPMMTR) is intended for statistics of the forward and reverse active and reactive energy. It has a high accuracy basically given by the measurements function (CVMMXN). This function has a site calibration possibility to further increase the total accuracy.

The function is connected to the instantaneous outputs of (CVMMXN) as shown in figure 169.

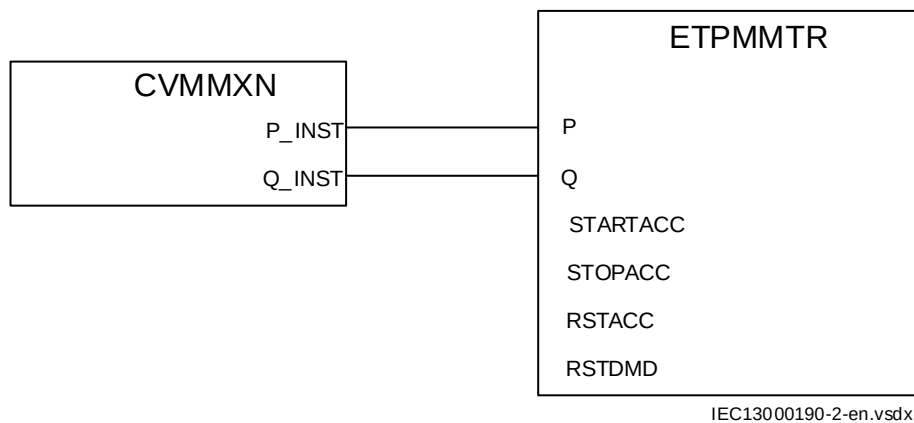


Figure 169: Connection of energy calculation and demand handling function ETPMMTR to the measurements function (CVMMXN)

The energy values can be read through communication in MWh and MVarh in monitoring tool of PCM600 and/or alternatively the values can be presented on the local HMI. The local HMI graphical display is configured with PCM600 Graphical Display Editor tool (GDE) with a measuring value which is selected to the active and reactive component as preferred. Also all Accumulated Active Forward, Active Reverse, Reactive Forward and Reactive Reverse energy values can be presented.

Maximum demand values are presented in MWh or MVarh in the same way.

Alternatively, the energy values can be presented with use of the pulse counters function (PCGGIO). The output energy values are scaled with the pulse output setting values *EAFAccPisQty*, *EARAccPisQty*, *ERFAccPisQty* and *ERVAccPisQty* of the energy metering function and then the pulse counter can be set-up to present the correct values by scaling in this function. Pulse counter values can then be presented on the local HMI in the same way and/or sent to the SA (Substation Automation) system through communication where the total energy then is calculated by summation of the energy pulses. This principle is good for very high values of energy as the saturation of numbers else will limit energy integration to about one year with 50 kV and 3000 A. After that the accumulation will start on zero again.

16.2.3 Setting guidelines

The parameters are set via the local HMI or PCM600.

The following settings can be done for the energy calculation and demand handling function ETPMMTR:

GlobalBaseSel: Selects the global base value group used by the function to define *IBase*, *UBase* and *SBase*. Note that this function will only use *IBase* value.

Operation: Off/On

EnaAcc: Off/On is used to switch the accumulation of energy on and off.

tEnergy: Time interval when energy is measured.

tEnergyOnPls: gives the pulse length ON time of the pulse. It should be at least 100 ms when connected to the Pulse counter function block. Typical value can be 100 ms.

tEnergyOffPls: gives the OFF time between pulses. Typical value can be 100 ms.

EAFAccPlsQty and *EARAccPlsQty*: gives the MWh value in each pulse. It should be selected together with the setting of the Pulse counter (PCGGIO) settings to give the correct total pulse value.

ERFAccPlsQty and *ERVAccPlsQty* : gives the MVarh value in each pulse. It should be selected together with the setting of the Pulse counter (PCGGIO) settings to give the correct total pulse value.

For the advanced user there are a number of settings for direction, zero clamping, max limit, and so on. Normally, the default values are suitable for these parameters.

Section 17 Ethernet-based communication

17.1 Access point

17.1.1 Application

The access points are used to connect the IED to the communication buses (like the station bus) that use communication protocols. The access point can be used for single and redundant data communication. The access points are also used for communication with the merging units and for time synchronization using Precision Time Protocol (PTP).

17.1.2 Setting guidelines



The physical ports allocated to access points 2–4 have to be added in the hardware tool in PCM600 before the access points can be configured. The factory setting only includes the physical ports allocated to the front port and access point 1.



The front port might or might not be available depending on the order type of the display. In the Ethernet configuration, the front port setting will still be available.

The settings for the access points are configured using the Ethernet configuration tool (ECT) in PCM600.

The access point is activated if the *Operation* checkbox is checked for the respective access point and a partial or common write to IED is performed.



To increase security, it is recommended to deactivate the access point when it is not in use.

Redundancy and *PTP* cannot be set for the front port (Access point 0) as redundant communication and PTP are only available for the rear optical Ethernet ports.

Subnetwork shows the SCL subnetwork to which the access point is connected. This column shows the SCL subnetworks available in the PCM600 project. SCL subnetworks can be created/deleted in the Subnetworks tab of IEC 61850 Configuration tool in PCM600.



When saving the ECT configuration after selecting a subnetwork, ECT creates the access point in the SCL model. Unselecting the subnetwork removes the access point from the SCL model. This column is editable for IEC 61850 Ed2 IEDs and not editable for IEC 61850 Ed1 IEDs because in IEC 61850 Ed1 only one access point can be modelled in SCL.

The IP address can be set in *IP address*. ECT validates the value, the access points have to be on separate subnetworks.

The subnetwork mask can be set in *Subnet mask*. This field will be updated to the SCL model based on the *Subnetwork* selection.

To select which communication protocols can be run on the respective access points, check or uncheck the check box for the relevant protocol. The protocols are not activated/deactivated in ECT, only filtered for the specific access point. For information on how to activate the individual communication protocols, see the communication protocol chapters.



To increase security it is recommended to uncheck protocols that are not used on the access point.

The default gateway can be selected by entering the IP address in *Default gateway*. The default gateway is the router that is used to communicate with the devices in the other subnetwork. By default this is set to *0.0.0.0* which means that no default gateway is selected. ECT validates the entered value, but the default gateway has to be in the same subnetwork as the access point. The default gateway is the router that is being used as default, that is when no route has been set up for the destination. If communication with a device in another subnetwork is needed, a route has to be set up. For more information on routes, see the *Routes* chapter in the *Technical manual* and the *Application manual*.

DHCP can be activated for the front port from the LHMI in **Main menu/Configuration / Communication/Ethernet configuration /Front port/DHCP:1**

17.1.2.1 Setting IP address, Subnet mask and Default gateway of Access Points from LHMI

To set the access point parameters navigate to **Configuration/Communication /Ethernet configuration**.



Additional checks are added while setting the Access Point configuration from LHMI to prevent the user from wrongly configuring the parameters.

Subnetting Rules

To correctly configure access points' parameters such as IP address, Subnet mask, and Default gateway address. Subnetting rules should be considered. Subnetting puts a limit on the range of IP addresses that can be assigned to the devices (hosts) in a given subnetwork. This limit is decided by the subnet mask.

Subnetwork of any access point is decided by the combination of the assigned IP address and subnet mask. For all configured AP's in the IED, there should not be any duplication of subnet. This means each access point should be configured in a separate subnet. Please note that in LHMI, subnetting rules are checked on enabled access points only.

If the user sets an IP address and Subnet mask that violates subnetting rules, then the following pop-up will be shown before the user tries to save the changes.

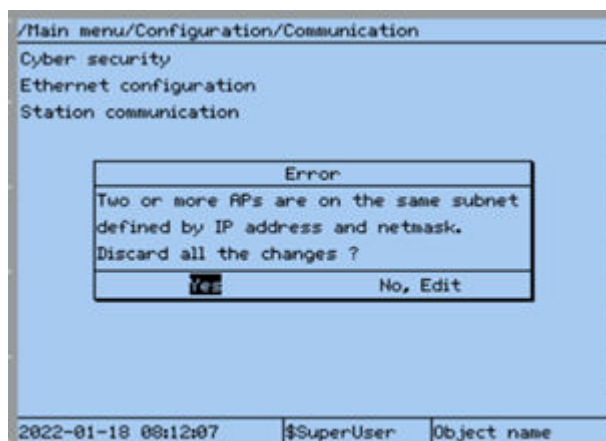


Figure 170: Error

User Options

- If the user selects 'Yes', then all the changes made under the last edit will be discarded. This includes all settings of the given access points that have been edited.
- User can select 'No, edit' if the user wishes to re-edit or correct the settings.

Rules for default gateway setting of given access point

Default Gateway IP address can be 0.0.0.0 or it should fall in the same subnetwork (subnet) which is defined by the IP address and subnet mask of the given access point.

If the user configures the default gateway in a subnet other than the subnet of the access point, then the following pop-up will be shown to the user before saving the changes.

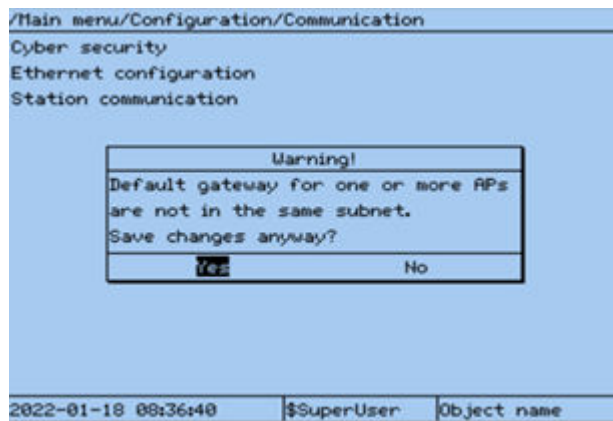


Figure 171: Warning

- If the user selects 'Yes', then the default gateway setting will be saved.
- User can select 'No' if the user wishes to re-edit or correct the settings.

17.2 Redundant communication

17.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IEC 62439-3 Parallel redundancy protocol	PRP	-	-
IEC 62439-3 High-availability seamless redundancy	HSR	-	-
Access point diagnostic for redundant Ethernet ports	RCHLCCH	-	-

17.2.2 Application

Dynamic access point diagnostic (RCHLCCH) is used to supervise and assure redundant Ethernet communication over two channels. This will secure data transfer even though one communication channel might not be available for some reason

Parallel Redundancy Protocol (PRP) and High-availability Seamless Redundancy (HSR) provides redundant communication over station bus running the available communication protocols. The redundant communication uses two Ethernet ports.

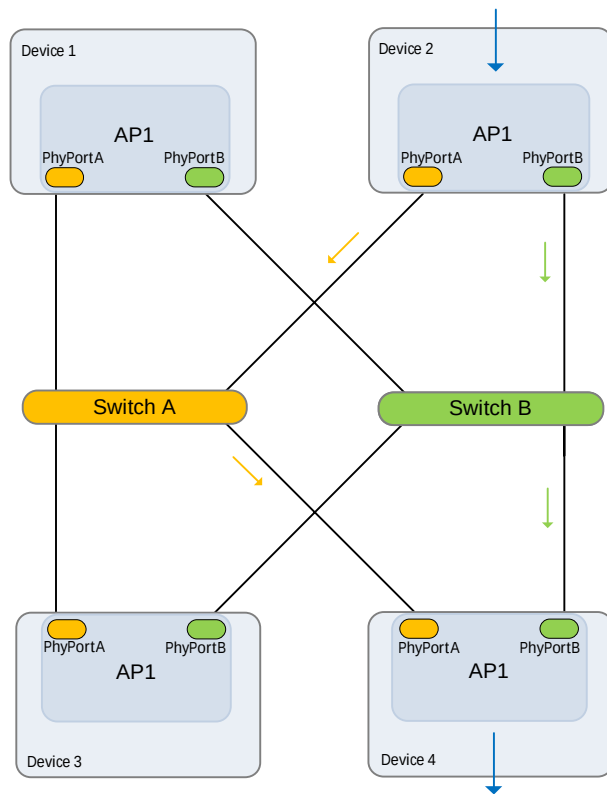


Figure 172: Parallel Redundancy Protocol (PRP)

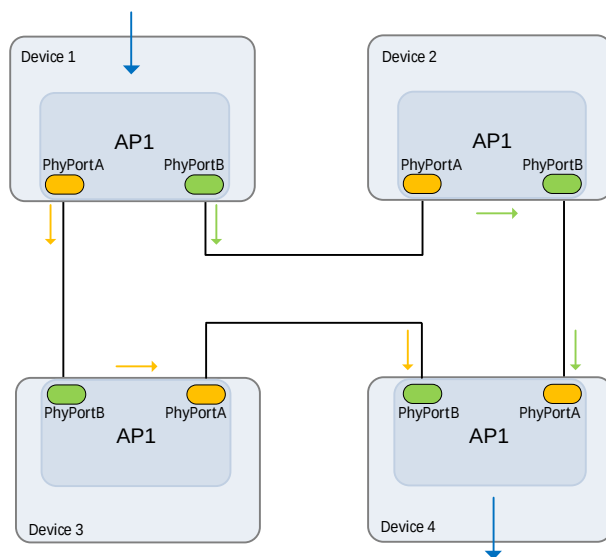


Figure 173: High-availability Seamless Redundancy (HSR)

17.2.3 Setting guidelines

Redundant communication is configured with the Ethernet configuration tool in PCM600.

Redundancy: redundant communication is activated when the parameter is set to *PRP-0*, *PRP-1* or *HSR*. The settings for the next access point will be hidden and PhyPortB will show the second port information. Redundant communication is activated after a common write to IED is done.

PRP-1 should be used primarily, *PRP-0* is intended only for use in existing PRP-networks. PRP-1 and HSR can be combined in a mixed network.

If the access point is not taken into operation, the write option in Ethernet Configuration Tool can be used to activate the access point.

Access points					
Merging units					
Routes					
Access point	Description	Operation	Redundancy	Physical port A	Physical port B
0	FrontPort	☒	None	ETH_Front	
1	Station bus	☒	PRP-1	SFP_301	SFP_302
3	Accesspoint 3	☒	HSR	SFP_303	SFP_304

IEC16000039-1-en.vsd.x

Figure 174: ECT screen with Redundancy set to PRP-1 on Access point 1 and HSR Access point 3

17.3 Merging unit

17.3.1 Application

The IEC/UCA 61850-9-2LE process bus communication protocol enables an IED to communicate with devices providing measured values in digital format, commonly known as Merging Units (MU). The rear access points are used for the communication.

The merging units (MU) are called so because they can gather analog values from one or more measuring transformers, sample the data and send the data over process bus to other clients (or subscribers) in the system. Some merging units are able to get data from classical measuring transformers, others from non-conventional measuring transducers and yet others can pick up data from both types.

Access points			
Merging units			
Routes			
MU	Name	AP connection	Sample Value ID
9201	MU1	AP1:Station bus	ABB_MU0101
9202	MU2	AP1:Station bus	ABB_MU0102
9203	MU3	AP2:Accesspoint 2	ABB_MU0103
9204	MU4	AP2:Accesspoint 2	ABB_MU0104

IEC17000044-1-en.vsd.x

Figure 175: Merging unit

17.3.2 Setting guidelines

For information on the merging unit setting guidelines, see section [IEC/UCA 61850-9-2LE communication protocol](#).

17.4 Routes

17.4.1 Application

Setting up a route enables communication to a device that is located in another subnetwork. Routing is used when the destination device is not in the same subnetwork as the default gateway.

The route specifies that when a package is sent to the destination device it should be sent through the selected router. If no route is specified the source device will not find the destination device.

17.4.2 Setting guidelines

Routes are configured using the Ethernet configuration tool in PCM600.

Operation for the route can be set to *On/Off* by checking and unchecking the check-box in the operation column.

Gateway specifies the address of the gateway.

Destination specifies the destination.

Destination subnet mask specifies the subnetwork mask of the destination.

Section 18 Station communication

18.1 Communication protocols

Each IED is provided with several communication interfaces enabling it to connect to one or many substation level systems or equipment, either on the Substation Automation (SA) bus or Substation Monitoring (SM) bus.

Available communication protocols are:

- IEC 61850-8-1 communication protocol
- IEC/UCA 61850-9-2LE communication protocol
- LON communication protocol
- SPA communication protocol
- IEC 60870-5-103 communication protocol
- Syslog (RFC 5424) standard

Several protocols can be combined in the same IED.



The LPHD.PhyHealth reflects the physical health of the IED. The status is set to Alarm when there is an internal failure in the IED or Warning if any active communication link fails.

18.2 IEC 61850-8-1 communication protocol

18.2.1 Application IEC 61850-8-1

IEC 61850-8-1 communication protocol allows vertical communication to HSI clients and allows horizontal communication between two or more intelligent electronic devices (IEDs) from one or several vendors to exchange information and to use it in the performance of their functions and for correct co-operation.

GOOSE (Generic Object Oriented Substation Event), which is a part of IEC 61850–8–1 standard, allows the IEDs to communicate state and control information amongst themselves, using a publish-subscribe mechanism. That is, upon detecting an event, the IED(s) use a multi-cast transmission to notify those devices that have registered to receive the data. An IED can, by publishing a GOOSE message, report its status. It can also request a control action to be directed at any device in the network.

Figure [176](#) shows the topology of an IEC 61850–8–1 configuration. IEC 61850–8–1 specifies only the interface to the substation LAN. The LAN itself is left to the system integrator.

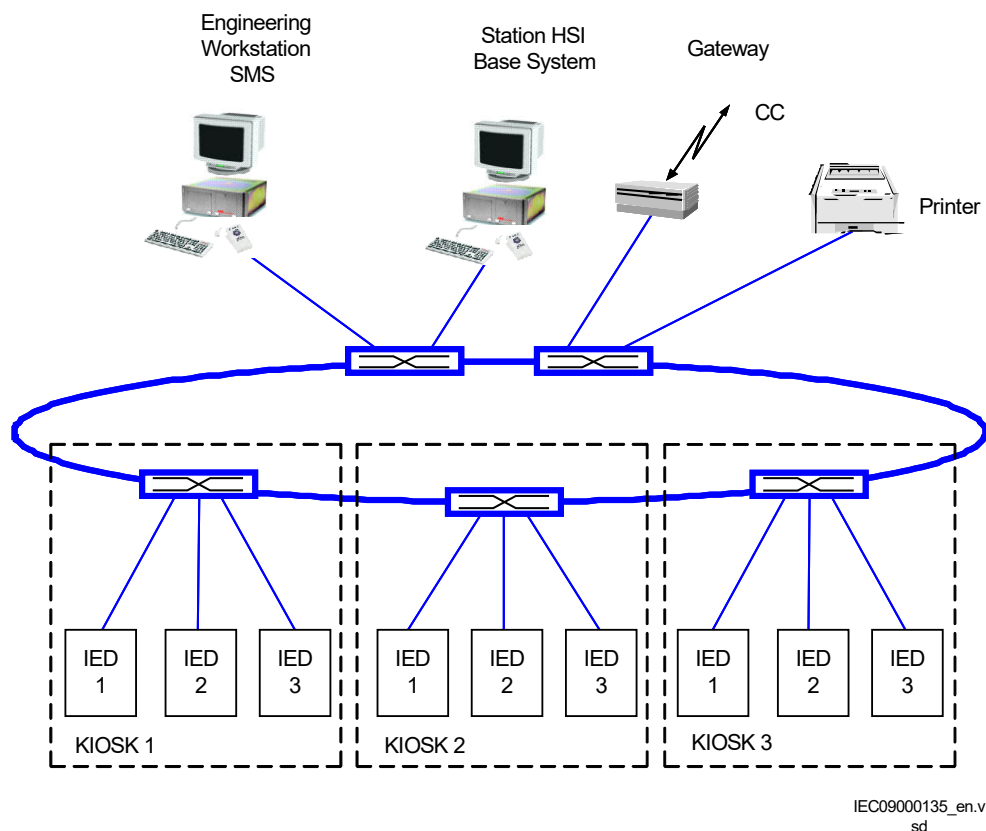


Figure 176: SA system with IEC 61850–8–1

Figure 177 shows the GOOSE peer-to-peer communication.

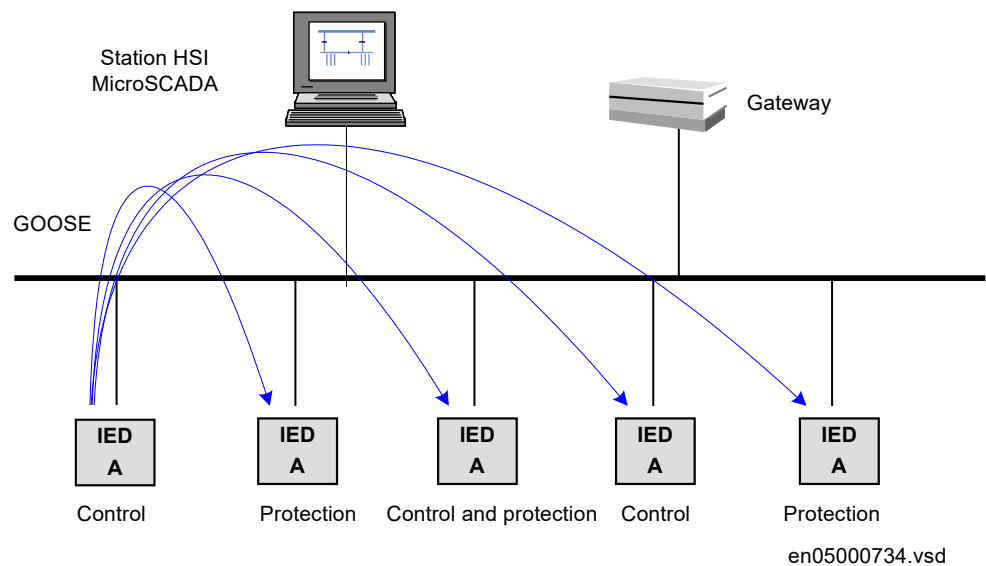


Figure 177: Example of a broadcasted GOOSE message

18.2.2 Setting guidelines

There are two settings related to the IEC 61850–8–1 protocol:

Operation: User can set IEC 61850 communication to *On* or *Off*.

GOOSEPortEd1: Selection of the Ethernet link where GOOSE traffic shall be sent and received. This is only valid for Edition 1 and can be ignored if Edition 2 is used. For Edition 2, the Ethernet link selection is done with the Ethernet Configuration Tool (ECT) in PCM600.

18.2.3 Horizontal communication via GOOSE

18.2.3.1 Sending data

In addition to the data object and data attributes of the logical nodes, it is possible to send the outputs of the function blocks using the generic communication blocks. The outputs of this function can be set in a dataset and be sent in a GOOSE Control Block to other subscriber IEDs. There are different function blocks for different type of sending data.

Generic communication function for single point indication SPGAPC, SP16GAPC

Application

Generic communication function for Single Point Value (SPGAPC) function is used to send one single logical output to other systems or equipment in the substation. SP16GAPC can be used to send up to 16 single point values from the application functions running in the same cycle time. SPGAPC has one visible input and SPGAPC16 has 16 visible inputs that should be connected in the ACT tool.

Setting guidelines

There are no settings available for the user for SPGAPC.

Generic communication function for Measured Value MVGAPC

Application

Generic communication function for measured values (MVGAPC) function is used to send the instantaneous value of an analog signal to other systems or equipment in the substation. It can also be used inside the same IED, to attach a RANGE aspect to an analog value and to permit measurement supervision on that value.

Setting guidelines

The settings available for Generic communication function for Measured Value (MVGAPC) function allows the user to choose a deadband and a zero deadband for the monitored signal. Values within the zero deadband are considered as zero.

The high and low limit settings provides limits for the high-high-, high, normal, low and low-low ranges of the measured value. The actual range of the measured value is shown on the range output of MVGAPC function block. When a Measured value expander block (RANGE_XP) is connected to the range output, the logical outputs of the RANGE_XP are changed accordingly.

18.2.3.2 Receiving data

The GOOSE data must be received at function blocks. There are different GOOSE receiving function blocks depending on the type of the received data. Refer to the Engineering manual for more information about how to configure GOOSE.

Function block type	Data Type
GOOSEBINRCV	16 single point
GOOSEINTLKRCV	2 single points 16 double points
GOOSEDPRCV	Double point
GOOSEINTRCV	Integer
Table continues on next page	

Function block type	Data Type
GOOSEMVRCV	Analog value
GOOSESPRCV	Single point
GOOSEXLNRCV	Switch status

Application

The GOOSE receive function blocks are used to receive subscribed data from the GOOSE protocol. The validity of the data value is exposed as outputs of the function block as well as the validity of the communication. It is recommended to use these outputs to ensure that only valid data is handled on the subscriber IED. An example could be to control the external reservation before operating on a bay. In the figure below, the GOOSESPRCV is used to receive the status of the bay reservation. The validity of the received data is used in additional logic to guarantee that the value has good quality before operation on that bay.

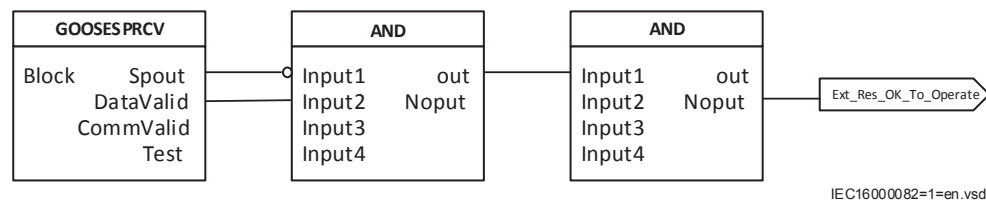


Figure 178: GOOSESPRCV and AND function blocks - checking the validity of the received data

18.3 IEC/UCA 61850-9-2LE communication protocol

18.3.1 Introduction

Every IED can be provided with communication interfaces enabling it to connect to the process buses in order to get data from analog data acquisition units close to the process (primary apparatus), commonly known as Merging Units (MU). The protocol used in this case is the IEC/UCA 61850-9-2LE communication protocol.

The IEC/UCA 61850-9-2LE standard does not specify the quality of the sampled values. Thus, the accuracy of the current and voltage inputs to the merging unit and the inaccuracy added by the merging unit must be coordinated with the requirement for the actual type of protection function.

Factors influencing the accuracy of the sampled values from the merging unit are, for example, anti aliasing filters, frequency range, step response, truncating, A/D conversion inaccuracy, time tagging accuracy etc.

In principle, the accuracy of the current and voltage transformers, together with the merging unit, will have the same quality as the direct input of currents and voltages.

The process bus physical layout can be arranged in several ways, described in Annex B of the standard, depending on what are the needs for sampled data in a substation.

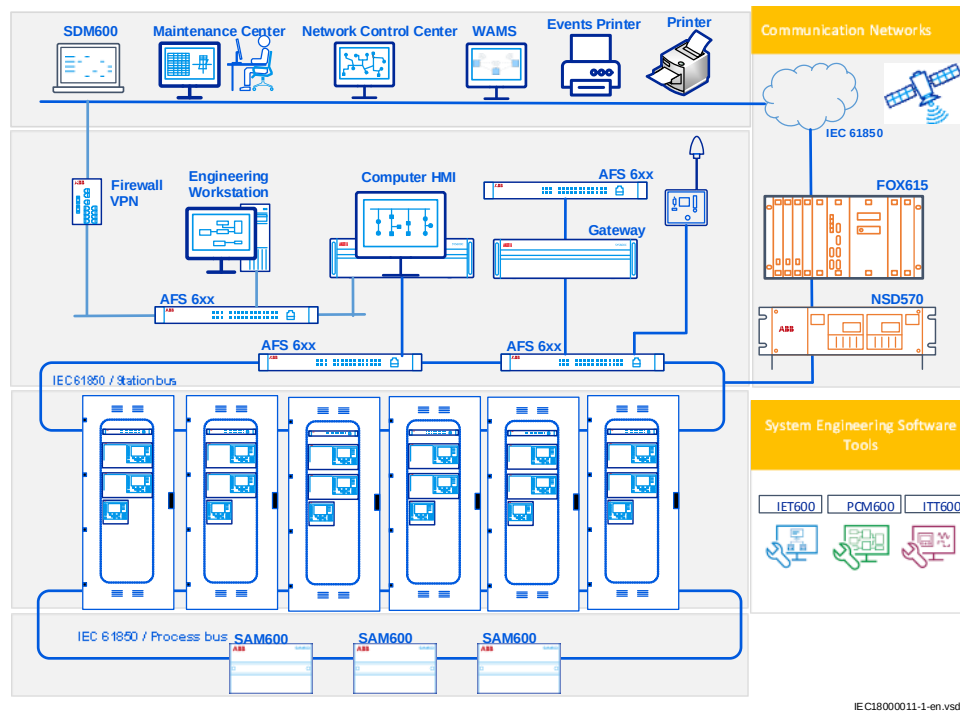


Figure 179: Example of a station configuration with separated process bus and station bus

The IED can get analog values simultaneously from a classical CT or VT and from a Merging Unit, like in this example:

The merging units (MU) are called so because they can gather analog values from one or more measuring transformers, sample the data and send the data over process bus to other clients (or subscribers) in the system. Some merging units are able to get data from classical measuring transformers, others from non-conventional measuring transducers and yet others can pick up data from both types. The electronic part of a non-conventional measuring transducer (like a Rogowski coil or a capacitive divider) can represent a MU by itself as long as it can send sampled data over process bus.

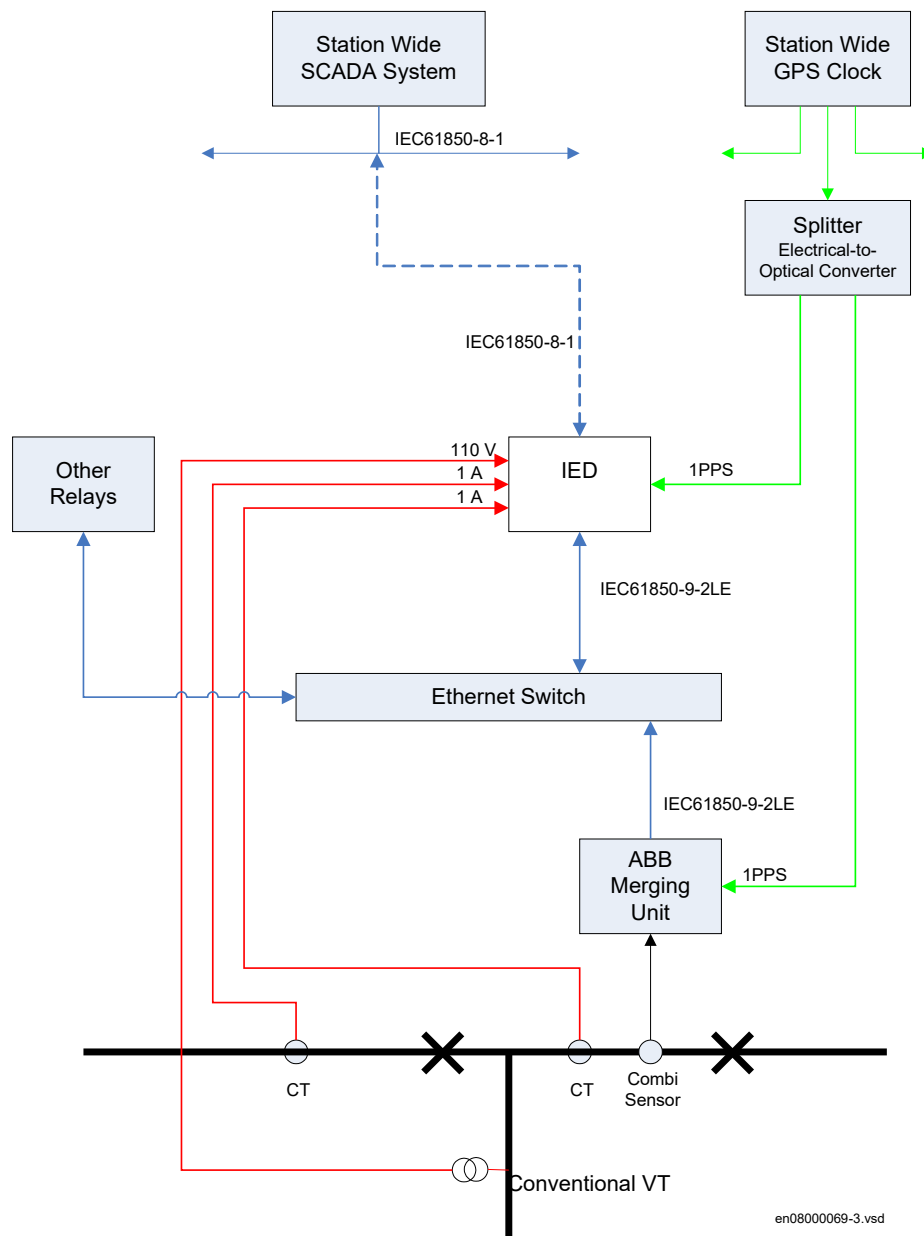


Figure 180: Example of a station configuration with the IED receiving analog values from both classical measuring transformers and merging units.

18.3.2 Faulty merging unit for bay in service

When a merging unit goes faulty while the bay is in service, the protection functions connected to that merging unit get blocked. Also, protection functions configured in a 1 1/2 circuit breaker applications, where two SV streams from different merging units are combined get blocked. Thus, this has no effect on protection functions in a 1 1/2 circuit breaker configuration.

This can be resolved by connecting external binary input signals to the BLOCK input on the respective SMAI function blocks with the use of ACT. When the BLOCK input on a SMAI function is energized, the SMAI function delivers a magnitude of zero with good quality for all the channels. Thus, this has no effect on a busbar protection, nor protections in an 1 1/2 circuit breaker configuration.



SMAI function blocks exist in different cycle times, and all the SMAI blocks that receive SV streams from the merging units must have the block input signal configured in the same way to get the correct behavior.

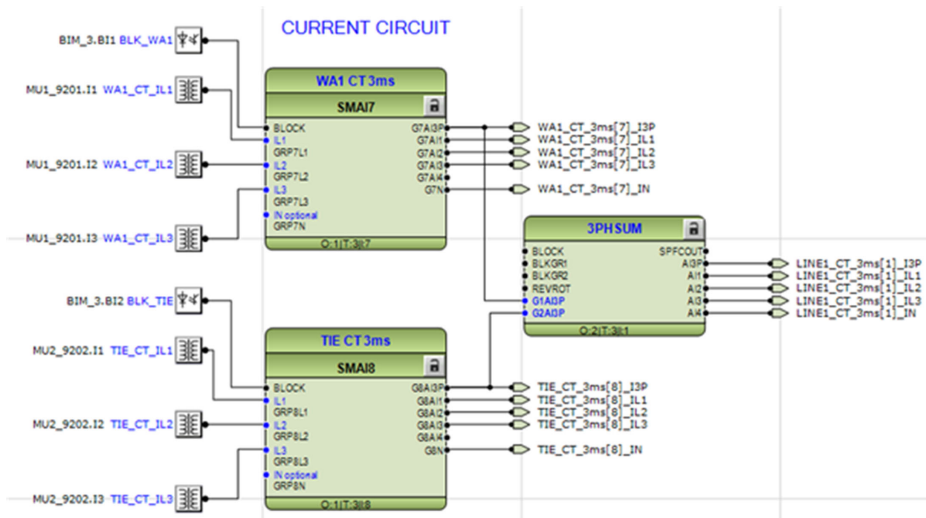


Figure 181: Configuration of current inputs using SMAIs in a 1 1/2 circuit breaker application.

Procedure to bring protections back into service and enable maintenance of a faulty merging unit

1. Disconnect bay
2. Energize binary input, block of bay. Protections are now back in service.
3. Maintenance of the merging unit can start.

Procedure to bring bay back into service after maintenance of a merging unit

1. Energize merging unit.
2. De-energize binary input block of bay. Protections are now back in service.
3. Reconnect bay.

18.3.3 Bay out of service for maintenance

When a bay need maintenance and has energized merging unit connected, it is always a risk to get unplanned interruptions in the auxiliary power supply which may lead to unwanted blocking of protections.

This is resolved by setting the merging unit “out of service” by setting the parameter “Operation” in “Main menu/Configuration/Analog modules/Mu...”, to “Out of service” instead of “In service”. The merging unit will look like it is in normal operation from the protection point of view, with perfect 0-value input values, comparable to a TRM that is not connected. A hint will be shown to inform that a merging unit is out of service.

18.3.4 Setting guidelines

Merging Units (MUs) have several settings on local HMI under:

- **Main menu /Configuration /Analog modules /MUx:92xx** . The corresponding settings are also available in PST (PCM600).
- **Main menu /Configuration /Communication /Merging units configuration /MUx:92xx** . The corresponding settings are also available in ECT (PCM600).

Xx can take value 1–4.

18.3.4.1 Specific settings related to the IEC/UCA 61850-9-2LE communication

The process bus communication IEC/UCA 61850-9-2LE has specific settings, similar to the analog inputs modules.

If there are more than one sample group involved, time synch is mandatory. If there is no time synchronization, the protection functions will be blocked due to condition blocking.

CTStarPointx: These parameters specify the direction to or from object. See also section ["Setting of current channels"](#).

SyncLostMode: If this parameter is set to *Block* and the IED hardware time synchronization is lost or the synchronization to the MU time is lost, the protection functions in the list "" will be blocked due to conditional blocking. If this parameter is set to *BlockOnLostUTC*, the protection functions in list "" are blocked if the IED hardware time synchronization is lost or the synchronization of the MU time is lost or the IED has lost global common synchronization (i.e. GPS, IRIG-B or PTP). *SYNCH* output will be set if IED hardware time synchronization is lost. *MUSYNCH* output will be set if either of MU or IED hardware time synchronization is lost.



Binary signals over LDCM are transmitted as valid and processed normally even when analog signals are transmitted as invalid due to loss of communication or loss of time synchronization.

Table 40: Blocked protection functions if IEC/UCA 61850-9-2LE communication is interrupted and functions are connected to specific MUs

Function description	IEC 61850 identification
Broken conductor check	BRCPTOC
Overcurrent protection with binary release	BRPTOC
Pole discordance protection	CCPDSC
Breaker failure protection	CCRBRF
Current circuit supervision	CCSSPVC
Current delta supervision	DELISPVC
Voltage delta supervision	DELVSPVC
Real delta supervision, real	DELSPVC
Current reversal and weakend infeed logic for residual overcurrent protection	ECRWPSCH
Four step residual overcurrent protection	EF4PTOC
Instantaneous residual overcurrent protection	EFPIOC
Fault current and voltage monitoring	FLTMMXU
Fuse failure supervision	FUFSPVC
Thermal overload protection, one time constant	LCPTTR
Line differential coordination	LDLPSCCH
Additional security logic for differential protection	LDRGFC
Thermal overload protection, one time constant	LFPTTR
Loss of voltage check	LOVPTUV
Table continues on next page	

Function description	IEC 61850 identification
Line differential protection for 3 CT sets, with inzone transformers, 2-3 line ends	LT3CPDIF
Four step phase overcurrent protection	OC4PTOC
Out-of-step protection	OOSPPAM
Two step overvoltage protection	OV2PTOV
Instantaneous phase overcurrent protection	PHPIOC
Two step residual overvoltage protection	ROV2PTOV
Rate-of-change frequency protection	SAPFRC
Overfrequency protection	SAPTOF
Underfrequency protection	SAPTUF
Synchrocheck, energizing check, and synchronizing	SESRSYN
Circuit breaker condition monitoring	SSCBR
Insulation gas monitoring	SSIMG
Insulation liquid monitoring	SSIML
Stub protection	STBPTOC
Two step undervoltage protection	UV2PTUV
Voltage differential protection	VDCPTOV
Local acceleration logic	ZCLCPSCH
Scheme communication logic for distance or overcurrent protection	ZCPSCH
Current reversal and weak-end infeed logic for distance protection	ZCRWPSCH
Automatic switch onto fault logic, voltage and current based	ZCVPSOF
Power swing detection	ZMRPSB

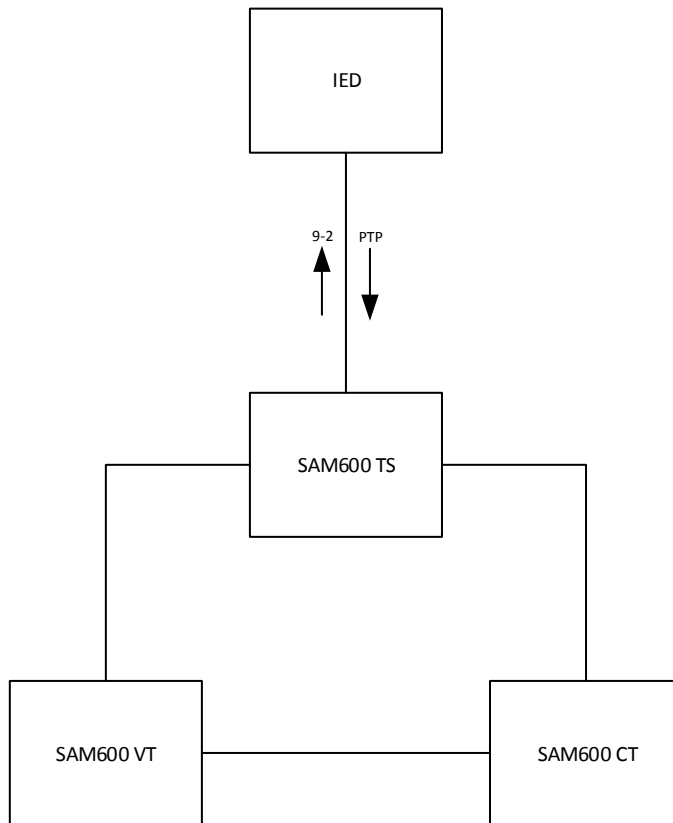
18.3.4.2 Setting examples for IEC/UCA 61850-9-2LE and time synchronization

The IED and the Merging Units (MU) should use the same time reference especially if analog data is used from several sources, for example from an internal TRM and an MU, or if several physical MUs are used. Having the same time reference is important to correlate data so that channels from different sources refer to the correct phase angle.

When only one MU is used as an analog source, it is theoretically possible to do without time synchronization. However, this would mean that timestamps for analog and binary data/events become uncorrelated. If the IED has no time synchronization source configured, then the binary data/events will be synchronized with the merging unit. However, the global/complete time might not be correct. Disturbance recordings then appear incorrect since analog data is timestamped by MU, and binary events use the internal IED time. It is thus recommended to use time synchronization also when analog data emanate from only one MU.

An external time source can be used to synchronize both the IED and the MU. It is also possible to use the MU as a clock master to synchronize the IED from the MU. When using an external clock, it is possible to set the IED to be synchronized via PPS, IRIG-B or PTP. It is also possible to use an internal GPS receiver in the IED (if the external clock is using GPS).

Using PTP for synchronizing the MU



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Figure 182: Setting example with PTP synchronization

Settings on the local HMI under **Main menu/Configuration/Time/Synchronization/TIMESYNCHGEN:1/IEC61850-9-2:**

- *HwSyncSrc*: is not used as the SW-time and HW-time are connected with each other due to PTP
- *SyncLostMode* : set to *Block* to block protection functions if time synchronization is lost or set to *BlockOnLostUTC* if the protection functions are to be blocked when global common synchronization is lost
- *SyncAccLevel*: can be set to $1\mu\text{s}$ since this corresponds to a maximum phase angle error of 0.018 degrees at 50Hz

Settings on the local HMI under **Main menu/Configuration/Communication/Ethernet configuration/Access point/AP_X:**

- Operation: On
- PTP: On

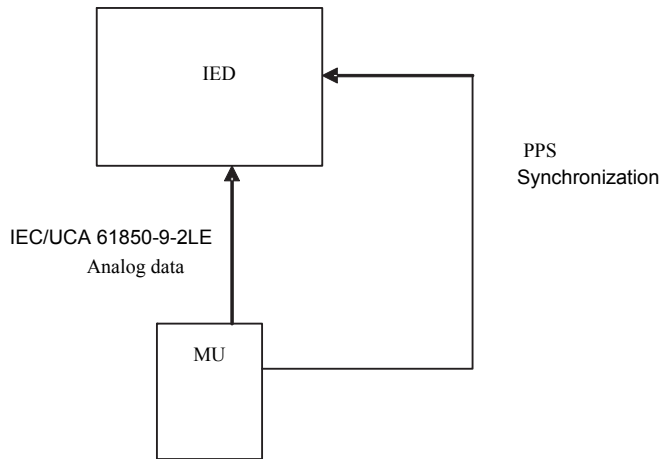
Two status monitoring signals can be:

- SYNCH signal on the MUX function block indicates that protection functions are blocked due to loss of internal time synchronization to the IED
- MUSYNCH signal on the MUX function block monitors the synchronization flag *smpSynch* in the datastream and IED hardware time synchronization.

Using MU for time synchronization via PPS



This example is not valid when GPS time is used for differential protection or when PTP is enabled.



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Figure 183: Setting example when MU is the synchronizing source

Settings on the local HMI under **Main menu/Configuration/Time/Synchronization/TIMESYNCHGEN:1/IEC61850-9-2:**

- *HwSyncSrc*: set to *PPS* as generated by the MU (Hitachi Energy MU)
- *SyncLostMode*: set to *Block* to block protection functions if time synchronization is lost
- *SyncAccLevel*: can be set to $4\mu\text{s}$ since this corresponds to a maximum phase angle error of 0.072 degrees at 50Hz

Settings on the local HMI under **Main menu/Configuration/Time/Synchronization/TIMESYNCHGEN:1/General:**

- *fineSyncSource* can be set to something different to correlate events and data to other IEDs in the station.

Two status monitoring signals can be:

- SYNCH signal on the MUX function block indicates that protection functions are blocked due to loss of internal time synchronization to the IED.
- MUSYNCH signal on the MUX function block monitors the synchronization flag *smpSynch* in the datastream and IED hardware time synchronization.

SMPLLOST indicates that merging unit data are generated by internal substitution or one/more channel's Quality is not good or merging unit is in Testmode/detailed quality=Test, IED is not in test mode.

Using external clock for time synchronization



This example is not valid when GPS time is used for differential protection or when PTP is enabled.

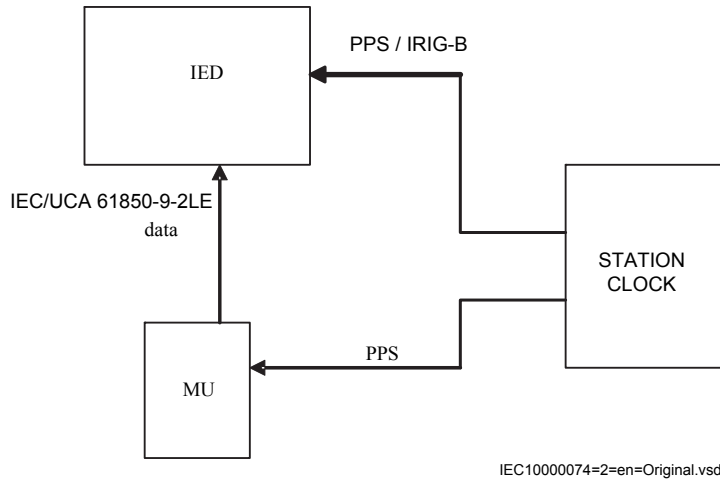


Figure 184: Setting example with external synchronization

Settings on the local HMI under **Main menu/Configuration/Time/Synchronization/TIMESYNCHGEN:1/IEC61850-9-2:**

- *HwSyncSrc*: set to *PPS/IRIG-B* depending on available outputs on the clock.
- *SyncLostMode*: set to *Block* to block protection functions if time synchronization is lost.
- *SyncAccLevel*: can be set to $4\mu\text{s}$ since this corresponds to a maximum phase angle error of 0.072 degrees at 50Hz.
- *fineSyncSource*: should be set to *IRIG-B* if available from the clock. If *PPS* is used for *HwSyncSrc*, “full-time” has to be acquired from another source. If station clock is on the local area network (LAN) and has an sntp-server, this is one option.

Two status monitoring signals can be:

- *SYNCH* signal on the MUX function block indicates that protection functions are blocked due to loss of internal time synchronization to the IED (that is loss of the hardware *synchSrc*).
- *MUSYNCH* signal on the MUX function block monitors the synchronization flag *smpSynch* in the datastream and IED hardware time synchronization.

No time synchronization



This example is not valid when GPS time is used for differential protection or when PTP is enabled.

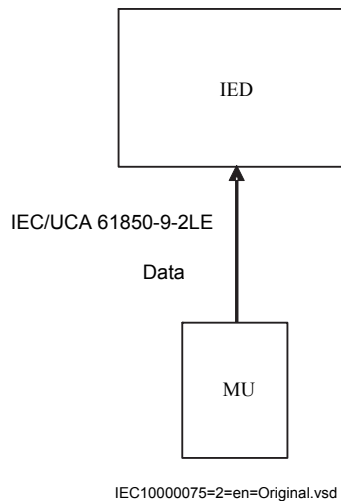


Figure 185: Setting example without time synchronization

It is also possible to use IEC/UCA 61850-9-2LE communication without time synchronization.

Settings on the local HMI under **Main menu/Configuration/Time/Synchronization/TIMESYNCHGEN:1/IEC61850-9-2:**

- *HwSyncSrc*: set to *Off*
- *SyncLostMode*: set to *No block* to indicate that protection functions are not blocked
- *SyncAccLevel*: set to *unspecified*

Two status monitoring signals with no time synchronization:

- SYNCH signal on the MUX function block indicates that protection functions are blocked due to loss of internal time synchronization to the IED. Since *SyncLostMode* is set to *No block*, this signal is not set.
- MUSYNCH signal on the MUX function block is set if the datastream indicates time synchronization loss. However, protection functions are not blocked.

To get higher availability in protection functions, it is possible to avoid blocking during time synchronization loss if there is a single source of analog data. This means that if there is only one physical MU and no TRM, parameter *SyncLostMode* is set to *No block* but parameter *HwSyncSrc* is still set to *PPS*. This maintains analog and binary data correlation in disturbance recordings without blocking protection functions if PPS is lost.

18.3.5 IEC 61850 quality expander QUALEXP

The quality expander component is used to display the detailed quality of an IEC/UCA 61850-9-2LE analog channel. The component expands the channel quality output of a Merging Unit analog channel received in the IED as per the IEC 61850-7-3 standard. This component can be used during the ACT monitoring to get the particular channel quality of the Merging Unit.

Figure [186](#) depicts the usage of the quality expander block in ACT.

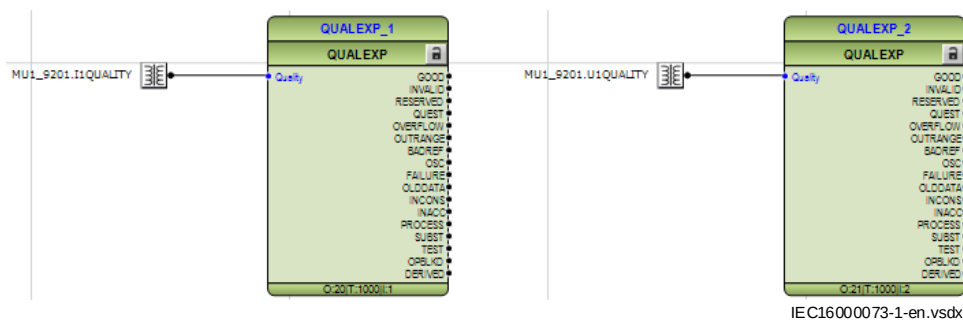


Figure 186: Quality expander block in ACT

The expanded quality bits are visible on the outputs as per IEC 61850-7-3 standard. When written to IED, the configuration will show the expanded form of the respective MU channel quality information during the online monitoring in the ACT.



The quality expander function is intended for monitoring purposes, not for being used in a logic controlling the behaviour of the protection or control functions in the IED. The function outputs are updated once every second and, therefore, do not reflect the quality bits in real time.

18.4 LON communication protocol

18.4.1 Application

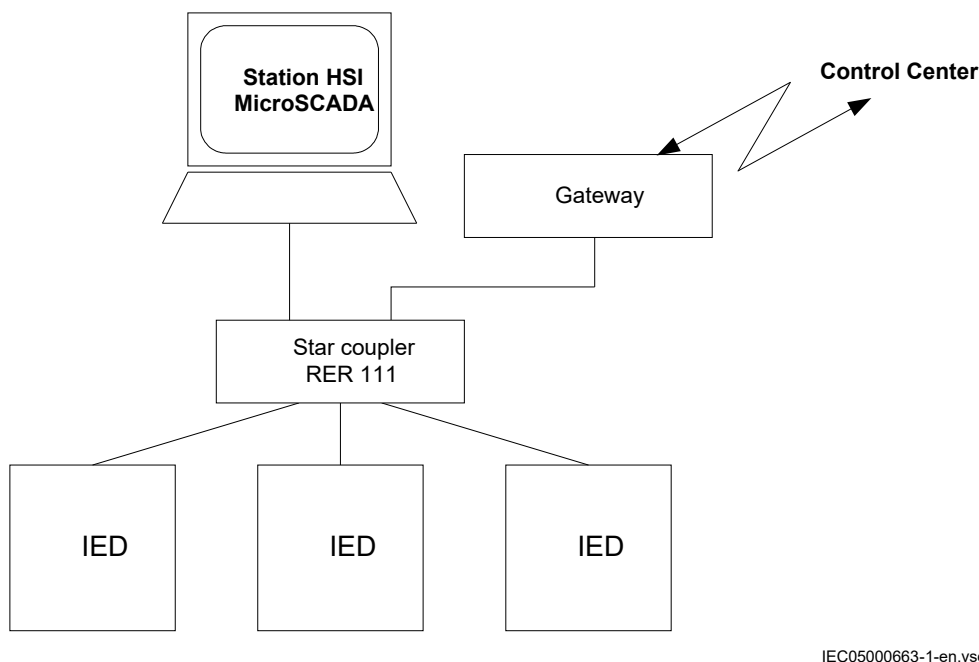


Figure 187: Example of LON communication structure for a station automation system

An optical network can be used within the station automation system. This enables communication with the IEDs through the LON bus from the operator's workplace, from the control center and also from other IEDs via bay-to-bay horizontal communication. For LON communication an SLM card should be ordered for the IEDs.

The fiber optic LON bus is implemented using either glass core or plastic core fiber optic cables.

Table 41: Specification of the fiber optic connectors

	Glass fiber	Plastic fiber
Cable connector	ST-connector	snap-in connector
Cable diameter	62.5/125 m	1 mm
Max. cable length	1000 m	10 m
Wavelength	820-900 nm	660 nm
Transmitted power	-13 dBm (HFBR-1414)	-13 dBm (HFBR-1521)
Receiver sensitivity	-24 dBm (HFBR-2412)	-20 dBm (HFBR-2521)

The LON Protocol

The LON protocol is specified in the LonTalkProtocol Specification Version 3 from Echelon Corporation. This protocol is designed for communication in control networks and is a peer-to-peer protocol where all the devices connected to the network can communicate with each other directly. For more information of the bay-to-bay communication, refer to the section Multiple command function.

Hardware and software modules

The hardware needed for applying LON communication depends on the application, but one very central unit needed is the LON Star Coupler and optical fibers connecting the star coupler to the IEDs. To interface the IEDs from the MicroSCADA with Classic Monitor, application library LIB520 is required.

The HV Control 670 software module is included in the LIB520 high-voltage process package, which is a part of the Application Software Library in MicroSCADA applications.

The HV Control 670 software module is used for control functions in the IEDs. The module contains a process picture, dialogues and a tool to generate a process database for the control application in MicroSCADA.

When using MicroSCADA Monitor Pro instead of the Classic Monitor, SA LIB is used together with 670 series Object Type files.



The HV Control 670 software module and 670 series Object Type files are used with both 650 and 670 series IEDs.

Use the LON Network Tool (LNT) to set the LON communication. This is a software tool applied as one node on the LON bus. To communicate via LON, the IEDs need to know

- The node addresses of the other connected IEDs.
- The network variable selectors to be used.

This is organized by LNT.

The node address is transferred to LNT via the local HMI by setting the parameter *ServicePinMsg* = Yes. The node address is sent to LNT via the LON bus, or LNT can scan the network for new nodes.

The communication speed of the LON bus is set to the default of 1.25 Mbit/s. This can be changed by LNT.

18.4.2 MULTICMDRCV and MULTICMDSND

18.4.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Multiple command and receive	MULTICMDRCV	-	-
Multiple command and send	MULTICMDSND	-	-

18.4.2.2 Application

The IED provides two function blocks enabling several IEDs to send and receive signals via the interbay bus. The sending function block, MULTICMDSND, takes 16 binary inputs. LON enables these to be transmitted to the equivalent receiving function block, MULTICMDRCV, which has 16 binary outputs.

18.4.2.3 Setting guidelines

Settings

The parameters for the multiple command function are set via PCM600.

The *Mode* setting sets the outputs to either a *Steady* or *Pulsed* mode.

18.5 SPA communication protocol

18.5.1 Application

SPA communication protocol is an alternative to IEC 60870-5-103, and they use the same rear communication port.

When communicating with a PC connected to the utility substation LAN via WAN and the utility office LAN (see Figure 188), and when using the rear optical Ethernet port, the only hardware required for a station monitoring system is:

- Optical fibers from the IED to the utility substation LAN
- PC connected to the utility office LAN

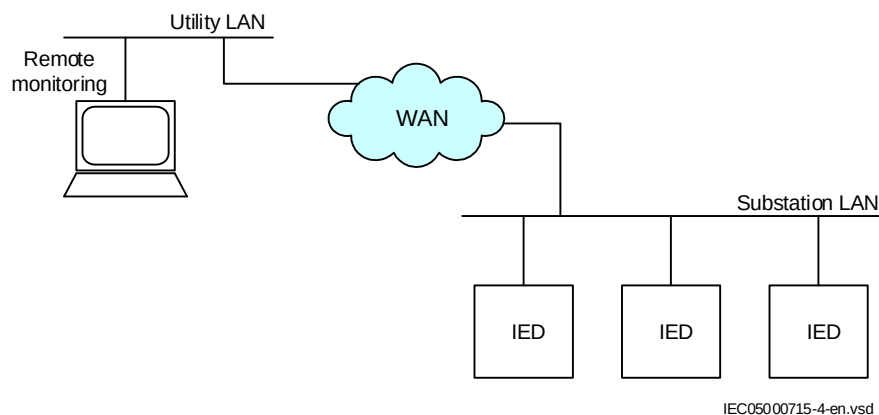


Figure 188: SPA communication structure for a remote monitoring system via a substation LAN, WAN and utility LAN

SPA communication is mainly used for the Station Monitoring System. It can include different IEDs with remote communication possibilities. Connection to a PC can be made directly (if the PC is located in the substation), via a telephone modem through a telephone network with ITU (former CCITT) characteristics or via a LAN/WAN connection.

glass	<1000 m according to optical budget
plastic	<25 m (inside cubicle) according to optical budget

Functionality

The SPA protocol V2.5 is an ASCII-based protocol for serial communication. The communication is based on a master-slave principle, where the IED is a slave and the PC is the master. Only one master can be applied on each fiber optic loop. A program is required in the master computer for interpretation of the SPA-bus codes and for translation of the data that should be sent to the IED.

For the specification of the SPA protocol V2.5, refer to SPA-bus Communication Protocol V2.5.

18.5.2 Setting guidelines

SPA, IEC 60870-5-103 and DNP3 use the same rear communication port. This port can be set for SPA use on the local HMI under **Main menu / Configuration / Communication / Station communication / Port configuration / SLM optical serial port / PROTOCOL:1**. When the communication protocol is selected, the IED is automatically restarted, and the port then operates as a SPA port.

The SPA communication setting parameters are set on the local HMI under **Main menu / Configuration / Communication / Station communication / SPA / SPA:1**.

The most important SPA communication setting parameters are *SlaveAddress* and *BaudRate*. They are essential for all communication contact to the IED. *SlaveAddress* and *BaudRate* can be set only on the local HMI for rear and front channel communication.

SlaveAddress can be set to any value between 1–899 as long as the slave number is unique within the used SPA loop. *BaudRate* (communication speed) can be set between 300–38400 baud. *BaudRate* should be the same for the whole station although different communication speeds in a loop are possible. If different communication speeds are used in the same fiber optical loop or RS485 network, take this into account when making the communication setup in the communication master (the PC).

With local fiber optic communication, communication speed is usually set to 19200 or 38400 baud. With telephone communication, the speed setting depends on the quality of the connection and the type of modem used. Refer to technical data to determine the rated communication speed for the selected communication interfaces.



The IED does not adapt its speed to the actual communication conditions because the communication speed is set on the local HMI.

18.6 IEC 60870-5-103 communication protocol

18.6.1 Application

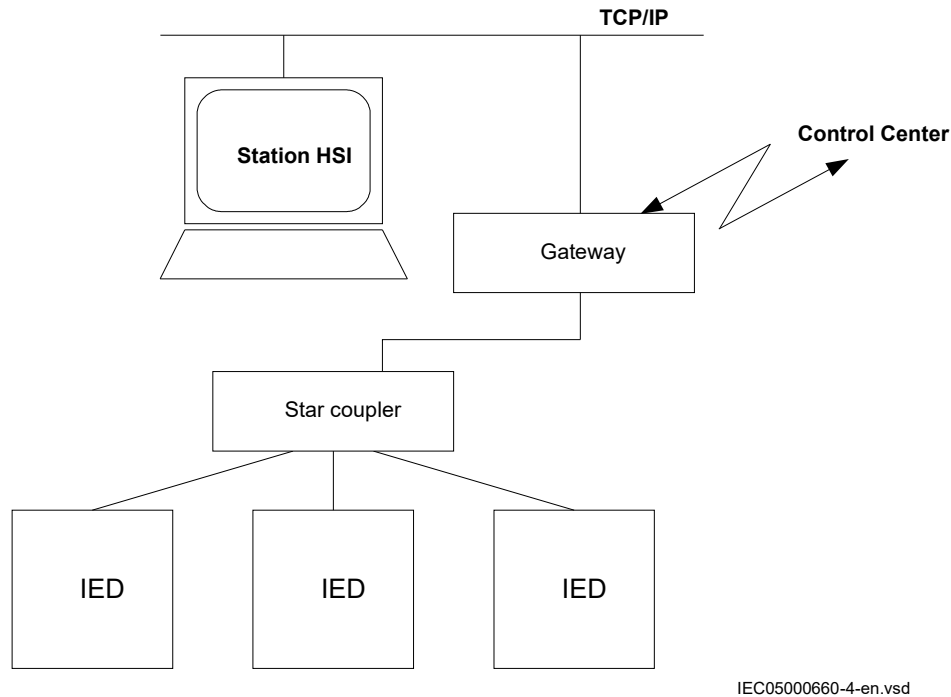


Figure 189: Example of IEC 60870-5-103 communication structure for a substation automation system

IEC 60870-5-103 communication protocol is mainly used when a protection IED communicates with a third party control or monitoring system. This system must have software that can interpret the IEC 60870-5-103 communication messages.

When communicating locally in the station using a Personal Computer (PC) or a Remote Terminal Unit (RTU) connected to the Communication and processing module, the only hardware needed is optical fibers and an opto/electrical converter for the PC/RTU, or a RS-485 connection depending on the used IED communication interface.

18.6.1.1 Functionality

IEC 60870-5-103 is an unbalanced (master-slave) protocol for coded-bit serial communication exchanging information with a control system. In IEC terminology a primary station is a master and a secondary station is a slave. The communication is based on a point-to-point principle. The master must have software that can interpret the IEC 60870-5-103 communication messages. For detailed information about IEC 60870-5-103, refer to IEC 60870 standard part 5: Transmission protocols, and to the section 103, Companion standard for the informative interface of protection equipment.

18.6.1.2 Design

General

The protocol implementation consists of the following functions:

- Event handling
- Report of analog service values (measurands)
- Fault location
- Command handling
 - Autorecloser ON/OFF
 - Teleprotection ON/OFF
 - Protection ON/OFF
 - LED reset
 - Characteristics 1 - 4 (Setting groups)
- File transfer (disturbance files)
- Time synchronization

Hardware

When communicating locally with a Personal Computer (PC) or a Remote Terminal Unit (RTU) in the station, using the SPA/IEC port, the only hardware needed is:· Optical fibers, glass/plastic· Opto/ electrical converter for the PC/RTU· PC/RTU

Commands

The commands defined in the IEC 60870-5-103 protocol are represented in dedicated function blocks. These blocks have output signals for all available commands according to the protocol. For more information, refer to the *Communication protocol manual, IEC 60870-5-103*.

- IED commands in control direction

Function block with defined IED functions in control direction, I103IEDCMD. This block use PARAMETR as FUNCTION TYPE, and INFORMATION NUMBER parameter is defined for each output signal.

- Function commands in control direction

Function block with pre-defined functions in control direction, I103CMD. This block includes the FUNCTION TYPE parameter, and the INFORMATION NUMBER parameter is defined for each output signal.

- Function commands in control direction

Function block with user defined functions in control direction, I103USRCMD. These function blocks include the FUNCTION TYPE parameter for each block in the private range, and the INFORMATION NUMBER parameter for each output signal.

Status



For more information on the function blocks below, refer to the *Communication protocol manual, IEC 60870-5-103*.

The events created in the IED available for the IEC 60870-5-103 protocol are based on the:

- IED status indication in monitor direction

Function block with defined IED functions in monitor direction, I103IED. This block use PARAMETER as FUNCTION TYPE, and INFORMATION NUMBER parameter is defined for each input signal.

- Function status indication in monitor direction, user-defined

Function blocks with user defined input signals in monitor direction, I103UserDef. These function blocks include the FUNCTION TYPE parameter for each block in the private range, and the INFORMATION NUMBER parameter for each input signal.

- Supervision indications in monitor direction

Function block with defined functions for supervision indications in monitor direction, I103Superv. This block includes the FUNCTION TYPE parameter, and the INFORMATION NUMBER parameter is defined for each output signal.

- Earth fault indications in monitor direction

Function block with defined functions for earth fault indications in monitor direction, I103EF. This block includes the FUNCTION TYPE parameter, and the INFORMATION NUMBER parameter is defined for each output signal.

- Fault indications in monitor direction

Function block with defined functions for fault indications in monitor direction, I103FLTPROT. This block includes the FUNCTION TYPE parameter, and the INFORMATION NUMBER parameter is defined for each input signal.

This block is suitable for distance protection, line differential, transformer differential, over-current and earth-fault protection functions.

- Autorecloser indications in monitor direction

Function block with defined functions for autorecloser indications in monitor direction, I103AR. This block includes the FUNCTION TYPE parameter, and the INFORMATION NUMBER parameter is defined for each output signal.

Measurands

The measurands can be included as type 3.1, 3.2, 3.3, 3.4 and type 9 according to the standard.

- Measurands in public range

Function block that reports all valid measuring types depending on connected signals, I103Meas.

- Measurands in private range

Function blocks with user defined input measurands in monitor direction, I103MeasUsr. These function blocks include the FUNCTION TYPE parameter for each block in the private range, and the INFORMATION NUMBER parameter for each block.

Fault location

The fault location is expressed in reactive ohms. In relation to the line length in reactive ohms, it gives the distance to the fault in percent. The data is available and reported when the fault locator function is included in the IED.

Disturbance recordings

- The transfer functionality is based on the Disturbance recorder function. The analog and binary signals recorded will be reported to the master by polling. The eight last disturbances that are recorded are available for transfer to the master. A file that has been transferred and acknowledged by the master cannot be transferred again.
- The binary signals that are included in the disturbance recorder are those that are connected to the disturbance function blocks B1RBDR to B22RBDR. These function blocks include the function type and the information number for each signal. For more information on the description of the Disturbance report in the Technical reference manual. The analog channels, that are reported, are those connected to the disturbance function blocks A1RADR to A4RADR. The eight first ones belong to the public range and the remaining ones to the private range.

18.6.2 Settings

18.6.2.1 Settings for RS485 and optical serial communication

General settings

SPA, DNP and IEC 60870-5-103 can be configured to operate on the SLM optical serial port while DNP and IEC 60870-5-103 additionally can utilize the RS485 port. A single protocol can be active on a given physical port at any time.

Two different areas in the HMI are used to configure the IEC 60870-5-103 protocol.

- The port specific IEC 60870-5-103 protocol parameters are configured under:
Main menu /Configuration /Communication /Station Communication /IEC60870-5-103 /
 - <config-selector>
 - SlaveAddress
 - BaudRate
 - RevPolarity (optical channel only)
 - CycMeasRepTime
 - MasterTimeDomain
 - TimeSyncMode
 - EvalTimeAccuracy
 - EventRepMode
 - CmdMode
 - RepIntermediatePos

<config-selector> is:

 - “OPTICAL103:1” for the optical serial channel on the SLM
 - “RS485103:1” for the RS485 port
- The protocol to activate on a physical port is selected under:
Main menu /Configuration /Communication /Station Communication /Port configuration /
 - RS485 port
 - RS485PROT:1 (off, DNP, IEC103)
 - SLM optical serial port
 - PROTOCOL:1 (off, DNP, IEC103, SPA)

Operation		Off		
SlaveAddress		1	1	254
BaudRate		9600 Bd		
RevPolarity		On		
CycMeasRepTime		5.0	s	1.0
MasterTimeDomain		UTC		
TimeSyncMode		IEDTime		
✓ EvalTimeAccuracy		5ms		
EventRepMode		SeqOfEvent		

Figure 190: Settings for IEC 60870-5-103 communication

The general settings for IEC 60870-5-103 communication are the following:

- SlaveAddress** and **BaudRate**: Settings for slave number and communication speed (baud rate). The slave number can be set to any value between 1 and 254. The communication speed, can be set either to 9600 bits/s or 19200 bits/s.
- RevPolarity**: Setting for inverting the light (or not). Standard IEC 60870-5-103 setting is *On*.
- CycMeasRepTime**: See I103MEAS function block for more information.
- EventRepMode**: Defines the mode for how events are reported. The event buffer size is 5000 events.

Event reporting mode

If *EventRepMode* = *SeqOfEvent*, all GI and spontaneous events will be delivered in the order they were generated by BSW. The most recent value is the latest value delivered. All GI data from a single block will come from the same cycle.

If *EventRepMode* = *HiPriSpont*, spontaneous events will be delivered prior to GI event. To prevent old GI data from being delivered after a new spontaneous event, the pending GI event is modified to contain the same value as the spontaneous event. As a result, the GI dataset is not time-correlated.

18.6.2.2 Settings from PCM600

I103USEDEF

For each input of the I103USEDEF function there is a setting for the information number of the connected signal. The information number can be set to any value between 0 and 255. To get proper operation of the sequence of events the event masks in the event function is to be set to ON_CHANGE. For single-command signals, the event mask is to be set to ON_SET.

In addition there is a setting on each event block for function type. Refer to description of the Main Function type set on the local HMI.

Commands

As for the commands defined in the protocol there is a dedicated function block with eight output signals. Use PCM600 to configure these signals. To realize the BlockOfInformation command, which is operated from the local HMI, the output BLKINFO on the IEC command function block ICOM has to be connected to an input on an event function block. This input must have the information number 20 (monitor direction blocked) according to the standard.

Disturbance Recordings

For each input of the Disturbance recorder function there is a setting for the information number of the connected signal. The function type and the information number can be set to any value between 0 and 255. To get INF and FUN for the recorded binary signals, there are parameters on the disturbance recorder for each input. The user must set these parameters to whatever he connects to the corresponding input.

Refer to description of Main Function type set on the local HMI.

Recorded analog channels are sent with ASDU26 and ASDU31. One information element in these ASDUs is called ACC, and it indicates the actual channel to be processed. The channels on disturbance recorder are sent with an ACC as shown in Table 42.

Table 42: Channels on disturbance recorder sent with a given ACC

DRA#-Input	ACC	IEC 60870-5-103 meaning
1	1	IL1
2	2	IL2
3	3	IL3
4	4	IN
5	5	UL1
6	6	UL2
7	7	UL3
8	8	UN
9	64	Private range
10	65	Private range
11	66	Private range
Table continues on next page		

DRA#-Input	ACC	IEC 60870-5-103 meaning
12	67	Private range
13	68	Private range
14	69	Private range
15	70	Private range
16	71	Private range
17	72	Private range
18	73	Private range
19	74	Private range
20	75	Private range
21	76	Private range
22	77	Private range
23	78	Private range
24	79	Private range
25	80	Private range
26	81	Private range
27	82	Private range
28	83	Private range
29	84	Private range
30	85	Private range
31	86	Private range
32	87	Private range
33	88	Private range
34	89	Private range
35	90	Private range
36	91	Private range
37	92	Private range
38	93	Private range
39	94	Private range
40	95	Private range

18.6.3 Function and information types

Product type IEC103mainFunType value Comment:

REL 128 Compatible range

REC 242 Private range, use default

RED 192 Compatible range

RET 176 Compatible range

REB 207 Private range

REQ 245 Private range

Refer to the tables in the Technical reference manual /Station communication, specifying the information types supported by the communication protocol IEC 60870-5-103.

To support the information, corresponding functions must be included in the protection IED.

There is no representation for the following parts:

- Generating events for test mode
- Cause of transmission: Info no 11, Local operation

Glass or plastic fiber should be used. BFOC/2.5 is the recommended interface to use (BFOC/2.5 is the same as ST connectors). ST connectors are used with the optical power as specified in standard.

For more information, refer to IEC standard IEC 60870-5-103.

18.7 DNP3 Communication protocol

18.7.1 Application

For more information on the application and setting guidelines for the DNP3 communication protocol refer to the DNP3 Communication protocol manual.

Section 19 Remote communication

19.1 Binary signal transfer

19.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Binary signal transfer, receive	BinSignRec1_1 BinSignRec1_2	-	-
Binary signal transfer, transmit	BinSignTrans1_1 BinSignTrans1_2	-	-

19.1.2 Application

The IEDs can be equipped with communication devices for line differential communication (not applicable for RER670) and/or communication of binary signals between IEDs. The same communication hardware is used for both purposes.

Communication between two IEDs geographically on different locations is a fundamental part of the line differential function.

Sending of binary signals between two IEDs is used in teleprotection schemes and for direct transfer trips. In addition to this, there are application possibilities, for example, blocking/enabling functionality in the remote substation, changing setting group in the remote IED depending on the switching situation in the local substation and so on.

If equipped with a 64kbit/s LDCM module, the IED can be configured to send either 192 binary signals or 3 analog and 8 binary signals to a remote IED. If equipped with a 2Mbps LDCM module, the IED can send 9 analog channels and 192 binary channels to a remote IED. For line differential, the number of binary signals is limited to 8 because the line differential communication is included in the same telegrams.

This functionality is mainly used for the line differential protection. However, it can be used in other products as well.

Remote current received through LDCM must be connected only to 1ms pre-processing SMAI block. Consequently, the same 1ms pre-processing block used for differential protection must be used for connecting remote currents to the disturbance recorder.

Important to know when connecting LDCM to SMAI function block with 3 or 8 ms cycle time.



Doing so will affect all protections for the connected cycle time.

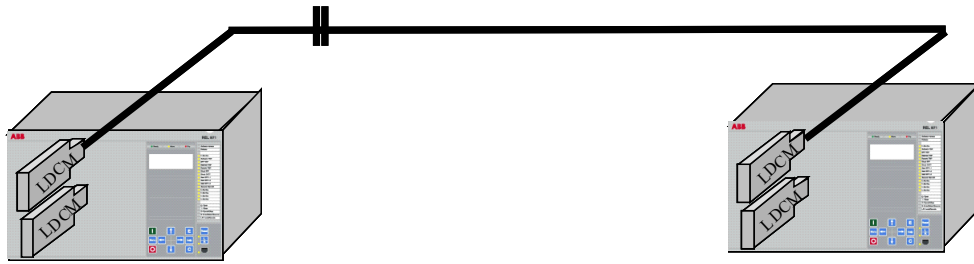
LDCM 64kbit will increase trip time about 5 - 15 ms during normal conditions.

LDCM 2Mbit will increase trip time about 2-3 ms during normal conditions.

In addition IED can get transmission delay from communication either from direct fiber or other equipment such as MUXs etc. Maximum supported communication delay is 40 ms.

19.1.2.1 Communication hardware solutions

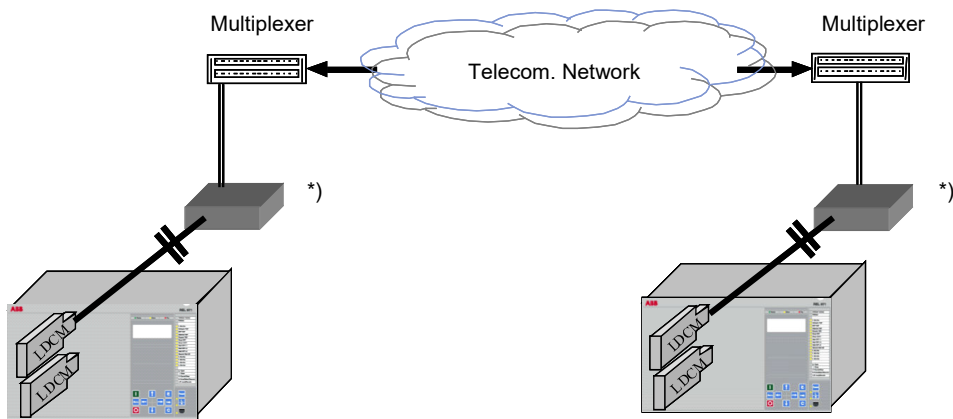
The LDCM (Line Data Communication Module) has an optical connection such that two IEDs can be connected over a direct fiber (multimode), as shown in figure [191](#). The protocol used is IEEE/ANSI C37.94. The distance with this solution is typical 110 km.



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Figure 191: Direct fiber optical connection between two IEDs with LDCM

The LDCM can also be used together with an external optical to galvanic G.703 converter as shown in figure 192. These solutions are aimed for connections to a multiplexer, which in turn is connected to a telecommunications transmission network (for example PDH).



*) Converting optical to galvanic G.703

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Figure 192: LDCM with an external optical to galvanic converter and a multiplexer

When an external modem G.703 is used, the connection between LDCM and the modem is made with a multimode fiber of max. 3 km length. The IEEE/ANSI C37.94 protocol is always used between LDCM and the modem.

19.1.3 Setting guidelines

ChannelMode can be set to *Normal* or *Blocked*. It can also be set to *OutOfService*. In that case, the communication channel remains active, and a message is sent to the remote IED that the local IED is out of service. However, no COMFAIL signal exists and the analog and binary values are sent as zero.

TerminalNo is used to assign a unique address to each LDCM in all current differential IEDs. Up to 256 LDCMs can be assigned a unique number. For example, in a local IED with two LDCMs:

- LDCM for slot 305: set *TerminalNo* to 1 and *RemoteTermNo* to 2
- LDCM for slot 306: set *TerminalNo* to 3 and *RemoteTermNo* to 4



A unique address is necessary to give high security against incorrect addressing in the communication system. If the same number is used for *TerminalNo* in some of the LDCMs, a loop-back test in the communication system can give an incorrect trip.

RemoteTermNo is used to assign a number to each related LDCM in the remote IED. For each LDCM, *RemoteTermNo* is set to a different value than *TerminalNo*, but equal to the *TerminalNo* of the remote end LDCM. In the remote IED, *TerminalNo* and *RemoteTermNo* are reversed as follows:

- LDCM for slot 305: set *TerminalNo* to 2 and *RemoteTermNo* to 1
- LDCM for slot 306: set *TerminalNo* to 4 and *RemoteTermNo* to 3

The redundant channel is always configured to the lower position, for example:



- Slot 305: main channel
- Slot 306: redundant channel

The same is applicable for slot 312-313.

DiffSync: defines the method of time synchronization for the line differential function: *Echo*



Using *Echo* in this case is safe only if there is no risk of varying transmission asymmetry.

CommSync defines the *Master* and *Slave* relation in the communication system, and should not be mistaken for the synchronization of line differential current samples. When direct fiber is used, one LDCM is set as *Master* and the other as *Slave*. When a modem and multiplexer is used, the IED is always set as *Slave* because the telecommunication system provides the clock master.

OptoPower has two settings: *LowPower* is used for fibers 0 – 1 km and *HighPower* for fibers >1 km.

ComFailAlrmDel defines the time delay for communication failure alarm. In communication systems, route switching can sometimes cause interruptions with a duration of up to 50 ms. Too short a time delay can thus cause nuisance alarms.

ComFailResDel defines the time delay for communication failure alarm reset.

RedChSwTime defines the time delay before switching over to a redundant channel in case of primary channel failure.

RedChRturnTime defines the time delay before switching back to the primary channel after channel failure.

AsymDelay denotes asymmetry which is defined as transmission delay minus receive delay. If fixed asymmetry is known, *Echo* synchronization method can be used, provided that *AsymDelay* is properly set. From the definition follows that asymmetry is always positive at one end and negative at the other end.

AnalogLatency specifies the time delay (number of samples) between actual sampling and the time the sample reaches LDCM. The value is set to 2 when transmitting analog data..

MaxTransmDelay indicates maximum transmission delay. Data for maximum 40 ms transmission delay can be buffered up. Delay times in the range of some ms are common. If data arrive in wrong order, the oldest data is disregarded.

MaxtDiffLevel indicates the maximum time difference allowed between internal clocks in respective line ends.

TransmCurr is used to select among the following:

- one of the two possible local currents is transmitted
- sum of the two local currents is transmitted
- channel is used as a redundant backup channel

1½ breaker arrangement has two local currents, and the Current Transformer (CT) earthing for those can differ. *CT-SUM* transmits the sum of the two CT groups. *CT-DIFF1* transmits CT group 1 minus CT group 2 and *CT-DIFF2* transmits CT group 2 minus CT group 1.

CT-GRP1 and *CT-GRP2* transmit the respective CT groups, and setting *RedundantChannel* determines that the channel is used as a redundant backup channel. The redundant channel takes the CT group setting of the main channel.

RemAinLatency corresponds to *LocAinLatency* set in the remote IED.

CompRange value indicates the current peak value over which truncation is made. To set this value, knowledge of fault current levels is required. However, the setting is not very critical as it considers very high current values in which correct operation can usually still be achieved.

Section 20 Security

20.1 Authority status ATHSTAT

20.1.1 Application

Authority status (ATHSTAT) function is an indication function block, which informs about two events related to the IED and the user authorization:

- the fact that at least one user has tried to log on wrongly into the IED and it was blocked (the output USRBLKED)
- the fact that at least one user is logged on (the output LOGGEDON)

The two outputs of ATHSTAT function can be used in the configuration for different indication and alarming reasons, or can be sent to the station control for the same purpose.

20.2 Self supervision with internal event list INTERRSIG

20.2.1 Application

The protection and control IEDs have many functions included. The included self-supervision with internal event list function block provides good supervision of the IED. The fault signals make it easier to analyze and locate a fault.

Both hardware and software supervision is included and it is also possible to indicate possible faults through a hardware contact on the power supply module and/or through the communication.

Internal events are generated by the built-in supervisory functions. The supervisory functions supervise the status of the various modules in the IED and, in case of failure, a corresponding event is generated. Similarly, when the failure is corrected, a corresponding event is generated.

Apart from the built-in supervision of the various modules, events are also generated when the status changes for the:

- built-in real time clock (in operation/out of order).
- external time synchronization (in operation/out of order).

Events are also generated:

- whenever any setting in the IED is changed.

The internal events are time tagged with a resolution of 1 ms and stored in a list. The list can store up to 40 events. The list is based on the FIFO principle, that is, when it is full, the oldest event is overwritten. The list contents cannot be modified, but the whole list can be cleared using the Reset menu in the LHMI.

The list of internal events provides valuable information, which can be used during commissioning and fault tracing.

The information can, in addition to be viewed on the built in HMI, also be retrieved with the aid of a PC with PCM600 installed and by using the Event Monitoring Tool. The PC can either be connected to the front port, or to the port at the back of the IED.

20.3 Change lock CHNGLCK

20.3.1 Application

Change lock function CHNGLCK is used to block further changes to the IED configuration once the commissioning is complete. The purpose is to make it impossible to perform inadvertent IED configuration and setting changes.

However, when activated, CHNGLCK will still allow the following actions that does not involve reconfiguring of the IED:

- Monitoring
- Reading events
- Resetting events
- Reading disturbance data
- Clear disturbances
- Reset LEDs
- Reset counters and other runtime component states
- Control operations
- Set system time
- Enter and exit from test mode
- Change of active setting group

The binary input controlling the function is defined in ACT or SMT. The CHNGLCK function is configured using ACT.

LOCK Binary input signal that will activate/deactivate the function, defined in ACT or SMT.

Change lock functionality can be temporarily disabled/overridden using Maintenance menu.

Maintenance menu/Recovery Menu (Password Protected)/Turn off Change-lock (Temporary).

Turning off the change-lock will override the change lock function until the next reboot of the IED. In this case, the change lock function cannot be activated, and the Override output will indicate that the change-lock is overridden.



When CHNGLCK has a logical one on its input, then all attempts to modify the IED configuration and setting will be denied and the message "Error: Changes blocked" will be displayed on the local HMI; in PCM600 the message will be "Operation denied by active ChangeLock". The CHNGLCK function should be configured so that it is controlled by a signal from a binary input card. This guarantees that by setting that signal to a logical zero, CHNGLCK is deactivated. If any logic is included in the signal path to the CHNGLCK input, that logic must be designed so that it cannot permanently issue a logical one to the CHNGLCK input. If such a situation would occur in spite of these precautions, then please contact the local Hitachi Energy representative for remedial action.

20.4 Denial of service SCHLCCH/RCHLCCH

20.4.1 Application

The denial of service functionality is designed to limit the CPU load that can be produced by Ethernet network traffic on the IED. The communication facilities must not be allowed to compromise the primary functionality of the device. All inbound network traffic will be quota controlled so that too heavy network loads can be controlled. Heavy network load might for instance be the result of malfunctioning equipment connected to the network.

The functions Access point diagnostics function block measure the IED load from communication and, if necessary, limit it for not jeopardizing the IEDs control and protection functionality due to high CPU load. The function has the following denial of service related outputs:

- LINKSTS indicates the Ethernet link status for the rear ports (single communication)
- CHALISTS and CHBLISTS indicates the Ethernet link status for the rear ports channel A and B (redundant communication)
- LinkStatus indicates the Ethernet link status for the front port

20.4.2 Setting guidelines

The function does not have any parameters available in the local HMI or PCM600.

Section 21 Basic IED functions

21.1 IED identifiers TERMINALID

21.1.1 Application

IED identifiers (TERMINALID) function allows the user to identify the individual IED in the system, not only in the substation, but in a whole region or a country.



Use only characters A-Z, a-z and 0-9 in station, object and unit names.

21.2 Product information PRODINF

21.2.1 Application

Product information contains unchangeable data that uniquely identifies the IED.

Product information data is visible on the local HMI under **Main menu/Diagnostics/IED status/Product identifiers** and under **Main menu/Diagnostics/IED Status/Identifiers**:

Product information data is visible on the local HMI under **Main menu/Diagnostics/IED status/Product identifiers** and under **Main menu/Diagnostics/IED Status/Identifiers**.

- ProductVer
- ProductDef
- FirmwareVer
- SerialNo
- OrderingNo
- ProductionDate
- IEDProdType

Figure 193: IED summary

This information is very helpful when interacting with Hitachi Energy product support (for example during repair and maintenance).

21.2.2 Factory defined settings

The factory defined settings are very useful for identifying a specific version and very helpful in the case of maintenance, repair, interchanging IEDs between different Substation Automation Systems and upgrading. The factory made settings can not be changed by the customer. They can only be viewed. The settings are found in the local HMI under **Main menu/Diagnostics /IED status/Product identifiers**

The following identifiers are available:

- IEDProdType
 - Describes the type of the IED. Example: *REL650*
- ProductDef
 - Describes the release number from the production. Example: *2.1.0*
- FirmwareVer

- Describes the firmware version.
 - The firmware version can be checked from **Main menu/Diagnostics/IED status/Product identifiers**
 - Firmware version numbers run independently from the release production numbers. For every release number there can be one or more firmware versions depending on the small issues corrected in between releases.
 - ProductVer
 - Describes the product version. Example: 2.1.0
- | | |
|---|--|
| 1 | is the Major version of the manufactured product this means, new platform of the product |
| 2 | is the Minor version of the manufactured product this means, new functions or new hardware added to the product |
| 3 | is the Major revision of the manufactured product this means, functions or hardware is either changed or enhanced in the product |
- IEDMainFunType
 - Main function type code according to IEC 60870-5-103. Example: 128 (meaning line protection).
 - SerialNo
 - OrderingNo
 - ProductionDate

21.3 Measured values expander block RANGE_XP

21.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Measured values expander block	RANGE_XP	-	-

21.3.2 Application

The current and voltage measurements functions (CVMMXN, CMMXU, VMMXU and VNMMXU), current and voltage sequence measurement functions (CMSQI and VMSQI) and IEC 61850 generic communication I/O functions (MVGAPC) are provided with measurement supervision functionality. All measured values can be supervised with four settable limits, that is low-low limit, low limit, high limit and high-high limit. The measure value expander block (RANGE_XP) has been introduced to be able to translate the integer output signal from the measuring functions to 5 binary signals, that is below low-low limit, below low limit, normal, above high-high limit or above high limit. The output signals can be used as conditions in the configurable logic.

21.3.3 Setting guidelines

There are no settable parameters for the measured values expander block function.

21.4 Parameter setting groups

21.4.1 Application

Six sets of settings are available to optimize IED operation for different power system conditions. By creating and switching between fine tuned setting sets, either from the local HMI or configurable binary inputs, results in a highly adaptable IED that can cope with a variety of power system scenarios.

Different conditions in networks with different voltage levels require highly adaptable protection and control units to best provide for dependability, security and selectivity requirements. Protection units operate with a higher degree of availability, especially, if the setting values of their parameters are continuously optimized according to the conditions in the power system.

Operational departments can plan for different operating conditions in the primary equipment. The protection engineer can prepare the necessary optimized and pre-tested settings in advance for different protection functions. Six different groups of setting parameters are available in the IED. Any of them can be activated through the different programmable binary inputs by means of external or internal control signals.

A function block, SETGRPS, defines how many setting groups are used. Setting is done with parameter *MAXSETGR* and shall be set to the required value for each IED. Only the number of setting groups set will be available in the Parameter Setting tool for activation with the ActiveGroup function block.

21.4.2 Setting guidelines

The setting *ActiveSetGrp*, is used to select which parameter group to be active. The active group can also be selected with configured input to the function block SETGRPS.

The length of the pulse, sent out by the output signal SETCHGD when an active group has changed, is set with the parameter *t*.

The parameter *MAXSETGR* defines the maximum number of setting groups in use to switch between. Only the selected number of setting groups will be available in the Parameter Setting tool (PST) for activation with the ActiveGroup function block.

21.5 Primary system values PRIMVAL

21.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Primary system values	PRIMVAL	-	-

21.5.2 Application

The rated system frequency and phase rotation direction are set under **Main menu / Configuration / Power system / Primary Values** in the local HMI and PCM600 parameter setting tree.

21.5.3 Setting guidelines

Set the system rated frequency. Refer to section ["Signal matrix for analog inputs SMAI"](#) for description on frequency tracking.

21.6 Summation block 3 phase 3PHSUM

21.6.1 Application

The analog summation block 3PHSUM function block is used in order to get the sum of two sets of 3 phase analog signals (of the same type) for those IED functions that might need it.

21.6.2 Setting guidelines

The summation block receives the three-phase signals from SMAI blocks. The summation block has several settings.

SummationType: Summation type (*Group 1 + Group 2*, *Group 1 - Group 2*, *Group 2 - Group 1* or *– (Group 1 + Group 2)*).

DFTReference: The reference DFT block (*InternalDFT Ref*, *DFTRefGrp1* or *External DFT ref*).

DFTRefGrp1: This setting means use own internal adaptive DFT reference (this setting makes the *SUM3PH* self DFT adaptive, that is, it will use the measured frequency for the summation signal to adapt DFT).

InternalDFTRef: Gives fixed window DFT (to nominal system frequency).

ExternalDFTRef: This setting means that the DFT samples-per-cycle (adaptive DFT) will be controlled by SMAI1 SPFCOUT.

FreqMeasMinVal: The minimum value of the voltage for which the frequency is calculated, expressed as percent of *UBasebase* voltage setting (for each instance x).

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*UBase*) and (*SBase*).

21.7 Global base values GBASVAL

21.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Global base values	GBASVAL	-	-

21.7.2 Application

Global base values function (GBASVAL) is used to provide global values, common for all applicable functions within the IED. One set of global values consists of values for current, voltage and apparent power and it is possible to have twelve different sets.

This is an advantage since all applicable functions in the IED use a single source of base values. This facilitates consistency throughout the IED and also facilitates a single point for updating values when necessary.

Each applicable function in the IED has a parameter, *GlobalBaseSel*, defining one out of the twelve sets of GBASVAL functions.

21.7.3 Setting guidelines

UBase: Phase-to-phase voltage value to be used as a base value for applicable functions throughout the IED.

IBase: Phase current value to be used as a base value for applicable functions throughout the IED.

SBase: Standard apparent power value to be used as a base value for applicable functions throughout the IED, typically $SBase = \sqrt{3} \cdot UBase \cdot IBase$.

21.8 Signal matrix for binary inputs SMBI

21.8.1 Application

The Signal matrix for binary inputs function SMBI is used within the Application Configuration tool in direct relation with the Signal Matrix tool. SMBI represents the way binary inputs are brought in for one IED configuration.

21.8.2 Setting guidelines

There are no setting parameters for the Signal matrix for binary inputs SMBI available to the user in Parameter Setting tool. However, the user shall give a name to SMBI instance and the SMBI inputs, directly in the Application Configuration tool. These names will define SMBI function in the Signal Matrix tool. The user defined name for the input or output signal will also appear on the respective output or input signal.

21.9 Signal matrix for binary outputs SMBO

21.9.1 Application

The Signal matrix for binary outputs function SMBO is used within the Application Configuration tool in direct relation with the Signal Matrix tool. SMBO represents the way binary outputs are sent from one IED configuration.

21.9.2 Setting guidelines

There are no setting parameters for the Signal matrix for binary outputs SMBO available to the user in Parameter Setting tool. However, the user must give a name to SMBO instance and SMBO outputs, directly in the Application Configuration tool. These names will define SMBO function in the Signal Matrix tool.

21.10 Signal matrix for analog inputs SMAI

21.10.1 Application

Signal matrix for analog inputs (SMAI), also known as the preprocessor function block, analyses the connected four analog signals (three phases and neutral) and calculates all relevant information from them like the phasor magnitude, phase angle, frequency, true RMS value, harmonics, sequence components and so on. This information is then used by the respective functions connected to this SMAI block in ACT (for example protection, measurement or monitoring functions).

21.10.2 Frequency values

The SMAI function includes a functionality based on the level of positive sequence voltage, *MinValFreqMeas*, to validate if the frequency measurement is valid or not. If the positive sequence voltage is lower than *MinValFreqMeas*, the function freezes the frequency output value for 500 ms and after that the frequency output is set to the nominal value. A signal is available for the SMAI function to prevent operation due to non-valid frequency values. *MinValFreqMeas* is set as % of $U_{Base}/\sqrt{3}$

If SMAI setting *ConnectionType* is *Ph-Ph*, at least two of the inputs GRPxL1, GRPxL2 and GRPxL3, where $1 \leq x \leq 12$, must be connected in order to calculate the positive sequence voltage. Note that phase to phase inputs shall always be connected as follows: L1-L2 to GRPxL1, L2-L3 to GRPxL2, L3-L1 to GRPxL3. If SMAI setting *ConnectionType* is *Ph-N*, all three inputs GRPxL1, GRPxL2 and GRPxL3 must be connected in order to calculate the positive sequence voltage.

If only one phase-phase voltage is available and SMAI setting *ConnectionType* is *Ph-Ph*, the user is advised to connect two (not three) of the inputs GRPxL1, GRPxL2 and GRPxL3 to the same voltage input as shown in figure 194 to make SMAI calculate a positive sequence voltage.

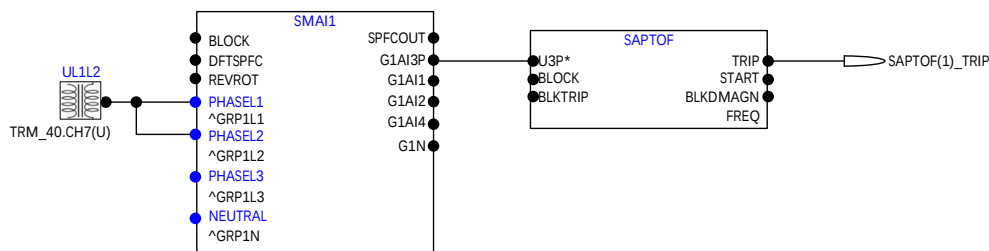


Figure 194: Connection example



The above described scenario does not work if SMAI setting *ConnectionType* is *Ph-N*. If only one phase-earth voltage is available, the same type of connection can be used but the SMAI *ConnectionType* setting must still be *Ph-Ph* and this has to be accounted for when setting *MinValFreqMeas*. If SMAI setting *ConnectionType* is *Ph-N* and the same voltage is connected to all three SMAI inputs, the positive sequence voltage will be zero and the frequency functions will not work properly.



The outputs from the above configured SMAI block shall only be used for Overfrequency protection (SAPTOF), Underfrequency protection (SAPTUF) and Rate-of-change frequency protection (SAPFRC) due to that all other information except frequency and positive sequence voltage might be wrongly calculated.

21.10.3 SMAI incorrect calculated phase-earth

In some configurations SMAI may produce incorrectly calculated phase-earth values, when this is the case, a hint will be available in LHMI with text as below.

Calculated phase-earth values are used from one or more SMAIs configured for phase-phase inputs, without connection to N input.

However, this configuration, combined with unbalanced three-phase input, results in incorrect calculated phase-earth values.

This in turn may result in maloperation of functions connected to SMAIs configured in this way, if the function uses phase-earth based values.

Further, if SUM3PH is connected to such a SMAI, then its output values will be incorrect, and the connected functions may maloperate.

To rectify this situation, revise the configuration from this perspective.

21.10.4 Setting guidelines

The parameters for the signal matrix for analog inputs (SMAI) functions are set via the local HMI or PCM600.

Every SMAI function block can receive four analog signals (three phases and one neutral value), either voltage or current. SMAI outputs give information about every aspect of the 3ph analog signals acquired (phase angle, RMS value, frequency and frequency derivatives, and so on – 244 values in total). Besides the block “group name”, the analog inputs type (voltage or current) and the analog input names can be set directly in ACT.

Application functions should be connected to a SMAI block with same task cycle as the application function, except for e.g. measurement functions that run in slow cycle tasks.

DFTRefExtOut: Parameter valid only for function block SMAI1 .

Reference block for external output (SPFCOUT function output).

DFTReference: Reference DFT for the SMAI block use.

These DFT reference block settings decide DFT reference for DFT calculations. The setting *InternalDFTRef* will use fixed DFT reference based on set system frequency. *DFTRefGrp(n)* will use DFT reference from the selected group block, when own group is selected, an adaptive DFT reference will be used based on calculated signal frequency from own group. The setting *ExternalDFTRef* will use reference based on what is connected to input DFTSPFC.

The setting *ConnectionType*: Connection type for that specific instance (n) of the SMAI (if it is *Ph-N* or *Ph-Ph*). Depending on connection type setting the not connected *Ph-N* or *Ph-Ph* outputs will be calculated as long as they are possible to calculate. E.g. at *Ph-Ph* connection L1, L2 and L3 will be calculated for use in symmetrical situations. If N component should be used respectively the phase component during faults I_N/U_N must be connected to input 4.

Negation: If the user wants to negate the 3ph signal, it is possible to choose to negate only the phase signals *Negate3Ph*, only the neutral signal *NegateN* or both *Negate3Ph+N*. negation means rotation with 180° of the vectors.

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*UBase*) and (*SBase*).

MinValFreqMeas: The minimum value of the voltage for which the frequency is calculated, expressed as percent of UBase (for each instance n).



Settings *DFTRefExtOut* and *DFTReference* shall be set to default value *InternalDFTRef* if no VT inputs are available.



Even if the user sets the *AnalogInputType* of a SMAI block to “*Current*”, the *MinValFreqMeas* is still visible. However, using the current channel values as base for frequency measurement is **not recommendable** for a number of reasons, not last among them being the low level of currents that one can have in normal operating conditions.

Examples of adaptive frequency tracking



Preprocessing block shall only be used to feed functions within the same execution cycles (e.g. use preprocessing block with cycle 1 to feed transformer differential protection). The only exceptions are measurement functions (CVMMXN, CMMXU, VMMXU, etc.) which shall be fed by preprocessing blocks with cycle 8.



When two or more preprocessing blocks are used to feed one protection function (e.g. over-power function GOPPDOP), it is of outmost importance that parameter setting DFTReference has the same set value for all of the preprocessing blocks involved

Task time group 1	
SMAI instance	3 phase group
SMAI1:1	1
SMAI2:2	2
SMAI3:3	3
SMAI4:4	4
SMAI5:5	5
SMAI6:6	6
SMAI7:7	7
SMAI8:8	8
SMAI9:9	9
SMAI10:10	10
SMAI11:11	11
SMAI12:12	12

DFTRefGrp7

Task time group 2	
SMAI instance	3 phase group
SMAI1:13	1
SMAI2:14	2
SMAI3:15	3
SMAI4:16	4
SMAI5:17	5
SMAI6:18	6
SMAI7:19	7
SMAI8:20	8
SMAI9:21	9
SMAI10:22	10
SMAI11:23	11
SMAI12:24	12

DFTRefGrp4

Task time group 3	
SMAI instance	3 phase group
SMAI1:25	1
SMAI2:26	2
SMAI3:27	3
SMAI4:28	4
SMAI5:29	5
SMAI6:30	6
SMAI7:31	7
SMAI8:32	8
SMAI9:33	9
SMAI10:34	10
SMAI11:35	11
SMAI12:36	12

Task time group 4	
SMAI instance	3 phase group
SMAI1:37	1
SMAI2:38	2
SMAI3:39	3
SMAI4:40	4
SMAI5:41	5
SMAI6:42	6
SMAI7:43	7
SMAI8:44	8
SMAI9:45	9
SMAI10:46	10
SMAI11:47	11
SMAI12:48	12

DFTRefGrp6

IEC07000197.vsd

Figure 195: Twelve SMAI instances are grouped within one task time. SMAI blocks are available in four different task times in the IED. Three pointed instances are used in the following examples.

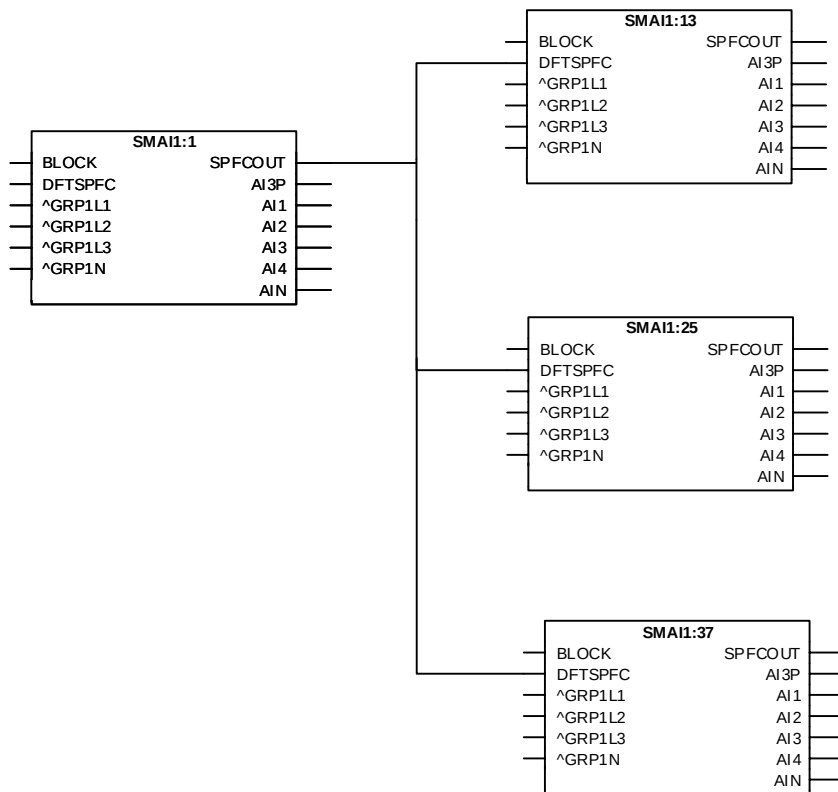
The examples shows a situation with adaptive frequency tracking with one reference selected for all instances. In practice each instance can be adapted to the needs of the actual application. The adaptive frequency tracking is needed in IEDs that belong to the protection system of synchronous machines and that are active during run-up and shut-down of the machine. Also, adaptive frequency

tracking is needed in PMU application to be compliant to PMU standards. In other application the usual setting of the parameter *DFTReference* of SMAI is *InternalDFTRef*.



The user should use 0.9 ms task time for connection to PMU functions.

Example 1



IEC07000198-4-en.vsd

Figure 196: Configuration for using an instance in task time group 1 as DFT reference

Assume instance SMAI7:7 in task time group 1 has been selected in the configuration to control the frequency tracking. Observe that the selected reference instance (i.e. frequency tracking master) must be a voltage type. Observe that positive sequence voltage is used for the frequency tracking feature.

For task time group 1 this gives the following settings (see Figure 195 for numbering):

SMAI1:1: *DFTRefExtOut* = *DFTRefGrp7* to route SMAI7:7 reference to the SPFCOUT output, *DFTReference* = *DFTRefGrp7* for SMAI1:1 to use SMAI7:7 as reference (see Figure 196) SMAI2:2 – SMAI12:12: *DFTReference* = *DFTRefGrp7* for SMAI2:2 – SMAI12:12 to use SMAI7:7 as reference.

For task time group 2 this gives the following settings:

SMAI1:13 – SMAI12:24: *DFTReference* = *ExternalDFTRef* to use DFTSPFC input of SMAI1:13 as reference (SMAI7:7)

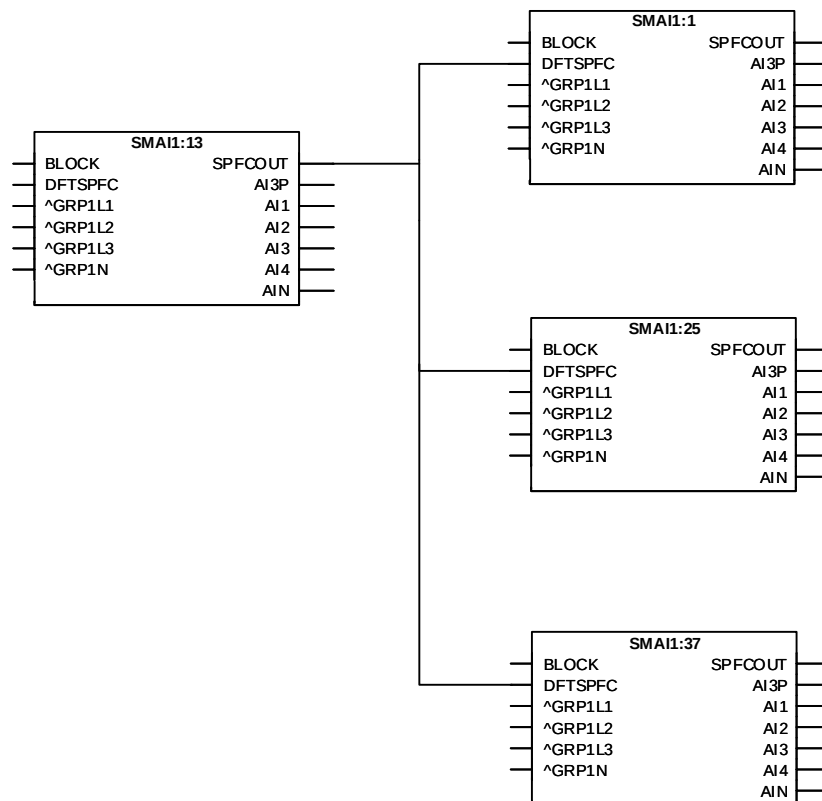
For task time group 3 this gives the following settings:

SMAI1:25 – SMAI12:36: *DFTReference* = *ExternalDFTRef* to use DFTSPFC input as reference (SMAI7:7)

For task time group 4 this gives the following settings:

SMAI1:37 – SMAI12:48: *DFTReference* = *ExternalDFTRef* to use DFTSPFC input as reference (SMAI7:7)

Example 2



IEC07000199-4-en.vsd

Figure 197: Configuration for using an instance in task time group 2 as DFT reference.

Assume instance SMAI4:16 in task time group 2 has been selected in the configuration to control the frequency tracking for all instances. Observe that the selected reference instance (i.e. frequency tracking master) must be a voltage type. Observe that positive sequence voltage is used for the frequency tracking feature.

For task time group 1 this gives the following settings (see Figure 195 for numbering):

SMAI1:1 – SMAI12:12: *DFTReference* = *ExternalDFTRef* to use DFTSPFC input as reference (SMAI4:16)

For task time group 2 this gives the following settings:

SMAI1:13: *DFTRefExtOut* = *DFTRefGrp4* to route SMAI4:16 reference to the SPFCOUT output, *DFTReference* = *DFTRefGrp4* for SMAI1:13 to use SMAI4:16 as reference (see Figure 197)
SMAI2:14 – SMAI12:24: *DFTReference* = *DFTRefGrp4* to use SMAI4:16 as reference.

For task time group 3 this gives the following settings:

SMAI1:25 – SMAI12:36: *DFTReference* = *ExternalDFTRef* to use DFTSPFC input as reference (SMAI4:16)

For task time group 4 this gives the following settings:

SMAI1:37 – SMAI12:48: *DFTReference* = *ExternalDFTRef* to use DFTSPFC input as reference (SMAI4:16)

Example 3

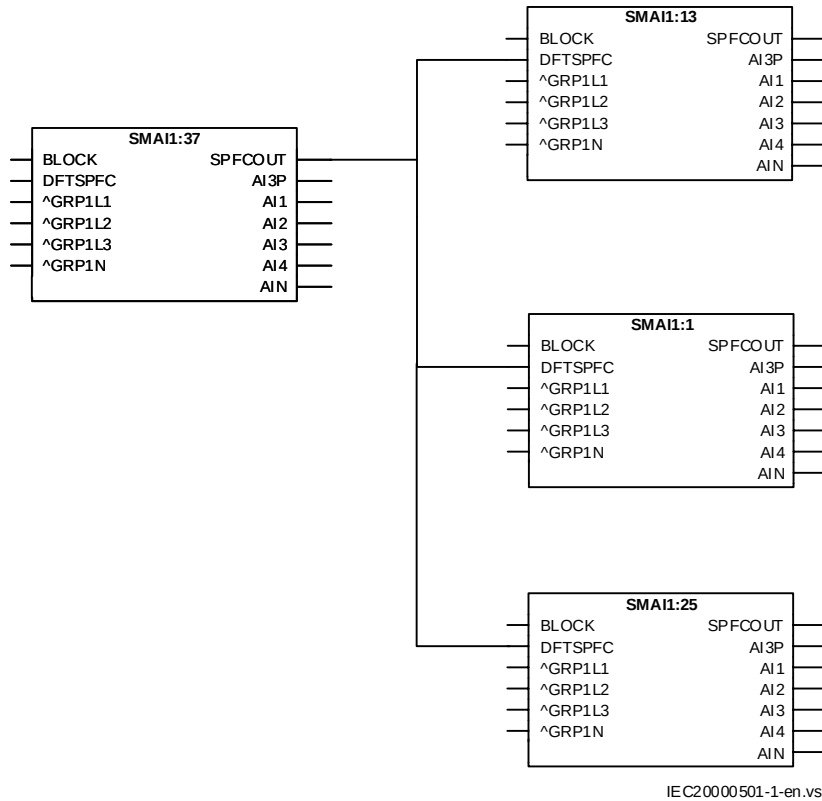


Figure 198: Configuration for using an instance in task time group 4 as DFT reference.

Assume instance SMAI6:42 in task time group 4 has been selected in the configuration to control the frequency tracking for all instances. Observe that the selected reference instance (that is, frequency tracking master) must be a voltage type. Observe that positive sequence voltage is used for the frequency tracking feature.

For task time group 1 this gives the following settings (see Figure 195 for numbering):

SMAI1:1 – SMAI12:12: *DFTReference* = *ExternalDFTRef* to use DFTSPFC input as reference (SMAI6:42)

For task time group 2 this gives the following settings:

SMAI1:13 – SMAI12:24: *DFTReference* = *ExternalDFTRef* to use DFTSPFC input as reference (SMAI6:42)

For task time group 3 this gives the following settings:

SMAI1:25 – SMAI12:36: *DFTReference* = *ExternalDFTRef* to use DFTSPFC input as reference (SMAI6:42)

For task time group 4 this gives the following settings:

SMA1:37: *DFTRefExtOut* = *DFTRefGrp6* to route SMA16:42 reference to the SPFCOUT output, *DFTRefGrp6* for SMA1:37 to use SMA16:42 as reference (see Figure 198)
 SMA12:38 – SMA12:48: *DFTRefGrp6* = *DFTRefGrp6* to use SMA16:42 as reference.

21.11 Test mode functionality TESTMODE

21.11.1 Application

The protection and control IEDs may have a complex configuration with many included functions. To make the testing procedure easier, the IEDs include the feature that allows individual blocking of a single-, several-, or all functions.

This means that it is possible to see when a function is activated or trips. It also enables the user to follow the operation of several related functions to check correct functionality and to check parts of the configuration, and to check parts.

21.11.1.1 IEC 61850 protocol test mode

The function block TESTMODE has implemented the extended testing mode capabilities for IEC 61850 Ed2 systems. Operator commands sent to the function block TESTMODE determine the behavior of the functions. The command can be given remotely from an IEC 61850 client or from the LHMI under the **Main menu /Test/Function test modes /Communication/Station Communication /IEC61850 LD0 LLN0/LD0LLN0:1**. The possible values of the function block TESTMODE are described in *Communication protocol manual, IEC 61850 Edition 1* and *Edition 2*.

There is no setting in PCM600 via PST for the TESTMODE function block.



To be able to set the function block TESTMODE remotely, the setting via path on LHMI and in PST: **Main menu /Configuration/Communication / Station Communication/ IEC61850-8-1 /IEC61850-8-1:1 RemoteModControl** may not be set to *Off*. The possible values of the parameter *RemoteModControl* are *Off*, *Maintenance* or *All levels*. The *Off* value denies all access to function block TESTMODE from remote, *Maintenance* requires that the category of the originator (orCat) is *Maintenance* and *All levels* allow any orCat.

The DataObject Mod of the Root LD.LNN0 can be set on the LHMI under **Main menu/Test/Function test modes/Communication/Station communication /IEC61850 LD0 LLN0/LD0LLN0:1** to *On*, *Off*, *TestBlocked*, *Test* or *Blocked*.

When the setting of the DataObject Mod is changed at this level, all Logical Nodes inside the logical device update their own behavior according to IEC 61850-7-4. The supported values of the function block TESTMODE are described in *Communication protocol manual, IEC 61850 Edition 2*. When the function block TESTMODE is in test mode the Start LED on the LHMI is turned on with steady light.

The parameter *Mod* of any specific function block can be configured under **Main menu/Test/Function test modes/Communication /Station Communication**

The parameter *Mod* can be set on the LHMI to the same values as for the DataObject Mod of the Root LD.LNN0 to *On*, *Off*, *TestBlocked*, *Test* or *Blocked*. For Example, Main menu/ Test/ Function test modes/ Differential protection/GeneratorDiff(87G,3Id/I>)/ GENPDIF(87G,3Id/I>):1.

It is possible that the behavior of the function block TESTMODE is also influenced by other sources as well, independent of the mode communicated via the IEC 61850-8-1 station bus. For example the insertion of the test handle into the test switch with its auxiliary contact is connected to a BI on the IED and further inside the configuration to the input IED_TEST on the function block TESTMODE. Another example is when loss of Service Values appears, or as explained above the setting via the LHMI.

When setting via PST or LHMI the parameter *Operation* of any function in an IED is set to *Off*, the function is not executed and the behavior (*beh*) is set to *Off* and it is not possible to override it. When a behavior of a function is *Off* the function will not execute. The related *Mod* keeps its current state.



When IEC 61850 Mod of a function is set to *Off* or *Blocked*, the Start LED on the LHMI will be set to flashing to indicate the abnormal operation of the IED.

The IEC 61850-7-4 gives a detailed overview over all aspects of the test mode and other states of mode and behavior. The status of a function block behavior *Beh* is shown on the LHMI under the **Main menu /Test/Function status /Function group/Function block descriptive name/LN name/Outputs**.

- When the *Beh* of a function block is set to *Test*, the function block is not blocked and all control commands with a test bit are accepted.
- When the *Beh* of a function block is set to *Test/blocked*, all control commands with a test bit are accepted. Outputs to the process via a non-IEC 61850 link data are blocked by the function block. Only process-related outputs on function blocks related to primary equipment are blocked. If there is an XCBR function block used, the outputs *EXC_Open* and *EXC_Close* are blocked.
- When the *Beh* of a function block is set to *Blocked*, all control commands with a test bit are accepted. Outputs to the process via a non-IEC 61850 link data are blocked by the function block. In addition, the function block can be blocked when their *Beh* is *blocked*. This can be done if the function block has a block input.

The block status of a component is shown on the LHMI as the *Blk* output under the same path as for *Beh*: **Main menu/Test/Function status/Function group /Function block descriptive name/LN name/Outputs**. If the *Blk* output is not shown, the component cannot be blocked.

21.11.2 Setting guidelines

Remember always that there are two possible ways to place the IED in the *TestMode= On* state. If, the IED is set to normal operation (*TestMode = Off*), but the functions are still shown being in the test mode, the input signal IED_TEST on the TESTMODE function block is activated in the configuration.

Forcing of binary input and output signals is only possible when the IED is in IED test mode.

21.12 Time synchronization TIMESYNCHGEN

21.12.1 Application

Use time synchronization to achieve a common time base for the IEDs in a protection and control system. This makes it possible to compare events and disturbance data between all IEDs in the system.

Time-tagging of internal events and disturbances are an excellent help when evaluating faults. Without time synchronization, only the events within one IED can be compared with each other. With time synchronization, events and disturbances within the whole network, can be compared and evaluated.

In the IED, the internal time can be synchronized from the following sources:

- BIN (Binary Minute Pulse)
- DNP
- IEC103
- SNTP
- IRIG-B
- SPA

- LON
- PPS
- IEEE 1588 (PTP)

For time synchronization of line differential protection with diff communication in GPS-mode, a GPS-based time synchronization is needed. This can be optical IRIG-B with 1344 from an external GPS-clock.

Out of these, LON and SPA contains two types of synchronization messages:

- Coarse time messages are sent every minute and contain complete date and time, that is year, month, day, hour, minute, second and millisecond.
- Fine time messages are sent every second and comprise only seconds and milliseconds.

The selection of the time source is done via the corresponding setting.

If PTP is activated, the device with the best accuracy within the synchronizing group will be selected as the source. For more information about PTP, see the Technical manual.

IEEE 1588 (PTP)

PTP according to IEEE 1588-2008 and specifically its profile IEC/IEEE 61850-9-3 for power utility automation is a synchronization method that can be used to maintain a common time within a station. This time can be synchronized to the global time using, for instance, a GPS receiver. If PTP is enabled on the IEDs and the switches that connect the station are compatible with IEEE 1588, the station will become synchronized to one common time with an accuracy of under 1us. Using an IED as a boundary clock between several networks will keep 1us accuracy on three levels or when using an HSR, 15 IEDs can be connected in a ring without losing a single microsecond in accuracy.

21.12.2 Setting guidelines

All the parameters related to time are divided into two categories: System time and Synchronization.

21.12.2.1 System time

The time is set with years, month, day, hour, minute, second and millisecond.

21.12.2.2 Synchronization

The setting parameters for the real-time clock with external time synchronization are set via local HMI or PCM600. The path for Time Synchronization parameters on local HMI is **Main menu/ Configuration /Time/Synchronization**. The parameters are categorized as Time Synchronization (TIMESYNCHGEN) and IRIG-B settings (IRIG-B:1) in case that IRIG-B is used as the external time synchronization source.

TimeSynch

When the source of the time synchronization is selected on the local HMI, the parameter is called *TimeSynch*. The time synchronization source can also be set from PCM600. The setting alternatives are:

FineSyncSource can have the following values:

- Off
- SPA
- LON
- BIN (Binary Minute Pulse)
- SNTP
- IRIG-B
- PPS

- Off
- SPA
- LON
- DNP
- IEC 60870-5-103

The system time can be set manually, either via the local HMI or via any of the communication ports. The time synchronization fine tunes the clock (seconds and milliseconds).

- Off
- *SNTP -Server*



IEEE 1588 (PTP)

PTP can be set to *On*, *Off* or *Slave only*. When set to *Slave only* the IED is connected to the PTP-group and will synchronize to the grandmaster but cannot function as the grandmaster.

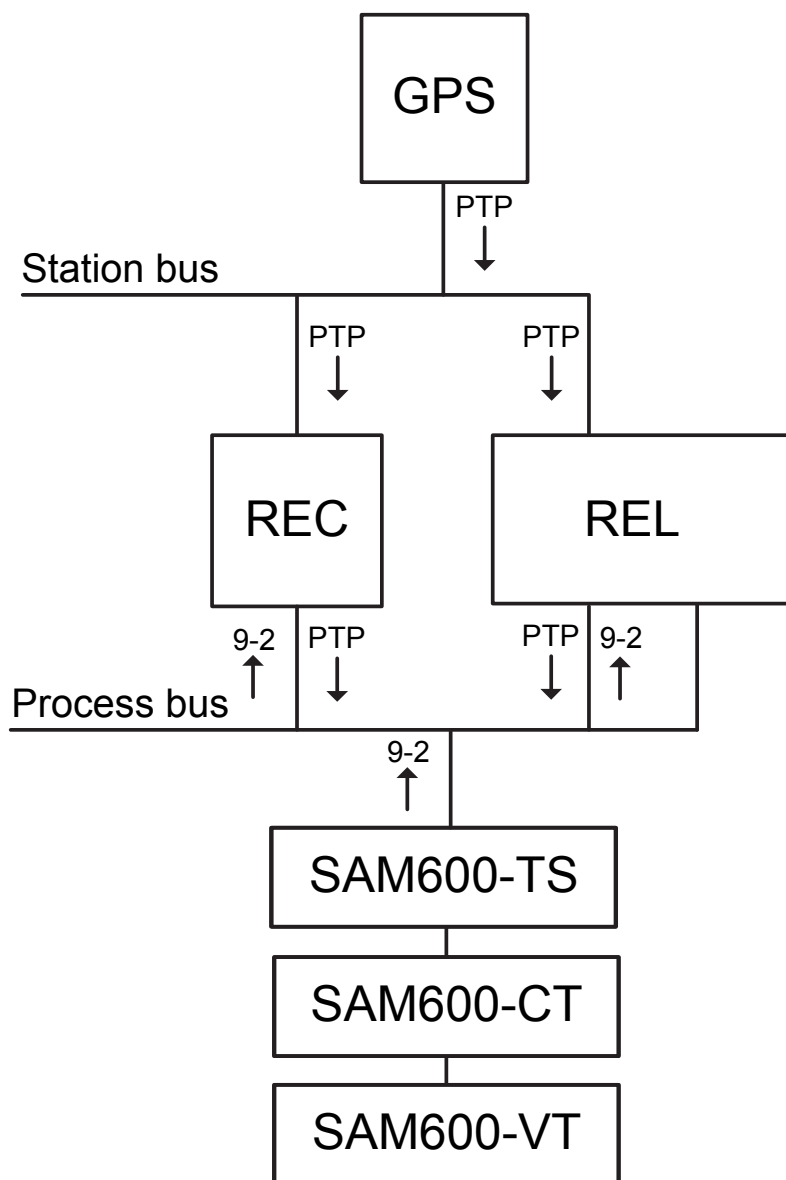
A PTP-group is set up by connecting the IEDs to a network and enabling PTP. To set one IED as the grandmaster change Priority2 to 127 instead of the default 128.

[illegible]

Figure 199: Enabling PTP in ECT

The *PTP VLAN* tag must have the same value in station clock and in the IED. The default value is set to 0.

The *PTP VLAN* tag does not need to be the same on all access points in one IED. It is possible to mix as long as they are the same for all devices on each subnet.

Setting example

IEC17000069=1=en.vsdX

Figure 200: Example system

Figure 200 describes an example system. The REC and REL are both using the 9-2 stream from the SAM600, and gets its synch from the GPS. Moreover, the REL and REC both acts as a boundary clock to provide synch to the SAM600.

On all access points, the *PTP* parameter is “ON”.

21.12.2.3 Process bus IEC/UCA 61850-9-2LE synchronization

When process bus communication (IEC/UCA 61850-9-2LE protocol) is used, it is essential that the merging units are synchronized with the hardware time of the IED (see Technical manual, section *Design of the time system (clock synchronization)*). To achieve this, PTP, PPS or IRIG-B can be used depending of the facilities of the merging unit.

If the merging unit supports PTP, use PTP. If PTP is used in the IED and the merging unit cannot be synchronized from the IED, then use GPS-based clocks to provide PTP sync as well as sync to the merging unit.

If synchronization of the IED and the merging unit is based on GPS, set the parameter *SyncLostMode* to *BlockOnLostUTC* in order to provide a block of protection functions whenever the global common time is lost.

If PTP is not used, use the same synchronization method for the *HwSyncSrc* as the merging unit provides. For instance, if the merging unit provides PPS as synchronization, use PPS as *HwSyncSrc*. If LDCM in GPS-mode is used, that is, the hardware and software clocks are connected to each other, *HwSyncSrc* is not used and other means to synchronize the merging unit to the IED is required. For instance, *FineSyncSource* is set to the same source that the merging unit uses.



If the IED is used together with a merging unit and no time synchronization is available, for example, in the laboratory test, the IED will synchronize to the SV data stream. During the re-synchronization, the protection functions will be blocked once a second for about 45 ms, and this will continue for up to 10 minutes. To avoid this, configure PTP (IEEE 1588) to *On* for the access point where the merging unit is configured.

21.12.2.4 Time synchronization for differential protection and IEC/UC 61850-9-2LE sampled data

When using differential communication in conjunction with sampled data received from merging units (MU) over the IEC/UC 61850-9-2LE process bus, the MU and the IED needs to be controlled by the same GPS synchronized clock. The required accuracy is $\pm 4 \mu\text{s}$. The accuracy can be achieved by using a GTM, GPS-based IRIG-B clock or PTP clock, and synchronizing MU from the same clock or from the PPS output of the GTM card. If, for instance, IRIG-B is used, the settings for time synchronization should be *CourseSyncSrc* = *Off*, *FineSyncSource* = *IRIG-B*, *TimeAdjustRate* = *Fast*. The setting for *Encoding* in SYNCHIRIG-B needs to be set to *1344*.

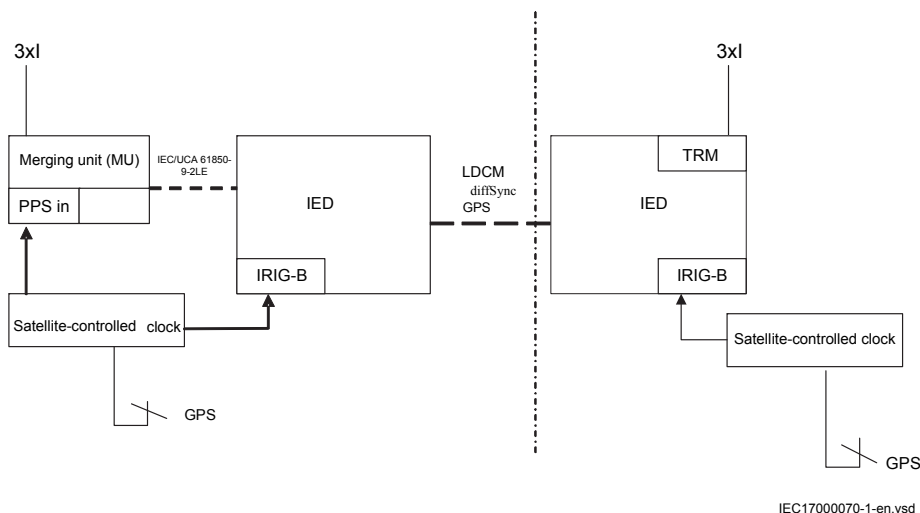


Figure 201: Time synchronization of merging unit and IED

The parameter *DiffSync* for the LDCM needs to be set to *GPS* and the *GPSSyncErr* needs to be set to *Block*.

In "ECHO" mode MU and IED still need to be synchronized. In this case they can be synchronized with either PPS or IRIG-B.

Section 22 Requirements

22.1 Current transformer requirements

The performance of a protection function will depend on the quality of the measured current signal. Saturation of the current transformers (CTs) will cause distortion of the current signals and can result in a failure to operate or cause unwanted operations of some functions. Consequently CT saturation can have an influence on both the dependability and the security of the protection. This protection IED has been designed to permit heavy CT saturation with maintained correct operation.

22.1.1 Current transformer basic classification and requirements

To guarantee correct operation, the current transformers (CTs) must be able to correctly reproduce the current for a minimum time before the CT will begin to saturate. To fulfill the requirement on a specified time to saturation the CTs must fulfill the requirements of a minimum secondary e.m.f. that is specified below.

CTs are specified according to many different classes and standards. In principle, there are three different types of protection CTs. These types are related to the design of the iron core and the presence of airgaps. Airgaps affects the properties of the remanent flux.

The following three different types of protection CTs have been specified:

- The High Remanence type with closed iron core and no specified limit of the remanent flux
- The Low Remanence type with small airgaps in the iron core and the remanent flux limit is specified to be maximum 10% of the saturation flux
- The Non Remanence type with big airgaps in the iron core and the remanent flux can be neglected

Even though no limit of the remanent flux is specified in the IEC standard for closed core CTs, it is a common opinion that the remanent flux is normally limited to maximum 75 - 80 % of the saturation flux.

Since approximately year 2000 some CT manufactures have introduced new core materials that gradually have increased the possible maximum levels of remanent flux even up to 95 % related to the hysteresis curve. Corresponding level of actual remanent flux is 90 % of the saturation flux (Ψ_{sat}). As the present CT standards have no limitation of the level of remanent flux, these CTs are also classified as for example, class TPX, P and PX according to IEC. The IEC TR 61869-100, Edition 1.0 2017-01, Instrument transformers – Guidance for application of current transformers in power system protection, is the first official document that highlighted this development. So far remanence factors of maximum 80% have been considered when CT requirements have been decided for Hitachi Energy IEDs. Even in the future this level of remanent flux probably will be the maximum level that will be considered when decided the CT requirements. If higher remanence levels should be considered, it should often lead to unrealistic CT sizes.

Thus, now there is a need to limit the acceptable level of remanent flux. To be able to guarantee the performance of protection IEDs, we need to introduce the following classification of CTs.

There are many different standards and a lot of classes but fundamentally there are four different types of CTs:

- Very High Remanence type CT
- High Remanence type CT
- Low Remanence type CT
- Non Remanence type CT

The Very High Remanence (VHR) type is a CT with closed iron core (for example, protection classes TPX, P, PX according to IEC, class C, K according to ANSI/IEEE) and with an iron core

material (new material, typically new alloy based magnetic materials) that gives a remanent flux higher than 80 % of the saturation flux.

The High Remanence (HR) type is a CT with closed iron core (for example, protection classes TPX, P, PX according to IEC, class C, K according to ANSI/IEEE) but with an iron core material (traditional material) that gives a remanent flux that is limited to maximum 80 % of the saturation flux.

The Low Remanence (LR) type is a CT with small airgaps in the iron core (for example, TPY, PR, PXR according to IEC) and the remanent flux limit is specified to be maximum 10% of the saturation flux.

The Non Remanence (NR) type is a CT with big airgaps in the core (for example, TPZ according to IEC) and the remanent flux can be neglected.

It is also possible that different CT classes of HR and LR type may be mixed.

CT type VHR (using new material) should not be used for protection CT cores. This means that it is important to specify that the remanence factor must not exceed 80 % when ordering for example, class P, PX or TPX CTs. If CT manufacturers are using new core material and are not able to fulfill this requirement, the CTs shall be specified with small airgaps and therefore will be CTs of LR type (for example, class PR, TPY or PXR). Very high remanence level in a protection core CT can cause the following problems for protection IEDs:

1. Unwanted operation of differential (i.e. unit) protections for external faults
2. Unacceptably delayed or even missing operation of all types of protections (for example, distance, differential, overcurrent, etc.) which can result in losing protection selectivity in the network

No information is available about how frequent the use of the new iron core material is for protection CT cores, but it is known that some CT manufacturers are using the new material while other manufacturers continue to use the old traditional core material for protection CT cores. In a case where VHR type CTs have been already installed, the calculated values of E_{al} for HR type CTs, for which the formulas are given in this document, must be multiplied by factor two-and-a-half in order for VHR type CTs (i.e. with new material) to be used together with Hitachi Energy protection IEDs. However, this may result in unacceptably big CT cores, which can be difficult to manufacture and fit in available space.

Different standards and classes specify the saturation e.m.f. in different ways but it is possible to approximately compare values from different classes. The rated equivalent limiting secondary e.m.f. E_{al} according to the IEC 61869–2 standard is used to specify the CT requirements for the IED. The requirements are also specified according to other standards.

22.1.2 Conditions

The requirements are a result of investigations performed in our network simulator. The current transformer models are representative for current transformers of high remanence and low remanence type. The results may not always be valid for non remanence type CTs (TPZ).

The performances of the protection functions have been checked in the range from symmetrical to fully asymmetrical fault currents. Primary time constants of at least 120 ms have been considered at the tests. The current requirements below are thus applicable both for symmetrical and asymmetrical fault currents.

Depending on the protection function phase-to-earth, phase-to-phase and three-phase faults have been tested for different relevant fault positions for example, close in forward and reverse faults, zone 1 reach faults, internal and external faults. The dependability and security of the protection was verified by checking for example, time delays, unwanted operations, directionality, overreach and stability.

The remanence in the current transformer core can cause unwanted operations or minor additional time delays for some protection functions. As unwanted operations are not acceptable at all maximum remanence has been considered for fault cases critical for the security, for example, faults in reverse direction and external faults. Because of the almost negligible risk of additional time delays and the non-existent risk of failure to operate the remanence have not been considered for the dependability cases. The requirements below are therefore fully valid for all normal applications.

It is difficult to give general recommendations for additional margins for remanence to avoid the minor risk of an additional time delay. They depend on the performance and economy requirements. When current transformers of low remanence type (for example, TPY, PR) are used, normally no additional margin is needed. For current transformers of high remanence type (for example, P, PX, TPX) the small probability of fully asymmetrical faults, together with high remanence in the same direction as the flux generated by the fault, has to be kept in mind at the decision of an additional margin. Fully asymmetrical fault current will be achieved when the fault occurs at approximately zero voltage (0°). Investigations have shown that 95% of the faults in the network will occur when the voltage is between 40° and 90° . In addition fully asymmetrical fault current will not exist in all phases at the same time.

22.1.3 Fault current

The current transformer requirements are based on the maximum fault current for faults in different positions. Maximum fault current will occur for three-phase faults or single phase-to-earth faults. The current for a single phase-to-earth fault will exceed the current for a three-phase fault when the zero sequence impedance in the total fault loop is less than the positive sequence impedance.

When calculating the current transformer requirements, maximum fault current for the relevant fault position should be used and therefore both fault types have to be considered.

22.1.4 Secondary wire resistance and additional load

The voltage at the current transformer secondary terminals directly affects the current transformer saturation. This voltage is developed in a loop containing the secondary wires and the burden of all relays in the circuit. For earth faults the loop includes the phase and neutral wire, normally twice the resistance of the single secondary wire. For three-phase faults the neutral current is zero and it is just necessary to consider the resistance up to the point where the phase wires are connected to the common neutral wire. The most common practice is to use four wires secondary cables so it normally is sufficient to consider just a single secondary wire for the three-phase case.

The conclusion is that the loop resistance, twice the resistance of the single secondary wire, must be used in the calculation for phase-to-earth faults and the phase resistance, the resistance of a single secondary wire, may normally be used in the calculation for three-phase faults.

As the burden can be considerable different for three-phase faults and phase-to-earth faults it is important to consider both cases. Even in a case where the phase-to-earth fault current is smaller than the three-phase fault current the phase-to-earth fault can be dimensioning for the CT depending on the higher burden.

In isolated or high impedance earthed systems the phase-to-earth fault is not the dimensioning case. Therefore, the resistance of the single secondary wire can always be used in the calculation for this kind of power systems.

22.1.5 General current transformer requirements

The current transformer ratio is mainly selected based on power system data for example, maximum load and/or maximum fault current. It should be verified that the current to the protection is higher than the minimum operating value for all faults that are to be detected with the selected CT ratio. It should also be verified that the maximum possible fault current is within the limits of the IED.

The current error of the current transformer can limit the possibility to use a very sensitive setting of a sensitive residual overcurrent protection. If a very sensitive setting of this function will be used it is recommended that the current transformer should have an accuracy class which have an current error at rated primary current that is less than $\pm 1\%$ (for example, 5P). If current transformers with less accuracy are used it is advisable to check the actual unwanted residual current during the commissioning.

22.1.6 Rated equivalent secondary e.m.f. requirements

With regard to saturation of the current transformer all current transformers of high remanence and low remanence type that fulfill the requirements on the rated equivalent limiting secondary e.m.f. E_{al} below can be used. The characteristic of the non remanence type CT (TPZ) is not well defined as far as the phase angle error is concerned. If no explicit recommendation is given for a specific function we therefore recommend contacting Hitachi Energy to confirm that the non remanence type can be used.

The CT requirements for the different functions below are specified as a rated equivalent limiting secondary e.m.f. E_{al} according to the IEC 61869-2 standard. Requirements for CTs specified according to other classes and standards are given at the end of this section.

22.1.6.1 Line differential protection

The current transformers must have a rated equivalent limiting secondary e.m.f. E_{al} that is larger than the maximum of the required rated equivalent limiting secondary e.m.f. E_{alreq} below:

$$E_{al} \geq E_{alreq} = I_{kmax} \cdot \frac{I_{sr}}{I_{pr}} \cdot \left(R_{ct} + R_L + \frac{S_R}{I_r^2} \right) \quad (\text{Equation 135})$$

$$E_{al} \geq E_{alreq} = 2 \cdot I_{tmax} \cdot \frac{I_{sr}}{I_{pr}} \cdot \left(R_{ct} + R_L + \frac{S_R}{I_r^2} \right) \quad (\text{Equation 136})$$

where:

I_{kmax}	Maximum primary fundamental frequency fault current for internal close-in faults (A)
I_{tmax}	Maximum primary fundamental frequency fault current for through fault current for external faults (A)
I_{pr}	The rated primary CT current (A)
I_{sr}	The rated secondary CT current (A)
I_r	The rated current of the protection IED (A)
R_{ct}	The secondary resistance of the CT (Ω)
R_L	The resistance of the secondary wire and additional load (Ω). The loop resistance containing the phase and neutral wires must be used for faults in solidly earthed systems. The resistance of a single secondary wire should be used for faults in high impedance earthed systems.
S_R	The burden of an IED current input channel (VA). $S_R=0.020$ VA/channel for $I_r=1$ A and $S_R=0.150$ VA/channel for $I_r=5$ A

In substations with breaker-and-a-half or double-busbar double-breaker arrangement, the through fault current may pass two main CTs for the line differential protection without passing the protected

line. In such cases and if both main CTs have equal ratios and magnetization characteristics the CTs must satisfy equation 135 and equation 137.

$$E_{al} \geq E_{alreq} = I_{tfdb} \cdot \frac{I_{sr}}{I_{pr}} \cdot \left(R_{ct} + R_L + \frac{S_R}{I_r^2} \right)$$

(Equation 137)

where:

I_{tfdb} Maximum primary fundamental frequency through fault current that passes two main CTs (one-and-a-half or double-breaker) without passing the protected line (A)

If a power transformer is included in the protected zone of the line differential protection the CTs must also fulfill equation 138.

$$E_{al} \geq E_{alreq} = 30 \cdot I_{rt} \cdot \frac{I_{sr}}{I_{pr}} \cdot \left(R_{ct} + R_L + \frac{S_R}{I_r^2} \right)$$

(Equation 138)

where:

I_{rt} The rated primary current of the power transformer (A)

22.1.6.2 Distance protection

The current transformers must have a rated equivalent limiting secondary e.m.f. E_{al} that is larger than the maximum of the required rated equivalent limiting secondary e.m.f. E_{alreq} below:

$$E_{al} \geq E_{alreq} = \frac{I_{kmax} \cdot I_{sr}}{I_{pr}} \cdot a \cdot \left(R_{ct} + R_L + \frac{S_R}{I_r^2} \right)$$

(Equation 139)

$$E_{al} \geq E_{alreq} = \frac{I_{kzone1} \cdot I_{sr}}{I_{pr}} \cdot k \cdot \left(R_{ct} + R_L + \frac{S_R}{I_r^2} \right)$$

(Equation 140)

where:

I_{kmax}	Maximum primary fundamental frequency current for close-in forward and reverse faults (A)
I_{kzone1}	Maximum primary fundamental frequency current for faults at the end of zone 1 reach (A)
I_{pr}	The rated primary CT current (A)
I_{sr}	The rated secondary CT current (A)
I_r	The rated current of the protection IED (A)
R_{ct}	The secondary resistance of the CT (Ω)

Table continues on next page

R_L	The resistance of the secondary wire and additional load (Ω). In solidly earthed systems the loop resistance containing the phase and neutral wires should be used for phase-to-earth faults and the resistance of the phase wire should be used for three-phase faults. In isolated or high impedance earthed systems the resistance of the single secondary wire can always be used.
S_R	The burden of an IED current input channel (VA). $S_R=0.020$ VA/channel for $I_r=1$ A and $S_R=0.150$ VA/channel for $I_r=5$ A
a	This factor depends on the design of the protection function and can be a function of the primary DC time constant of the close-in fault current.
k	This factor depends on the design of the protection function and can be a function of the primary DC time constant of the fault current for a fault at the set reach of zone 1. The a- and k-factors have the following values for the different types of distance function: High speed distance: (ZMFDPDIS and ZMFCPDIS) Quadrilateral characteristic: $a = 1$ for primary time constant $T_p \leq 400$ ms $k = 3$ for primary time constant $T_p \leq 200$ ms Mho characteristic: $a = 2$ for primary time constant $T_p \leq 400$ ms (For $a = 1$ the delay in operation due to saturation is still under 1.5 cycles) $k = 3$ for primary time constant $T_p \leq 200$ ms Quadrilateral distance: (ZMQPDIS, ZMQAPDIS and ZMCPDIS, ZMCAPDIS and ZMMPDIS, ZMMAPDIS) $a = 1$ for primary time constant $T_p \leq 100$ ms $a = 3$ for primary time constant $T_p > 100$ and ≤ 400 ms $k = 4$ for primary time constant $T_p \leq 50$ ms $k = 5$ for primary time constant $T_p > 50$ and ≤ 150 ms Mho distance: (ZMHPDIS) $a = 1$ for primary time constant $T_p \leq 100$ ms $a = 3$ for primary time constant $T_p > 100$ and ≤ 400 ms $k = 4$ for primary time constant $T_p \leq 40$ ms $k = 5$ for primary time constant $T_p > 40$ and ≤ 150 ms

22.1.6.3 Breaker failure protection

The CTs must have a rated equivalent limiting secondary e.m.f. E_{al} that is larger than or equal to the required rated equivalent limiting secondary e.m.f. E_{alreq} below:

$$E_{al} \geq E_{alreq} = 5 \cdot I_{op} \cdot \frac{I_{sr}}{I_{pr}} \cdot \left(R_{ct} + R_L + \frac{S_R}{I_r^2} \right)$$

(Equation 141)

where:

I_{op}	The primary operate value (A)
I_{pr}	The rated primary CT current (A)
I_{sr}	The rated secondary CT current (A)
I_r	The rated current of the protection IED (A)
R_{ct}	The secondary resistance of the CT (Ω)
R_L	The resistance of the secondary cable and additional load (Ω). The loop resistance containing the phase and neutral wires, must be used for faults in solidly earthed systems. The resistance of a single secondary wire should be used for faults in high impedance earthed systems.
S_R	The burden of an IED current input channel (VA). $S_R=0.020$ VA/channel for $I_r=1$ A and $S_R=0.150$ VA/channel for $I_r=5$ A

22.1.7 Current transformer requirements for CTs according to other standards

All kinds of conventional magnetic core CTs are possible to use with the IEDs if they fulfill the requirements corresponding to the above specified expressed as the rated equivalent limiting secondary e.m.f. E_{al} according to the IEC 61869-2 standard. From different standards and available data for relaying applications it is possible to approximately calculate a secondary e.m.f. of the CT comparable with E_{al} . By comparing this with the required rated equivalent limiting secondary e.m.f. E_{alreq} it is possible to judge if the CT fulfills the requirements. The requirements according to some other standards are specified below.

22.1.7.1 Current transformers according to IEC 61869-2, class P, PR

A CT according to IEC 61869-2 is specified by the secondary limiting e.m.f. E_{ALF} . The value of the E_{ALF} is approximately equal to the corresponding E_{al} . Therefore, the CTs according to class P and PR must have a secondary limiting e.m.f. E_{ALF} that fulfills the following:

$$E_{ALF} > \max E_{alreq}$$

(Equation 142)

22.1.7.2 Current transformers according to IEC 61869-2, class PX, PXR (and old IEC 60044-6, class TPS and old British Standard, class X)

CTs according to these classes are specified approximately in the same way by a rated knee point e.m.f. E_{knee} (E_k for class PX and PXR, E_{kneeBS} for class X and the limiting secondary voltage U_{al} for TPS). The value of the E_{knee} is lower than the corresponding E_{al} according to IEC 61869-2. It is not possible to give a general relation between the E_{knee} and the E_{al} but normally the E_{knee} is approximately 80 % of the E_{al} . Therefore, the CTs according to class PX, PXR, X and TPS must have a rated knee point e.m.f. E_{knee} that fulfills the following:

$$E_{knee} \approx E_k \approx E_{kneeBS} \approx U_{al} > 0.8 \cdot (\text{maximum of } E_{alreq})$$

(Equation 143)

22.1.7.3 Current transformers according to ANSI/IEEE

Current transformers according to ANSI/IEEE are partly specified in different ways. A rated secondary terminal voltage U_{ANSI} is specified for a CT of class C. U_{ANSI} is the secondary terminal voltage the CT will deliver to a standard burden at 20 times rated secondary current without exceeding 10 % ratio correction. There are a number of standardized U_{ANSI} values for example, U_{ANSI} is 400 V for a C400 CT. A corresponding rated equivalent limiting secondary e.m.f. E_{alANSI} can be estimated as follows:

$$E_{alANSI} = |20 \cdot I_{sr} \cdot R_{ct} + U_{ANSI}| = |20 \cdot I_{sr} \cdot R_{ct} + 20 \cdot I_{sr} \cdot Z_{bANSI}|$$

(Equation 144)

where:

Z_{bANSI} The impedance (that is, with a complex quantity) of the standard ANSI burden for the specific C class (Ω)

U_{ANSI} The secondary terminal voltage for the specific C class (V)

The CTs according to class C must have a calculated rated equivalent limiting secondary e.m.f. E_{alANSI} that fulfils the following:

$$E_{alANSI} > \text{maximum of } E_{alreq}$$

(Equation 145)

A CT according to ANSI/IEEE is also specified by the knee point voltage $U_{kneeANSI}$ that is graphically defined from an excitation curve. The knee point voltage $U_{kneeANSI}$ normally has a lower value than the knee-point e.m.f. according to IEC and BS. $U_{kneeANSI}$ can approximately be estimated to 75 % of the corresponding E_{al} according to IEC 61869-2. Therefore, the CTs according to ANSI/IEEE must have a knee point voltage $U_{kneeANSI}$ that fulfils the following:

$$V_{kneeANSI} > 0.75 \cdot (\text{maximum of } E_{alreq})$$

(Equation 146)

22.2 Voltage transformer requirements

The performance of a protection function will depend on the quality of the measured input signal. Transients caused by capacitive voltage transformers (CVTs) can affect some protection functions.

Magnetic or capacitive voltage transformers can be used.

The capacitive voltage transformers (CVTs) should fulfill the requirements according to the IEC 61869-5 standard regarding ferro-resonance and transients. The ferro-resonance requirements of the CVTs are specified in chapter 6.502 of the standard.

The transient responses for three different standard transient response classes, T1, T2 and T3 are specified in chapter 6.503 of the standard. CVTs according to all classes can be used.

The protection IED has effective filters for these transients, which gives secure and correct operation with CVTs.

22.3 SNTP server requirements

The SNTP server to be used is connected to the local network, that is not more than 4-5 switches or routers away from the IED. The SNTP server is dedicated for its task, or at least equipped with a real-time operating system, that is not a PC with SNTP server software. The SNTP server should be stable, that is, either synchronized from a stable source like GPS, or local without synchronization. Using a local SNTP server without synchronization as primary or secondary server in a redundant configuration is not recommended.



The IED supports SNTPv4 (RFC2030).

22.4 PTP requirements

For PTP to perform properly, the Ethernet equipment that is used needs to be compliant with IEEE1588. The clocks used must follow the IEEE1588 standard BMC (Best Master Algorithm) and shall, for instance, not claim class 7 for a longer time than it can guarantee 1us absolute accuracy.

22.5 Sample specification of communication requirements for the protection and control terminals in digital telecommunication networks

The communication requirements are based on echo timing.

Bit Error Rate (BER) according to ITU-T G.821, G.826 and G.828

- $<10^{-6}$ according to the standard for data and voice transfer

Bit Error Rate (BER) for high availability of the differential protection

- $<10^{-8}$ - 10^{-9} during normal operation
- $<10^{-6}$ during disturbed operation

During disturbed conditions, the trip security function can cope with high bit error rates up to 10^{-5} or even up to 10^{-4} . The trip security can be configured to be independent of COMFAIL from the differential protection communication supervision, or blocked when COMFAIL is issued after receive error >100 ms. (Default).

Synchronization in SDH systems with G.703 E1 or IEEE C37.94

The G.703 E1, 2 Mbit shall be set according to ITU-T G.803, G.810-13

- One master clock for the actual network
- The actual port Synchronized to the SDH system clock at 2048 kbit
- Synchronization; bit synchronized, synchronized mapping
- Maximum clock deviation $<\pm 50$ ppm nominal, $<\pm 100$ ppm operational
- Jitter and Wander according to ITU-T G.823 and G.825
- Buffer memory <250 μ s, <100 μ s asymmetric difference
- Format: G 704 frame, structured etc.Format.
- No CRC-check

Synchronization in PDH systems connected to SDH systems

- Independent synchronization, asynchronous mapping
- The actual SDH port must be set to allow transmission of the master clock from the PDH-system via the SDH-system in transparent mode.
- Maximum clock deviation $<\pm 50$ ppm nominal, $<\pm 100$ ppm operational
- Jitter and Wander according to ITU-T G.823 and G.825
- Buffer memory <100 μ s
- Format: Transparent
- Maximum channel delay
- Loop time <40 ms continuous (2 x 20 ms)

IED with echo synchronization of differential clock (without GPS clock)

- Both channels must have the same route with maximum asymmetry of 0,2-0,5 ms, depending on set sensitivity of the differential protection.
- A fixed asymmetry can be compensated (setting of asymmetric delay in built in HMI or the parameter setting tool PST).

22.6 IEC/UCA 61850-9-2LE Merging unit requirements

The merging units that supply the IED with measured values via the process bus must fulfill the IEC/UCA 61850-9-2LE standard.

This part of the IEC 61850 is specifying "Communication Service Mapping (SCSM) – Sampled values over ISO/IEC 8802", in other words – sampled data over Ethernet. The 9-2 part of the IEC 61850

protocol uses also definitions from 7-2, "Basic communication structure for substation and feeder equipment – Abstract communication service interface (ACSI)". The set of functionality implemented in the IED (IEC/UCA 61850-9-2LE) is a subset of the IEC 61850-9-2. For example the IED covers the client part of the standard, not the server part.

The standard does not define the sample rate for data, but in the UCA users group recommendations there are indicated sample rates that are adopted, by consensus, in the industry.

There are two sample rates defined: 80 samples/cycle (4000 samples/sec. at 50Hz or 4800 samples/sec. at 60 Hz) for a merging unit "type1" and 256 samples/cycle for a merging unit "type2". The IED can receive data rates of 80 samples/cycle.

Note that the IEC/UCA 61850-9-2LE standard does not specify the quality of the sampled values, only the transportation. Thus, the accuracy of the current and voltage inputs to the merging unit and the inaccuracy added by the merging unit must be coordinated with the requirement for actual type of protection function.

Factors influencing the accuracy of the sampled values from the merging unit are for example anti aliasing filters, frequency range, step response, truncating, A/D conversion inaccuracy, time tagging accuracy etc.

In principle the accuracy of the current and voltage transformers, together with the merging unit, shall have the same quality as direct input of currents and voltages.

Section 23

Glossary

AC	Alternating current
ACC	Actual channel
ACT	Application configuration tool within PCM600
A/D converter	Analog-to-digital converter
ADBS	Amplitude deadband supervision
ADM	Analog digital conversion module, with time synchronization
AI	Analog input
ANSI	American National Standards Institute
AP	Access Point
AR	Autoreclosing
ASCT	Auxiliary summation current transformer
ASD	Adaptive signal detection
ASDU	Application service data unit
AWG	American Wire Gauge standard
BBP	Busbar protection
BFOC/2,5	Bayonet fiber optic connector
BFP	Breaker failure protection
BI	Binary input
BIM	Binary input module
BOM	Binary output module
BOS	Binary outputs status
BR	External bistable relay
BS	British Standards
BSR	Binary signal transfer function, receiver blocks
BST	Binary signal transfer function, transmit blocks
C37.94	IEEE/ANSI protocol used when sending binary signals between IEDs
CAM	Central Account Management
CAN	Controller Area Network. ISO standard (ISO 11898) for serial communication
CB	Circuit breaker
CBM	Combined backplane module
CCITT	Consultative Committee for International Telegraph and Telephony. A United Nations-sponsored standards body within the International Telecommunications Union.
CCM	CAN carrier module
CCVT	Capacitive Coupled Voltage Transformer
Class C	Protection Current Transformer class as per IEEE/ ANSI
CMPPS	Combined megapulses per second

CMT	Communication Management tool in PCM600
CO cycle	Close-open cycle
Codirectional	Way of transmitting G.703 over a balanced line. Involves two twisted pairs making it possible to transmit information in both directions
COM	Command
COMTRADE	Standard Common Format for Transient Data Exchange format for Disturbance recorder according to IEEE/ANSI C37.111, 1999 / IEC 60255-24
Contra-directional	Way of transmitting G.703 over a balanced line. Involves four twisted pairs, two of which are used for transmitting data in both directions and two for transmitting clock signals
COT	Cause of transmission
CPU	Central processing unit
CR	Carrier receive
CRC	Cyclic redundancy check
CROB	Control relay output block
CS	Carrier send
CT	Current transformer
CU	Communication unit
CVT or CCVT	Capacitive voltage transformer
DAR	Delayed autoreclosing
DARPA	Defense Advanced Research Projects Agency (The US developer of the TCP/IP protocol etc.)
DBDL	Dead bus dead line
DBLL	Dead bus live line
DC	Direct current
DFC	Data flow control
DFT	Discrete Fourier transform
DHCP	Dynamic Host Configuration Protocol
DIP-switch	Small switch mounted on a printed circuit board
DI	Digital input
DLLB	Dead line live bus
DNP	Distributed Network Protocol as per IEEE Std 1815-2012
DR	Disturbance recorder
DRAM	Dynamic random access memory
DRH	Disturbance report handler
DSP	Digital signal processor
DTT	Direct transfer trip scheme
ECT	Ethernet configuration tool
EHV network	Extra high voltage network
EIA	Electronic Industries Association
EMC	Electromagnetic compatibility

EMF	Electromotive force
EMI	Electromagnetic interference
EnFP	End fault protection
EPA	Enhanced performance architecture
ESD	Electrostatic discharge
F-SMA	Type of optical fiber connector
FAN	Fault number
FIPS	Federal Information Processing Standards
FCB	Flow control bit; Frame count bit
FOX 20	Modular 20 channel telecommunication system for speech, data and protection signals
FOX 512/515	Access multiplexer
FOX 6Plus	Compact time-division multiplexer for the transmission of up to seven duplex channels of digital data over optical fibers
FPN	Flexible product naming
FTP	File Transfer Protocol
FUN	Function type
G.703	Electrical and functional description for digital lines used by local telephone companies. Can be transported over balanced and unbalanced lines
GCM	Communication interface module with carrier of GPS receiver module
GDE	Graphical display editor within PCM600
GI	General interrogation command
GIS	Gas-insulated switchgear
GOOSE	Generic object-oriented substation event
GPS	Global positioning system
GSAL	Generic security application
GSE	Generic substation event
HDLC protocol	High-level data link control, protocol based on the HDLC standard
HFBR connector type	Plastic fiber connector
HLV circuit	Hazardous Live Voltage according to IEC60255-27
HMI	Human-machine interface
HSAR	High speed autoreclosing
HSR	High-availability Seamless Redundancy
HV	High-voltage
HVDC	High-voltage direct current
IDBS	Integrating deadband supervision
IEC	International Electrical Committee
IEC 60044-6	IEC Standard, Instrument transformers – Part 6: Requirements for protective current transformers for transient performance
IEC 60870-5-103	Communication standard for protection equipment. A serial master/slave protocol for point-to-point communication
IEC 61850	Substation automation communication standard

IEC 61850–8–1	Communication protocol standard
IEEE	Institute of Electrical and Electronics Engineers
IEEE 802.12	A network technology standard that provides 100 Mbits/s on twisted-pair or optical fiber cable
IEEE P1386.1	PCI Mezzanine Card (PMC) standard for local bus modules. References the CMC (IEEE P1386, also known as Common Mezzanine Card) standard for the mechanics and the PCI specifications from the PCI SIG (Special Interest Group) for the electrical EMF (Electromotive force).
IEEE 1686	Standard for Substation Intelligent Electronic Devices (IEDs) Cyber Security Capabilities
IED	Intelligent electronic device
IET600	Integrated engineering tool
I-GIS	Intelligent gas-insulated switchgear
IOM	Binary input/output module
Instance	When several occurrences of the same function are available in the IED, they are referred to as instances of that function. One instance of a function is identical to another of the same kind but has a different number in the IED user interfaces. The word "instance" is sometimes defined as an item of information that is representative of a type. In the same way an instance of a function in the IED is representative of a type of function.
IP	1. Internet protocol. The network layer for the TCP/IP protocol suite widely used on Ethernet networks. IP is a connectionless, best-effort packet-switching protocol. It provides packet routing, fragmentation and reassembly through the data link layer. 2. Ingression protection, according to IEC 60529
IP 20	Ingression protection, according to IEC 60529, level 20
IP 40	Ingression protection, according to IEC 60529, level 40
IP 54	Ingression protection, according to IEC 60529, level 54
IRF	Internal failure signal
IRIG-B:	InterRange Instrumentation Group Time code format B, standard 200
ITU	International Telecommunications Union
LAN	Local area network
LIB 520	High-voltage software module
LCD	Liquid crystal display
LDAPS	Lightweight Directory Access Protocol
LDCM	Line data communication module
LDD	Local detection device
LED	Light-emitting diode
LNT	LON network tool
LON	Local operating network
MCB	Miniature circuit breaker
MCM	Mezzanine carrier module
MPM	Main processing module
MVAL	Value of measurement

MVB	Multifunction vehicle bus. Standardized serial bus originally developed for use in trains.
NCC	National Control Centre
NOF	Number of grid faults
NUM	Numerical module
OCO cycle	Open-close-open cycle
OCF	Overcurrent protection
OLTC	On-load tap changer
OTEV	Disturbance data recording initiated by other event than start/pick-up
OV	Overvoltage
Overreach	A term used to describe how the relay behaves during a fault condition. For example, a distance relay is overreaching when the impedance presented to it is smaller than the apparent impedance to the fault applied to the balance point, that is, the set reach. The relay “sees” the fault but perhaps it should not have seen it.
PCI	Peripheral component interconnect, a local data bus
PCM	Pulse code modulation
PCM600	Protection and control IED manager
PC-MIP	Mezzanine card standard
PELV circuit	Protected Extra-Low Voltage circuit type according to IEC60255-27
PMC	PCI Mezzanine card
POR	Permissive overreach
POTT	Permissive overreach transfer trip
Process bus	Bus or LAN used at the process level, that is, in near proximity to the measured and/or controlled components
PRP	Parallel redundancy protocol
PSM	Power supply module
PST	Parameter setting tool within PCM600
PTP	Precision time protocol
PT ratio	Potential transformer or voltage transformer ratio
PUTT	Permissive underreach transfer trip
RASC	Synchrocheck relay, COMBIFLEX
RCA	Relay characteristic angle
RISC	Reduced instruction set computer
RMS value	Root mean square value
RS422	A balanced serial interface for the transmission of digital data in point-to-point connections
RS485	Serial link according to EIA standard RS485
RTC	Real-time clock
RTU	Remote terminal unit
SA	Substation Automation
SBO	Select-before-operate
SC	Switch or push button to close

SCL	Short circuit location
SCS	Station control system
SCADA	Supervision, control and data acquisition
SCT	System configuration tool according to standard IEC 61850
SDU	Service data unit
SELV circuit	Safety Extra-Low Voltage circuit type according to IEC60255-27
SFP	Small form-factor pluggable (abbreviation) Optical Ethernet port (explanation)
SLM	Serial communication module.
SMA connector	Subminiature version A, A threaded connector with constant impedance.
SMT	Signal matrix tool within PCM600
SMS	Station monitoring system
SNTP	Simple network time protocol – is used to synchronize computer clocks on local area networks. This reduces the requirement to have accurate hardware clocks in every embedded system in a network. Each embedded node can instead synchronize with a remote clock, providing the required accuracy.
SOF	Status of fault
SPA	Strömberg Protection Acquisition (SPA), a serial master/slave protocol for point-to-point and ring communication.
SRY	Switch for CB ready condition
ST	Switch or push button to trip
Starpoint	Neutral point of transformer or generator
SVC	Static VAr compensation
TC	Trip coil
TCS	Trip circuit supervision
TCP	Transmission control protocol. The most common transport layer protocol used on Ethernet and the Internet.
TCP/IP	Transmission control protocol over Internet Protocol. The de facto standard Ethernet protocols incorporated into 4.2BSD Unix. TCP/IP was developed by DARPA for Internet working and encompasses both network layer and transport layer protocols. While TCP and IP specify two protocols at specific protocol layers, TCP/IP is often used to refer to the entire US Department of Defense protocol suite based upon these, including Telnet, FTP, UDP and RDP.
TEF	Time delayed earth-fault protection function
TLS	Transport Layer Security
TM	Transmit (disturbance data)
TNC connector	Threaded Neill-Concelman, a threaded constant impedance version of a BNC connector
TP	Trip (recorded fault)
TPZ, TPY, TPX, TPS	Current transformer class according to IEC
TRM	Transformer Module. This module transforms currents and voltages taken from the process into levels suitable for further signal processing.
TYP	Type identification

UMT	User management tool
Underreach	A term used to describe how the relay behaves during a fault condition. For example, a distance relay is underreaching when the impedance presented to it is greater than the apparent impedance to the fault applied to the balance point, that is, the set reach. The relay does not “see” the fault but perhaps it should have seen it. See also Overreach.
UTC	Coordinated Universal Time. A coordinated time scale, maintained by the Bureau International des Poids et Mesures (BIPM), which forms the basis of a coordinated dissemination of standard frequencies and time signals. UTC is derived from International Atomic Time (TAI) by the addition of a whole number of "leap seconds" to synchronize it with Universal Time 1 (UT1), thus allowing for the eccentricity of the Earth's orbit, the rotational axis tilt (23.5 degrees), but still showing the Earth's irregular rotation, on which UT1 is based. The Coordinated Universal Time is expressed using a 24-hour clock, and uses the Gregorian calendar. It is used for aeroplane and ship navigation, where it is also sometimes known by the military name, "Zulu time." "Zulu" in the phonetic alphabet stands for "Z", which stands for longitude zero.
UV	Undervoltage
WEI	Weak end infeed logic
VT	Voltage transformer
3I₀	Three times zero-sequence current. Often referred to as the residual or the earth-fault current
3U₀	Three times the zero sequence voltage. Often referred to as the residual voltage or the neutral point voltage

Hitachi Energy Sweden AB
Grid Automation Products
SE-721 59 Västerås, Sweden
Phone +46 (0) 10 738 00 00

<https://hitachienergy.com/protection-control>



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