

RELION® 670 SERIES

Phasor measurement unit RES670

Version 2.2 ANSI

Application manual





Document ID: 1MRK 511 407-UUS
Issued: June 2018
Revision: C
Product version: 2.2

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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 ABB 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 and ANSI C37.90.

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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

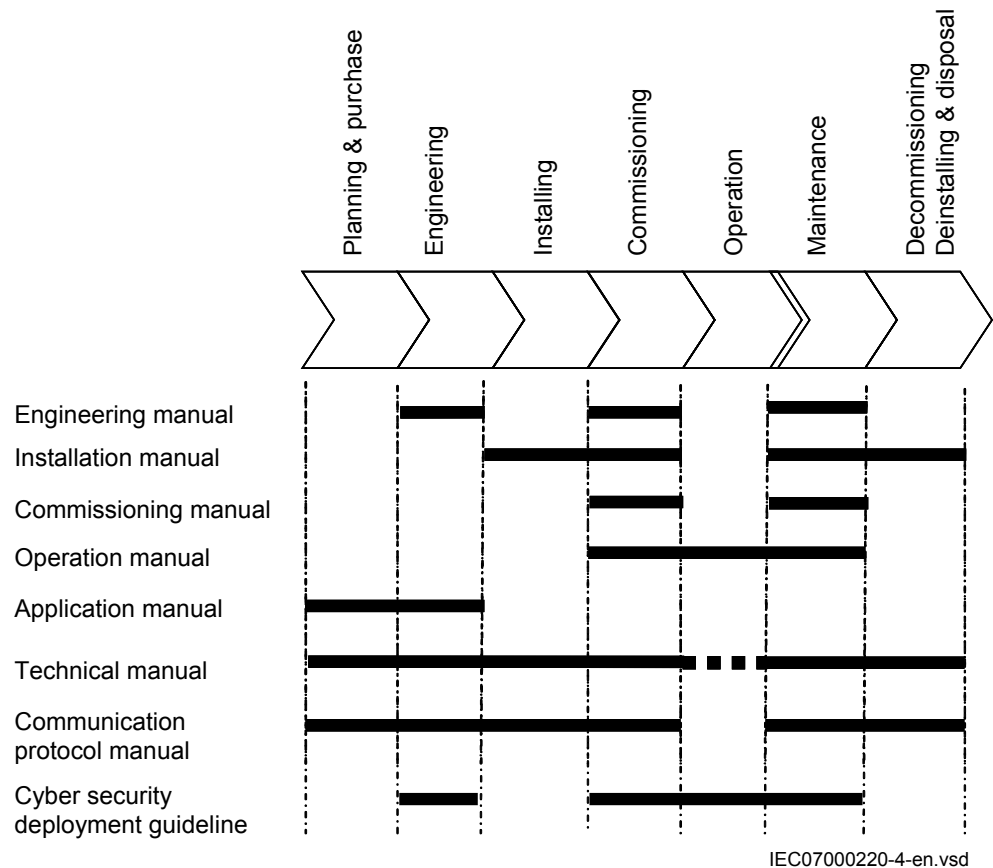


Figure 1: The intended use of manuals throughout the product lifecycle

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 substation 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	History
–/May 2017	First release
A/October 2017	Information updated
B/March 2018	2.2 Maintenance release 1
C/June 2018	Added new functions and resolved bugs

1.3.3 Related documents

Documents related to RES670	Document numbers
Application manual	1MRK 511 407-UUS
Commissioning manual	1MRK 511 409-UUS
Product guide	1MRK 511 410-BEN
Technical manual	1MRK 511 408-UUS
Type test certificate	1MRK 511 410-TUS

670 series manuals	Document numbers
Operation manual	1MRK 500 127-UUS
Engineering manual	1MRK 511 398-UUS
Installation manual	1MRK 514 026-UUS
Communication protocol manual, DNP3	1MRK 511 391-UUS
Communication protocol manual, IEC 61850 Edition 2	1MRK 511 393-UEN
Point list manual, DNP3	1MRK 511 397-UUS
Accessories guide	1MRK 514 012-BUS
Connection and Installation components	1MRK 513 003-BEN
Test system, COMBITEST	1MRK 512 001-BEN

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 mapping

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

Table 1: IEC 61850 edition 1 / edition 2 mapping

Function block name	Edition 1 logical nodes	Edition 2 logical nodes
AEGPVOC	AEGGAPC	AEGPVOC
AGSAL	AGSAL SECLLN0	AGSAL
ALMCALH	ALMCALH	ALMCALH
ALTIM	-	ALTIM
ALTMS	-	ALTMS
ALTRK	-	ALTRK
BCZPDIF	BCZPDIF	BCZPDIF
BCZSPDIF	BCZSPDIF	BCZSPDIF
BCZTPDIF	BCZTPDIF	BCZTPDIF
BDCGAPC	SWSGGIO	BBCSWI BDCGAPC
BDZSGAPC	BBS6LLN0 BDZSGAPC	LLN0 BDZSGAPC
BFPTRC_F01	BFPTRC	BFPTRC
BFPTRC_F02	BFPTRC	BFPTRC
BFPTRC_F03	BFPTRC	BFPTRC
BFPTRC_F04	BFPTRC	BFPTRC
BFPTRC_F05	BFPTRC	BFPTRC
BFPTRC_F06	BFPTRC	BFPTRC
BFPTRC_F07	BFPTRC	BFPTRC
BFPTRC_F08	BFPTRC	BFPTRC
Table continues on next page		

Function block name	Edition 1 logical nodes	Edition 2 logical nodes
BFPTRC_F09	BFPTRC	BFPTRC
BFPTRC_F10	BFPTRC	BFPTRC
BFPTRC_F11	BFPTRC	BFPTRC
BFPTRC_F12	BFPTRC	BFPTRC
BFPTRC_F13	BFPTRC	BFPTRC
BFPTRC_F14	BFPTRC	BFPTRC
BFPTRC_F15	BFPTRC	BFPTRC
BFPTRC_F16	BFPTRC	BFPTRC
BFPTRC_F17	BFPTRC	BFPTRC
BFPTRC_F18	BFPTRC	BFPTRC
BFPTRC_F19	BFPTRC	BFPTRC
BFPTRC_F20	BFPTRC	BFPTRC
BFPTRC_F21	BFPTRC	BFPTRC
BFPTRC_F22	BFPTRC	BFPTRC
BFPTRC_F23	BFPTRC	BFPTRC
BFPTRC_F24	BFPTRC	BFPTRC
BICPTRC_01	BICPTRC	BICPTRC
BICPTRC_02	BICPTRC	BICPTRC
BICPTRC_03	BICPTRC	BICPTRC
BICPTRC_04	BICPTRC	BICPTRC
BICPTRC_05	BICPTRC	BICPTRC
BRCPTOC	BRCPTOC	BRCPTOC
BRPTOC	BRPTOC	BRPTOC
BTIGAPC	B16IFCVI	BTIGAPC
BUSPTRC_B1	BUSPTRC BBSPLLN0	BUSPTRC
BUSPTRC_B2	BUSPTRC	BUSPTRC
BUSPTRC_B3	BUSPTRC	BUSPTRC
BUSPTRC_B4	BUSPTRC	BUSPTRC
BUSPTRC_B5	BUSPTRC	BUSPTRC
BUSPTRC_B6	BUSPTRC	BUSPTRC
BUSPTRC_B7	BUSPTRC	BUSPTRC
BUSPTRC_B8	BUSPTRC	BUSPTRC
BUSPTRC_B9	BUSPTRC	BUSPTRC
BUSPTRC_B10	BUSPTRC	BUSPTRC
BUSPTRC_B11	BUSPTRC	BUSPTRC
BUSPTRC_B12	BUSPTRC	BUSPTRC
Table continues on next page		

Function block name	Edition 1 logical nodes	Edition 2 logical nodes
BUSPTRC_B13	BUSPTRC	BUSPTRC
BUSPTRC_B14	BUSPTRC	BUSPTRC
BUSPTRC_B15	BUSPTRC	BUSPTRC
BUSPTRC_B16	BUSPTRC	BUSPTRC
BUSPTRC_B17	BUSPTRC	BUSPTRC
BUSPTRC_B18	BUSPTRC	BUSPTRC
BUSPTRC_B19	BUSPTRC	BUSPTRC
BUSPTRC_B20	BUSPTRC	BUSPTRC
BUSPTRC_B21	BUSPTRC	BUSPTRC
BUSPTRC_B22	BUSPTRC	BUSPTRC
BUSPTRC_B23	BUSPTRC	BUSPTRC
BUSPTRC_B24	BUSPTRC	BUSPTRC
BUTPTRC_B1	BUTPTRC BBTPLL0	BUTPTRC
BUTPTRC_B2	BUTPTRC	BUTPTRC
BUTPTRC_B3	BUTPTRC	BUTPTRC
BUTPTRC_B4	BUTPTRC	BUTPTRC
BUTPTRC_B5	BUTPTRC	BUTPTRC
BUTPTRC_B6	BUTPTRC	BUTPTRC
BUTPTRC_B7	BUTPTRC	BUTPTRC
BUTPTRC_B8	BUTPTRC	BUTPTRC
BZISGGIO	BZISGGIO	BZISGAPC
BZITGGIO	BZITGGIO	BZITGAPC
BZNPDIF_Z1	BZNPDIF	BZNPDIF
BZNPDIF_Z2	BZNPDIF	BZNPDIF
BZNPDIF_Z3	BZNPDIF	BZNPDIF
BZNPDIF_Z4	BZNPDIF	BZNPDIF
BZNPDIF_Z5	BZNPDIF	BZNPDIF
BZNPDIF_Z6	BZNPDIF	BZNPDIF
BZNSPDIF_A	BZNSPDIF	BZASGAPC BZASPDIF BZNSGAPC BZNSPDIF
BZNSPDIF_B	BZNSPDIF	BZBSGAPC BZBSPDIF BZNSGAPC BZNSPDIF
Table continues on next page		

Function block name	Edition 1 logical nodes	Edition 2 logical nodes
BZNTPDIF_A	BZNTPDIF	BZATGAPC BZATPDIF BZNTGAPC BZNTPDIF
BZNTPDIF_B	BZNTPDIF	BZBTGAPC BZBTPDIF BZNTGAPC BZNTPDIF
CBPGAPC	CBPLL0 CBPMMXU CBPPTRC HOLPTOV HPH1PTOV PH3PTUC PH3PTOC RP3PDOP	CBPMMXU CBPPTRC HOLPTOV HPH1PTOV PH3PTOC PH3PTUC RP3PDOP
CCPDSC	CCRPLD	CCPDSC
CCRBRF	CCRBRF	CCRBRF
CCRWRBRF	CCRWRBRF	CCRWRBRF
CCSRBRF	CCSRBRF	CCSRBRF
CCSSPVC	CCSRDIF	CCSSPVC
CMMXU	CMMXU	CMMXU
CMSQI	CMSQI	CMSQI
COUVGAPC	COUVLLN0 COUVPTOV COUVPTUV	COUVPTOV COUVPTUV
CVGAPC	GF2LLN0 GF2MMXN GF2PHAR GF2PTOV GF2PTUC GF2PTUV GF2PVOC PH1PTRC	GF2MMXN GF2PHAR GF2PTOV GF2PTUC GF2PTUV GF2PVOC PH1PTRC
CVMMXN	CVMMXN	CVMMXN
D2PTOC	D2LLN0 D2PTOC PH1PTRC	D2PTOC PH1PTRC
DPGAPC	DPGGIO	DPGAPC
DRPRDRE	DRPRDRE	DRPRDRE
ECPSCH	ECPSCH	ECPSCH
ECRWPSCH	ECRWPSCH	ECRWPSCH
EF2PTOC	EF2LLN0 EF2PTRC EF2RDIR GEN2PHAR PH1PTOC	EF2PTRC EF2RDIR GEN2PHAR PH1PTOC
Table continues on next page		

Function block name	Edition 1 logical nodes	Edition 2 logical nodes
EF4PTOC	EF4LLN0 EF4PTRC EF4RDIR GEN4PHAR PH1PTOC	EF4PTRC EF4RDIR GEN4PHAR PH1PTOC
EFPIOC	EFPIOC	EFPIOC
EFRWPIOC	EFRWPIOC	EFRWPIOC
ETPMTR	ETPMTR	ETPMTR
FDPSPDIS	FDPSPDIS	FDPSPDIS
FMPSPDIS	FMPSPDIS	FMPSPDIS
FRPSPDIS	FPSRPDIS	FPSRPDIS
FTAQFVR	FTAQFVR	FTAQFVR
FUFSPVC	SDDRFUF	FUFSPVC SDDSPVC
GENPDIF	GENPDIF	GENGAPC GENPDIF GENPHAR GENPTRC
GOPPDOP	GOPPDOP	GOPPDOP PH1PTRC
GRPTTR	GRPTTR	GRPTTR
GSPTTR	GSPTTR	GSPTTR
GUPPDUP	GUPPDUP	GUPPDUP PH1PTRC
HZPDIF	HZPDIF	HZPDIF
INDCALCH	INDCALH	INDCALH
ITBGAPC	IB16FCVB	ITBGAPC
L3CPDIF	L3CPDIF	L3CGAPC L3CPDIF L3CPHAR L3CPTRC
L4CPDIF	L4CLLN0 L4CPDIF L4CPTRC	LLN0 L4CGAPC L4CPDIF L4CPSCH L4CPTRC
L4UFCNT	L4UFCNT	L4UFCNT
L6CPDIF	L6CPDIF	L6CGAPC L6CPDIF L6CPHAR L6CPTRC
LAPPGAPC	LAPLLN0 LAPPPDUP LAPPPUPF	LAPPPDUP LAPPPUPF
LCCRPTRC	LCCRPTRC	LCCRPTRC
Table continues on next page		

Function block name	Edition 1 logical nodes	Edition 2 logical nodes
LCNSPTOC	LCNSPTOC	LCNSPTOC
LCNSPTOV	LCNSPTOV	LCNSPTOV
LCP3PTOC	LCP3PTOC	LCP3PTOC
LCP3PTUC	LCP3PTUC	LCP3PTUC
LCPTTR	LCPTTR	LCPTTR
LCZSPTOC	LCZSPTOC	LCZSPTOC
LCZSPTOV	LCZSPTOV	LCZSPTOV
LD0LLN0	LLN0	-
LDLPSC	LDLPDIF	LDLPSC
LDRGFC	STSGGIO	LDRGFC
LEXPDIS	LEXPDIS	LEXPDIS LEXPTRC
LFPTTR	LFPTTR	LFPTTR
LMBRFLO	LMBRFLO	LMBRFLO
LOLSPTR	LOLSPTR	LOLSPTR
LOVPTUV	LOVPTUV	LOVPTUV
LPHD	LPHD	
LPTTR	LPTTR	LPTTR
LT3CPDIF	LT3CPDIF	LT3CGAPC LT3CPDIF LT3CPHAR LT3CPTRC
LT6CPDIF	LT6CPDIF	LT6CGAPC LT6CPDIF LT6CPHAR LT6CPTRC
MVGAPC	MVGGIO	MVGAPC
NS2PTOC	NS2LLN0 NS2PTOC NS2PTRC	NS2PTOC NS2PTRC
NS4PTOC	EF4LLN0 EF4PTRC EF4RDIR GEN4PHAR PH1PTOC	EF4PTRC EF4RDIR PH1PTOC
O2RWPTOV	GEN2LLN0 O2RWPTOV PH1PTRC	O2RWPTOV PH1PTRC
OC4PTOC	OC4LLN0 GEN4PHAR PH3PTOC PH3PTRC	GEN4PHAR PH3PTOC PH3PTRC
OEXPVPH	OEXPVPH	OEXPVPH
Table continues on next page		

Function block name	Edition 1 logical nodes	Edition 2 logical nodes
OOSPPAM	OOSPPAM	OOSPPAM OOSPTRC
OV2PTOV	GEN2LLN0 OV2PTOV PH1PTRC	OV2PTOV PH1PTRC
PAPGAPC	PAPGAPC	PAPGAPC
PCFCNT	PCGGIO	PCFCNT
PH4SPTOC	GEN4PHAR OCNDLLN0 PH1BPTOC PH1PTRC	GEN4PHAR PH1BPTOC PH1PTRC
PHPIOC	PHPIOC	PHPIOC
PSLPSCH	ZMRPSL	PSLPSCH
PSPPPAM	PSPPPAM	PSPPPAM PSPPTRC
QCBAY	QCBAY	BAY/LLN0
QCRSV	QCRSV	QCRSV
RCHLCCH	RCHLCCH	RCHLCCH
REFPDIF	REFPDIF	REFPDIF
ROTIPHIZ	ROTIPHIZ	ROTIPHIZ ROTIPTRC
ROV2PTOV	GEN2LLN0 PH1PTRC ROV2PTOV	PH1PTRC ROV2PTOV
SAPFRC	SAPFRC	SAPFRC
SAPTOF	SAPTOF	SAPTOF
SAPTUF	SAPTUF	SAPTUF
SCCVPTOC	SCCVPTOC	SCCVPTOC
SCHLCCH	SCHLCCH	SCHLCCH
SCILO	SCILO	SCILO
SCSWI	SCSWI	SCSWI
SDEPSDE	SDEPSDE	SDEPSDE SDEPTOC SDEPTOV SDEPTRC
SESRSYN	RSY1LLN0 AUT1RSYN MAN1RSYN SYNRSYN	AUT1RSYN MAN1RSYN SYNRSYN
SLGAPC	SLGGIO	SLGAPC
SMBRREC	SMBRREC	SMBRREC
SMPPTRC	SMPPTRC	SMPPTRC
Table continues on next page		

Function block name	Edition 1 logical nodes	Edition 2 logical nodes
SP16GAPC	SP16GGIO	SP16GAPC
SPC8GAPC	SPC8GGIO	SPC8GAPC
SPGAPC	SPGGIO	SPGAPC
SSCBR	SSCBR	SSCBR
SSIMG	SSIMG	SSIMG
SSIML	SSIML	SSIML
PTRSTHR	PTRSTHR	PTRSTHR
STBPTOC	STBPTOC	BBPMSS STBPTOC
STEFPHIZ	STEFPHIZ	STEFPHIZ
STTIPHIZ	STTIPHIZ	STTIPHIZ
SXCBR	SXCBR	SXCBR
SXSWI	SXSWI	SXSWI
T2WPDIF	T2WPDIF	T2WGAPC T2WPDIF T2WPHAR T2WPTRC
T3WPDIF	T3WPDIF	T3WGAPC T3WPDIF T3WPHAR T3WPTRC
TCLYLTC	TCLYLTC	TCLYLTC TCSLTC
TCMYLTC	TCMYLTC	TCMYLTC
TEIGAPC	TEIGGIO	TEIGAPC TEIGGIO
TEILGAPC	TEILGGIO	TEILGAPC
TMAGAPC	TMAGGIO	TMAGAPC
TPPIOC	TPPIOC	TPPIOC
TR1ATCC	TR1ATCC	TR1ATCC
TR8ATCC	TR8ATCC	TR8ATCC
TRPTTR	TRPTTR	TRPTTR
U2RWPTUV	GEN2LLN0 PH1PTRC U2RWPTUV	PH1PTRC U2RWPTUV
UV2PTUV	GEN2LLN0 PH1PTRC UV2PTUV	PH1PTRC UV2PTUV
VDCPTOV	VDCPTOV	VDCPTOV
VDSPVC	VDRFUF	VDSPVC
VMMXU	VMMXU	VMMXU
Table continues on next page		

Function block name	Edition 1 logical nodes	Edition 2 logical nodes
VMSQI	VMSQI	VMSQI
VNMMXU	VNMMXU	VNMMXU
VRPVOC	VRLLN0 PH1PTRC PH1PTUV VRPVOC	PH1PTRC PH1PTUV VRPVOC
VSGAPC	VSGGIO	VSGAPC
WRNCALH	WRNCALH	WRNCALH
ZC1PPSCH	ZPCPSCH	ZPCPSCH
ZC1WPSCH	ZPCWPSCH	ZPCWPSCH
ZCLCPSCH	ZCLCPLAL	ZCLCPSCH
ZCPSCH	ZCPSCH	ZCPSCH
ZCRWPSCH	ZCRWPSCH	ZCRWPSCH
ZCVPSOF	ZCVPSOF	ZCVPSOF
ZGVPDIS	ZGVLLN0 PH1PTRC ZGVPDIS ZGVPTUV	PH1PTRC ZGVPDIS ZGVPTUV
ZMCAPDIS	ZMCAPDIS	ZMCAPDIS
ZMCPDIS	ZMCPDIS	ZMCPDIS
ZMFCPDIS	ZMFLLN0 PSFPDIS ZMFPDIS ZMFPTRC ZMMMIXU	PSFPDIS ZMFPDIS ZMFPTRC ZMMMIXU
ZMFPDIS	ZMFLN0 PSFPDIS ZMFPDIS ZMFPTRC ZMMMIXU	PSFPDIS PSFPDIS ZMFPDIS ZMFPTRC ZMMMIXU
ZMHPDIS	ZMHPDIS	ZMHPDIS
ZMMAPDIS	ZMMAPDIS	ZMMAPDIS
ZMMPDIS	ZMMPDIS	ZMMPDIS
ZMQAPDIS	ZMQAPDIS	ZMQAPDIS
ZMQPDIS	ZMQPDIS	ZMQPDIS
ZMRAPDIS	ZMRAPDIS	ZMRAPDIS
ZMRPDIS	ZMRPDIS	ZMRPDIS
ZMRPSB	ZMRPSB	ZMRPSB
ZSMGAPC	ZSMGAPC	ZSMGAPC

Section 2 Application

2.1 General IED application

RES670 is a Phasor Measurement Unit (PMU) that provides power system AC voltages and currents as phasors for all voltage levels in power system networks. Phasors are provided as real and imaginary or as magnitude and phase angle. The reference for the phase angle may be either a PTP time synchronization source or the NavStar Global Positioning System - GPS, both supplying highly accurate time and date. The measured data in each PMU is time synchronized via one of the mentioned time synchronization sources - with an accuracy of one microsecond - and transmitted to Phasor Data Concentrators (every 100 milliseconds, for example). The accurate time tagging of measurements taken at different geographical locations makes it possible to derive the synchronized phasor quantities (synchrophasors). Based on synchrophasors, a number of power system applications are available.

The PMUs are installed at substation level, and can be connected directly to the current and voltage transformers within the substations. Each RES670 may be fitted with different options for time synchronization: PTP via the Ethernet network, via the GPS system with an own antenna for the RES670, or via the IRIG-B signal received from an external GPS-based clock. It is also possible to have a combination of the three to provide time synchronization redundancy for the PMU. RES670 streams out its synchrophasor data according to IEEE C37.118 and/or IEEE 1344 standards for synchrophasor data streaming and with user-selectable reporting rates. RES670 supports reporting rates of 10, 25, 50, 100, and 200 frames per second for 50Hz system (or 10, 12, 15, 30, 60, 120, and 240 frames per second for 60Hz system). Each RES670 can communicate its synchrophasor data to up to eight independent clients over TCP and/or six independent UDP channels (unicast/multicast), simultaneously. More information is available in RES670 Application Manual under [Wide Area Measurement System](#) section.

In addition to the synchrophasor communication standard (IEEE 1344, IEEE C37.118), RES670 is also compliant to IEC 61850-8-1 standard for integration to substation automation systems and exchange of GOOSE messages, when necessary. RES670 is able to communicate over IEC 62439-3 PRP for redundant station bus communication for both IEEE C37.118 and IEC 61850-8-1, simultaneously.

[Figure 2](#) shows an example of a system architecture for a Wide Area Monitoring System (WAMS). PMUs are the building blocks for a WAMS. The architecture of a WAMS consists of the following main components:

- **PMU** Phasor Measurement Unit, including all accessories for time synchronization
- **TCP/IP** and/or **UDP/IP** communication network infra-structure
- **PDC** Phasor Data Concentrator, including wide area applications

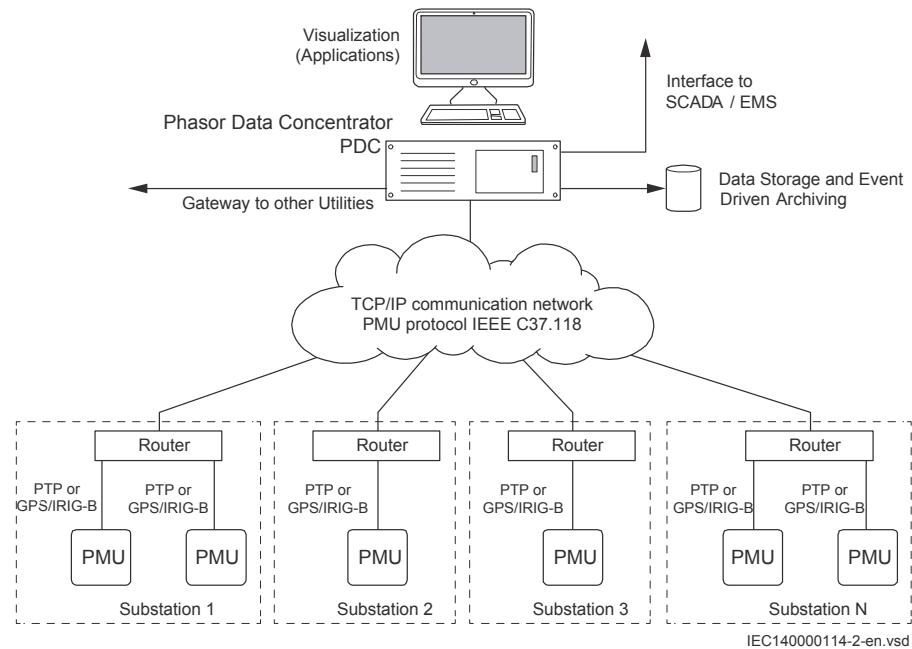


Figure 2: Wide Area Monitoring System architecture — overview

A Wide Area Monitoring System collects, stores, transmits and provides ways to analyze critical data from key points across the power networks and over large geographical areas. The architecture of the WAMS can provide a scalable solution, from small installations for data collection and basic visualization (PDC) to larger systems with intelligent monitoring using wide area applications. The Wide Area Monitoring applications are designed to detect abnormal system conditions and evaluate large area disturbances in order to preserve system integrity and maintain acceptable power system performance.

The WAMS is configured in a way to acquire synchrophasor data from several PMUs. Based on the data collected in the PDCs, WAMS is able to present the state of the grid to the power system operator, and to provide monitoring of the power system based on real-time measurements and the results of on-line applications. In addition, the data available from PDCs enables off-line analysis of the power system for post-disturbance assessments. It is possible to communicate the PMU measurements and the results of the advanced applications to SCADA/EMS systems as a way to improve the supervision of the system, providing the operator with a clear indication how likely the system is to collapse, thus giving the possibility to react in time.

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, IOM & SOM) 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 exposed in all IEC 61850 communication, 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.

2.2 Wide area measurement functions

IEC 61850	ANSI	Function description	Phasor measurement RES670 (Customized)
PMUCONF		Configuration parameters for C37.118 2011 and IEEE1344 protocol	1
PMUREPORT		Protocol reporting via IEEE1344 and C37.118	1-2
PHASORREPO RT1		Protocol reporting of phasor data via IEEE 1344 and C37.118, phasors 1-8	1-2
PHASORREPO RT2		Protocol reporting of phasor data via IEEE 1344 and C37.118, phasors 9-16	0-2
PHASORREPO RT3		Protocol reporting of phasor data via IEEE 1344 and C37.118, phasors 17-24	0-2
PHASORREPO RT4		Protocol reporting of phasor data via IEEE 1344 and C37.118, phasors 25-32	0-2
ANALOGREPO RT1		Protocol reporting of analog data via IEEE 1344 and C37.118, analogs 1-8	0-2
ANALOGREPO RT2		Protocol reporting of analog data via IEEE 1344 and C37.118, analogs 9-16	0-2
ANALOGREPO RT3		Protocol reporting of analog data via IEEE 1344 and C37.118, analogs 17-24	0-2

Table continues on next page

IEC 61850	ANSI	Function description	Phasor measurement RES670 (Customized)
BINARYREPO RT1		Protocol reporting of binary data via IEEE 1344 and C37.118, binary 1-8	0-2
BINARYREPO RT2		Protocol reporting of binary data via IEEE 1344 and C37.118, binary 9-16	0-2
BINARYREPO RT3		Protocol reporting of binary data via IEEE 1344 and C37.118, binary 17-24	0-2
PMSTATUS		Diagnostics for C37.118 2011 and IEEE1344 protocol	1

2.3 Back-up protection functions

IEC 61850 or function name	ANSI	Function description	RES670 (Customized)
Impedance protection			
ZMRPSB	68	Power swing detection	0-1
OOSPPAM	78	Out-of-step protection	0-2
Current protection			
OC4PTOC	51_67 ¹⁾	Directional phase overcurrent protection, four steps	0-6
EF4PTOC	51N 67N ²⁾	Directional residual overcurrent protection, four steps	0-6
NS4PTOC	46I2	Four step directional negative phase sequence overcurrent protection	0-6
SDEPSDE	67N	Sensitive directional residual overcurrent and power protection	0-6
LCPTTR	26	Thermal overload protection, one time constant, Celsius	0-6
LFPTTR	26	Thermal overload protection, one time constant, Fahrenheit	0-6
GUPPDUP	37	Directional underpower protection	0-4
GOPPDOP	32	Directional overpower protection	0-4
Voltage protection			
UV2PTUV	27	Two step undervoltage protection	0-4
OV2PTOV	59	Two step overvoltage protection	0-4
Frequency protection			
SAPTUF	81	Underfrequency protection	0-6
SAPTOF	81	Overfrequency protection	0-6
SAPFRC	81	Rate-of-change of frequency protection	0-6

Table continues on next page

IEC 61850 or function name	ANSI	Function description	RES670 (Customized)
FTAQFVR	81A	Frequency time accumulation protection	0-4
Multipurpose protection			
CVGAPC		General current and voltage protection	0-8
General calculation			
SMAHPAC		Multipurpose filter	0-6

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

2.4 Control and monitoring functions

IEC 61850 or function name	ANSI	Function description	Phasor measurement unit
			RES670 (Customized)
Control			
QCBAY		Bay control	1
LOCREM		Handling of LR-switch positions	1
LOCREMCTRL		LHMI control of PSTO	1
SXCBR		Circuit breaker	18
SLGAPC		Logic rotating switch for function selection and LHMI presentation	15
VSGAPC		Selector mini switch	30
DPGAPC		Generic communication function for Double Point indication	32
SPC8GAPC		Single point generic control function 8 signals	5
AUTOBITS		Automation bits, command function for DNP3.0	3
SINGLECMD		Single command, 16 signals	4
I103CMD		Function commands for IEC 60870-5-103	1

Table continues on next page

IEC 61850 or function name	ANSI	Function description	Phasor measurement unit RES670 (Customized)
I103GENCMD		Function commands generic for IEC 60870-5-103	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			
CCSSPVC	87	Current circuit supervision	0-5
FUFSPVC		Fuse failure supervision	0-4
Logic			
SMPPTRC	94	Tripping logic	12
SMAGAPC		General start matrix block	12
TMAGAPC		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 2)	40-420
ANDQT, INDCOMBSPQT, INDEXTSPQT, INVALIDQT, INVERTERQT, ORQT, PULSETIMERQT, RSMEMORYQT, SRMEMORYQT, TIMERSETQT, XORQT		Configurable logic blocks Q/T (see Table 3)	0-1

Table continues on next page

IEC 61850 or function name	ANSI	Function description	Phasor measurement unit		
			RES670 (Customized)		
AND, GATE, INV, LLD, OR, PULSETIMER, RSMEMORY, SLGAPC, SRMEMORY, TIMERSET, VSGAPC, XOR		Extension logic package (see Table 4)	0-1		
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	18		
ITBGAPC		Integer to Boolean 16 conversion with Logic Node representation	16		
TEIGAPC		Elapsed time integrator with limit transgression and overflow supervision	12		
INTCOMP		Comparator for integer inputs	30		
REALCOMP		Comparator for real inputs	30		

Table 2: 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	298
PULSETIMER	40
RSMEMORY	40
SRMEMORY	40
TIMERSET	60
XOR	40

Table 3: Total number of instances for configurable logic blocks Q/T

Configurable logic blocks Q/T	Total number of instances
ANDQT	120
INDCOMBSPQT	20
INDEXTSPQT	20
INVALIDQT	22
INVERTERQT	120
ORQT	120
PULSETIMERQT	40
RSMEMORYQT	40
SRMEMORYQT	40
TIMERSETQT	40
XORQT	40

Table 4: Total number of instances for extended logic package

Extended configurable logic block	Total number of instances
AND	220
GATE	49
INV	220
LLD	49
OR	220
PULSETIMER	89
RSMEMORY	40
SLGAPC	74
SRMEMORY	130
TIMERSET	113
VSGAPC	120
XOR	89

IEC 61850 or function name	ANSI	Function description	Phasor measurement unit
			RES670 (Customized)
Monitoring			
CVMMXN		Power system measurement	6
CMMXU		Current measurement	10

Table continues on next page

IEC 61850 or function name	ANSI	Function description	Phasor measurement unit
			RES670 (Customized)
VMMXU		Voltage measurement phase-phase	6
CMSQI		Current sequence measurement	6
VMSQI		Voltage sequence measurement	6
VNMMXU		Voltage measurement phase-ground	6
AISVBAS		General service value presentation of analog inputs	1
EVENT		Event function	20
DRPRDRE, A4RADR, B1RBDR-B22RBDR		Disturbance report	1
SPGAPC		Generic communication function for Single Point indication	96
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
SSIMG	63	Insulation supervision for gas medium	21
SSIML	71	Insulation supervision for liquid medium	3
SSCBR		Circuit breaker condition monitoring	0-18
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

Table continues on next page

IEC 61850 or function name	ANSI	Function description	Phasor measurement unit
			RES670 (Customized)
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
Metering			
PCFCNT		Pulse-counter logic	16
ETPMTR		Function for energy calculation and demand handling	6

2.5 Communication

IEC 61850 or function name	ANSI	Function description	Phasor measurement unit
			RES670 (Customized)
Station communication			
ADE		LON communication protocol	1
HORZCOMM		Network variables via LON	1
IEC 61850-8-1		IEC 61850	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
GOOSEMVRCV		GOOSE function block to receive a measurand value	60
GOOSESPRCV		GOOSE function block to receive a single point value	64

Table continues on next page

IEC 61850 or function name	ANSI	Function description	Phasor measurement unit
			RES670 (Customized)
MULTICMDRCV, MULTICMDSND		Multiple command and transmit	60/10
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
FSTACCS		Field service tool access	1
		IEC 61850-9-2 Process bus communication, 8 merging units	0-1
ACTIVLOG		Activity logging	1
ALTRK		Service tracking	1
PRP		IEC 62439-3 Parallel redundancy protocol	0-1
HSR		IEC 62439-3 High-availability seamless redundancy	0-1
PMUSTATUS		Diagnostics for C37.118 2011 and IEEE1344 protocol	1
PTP		Precision time protocol	1
SCHLCCH		Access point diagnostic for non-redundant Ethernet port	6
RCHLCCH		Access point diagnostic for redundant Ethernet ports	3
Remote communication			

2.6 Basic IED functions

Table 5: Basic IED functions

IEC 61850 or function name	Description
INTERRSIG	Self supervision with internal event list
TIMESYNCHGEN	Time synchronization module
SYNCHCAN, SYNCHCMPPS, SYNCHPPS, SYNCHCMPPS	Time synchronization
TIMEZONE	Time synchronization
IRIG-B	Time synchronization
Table continues on next page	

IEC 61850 or function name	Description
SETGRPS	Number of setting groups
ACTVGRP	Parameter setting groups
TESTMODE	Test mode functionality
CHNGLCK	Change lock function
SMBI	Signal matrix for binary inputs
SMBO	Signal matrix for binary outputs
SMMI	Signal matrix for mA inputs
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
GBASVAL	Global base values for settings
ALTMS	Time master supervision
ALTIM	Time management
COMSTATUS	Protocol diagnostic

Table 6: *Local HMI functions*

IEC 61850 or function name	ANSI	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 Introduction

3.2 Description of configuration RES670

3.2.1 Introduction

3.2.1.1 Description of configuration A20

The configuration of the IED is shown in [figure 3](#).

RES670 A20 configuration is applicable for a typical single busbar single breaker arrangement monitoring up to three bays. RES670 A20 is delivered in 1/2, 3/4 and full (1/1)19" rack casing. For this application 12 analog inputs are used, thus only one transformer module (TRM) with 12 analog inputs (9I+3U) is available in A20 standard configuration. As shown in [figure 3](#), RES670 A20 configuration as a PMU is measuring one 3-phase voltage of the busbar and three 3-phase currents of bays 1 to 3. There are two instances of PMU reporting functionality available in A20 configuration, meaning two independent IEEE C37.118/1344 data streams. In the standard A20 configuration, each instance of PMU, in addition to frequency-deviation and rate-of-change-of-frequency data, is reporting 16 synchrophasors over IEEE C37.118/1344; that is four 3-phase synchrophasors and 12 single phase synchrophasors in each data stream corresponding to the AC voltage and current measurements.

In addition, each data stream includes 8 analog and 8 binary reporting channels over IEEE C37.118/1344 in the standard configuration. The number of analog and binary reporting channels can be extended to maximum 24 channels per PMU instance (on each data stream) on request. This can be done when ordering the RES670 A20 configuration. In the standard A20 configuration, the analog reporting channels are used for reporting P and Q measurements from each bay over IEEE C37.118/1344.

In addition to the binary reporting channels, there are 4 trigger bits (FREQTRIG, DFDTRIG, OCTRIG and UVTRIG) available per PMU instance, which are used to report the existing protection function triggers over IEEE C37.118/1344.

The main functionality of the RES670 is synchrophasor reporting or PMU functionality. In addition, this configuration also includes general back-up protection functions which are mainly intended for alarm purposes. Available protection functions in standard A20 configuration are Overvoltage, Undervoltage, Overfrequency, Underfrequency and Rate-of-change frequency.

Measuring functions for S, P, Q, I, V, PF, f are available for local presentation on the local HMI and remote presentation via IEEE C37.118/1344 and/or via IEC 61850. The calibration parameters on the measurement function allows calibration at site to very high accuracy.

As shown in [figure 3](#), there are optional functions such as ground fault protection (EF4 PTOC), Overcurrent protection (OC4 PTOC), Under/Over power protection (GUPPDUP, GOPPDOP), etc. which can be added per request. RES670 A20 function library also includes additional functions, which are available but not configured. Note that RES670 A20 must be reconfigured if any additional functions are used.

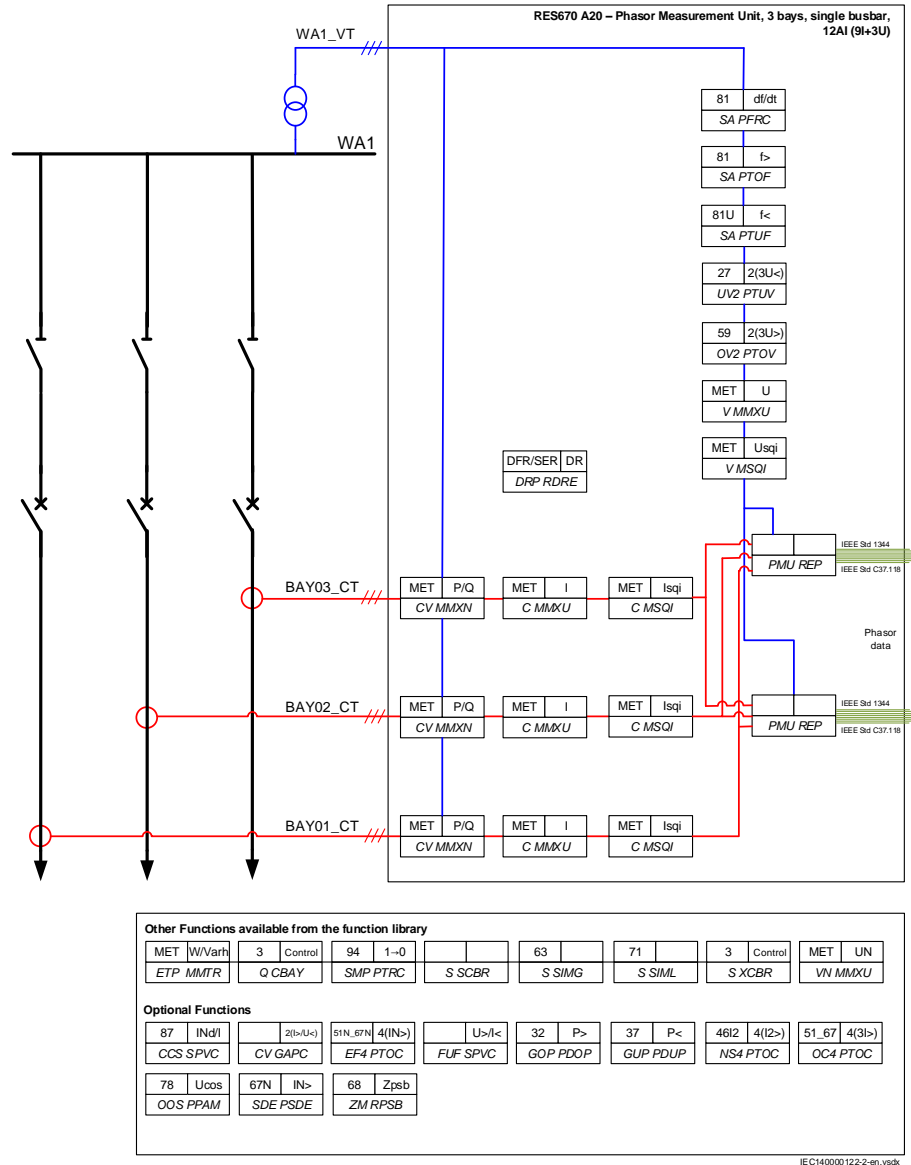


Figure 3: Configuration diagram for configuration A20

3.2.1.2

Description of configuration B20

The configuration of the IED is shown in [figure 4](#).

RES670 B20 configuration is applicable for a typical double busbar single breaker arrangement monitoring up to six bays. RES670 B20 is delivered in ¼, and full

(1/1)19" rack casing. For this application 24 analog inputs are used, thus two transformer modules (TRM) with 12 analog inputs (9I+3U) per TRM are available in B20 standard configuration. As shown in [figure 4](#), RES670 B20 configuration as a PMU is measuring two 3-phase voltages of the busbars and six 3-phase currents of bays 1 to 6. There are two instances of PMU reporting functionality available in B20 configuration, meaning two independent IEEE C37.118/1344 data streams. Each instance of PMU is reporting frequency-deviation and rate-of-change-of-frequency data. In the standard B20 configuration, in addition to frequency data, first instance of PMU (first data stream) is reporting 32 synchrophasors over IEEE C37.118/1344; that is eight 3-phase synchrophasors and 24 single phase synchrophasors corresponding to the AC voltage and current measurements. Second instance of PMU (second data stream) is reporting 16 synchrophasors over IEEE C37.118/1344; that is four 3-phase synchrophasors and 12 single phase synchrophasors corresponding to the AC voltage and current measurements. The number of synchrophasor reporting channels on second instance of PMU can be extended to 32 channels per request. This can be done when ordering the RES670 B20 configuration.

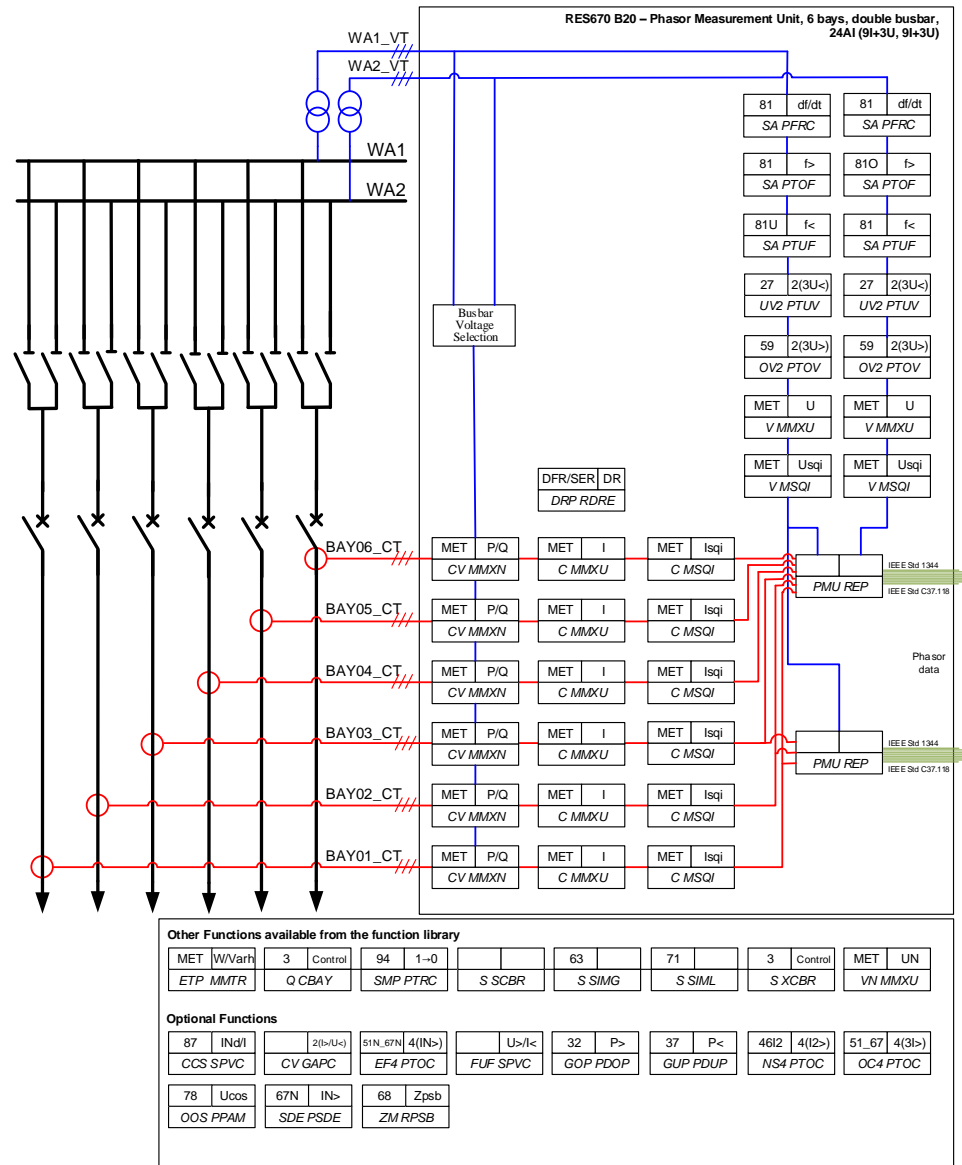
In addition, each data stream includes 16 analog and 16 binary reporting channels over IEEE C37.118/1344 in the standard configuration. The number of analog and binary reporting channels can be extended to maximum 24 channels per PMU instance (on each data stream) on request. This can be done when ordering the RES670 B20 configuration. In the standard B20 configuration the analog reporting channels are used for reporting P and Q measurements from each bay over IEEE C37.118/1344.

In addition to the binary reporting channels there are 4 trigger bits (FREQTRIG, DFDTTRIG, OCTRIG, and UVTRIG) available per PMU instance which are used to report the existing protection function triggers over IEEE C37.118/1344.

The main functionality of the RES670 is synchrophasor reporting or PMU functionality. In addition, this configuration also includes general back-up protection functions which are mainly intended for alarm purposes. Available protection functions in standard B20 configuration are Over Voltage, Under Voltage, Over Frequency, Under Frequency and Rate of Change of Frequency.

Measuring functions for S, P, Q, I, V, PF, f are available for local presentation on the local HMI and remote presentation via IEEE C37.118/1344 and/or via IEC 61850. The calibration parameters on the measurement function allows calibration at site to very high accuracy.

As shown in [figure 4](#), there are optional functions such as ground fault protection (EF4 PTOC), Overcurrent protection (OC4 PTOC), Under/Over power protection (GUPPDUP, GOPPDOP), etc. which can be added per request. RES670 B20 function library also includes additional functions which are available but not configured. Note that RES670 B20 must be reconfigured if any additional functions are used.



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Figure 4: Configuration diagram for configuration B20

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

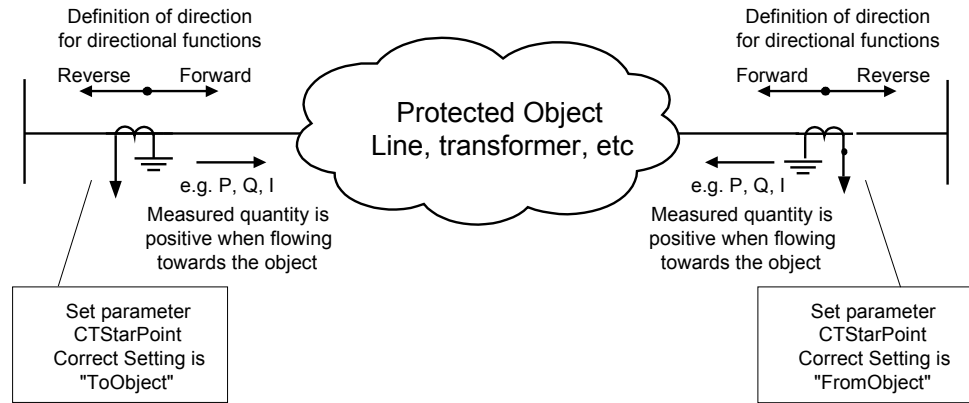
Usually the A phase-to-ground voltage connected to the first VT channel number of the transformer input module (TRM) is selected as the phase reference. The first VT channel number depends on the type of transformer input module.

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 Wye (star) connected and can be connected with the grounding 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 5](#)

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 5](#).



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Figure 5: Internal convention of the directionality in the IED

With correct setting of the primary CT direction, *CT_WyePoint* 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.

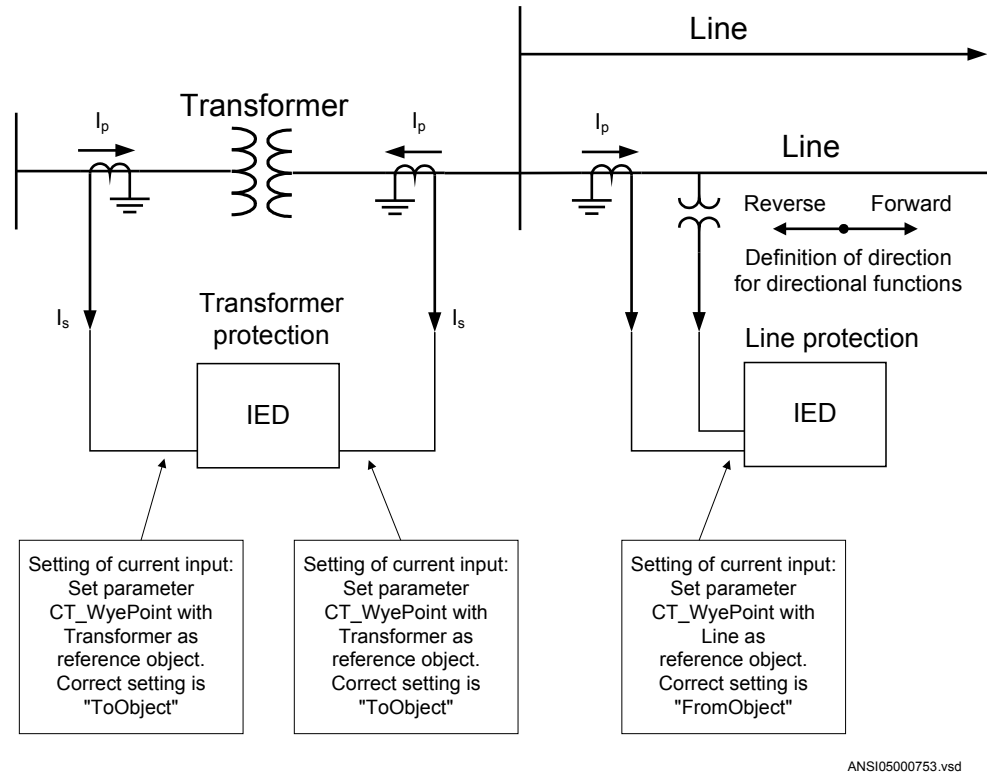


Figure 6: Example how to set CT_WyePoint parameters in the IED

Figure 6 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.

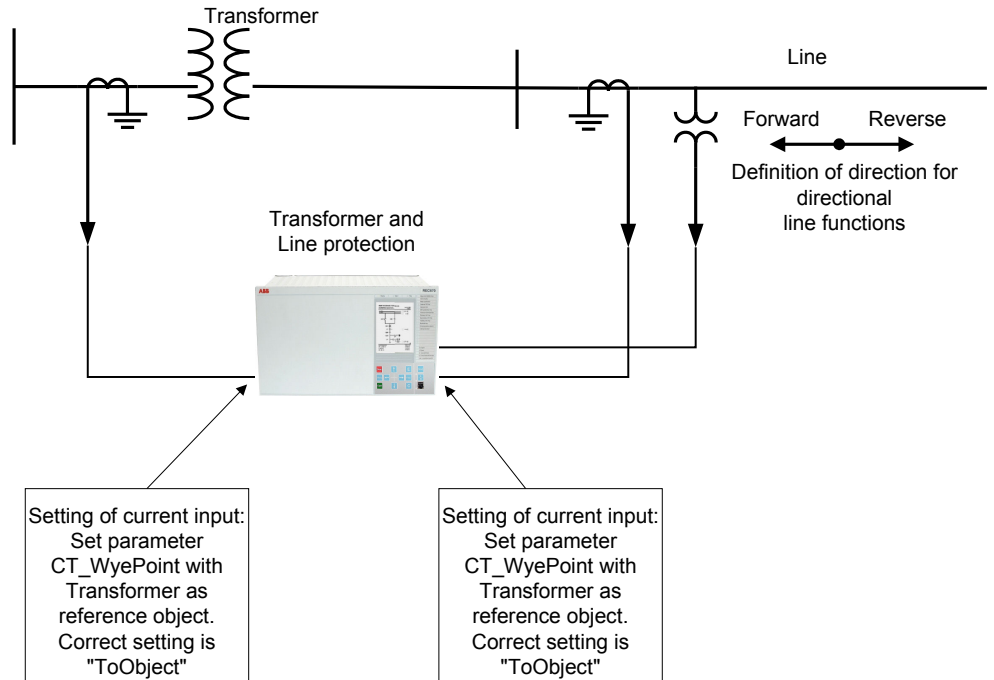
Figure 7: Example how to set CT_WyePoint parameters in the IED

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.



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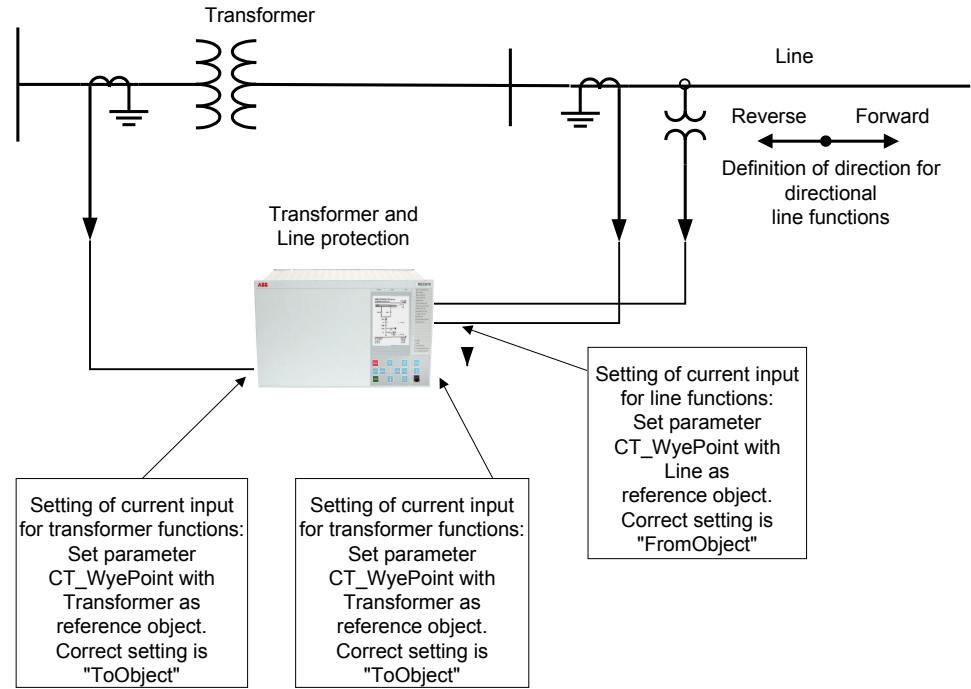
Figure 8: Example how to set CT_WyePoint parameters in the IED

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.

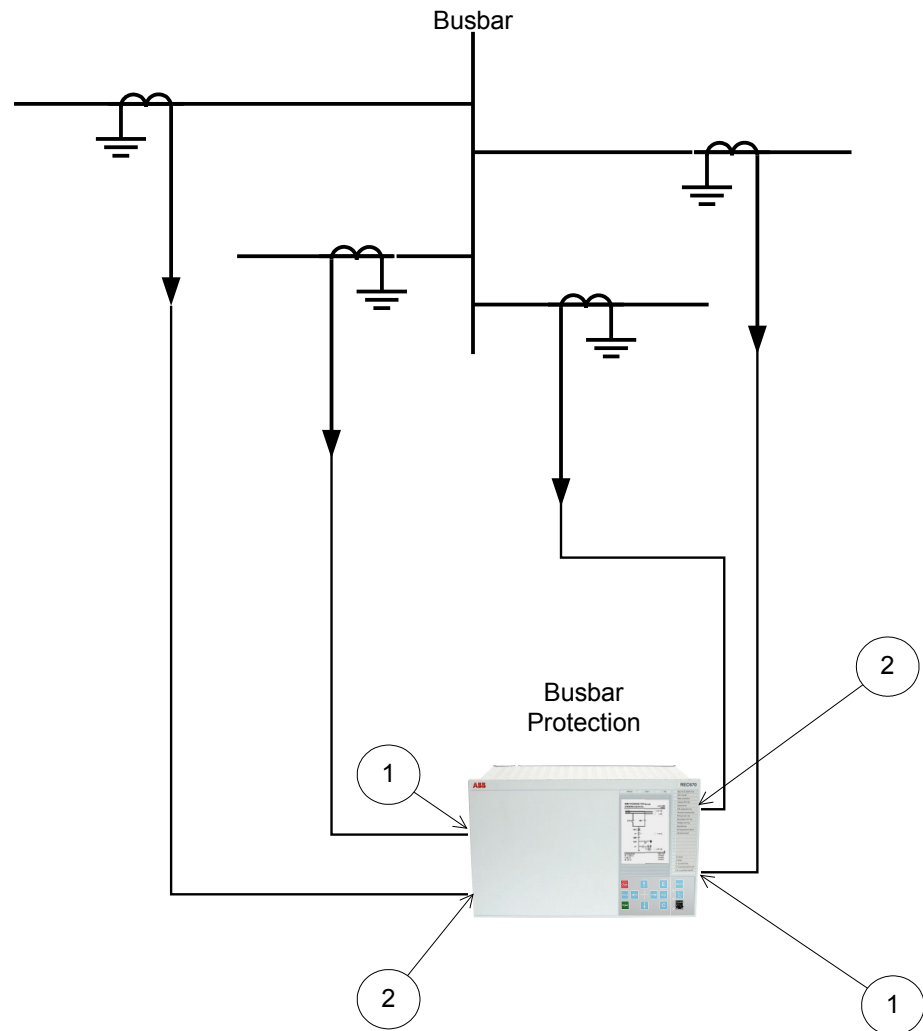
If the IED has sufficient number of analog current inputs, an alternative solution is shown in Figure 9. The same currents are fed to two separate groups of inputs and the line and transformer protection functions are configured to the different inputs. The CT

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.



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Figure 9: Example how to set CT_WyePoint parameters in the IED



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Figure 10: Example how to set $CT_WyePoint$ parameters in the IED

For busbar protection, it is possible to set the $CT_WyePoint$ 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 10, set $CT_WyePoint = ToObject$, and for all CT inputs marked with 2 in Figure 10, set $CT_WyePoint = FromObject$.

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 10, set $CT_WyePoint = FromObject$, and for all CT inputs marked with 2 in Figure 10, set $CT_WyePoint = ToObject$.

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 CT_{sec} and CT_{prim} for each current channel. For a 1000/5 A CT, the following settings shall be used:

- $CT_{prim} = 1000$ (value in A)
- $CT_{sec} = 5$ (value in A).

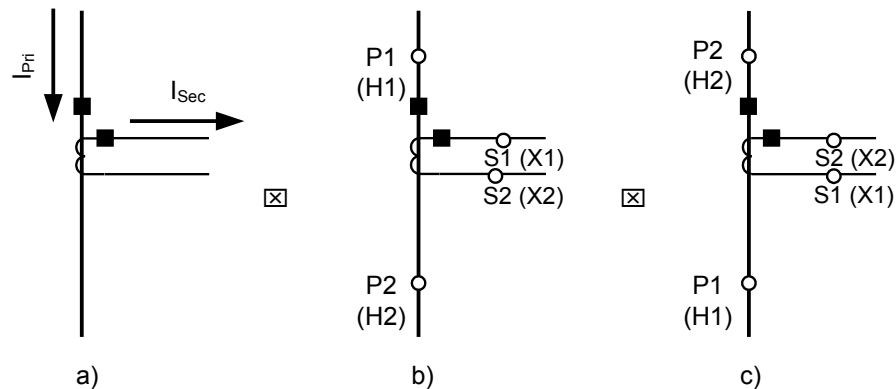
4.2.2.4

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

Figure 11 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-ground and *GlobalBaseSel*.



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Figure 11: 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

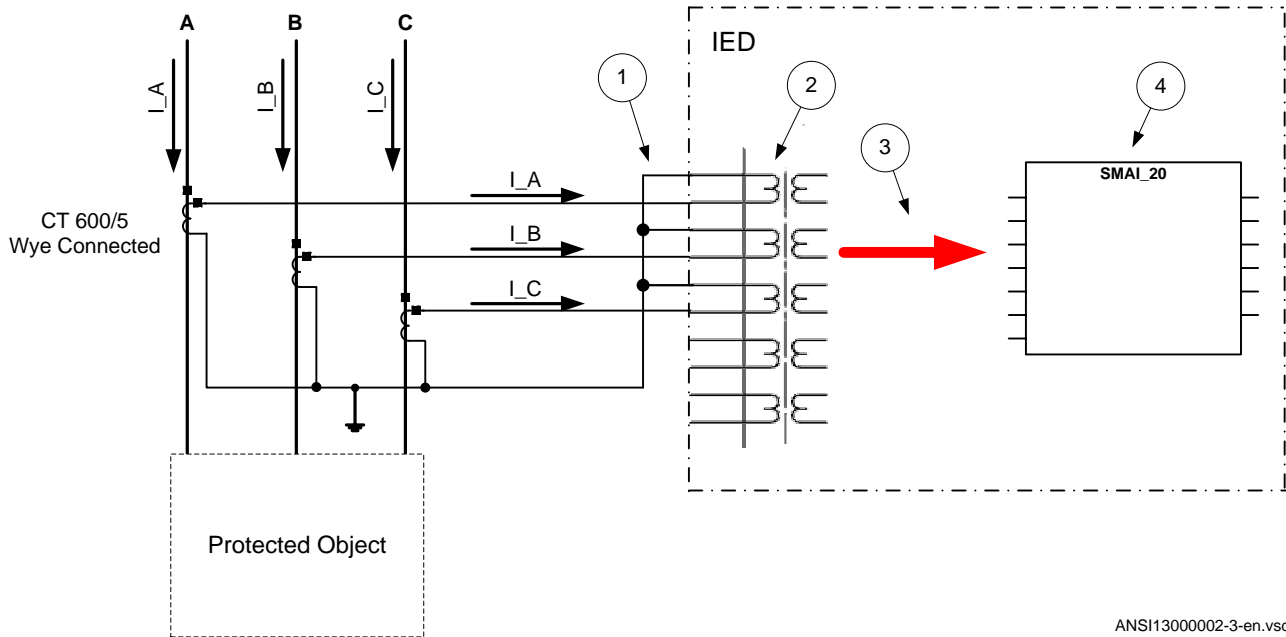
4.2.2.5

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

Figure [12](#) gives an example about the wiring of a wye 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.



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Figure 12: Wye connected three-phase CT set with wye point towards the protected object

Where:

- 1) The drawing shows how to connect three individual phase currents from a wye 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 12.
 - $CT_{prim}=600A$
 - $CT_{sec}=5A$
 - $CT_{StarPoint}=ToObject$

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)

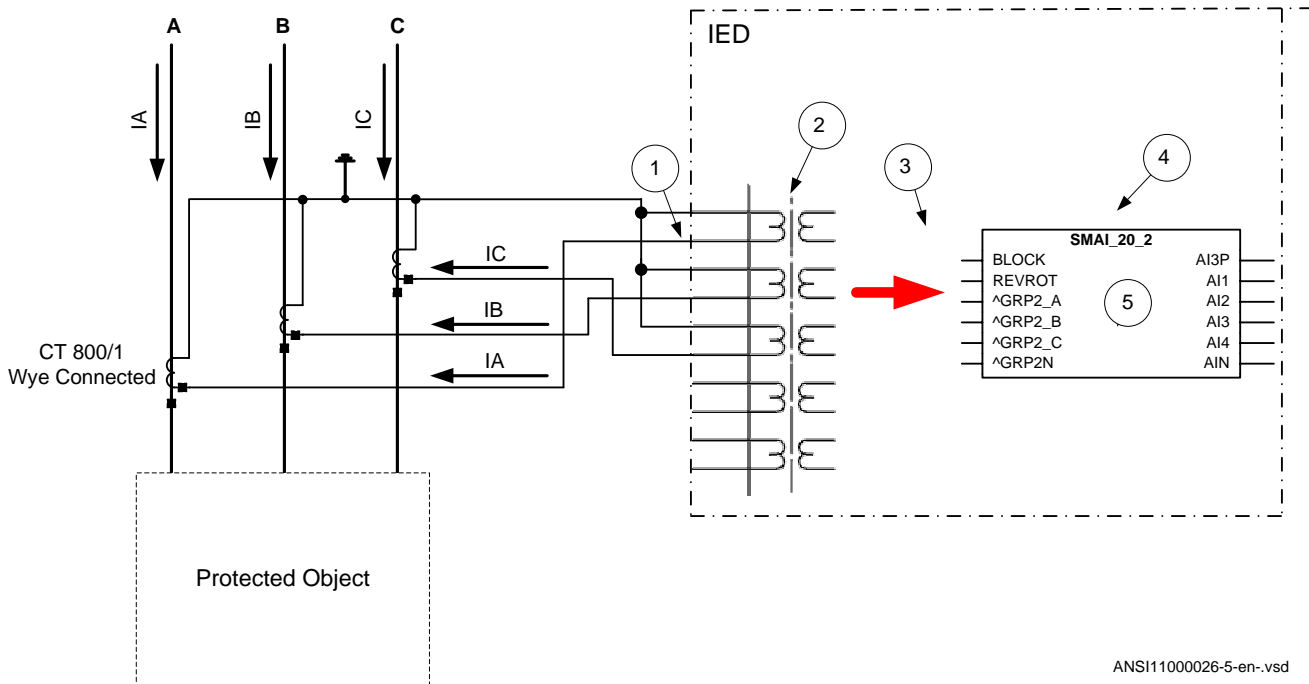
These calculated values are then available for all built-in protection and control functions within the IED, which are connected to this preprocessing function block. For this application most of the preprocessing settings can be left to the default values.

If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in power plants), then the setting parameters DFTRreference 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 A, B, C 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 GRP_A, GRP_B and GRP_C. If GRP2N is connected, the data reflects the measured value of GRP2N.

Another alternative is to have the wye point of the three-phase CT set as shown in figure [13](#):



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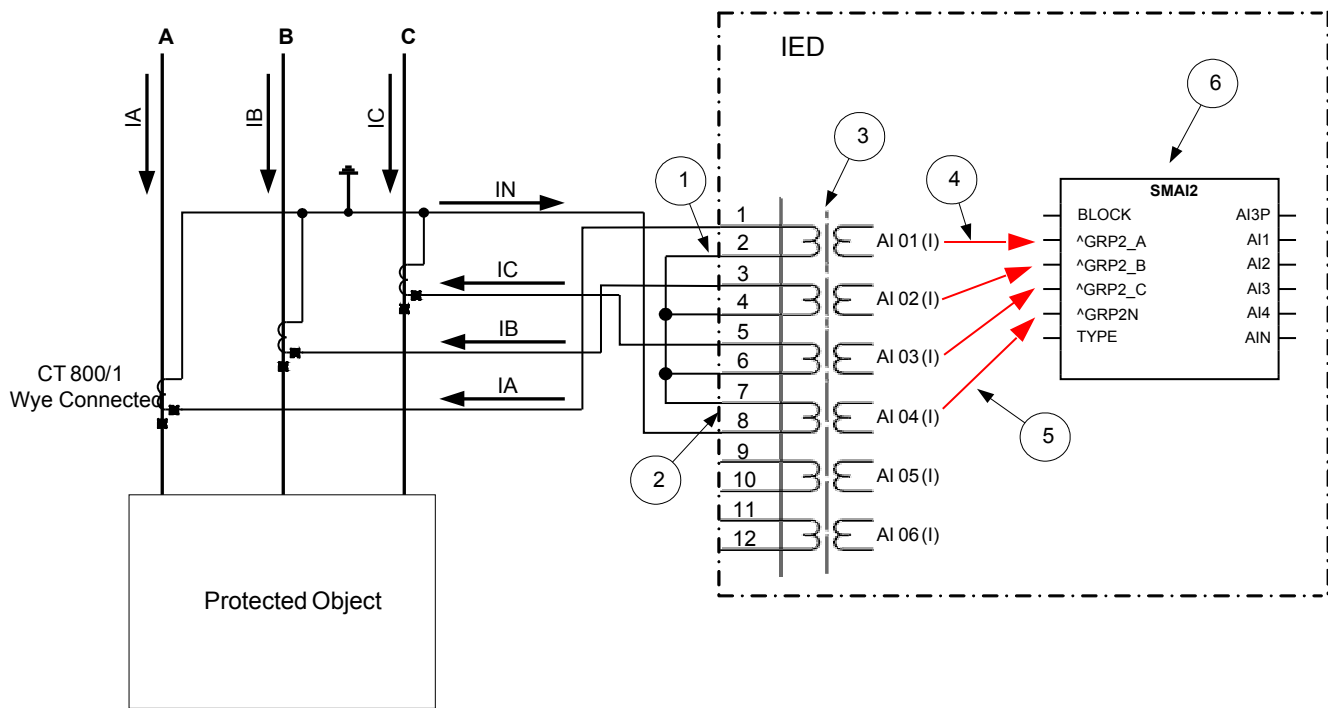
Figure 13: Wye connected three-phase CT set with its wye point away from the protected object

In the example, everything is done in a similar way as in the above described example (Figure 12). The only difference is the setting of the parameter *CTStarPoint* of the used current inputs on the TRM (item 2 in Figure 13 and 12):

- *CTprim*=600A
- *CTsec*=5A
- *CTWyePoint*=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 13.



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Figure 14: Wye connected three-phase CT set with its wye 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 wye 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 DFTReference shall be set accordingly.

4.2.2.6

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

Figure [15](#) 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.

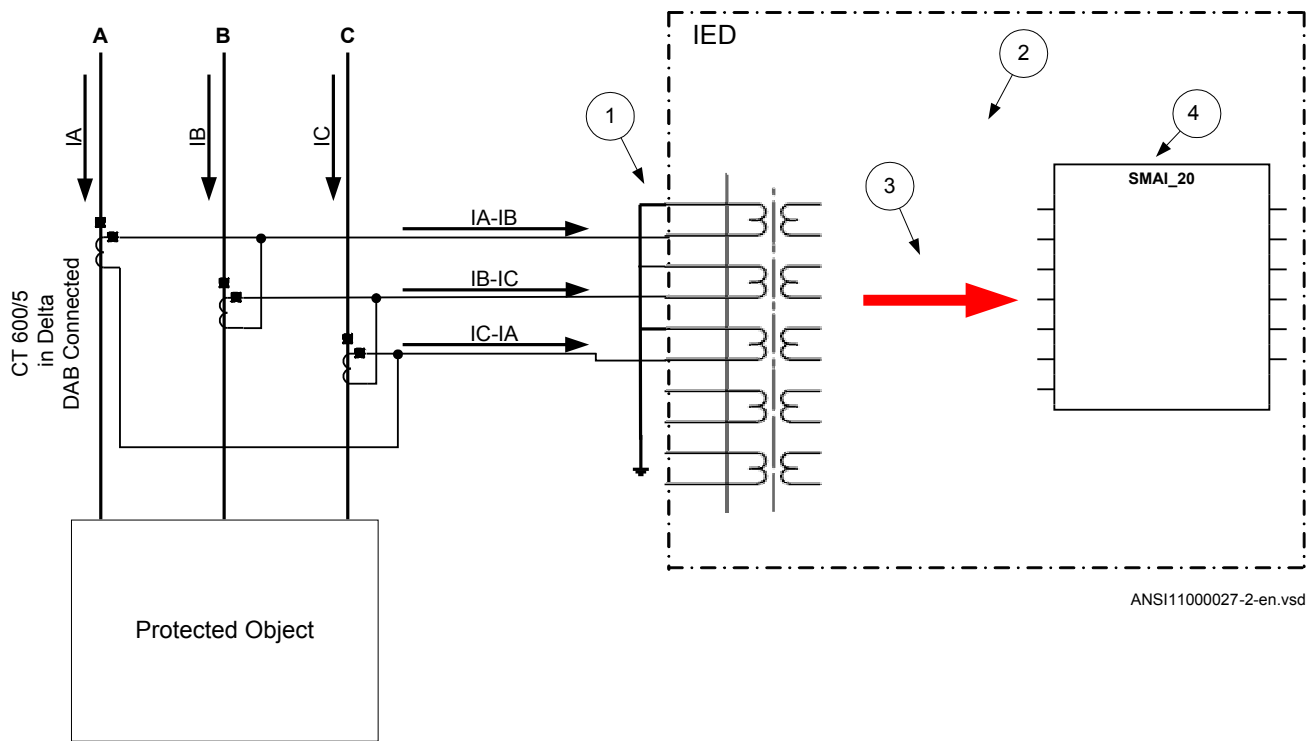


Figure 15: Delta DAB connected three-phase CT set

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.
 $CT_{prim}=600A$
 $CT_{sec}=5A$
 - $CTWyePoint=ToObject$
 - $ConnectionType=Ph-Ph$
- 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 than 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 [16](#):

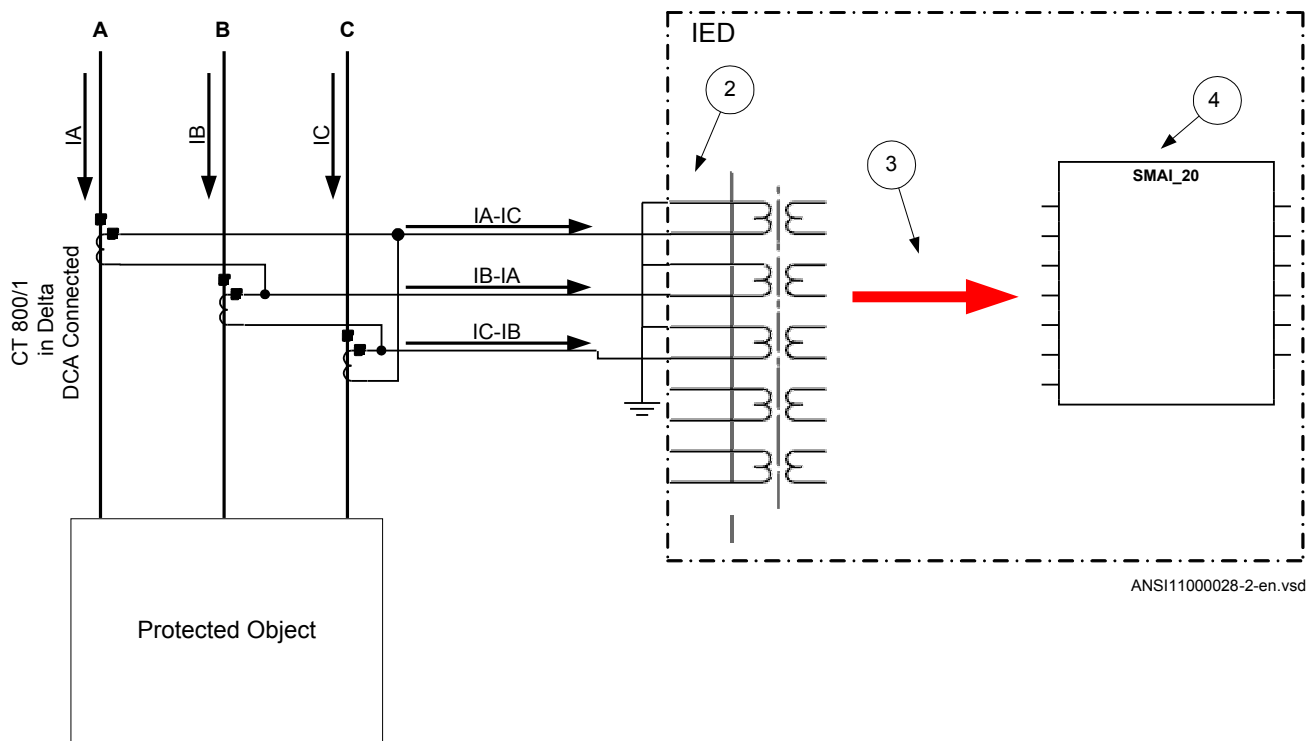


Figure 16: Delta DAC connected three-phase CT set

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:

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

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

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

It is important to notice the references in SMAI. As inputs at $Ph-Ph$ are expected to be A-B, B-C respectively C-A we need to tilt 180° by setting $ToObject$.

4.2.2.7

Example how to connect single-phase CT to the IED

Figure 17 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.

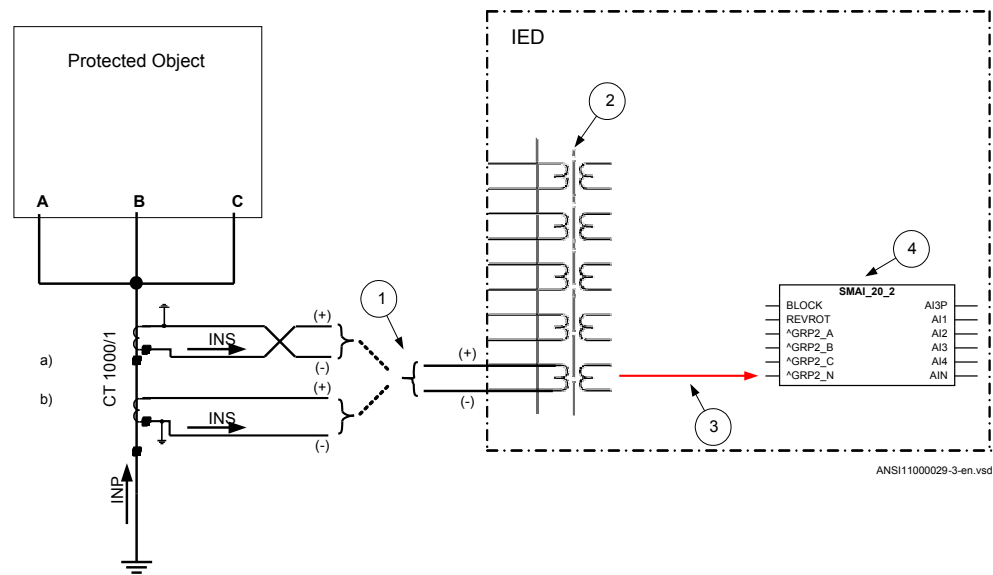


Figure 17: Connections for single-phase CT input

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 17:
 $CT_{prim} = 1000\text{ A}$
 $CT_{sec} = 1\text{ A}$
 $CT_{WyePoint} = ToObject$
 For connection (b) shown in Figure 17:
 $CT_{prim} = 1000\text{ A}$
 $CT_{sec} = 1\text{ A}$
 $CT_{WyePoint} = FromObject$
- 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 $DFTR_{reference}$ 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 SMAIHPAC 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-ground voltage from the VT.

4.2.4.1

Example

Consider a VT with the following data:

$$\frac{132\text{kV}}{\sqrt{3}} / \frac{120\text{V}}{\sqrt{3}}$$

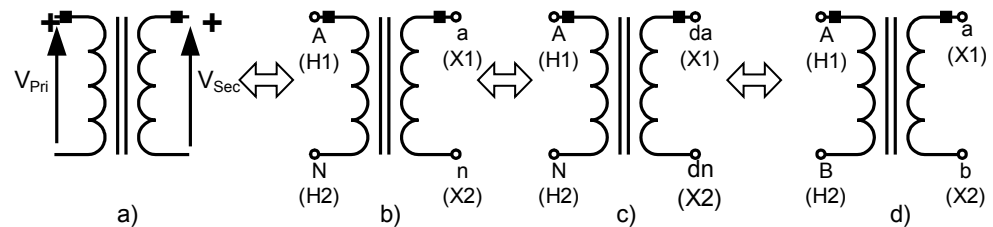
(Equation 1)

The following setting should be used: $VT_{prim}=132$ (value in kV) $VT_{sec}=120$ (value in V)

4.2.4.2

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

Figure 18 defines the marking of voltage transformer terminals commonly used around the world.



ANSI11000175_1_en.vsd

Figure 18: 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-ground 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.

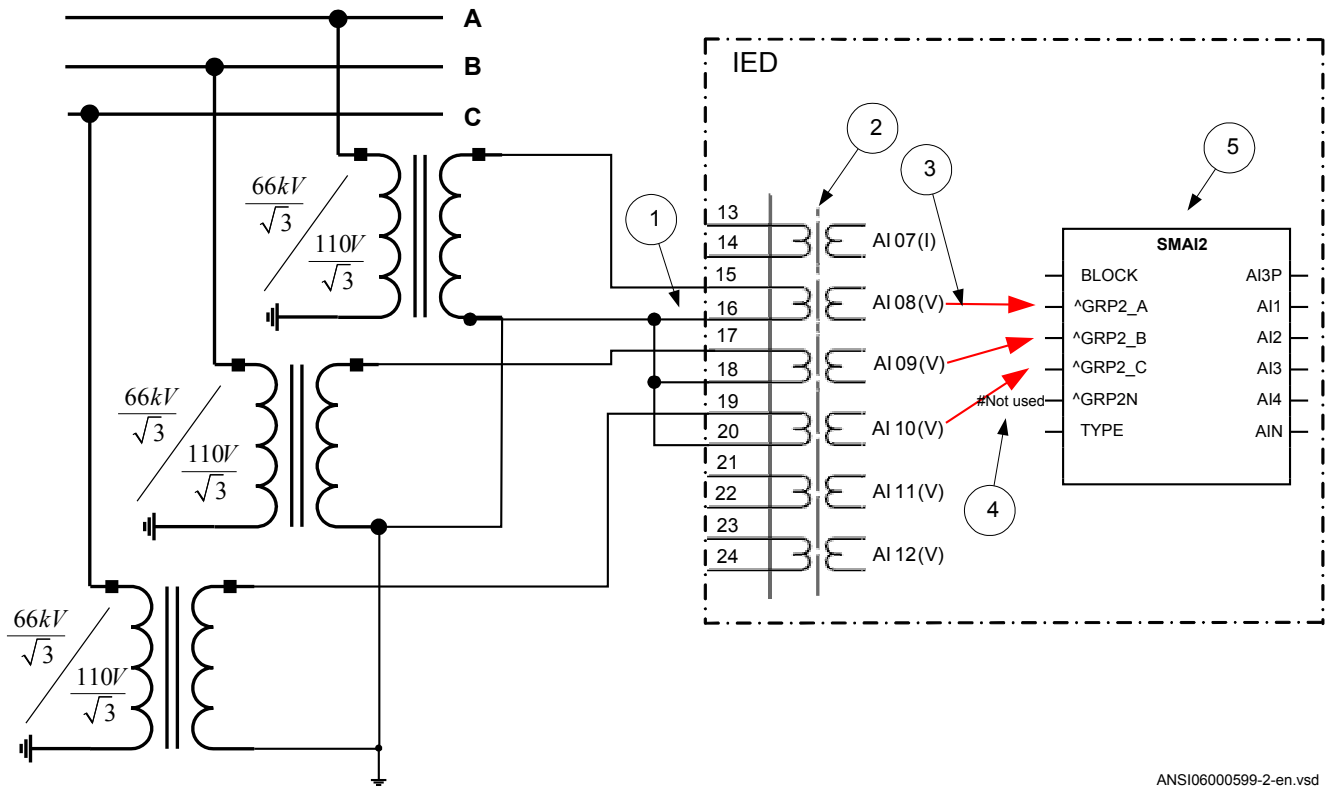
4.2.4.3

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

Figure [19](#) gives an example on how to connect the three phase-to-ground 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.

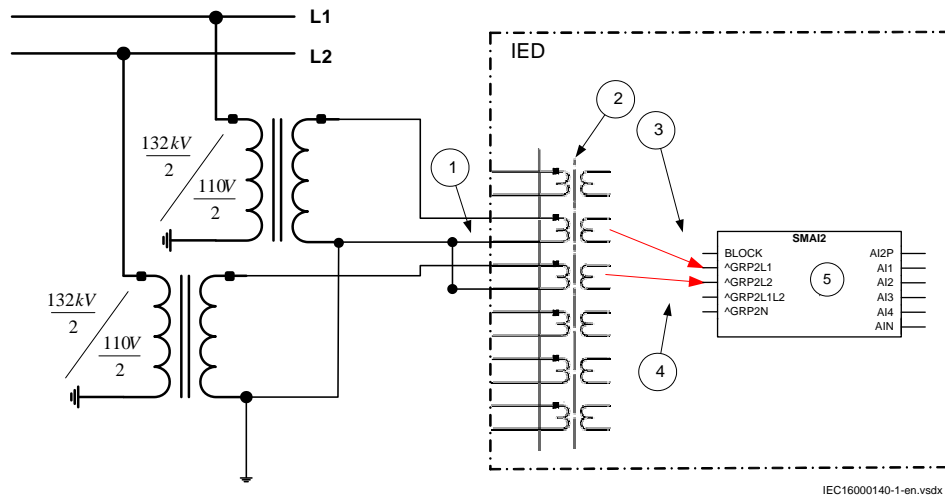


For correct terminal designations, see the connection diagrams valid for the delivered IED.



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Figure 19: A Three phase-to-ground connected VT



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Figure 20: A two phase-to-earth connected VT

Where:

- 1) shows how to connect three secondary phase-to-ground 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)

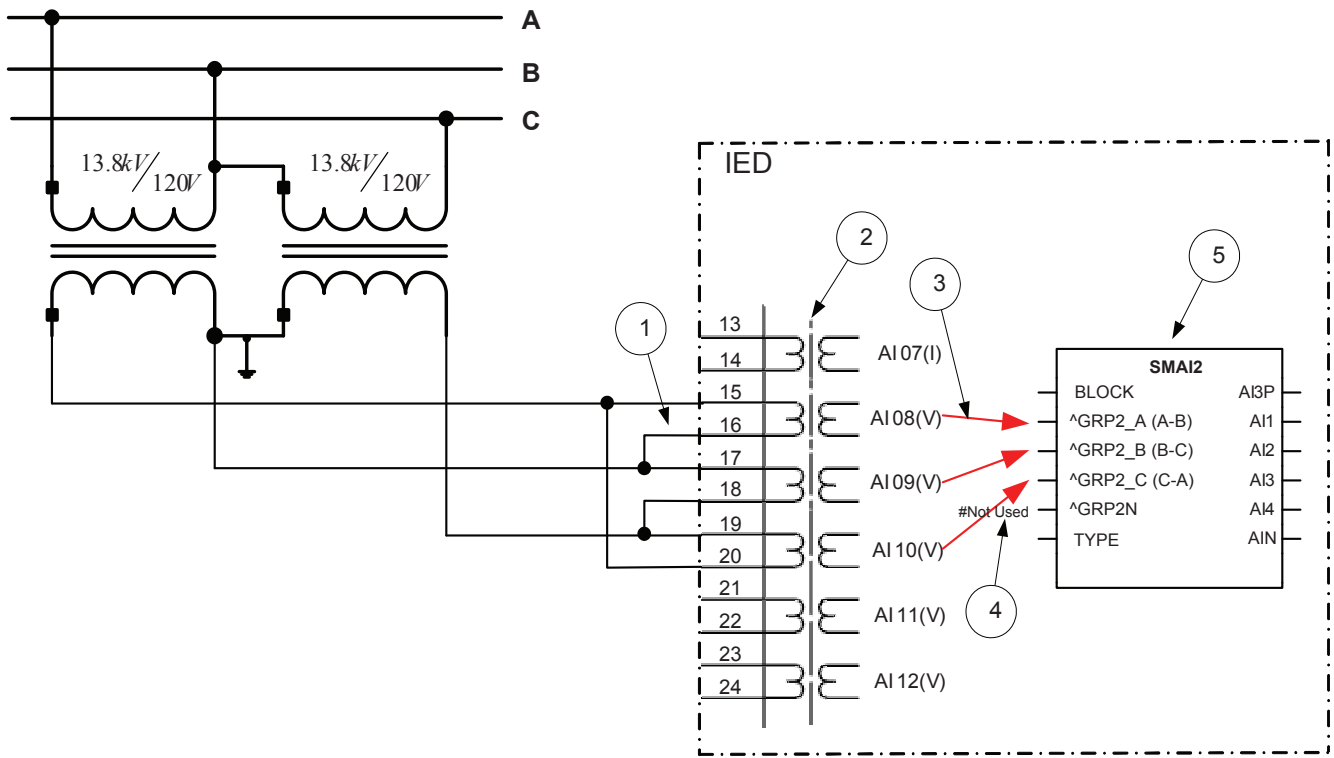
- 3) are three connections made in Signal Matrix Tool (SMT), which connect these three voltage inputs to first three input channels of the preprocessing function block 5). Depending on the type of functions which need this voltage information, more than one preprocessing block might be connected in parallel 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 $3V_0$ inside by vectorial sum from the three phase to ground 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 22.
- 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:
 $V_{Base} = 66 \text{ kV}$ (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 *DFTReference* shall be set accordingly.

4.2.4.4

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

Figure 21 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).



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Figure 21: 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.

Table continues on next page

- 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 V_A , V_B , V_C , V_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
VBase=13.8 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 grounded or ungrounded networks

Figure 22 gives an example about the wiring of an open delta VT to the IED for high impedance grounded or ungrounded power systems. It shall be noted that this type of VT connection presents a secondary voltage proportional to $3V_0$ to the IED.

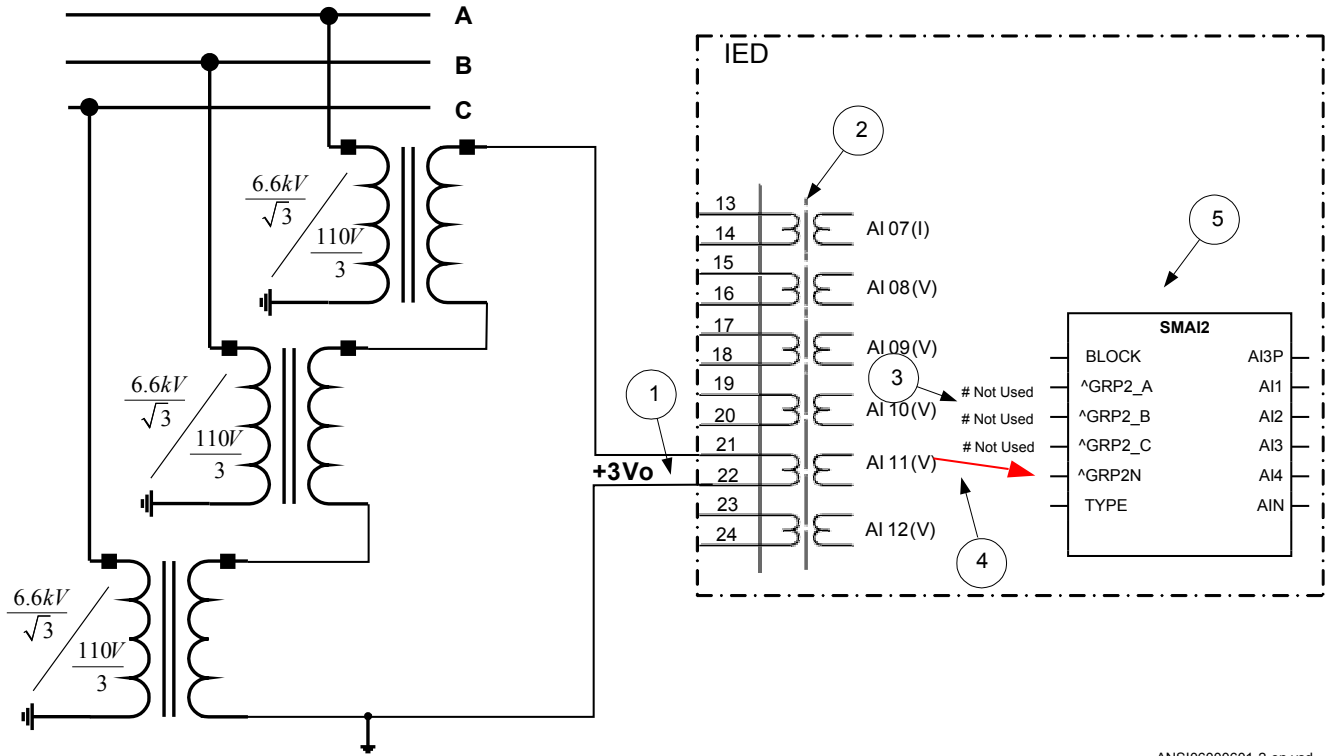
In case of a solid ground fault close to the VT location the primary value of $3V_0$ will be equal to:

$$3V_0 = \sqrt{3} \cdot V_{Ph-Ph} = 3 \cdot V_{Ph-Gnd}$$

(Equation 3)

The primary rated voltage of an open Delta VT is always equal to V_{Ph-Gnd} . 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 22 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.



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Figure 22: Open delta connected VT in high impedance grounded power system

Where:

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



+3Vo 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 *DFTReference* shall be set accordingly.

4.2.4.6

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

Figure 23 gives an example about the connection of an open delta VT to the IED for low impedance grounded or solidly grounded power systems. It shall be noted that this type of VT connection presents secondary voltage proportional to $3V_0$ to the IED.

In case of a solid ground fault close to the VT location the primary value of $3V_0$ will be equal to:

$$3V_0 = \frac{V_{Ph-Ph}}{\sqrt{3}} = V_{Ph-Gnd}$$

(Equation 7)

The primary rated voltage of such VT is always equal to V_{Ph-Gnd} . 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 23 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.

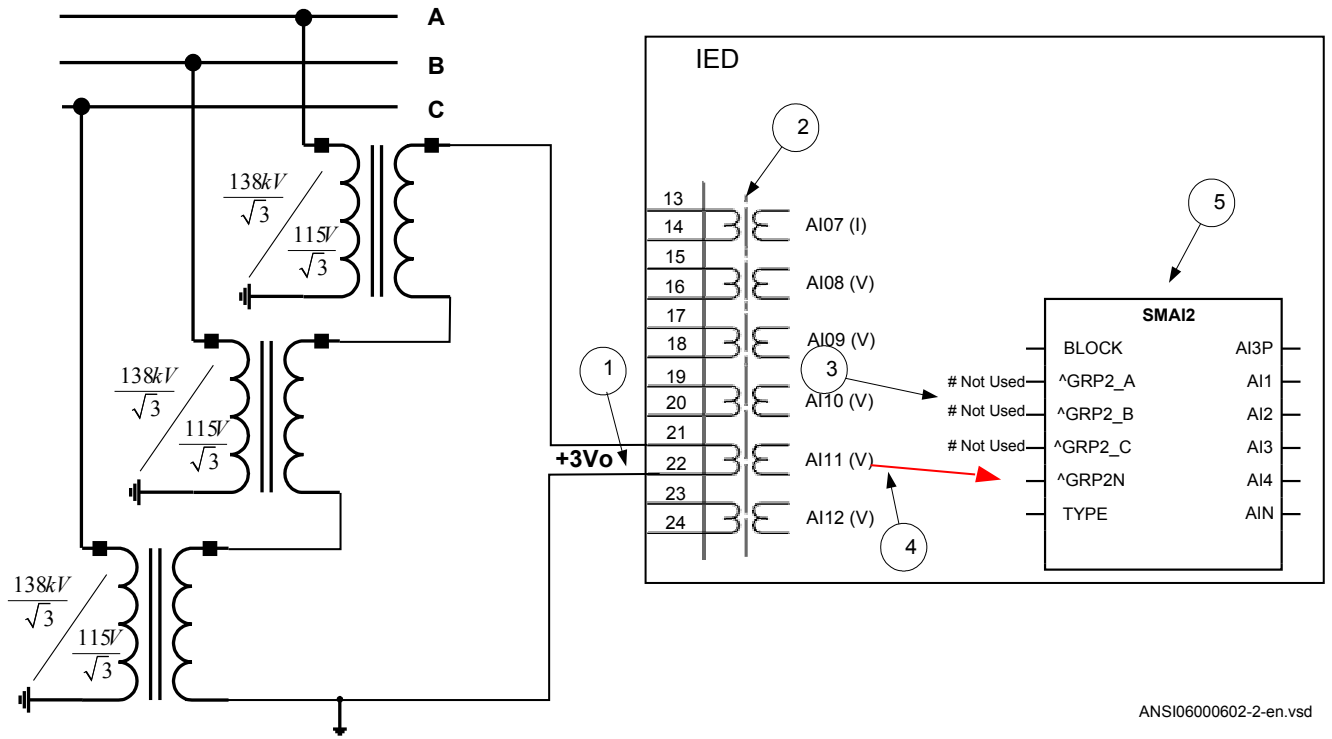


Figure 23: Open delta connected VT in low impedance or solidly grounded power system

Where:

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



+3Vo 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.

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

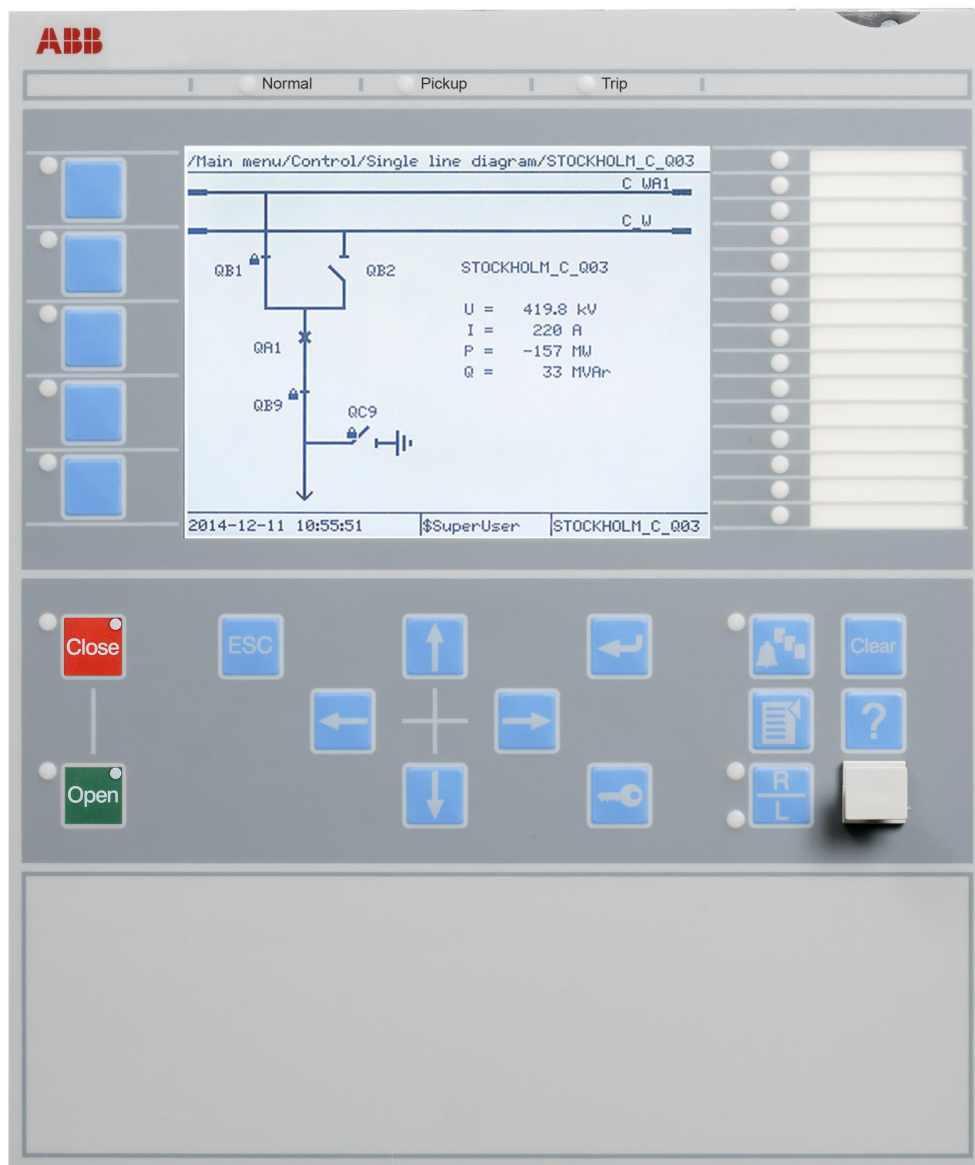
(Equation 10)

- 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 *DFTR* shall be set accordingly.

Section 5 Local HMI



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Figure 24: 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 display view is divided into four basic areas.

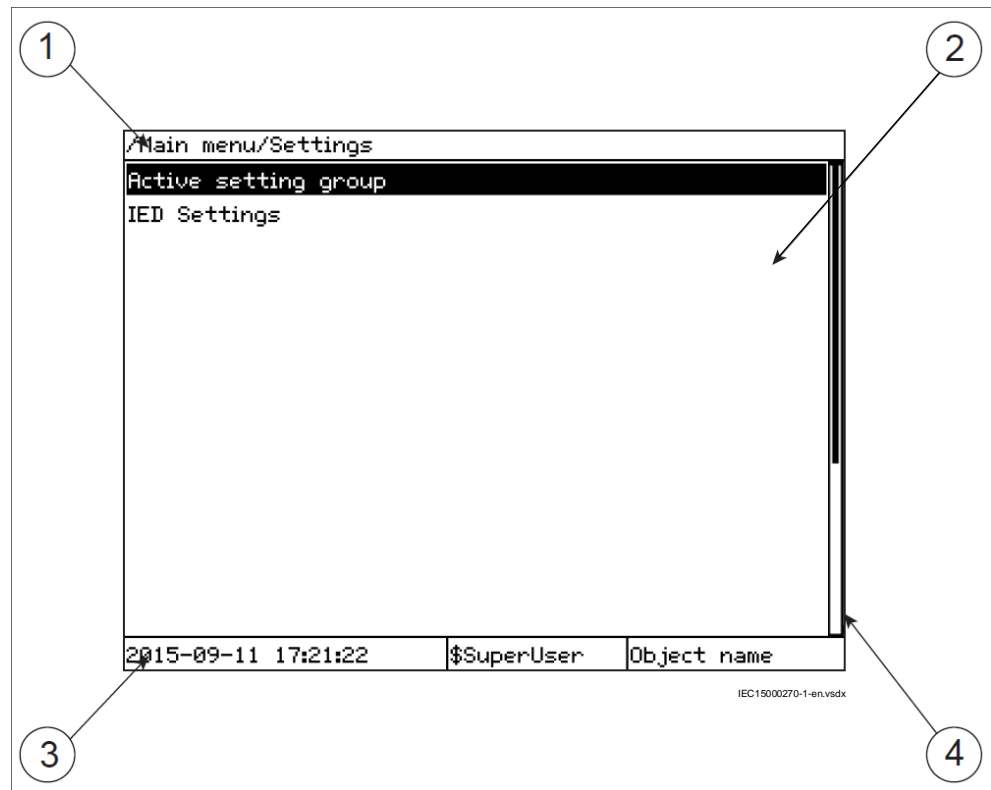
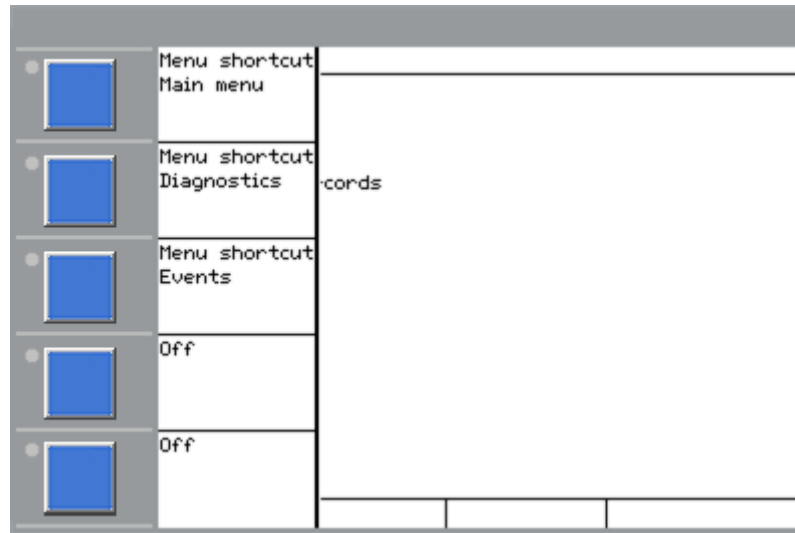


Figure 25: Display layout

- 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.



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Figure 26: Function button panel

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

/Main menu	1	G2L01_YELLOW
Control	2	
Events	3	
Measurements		
Disturbance records		G2L05_YELLOW
Settings		
Configuration		TRIP CKT ALARM
Diagnostics		
Test		
Clear		
Language		

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Figure 27: 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 protection status LEDs above the display: Normal, Pickup and Trip.

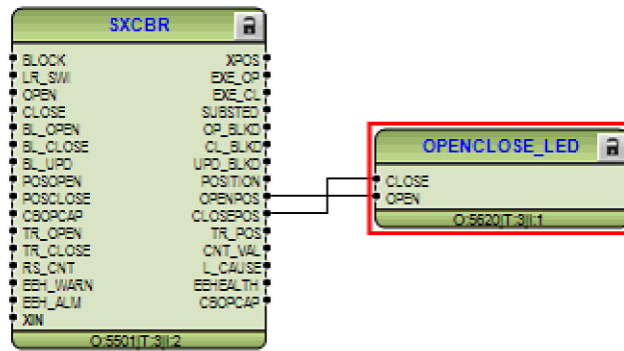
There are 15 programmable indication LEDs on the front of the LHMI. Each LED can indicate three states with the colors: green, yellow and red. The texts related to each three-color LED are divided into three panels.

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.



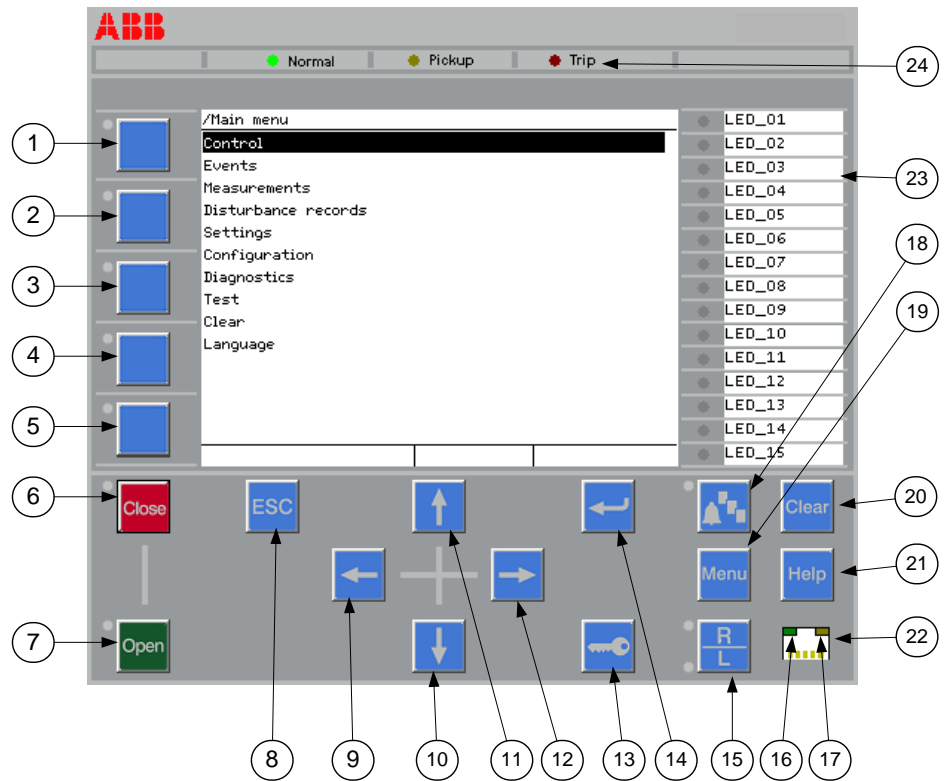
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Figure 28: *OPENCLOSE_LED connected to SXCBR*

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.



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Figure 29: LHM1 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
- 24 IED status LEDs

5.4 Local HMI functionality

5.4.1 Protection and alarm indication

Protection indicators

The protection indicator LEDs are Normal, Pickup and Trip.

Table 7: *Normal LED (green)*

LED state	Description
Off	Auxiliary supply voltage is disconnected.
On	Normal operation.
Flashing	Internal fault has occurred.

Table 8: *PickUp LED (yellow)*



LED state	Description
Off	Normal operation.
On	A protection function has picked up and an indication message is displayed. The pick up 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	The IED is in test mode and protection functions are blocked, or the IEC61850 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 IEC61850 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	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 IED.

Table 10: *Alarm indications*

LED state	Description
Off	Normal operation. All activation signals are off.
On	<ul style="list-style-type: none"> 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	<ul style="list-style-type: none"> 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.

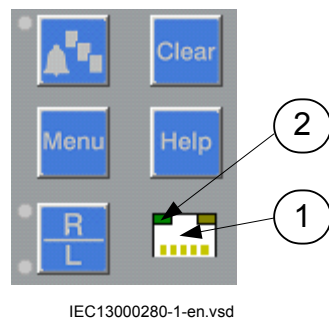


Figure 30: RJ-45 communication port and green indicator LED

- 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 255.255.254.0. 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 Wide area measurement system

6.1 Protocol reporting via IEEE 1344 and C37.118 PMUREPORT

6.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Protocol reporting via IEEE 1344 and C37.118	PMUREPORT	-	-

6.1.2 Application

The phasor measurement reporting block moves the phasor calculations into an IEEE C37.118 and/or IEEE 1344 synchrophasor frame format. The PMUREPORT block contains parameters for PMU performance class and reporting rate, the IDCODE and Global PMU ID, format of the data streamed through the protocol, the type of reported synchrophasors, as well as settings for reporting analog and digital signals.

The message generated by the PMUREPORT function block is set in accordance with the IEEE C37.118 and/or IEEE 1344 standards.

There are settings for Phasor type (positive sequence, negative sequence or zero sequence in case of 3-phase phasor and A, B or C in case of single phase phasor), PMU's Service class (Protection or Measurement), Phasor representation (polar or rectangular) and the data types for phasor data, analog data and frequency data.

Synchrophasor data can be reported to up to 8 clients over TCP and/or 6 UDP group clients for multicast or unicast transmission of phasor data from the IED. More information regarding synchrophasor communication structure and TCP/UDP configuration is available in section [C37.118 Phasor Measurement Data Streaming Protocol Configuration](#).

Multiple PMU functionality can be configured in the IED, which can stream out same or different data at different reporting rates or different performance (service) classes. There are 2 instances of PMU functionality available in the IED. Each instance of PMU functionality includes a set of PMU reporting function blocks tagged by the same

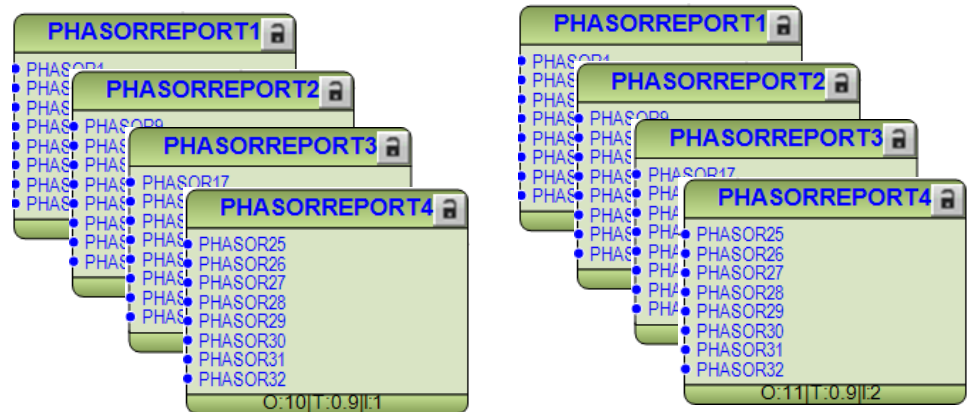
instance number (1 or 2). As shown in the following figures, each set of PMU reporting function blocks includes PMUREPORT, PHASORREPORT1-4, ANALOGREPORT1-3, and BINARYREPORT1-3 function blocks. In general, each instance of PMU functionality has 32 configurable phasor channels (PHASORREPORT1–4 blocks), 24 analog channels (ANALOGREPORT1-3 blocks), and 28 digital channels (24 digital-report channels in BINARYREPORT1-3 and 4 trigger-report channels in PMUREPORT function block). Special rules shall be taken into account in PCM600 for Application Configuration and Parameter Settings of multiple PMUREPORT blocks. These rules are explained in the the Application Manual in section [PMU Report Function Blocks Connection Rules](#).

Figure 31 shows both instances of the PMUREPORT function block. As seen, each PMUREPORT instance has 4 predefined binary input signals corresponding to the Bits 03-00: Trigger Reason defined in STAT field of the Data frame in IEEE C37.118.2 standard. These are predefined inputs for Frequency Trigger, Rate of Change of Frequency trigger, Magnitude High and Magnitude Low triggers.



Figure 31: Multiple instances of PMUREPORT function block

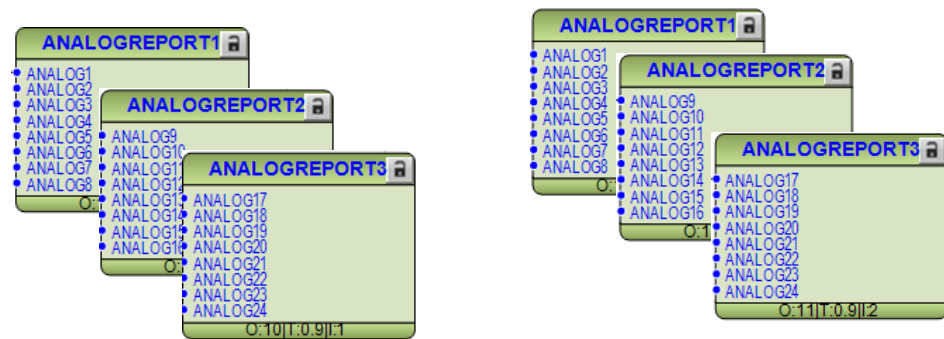
Figure 32 shows both instances of the PHASORREPORT function blocks. The instance number is visible in the bottom of each function block. For each instance, there are four separate PHASORREPORT blocks including 32 configurable phasor channels (8 phasor channels in each PHASORREPORT block). Each phasor channel can be configured as a 3-phase (symmetrical components positive/negative/zero) or single-phase phasor (A/B/C).



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Figure 32: Multiple instances of PHASORREPORT blocks

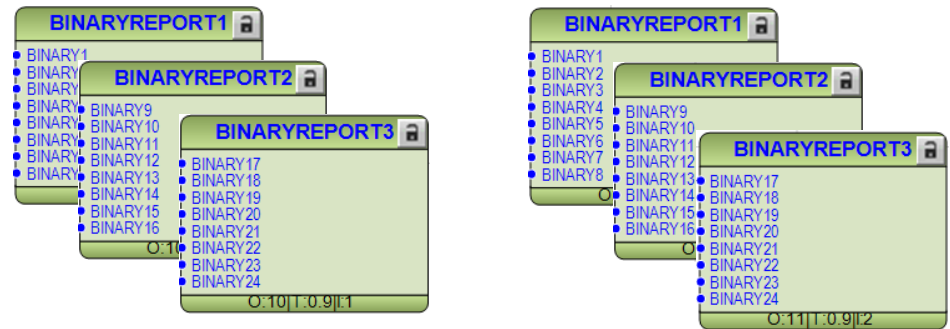
Figure 33 shows both instances of ANALOGREPORT function blocks. The instance number is visible in the bottom of each function block. For each instance, there are three separate ANALOGREPORT blocks capable of reporting up to 24 Analog signals (8 Analog signals in each ANALOGREPORT block). These can include for example transfer of active and reactive power or reporting the milliamperere input signals to the PDC clients as defined in IEEE C37.118 data frame format.



IEC14000120-2-en.vsd

Figure 33: Multiple instances of ANALOGREPORT blocks

Figure 34 shows both instances of BINARYREPORT function blocks. The instance number is visible in the bottom of each function block. For each instance, there are three separate BINARYREPORT blocks capable of reporting up to 24 Binary signals (8 Binary signals in each BINARYREPORT block). These binary signals can be for example dis-connector or breaker position indications or internal/external protection alarm signals.



IEC140000121-2-en.vsd

Figure 34: Multiple instances of BINARYREPORT blocks

6.1.3 Operation principle

The Phasor Measurement Unit (PMU) features three main functional principles:

- To measure the power system related AC quantities (voltage, current) and to calculate the phasor representation of these quantities.
- To synchronize the calculated phasors with the UTC by time-tagging, in order to make synchrophasors (time is reference).
- To publish all phasor-related data by means of TCP/IP or UDP/IP, following the standard IEEE C37.118 protocol.

The C37.118 standard imposes requirements on the devices and describes the communication message structure and data. The PMU complies with all the standard requirements with a specific attention to the Total Vector Error (TVE) requirement. The TVE is calculated using the following equation:

$$TVE = \sqrt{\frac{(X_r(n) - X_r)^2 + (X_i(n) - X_i)^2}{X_r^2 + X_i^2}}$$

(Equation 11)

where,

- $X_r(n)$ and $X_i(n)$ are the measured values
- X_r and X_i are the theoretical values

In order to comply with TVE requirements, special calibration is done in the factory on the analog input channels of the PMU, resulting in increased accuracy of the measurements. The IEEE C37.118 standard also imposes a variety of steady state and

dynamic requirements which are fulfilled in the IED with the help of high accuracy measurements and advanced filtering techniques.

Figure 35 shows an overview of the PMU functionality and operation. In this figure, only one instance of PMUREPORT (PMUREPORT1) is shown. Note that connection of different signals to the PMUREPORT, in this figure, is only an example and the actual connections and reported signals on the IEEEC37.118/1344 can be defined by the user.

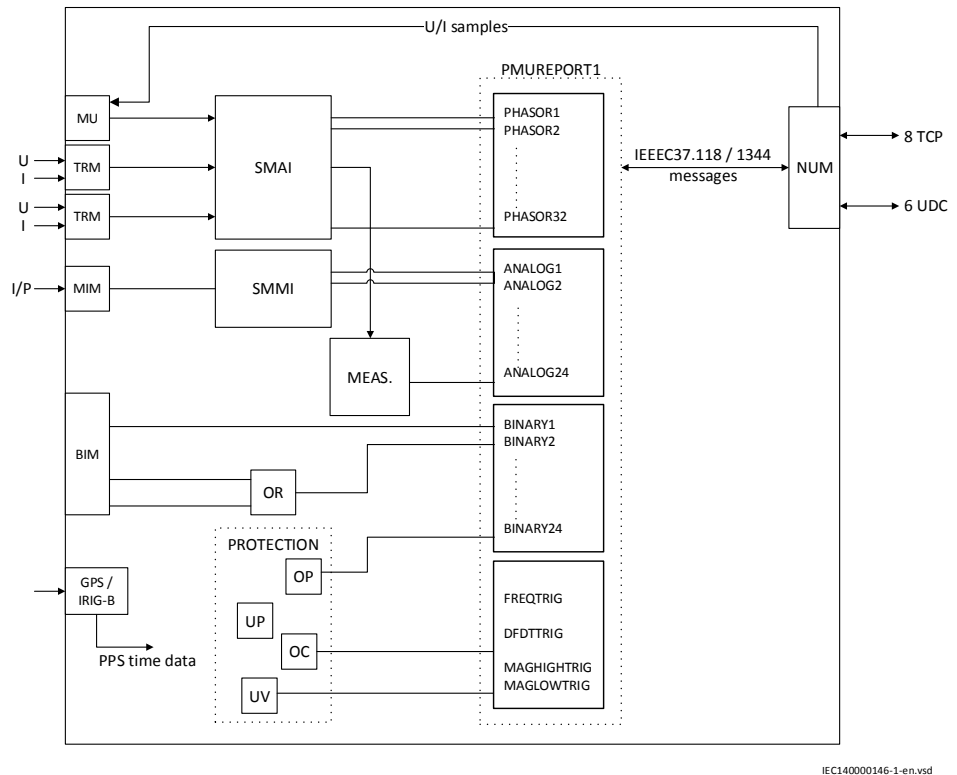


Figure 35: Overview of reporting functionality (PMUREPORT)

The TRM modules are individually AC-calibrated in the factory. The calibration data is stored in the prepared area of the TRM EEPROM. The pre-processor block is extended with calibration compensation and a new angle reference method based on timestamps. The AI3P output of the preprocessor block is used to provide the required information for each respective PMUREPORT phasor channel. More information about preprocessor block is available in the section **Signal matrix for analog inputs SMAI**.

6.1.3.1 Frequency reporting

By using patented algorithm the IED can track the power system frequency in quite wide range from 9 Hz to 95 Hz. In order to do that, the three-phase voltage signal shall be connected to the IED. Then IED can adapt its filtering algorithm in order to properly measure phasors of all current and voltage signals connected to the IED. This feature is essential for proper operation of the PMUREPORT function or for protection during generator start-up and shut-down procedure.

This adaptive filtering is ensured by proper configuration and settings of all relevant pre-processing blocks, see Signal matrix for analog inputs in the Application manual. Note that in all preconfigured IEDs such configuration and settings are already made and the three-phase voltage are used as master for frequency tracking. With such settings the IED will be able to properly estimate the magnitude and the phase angle of measured current and voltage phasors in this wide frequency range.

One of the important functions of a PMU is reporting a very accurate system frequency to the PDC client. In the IED, each of the PMUREPORT instances is able to report an accurate frequency. Each voltage-connected preprocessor block (SMAI block) delivers the frequency data, derived from the analog input AC voltage values, to the respective voltage phasor channel. Every phasor channel has a user-settable parameter (*PhasorXUseFreqSrc*) to be used as a source of frequency data for reporting to the PDC client. It is very important to set this parameter to On for the voltage-connected phasor channels. There is an automatic frequency source selection logic to ensure an uninterrupted reporting of the system frequency to the PDC client. In this frequency source selection logic, the following general rules are applied:

- Only the voltage phasor channels are used
- The phasor channel with a lower channel number is prioritized to the one with a higher channel number

As a result, the first voltage phasor is always the one delivering the system frequency to the PDC client and if, by any reason, this voltage gets disconnected then the next available voltage phasor is automatically used as the frequency source and so on. If the first voltage phasor comes back, since it has a higher priority compare to the currently selected phasor channel, after 500 ms it will be automatically selected again as the frequency source. There is also an output available on the component which shows if the reference frequency is good, error or reference channel unavailable.

It is possible to monitor the status of the frequency reference channel (frequency source) for the respective PMUREPORT instance on Local HMI under **Test/Function status/Communication/Station Communication/PMU Report/PMUREPORT:1/Outputs**, where the *FREQREFCHSEL* output shows the selected channel as the reference for frequency and *FREQREFCHERR* output states if the reference frequency

is good, or if there is an error or if the reference channel is unavailable. For more information refer to the table PMUREPORT monitored data.

Table 11: *PMUREPORT Monitored data*

Name	Type	Values (Range)	Unit	Description
TIMESTAT	BOOLEAN	1=Ready 0=Fail	-	Time synchronization status
FREQ	REAL	-	Hz	Frequency
FREQGRAD	REAL	-	-	Rate of change of frequency
FREQREFCHSEL	INTEGER	-	-	Frequency reference channel number selected
FREQREFCHERR	BOOLEAN	0=Freq ref not available 1=Freq ref error 2=Freq ref available	-	Frequency reference channel error
FREQTRIG	BOOLEAN	-	-	Frequency trigger
DFDTTRIG	BOOLEAN	-	-	Rate of change of frequency trigger
MAGHIGHTRIG	BOOLEAN	-	-	Magnitude high trigger
MAGLOWTRIG	BOOLEAN	-	-	Magnitude low trigger

6.1.3.2

Reporting filters

The PMUREPORT function block implements the reporting filters designed to avoid aliasing as the reporting frequency is lower than the sample/calculation frequency. This means, the synchrophasor and frequency data which are included in the C37.118 synchrophasor streaming data are filtered in order to suppress aliasing effects, as the rate of the C37.118 data is slower than the data rate for internal processing. For this purpose, there is an anti-aliasing filter designed for each reporting rate. The correct anti-aliasing filter will be automatically selected based on the reporting rate and the performance class (P/M) settings. The filters are designed to attenuate all aliasing frequencies to at least -40 dB (a gain of 0.01) at M class.



The synchrophasor measurement is adaptive as it follows the fundamental frequency over a wide range despite the reporting rate.

For example, when the synchrophasor measurement follows the fundamental frequency beyond the fixed Nyquist limits in C37.118 standard, the anti-aliasing filter stopband moves with the measured fundamental frequency. This has to be considered in connection with C37.118, where the passband is defined relative to a fixed nominal frequency as shown in the equation [12](#).

$$f_0 \pm \frac{F_s}{2}$$

(Equation 12)

where,

f_0 is the nominal frequency

F_s is the reporting rate

6.1.3.3

Scaling Factors for ANALOGREPORT channels

The internal calculation of analog values in the IED is based on 32 bit floating point. Therefore, if the user selects to report the analog data (*AnalogDataType*) as *Integer*, there will be a down-conversion of a 32 bit floating value to a new 16 bit integer value. In such a case, in order to optimize the resolution of the reported analog data, the user-defined analog scaling is implemented in the IED.

The analog scaling in the IED is automatically calculated by use of the user-defined parameters *AnalogXRange* for the respective analog channel X. The analog data value on the input X will have a range between $-AnalogXRange$ and $+AnalogXRange$. The resulting scale factor will be applied to the reported analog data where applicable.

If the *AnalogDataType* is selected as *Float*, then these settings are ignored.

The analog scaling in the IED is calculated using the equation:

$$Scalefactor = \frac{AnalogXRange \times 2}{65535.0}$$

$$offset = 0.0$$

$$65535.0 = 16 \text{ bit integer range}$$

According to the IEEE C37.118.2 standard, the scale factors (conversion factor) for analog channels are defined in configuration frame 2 (CFG-2) and configuration frame 3 (CFG-3) frames as follows:

- **CFG-2 frame:** The field ANUNIT (4 bytes) specifies the conversion factor as a signed 24 bit word for user defined scaling. Since it is a 24 bit integer, in order to support the floating point scale factor, the scale factor itself is multiplied in 10, so that a minimum of 0.1 scale factor can be sent over the CFG-2 frame. The resulting scale factor is rounded to the nearest decimal value. The clients receiving

the Analog scale factor over CFG-2 should divide the received scale factor by 10 and then apply it to the corresponding analog data value.

- **CFG-3 frame:** The field ANSCALE (8 bytes) specifies the conversion factor as $X' = M * X + B$ where; M is magnitude scaling in 32 bit floating point (first 4 bytes) and B is the offset in 32 bit floating point (last 4 bytes).

The server uses CFG-3 scale factor to scale the analog data values. As a result, the clients which use scale factors in CFG-3 in order to recalculate analog values, will get a better resolution than using the scale factors in CFG-2.

The following examples show how the scale factor is calculated.

Example 1:

$$\text{AnalogXRange} = 3277.0$$

The scale factor is calculated as follows:

$$\text{scalefactor} = \frac{(3277.0 \times 2.0)}{65535.0} = 0.1 \text{ and } \text{offset} = 0.0$$

The scale factor will be sent as 1 on configuration frame 2, and 0.1 on configuration frame 3. The range of analog values that can be transmitted in this case is -0.1 to -3276.8 and $+0.1$ to $+3276.7$.

Example 2:

$$\text{AnalogXRange} = 4915.5$$

The scale factor is calculated as follows:

$$\text{scalefactor} = \frac{(4915.5 \times 2.0)}{65535.0} = 0.15 \text{ and } \text{offset} = 0.0$$

The scale factor will be sent as 1 on configuration frame 2, and 0.15 on configuration frame 3. The range of analog values that can be transmitted in this case is -0.15 to -4915.5 and $+0.15$ to $+4915.5$.

Example 3:

$$\text{AnalogXRange} = 10000000000$$

The scale factor is calculated as follows:

$$scalefactor = \frac{(10000000000 \times 2.0)}{65535.5} = 305180.43 \text{ and } offset = 0.0$$

The scale factor will be sent as 3051804 on configuration frame 2, and 305180.43 on configuration frame 3. The range of analog values that can be transmitted in this case is -305181 to -10000000000 and +305181 to +10000000000.

6.1.3.4

PMU Report Function Blocks Connection Rules in PCM600 Application Configuration Tool (ACT)

There are 3 important general rules which have to be considered in PCM600 ACT for the connection of preprocessor blocks (SMAI) and 3PHSUM blocks to PHASORREPORT blocks:

Rule 1:

Only SMAI or 3PHSUM blocks shall be connected to PMU PHASORREPORT blocks and they shall have the same cycle time, 0.9 ms.

Figure 36 shows an example of correct connection of SMAI and PHASORREPORT blocks in ACT where both function blocks are working on 0.9 ms cycle time.

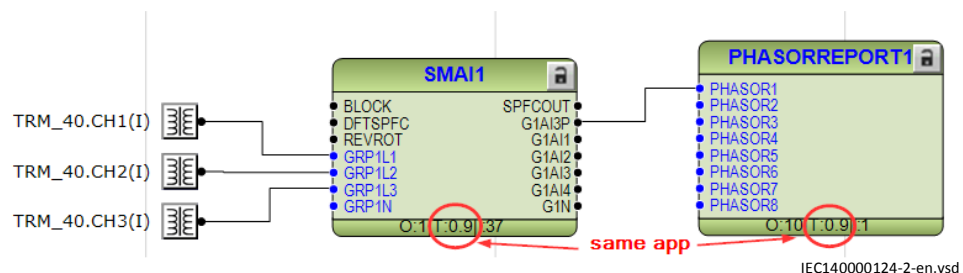


Figure 36: An example of correct connection of SMAI and PHASORREPORT blocks in ACT

Figure 37 shows an example of wrong connection of SMAI and PHASORREPORT blocks in ACT where the SMAI block is working on 3 ms while PHASORREPORT block is working on 0.9 ms cycle time.

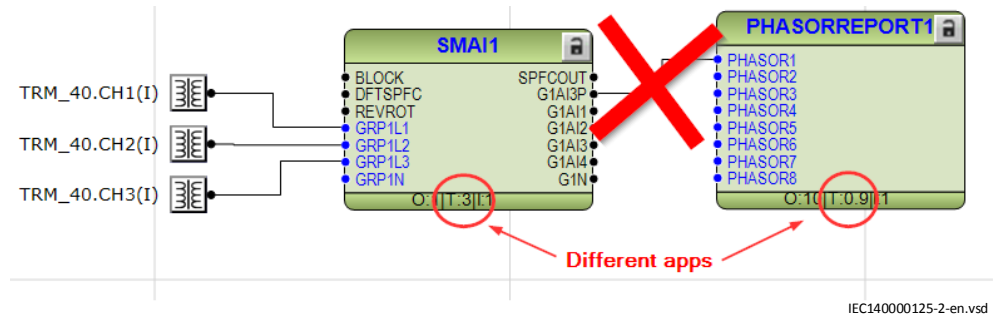


Figure 37: An example of wrong connection of SMAI and PHASORREPORT blocks in ACT

Violation of rule 1 results in PMU applications not running at all. The reason is the inconsistent cycle time. For example, in Figure 37, the SMAI block is updating its output every 3 ms while the PHASORREPORT block is expecting input every 0.9 ms. The PHASORREPORT filtering window is designed to receive updated input every 0.9 ms and therefore the application will fail.

Rule 2:

The same SMAI or 3PHSUM block can be connected to more than one PHASORREPORT block only if all the connected PHASORREPORT blocks have similar instance number or only if all the connected PHASORREPORT blocks have similar settings for SvcClass and ReportRate. Figure 38 shows the settings for PMUREPORT function block demonstrated by PCM600 Parameter Setting Tool (PST).

PMUREPORT: 1				
✓ Operation		On		
✓ SvcClass		P class		
✓ Global_PMU_ID		0		16 character
✓ PMUdataStreamIDCODE		1	1	65534
✓ PhasorFormat		Rectangular		
✓ PhasorDataType		Float		
✓ AnalogDataType		Float		
✓ FrequencyDataType		Float		
✓ SendFreqInfo		On		
✓ ReportRate		10/10 fr/s (60/50Hz)		
✓ RptTimetag		MiddleSample		

Figure 38: PMUREPORT settings in PCM600 PST

Figure 39 shows an example of correct connection of SMAI and PHASORREPORT blocks in ACT where two different SMAI blocks are connected to different PHASORREPORT blocks with different instance numbers. In this example, as the

PHASORREPORT blocks have different instance numbers and different settings for SvcClass and ReportRate, a separate SMAI block is used for each PHASORREPORT block.

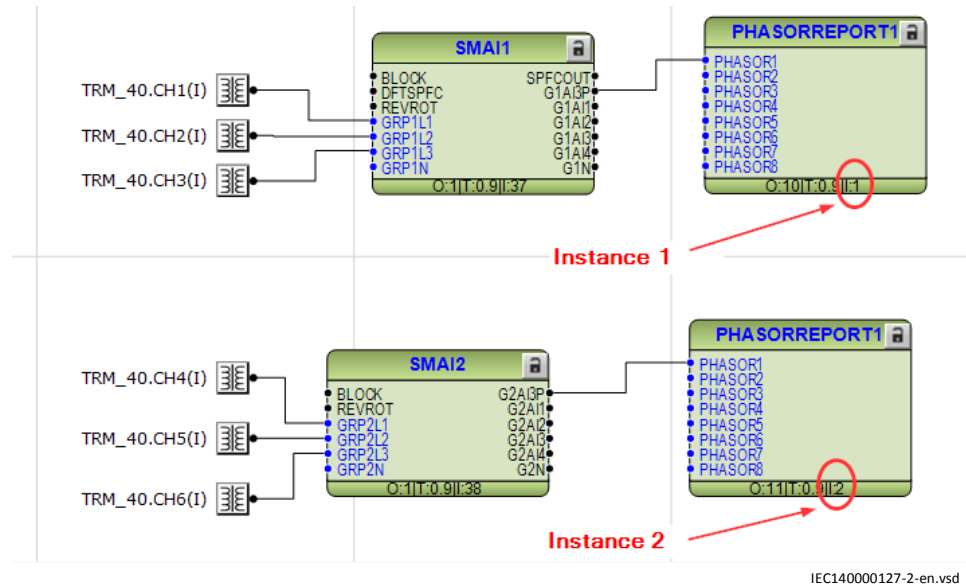


Figure 39: An example of correct connection of SMAI and PHASORREPORT blocks in ACT

Figure 40 shows an example of wrong connection of SMAI and PHASORREPORT blocks in ACT where the same SMAI block is connected to different PHASORREPORT blocks with different instance numbers. Such connection will be only correct if both connected PHASORREPORT blocks have similar settings for SvcClass and ReportRate. If settings for PMUREPORT instances differ for SvcClass or ReportRate, then PHASOR1 connection in PHASORREPORT1 instance 2 will not be compliant with IEEE C37.118 standard. The reason is that the filtering in SMAI/3PHSUM block is adapted according to the performance class (SvcClass) and reporting rate of the connected instance of PHASORREPORT function block. In this example, SMAI1 will adapt its filtering according to PHASORREPORT instance 1 (because of higher priority) and therefore PHASORREPORT instance 2 will receive data which does not match its performance class and report rate.

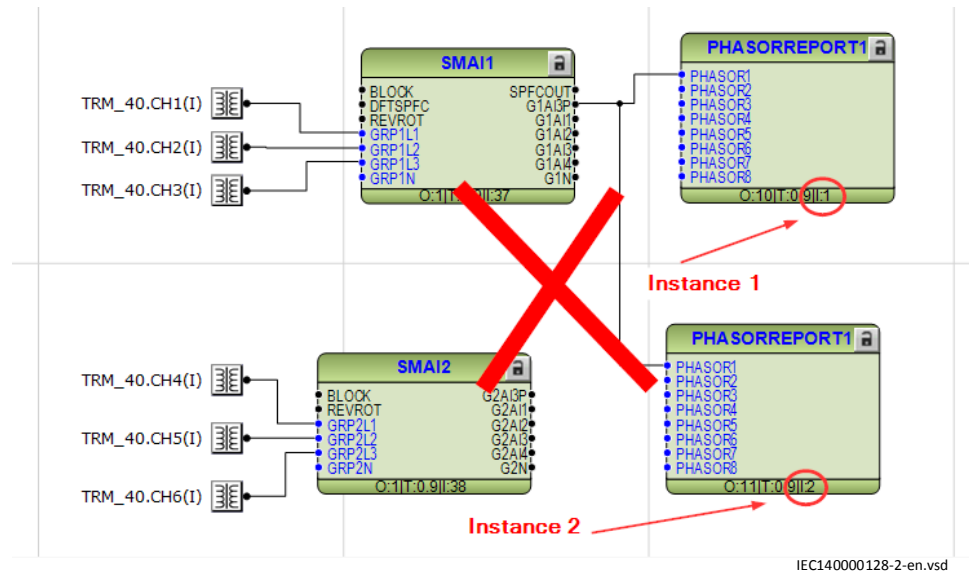


Figure 40: An example of wrong connection of SMAI and PHASORREPORT blocks in ACT

Rule 3:

This rule is only related to the connection of 3PHSUM block to the PHASORREPORT block. If 3PHSUM block is configured to use external DFT reference (from SMAI reference block), it shall only be connected to the same PHASORREPORT block instance as the one the SMAI reference block is connected to. In other words, both the SMAI reference block and 3PHSUM block (3PHSUM block with external DFT reference) shall be connected to the same instance of PHASORREPORT block (PHASOR1-32 of Instance number 1 or 2).

Figure 41 shows an example of correct connection of 3PHSUM and PHASORREPORT blocks in ACT where SMAI3 is configured as the reference block for DFT reference external out (DFTRefExtOut) and 3PHSUM uses external DFT reference (from SMAI3). Figures 42 and 43 show the corresponding setting parameters.

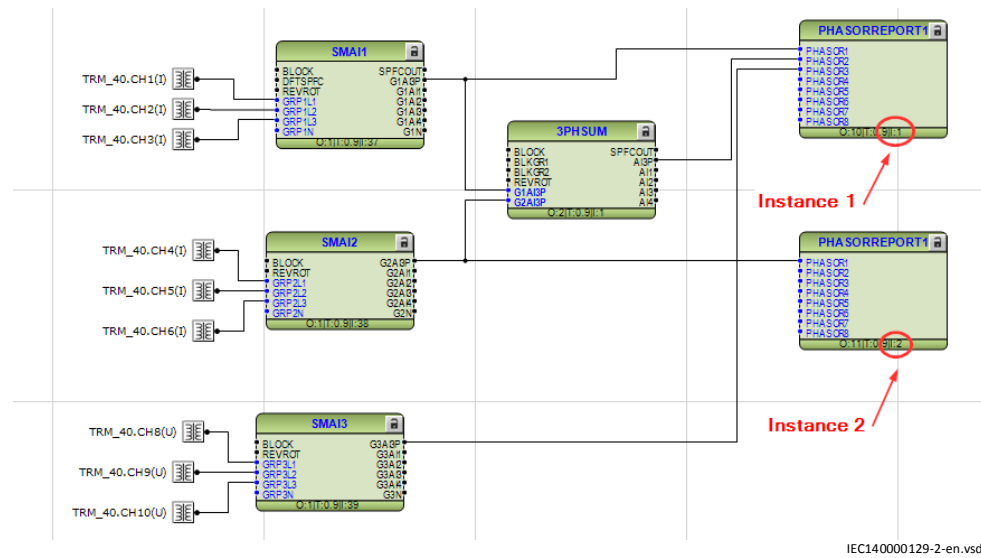


Figure 41: An example of correct connection of 3PHSUM and PHASORREPORT blocks in ACT

✓	SMA1: 25	
✓	AI1NAME	GRP1L1
✓	AI2NAME	GRP1L2
✓	AI3NAME	GRP1L3
✓	AI4NAME	GRP1N
✓	GlobalBaseSel	1
✓	DFTRefExtOut	DFTRefGrp3
✓	DFTReference	DFTRefGrp3
✓	ConnectionType	Dh-N

IEC140000130-1-en.vsd

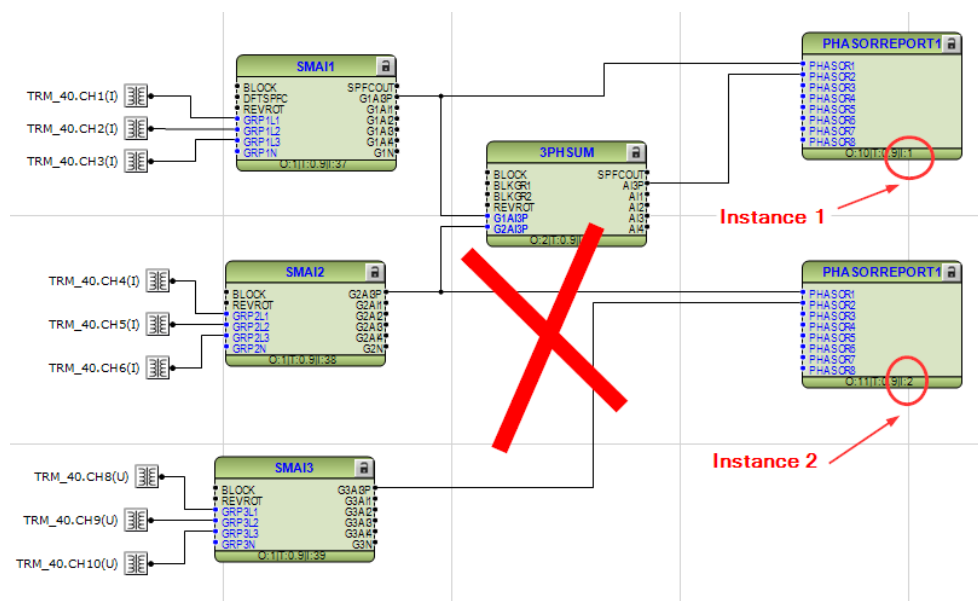
Figure 42: SMA1 setting parameters example-showing that SMA13 is selected as the DFT reference (DFTRefGrp3)

3PHSUM: 13	
GRP1NAME	G1AI3P
GRP2NAME	G2AI3P
GlobalBaseSel	1
SummationType	Group1+Group2
DFTReference	External DFT ref
FromMascMinVal	10

IEC140000131-1-en

Figure 43: 3PHSUM setting parameters example-showing that 3PHSUM is using the External DFT reference coming indirectly from SMAI3

Figure 44 shows an example of wrong connection of 3PHSUM and PHASORREPORT blocks in ACT where SMAI3 is configured as the reference block for DFT reference external out (DFTRefExtOut) and 3PHSUM uses external DFT reference (from SMAI3).



IEC140000132-2-en.vsd

Figure 44: An example of wrong connection of 3PHSUM and PHASORREPORT blocks in ACT

If settings for PMUREPORT instances (PHASORREPORT1 instances 1 and 2 above) differ for SvcClass or ReportRate, then the synchrophasor reported by PHASOR2 connection from PHASORREPORT1 instance 2 will not be compliant with IEEE C37.118 standard. The reason is as in the rule 2, the filtering in SMAI/3PHSUM block

is adapted according to the performance class (SvcClass) and reporting rate of the connected instance of PHASORREPORT function block. On the other hand, when 3PHSUM uses external DFT reference, it also adapts its filtering according to the SMAI reference block. Therefore, in order to avoid two different filtering applied to the 3PHSUM block, both SMAI reference block and 3PHSUM shall be connected to the same PHASORREPORT instance. In this example (Figure 44), SMAI3 adapts its filtering according to PHASORREPORT1 instance 2 (due to connection) and 3PHSUM is adapting its filtering according to PHASORREPORT1 instance 1. On the other hand, since 3PHSUM is set to receive external DFT reference from SMAI3, therefore If settings for PHASORREPORT1 instances 1 and 2 above differ for SvcClass or ReportRate, then 3PHSUM block will be affected by two different filtering at the same time which is not possible. For example in Figure 44, PHASOR2 from PHASORREPORT1 instance 1 may not be fully compliant with IEEE C37.118 standard.

Note: If the SMAI reference block is not connected to any PHASORREPORT block, then 3PHSUM block can be freely connected to any PHASORREPORT block regardless of its DFT reference setting.

Note: If more 3PHSUM blocks need to be used, all 3PHSUM blocks (using external DFT ref) have to be connected to the same instance of PHASORREPORT blocks (PHASOR1-32 of Instance number 1 or 2).

Note: If settings SvcClass and ReportRate are the same for different instances of PHASORREPORT blocks, then 3PHSUM block can be freely connected to any of them regardless of 3PHSUM block DFT reference setting or the reference SMAI block connection.

Note: Violation of rules 2 or 3 results in non-compliance with IEEE C37.118 standard for some of the synchrophasors. In case of rule 2 violation, the non-compliance only applies to synchrophasors from instance 2 and the synchrophasors from instance 1 will be still compliant. The non-compliance with the standard may be quite obvious as in case of rule 2 violation with different SvcClass settings. This produces big angle error. On the other hand, it may be difficult to detect the non-compliance with the standard if rule 2 is violated with different ReportRates, or if rule 3 is violated. In such cases, the synchrophasors may only fail to comply (with small error) in some particular test case(s).

For more information regarding 3PHSUM block application, please refer to the Application Manual under section Basic IED functions.

6.1.4

Setting guidelines

Based on the functionality and appearance in PCM600, the PMU reporting functionality is categorized into 4 different categories (function block) as follows:

1. PMUREPORT
2. PHASORREPORT
3. ANALOGREPORT
4. BINARYREPORT

Each category has its corresponding parameter settings except for BINARYREPORT function block which does not have any specific parameters and settings.

1. PMUREPORT is the main function block which controls the operation of other PMU reporting function blocks. Each instance of PMUREPORT function block has the following parameters:
 - *Operation*: Enables/Disables the operation of the corresponding instance of PMU reporting functionality by choosing *On/Off* setting.
 - *SvcClass*: It refers to the 1-byte SVC_CLASS field of the configuration frame 3 (CFG-3) organization defined in IEEE C37.118.2 message format. Here the user can select the performance class (service class) used for synchrophasor data measurement according to IEEE C37.118.1 standard. The options are *P class* or *M class*.
Note: There are 2 PMUREPORT instances available (PMUREPORT:1 and PMUREPORT:2) corresponding to 2 independent data streams. The user can set different or identical service class for each data stream. In case of different service classes, special rules shall be considered in PCM600 ACT for the connection of preprocessor blocks (SMAI) and 3PHSUM blocks to PHASORREPORT blocks. More details are available under section [PMU Report Function Blocks Connection Rules in PCM600 Application Configuration Tool \(ACT\)](#).
 - *Global_PMU_ID*: It refers to the 16-byte G_PMU_ID field of the configuration frame 3 (CFG-3) organization defined in IEEE C37.118.2 message format. It is a 16-character (128 bits) user-assigned value which can be sent with the configuration 3 message. It allows uniquely identifying PMUs in a system that has more than 65535 PMUs. The coding for the 16 bytes is left to the user for assignment.
 - *PMUdataStreamIDCODE*: It refers to the 2-byte IDCODE field of the configuration frame and data frame organization defined in IEEE C37.118.2 message format. It is a user assigned ID number (1-65534) for each data stream sent out from the PMU. This is especially important when having multiple data streams (multiple PMU functionality).
Note: The data stream IDCODE is a unique code for each and every data stream in one physical PMU device. In the IED, there are 2 PMUREPORT instances available (PMUREPORT:1 and PMUREPORT:2) corresponding to 2 independent data streams. The user must set different IDCODEs for each instance.
 - *PhasorFormat*: It refers to the Bit 0 of the FORMAT field of the configuration frames 1, 2 and 3 organization defined in IEEE C37.118.2 message format. Here the user can select the format of the calculated

synchrophasors. The options are *Rectangular* or *Polar* format. Rectangular format represents the synchrophasor as real and imaginary values, real value first ($\mathbf{a} + \mathbf{bj}$) while the Polar format represents the synchrophasor as magnitude and angle, magnitude first ($\mathbf{A} e^{j\alpha}$).

- *PhasorDataType*: It refers to the Bit 1 of the FORMAT field of the configuration frames 1, 2 and 3 organization defined in IEEE C37.118.2 message format. Here the user can select the data type of the calculated synchrophasors. The options are *Integer* or *Float* data. The synchrophasor data are sent via the PHASORS field of data frame organization of IEEE C37.118.2 message format. Depends on the phasor data type, the size of PHASORS field can be 4 (Integer) or 8 (Float) bytes per IEEE C37.118.2 message.

Integer data type for the phasors corresponds to a 16-bit integer value. It represents a 16-bit signed integer, range $-32\,767$ to $+32\,767$, in rectangular format, and in polar format it represents a 16-bit unsigned integer range 0 to 65535 for the magnitude and a 16-bit signed integer, in radians $\times 10^4$, range $-31\,416$ to $+31\,416$ for the angle.

Float data type for the phasors corresponds to 32-bit values in IEEE floating-point format. In rectangular format, it represents real and imaginary, in engineering units (real value first) and in polar format it represents magnitude and angle, in engineering units (magnitude first) and angle in radians, range $-\pi$ to $+\pi$.

- *AnalogDataType*: It refers to the Bit 2 of the FORMAT field of the configuration frames 1, 2 and 3 organization defined in IEEE C37.118.2 message format. Here the user can select the type of the analog data which are reported along with the synchrophasor data over IEEE C37.118.2 message. The options are *Integer* or *Float* data corresponding to the 16-bit integer or 32-bit IEEE floating-point values, respectively. The analog data could be sampled data such as control signal or transducer values, or it can be active and reactive power measurement values from each feeder in the substation. Values and ranges are separately defined by user via the parameter settings related to the ANALOGREPORT function block. The analog data are sent via the ANALOG field of data frame organization of IEEE C37.118.2 message format. Depends on the analog data type, the size of ANALOG field can be 2 (Integer) or 4 (Float) bytes per IEEE C37.118.2 message. More information is available under the section [Scaling Factors for ANALOGREPORT channels](#).
- *FrequencyDataType*: It refers to the Bit 3 of the FORMAT field of the configuration frames 1, 2 and 3 organization defined in IEEE C37.118.2 message format. Here the user can select the type of the frequency-deviation and rate-of-change-of-frequency data (FREQ/DFREQ) which can be reported along with the synchrophasor data over IEEE C37.118.2 message. The options are *Integer* or *Float* data corresponding to the 16-bit integer or 32-bit IEEE floating-point value, respectively.

The frequency-deviation and rate-of-change-of-frequency data are sent via the FREQ and DFREQ fields of data frame organization of IEEE C37.118.2 message format. Depends on the selected data type, the size of each field can be 2 (Integer) or 4 (Float) bytes per IEEE C37.118.2 message.

The data sent via the FREQ field is frequency deviation from nominal frequency (50 Hz or 60 Hz), in mHz. It is ranged from -32.767 to $+32.767$ Hz. *Integer* data type for frequency-deviation data represents 16-bit signed integers, range $-32\,767$ to $+32\,767\,32$, and *Float* data type represents actual frequency value in IEEE floating-point format.

The data sent via the DFREQ field is Rate Of Change Of Frequency (ROCOF), in Hertz per second times 100. It is ranged from -327.67 to $+327.67$ Hz per second. *Integer* data type for ROCOF data represents 16-bit signed integers, range $-32\,767$ to $+32\,767\,32$, and *Float* data type represents actual value in IEEE floating-point format.

- *SendFreqInfo*: Enables/Disables sending of the frequency-deviation and Rate Of Change Of Frequency (ROCOF) data by choosing *On/Off* setting.
- *ReportRate*: It refers to the 2-byte DATA_RATE field of the configuration frames 1, 2 and 3 organization defined in IEEE C37.118.2 message format. The DATA_RATE field is identifying the Rate of phasor data transmissions by a 2-byte integer word ($-32\,767$ to $+32\,767$). Here the user can select the synchrophasor data reporting rate from the PMU based on the number of frames per second.

In general, the IED has 5 different reporting rates (10, 25, 50, 100, 200 fr/s) on the 50 Hz system frequency, and has 8 different reporting rates (10, 12, 15, 20, 30, 60, 120, 240 fr/s) on the 60 Hz system frequency. The options are as follows:

- 10/10 fr/s (60/50Hz)
- 12/10 fr/s (60/50Hz)
- 15/10 fr/s (60/50Hz)
- 20/25 fr/s (60/50Hz)
- 30/25 fr/s (60/50Hz)
- 60/50 fr/s (60/50Hz)
- 120/100 fr/s (60/50Hz)
- 240/200 fr/s (60/50Hz)

The first number is identifying the reporting rate in a 60Hz system, and the second number is the reporting rate in a 50Hz system. For example, if the selected setting is *15/10 fr/s (60/50Hz)*, this means that the synchrophasor data reporting rate would be 15 frames per second if the system frequency is 60Hz. Likewise, if the system frequency is 50Hz, the selected rate is equal to 10 frames per second.

- *RptTimetag*: It refers to the method of time-tagging used in the IED which is related to the phasor estimation and filtering technique. The options are *FirstSample*, *MiddleSample* and *LastSample*. The time-stamp of the PMU output represents the phasor equivalent, frequency, and ROCOF of the

power system signal at the time it is applied to the PMU input. All of these estimates must be compensated for PMU processing delays including analog input filtering, sampling, and estimation group delay. If the sample time tags are compensated for all input delays, the time tag of the sample in the middle of the estimation window can be used for the phasor estimation (output) time tag as long as the filtering coefficients are symmetrical across the filtering window.

Note: It is recommended to set this parameter on *MiddleSample*.

2. PHASORREPORT is the function block responsible for reporting the synchrophasors. Each instance of PMUREPORT function block has 32 phasor channels with the following setting parameters; where X is a number from 1 to 32:
 - *PhasorXReport*: Enables/Disables the phasor channel X (reporting of PhasorX) by choosing *On/Off* setting.
 - *PhasorX*: The group selector for PhasorX. Here, the user can select the type of reported synchrophasor from the phasor channel X as either a 3-phase symmetrical component or a single-phase phasor. The options are as follows:
 - A
 - B
 - C
 - NEGSEQ
 - POSSEQ
 - ZEROSEQ
 - *PhasorXUseFreqSrc*: Enables/Disables the contribution of Phasor channel X in automatic frequency source selection by choosing *On/Off* setting. Each voltage-connected preprocessor block delivers the frequency data, derived from the analog input AC voltage values, to the respective voltage phasor channel. Every phasor channel has a user-settable parameter (*PhasorXUseFreqSrc*) to be used as a source of frequency data for reporting to the PDC client. It is very important to set this parameter to *On* for the voltage-connected phasor channels. There is an automatic frequency source selection logic to ensure an uninterrupted reporting of the system frequency to the PDC client. More information is available under the section [Frequency reporting](#).
3. ANALOGREPORT is the function block responsible for reporting the analog values. Each instance of ANALOGREPORT function block has 24 analog channels with the following setting parameters; where X is a number from 1 to 24:
 - *AnalogXRange*: This parameter defines a range between *-AnalogXRange* and *+AnalogXRange* for AnalogX value. The range will be used by the IED to apply a proper scale factor to the AnalogX values when *Integer* format is used. It refers to the 4-byte ANUNIT field of the configuration frames 1, 2 organization and the 8-byte ANSCALE field of the configuration frame 3 organization defined in IEEE C37.118.2 message format. The *AnalogXRange* value can be a number between 3277.0 and 1000000000.

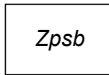
This setting is only important if the AnalogDataType setting is selected as *Integer*. More information is available under the section [Scaling Factors for ANALOGREPORT channels](#).

- *AnalogXUnitType*: Unit type for analog signal X. It refers to the 4-byte ANUNIT field of the configuration frames 1, 2 organization defined in IEEE C37.118.2 message format. The options are *Single point-on-wave*, *RMS of analog input* and *Peak of analog input*.

Section 7 Impedance protection

7.1 Power swing detection ZMRPSB (68)

7.1.1 Identification

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

7.1.2 Application

7.1.2.1 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 45. This locus can enter the operating characteristic of a distance protection and cause, if no preventive measures have been considered, its unwanted operation.

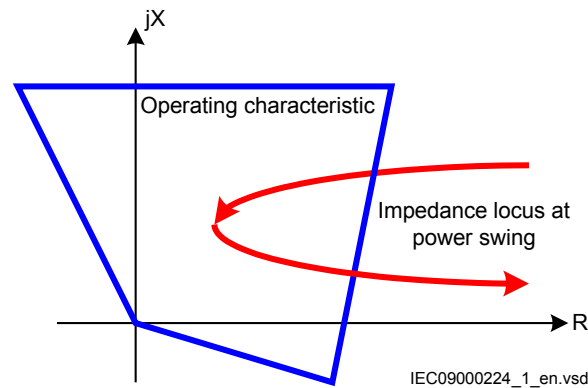


Figure 45: Impedance plane with Power swing detection operating characteristic and impedance locus at power swing

7.1.2.2

Basic characteristics

Power swing detection function (ZMRPSB, 78) 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 (78) 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 (78) 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.

7.1.3

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 [46](#).

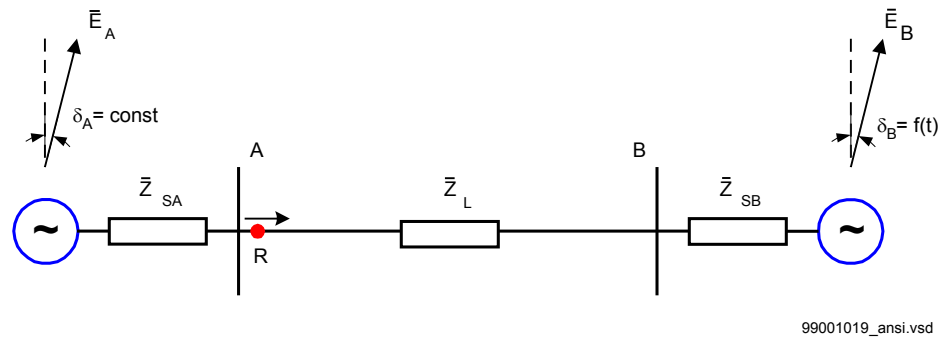


Figure 46: Protected power line as part of a two-machine system

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:

$$V_r = 400kV$$

Rated system voltage

$$V_{\min} = 380kV$$

Minimum expected system voltage under critical system conditions

$$f_n = 60Hz$$

Rated system frequency

$$V_p = \frac{400}{\sqrt{3}} kV$$

Rated primary voltage of voltage (or potential) transformers used

$$V_s = \frac{0.115}{\sqrt{3}} kV$$

Rated secondary voltage of voltage (or potential) transformers used

$$I_p = 1200 A$$

Rated primary current of current transformers used

$$I_s = 5 A$$

Rated secondary current of current transformers used

$$\bar{Z}_{L1} = (10.71 + j75.6) \Omega$$

Positive sequence line impedance

Table continues on next page

$\bar{Z}_{SA1} = (1.15 + j43.5)\Omega$	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 V_{\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 [13](#).

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

(Equation 13)

The minimum load resistance $R_{L\min}$ at maximum load and minimum system voltage is equal to equation [14](#).

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

(Equation 14)

The system impedance Z_S is determined as a sum of all impedances in an equivalent two-machine system, see figure [46](#). Its value is calculated according to equation [15](#).

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

(Equation 15)

The calculated value of the system impedance is of informative nature and helps in determining the position of the oscillation center, see figure [47](#), which is for a general case calculated according to equation [16](#).

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

(Equation 16)

In particular cases, when

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

(Equation 17)

The center of oscillation resides on the impedance point according to equation [18](#).

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

(Equation 18)

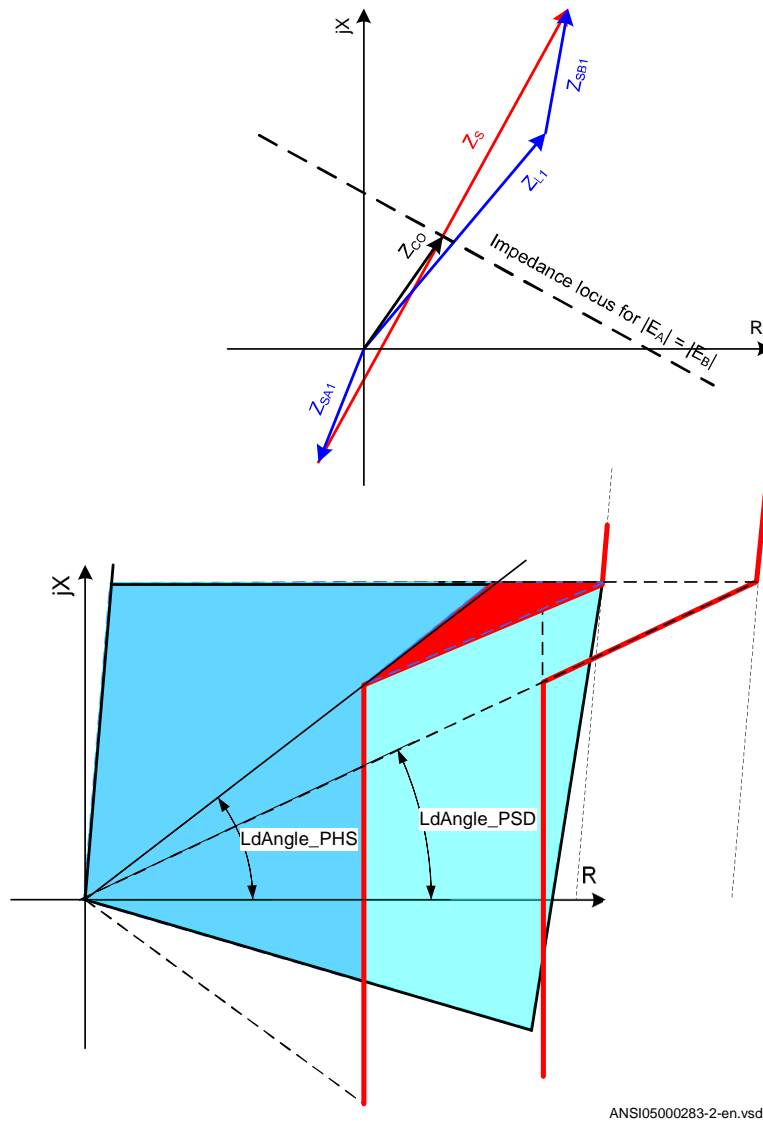


Figure 47: Impedance diagrams with corresponding impedances under consideration

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 100 miles
- $K_L = 0.85$ for lines between 50 and 100 miles
- $K_L = 0.8$ for lines shorter than 50 miles

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 [19](#).

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

(Equation 19)

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 [20](#) presents the corresponding maximum possible value of $RLdInFw$.

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

(Equation 20)

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 [21](#) and [22](#) 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 21)

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

(Equation 22)

The required setting $tP1$ of the initial oscillation detection timer depends on the load angle difference according to equation [23](#).

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

(Equation 23)

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 [24](#), [25](#), [26](#) and [27](#).

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

(Equation 24)

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

(Equation 25)

$$RLdInFw_{\max 1} = \frac{|\bar{Z}_S|}{2 \cdot \tan\left(\frac{\delta_{in-\min}}{2}\right)} = \frac{155.75}{2 \cdot \tan\left(\frac{91.5}{2}\right)} = 75.8\Omega$$

(Equation 26)

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

(Equation 27)

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 [28](#).

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

(Equation 28)

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 $RLdFwd$ in Phase selection with load encroachment (FDPSDIS, 21 or FRPSDIS, 21) 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 FDPSDIS (21) or FRPSDIS (21) to follow the condition presented in equation [29](#).



Index PHS designates correspondence to FDPSDIS (21) or FRPSDIS (21) function and index PSD the correspondence to ZMRPSB (68) function.

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

(Equation 29)

Consider equation [30](#),

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

(Equation 30)

then it is necessary to set the load angle in FDPSDIS (21) or FRPSDIS (21) function to not less than equation [31](#).

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

(Equation 31)

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, 68) during the power swing, even after the transient impedance leaves ZMRPSB (68) 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.

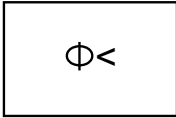
The $tR1$ inhibit timer delays the influence of the detected residual current on the inhibit criteria for ZMRPSB(68). It prevents operation of the function for short transients in the residual current measured by the IED.

The $tR2$ inhibit timer disables the output PICKUP signal from ZMRPSB (68) function, if the measured impedance remains within ZMRPSB (68) 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 tGF 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.

7.2 Out-of-step protection OOSPPAM (78)

7.2.1 Identification

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

7.2.2 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.

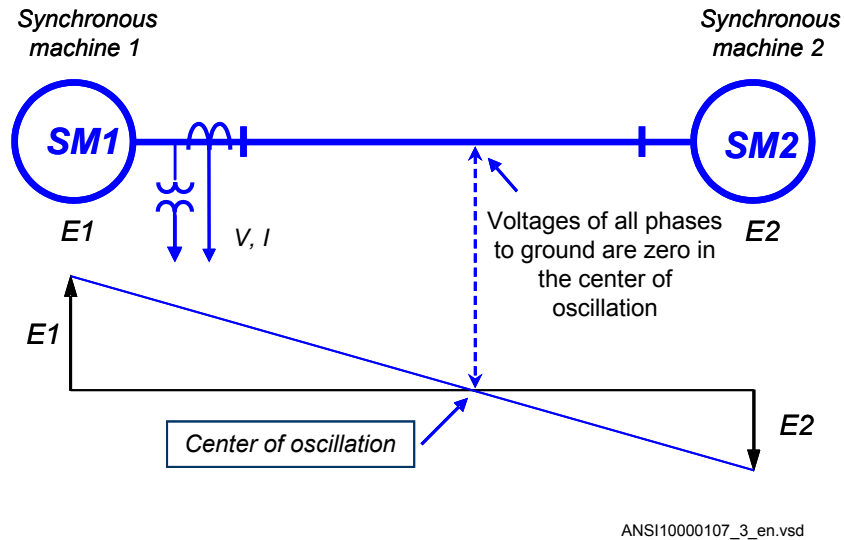


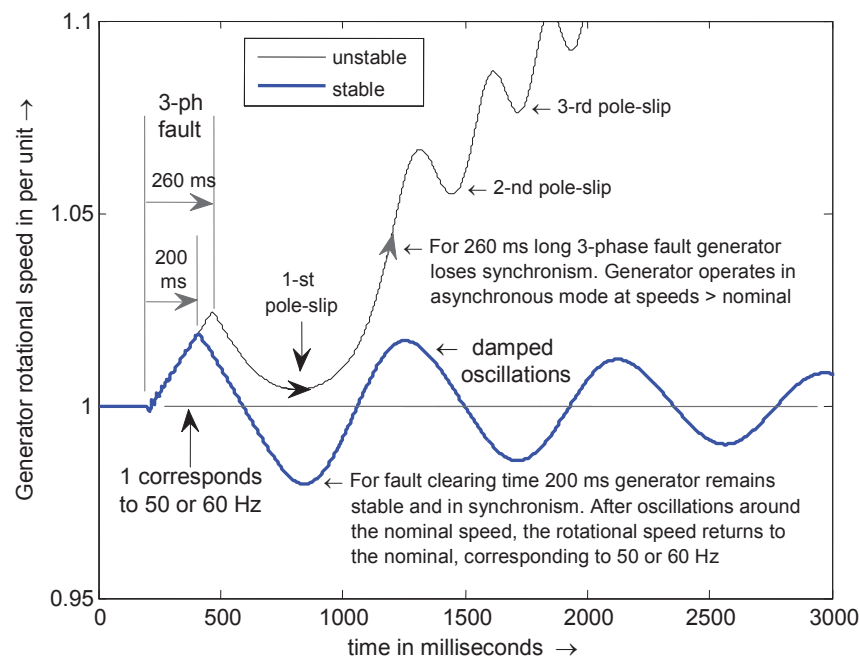
Figure 48: The center of electromechanical oscillation

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 49.



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Figure 49: *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.

7.2.3 Setting guidelines

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

Table 12: An example how to calculate values for the settings *ForwardR*, *ForwardX*, *ReverseR*, and *ReverseX*

	Generator	Step-up transformer	Single power line	Power system
Data required	VBase = Vgen = 13.8 kV IBase = Igen = 8367 A Xd' = 0.2960 pu Rs = 0.0029 pu	V1 = 13.8 kV usc = 10% V2 = 230 kV I1 = 12 551 A Xt = 0.1000 pu (transf. ZBase)	Vline = 230 kV Xline/km = 0.4289 Ω/km Rline/km = 0.0659 Ω/km	Vnom = 230 kV SC level = 5000 MVA SC current = 12 551 A φ = 84.289° Ze = 10.5801 Ω

Table continues on next page

		Rt = 0.0054 pu (transf. ZBase)		
1-st step in calculation	ZBase = 0.9522 Ω (generator) Xd' = 0.2960 · 0.952 = 0.282 Ω Rs = 0.0029 · 0.952 = 0.003 Ω	ZBase (13.8 kV) = 0.6348 Ω Xt = 0.100 · 0.6348 = 0.064 Ω Rt = 0.0054 · 0.635 = 0.003 Ω	Xline = 300 · 0.4289 = 128.7 Ω Rline = 300 · 0.0659 = 19.8 Ω (X and R above on 230 kV basis)	Xe = Ze · sin(φ) = 10.52 Ω Re = Ze · cos(φ) = 1.05 Ω (Xe and Re on 230 kV basis)
2-nd step in calculation	Xd' = 0.2960 · 0.952 = 0.282 Ω Rs = 0.0029 · 0.952 = 0.003 Ω	Xt = 0.100 · 0.6348 = 0.064 Ω Rt = 0.0054 · 0.635 = 0.003 Ω	Xline = 128.7 · (13.8/230) ² = 0.463 Ω Rline = 19.8 · (13.8/230) ² = 0.071 Ω (X and R referred to 13.8 kV)	Xe = 10.52 · (13.8/230) ² = 0.038 Ω Re = 1.05 · (13.8/230) ² = 0.004 Ω (X and R referred to 13.8 kV)
3-rd step in calculation	ForwardX = Xt + Xline + Xe = 0.064 + 0.463 + 0.038 = 0.565 Ω; ReverseX = Xd' = 0.282 Ω (all referred to gen. voltage 13.8 kV) ForwardR = Rt + Rline + Re = 0.003 + 0.071 + 0.004 = 0.078 Ω; ReverseR = Rs = 0.003 Ω (all referred to gen. voltage 13.8 kV)			
Final resulted settings	ForwardX = 0.565/0.9522 · 100 = 59.33 in % ZBase; ReverseX = 0.282/0.9522 · 100 = 29.6 in % ZBase (all referred to 13.8 kV) ForwardR = 0.078/0.9522 · 100 = 8.19 in % ZBase; ReverseR = 0.003/0.9522 · 100 = 0.29 in % ZBase (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 12, 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 must be referred to the voltage level where the Out-of-step relay is installed; for the example case shown in Table 12, this is the generator nominal voltage VBase = 13.8 kV. This affects all the forward reactances and resistances in Table 12.
- All reactances and resistances must be finally expressed in percent of ZBase, where ZBase is for the example shown in Table 12 the base impedance of the generator, ZBase = 0.9522 Ω. Observe that the power transformer's base impedance is different, ZBase = 0.6348 Ω. Observe that this latter power transformer ZBase = 0.6348 Ω must be used when the power transformer reactance and resistance are transformed.

- For the synchronous machines as the generator in Table [12](#), 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 [12](#) 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 [12](#), where the reactance of the 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 – 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.
- *pick up Angle*: 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 pickup 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 (PICKUP) 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 exactly 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*.

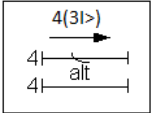
- *tReset*: Interval of time since the last pole-slip detected, when the Out-of-step protection is reset. If there is no more pole slips detected under the time interval specified by *tReset* since the previous one, the function is reset. All outputs are set to 0 (FALSE). If no pole slip at all is detected under interval of time specified by *tReset* since the pickup signal has been set (for example a stable case with synchronism retained), the function is as well reset, which includes the pickup output signal (PICKUP), 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 12, 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 *Enabled, Disabled*. If *OperationZ1* = *Disabled*, all pole-slips with centre of the electromagnetic oscillation within zone 1 are ignored. Default setting = *Enabled*. 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 *Enabled, Disabled*. If *OperationZ1* = *Disabled*, all pole-slips with centre of the electromagnetic oscillation within zone 2 are ignored. Default setting = *Enabled*.
- *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.
- *VBase*: This is the voltage at the point where the Out-of-step protection is installed. If the protection is installed on the generator output terminals, then *VBase* is the nominal (rated) phase to phase voltage of the protected generator. All the resistances and reactances are measured and displayed referred to voltage *VBase*. Observe that *ReverseX*, *ForwardX*, *ReverseR*, and *ForwardR* must be given referred to *VBase*. *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 (LV-side) then inversion is not necessary (*InvertCTCurr* = *Disabled*), provided that the CT's orientation complies with ABB recommendations, as shown in Table 12. If the currents fed to the Out-of-step

protection are measured on the protected generator output terminals side (HV-side), then inversion is necessary (*InvertCTCurr = Enabled*), provided that the CT's actual direction complies with ABB recommendations, as shown in Table [12](#).

Section 8 Current protection

8.1 Directional phase overcurrent protection, four steps OC4PTOC(51_67)

8.1.1 Identification

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

8.1.2 Application

Directional phase overcurrent protection, four steps OC4PTOC (51_67) 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 (51_67) 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 *DirModeSelx* ($x = \text{step } 1, 2, 3 \text{ or } 4$) 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 (51/67) 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 ground faults by the phase overcurrent protection. This fault type is detected and cleared after operation of ground 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 ground faults are not detected.

8.1.3 Setting guidelines



When inverse time overcurrent characteristic is selected, the trip 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 (51/67) are set via the local HMI or PCM600.

The following settings can be done for OC4PTOC (51/67).

Common base IED values for the primary current (*IBase*), primary voltage (*VBase*) 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*, *VBase* and *SBase* as applicable.

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 *Enabled* or *Disabled*.

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 50.

NumPhSel: 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*.

PUMinOpPhSel: Minimum current setting level for releasing the directional start signals in % of *IB*. This setting should be less than the lowest step setting. The default setting is 7% of *IB*.

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%.

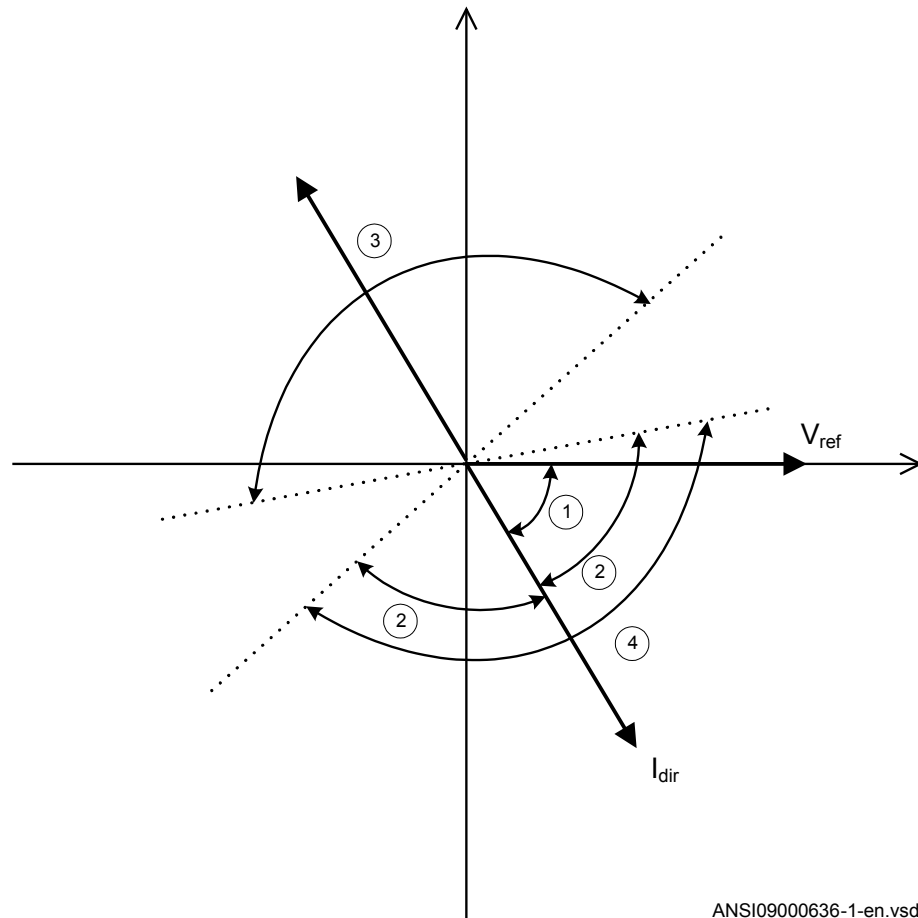


Figure 50: Directional function characteristic

1. RCA = Relay characteristic angle
2. ROA = Relay operating angle
3. Reverse
4. Forward

8.1.3.1

Settings for each step



x means step 1, 2, 3 and 4.

DirModeSelx: The directional mode of step x . Possible settings are *Disabled/Non-directional/Forward/Reverse*.

Characteristic: Selection of time characteristic for step x . Definite time delay and different types of inverse time characteristics are available according to Table 13.

Table 13: *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*.

Pickup x : Operate phase current level for step x given in % of IB .

$I_{x>Max}$ 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.

TD_x : Time multiplier for inverse time delay for step x .

I_{Minx} : Minimum operate current in % of IB for all inverse time characteristics, below which no operation takes place.

IMinx: Minimum pickup current for step x in % of I_{Base} . Set *IMinx* below *Pickup_x* for every step to achieve ANSI reset characteristic according to standard. If *IMinx* is set above *Pickup_x* for any step the ANSI reset works as if current is zero when current drops below *IMinx*.

txMin: Minimum trip 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.

MultPU_x: 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

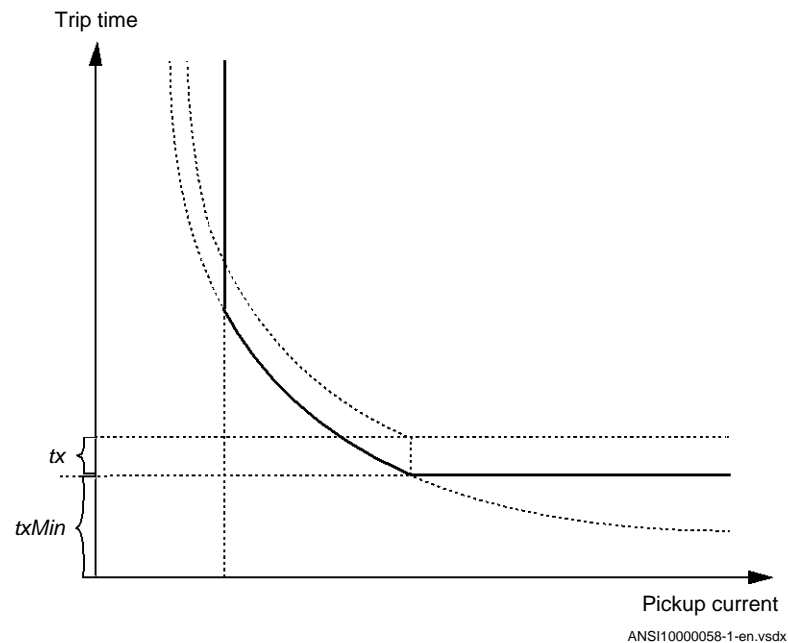


Figure 51: Minimum pickup current and trip time for inverse time characteristics

In order to fully comply with the definition of the curve, the setting parameter *txMin* 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 kx .

ResetTypeCrvx: The reset of the delay timer can be made as shown in Table 14.

Table 14: *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.

$tResetx$: Constant reset time delay in seconds for step x.

$tPCrvx$, $tACrvx$, $tBCrvx$, $tCCrvx$: These parameters are used by the customer to create the inverse time characteristic curve. See equation 32 for the time characteristic equation. For more information, refer to *Technical manual*.

$$t[s] = \left(\frac{A}{\left(\frac{i}{in>} \right)^p - C} + B \right) \cdot MultPUx$$

(Equation 32)

$tPRCrvx$, $tTRCrvx$, $tCRCrvx$: These parameters are used by the customer to create the inverse reset time characteristic curve. For more information, refer to *Technical manual*.

$HarmRestrinx$: Enables the block 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 *Disabled/Enabled*.

8.1.3.2 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 pickup 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 52.

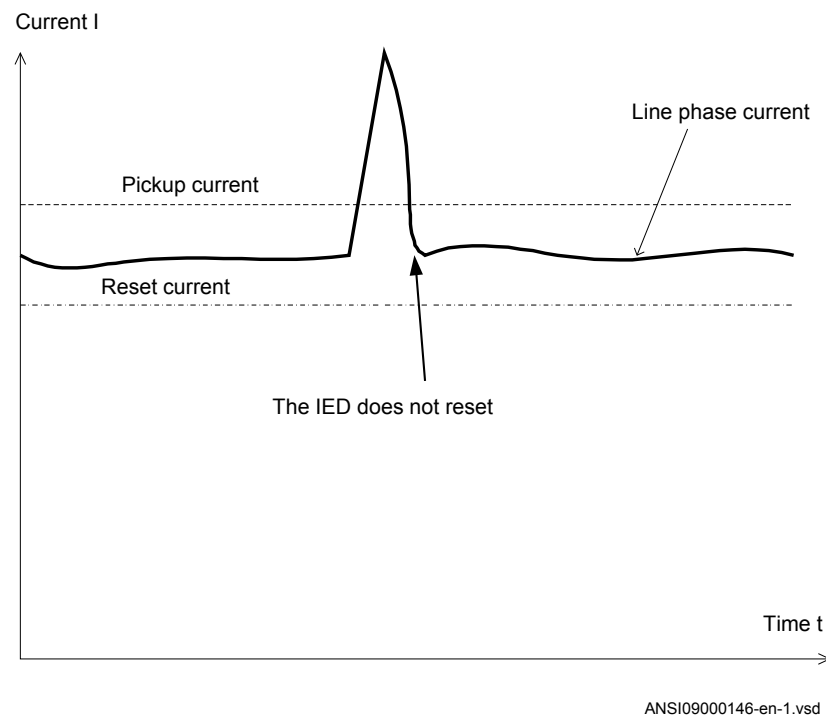


Figure 52: Pickup and reset current for an overcurrent protection

The lowest setting value can be written according to Equation 33.

$$I_{pu} \geq 1.2 \cdot \frac{I_{max}}{k}$$

(Equation 33)

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 [34](#).

$$I_{pu} \leq 0.7 \cdot I_{sc \min}$$

(Equation 34)

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 pickup current shall be chosen within the interval stated in Equation [35](#).

$$1.2 \cdot \frac{I_{max}}{k} \leq I_{pu} \leq 0.7 \cdot I_{sc \min}$$

(Equation 35)

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 36)

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 1.05

I_{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 53 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.

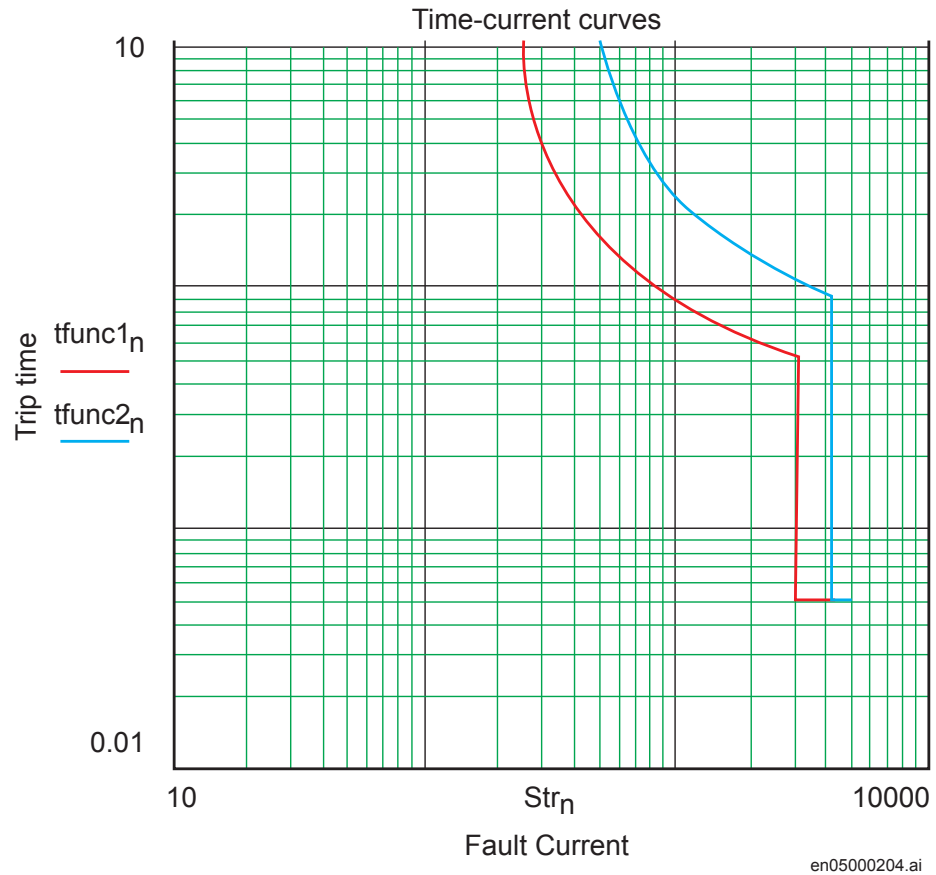


Figure 53: Fault time with maintained selectivity

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 54. 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 54.

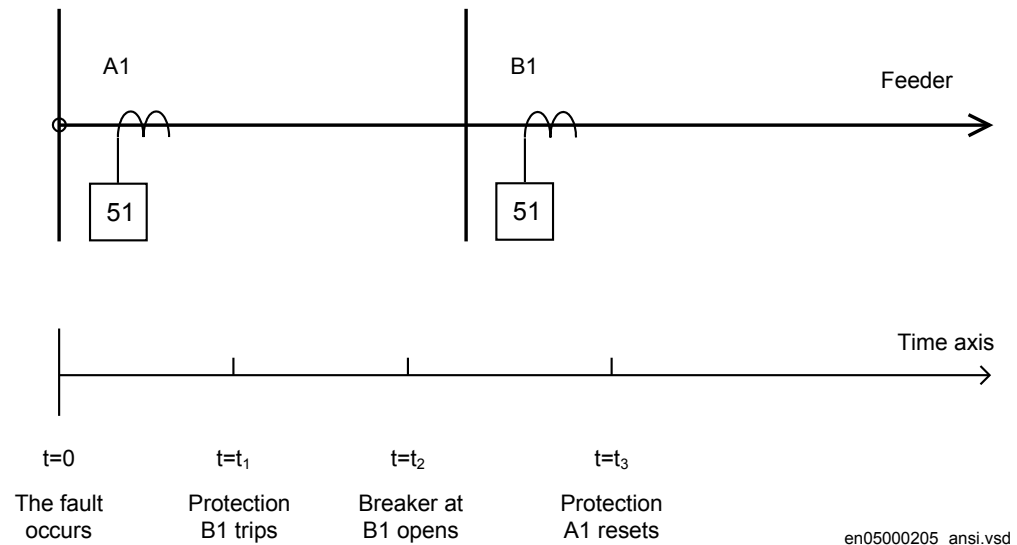


Figure 54: Sequence of events during fault

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 37.

$$\Delta t \geq 40 \text{ ms} + 100 \text{ ms} + 40 \text{ ms} + 40 \text{ ms} = 220 \text{ ms}$$

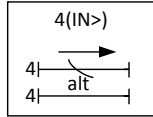
(Equation 37)

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

8.2 Directional residual overcurrent protection, four steps EF4PTOC (51N/67N)

8.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Directional residual overcurrent protection, four steps	EF4PTOC		51N_67N

8.2.2 Setting guidelines



When inverse time overcurrent characteristic is selected, the trip 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 overcurrent 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 (I_{Base}), primary voltage (V_{Base}) and primary power (S_{Base}) are set in global base values for settings function GBASVAL.

GlobalBaseSel: Selects the global base value group used by the function to define *I*Base, *V*Base and *S*Base as applicable.

SeqTypeUPol: This is used to select the type of voltage polarising quantity i.e. Zero seq or Neg seq for direction detection.

SeqTypeIPol: This is used to select the type of current polarising quantity i.e. Zero seq or Neg seq for direction detection.

SeqTypeIDir: This is used to select the type of operating current quantity i.e. Zero seq or Neg seq for direction detection.

8.2.2.1

Common settings for all steps

AngleRCA: Relay characteristic angle given in degree. This angle is defined as shown in Figure 55. The angle is defined positive when the residual current lags the reference voltage ($V_{pol} = 3V_0$ or V_2)

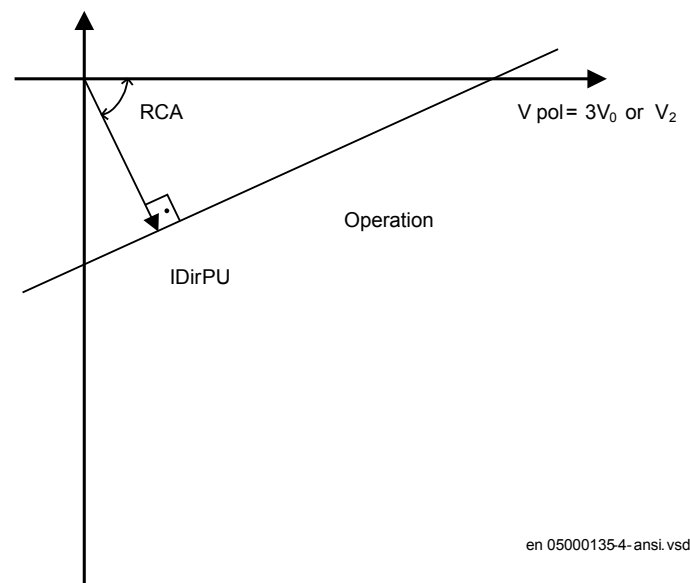


Figure 55: Relay characteristic angle given in degree

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* ($3V_0$ or V_2)
- *Current* ($3I_0 \cdot Z_{Npol}$ or $3I_2 \cdot Z_{Npol}$ where Z_{Npol} is $R_{Npol} + jX_{Npol}$), or
- both currents and voltage, *Dual* (dual polarizing, $(3V_0 + 3I_0 \cdot Z_{Npol})$ or $(V_2 + I_2 \cdot Z_{Npol})$).

Normally voltage polarizing from the internally calculated residual sum or an external open delta is used.

Current polarizing is useful when the local source is strong and a high sensitivity is required. In such cases the polarizing voltage ($3V_0$) can be below 1% and it is then necessary to use current polarizing or dual polarizing. Multiply the required set current (primary) with the minimum impedance (Z_{Npol}) and check that the percentage of the phase-to-ground voltage is definitely higher than 1% (minimum $3V_0 > V_{PolMin}$ setting) as a verification.

RNPOL, *XNPOL*: The zero-sequence source is set in primary ohms as base for the current polarizing. The polarizing voltage is then achieved as $3I_0 \cdot Z_{Npol}$. The Z_{Npol} can be defined as $(Z_{S1} - Z_{S0})/3$, that is the ground return impedance of the source behind the protection. The maximum ground-fault current at the local source can be used to calculate the value of Z_N as $V/(\sqrt{3} \cdot 3I_0)$. 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 *Pickupx* or the product $3I_0 \cdot Z_{Npol}$ is not greater than $3V_0$. If so, there is a risk for incorrect operation for faults in the reverse direction.

IPolMin: is the minimum ground-fault current accepted for directional evaluation. For smaller currents than this value, the operation will be blocked. A typical setting is 5-10% of I_B .

VPolMin: Minimum polarization (reference) polarizing voltage for the directional function, given in % of $V_{Base}/\sqrt{3}$.

IDirPU: Operate residual current release level in % of I_B for directional comparison scheme. The setting is given in % of I_B and must be set below the lowest I_{Nx} setting, set for the directional measurement. The output signals, PUFW and PUREV can be used in a teleprotection scheme. The appropriate signal should be configured to the communication scheme block.

8.2.2.2

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 overcurrent 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 function.

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.

8.2.2.3

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.

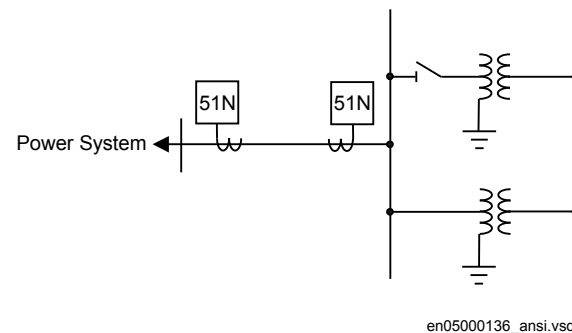


Figure 56: Application for parallel transformer inrush current logic

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 (51N_67N). 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: This is used to *Enable* blocking at energising of parallel transformers.

Use_PUValue: 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.

8.2.2.4

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 function 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: *Disabled/SOTF/Under Time/SOTF+Under Time*.

SOTFSel: 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 pickup signal will be used as current set level. If set on step 2, the step 2 pickup signal will be used as current set level.

HarmBlkSOTF: This is used to *On/Off* harmonic restrain during SOTF conditions.

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.

ActUndrTimeSel: 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

8.2.2.5

Settings for each step (x = 1, 2, 3 and 4)

Operation: Sets the protection to *Enabled* or *Disabled*.

DirModeSelx: The directional mode of step *x*. Possible settings are *Disabled/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 trip 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.

Pickup"x": 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 pickup current for step x in % of IB . Set $IMinx$ below $Pickupx$ for every step to achieve ANSI reset characteristic according to standard. If $IMinx$ is set above 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.

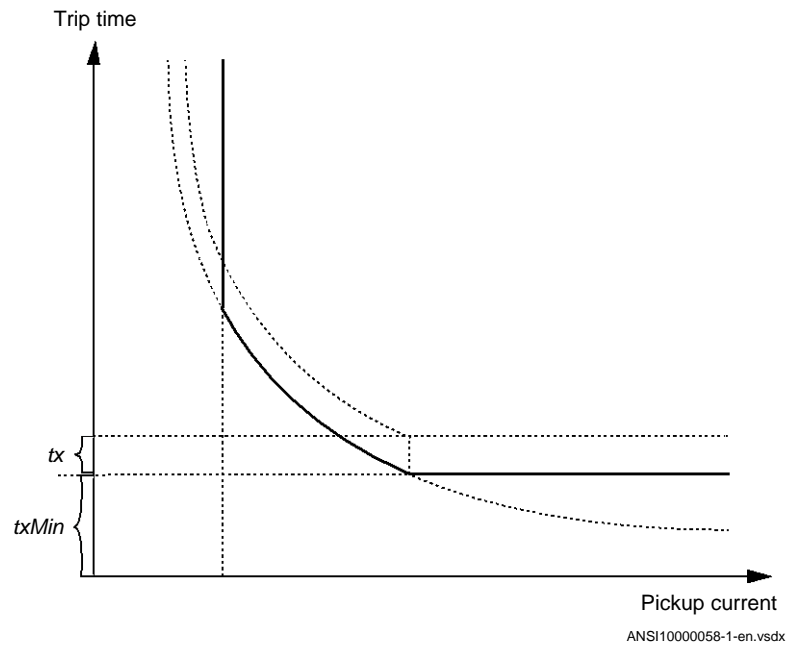


Figure 57: Minimum pickup current and trip time for inverse time characteristics

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 (MULTPU x) 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: This is used to enable block 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 38:

$$t[s] = \left(\frac{A}{\left(\frac{i}{i_{pickup}} \right)^p - C} + B \right) \cdot TD$$

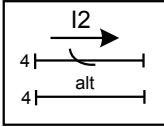
(Equation 38)

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.

8.3 Four step directional negative phase sequence overcurrent protection NS4PTOC (46I2)

8.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Four step negative sequence overcurrent protection	NS4PTOC		46I2

8.3.2 Application

Four step negative sequence overcurrent protection NS4PTOC (46I2) is used in several applications in the power system. Some applications are:

- Ground-fault and phase-phase short circuit protection of feeders in effectively grounded distribution and subtransmission systems. Normally these feeders have radial structure.
- Back-up ground-fault and phase-phase short circuit protection of transmission lines.
- Sensitive ground-fault protection of transmission lines. NS4PTOC (4612) can have better sensitivity to detect resistive phase-to-ground-faults compared to distance protection.
- Back-up ground-fault and phase-phase short circuit protection of power transformers.
- Ground-fault and phase-phase short circuit 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 pickup levels and time delays are needed. NS4PTOC (4612) can have up to four, individual settable steps. The flexibility of each step of NS4PTOC (4612) function 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 unsymmetrical fault protection in meshed and effectively grounded transmission systems. The directional negative sequence overcurrent protection is also well suited to operate in teleprotection communication schemes, which enables fast clearance of unsymmetrical faults on transmission lines. The directional function uses the voltage polarizing quantity.

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 operating time of the different protections. To enable optimal co-ordination all overcurrent relays, to be co-ordinated against each other, should have the same time characteristic. Therefore a wide range of standardized inverse time characteristics are available: IEC and ANSI.

Table 15: *Inverse time characteristics*

Curve name
ANSI Extremely Inverse
ANSI Very Inverse
ANSI Normal Inverse
ANSI Moderately Inverse
ANSI/IEEE Definite time
Table continues on next page

Curve name
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 (logarithmic)

There is also a user programmable inverse time characteristic.

Normally it is required that the negative sequence overcurrent function 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 pickup level for some time. Therefore there is a possibility to give a setting of a multiplication factor $MultP_{Ux}$ to the negative sequence current pick-up level. This multiplication factor is activated from a binary input signal $MULTP_{Ux}$ to the function.

8.3.3

Setting guidelines

The parameters for Four step negative sequence overcurrent protection NS4PTOC (46I2) are set via the local HMI or Protection and Control Manager (PCM600).

The following settings can be done for the four step negative sequence overcurrent protection:

Operation: Sets the protection to *Enabled* or *Disabled*.

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

GlobalBaseSel: Selects the global base value group used by the function to define *I*Base, *V*Base and *S*Base as applicable.



When inverse time overcurrent characteristic is selected, the trip 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.

8.3.3.1

Settings for each step



x means step 1, 2, 3 and 4.

DirModeSelx: The directional mode of step x. Possible settings are off/nondirectional/forward/reverse.

Characteristicx: Selection of time characteristic for step x. Definite time delay and different types of inverse time characteristics are available.

Table 16: *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 (logarithmic)

The different characteristics are described in the Technical Reference Manual (TRM).

Pickup_x: Operation negative sequence current level for step x given in % of *I_{Base}*.

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.

TD_x: Time multiplier for the dependent (inverse) characteristic.

IMinx: Minimum pickup current for step x in % of *I_{Base}*. Set *IMinx* below *Pickup_x* for every step to achieve ANSI reset characteristic according to standard. If *IMinx* is set above *Pickup_x* for any step the ANSI reset works as if current is zero when current drops below *IMinx*.

MultPU_x: Multiplier for scaling of the current setting value. If a binary input signal (ENMULT_x) is activated the current operation level is multiplied by this setting constant.

t_{xMin}: Minimum operation 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.

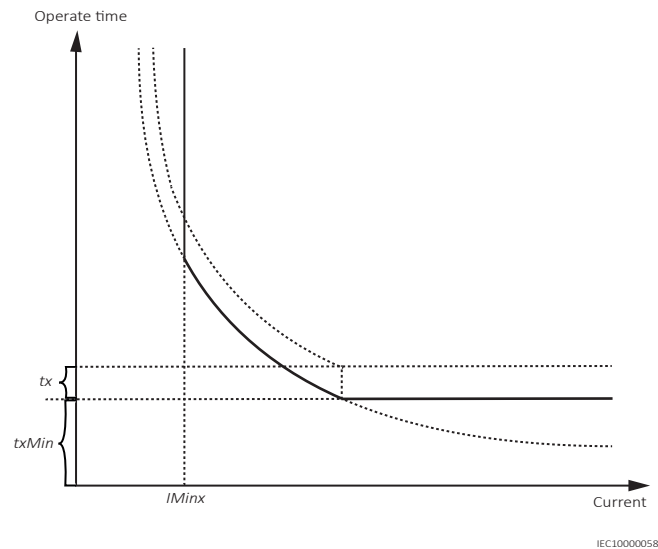


Figure 58: Minimum operate current and operation time for inverse time characteristics

ResetTypeCrvx: The reset of the delay timer can be made in different ways. By choosing setting there are the following possibilities:

Curve name
Instantaneous
IEC Reset (constant time)
ANSI Reset (inverse time)

The different reset characteristics are described in the Technical Reference Manual (TRM). There are some restrictions regarding the choice of reset delay.

For the independent time delay characteristics the possible delay time settings are instantaneous (1) and IEC (2 = set constant time reset).

For ANSI inverse time delay 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 delay characteristics the possible delay time settings are instantaneous (1) and IEC (2 = set constant time reset).

For the programmable inverse time delay 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). If the current dependent type is used settings pr , tr and cr must be given.

$tPCrvx$, $tACrvx$, $tBCrvx$, $tCCrvx$: Parameters for programmable inverse time characteristic curve. The time characteristic equation is according to equation [39](#):

$$t[s] = \left(\frac{A}{\left(\frac{i}{i_{pickup}} \right)^p - C} + B \right) \cdot TD$$

(Equation 39)

Further description can be found in the Technical reference manual (TRM).

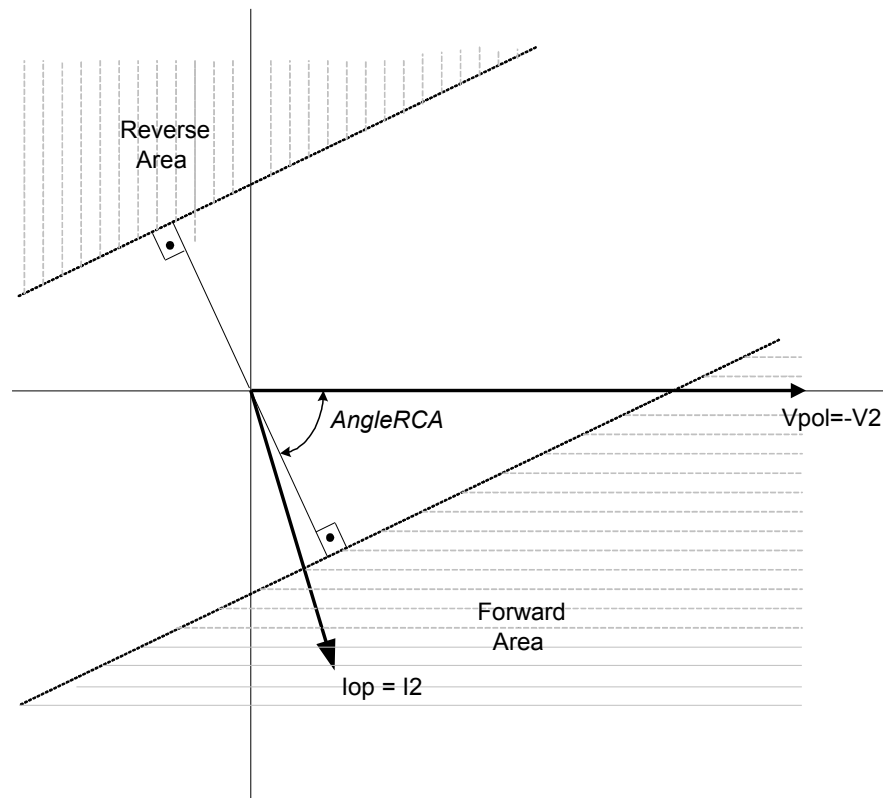
$tPRCrvx$, $tTRCrvx$, $tCRCrvx$: Parameters for customer creation of inverse reset time characteristic curve. Further description can be found in the Technical Reference Manual.

8.3.3.2 Common settings for all steps



x means step 1, 2, 3 and 4.

AngleRCA: Relay characteristic angle given in degrees. This angle is defined as shown in figure 59. The angle is defined positive when the residual current lags the reference voltage ($V_{pol} = -$)



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Figure 59: Relay characteristic angle given in degree

In a transmission network a normal value of RCA is about 80°.

VPolMin: Minimum polarization (reference) voltage % of *VBase*.

I>Dir: Operate residual current level for directional comparison scheme. The setting is given in % of *IBase*. The pickup forward or pickup reverse signals can be used in a communication scheme. The appropriate signal must be configured to the communication scheme block.

8.4 Sensitive directional residual overcurrent and power protection SDEPSDE (67N)

8.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Sensitive directional residual over current and power protection	SDEPSDE	-	67N

8.4.2 Application

In networks with high impedance grounding, the phase-to-ground fault current is significantly smaller than the short circuit currents. Another difficulty for ground fault protection is that the magnitude of the phase-to-ground fault current is almost independent of the fault location in the network.

Directional residual current can be used to detect and give selective trip of phase-to-ground faults in high impedance grounded networks. The protection uses the residual current component $3I_0 \cdot \cos \varphi$, where φ is the angle between the residual current and the residual voltage ($-3V_0$), compensated with a characteristic angle. Alternatively, the function can be set to strict $3I_0$ level with a check of angle φ .

Directional residual power can also be used to detect and give selective trip of phase-to-ground faults in high impedance grounded networks. The protection uses the residual power component $3I_0 \cdot 3V_0 \cdot \cos \varphi$, where φ is the angle between the residual current and the reference residual voltage, compensated with a characteristic angle.

A normal non-directional residual current function can also be used with definite or inverse time delay.

A backup neutral point voltage function is also available for non-directional residual overvoltage protection.

In an isolated network, that is, the network is only coupled to ground via the capacitances between the phase conductors and ground, the residual current always has -90° phase shift compared to the residual voltage ($3V_0$). The characteristic angle is chosen to -90° in such a network.

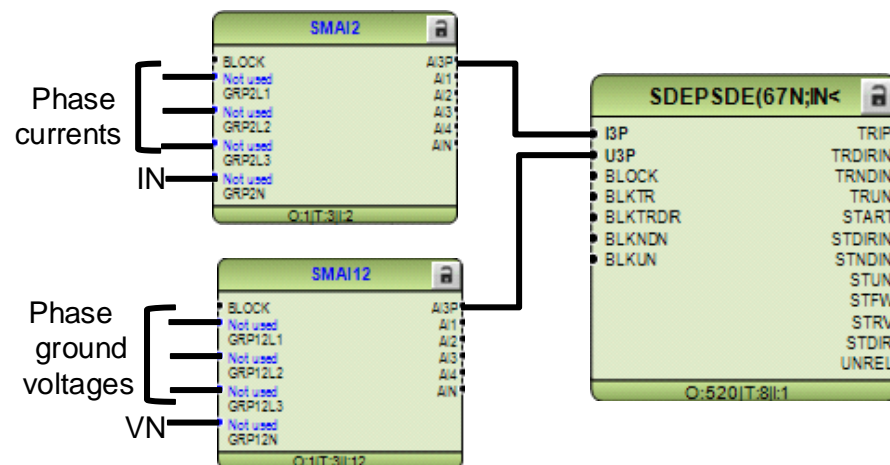
In resistance grounded networks or in Petersen coil grounded, with a parallel resistor, the active residual current component (in phase with the residual voltage) should be

used for the ground fault detection. In such networks, the characteristic angle is chosen to 0° .

As the magnitude of the residual current is independent of the fault location, the selectivity of the ground fault protection is achieved by time selectivity.

When should the sensitive directional residual overcurrent protection be used and when should the sensitive directional residual power protection be used? Consider the following:

- Sensitive directional residual overcurrent protection gives possibility for better sensitivity. The setting possibilities of this function are down to 0.25 % of IBase, 1 A or 5 A. This sensitivity is in most cases sufficient in high impedance network applications, if the measuring CT ratio is not too high.
- Sensitive directional residual power protection gives possibility to use inverse time characteristics. This is applicable in large high impedance grounded networks, with large capacitive ground fault currents. In such networks, the active fault current would be small and by using sensitive directional residual power protection, the operating quantity is elevated. Therefore, better possibility to detect ground faults. In addition, in low impedance grounded networks, the inverse time characteristic gives better time-selectivity in case of high zero-resistive fault currents.



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Figure 60: Connection of SDEPSDE to analog preprocessing function block

Overcurrent functionality uses true 3I0, i.e. sum of GRPxA, GRPxB and GRPxC. For 3I0 to be calculated, connection is needed to all three phase inputs.

Directional and power functionality uses IN and VN. If a connection is made to GRPxN this signal is used, else if connection is made to all inputs GRPxA, GRPxB and GRPxC the internally calculated sum of these inputs (3I0 and 3V0) will be used.

8.4.3 Setting guidelines

The sensitive ground-fault protection is intended to be used in high impedance grounded systems, or in systems with resistive grounding where the neutral point resistor gives an ground-fault current larger than what normal high impedance gives but smaller than the phase to phase short circuit current.

In a high impedance system the fault current is assumed to be limited by the system zero sequence shunt impedance to ground and the fault resistance only. All the series impedances in the system are assumed to be zero.

In the setting of ground-fault protection, in a high impedance grounded system, the neutral point voltage (zero sequence voltage) and the ground-fault current will be calculated at the desired sensitivity (fault resistance). The complex neutral point voltage (zero sequence) can be calculated as:

$$V_0 = \frac{V_{\text{phase}}}{1 + \frac{3 \cdot R_f}{Z_0}}$$

(Equation 40)

Where

V_{phase} is the phase voltage in the fault point before the fault,

R_f is the resistance to ground in the fault point and

Z_0 is the system zero sequence impedance to ground

The fault current, in the fault point, can be calculated as:

$$I_j = 3I_0 = \frac{3 \cdot V_{\text{phase}}}{Z_0 + 3 \cdot R_f}$$

(Equation 41)

The impedance Z_0 is dependent on the system grounding. In an isolated system (without neutral point apparatus) the impedance is equal to the capacitive coupling between the phase conductors and ground:

$$Z_0 = -jX_c = -j \frac{3 \cdot V_{\text{phase}}}{I_j}$$

(Equation 42)

Where

I_j is the capacitive ground fault current at a non-resistive phase-to-ground fault

X_c is the capacitive reactance to ground

In a system with a neutral point resistor (resistance grounded system) the impedance Z_0 can be calculated as:

$$Z_0 = \frac{-jX_c \cdot 3R_n}{-jX_c + 3R_n}$$

(Equation 43)

Where

R_n is the resistance of the neutral point resistor

In many systems there is also a neutral point reactor (Petersen coil) connected to one or more transformer neutral points. In such a system the impedance Z_0 can be calculated as:

$$Z_0 = -jX_c // 3R_n // j3X_n = \frac{9R_n X_n X_c}{3X_n X_c + j3R_n \cdot (3X_n - X_c)}$$

(Equation 44)

Where

X_n is the reactance of the Petersen coil. If the Petersen coil is well tuned we have $3X_n = X_c$. In this case the impedance Z_0 will be: $Z_0 = 3R_n$

Now consider a system with an grounding via a resistor giving higher ground fault current than the high impedance grounding. The series impedances in the system can no longer be neglected. The system with a single phase to ground fault can be described as in Figure [61](#).

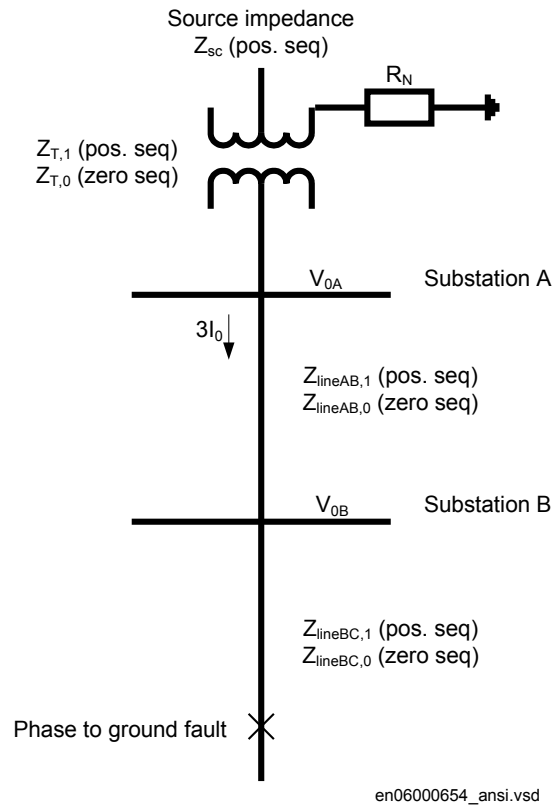


Figure 61: Equivalent of power system for calculation of setting

The residual fault current can be written:

$$3I_0 = \frac{3V_{\text{phase}}}{2 \cdot Z_1 + Z_0 + 3 \cdot R_f}$$

(Equation 45)

Where

V_{phase} is the phase voltage in the fault point before the fault

Z_1 is the total positive sequence impedance to the fault point. $Z_1 = Z_{sc} + Z_{T,1} + Z_{\text{lineAB},1} + Z_{\text{lineBC},1}$

Z_0 is the total zero sequence impedance to the fault point. $Z_0 = Z_{T,0} + 3R_N + Z_{\text{lineAB},0} + Z_{\text{lineBC},0}$

R_f is the fault resistance.

The residual voltages in stations A and B can be written:

$$V_{0A} = 3I_0 \cdot (Z_{T,0} + 3R_N)$$

(Equation 46)

$$V_{0B} = 3I_0 \cdot (Z_{T,0} + 3R_N + Z_{\text{lineAB},0})$$

(Equation 47)

The residual power, measured by the sensitive ground fault protections in A and B will be:

$$S_{0A} = 3V_{0A} \cdot 3I_0$$

(Equation 48)

$$S_{0B} = 3V_{0B} \cdot 3I_0$$

(Equation 49)

The residual power is a complex quantity. The protection will have a maximum sensitivity in the characteristic angle RCA. The apparent residual power component in the characteristic angle, measured by the protection, can be written:

$$S_{0A,\text{prot}} = 3V_{0A} \cdot 3I_0 \cdot \cos \varphi_A$$

(Equation 50)

$$S_{0B,\text{prot}} = 3V_{0B} \cdot 3I_0 \cdot \cos \varphi_B$$

(Equation 51)

The angles φ_A and φ_B are the phase angles between the residual current and the residual voltage in the station compensated with the characteristic angle RCA.

The protection will use the power components in the characteristic angle direction for measurement, and as base for the inverse time delay.

The inverse time delay is defined as:

$$t_{\text{inv}} = \frac{\text{TDSN} \cdot (3I_0 \cdot 3V_0 \cdot \cos \phi(\text{reference}))}{3I_0 \cdot 3V_0 \cos \phi(\text{measured})}$$

(Equation 52)

The function can be set *Enabled/Disabled* with the setting of *Operation*.

GlobalBaseSel: It is used to select a GBASVAL function for reference of base values.

RotResU: It is a setting for rotating the polarizing quantity ($3V_0$) by 0 or 180 degrees. This parameter is set to 180 degrees by default in order to inverse the residual voltage ($3V_0$) to calculate the reference voltage ($-3V_0 e^{-jRCADir}$). Since the reference voltage is used as the polarizing quantity for directionality, it is important to set this parameter correctly.

With the setting *OpModeSel* the principle of directional function is chosen.

With *OpModeSel* set to *3I0cosfi* the current component in the direction equal to the characteristic angle *RCADir* has the maximum sensitivity. The characteristic for *RCADir* is equal to 0° is shown in Figure 62.

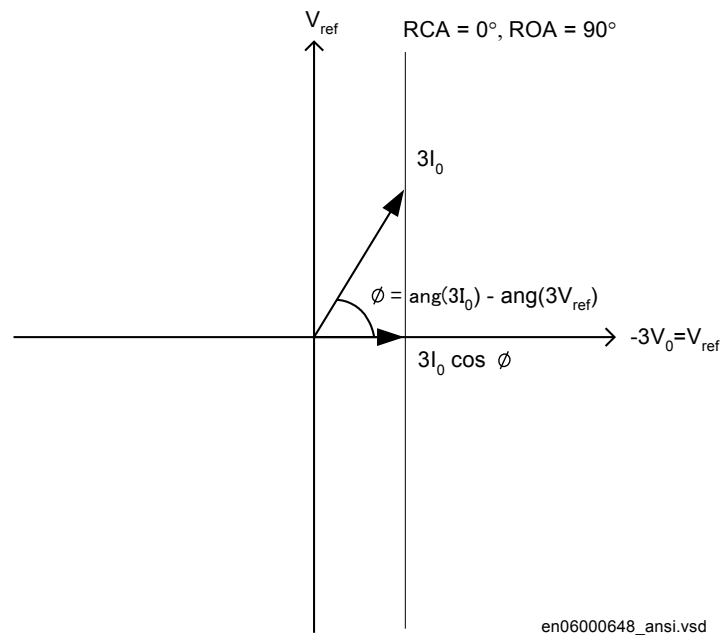


Figure 62: Characteristic for *RCADir* equal to 0°

The characteristic is for *RCADir* equal to -90° is shown in Figure 63.

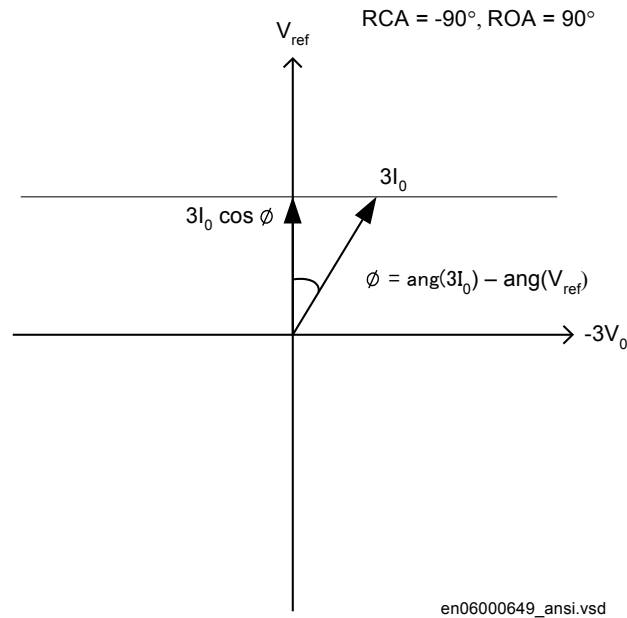


Figure 63: Characteristic for $RCADir$ equal to -90°

When $OpModeSel$ is set to $3I03V0Cosfi$ the apparent residual power component in the direction is measured.

When $OpModeSel$ is set to $3I0$ and fi the function will operate if the residual current is larger than the setting $INDirPU$ and the residual current angle is within the sector $RCADir \pm ROADir$.

The characteristic for this $OpModeSel$ when $RCADir = 0^\circ$ and $ROADir = 80^\circ$ is shown in figure 64.

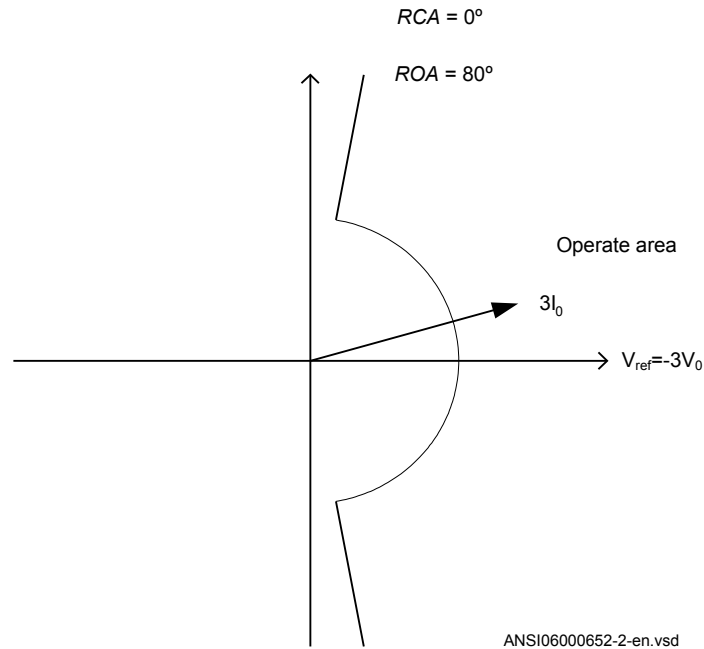


Figure 64: Characteristic for $RCADir = 0^\circ$ and $ROADir = 80^\circ$

DirMode is set *Forward* or *Reverse* to set the direction of the operation for the directional function selected by the *OpModeSel*.

All the directional protection modes have a residual current release level setting *INRelPU* which is set in % of *IBase*. This setting should be chosen smaller than or equal to the lowest fault current to be detected.

All the directional protection modes have a residual voltage release level setting *VNRelPU* which is set in % of *VBase*. This setting should be chosen smaller than or equal to the lowest fault residual voltage to be detected.

tDef is the definite time delay, given in s, for the directional residual current protection.

tReset is the time delay before the definite timer gets reset, given in s. With a *tReset* time of few cycles, there is an increased possibility to clear intermittent ground faults correctly. The setting shall be much shorter than the set trip delay. In case of intermittent ground faults, the fault current is intermittently dropping below the set value during consecutive cycles. Therefore the definite timer should continue for a certain time equal to *tReset* even though the fault current has dropped below the set value.

The characteristic angle of the directional functions *RCADir* is set in degrees. *RCADir* is normally set equal to 0° in a high impedance grounded network with a neutral point resistor as the active current component is appearing out on the faulted feeder only. *RCADir* is set equal to -90° in an isolated network as all currents are mainly capacitive.

ROADir is Relay Operating Angle. *ROADir* is identifying a window around the reference direction in order to detect directionality. *ROADir* is set in degrees. For angles differing more than *ROADir* from *RCADir* the function is blocked. The setting can be used to prevent unwanted operation for non-faulted feeders, with large capacitive ground fault current contributions, due to CT phase angle error.

INCosPhiPU is the pickup current level for the directional function when *OpModeSel* is set *3I0Cosfi*. The setting is given in % of *IBase*. The setting should be based on calculation of the active or capacitive ground fault current at required sensitivity of the protection.

SN_PU is the pickup power level for the directional function when *OpModeSel* is set *3I03V0Cosfi*. The setting is given in % of *SBase*. The setting should be based on calculation of the active or capacitive ground fault residual power at required sensitivity of the protection.

The input transformer for the Sensitive directional residual over current and power protection function has the same short circuit capacity as the phase current transformers. Hence, there is no specific requirement for the external CT core, i.e. any CT core can be used.

If the time delay for residual power is chosen the delay time is dependent on two setting parameters. *SRef* is the reference residual power, given in % of *SBase*. *TDSN* is the time multiplier. The time delay will follow the following expression:

$$t_{inv} = \frac{TDSN \cdot Sref}{3I_0 \cdot 3V_0 \cdot \cos \varphi(\text{measured})}$$

(Equation 53)

INDirPU is the pickup current level for the directional function when *OpModeSel* is set *3I0 and fi*. The setting is given in % of *IBase*. The setting should be based on calculation of the ground fault current at required sensitivity of the protection.

OpINNonDir is set *Enabled* to activate the non-directional residual current protection.

INNonDirPU is the pickup current level for the non-directional function. The setting is given in % of *IBase*. This function can be used for detection and clearance of cross-country faults in a shorter time than for the directional function. The current setting should be larger than the maximum single-phase residual current on the protected line.

TimeChar is the selection of time delay characteristic for the non-directional residual current protection. Definite time delay and different types of inverse time characteristics are available:

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 (logarithmic)

See chapter “Inverse time characteristics” in Technical Manual for the description of different characteristics

$tPCrv$, $tACrv$, $tBCrv$, $tCCrv$: Parameters for customer creation of inverse time characteristic curve (Curve type = 17). The time characteristic equation is:

$$t[s] = \left(\frac{A}{\left(\frac{i}{Pickup_N} \right)^p - C} + B \right) \cdot InMult$$

(Equation 54)

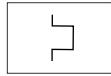
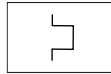
$tINNonDir$ is the definite time delay for the non directional ground fault current protection, given in s.

$OpVN$ is set *Enabled* to activate the trip function of the residual over voltage protection.

t/N is the definite time delay for the trip function of the residual voltage protection, given in s.

8.5 Thermal overload protection, one time constant Fahrenheit/Celsius LFPTTR/LCPTTR (26)

8.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Thermal overload protection, one time constant, Fahrenheit	LFPTTR		26
Thermal overload protection, one time constant, Celsius	LCPTTR		26

8.5.2 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 ground 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 LFPTTR or LCPTTR (26) 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.

8.5.3 Setting guideline

The parameters for the Thermal overload protection, one time constant, Fahrenheit/Celsius LFPTTR/LCPTTR (26) are set via the local HMI or PCM600.

The following settings can be done for the thermal overload protection.

Operation: Disabled/Enabled

GlobalBaseSel is used to select a GBASVAL function for reference of base values, primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*).

Imult: Enter the number of lines in case the protection function is applied on multiple parallel lines sharing one CT.

IRef: Reference, steady state current, given in % of *IBase* that will give a steady state (end) temperature rise *TRef*. 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).

TRef: Reference temperature rise (end temperature) corresponding to the steady state current *IRef*. From cable manuals current values with corresponding conductor temperature are often given. These values are given for conditions such as ground temperature, ambient air temperature, way of laying of cable and ground 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.

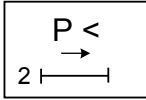
TripTemp: Temperature value for trip of the protected circuit. For cables, a maximum allowed conductor temperature is often stated to be 190°F (88°C). For overhead lines, the critical temperature for aluminium conductor is about 190-210°F (88-99°C). For a copper conductor a normal figure is 160°F (71°C).

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 150°F (66°C). Similar values are stated for overhead lines. A suitable setting can be about 60°F (16°C) below the trip value.

ReclTemp: 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 Directional underpower protection GUPPDUP (37)

8.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Directional underpower protection	GUPPDUP		37

8.6.2 Application

The task of a generator in a power plant is to convert mechanical energy available as a torque on a rotating shaft to electric energy.

Sometimes, the mechanical power from a prime mover may decrease so much that it does not cover bearing losses and ventilation losses. Then, the synchronous generator becomes a synchronous motor and starts to take electric power from the rest of the power system. This operating state, where individual synchronous machines operate as motors, implies no risk for the machine itself. If the generator under consideration is very large and if it consumes lots of electric power, it may be desirable to disconnect it to ease the task for the rest of the power system.

Often, the motoring condition may imply that the turbine is in a very dangerous state. The task of the reverse power protection is to protect the turbine and not to protect the generator itself.

Steam turbines easily become overheated if the steam flow becomes too low or if the steam ceases to flow through the turbine. Therefore, turbo-generators should have reverse power protection. There are several contingencies that may cause reverse power: break of a main steam pipe, damage to one or more blades in the steam turbine or inadvertent closing of the main stop valves. In the last case, it is highly desirable to

have a reliable reverse power protection. It may prevent damage to an otherwise undamaged plant.

During the routine shutdown of many thermal power units, the reverse power protection gives the tripping impulse to the generator breaker (the unit breaker). By doing so, one prevents the disconnection of the unit before the mechanical power has become zero. Earlier disconnection would cause an acceleration of the turbine generator at all routine shutdowns. This should have caused overspeed and high centrifugal stresses.

When the steam ceases to flow through a turbine, the cooling of the turbine blades will disappear. Now, it is not possible to remove all heat generated by the windage losses. Instead, the heat will increase the temperature in the steam turbine and especially of the blades. When a steam turbine rotates without steam supply, the electric power consumption will be about 2% of rated power. Even if the turbine rotates in vacuum, it will soon become overheated and damaged. The turbine overheats within minutes if the turbine loses the vacuum.

The critical time to overheating a steam turbine varies from about 0.5 to 30 minutes depending on the type of turbine. A high-pressure turbine with small and thin blades will become overheated more easily than a low-pressure turbine with long and heavy blades. The conditions vary from turbine to turbine and it is necessary to ask the turbine manufacturer in each case.

Power to the power plant auxiliaries may come from a station service transformer connected to the secondary side of the step-up transformer. Power may also come from a start-up service transformer connected to the external network. One has to design the reverse power protection so that it can detect reverse power independent of the flow of power to the power plant auxiliaries.

Hydro turbines tolerate reverse power much better than steam turbines do. Only Kaplan turbine and bulb turbines may suffer from reverse power. There is a risk that the turbine runner moves axially and touches stationary parts. They are not always strong enough to withstand the associated stresses.

Ice and snow may block the intake when the outdoor temperature falls far below zero. Branches and leaves may also block the trash gates. A complete blockage of the intake may cause cavitations. The risk for damages to hydro turbines can justify reverse power protection in unattended plants.

A hydro turbine that rotates in water with closed wicket gates will draw electric power from the rest of the power system. This power will be about 10% of the rated power. If there is only air in the hydro turbine, the power demand will fall to about 3%.

Diesel engines should have reverse power protection. The generator will take about 15% of its rated power or more from the system. A stiff engine may require perhaps

25% of the rated power to motor it. An engine that is good run in might need no more than 5%. It is necessary to obtain information from the engine manufacturer and to measure the reverse power during commissioning.

Gas turbines usually do not require reverse power protection.

Figure 65 illustrates the reverse power protection with underpower protection and with overpower protection. The underpower protection gives a higher margin and should provide better dependability. On the other hand, the risk for unwanted operation immediately after synchronization may be higher. One should set the underpower protection (reference angle set to 0) to trip if the active power from the generator is less than about 2%. One should set the overpower protection (reference angle set to 180) to trip if the power flow from the network to the generator is higher than 1%.

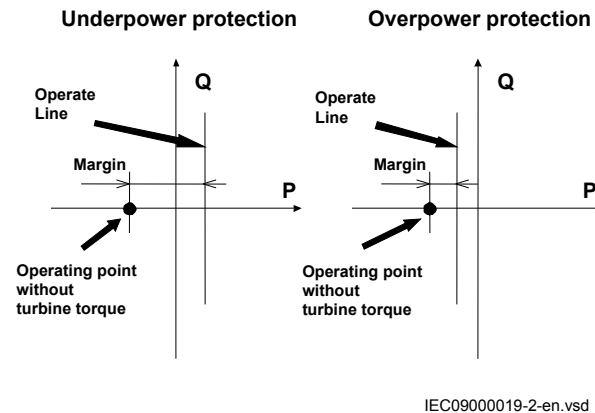


Figure 65: Reverse power protection with underpower or overpower protection

8.6.3 Setting guidelines

GlobalBaseSel: Selects the global base value group used by the function to define *IBase*, *VBase* and *SBase* as applicable.

Operation: With the parameter *Operation* the function can be set *Enabled/Disabled*.

Mode: The voltage and current used for the power measurement. The setting possibilities are shown in table 18.

Table 18: Complex power calculation

Set value <i>Mode</i>	Formula used for complex power calculation
A, B, C	$\bar{S} = \bar{V}_A \cdot \bar{I}_A^* + \bar{V}_B \cdot \bar{I}_B^* + \bar{V}_C \cdot \bar{I}_C^*$ (Equation 56)
Arone	$\bar{S} = \bar{V}_{AB} \cdot \bar{I}_A^* - \bar{V}_{BC} \cdot \bar{I}_C^*$ (Equation 57)
PosSeq	$\bar{S} = 3 \cdot \bar{V}_{PosSeq} \cdot \bar{I}_{PosSeq}^*$ (Equation 58)
AB	$\bar{S} = \bar{V}_{AB} \cdot (\bar{I}_A^* - \bar{I}_B^*)$ (Equation 59)
BC	$\bar{S} = \bar{V}_{BC} \cdot (\bar{I}_B^* - \bar{I}_C^*)$ (Equation 60)
CA	$\bar{S} = \bar{V}_{CA} \cdot (\bar{I}_C^* - \bar{I}_A^*)$ (Equation 61)
A	$\bar{S} = 3 \cdot \bar{V}_A \cdot \bar{I}_A^*$ (Equation 62)
B	$\bar{S} = 3 \cdot \bar{V}_B \cdot \bar{I}_B^*$ (Equation 63)
C	$\bar{S} = 3 \cdot \bar{V}_C \cdot \bar{I}_C^*$ (Equation 64)

The function has two stages that can be set independently.

With the parameter *OpMode1(2)* the function can be set *Enabled/Disabled*.

The function gives trip if the power component in the direction defined by the setting *Angle1(2)* is smaller than the set pick up power value *Power1(2)*

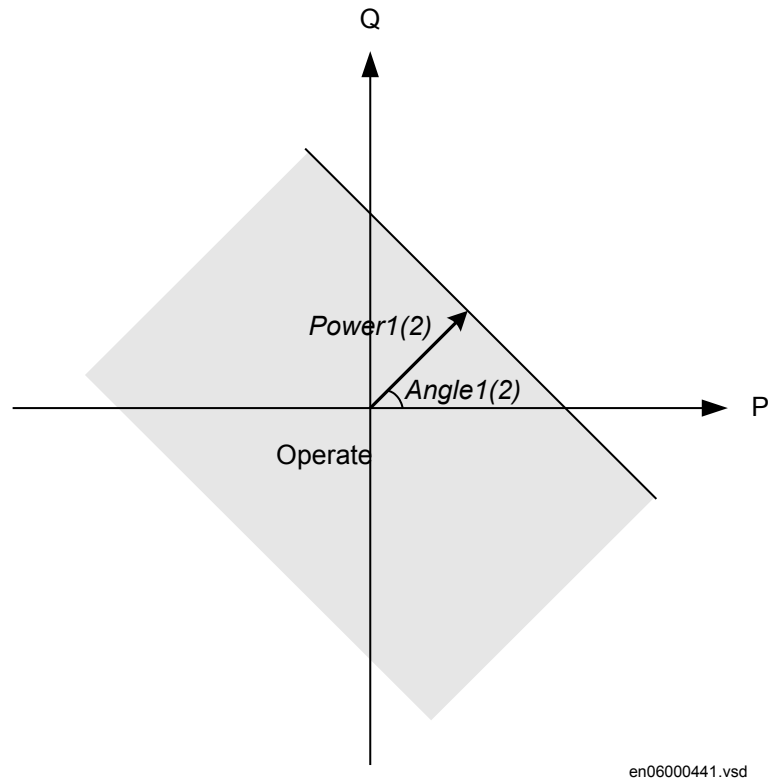


Figure 66: Underpower mode

The setting $Power1(2)$ gives the power component pick up value in the $Angle1(2)$ direction. The setting is given in p.u. of the generator rated power, see equation 65.

Minimum recommended setting is 0.2% of S_N when metering class CT inputs into the IED are used.

$$S_N = \sqrt{3} \cdot V_{Base} \cdot I_{Base}$$

(Equation 65)

The setting $Angle1(2)$ gives the characteristic angle giving maximum sensitivity of the power protection function. The setting is given in degrees. For active power the set angle should be 0° or 180° . 0° should be used for generator low forward active power protection.

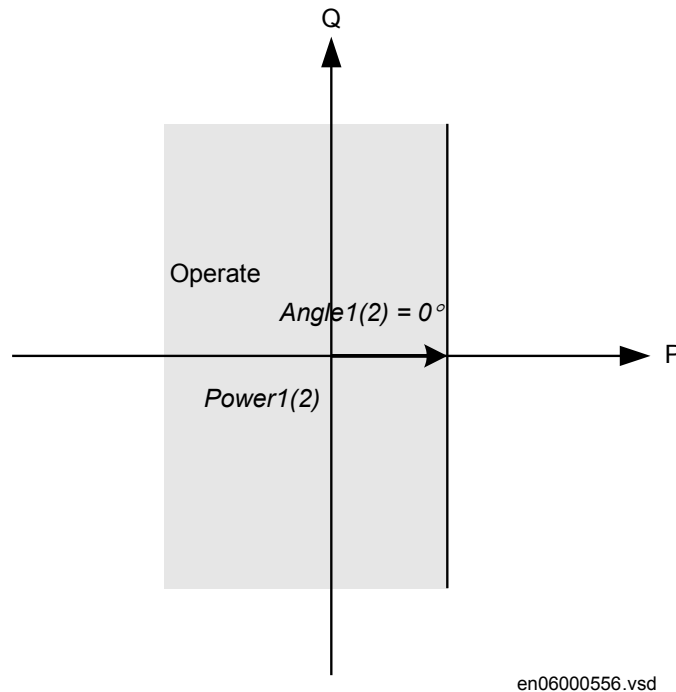


Figure 67: For low forward power the set angle should be 0° in the underpower function

$TripDelay1(2)$ is set in seconds to give the time delay for trip of the stage after pick up.

$Hysteresis1(2)$ is given in p.u. of generator rated power according to equation 66.

$$S_N = \sqrt{3} \cdot V_{Base} \cdot I_{Base}$$

(Equation 66)

The drop out power will be $Power1(2) + Hysteresis1(2)$.

The possibility to have low pass filtering of the measured power can be made as shown in the formula:

$$S = TD \cdot S_{Old} + (1 - TD) \cdot S_{Calculated}$$

(Equation 67)

Where

S is a new measured value to be used for the protection function

S_{Old} is the measured value given from the function in previous execution cycle

$S_{Calculated}$ is the new calculated value in the present execution cycle

TD is settable parameter

The value of $k=0.92$ is recommended in generator applications as the trip delay is normally quite long.

The calibration factors for current and voltage measurement errors are set % of rated current/voltage:

IMagComp5, IMagComp30, IMagComp100

VMagComp5, VMagComp30, VMagComp100

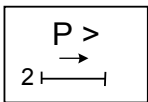
IMagComp5, IMagComp30, IMagComp100

The angle compensation is given as difference between current and voltage angle errors.

The values are given for operating points 5, 30 and 100% of rated current/voltage. The values should be available from instrument transformer test protocols.

8.7 Directional overpower protection GOPPDOP (32)

8.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Directional overpower protection	GOPPDOP		32

8.7.2 Application

The task of a generator in a power plant is to convert mechanical energy available as a torque on a rotating shaft to electric energy.

Sometimes, the mechanical power from a prime mover may decrease so much that it does not cover bearing losses and ventilation losses. Then, the synchronous generator becomes a synchronous motor and starts to take electric power from the rest of the power system. This operating state, where individual synchronous machines operate as motors, implies no risk for the machine itself. If the generator under consideration is very large and if it consumes lots of electric power, it may be desirable to disconnect it to ease the task for the rest of the power system.

Often, the motoring condition may imply that the turbine is in a very dangerous state. The task of the reverse power protection is to protect the turbine and not to protect the generator itself.

Steam turbines easily become overheated if the steam flow becomes too low or if the steam ceases to flow through the turbine. Therefore, turbo-generators should have reverse power protection. There are several contingencies that may cause reverse power: break of a main steam pipe, damage to one or more blades in the steam turbine or inadvertent closing of the main stop valves. In the last case, it is highly desirable to have a reliable reverse power protection. It may prevent damage to an otherwise undamaged plant.

During the routine shutdown of many thermal power units, the reverse power protection gives the tripping impulse to the generator breaker (the unit breaker). By doing so, one prevents the disconnection of the unit before the mechanical power has become zero. Earlier disconnection would cause an acceleration of the turbine generator at all routine shutdowns. This should have caused overspeed and high centrifugal stresses.

When the steam ceases to flow through a turbine, the cooling of the turbine blades will disappear. Now, it is not possible to remove all heat generated by the windage losses. Instead, the heat will increase the temperature in the steam turbine and especially of the blades. When a steam turbine rotates without steam supply, the electric power consumption will be about 2% of rated power. Even if the turbine rotates in vacuum, it will soon become overheated and damaged. The turbine overheats within minutes if the turbine loses the vacuum.

The critical time to overheating of a steam turbine varies from about 0.5 to 30 minutes depending on the type of turbine. A high-pressure turbine with small and thin blades will become overheated more easily than a low-pressure turbine with long and heavy blades. The conditions vary from turbine to turbine and it is necessary to ask the turbine manufacturer in each case.

Power to the power plant auxiliaries may come from a station service transformer connected to the primary side of the step-up transformer. Power may also come from a start-up service transformer connected to the external network. One has to design the reverse power protection so that it can detect reverse power independent of the flow of power to the power plant auxiliaries.

Hydro turbines tolerate reverse power much better than steam turbines do. Only Kaplan turbine and bulb turbines may suffer from reverse power. There is a risk that the turbine runner moves axially and touches stationary parts. They are not always strong enough to withstand the associated stresses.

Ice and snow may block the intake when the outdoor temperature falls far below zero. Branches and leaves may also block the trash gates. A complete blockage of the intake

may cause cavitations. The risk for damages to hydro turbines can justify reverse power protection in unattended plants.

A hydro turbine that rotates in water with closed wicket gates will draw electric power from the rest of the power system. This power will be about 10% of the rated power. If there is only air in the hydro turbine, the power demand will fall to about 3%.

Diesel engines should have reverse power protection. The generator will take about 15% of its rated power or more from the system. A stiff engine may require perhaps 25% of the rated power to motor it. An engine that is well run in might need no more than 5%. It is necessary to obtain information from the engine manufacturer and to measure the reverse power during commissioning.

Gas turbines usually do not require reverse power protection.

Figure 68 illustrates the reverse power protection with underpower IED and with overpower IED. The underpower IED gives a higher margin and should provide better dependability. On the other hand, the risk for unwanted operation immediately after synchronization may be higher. One should set the underpower IED to trip if the active power from the generator is less than about 2%. One should set the overpower IED to trip if the power flow from the network to the generator is higher than 1%.

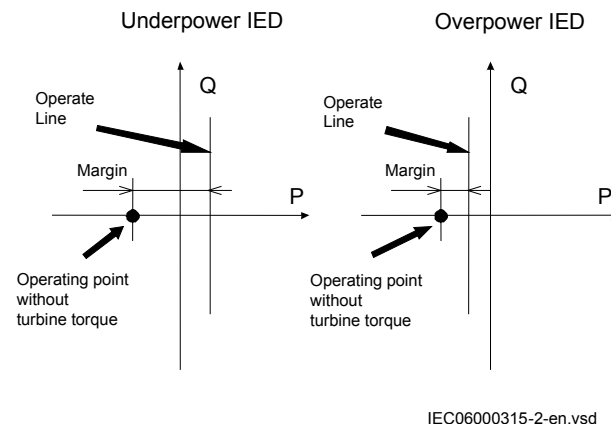


Figure 68: Reverse power protection with underpower IED and overpower IED

8.7.3 Setting guidelines

GlobalBaseSel: Selects the global base value group used by the function to define *IBase*, *VBase* and *SBase* as applicable.

Operation: With the parameter *Operation* the function can be set *Enabled/Disabled*.

Mode: The voltage and current used for the power measurement. The setting possibilities are shown in table 19.

Table 19: Complex power calculation

Set value <i>Mode</i>	Formula used for complex power calculation
A,B,C	$\bar{S} = \bar{V}_A \cdot \bar{I}_A^* + \bar{V}_B \cdot \bar{I}_B^* + \bar{V}_C \cdot \bar{I}_C^*$ (Equation 69)
Arone	$\bar{S} = \bar{V}_{AB} \cdot \bar{I}_A^* - \bar{V}_{BC} \cdot \bar{I}_C^*$ (Equation 70)
PosSeq	$\bar{S} = 3 \cdot \bar{V}_{\text{PosSeq}} \cdot \bar{I}_{\text{PosSeq}}^*$ (Equation 71)
A,B	$\bar{S} = \bar{V}_{AB} \cdot (\bar{I}_A^* - \bar{I}_B^*)$ (Equation 72)
B,C	$\bar{S} = \bar{V}_{BC} \cdot (\bar{I}_B^* - \bar{I}_C^*)$ (Equation 73)
C,A	$\bar{S} = \bar{V}_{CA} \cdot (\bar{I}_C^* - \bar{I}_A^*)$ (Equation 74)
A	$\bar{S} = 3 \cdot \bar{V}_A \cdot \bar{I}_A^*$ (Equation 75)
B	$\bar{S} = 3 \cdot \bar{V}_B \cdot \bar{I}_B^*$ (Equation 76)
C	$\bar{S} = 3 \cdot \bar{V}_C \cdot \bar{I}_C^*$ (Equation 77)

The function has two stages that can be set independently.

With the parameter *OpModel(2)* the function can be set *Enabled/Disabled*.

The function gives trip if the power component in the direction defined by the setting *Angle1(2)* is larger than the set pick up power value *Power1(2)*

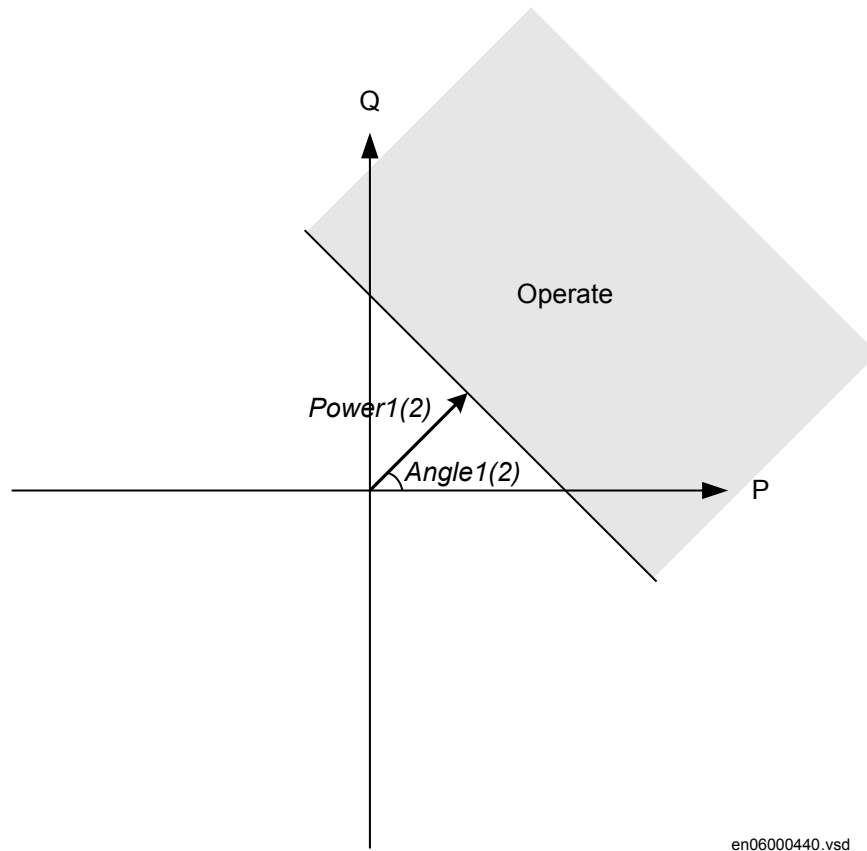


Figure 69: Overpower mode

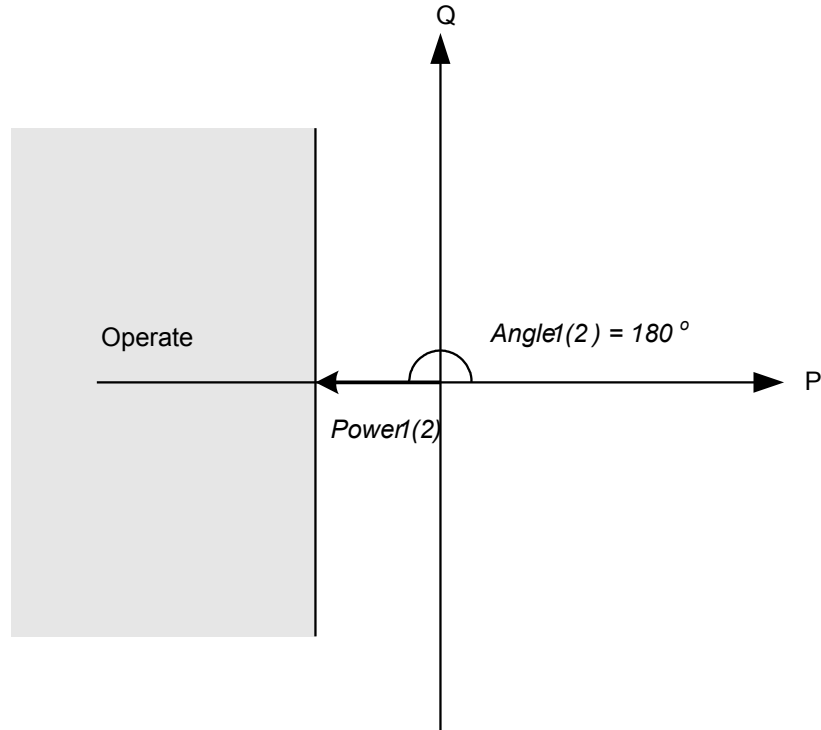
The setting *Power1(2)* gives the power component pick up value in the *Angle1(2)* direction. The setting is given in p.u. of the generator rated power, see equation 78.

Minimum recommended setting is 0.2% of S_N when metering class CT inputs into the IED are used.

$$S_N = \sqrt{3} \cdot V_{Base} \cdot I_{Base}$$

(Equation 78)

The setting *Angle1(2)* gives the characteristic angle giving maximum sensitivity of the power protection function. The setting is given in degrees. For active power the set angle should be 0° or 180°. 180° should be used for generator reverse power protection.



IEC06000557-2-en.vsd

Figure 70: For reverse power the set angle should be 180° in the overpower function

$TripDelay1(2)$ is set in seconds to give the time delay for trip of the stage after pick up.

$Hysteresis1(2)$ is given in p.u. of generator rated power according to equation [79](#).

$$S_N = \sqrt{3} \cdot V_{Base} \cdot I_{Base}$$

(Equation 79)

The drop out power will be $Power1(2) - Hysteresis1(2)$.

The possibility to have low pass filtering of the measured power can be made as shown in the formula:

$$S = TD \cdot S_{Old} + (1 - TD) \cdot S_{Calculated}$$

(Equation 80)

Where

- S is a new measured value to be used for the protection function
S_{Old} is the measured value given from the function in previous execution cycle
S_{Calculated} is the new calculated value in the present execution cycle
TD is settable parameter

The value of $TD=0.92$ is recommended in generator applications as the trip delay is normally quite long.

The calibration factors for current and voltage measurement errors are set % of rated current/voltage:

IMagComp5, IMagComp30, IMagComp100

VMagComp5, VMagComp30, VMagComp100

IAngComp5, IAngComp30, IAngComp100

The angle compensation is given as difference between current and voltage angle errors.

The values are given for operating points 5, 30 and 100% of rated current/voltage. The values should be available from instrument transformer test protocols.

Section 9 Voltage protection

9.1 Two step undervoltage protection UV2PTUV (27)

9.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Two step undervoltage protection	UV2PTUV	<div style="border: 1px solid black; padding: 5px; width: fit-content; margin: 0 auto;"> $3U<$ </div>	27

9.1.2 Application

Two-step undervoltage protection function (UV2PTUV ,27) 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-ground faults (unsymmetrical voltage decrease)

UV2PTUV (27) 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 (27) 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 (27) 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 V_{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 (27) is normally not critical, since there must be enough time available for the main protection to clear short circuits and ground 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 (27):

ConnType: Sets whether the measurement shall be phase-to-ground fundamental value, phase-to-phase fundamental value, phase-to-ground RMS value or phase-to-phase RMS value.

Operation: *Disabled* or *Enabled*.

VBase (given in *GlobalBaseSel*): Base voltage phase-to-phase in primary kV. This voltage is used as reference for voltage setting. UV2PTUV (27) will operate if the voltage becomes lower than the set percentage of *VBase*. This setting is used when *ConnType* is set to *PhPh DFT* or *PhPh RMS*. Therefore, always set *VBase* 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 (27) shall be insensitive for single phase-to-ground 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.

Pickupn: Set pickup undervoltage operation value for step n , given as % of the parameter *VBase*. 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 ground 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 *tMin* 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*.

tResetn: Reset time for step *n* if inverse time delay is used, given in s. The default value is 25 ms.

TDn: 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 *Disabled*, *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 *VBase*. This setting must be lower than the setting *Pickupn*. 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 trip time delay of the undervoltage protection step.

9.2

Two step overvoltage protection OV2PTOV (59)

9.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Two step overvoltage protection	OV2PTOV	<div style="border: 1px solid black; padding: 5px; width: fit-content; margin: 0 auto;"> $3U>$ </div>	59

9.2.2 Application

Two step overvoltage protection OV2PTOV (59) is applicable in all situations, where reliable detection of high voltage is necessary. OV2PTOV (59) 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 (59) is applied to power system elements, such as generators, transformers, motors and power lines in order to detect high voltage conditions. OV2PTOV (59) is used in combination with low current signals, to identify a transmission line, open in the remote end. In addition to that, OV2PTOV (59) 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 (59) 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. Ground-faults in high impedance grounded systems causes, beside the high voltage in the neutral, high voltages in the two non-faulted phases, (unsymmetrical voltage increase).

OV2PTOV (59) 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 ,59) are set via the local HMI or PCM600.

All the voltage conditions in the system where OV2PTOV (59) 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 (59) 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 grounded systems

In high impedance grounded systems, ground-faults cause a voltage increase in the non-faulty phases. Two step overvoltage protection (OV2PTOV, 59) 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 ground-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-ground fundamental value, phase-to-phase fundamental value, phase-to-ground RMS value or phase-to-phase RMS value.

Operation: Disabled/Enabled.

VBase (given in *GlobalBaseSel*): Base voltage phase to phase in primary kV. This voltage is used as reference for voltage setting. OV2PTOV (59) measures selectively phase-to-ground 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 *VBase*. When *ConnType* is set to *PhN DFT* or *PhN RMS* then the IED automatically divides set value for *VBase* by $\sqrt{3}$. When *ConnType* is set to *PhPh DFT* or *PhPh RMS* then set value for *VBase* is used. Therefore, always set *VBase* as rated primary phase-to-phase ground voltage of the protected object. If phase to neutral (PhN) measurement is selected as setting, the operation of phase-to-ground over voltage is automatically divided by $\sqrt{3}$. This means operation for phase-to-ground voltage over:

$$V > (\%) \cdot VBase(kV) / \sqrt{3}$$

(Equation 81)

and operation for phase-to-phase voltage over:

$$V_{pickup} > (\%) \cdot VBase(kV)$$

(Equation 82)

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-ground faults *1 out of 3* can be chosen, because the voltage will normally rise in the non-faulted phases at single phase-to-ground faults. In subtransmission and transmission networks the UV function is mainly a system supervision function and 3 out of 3 is selected.

Pickupn: Set pickup overvoltage operation value for step *n*, given as % of *VBase*. 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 *tMin* 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*.

tIResetn: Reset time for step *n* if inverse time delay is used, given in s. The default value is 25 ms.

TDn: 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 $Pickup>$ up to $Pickup> \cdot (1.0 + CrvSatn/100)$ the used voltage will be: $Pickup> \cdot (1.0 + CrvSatn/100)$. If the programmable curve is used, this parameter must be calculated so that:

$$B \cdot \frac{CrvSatn}{100} - C > 0$$

(Equation 83)

HystAbsn: Absolute hysteresis set in % of $VBase$. 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.

Section 10 Frequency protection

10.1 Underfrequency protection SAPTUF (81)

10.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Underfrequency protection	SAPTUF	<div style="border: 1px solid black; padding: 5px; width: fit-content; margin: 0 auto;"> $f <$ </div>	81

10.1.2 Application

Underfrequency protection SAPTUF (81) 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 (81) 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 (81) 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 (81) 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 (81):

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 pickup 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 pickup 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 (81) 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 (81)

10.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Overfrequency protection	SAPTOF	<div style="border: 1px solid black; padding: 5px; width: fit-content; margin: 0 auto;"> $f >$ </div>	81

10.2.2 Application

Overfrequency protection function SAPTOF (81) 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 (81) detects such situations and provides an output signal, suitable for generator shedding, HVDC-set-point change and so on. SAPTOF (81) 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 (81) 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 (81):

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 pickup value is set in Hz. All voltage magnitude related settings are made as a percentage of a settable global base voltage parameter $VBase$. 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 PICKUP 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 (81)

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	<div style="border: 1px solid black; padding: 5px; width: fit-content; margin: 0 auto;"> $df/dt \geq$ </div>	81

10.3.2 Application

Rate-of-change of frequency protection (SAPFRC, 81) is applicable in all situations, where reliable detection of change of the fundamental power system voltage frequency is needed. SAPFRC (81) can be used both for increasing frequency and for decreasing frequency. SAPFRC (81) 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 (81) 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 (81) 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 (81) 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 (81):

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 (81) 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 pickup value for SAPFRC (81) 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 (81) 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.

10.4 Frequency time accumulation protection function FTAQFVR (81A)

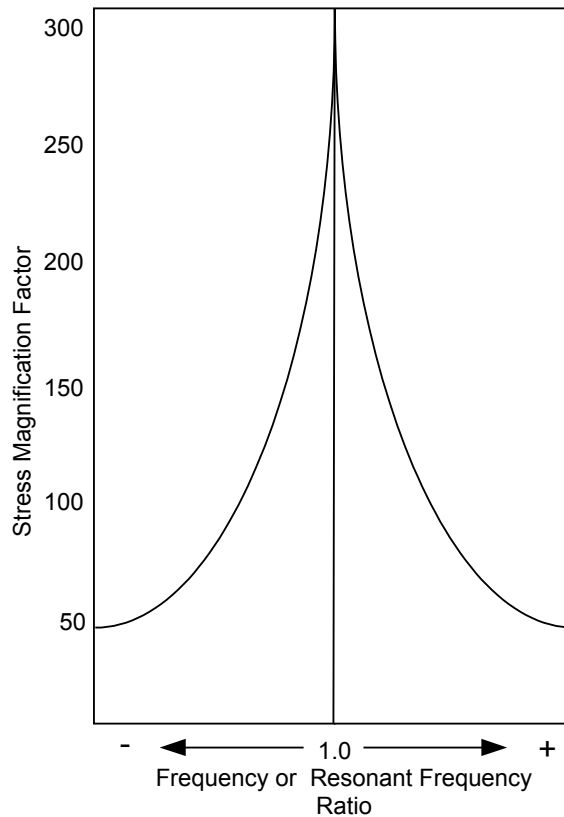
10.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/ IEEE identification
Frequency time accumulation protection	FTAQFVR	f<>	81A

10.4.2 Application

Generator prime movers are affected by abnormal frequency disturbances. Significant frequency deviations from rated frequency occur in case of major disturbances in the system. A rise of frequency occurs in case of generation surplus, while a lack of generation results in a drop of frequency.

The turbine blade is designed with its natural frequency adequately far from the rated speed or multiples of the rated speed of the turbine. This design avoids the mechanical resonant condition, which can lead to an increased mechanical stress on turbine blade. If the ratio between the turbine resonant frequencies to the system operating frequency is nearly equal to 1, mechanical stress on the blades is approximately 300 times the nonresonant operating condition stress values. The stress magnification factor is shown in the typical resonance curve in Figure [71](#).



IEC12000611-2-en.vsd

Figure 71: *Typical stress magnification factor curve according ANSI/IEEE C37.106-2003 Standard*

Each turbine manufactured for different design of blades has various time restriction limits for various frequency bands. The time limits depend on the natural frequencies of the blades inside the turbine, corrosion and erosion of the blade edges and additional loss of blade lifetime during the abnormal operating conditions.

The frequency limitations and their time restrictions for different types of turbines are similar in many aspects with steam turbine limitations. Certain differences in design and applications may result in different protective requirements. Therefore, for different type of turbine systems, different recommendations on the time restriction limits are specified by the manufacturer.

However, the IEEE/ANSI C37.106-2003 standard "Guide for Abnormal Frequency Protection for Power Generating Plants" provides some examples where the time accumulated within each frequency range is as shown in Figure 72.

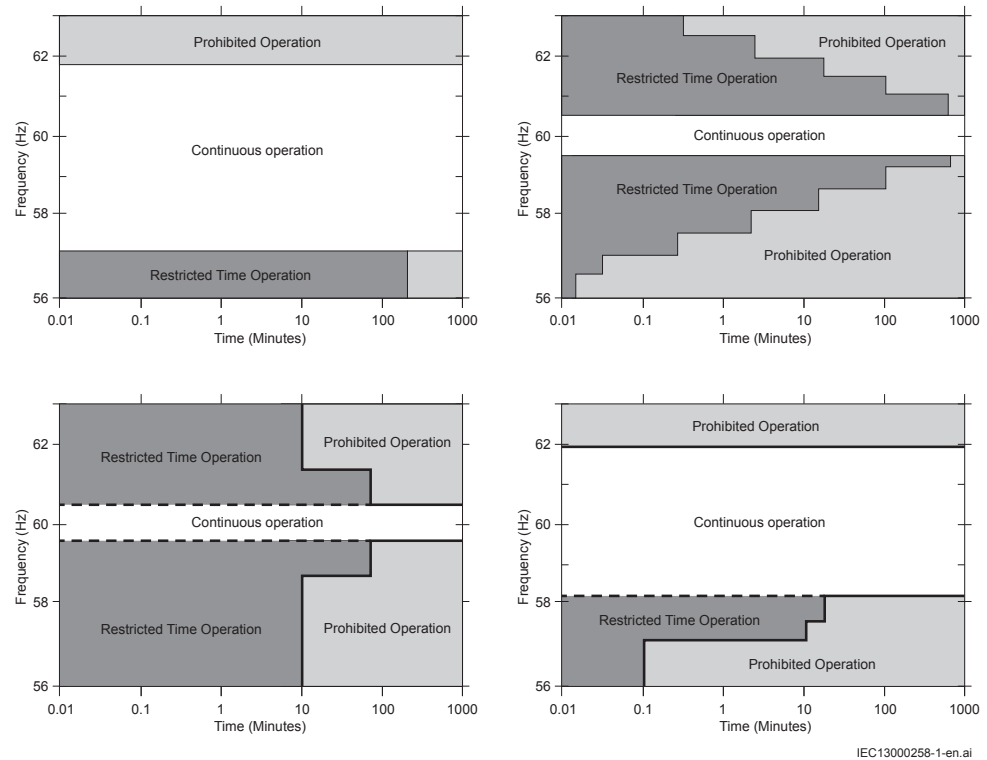


Figure 72: Examples of time frequency characteristics with various frequency band limits

Another application for the FTAQFVR (81A) protection function is to supervise variations from rated voltage-frequency. Generators are designed to accommodate the IEC 60034-3:1996 requirement of continuous operation within the confines of their capability curves over the ranges of $\pm 5\%$ in voltage and $\pm 2\%$ in frequency. Operation of the machine at rated power outside these voltage-frequency limits lead to increased temperatures and reduction of insulation life.

10.4.3 Setting guidelines

Among the generator protection functions, the frequency time accumulation protection FTAQFVR (81A) may be used to protect the generator as well as the turbine. Abnormal frequencies during normal operation cause material fatigue on turbine blades, trip points and time delays should be established based on the turbine manufacture's requirements and recommendations.

Continuous operation of the machine at rated power outside voltage-frequency limits lead to increased rotor temperatures and reduction of insulation life. Setting of extent, duration and frequency of occurrence should be set according to manufacture's requirements and recommendations.

Setting procedure on the IED

The parameters for the frequency time accumulation protection FTAQFVR (81A) are set using the local HMI or through the dedicated software tool in Protection and Control Manager (PCM600).

Common base IED values for primary current *I*Base and primary voltage *V*Base are set in the global base values for settings function GBASVAL. The *GlobalBaseSel* is used to select GBASVAL for the reference of base values.

FTAQFVR (81A) used to protect a turbine:

Frequency during start-up and shutdown is normally not calculated, consequently the protection function is blocked by CB position, parameter *CBCheck* enabled. If the generator supply any load when CB is in open position e.g. excitation equipment and auxiliary services this may be considered as normal condition and *CBCheck* is ignored when the load current is higher then the set value of *PickupCurrentLevel*. Set the current level just above minimum load.

EnaVoltCheck set to *Disable*.

tCont: to be coordinated to the grid requirements.

tAccLimit, *FreqHighLimit* and *FreqLowLimit* setting is derived from the turbine manufacturer's operating requirements, note that *FreqLowLimit* setting must always be lower than the set value of *FreqHighLimit*.

FTAQFVR (81A) used to protect a generator:

Frequency during start-up and shutdown is normally not calculated, consequently the protection function is blocked by CB position, parameter *CBCheck* enabled.

PickupCurrentLevel set to *Disable*.

EnaVoltCheck set to *Enable*, voltage and frequency limits set according to the generators manufacturer's operating requirements. Voltage and frequency settings should also be coordinated with the pickup values for over and underexcitation protection.

tCont: to be coordinated to the grid requirements.

tAccLimit, *FreqHighLimit* and *FreqLowLimit* setting is derived from the generator manufacturer's operating requirements.

Section 11 Multipurpose protection

11.1 General current and voltage protection CVGAPC

11.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
General current and voltage protection	CVGAPC	2(I>/U<)	-

11.1.2 Application

A breakdown of the insulation between phase conductors or a phase conductor and ground results in a short circuit or a ground fault respectively. Such faults can result in large fault currents and may cause severe damage to the power system primary equipment. Depending on the magnitude and type of the fault different overcurrent protections, based on measurement of phase, ground or sequence current components can be used to detect these faults. Additionally it is sometimes required that these overcurrent protections shall be directional and/or voltage controlled/restrained.

The over/under voltage protection is applied on power system elements, such as generators, transformers, motors and power lines in order to detect abnormal voltage conditions. Depending on the type of voltage deviation and type of power system abnormal condition different over/under voltage protections based on measurement of phase-to-ground, phase-to-phase, residual- or sequence- voltage components can be used to detect and operate for such incident.

The IED can be provided with multiple General current and voltage protection (CVGAPC) protection modules. The function is always connected to three-phase current and three-phase voltage input in the configuration tool, but it will always measure only one current and one voltage quantity selected by the end user in the setting tool.

Each CVGAPC function module has got four independent protection elements built into it.

1. Two overcurrent steps with the following built-in features:

-
- Definite time delay or Inverse Time Overcurrent (TOC/IDMT) delay for both steps
 - Second harmonic supervision is available in order to only allow operation of the overcurrent stage(s) if the content of the second harmonic in the measured current is lower than pre-set level
 - Directional supervision is available in order to only allow operation of the overcurrent stage(s) if the fault location is in the pre-set direction (*Forward* or *Reverse*). Its behavior during low-level polarizing voltage is settable (*Non-Directional*, *Block*, *Memory*)
 - Voltage restrained/controlled feature is available in order to modify the pick-up level of the overcurrent stage(s) in proportion to the magnitude of the measured voltage
 - Current restrained feature is available in order to only allow operation of the overcurrent stage(s) if the measured current quantity is bigger than the set percentage of the current restrain quantity.
2. Two undercurrent steps with the following built-in features:
 - Definite time delay for both steps
 3. Two overvoltage steps with the following built-in features
 - Definite time delay or Inverse Time Overcurrent TOC/IDMT delay for both steps
 4. Two undervoltage steps with the following built-in features
 - Definite time delay or Inverse Time Overcurrent TOC/IDMT delay for both steps

All these four protection elements within one general protection function works independently from each other and they can be individually enabled or disabled. However, note that all these four protection elements measure one selected current quantity and one selected voltage quantity (see table [20](#) and table [21](#)). It is possible to simultaneously use all four protection elements and their individual stages. Sometimes, it is necessary to provide interaction between two or more protection elements/stages within one CVGAPC function by appropriate IED configuration to obtain desired application functionality.

11.1.2.1 Current and voltage selection for CVGAPC function

CVGAPC function is always connected to three-phase current and three-phase voltage input in the configuration tool, but it will always measure only the single current and the single voltage quantity selected by the end user in the setting tool.

The user can select a current input, by a setting parameter *CurrentInput*, to measure one of the current quantities shown in table [20](#).

Table 20: Available selection for current quantity within CVGAPC function

	Set value for parameter "CurrentInput"	Comment
1	<i>PhaseA</i>	CVGAPC function will measure the phase A current phasor
2	<i>PhaseB</i>	CVGAPC function will measure the phase B current phasor
3	<i>PhaseC</i>	CVGAPC function will measure the phase C current phasor
4	<i>PosSeq</i>	CVGAPC function will measure internally calculated positive sequence current phasor
5	<i>NegSeq</i>	CVGAPC function will measure internally calculated negative sequence current phasor
6	<i>3 · ZeroSeq</i>	CVGAPC function will measure internally calculated zero sequence current phasor multiplied by factor 3
7	<i>MaxPh</i>	CVGAPC function will measure current phasor of the phase with maximum magnitude
8	<i>MinPh</i>	CVGAPC function will measure current phasor of the phase with minimum magnitude
9	<i>UnbalancePh</i>	CVGAPC function will measure magnitude of unbalance current, which is internally calculated as the algebraic magnitude difference between the current phasor of the phase with maximum magnitude and current phasor of the phase with minimum magnitude. Phase angle will be set to 0° all the time
10	<i>PhaseA-PhaseB</i>	CVGAPC function will measure the current phasor internally calculated as the vector difference between the phase A current phasor and phase B current phasor (VA-VB)
11	<i>PhaseB-PhaseC</i>	CVGAPC function will measure the current phasor internally calculated as the vector difference between the phase B current phasor and phase C current phasor (VB-VC)
12	<i>PhaseC-PhaseA</i>	CVGAPC function will measure the current phasor internally calculated as the vector difference between the phase C current phasor and phase A current phasor (VC-VA)
13	<i>MaxPh-Ph</i>	CVGAPC function will measure ph-ph current phasor with the maximum magnitude
14	<i>MinPh-Ph</i>	CVGAPC function will measure ph-ph current phasor with the minimum magnitude
15	<i>UnbalancePh-Ph</i>	CVGAPC function will measure magnitude of unbalance current, which is internally calculated as the algebraic magnitude difference between the ph-ph current phasor with maximum magnitude and ph-ph current phasor with minimum magnitude. Phase angle will be set to 0° all the time

The user can select a voltage input, by a setting parameter *VoltageInput*, to measure one of the voltage quantities shown in table [21](#).

Table 21: Available selection for voltage quantity within CVGAPC function

	Set value for parameter "VoltageInput"	Comment
1	<i>PhaseA</i>	CVGAPC function will measure the phase A voltage phasor
2	<i>PhaseB</i>	CVGAPC function will measure the phase B voltage phasor
3	<i>PhaseC</i>	CVGAPC function will measure the phase C voltage phasor
4	<i>PosSeq</i>	CVGAPC function will measure internally calculated positive sequence voltage phasor
5	<i>-NegSeq</i>	CVGAPC function will measure internally calculated negative sequence voltage phasor. This voltage phasor will be intentionally rotated for 180° in order to enable easier settings for the directional feature when used.
6	<i>-3*ZeroSeq</i>	CVGAPC function will measure internally calculated zero sequence voltage phasor multiplied by factor 3. This voltage phasor will be intentionally rotated for 180° in order to enable easier settings for the directional feature when used.
7	<i>MaxPh</i>	CVGAPC function will measure voltage phasor of the phase with maximum magnitude
8	<i>MinPh</i>	CVGAPC function will measure voltage phasor of the phase with minimum magnitude
9	<i>UnbalancePh</i>	CVGAPC function will measure magnitude of unbalance voltage, which is internally calculated as the algebraic magnitude difference between the voltage phasor of the phase with maximum magnitude and voltage phasor of the phase with minimum magnitude. Phase angle will be set to 0° all the time
10	<i>PhaseA-PhaseB</i>	CVGAPC function will measure the voltage phasor internally calculated as the vector difference between the phase A voltage phasor and phase B voltage phasor (VA-VB)
11	<i>PhaseB-PhaseC</i>	CVGAPC function will measure the voltage phasor internally calculated as the vector difference between the phase B voltage phasor and phase C voltage phasor (VB-VC)
12	<i>PhaseC-PhaseA</i>	CVGAPC function will measure the voltage phasor internally calculated as the vector difference between the phase C voltage phasor and phase A voltage phasor (VC-VA)
13	<i>MaxPh-Ph</i>	CVGAPC function will measure ph-ph voltage phasor with the maximum magnitude
14	<i>MinPh-Ph</i>	CVGAPC function will measure ph-ph voltage phasor with the minimum magnitude
15	<i>UnbalancePh-Ph</i>	CVGAPC function will measure magnitude of unbalance voltage, which is internally calculated as the algebraic magnitude difference between the ph-ph voltage phasor with maximum magnitude and ph-ph voltage phasor with minimum magnitude. Phase angle will be set to 0° all the time

Note that the voltage selection from table 21 is always applicable regardless the actual external VT connections. The three-phase VT inputs can be connected to IED as either three phase-to-ground voltages, VA, VB and VC or three phase-to-phase voltages V_{AB},

V_{BC} and V_{CA} . This information about actual VT connection is entered as a setting parameter for the pre-processing block, which will then be taken care automatically.

11.1.2.2 Base quantities for CVGAPC function

The parameter settings for the base quantities, which represent the base (100%) for pickup levels of all measuring stages shall be entered as setting parameters for every CVGAPC function.

Base current shall be entered as:

1. rated phase-to-earth current of the protected object in primary amperes, when the measured Current Quantity is selected from 1 to 9, as shown in table [20](#).
2. rated phase current of the protected object in primary amperes multiplied by $\sqrt{3}$ ($1.732 \times I_{\text{phase}}$), when the measured Current Quantity is selected from 10 to 15, as shown in table [20](#).

Base voltage shall be entered as:

1. rated phase-to-ground voltage of the protected object in primary kV, when the measured Voltage Quantity is selected from 1 to 9, as shown in table [21](#).
2. rated phase-to-phase voltage of the protected object in primary kV, when the measured Voltage Quantity is selected from 10 to 15, as shown in table [21](#).

11.1.2.3 Application possibilities

Due to its flexibility the general current and voltage protection (CVGAPC) function can be used, with appropriate settings and configuration in many different applications. Some of possible examples are given below:

1. Transformer and line applications:
 - Underimpedance protection (circular, non-directional characteristic) (21)
 - Underimpedance protection (circular mho characteristic) (21)
 - Voltage Controlled/Restrained Overcurrent protection (51C, 51V)
 - Phase or Negative/Positive/Zero Sequence (Non-Directional or Directional) Overcurrent protection (50, 51, 46, 67, 67N, 67Q)
 - Phase or phase-to-phase or Negative/Positive/Zero Sequence over/under voltage protection (27, 59, 47)
 - Thermal overload protection (49)
 - Open Phase protection
 - Unbalance protection
2. Generator protection

- 80-95% Stator earth fault protection (measured or calculated $3V_0$) (59GN)
- Rotor earth fault protection (with external COMBIFLEX RXTTE4 injection unit) (64F)
- Underimpedance protection (21)
- Voltage Controlled/Restrained Overcurrent protection (51C, 51V)
- Turn-to-Turn & Differential Backup protection (directional Negative Sequence. Overcurrent protection connected to generator HV terminal CTs looking into generator) (67Q)
- Stator Overload protection (49S)
- Rotor Overload protection (49R)
- Loss of Excitation protection (directional positive sequence OC protection) (40)
- Reverse power/Low forward power protection (directional positive sequence OC protection, 2% sensitivity) (32)
- Dead-Machine/Inadvertent-Energizing protection (51/27)
- Breaker head flashover protection
- Improper synchronizing detection
- Sensitive negative sequence generator over current protection and alarm (46)
- Phase or phase-to-phase or Negative/Positive/Zero Sequence over/under voltage protection (27x, 59x, 47)
- Generator out-of-step detection (based on directional positive sequence OC) (78)
- Inadvertent generator energizing

11.1.2.4 Inadvertent generator energization

When the generator is taken out of service, and stand-still, there is a risk that the generator circuit breaker is closed by mistake.

Three-phase energizing of a generator, which is at standstill or on turning gear, causes it to behave and accelerate similarly to an induction motor. The machine, at this point, essentially represents the subtransient reactance to the system and it can be expected to draw from one to four per unit current, depending on the equivalent system impedance. Machine terminal voltage can range from 20% to 70% of rated voltage, again, depending on the system equivalent impedance (including the block transformer). Higher quantities of machine current and voltage (3 to 4 per unit current and 50% to 70% rated voltage) can be expected if the generator is connected to a strong system. Lower current and voltage values (1 to 2 per unit current and 20% to 40% rated voltage) are representative of weaker systems.

Since a generator behaves similarly to an induction motor, high currents will develop in the rotor during the period it is accelerating. Although the rotor may be thermally damaged from excessive high currents, the time to damage will be on the order of a few seconds. Of more critical concern, however, is the bearing, which can be damaged

in a fraction of a second due to low oil pressure. Therefore, it is essential that high speed tripping is provided. This tripping should be almost instantaneous (< 100 ms).

There is a risk that the current into the generator at inadvertent energization will be limited so that the “normal” overcurrent or underimpedance protection will not detect the dangerous situation. The delay of these protection functions might be too long. The reverse power protection might detect the situation but the operation time of this protection is normally too long.

For big and important machines, fast protection against inadvertent energizing should, therefore, be included in the protective scheme.

The protection against inadvertent energization can be made by a combination of undervoltage, overvoltage and overcurrent protection functions. The undervoltage function will, with a delay for example 10 s, detect the situation when the generator is not connected to the grid (standstill) and activate the overcurrent function. The overvoltage function will detect the situation when the generator is taken into operation and will disable the overcurrent function. The overcurrent function will have a pick-up value about 50% of the rated current of the generator. The trip delay will be about 50 ms.

11.1.3

Setting guidelines



When inverse time overcurrent characteristic is selected, the trip 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 general current and voltage protection function (CVGAPC) are set via the local HMI or Protection and Control Manager (PCM600).

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

GlobalBaseSel: Selects the global base value group used by the function to define I_{Base} , V_{Base} and S_{Base} as applicable.



The overcurrent steps has a I_{Minx} ($x=1$ or 2 depending on step) setting to set the minimum pickup current. Set I_{Minx} below $PickupCurr_OCx$ for every step to achieve ANSI reset characteristic according to standard. If I_{Minx} is set above $PickupCurr_OCx$ for any step the ANSI reset works as if current is zero when current drops below I_{Minx} .

11.1.3.1 Directional negative sequence overcurrent protection

Directional negative sequence overcurrent protection is typically used as sensitive ground-fault protection of power lines where incorrect zero sequence polarization may result from mutual induction between two or more parallel lines. Additionally, it can be used in applications on underground cables where zero-sequence impedance depends on the fault current return paths, but the cable negative-sequence impedance is practically constant. It shall be noted that directional negative sequence OC element offers protection against all unbalance faults (phase-to-phase faults as well). Care shall be taken that the minimum pickup of such protection function shall be set above natural system unbalance level.

An example will be given, how sensitive-ground-fault protection for power lines can be achieved by using negative-sequence directional overcurrent protection elements within a CVGAPC function.

This functionality can be achieved by using one CVGAPC function. The following shall be done to ensure proper operation of the function:

1. Connect three-phase power line currents and three-phase power line voltages to one CVGAPC instance (for example, GF04)
2. Set *CurrentInput* to *NegSeq* (please note that CVGAPC function measures I2 current and NOT 3I2 current; this is essential for proper OC pickup level setting)
3. Set *VoltageInput* to *-NegSeq* (please note that the negative sequence voltage phasor is intentionally inverted in order to simplify directionality)
4. Set base current *IBase* value equal to the rated primary current of power line CTs
5. Set base voltage *UBase* value equal to the rated power line phase-to-phase voltage in kV
6. Set *RCADir* to value +65 degrees (*NegSeq* current typically lags the inverted *NegSeq* voltage for this angle during the fault)
7. Set *ROADir* to value 90 degree
8. Set *LowVolt_VM* to value 2% (*NegSeq* voltage level above which the directional element will be enabled)
9. Enable one overcurrent stage (for example, OC1)
10. By parameter *CurveType_OC1* select appropriate TOC/IDMT or definite time delayed curve in accordance with your network protection philosophy
11. Set *PickupCurr_OC1* to value between 3-10% (typical values)
12. Set *tDef_OC1* or parameter “TD” when TOC/IDMT curves are used to insure proper time coordination with other ground-fault protections installed in the vicinity of this power line
13. Set *DirMode_OC1* to *Forward*
14. Set *DirPrinc_OC1* to *IcosPhi&U*
15. Set *ActLowVoltI_VM* to *Block*
 - In order to insure proper restraining of this element for CT saturations during three-phase faults it is possible to use current restraint feature and enable this element to operate only when *NegSeq* current is bigger than a certain

percentage (10% is typical value) of measured *PosSeq* current in the power line. To do this the following settings within the same function shall be done:

16. Set *EnRestrainingCurr* to *On*
17. Set *RestrCurrInput* to *PosSeq*
18. Set *RestrCurrCoeff* to value 0.1

If required, this CVGAPC function can be used in directional comparison protection scheme for the power line protection if communication channels to the remote end of this power line are available. In that case typically two *NegSeq* overcurrent steps are required. One for forward and one for reverse direction. As explained before the OC1 stage can be used to detect faults in forward direction. The built-in OC2 stage can be used to detect faults in reverse direction.

However the following shall be noted for such application:

- the set values for *RCADir* and *ROADir* settings will be as well applicable for OC2 stage
- setting *DirMode_OC2* shall be set to *Reverse*
- setting parameter *PickupCurr_OC2* shall be made more sensitive than pickup value of forward OC1 element (that is, typically 60% of OC1 set pickup level) in order to insure proper operation of the directional comparison scheme during current reversal situations
- pickup signals from OC1 and OC2 elements shall be used to send forward and reverse signals to the remote end of the power line
- the available scheme communications function block within IED shall be used between multipurpose protection function and the communication equipment in order to insure proper conditioning of the above two pickup signals

Furthermore the other built-in UC, OV and UV protection elements can be used for other protection and alarming purposes.

11.1.3.2

Negative sequence overcurrent protection

Example will be given how to use one CVGAPC function to provide negative sequence inverse time overcurrent protection for a generator with capability constant of 20s, and maximum continuous negative sequence rating of 7% of the generator rated current.

The capability curve for a generator negative sequence overcurrent protection, often used world-wide, is defined by the ANSI standard in accordance with the following formula:

$$t_{op} = \frac{TD}{\left(\frac{I_{NS}}{I_r}\right)^2}$$

(Equation 84)

where:

t_{op} is the operating time in seconds of the negative sequence overcurrent IED

TD is the generator capability constant in seconds

I_{NS} is the measured negative sequence current

I_r is the generator rated current

By defining parameter x equal to maximum continuous negative sequence rating of the generator in accordance with the following formula

$$x = 7\% = 0.07 pu$$

(Equation 85)

Equation 84 can be re-written in the following way without changing the value for the operate time of the negative sequence inverse overcurrent IED:

$$t_{op} = \frac{TD \cdot \frac{1}{x^2}}{\left(\frac{I_{NS}}{x \cdot I_r}\right)^2}$$

(Equation 86)

In order to achieve such protection functionality with one CVGAPC functions the following must be done:

1. Connect three-phase generator currents to one CVGAPC instance (for example, GF01)
2. Set parameter *CurrentInput* to value *NegSeq*
3. Set base current value to the rated generator current in primary amperes
4. Enable one overcurrent step (for example, OC1)
5. Select parameter *CurveType_OC1* to value *Programmable*

$$t_{op} = TD \cdot \left(\frac{A}{M^P - C} + B \right)$$

(Equation 87)

where:

- t_{op} is the operating time in seconds of the Inverse Time Overcurrent TOC/IDMT algorithm
- TD is time multiplier (parameter setting)
- M is ratio between measured current magnitude and set pickup current level
- A, B, C and P are user settable coefficients which determine the curve used for Inverse Time Overcurrent TOC/IDMT calculation

When the equation [84](#) is compared with the equation [86](#) for the inverse time characteristic of the OC1 it is obvious that if the following rules are followed:

1. set TD equal to the generator negative sequence capability value
2. set A_OC1 equal to the value $1/x^2$
3. set $B_OC1 = 0.0$, $C_OC1 = 0.0$ and $P_OC1 = 2.0$
4. set $PickupCurr_OC1$ equal to the value x

then the OC1 step of the CVGAPC function can be used for generator negative sequence inverse overcurrent protection.

For this particular example the following settings shall be entered to insure proper function operation:

1. select negative sequence current as measuring quantity for this CVGAPC function
2. make sure that the base current value for the CVGAPC function is equal to the generator rated current
3. set $TD_OC1 = 20$
4. set $A_OC1 = 1/0.07^2 = 204.0816$
5. set $B_OC1 = 0.0$, $C_OC1 = 0.0$ and $P_OC1 = 2.0$
6. set $PickupCurr_OC1 = 7\%$

Proper timing of the CVGAPC function made in this way can easily be verified by secondary injection. All other settings can be left at the default values. If required delayed time reset for OC1 step can be set in order to ensure proper function operation in case of repetitive unbalance conditions.

Furthermore the other built-in protection elements can be used for other protection and alarming purposes (for example, use OC2 for negative sequence overcurrent alarm and OV1 for negative sequence overvoltage alarm).

11.1.3.3

Generator stator overload protection in accordance with IEC or ANSI standards

Example will be given how to use one CVGAPC function to provide generator stator overload protection in accordance with IEC or ANSI standard if minimum-operating current shall be set to 116% of generator rating.

The generator stator overload protection is defined by IEC or ANSI standard for turbo generators in accordance with the following formula:

$$t_{op} = \frac{TD}{\left(\frac{I_m}{I_r}\right)^2 - 1}$$

(Equation 88)

where:

t_{op} is the operating time of the generator stator overload IED

TD is the generator capability constant in accordance with the relevant standard (TD = 37.5 for the IEC standard or TD = 41.4 for the ANSI standard)

I_m is the magnitude of the measured current

I_r is the generator rated current

This formula is applicable only when measured current (for example, positive sequence current) exceeds a pre-set value (typically in the range from 105 to 125% of the generator rated current).

By defining parameter x equal to the per unit value for the desired pickup for the overload IED in accordance with the following formula:

$$x = 116\% = 1.16 pu$$

(Equation 89)

formula 3.5 can be re-written in the following way without changing the value for the operate time of the generator stator overload IED:

$$t_{op} = \frac{TD \cdot \frac{1}{x^2}}{\left(\frac{I_m}{x \cdot I_r}\right)^2 - \frac{1}{x^2}}$$

(Equation 90)

In order to achieve such protection functionality with one CVGAPC functions the following must be done:

1. Connect three-phase generator currents to one CVGAPC instance (for example, GF01)
2. Set parameter *CurrentInput* to value *PosSeq*
3. Set base current value to the rated generator current in primary amperes
4. Enable one overcurrent step (for example OC1)
5. Select parameter *CurveType_OC1* to value *Programmable*

$$t_{op} = TD \cdot \left(\frac{A}{M^P - C} + B \right)$$

(Equation 91)

where:

- t_{op} is the operating time in seconds of the Inverse Time Overcurrent TOC/IDMT algorithm
- TD is time multiplier (parameter setting)
- M is ratio between measured current magnitude and set pickup current level
- A, B, C and P are user settable coefficients which determine the curve used for Inverse Time Overcurrent TOC/IDMT calculation

When the equation 90 is compared with the equation 91 for the inverse time characteristic of the OC1 step in it is obvious that if the following rules are followed:

1. set TD equal to the IEC or ANSI standard generator capability value
2. set parameter *A_OC1* equal to the value $1/x^2$
3. set parameter *C_OC1* equal to the value $1/x^2$
4. set parameters *B_OC1* = 0.0 and *P_OC1* = 2.0
5. set *PickupCurr_OC1* equal to the value x

then the OC1 step of the CVGAPC function can be used for generator negative sequence inverse overcurrent protection.

1. select positive sequence current as measuring quantity for this CVGAPC function
2. make sure that the base current value for CVGAPC function is equal to the generator rated current
3. set TD = 37.5 for the IEC standard or TD = 41.4 for the ANSI standard
4. set *A_OC1* = $1/1.162 = 0.7432$
5. set *C_OC1* = $1/1.162 = 0.7432$
6. set *B_OC1* = 0.0 and *P_OC1* = 2.0
7. set *PickupCurr_OC1* = 116%

Proper timing of CVGAPC function made in this way can easily be verified by secondary injection. All other settings can be left at the default values. If required delayed time reset for OC1 step can be set in order to insure proper function operation in case of repetitive overload conditions.

Furthermore the other built-in protection elements can be used for other protection and alarming purposes.

In the similar way rotor overload protection in accordance with ANSI standard can be achieved.

11.1.3.4

Open phase protection for transformer, lines or generators and circuit breaker head flashover protection for generators

Example will be given how to use one CVGAPC function to provide open phase protection. This can be achieved by using one CVGAPC function by comparing the unbalance current with a pre-set level. In order to make such a function more secure it is possible to restrain it by requiring that at the same time the measured unbalance current must be bigger than 97% of the maximum phase current. By doing this it will be insured that function can only pickup if one of the phases is open circuited. Such an arrangement is easy to obtain in CVGAPC function by enabling the current restraint feature. The following shall be done in order to insure proper operation of the function:

1. Connect three-phase currents from the protected object to one CVGAPC instance (for example, GF03)
2. Set *CurrentInput* to value *UnbalancePh*
3. Set *EnRestrainingCurr* to *On*
4. Set *RestrCurrInput* to *MaxPh*
5. Set *RestrCurrCoeff* to value 0.97
6. Set base current value to the rated current of the protected object in primary amperes
7. Enable one overcurrent step (for example, OC1)
8. Select parameter *CurveType_OC1* to value *IEC Def. Time*
9. Set parameter *PickupCurr_OC1* to value 5%
10. Set parameter *tDef_OC1* to desired time delay (for example, 2.0s)

Proper operation of CVGAPC function made in this way can easily be verified by secondary injection. All other settings can be left at the default values. However it shall be noted that set values for restrain current and its coefficient will as well be applicable for OC2 step as soon as it is enabled.

Furthermore the other built-in protection elements can be used for other protection and alarming purposes. For example, in case of generator application by enabling OC2 step with set pickup to 200% and time delay to 0.1s simple but effective protection against circuit breaker head flashover protection is achieved.

11.1.3.5 Voltage restrained overcurrent protection for generator and step-up transformer

Example will be given how to use one CVGAPC function to provide voltage restrained overcurrent protection for a generator. Let us assume that the time coordination study gives the following required settings:

- Inverse Time Over Current TOC/IDMT curve: ANSI very inverse
- Pickup current of 185% of generator rated current at rated generator voltage
- Pickup current 25% of the original pickup current value for generator voltages below 25% of rated voltage

This functionality can be achieved by using one CVGAPC function. The following shall be done in order to ensure proper operation of the function:

1. Connect three-phase generator currents and voltages to one CVGAPC instance (for example, GF05)
2. Set *CurrentInput* to value *MaxPh*
3. Set *VoltageInput* to value *MinPh-Ph* (it is assumed that minimum phase-to-phase voltage shall be used for restraining. Alternatively, positive sequence voltage can be used for restraining by selecting *PosSeq* for this setting parameter)
4. Set base current value to the rated generator current primary amperes
5. Set base voltage value to the rated generator phase-to-phase voltage in kV
6. Enable one overcurrent step (for example, OC1)
7. Select *CurveType_OC1* to value *ANSI Very inv*
8. If required set minimum operating time for this curve by using parameter *tMin_OC1* (default value 0.05s)
9. Set *PickupCurr_OC1* to value 185%
10. Set *VCntrlMode_OC1* to *On*
11. Set *VDepMode_OC1* to *Slope*
12. Set *VDepFact_OC1* to value 0.25
13. Set *VHighLimit_OC1* to value 100%
14. Set *VLowLimit_OC1* to value 25%

Proper operation of the CVGAPC function made in this way can easily be verified by secondary injection. All other settings can be left at the default values. Furthermore the other built-in protection elements can be used for other protection and alarming purposes.

11.1.3.6 Loss of excitation protection for a generator

Example will be given how by using positive sequence directional overcurrent protection element within a CVGAPC function, loss of excitation protection for a

generator can be achieved. Let us assume that from rated generator data the following values are calculated:

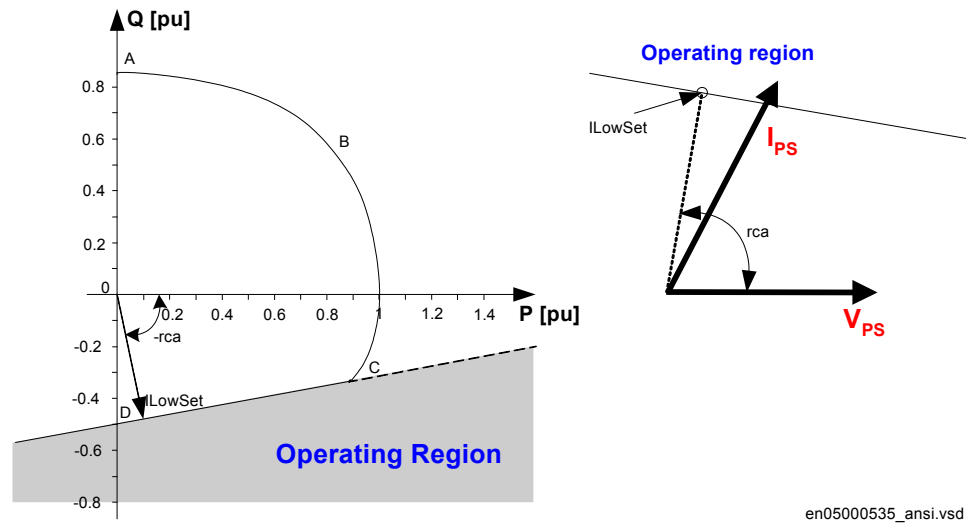
- Maximum generator capability to contentiously absorb reactive power at zero active loading 38% of the generator MVA rating
- Generator pull-out angle 84 degrees

This functionality can be achieved by using one CVGAPC function. The following shall be done in order to insure proper operation of the function:

1. Connect three-phase generator currents and three-phase generator voltages to one CVGAPC instance (for example, GF02)
2. Set parameter *CurrentInput* to *PosSeq*
3. Set parameter *VoltageInput* to *PosSeq*
4. Set base current value to the rated generator current primary amperes
5. Set base voltage value to the rated generator phase-to-phase voltage in kV
6. Set parameter *RCADir* to value -84 degree (that is, current lead voltage for this angle)
7. Set parameter *ROADir* to value 90 degree
8. Set parameter *LowVolt_VM* to value 5%
9. Enable one overcurrent step (for example, OC1)
10. Select parameter *CurveType_OC1* to value *IEC Def. Time*
11. Set parameter *PickupCurr_OC1* to value 38%
12. Set parameter *tDef_OC1* to value 2.0s (typical setting)
13. Set parameter *DirMode_OC1* to *Forward*
14. Set parameter *DirPrinc_OC1* to *IcosPhi&V*
15. Set parameter *ActLowVolt1_VM* to *Block*

Proper operation of the CVGAPC function made in this way can easily be verified by secondary injection. All other settings can be left at the default values. However it shall be noted that set values for RCA & ROA angles will be applicable for OC2 step if directional feature is enabled for this step as well. Figure [73](#) shows overall protection characteristic

Furthermore the other build-in protection elements can be used for other protection and alarming purposes.



en05000535_ansi.vsd

Figure 73: Loss of excitation

Section 12 System protection and control

12.1 Multipurpose filter SMAIHPAC

12.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Multipurpose filter	SMAIHPAC	-	-

12.1.2 Application

The multi-purpose filter, function block with name SMAI HPAC, is arranged as a three-phase filter. It has very much the same user interface (e.g. function block outputs) as the standard pre-processing function block SMAI. However the main difference is that it can be used to extract any frequency component from the input signal. For all four analogue input signals into this filter (i.e. three phases and the residual quantity) the input samples from the TRM module, which are coming at rate of 20 samples per fundamental system cycle, are first stored. When enough samples are available in the internal memory, the phasor values at set frequency defined by the setting parameter *SetFrequency* are calculated. The following values are internally available for each of the calculated phasors:

- Magnitude
- Phase angle
- Exact frequency of the extracted signal

The SMAI HPAC filter is always used in conjunction with some other protection function (e.g. multi-purpose protection function or overcurrent function or over-voltage function or over-power function). In this way many different protection applications can be arranged. For example the following protection, monitoring or measurement features can be realized:

- Sub-synchronous resonance protection for turbo generators
- Sub-synchronous protection for wind turbines/wind farms
- Detection of sub-synchronous oscillation between HVDC links and synchronous generators
- Super-synchronous protection
- Detection of presence of the geo-magnetic induced currents
- Overcurrent or overvoltage protection at specific frequency harmonic, sub-harmonic, inter-harmonic etc.
- Presence of special railway frequencies (e.g. 16.7Hz or 25Hz) in the three-phase power system
- Sensitive reverse power protection
- Stator or rotor earth fault protection for special injection frequencies (e.g. 25Hz) etc.

The filter output can also be connected to the measurement function blocks such as CVMMXN (Measurements), CMMXU (Phase current measurement), VMMXU (Phase-phase voltage measurement), etc. in order to report the extracted phasor values to the supervisory system (e.g. MicroSCADA).

The following figure shows typical configuration connections required to utilize this filter in conjunction with multi-purpose function as non-directional overcurrent protection.

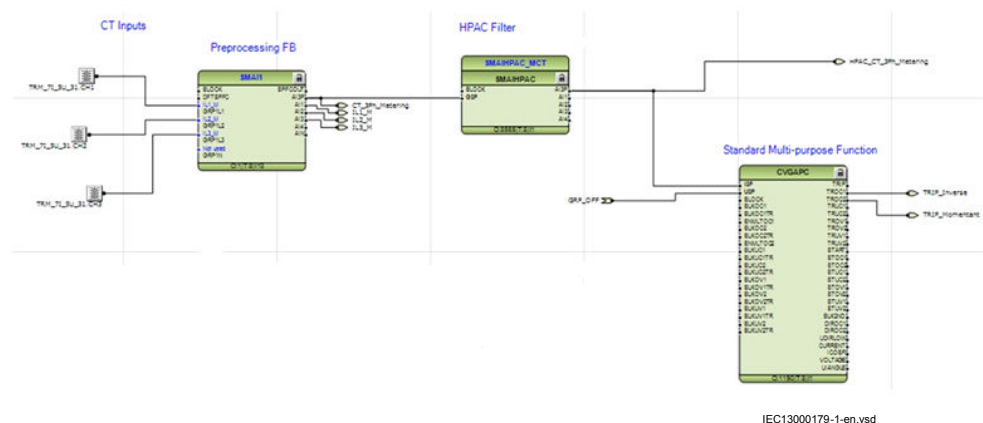


Figure 74: Required ACT configuration

Such overcurrent arrangement can be for example used to achieve the subsynchronous resonance protection for turbo generators.

12.1.3 Setting guidelines

12.1.3.1 Setting example

A relay type used for generator subsynchronous resonance overcurrent protection shall be replaced. The relay had inverse time operating characteristic as given with the following formula:

$$t_{op} = T_{01} + \frac{K}{I_s}$$

(Equation 92)

Where:

- t_{op} is the operating time of the relay
- T_{01} is fixed time delay (setting)
- K is a constant (setting)
- I_s is measured subsynchronous current in primary amperes

The existing relay was applied on a large 50Hz turbo generator which had shaft mechanical resonance frequency at 18.5Hz. The relay settings were $T^{01} = 0.64$ seconds, $K = 35566$ Amperes and minimal subsynchronous current trip level was set at $I_{S0} = 300$ Amperes primary.

Solution:

First the IED configuration shall be arranged as shown in [Figure 74](#). Then the settings for SMAI HPAC filter and multipurpose function shall be derived from existing relay settings in the following way:

The subsynchronous current frequency is calculated as follows:

$$f_s = 50\text{Hz} - 18.5\text{Hz} = 31.5\text{Hz}$$

(Equation 93)

In order to properly extract the weak subsynchronous signal in presence of the dominating 50Hz signal the SMAI HPAC filter shall be set as given in the following table:

Table 22: *Proposed settings for SMAIHPAC*

I_HPAC_31_5Hz: SMAIHPAC:1	
ConnectionType	Ph — N
SetFrequency	31.5
Table continues on next page	

FreqBandWidth	0.0
FilterLength	1.0 s
OverLap	75
Operation	On

Now the settings for the multi-purpose overcurrent stage one shall be derived in order to emulate the existing relay operating characteristic. To achieve exactly the same inverse time characteristic the programmable IDMT characteristic is used which for multi-purpose overcurrent stage one, which has the following equation (for more information see Section “Inverse time characteristics” in the TRM).

$$t[s] = \left(\frac{A}{\left(\frac{i}{in} \right)^p - C} + B \right) \cdot k$$

(Equation 94)

In order to adapt to the previous relay characteristic the above equation can be re-written in the following way:

$$t[s] = \left(\frac{\frac{K}{I_{so}}}{\left(\frac{I_s}{I_{so}} \right)^1 - 0} + T_{01} \right) \cdot 1$$

(Equation 95)

Thus if the following rules are followed when multi-purpose overcurrent stage one is set:

- $in > = I_{S0} = 300A$
- $A = \frac{K}{I_{so}} = \frac{35566}{300} = 118.55$
- $B = T_{01} = 0.64$
- $C = 0.0$
- $p = 1.0$
- $k = 1.0$

then exact replica of the existing relay will be achieved. The following table summarizes all required settings for the multi-purpose function:

Setting Group1	
Operation	On
CurrentInput	MaxPh
IBase	1000
VoltageInput	MaxPh
UBase	20.50
OPerHarmRestr	Off
I_2nd_fund	20.0
BlkLevel2nd	5000
EnRestrainedCurr	Off
RestrCurrInput	PosSeq
RestrCurrCoeff	0.00
RCADir	-75
ROADir	75
LowVolt_VM	0.5

OC1	
Setting Group1	
Operation_OC1	On
StartCurr_OC1	30.0
CurrMult_OC1	2.0
CurveType_OC1	Programmable
tDef_OC1	0.00
k_OC1	1.00
tMin1	30
tMin_OC1	1.40
ResCrvType_OC1	Instantaneous
tResetDef_OC1	0.00
P_OC1	1.000
A_OC1	118.55
B_OC1	0.640
C_OC1	0.000

Section 13 Secondary system supervision

13.1 Current circuit supervision (87)

13.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Current circuit supervision	CCSSPVC	-	87

13.1.2 Application

Open or short circuited current transformer cores can cause unwanted operation of many protection functions such as differential, ground-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 (87) 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.

13.1.3 Setting guidelines

GlobalBaseSel: Selects the global base value group used by the function to define *I*Base, *V*Base and *S*Base as applicable.

Current circuit supervision CCSSPVC (87) 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.

MinOp: 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.

Pickup_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.

13.2 Fuse failure supervision FUFSPVC

13.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Fuse failure supervision	FUFSPVC	-	-

13.2.2 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 disconnecter. 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 grounded networks: a high value of voltage $3V_2$ 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 grounded networks: a high value of voltage $3V_0$ 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.

13.2.3 Setting guidelines

13.2.3.1 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 (V_{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.

13.2.3.2 Setting of common parameters

Set the operation mode selector *Operation* to *Enabled* to release the fuse failure function.

The voltage threshold *VPPU* is used to identify low voltage condition in the system. Set *VPPU* below the minimum operating voltage that might occur during emergency conditions. We propose a setting of approximately 70% of *VBase*.

The drop off time of 200 ms for dead phase detection makes it recommended to always set *SealIn* to *Enabled* 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 *OpModeSel* 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 *OpModeSel* is set to either *V2I2* for selecting negative sequence algorithm or *V0I0* 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 *OpModeSel* is set to *V0I0 OR V2I2* or *OptimZsNs*. In mode *V0I0 OR V2I2* 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 *OpModeSel* can be selected to *V0I0 AND V2I2* 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 *BLKV* or *BLKZ*.

13.2.3.3 Negative sequence based

The relay setting value *3V2PU* is given in percentage of the base voltage *VBase* and should not be set lower than the value that is calculated according to equation [96](#).

$$3V2PU = \frac{V2}{VBase/\sqrt{3}} \cdot 100$$

(Equation 96)

where:

$V2PU$ is the maximal negative sequence voltage during normal operation conditions, plus a margin of 10...20%

$VBase$ is the base voltage for the function according to the setting *GlobalBaseSel*

The setting of the current limit $3I2PU$ is in percentage of parameter $IBase$. The setting of $3I2PU$ must be higher than the normal unbalance current that might exist in the system and can be calculated according to equation [97](#).

$$3I2PU = \frac{I2}{IBase} \cdot 100$$

(Equation 97)

where:

$I2$ is the maximal negative sequence current during normal operating conditions, plus a margin of 10...20%

$IBase$ is the base current for the function according to the setting *GlobalBaseSel*

13.2.3.4

Zero sequence based

The IED setting value $3V0PU$ is given in percentage of the base voltage $VBase$. The setting of $3V0PU$ should not be set lower than the value that is calculated according to equation [98](#).

$$3V0PU = \frac{3V0}{VBase/\sqrt{3}} \cdot 100$$

(Equation 98)

where:

$3V0$ is the maximal zero sequence voltage during normal operation conditions, plus a margin of 10...20%

$VBase$ is the base voltage for the function according to the setting *GlobalBaseSel*

The setting of the current limit $3I0PU$ is done in percentage of $IBase$. The setting of pickup must be higher than the normal unbalance current that might exist in the system. The setting can be calculated according to equation [99](#).

$$3I0PU = \frac{3I0}{IBase} \cdot 100$$

(Equation 99)

where:

$3I0PU$ is the maximal zero sequence current during normal operating conditions, plus a margin of 10...20%

$IBase$ is the base current for the function according to the setting *GlobalBaseSel*

13.2.3.5 Delta V and delta I

Set the operation mode selector *OpDVDI* to *Enabled* if the delta function shall be in operation.

The setting of *DVPU* should be set high (approximately 60% of *VBase*) and the current threshold *DIPU* low (approximately 10% of *IBase*) 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 $VSet_{prim}$ is the primary voltage for operation of dU/dt and $ISet_{prim}$ the primary current for operation of dI/dt, the setting of *DVPU* and *DIPU* will be given according to equation [100](#) and equation [101](#).

$$DVPU = \frac{VSet_{prim}}{VBase} \cdot 100$$

(Equation 100)

$$DIPU = \frac{ISet_{prim}}{IBase} \cdot 100$$

(Equation 101)

The voltage thresholds *VPPU* is used to identify low voltage condition in the system. Set *VPPU* below the minimum operating voltage that might occur during emergency conditions. A setting of approximately 70% of *VBase* is recommended.

The current threshold *50P* shall be set lower than the *IMinOp* for the distance protection function. A 5...10% lower value is recommended.

13.2.3.6 Dead line detection

The condition for operation of the dead line detection is set by the parameters *IDLDPU* for the current threshold and *UDLD<* for the voltage threshold.

Set the *IDLDPU* 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 *VDDLPU* with a sufficient margin below the minimum expected operating voltage. A safety margin of at least 15% is recommended.

Section 14 Control

14.1 Logic rotating switch for function selection and LHMI presentation SLGAPC

14.1.1 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	-	-

14.1.2 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).

14.1.3 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 *Enabled* or *Disabled*.

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.

14.2 Selector mini switch VSGAPC

14.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Selector mini switch	VSGAPC	-	43

14.2.2 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 enabled–disabled from a button symbol on the local HMI is shown in figure 75. The Close and Open buttons on the local HMI are normally used for enable–disable operations of the circuit breaker.

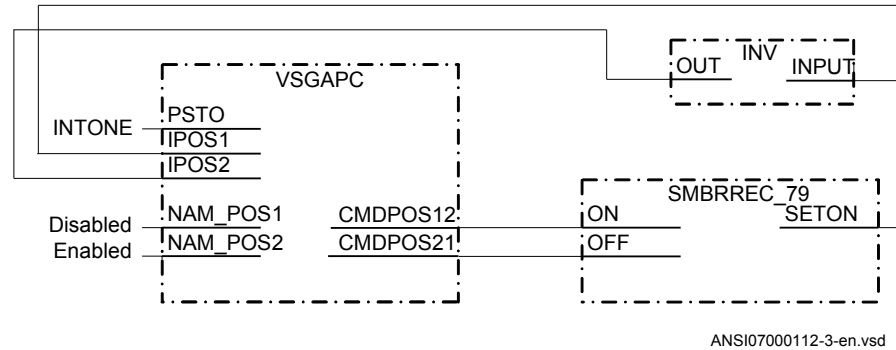


Figure 75: Control of Autorecloser from local HMI through Selector mini switch

VSGAPC is also provided with IEC 61850 communication so it can be controlled from SA system as well.

14.2.3 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*.

14.3 Generic communication function for Double Point indication DPGAPC

14.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Generic communication function for Double Point indication	DPGAPC	-	-

14.3.2 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 23 for the description of the input-output relationship in terms of the value and the quality attributes.

Table 23: *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

14.3.3 Setting guidelines

The function does not have any parameters available in the local HMI or PCM600.

14.4 Single point generic control 8 signals SPC8GAPC

14.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Single point generic control 8 signals	SPC8GAPC	-	-

14.4.2 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.

14.4.3 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 *Enabled/Disabled*.

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).

14.5 AutomationBits, command function for DNP3.0 AUTOBITS

14.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
AutomationBits, command function for DNP3	AUTOBITS	-	-

14.5.2 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.

14.5.3 Setting guidelines

AUTOBITS function block has one setting, (*Operation: Enabled/Disabled*) enabling or disabling the function. These names will be seen in the DNP3 communication management tool in PCM600.

14.6 Single command, 16 signals SINGLECMD

14.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Single command, 16 signals	SINGLECMD	-	-

14.6.2 Application

Single command, 16 signals (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 76 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 76 shows a close operation. An open breaker operation is performed in a similar way but without the synchro-check condition.

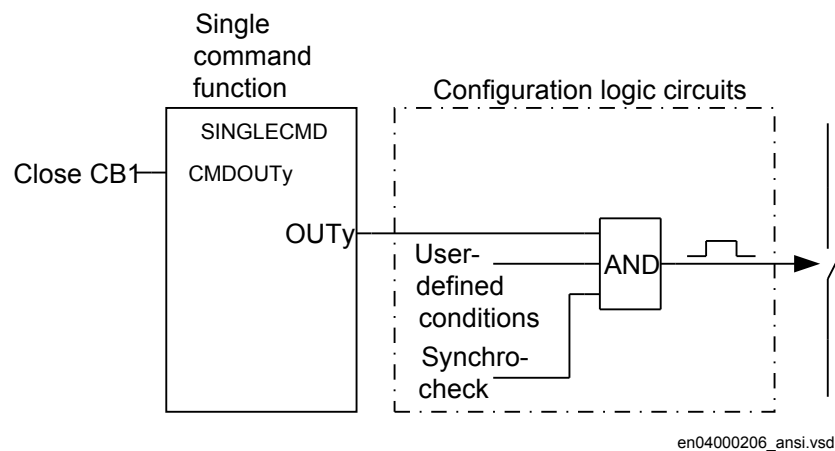
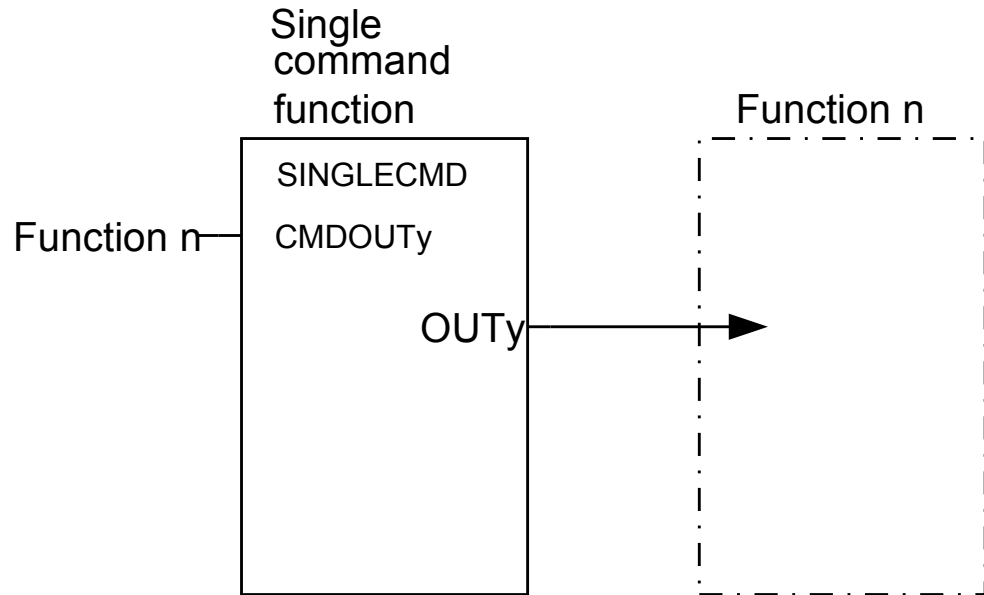


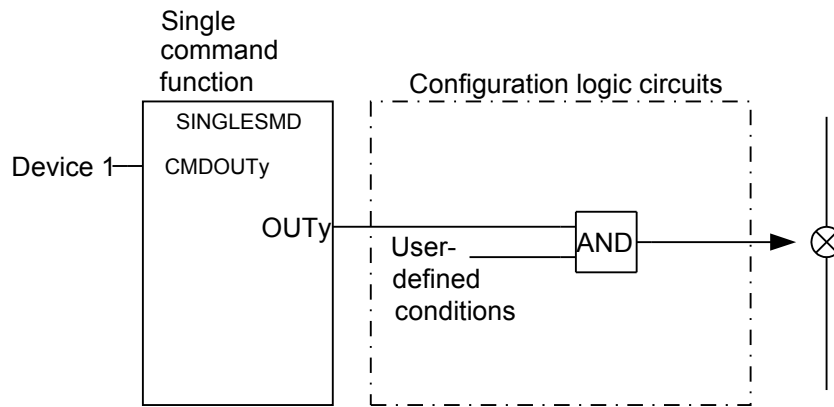
Figure 76: Application example showing a logic diagram for control of a circuit breaker via configuration logic circuits

Figure 77 and figure 78 show other ways to control functions, which require steady Enabled/Disabled signals. Here, the output is used to control built-in functions or external devices.



en04000207.vsd

Figure 77: Application example showing a logic diagram for control of built-in functions



en04000208_ansi.vsd

Figure 78: Application example showing a logic diagram for control of external devices via configuration logic circuits

14.6.3

Setting guidelines

The parameters for Single command, 16 signals (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 Disabled, Steady, or Pulse.

- Disabled, 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 15 Logic

15.1 Tripping logic SMPPTRC (94)

15.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Tripping logic	SMPPTRC	1 -> 0	94

15.1.2 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 (94) offers three different operating modes:

- Three-pole tripping for all fault types (3p operating mode)
- Single-pole tripping for single-phase faults and three-pole tripping for multi-phase and evolving faults (1p/3p operating mode).
- Single-pole tripping for single-pole faults, two-pole tripping for two-pole faults and three-pole tripping for three-pole faults (1p/2p/3p operating mode).

The logic also issues a three-pole tripping command when phase selection within the operating protection functions is not possible, or when external conditions request three-pole tripping. To meet the different double, breaker-and-a-half and other multiple circuit breaker arrangements, multiple identical SMPPTRC (94) function blocks are provided within the IED. In such installation, use one instance of SMPPTRC function per circuit breaker.

If the OHL is connected to the substation via more than one breaker, one SMPPTRC (94) function block should be used for each breaker. For example when single-pole

tripping and autoreclosing is used on the line, both breakers are normally set up for 1/3-pole tripping and 1/3-phase autoreclosing. Alternatively, the breaker chosen as master can have single-pole tripping, while the slave breaker could have three-pole 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-pole reclosing onto the non-faulted line.

The same philosophy can be used for two-pole tripping and autoreclosing.

To prevent closing of a circuit breaker after a trip, the function offers a lockout function.

15.1.2.1

Three-pole tripping

Connect the inputs from the protection functions to the input TRINP_3P. 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 TR_A, TR_B, TR_C will always be activated at every trip and can be utilized on individual trip outputs if single-pole operating devices are available on the circuit breaker even when a three-pole tripping scheme is selected.

Set the function block to *Program = 3 phase* and set the required length of the trip pulse to for example, $tTripMin = 150ms$.

The typical connection is shown below in figure 79.

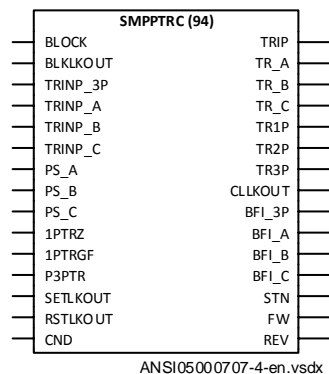


Figure 79: Tripping logic SMPPTRC (94) is used for a simple three-pole tripping application

15.1.2.2 Single- and/or three-pole tripping

The single-/three-pole tripping operation mode will give single-pole tripping for single-phase faults and three-pole tripping for multi-phase fault. This operating mode is always used together with a single-phase autoreclosing scheme.

The single-pole tripping can include different options and the use of the different inputs in the function block. Inputs TRINP_A, TRINP_B and TRINP_C shall be used for trip signals from functions with built-in pole selection logic such as distance or line differential protection functions.

The inputs 1PTRZ and 1PTRGF are used for single-pole tripping from functions which do not have built-in pole 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)
- 1PTRGF 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 PS_A, PS_B and PS_C to achieve the tripping on the respective single-pole trip outputs TR_A, TR_B and TR_C. 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, TR2P and TR3P will be activated as well.

When single-pole 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-pole trip P3PTR must be activated. This input is normally connected to the output PREP3P on the autorecloser function SMBRREC (79) 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 (79) 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 (79) function in order to switch SMBRREC (79) to perform a three-pole reclosing. If this signal is not activated, SMBRREC will use single-pole dead time.



If a second line protection is utilizing the same SMBRREC (79), the three-pole trip signal must be generated as OR conditions from both line protections.

Other back-up functions are connected to the input TRINP_3P as described above for three-pole tripping. A typical connection for a single-pole tripping scheme is shown in figure 80.

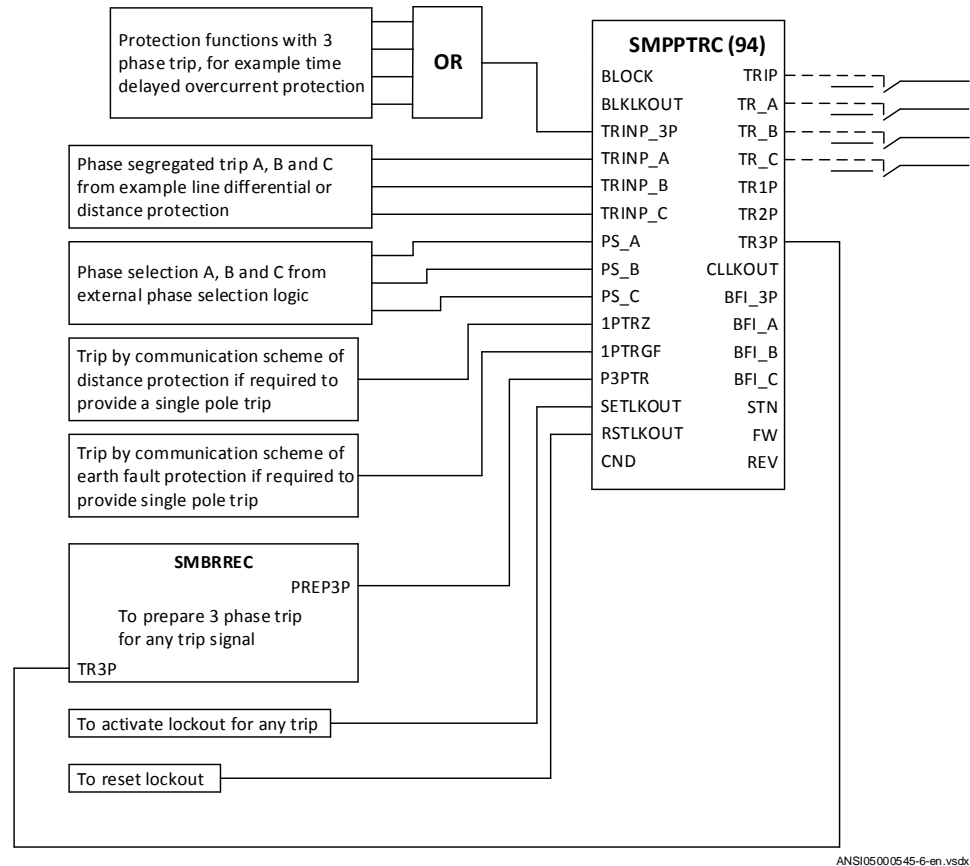


Figure 80: The trip logic function SMPPTRC (94) used for single-pole tripping application

15.1.2.3 Single-, two- or three-pole tripping

The single-/two-/three-pole tripping mode provides single-pole tripping for single-phase faults, two-pole tripping for two-phase faults and three-pole 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 (79) must also be informed that the trip is two phases by connecting the output TR2P to the input TR2P in the SMBRREC (79) function.

15.1.2.4**Lock-out**

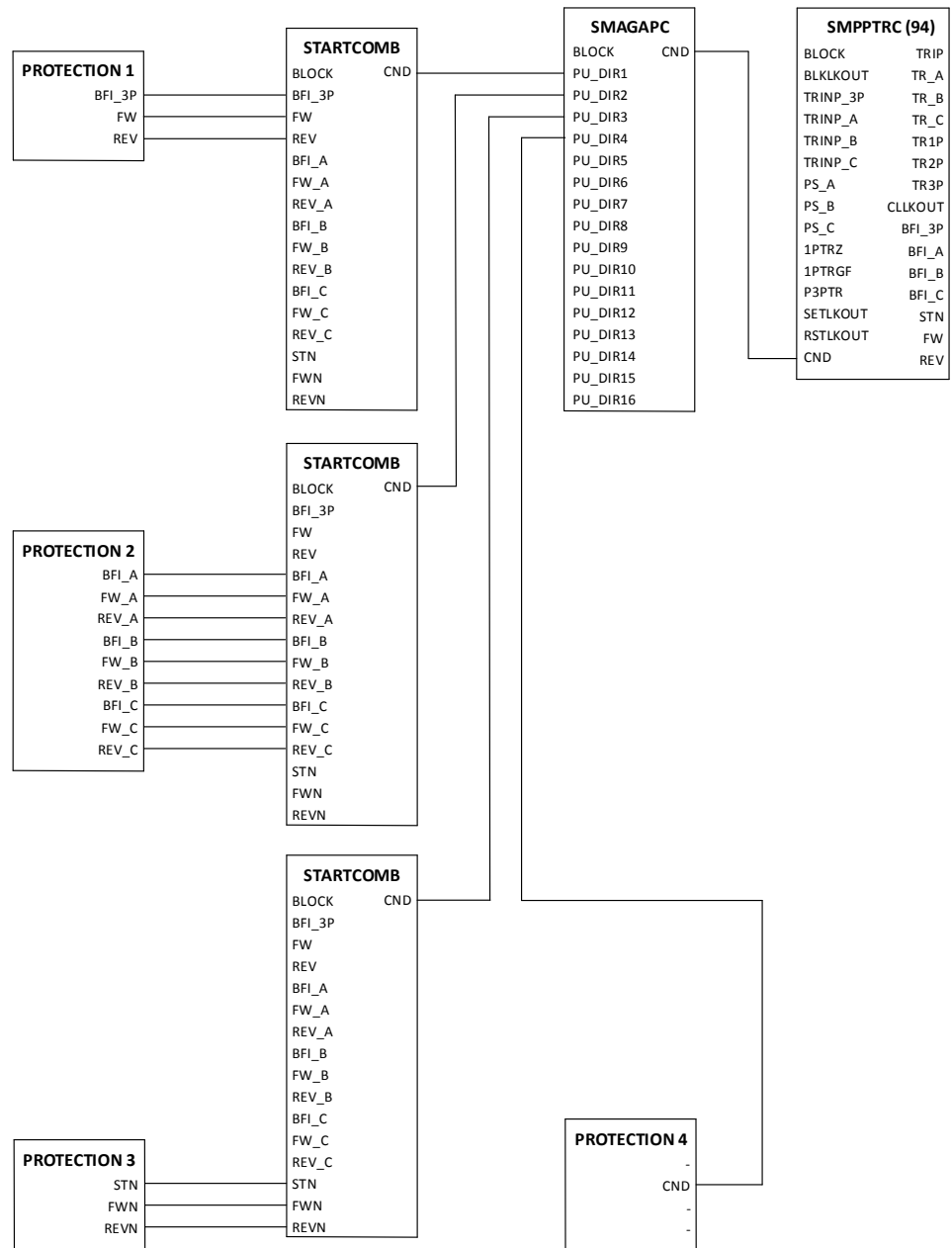
The SMPTRC function block is provided with possibilities to initiate lock-out. The lock-out can be set to only activate the block closing output CLLKOUT or initiate the block closing output and also maintain the trip signal output TR3P (latched trip).

The lock-out can then be manually reset after checking the primary fault by activating the input reset lock-out RSTLKOUT.

If external conditions are required to initiate a closing circuit lock-out but not to lockout trip, this can be achieved by activating input SETLKOUT. The setting *AutoLock = Disabled* means that the internal trip will not activate lock-out so only initiation of the input SETLKOUT will result in lock-out. This is normally the case for overhead line protection where most faults are transient. Unsuccessful autoreclose and back-up zone tripping can in such cases be connected to initiate lock-out by activating the input SETLKOUT.

15.1.2.5**Example of directional data**

An example how to connect the directional data from different application functions to the trip function is given below, see Figure [81](#):



ANSI16000180-2-en.vsdX

Figure 81: 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 (CND) 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 *BFI_3P*, *BFI_A*, *BFI_B*, *BFI_C*, *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*, *DIRL1*, *DIRL2*, *DIRL3* and *DIRN*.

15.1.2.6 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 lock-out output is achieved by activating the input *BLKLKOUT*.

15.1.3 Setting guidelines

The parameters for tripping logic SMPPTRC (94) are set via the local HMI or PCM600.

Operation: Sets the mode of operation. *Disabled* switches the tripping off. The normal selection is *Enabled*.

Program: Sets the required tripping scheme. Normally *3 phase* or *1p/3p* is used.

TripLockout: Sets the scheme for lock-out. *Disabled* only activates the closing circuit lock-out output. *Enabled* activates the closing circuit lock-out output and latches the TRIP related outputs. The normal selection is *Disabled*.

AutoLock: Sets the scheme for lock-out. *Disabled* only activates lock-out through the input *SETLKOUT*. *Enabled* additionally allows lock-out activation via the trip inputs. The normal selection is *Disabled*.

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 after any of the inputs *1PTRZ* or *1PTRGF* has been activated during which external pole selection must operate in order to get a single pole trip. If no pole selection has been achieved, a three-pole trip will be issued after this time has elapsed.

tEvolvingFault: Secures two- or three-pole tripping depending on *Program* selection during evolving faults.

15.2 Trip matrix logic TMAGAPC

15.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Trip matrix logic	TMAGAPC	-	-

15.3 Logic for group alarm ALMCALH

15.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Logic for group alarm	ALMCALH	-	-

15.3.2 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.

15.3.3 Setting guidelines

Operation: Enabled or Disabled

15.4 Logic for group alarm WRNCALH

15.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Logic for group warning	WRNCALH	-	-

15.4.1.1 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.

15.4.1.2 Setting guidelines

Operation Enabled or Disabled

15.5 Logic for group indication INDCALH

15.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Logic for group indication	INDCALH	-	-

15.5.1.1 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.

15.5.1.2 Setting guidelines

Operation: Enabled or Disabled

15.6 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.

15.6.1 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. Additional logic blocks that, beside the normal logical function, have the capability to propagate timestamp and quality are also available. Those blocks have a designation including the letters QT, like ANDQT, ORQT etc.

15.6.2 Setting guidelines

There are no settings for AND gates, OR gates, inverters or XOR gates as well as, for ANDQT gates, ORQT gates or XORQT 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.

15.6.2.1 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 82: Example designation, serial execution number and cycle time for logic function

IEC09000310-2-en.vsd

Figure 83: Example designation, serial execution number and cycle time for logic function that also propagates timestamp and quality of input signals

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.

15.7 Fixed signal function block FXDSIGN

15.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Fixed signals	FXDSIGN	-	-

15.7.2 Application

The Fixed signals function (FXDSIGN) has nine pre-set (fixed) 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) (87N) 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.

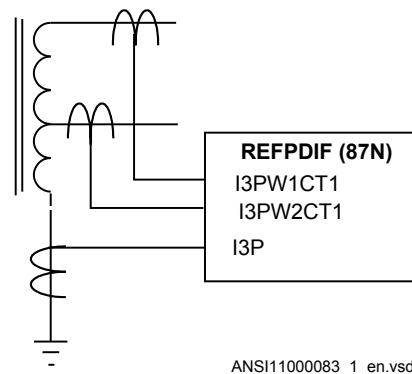
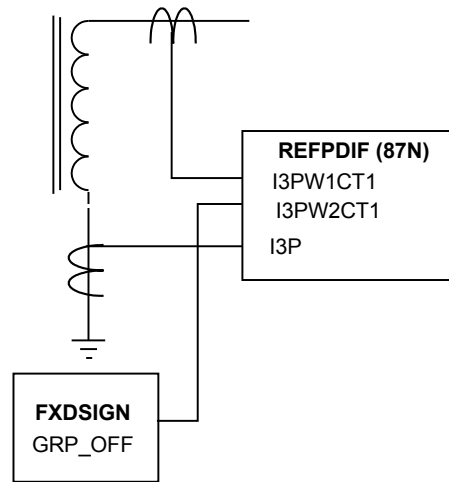


Figure 84: REFPDIF (87N) function inputs for autotransformer application

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.



ANSI11000084_1_en.vsd

Figure 85: REFPDIF (87N) function inputs for normal transformer application

15.8 Boolean 16 to Integer conversion B16I

15.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Boolean 16 to integer conversion	B16I	-	-

15.8.2 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 OUTx from function block B16I 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 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
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 B16I function block.

15.9

Boolean to integer conversion with logical node representation, 16 bit BTIGAPC

15.9.1 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	-	-

15.9.2 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 $1 \leq x \leq 16$ 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. 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 $1 \leq x \leq 16$.

The sum of the value on each IN_x corresponds to the integer presented on the output OUT on the function block 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

Table continues on next page

Name of input	Type	Default	Description	Value when activated	Value when deactivated
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 $1 \leq x \leq 16$) 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.

15.10 Integer to Boolean 16 conversion IB16

15.10.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Integer to boolean 16 conversion	IB16	-	-

15.10.2 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 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. 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 OUT_x 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.

15.11 Integer to Boolean 16 conversion with logic node representation ITBGAPC

15.11.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Integer to boolean 16 conversion with logic node representation	ITBGAPC	-	-

15.11.2 Application

Integer to boolean 16 conversion with logic node representation 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 16 conversion with logic node representation 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 OUT_x where 1≤x≤16.

The values of the different OUT_x are according to the Table 24.

If the BLOCK input is activated, it freezes the logical outputs at the last value.

Table 24: *Output signals*

Name of OUT _x	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 OUT_x (1≤x≤16) are active equals 65535. This is the highest integer that can be converted by the ITBGAPC function block.

15.12 Elapsed time integrator with limit transgression and overflow supervision TEIGAPC

15.12.1 Identification

Function Description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Elapsed time integrator	TEIGAPC	-	-

15.12.2 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.

15.12.3 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.

15.13 Comparator for integer inputs - INTCOMP

15.13.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Comparison of integer values	INTCOMP	Int<=>	

15.13.2 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.

15.13.3 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: This setting is used 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: This setting is used 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: This setting is used to set the reference value for comparison when setting *RefSource* is selected as *SetValue*.

15.13.4 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

15.14 Comparator for real inputs - REALCOMP

15.14.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Comparator for real inputs	REALCOMP	Real<=>	

15.14.2 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.

15.14.3 Setting guidelines

Setting procedure on the IED:

EnaAbs: This setting is used 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: This setting is used 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: This setting is used 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: This setting is used to set the unit of the reference value for comparison when setting *RefSource* is selected as *Set Value*. It has 5 unit selections and they are Milli, Unity, Kilo, Mega and Giga.

EqualBandHigh: This setting is used 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: This setting is used 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.

15.14.4

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 16 Monitoring

16.1 Measurement

16.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Power system measurements	CVMMXN	P, Q, S, I, U, f	-
Phase current measurement	CMMXU	I	-
Phase-phase voltage measurement	VMMXU	U	-
Current sequence component measurement	CMSQI	I_1, I_2, I_0	-
Voltage sequence component measurement	VMSQI	U_1, U_2, U_0	-
Phase-neutral voltage measurement	VNMMXU	U	-

16.1.2

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.

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
- V: phase-to-phase voltage magnitude
- I: phase current magnitude
- F: power system frequency

The measuring functions CMMXU, VMMXU and VNMMXU provide physical quantities:

- I: phase currents (magnitude and angle) (CMMXU)
- V: voltages (phase-to-ground and phase-to-phase voltage, magnitude and angle) (VMMXU, VNMMXU)

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 magnitude 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, magnitude and angle)
- V: sequence voltages (positive, zero and negative sequence, magnitude and angle).

16.1.3

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

Table continues on next page

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.

16.1.4

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 *I*Base, *V*Base and *S*Base as applicable.

Operation: Disabled/Enabled. Every function instance (CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU) can be taken in operation (*Enabled*) or out of operation (*Disabled*).

The following general settings can be set for the **Measurement function** (CVMMXN).

PowMagFact: Magnitude factor to scale power calculations.

PowAngComp: Angle compensation for phase shift between measured I & V.

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, V and I.

VGenZeroDb: Minimum level of voltage in % of *VBase*, used as indication of zero voltage (zero point clamping). If measured value is below *VGenZeroDb* 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.

VMagCompY: Magnitude compensation to calibrate voltage measurements at Y% of V_n , where Y is equal to 5, 30 or 100.

IMagCompY: Magnitude compensation to calibrate current measurements at Y% of I_n , where Y is equal to 5, 30 or 100.

IAngCompY: Angle compensation to calibrate angle measurements at Y% of I_n , where Y is equal to 5, 30 or 100.

The following general settings can be set for the **Phase current measurement** (CMMXU).

IMagCompY: Magnitude compensation to calibrate current measurements at Y% of I_n , where Y is equal to 5, 30 or 100.

IAngCompY: Angle compensation to calibrate angle measurements at Y% of I_n , where Y is equal to 5, 30 or 100.

The following general settings can be set for the **Phase-phase voltage measurement** (VMMXU).

VMagCompY: Amplitude compensation to calibrate voltage measurements at Y% of V_n , where Y is equal to 5, 30 or 100.

VAngCompY: Angle compensation to calibrate angle measurements at Y% of V_n , where Y is equal to 5, 30 or 100.

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, V, I, F, IA,IB,IC, VA, VB, VCVAB, VBC, VCA, I1, I2, 3I0, V1, V2 or 3V0.

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 (*VGenZeroDb* and *IGenZeroDb*). If measured value is below *VGenZeroDb* and/or *IGenZeroDb* calculated S, P, Q and PF will be zero and these settings will override *XZeroDb*.

XRepTyp: Reporting type. Cyclic (*Cyclic*), magnitude 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. Magnitude 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).

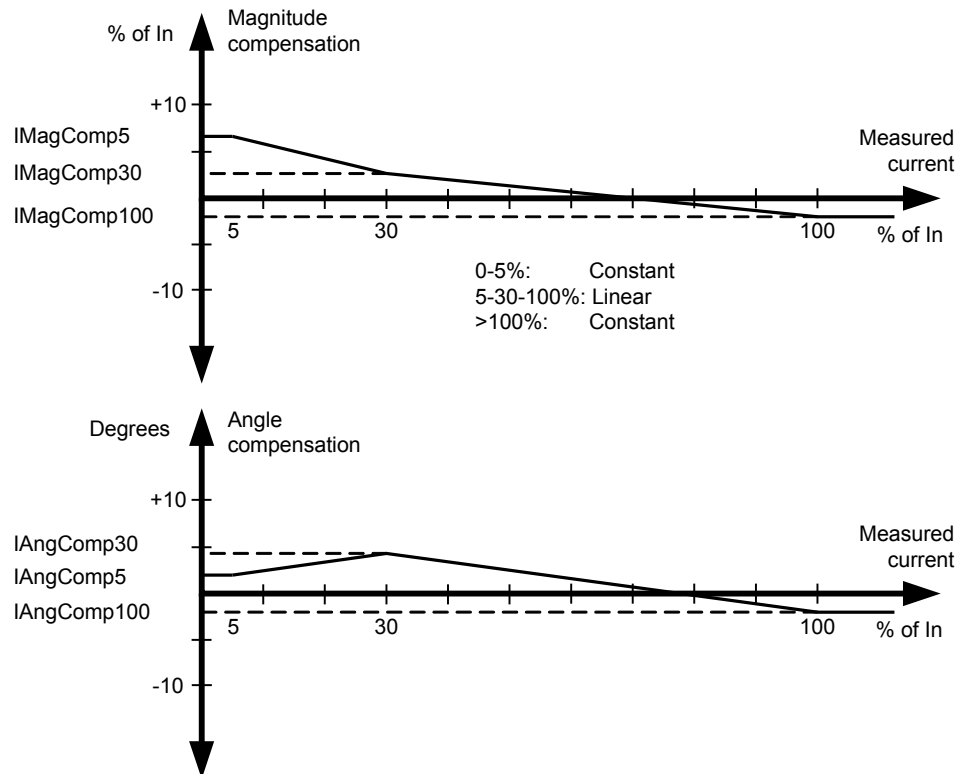
XLowLowLim: Low-low limit. Set as % of *YBase* (Y is *SBase* for S,P,Q *UBase* for Voltage measurement and *IBase* for current measurement).

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.

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 magnitude and angle compensation at 5, 30 and 100% of rated current and voltage. The compensation curve will have the characteristic for magnitude and angle compensation of currents as shown in figure 86 (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.



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Figure 86: Calibration curves

16.1.4.1

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 380kV OHL

Single line diagram for this application is given in figure 87:

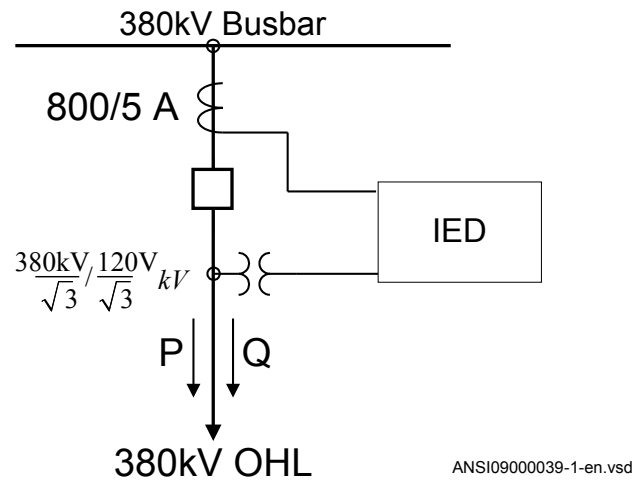


Figure 87: Single line diagram for 380kV OHL application

In order to monitor, supervise and calibrate the active and reactive power as indicated in figure 87 it is necessary to do the following:

1. Set correctly CT and VT data and phase angle reference channel *PhaseAngleRef* 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 25.
 - level supervision of active power as shown in table 26.
 - calibration parameters as shown in table 27.

Table 25: *General settings parameters for the Measurement function*

Setting	Short Description	Selected value	Comments
Operation	Operation Off/On	On	Function must be <i>On</i>
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-ground VT inputs are available
k	Low pass filter coefficient for power measurement, V and I	0.00	Typically no additional filtering is required
VGenZeroDb	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.
VBase (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 26: *Settings parameters for level supervision*

Setting	Short Description	Selected value	Comments
<i>PMin</i>	Minimum value	-100	Minimum expected load
<i>PMax</i>	Minimum value	100	Maximum expected load
<i>PZeroDb</i>	Zero point clamping in 0.001% of range	3000	Set zero point clamping to 60 MW that is, 3% of 200 MW
<i>PRepTyp</i>	Reporting type	db	Select magnitude deadband supervision
<i>PDbReplnt</i>	Cycl: Report interval (s), Db: In 0.001% of range, Int Db: In 0.001% <i>s</i>	2000	Set $\pm\Delta db=40$ MW that is, 2% (larger changes than 40 MW will be reported)
Table continues on next page			

Setting	Short Description	Selected value	Comments
<i>PHiHiLim</i>	High High limit (physical value), % of SBase	60	High alarm limit that is, extreme overload alarm, hence it will be 415 MW.
<i>PHiLim</i>	High limit (physical value), in % of SBase	50	High warning limit that is, overload warning, hence it will be 371 MW.
<i>PLowLim</i>	Low limit (physical value), in % of SBase	-50	Low warning limit -500 MW
<i>PLowLowLim</i>	Low Low limit (physical value), in % of SBase	-60	Low alarm limit -600 MW
<i>PLimHyst</i>	Hysteresis value in % of range (common for all limits)	1	Set $\pm\Delta$ Hysteresis 20 MW that is, 1% of range (2000 MW)

Table 27: *Settings for calibration parameters*

Setting	Short Description	Selected value	Comments
<i>IMagComp5</i>	Magnitude factor to calibrate current at 5% of In	0.00	
<i>IMagComp30</i>	Magnitude factor to calibrate current at 30% of In	0.00	
<i>IMagComp100</i>	Magnitude factor to calibrate current at 100% of In	0.00	
<i>VAmpComp5</i>	Magnitude factor to calibrate voltage at 5% of Vn	0.00	
<i>VMagComp30</i>	Magnitude factor to calibrate voltage at 30% of Vn	0.00	
<i>VMagComp100</i>	Magnitude factor to calibrate voltage at 100% of Vn	0.00	
<i>IAngComp5</i>	Angle calibration for current at 5% of In	0.00	
<i>IAngComp30</i>	Angle pre-calibration for current at 30% of In	0.00	
<i>IAngComp100</i>	Angle pre-calibration for current at 100% of In	0.00	

Measurement function application for a power transformer

Single line diagram for this application is given in figure [88](#).

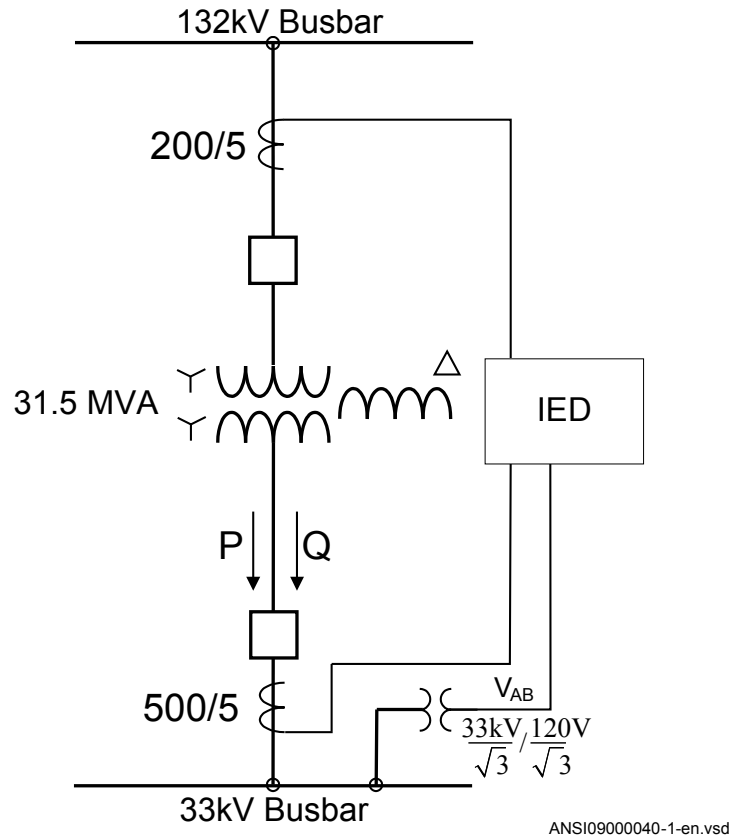


Figure 88: Single line diagram for transformer application

In order to measure the active and reactive power as indicated in figure 88, it is necessary to do the following:

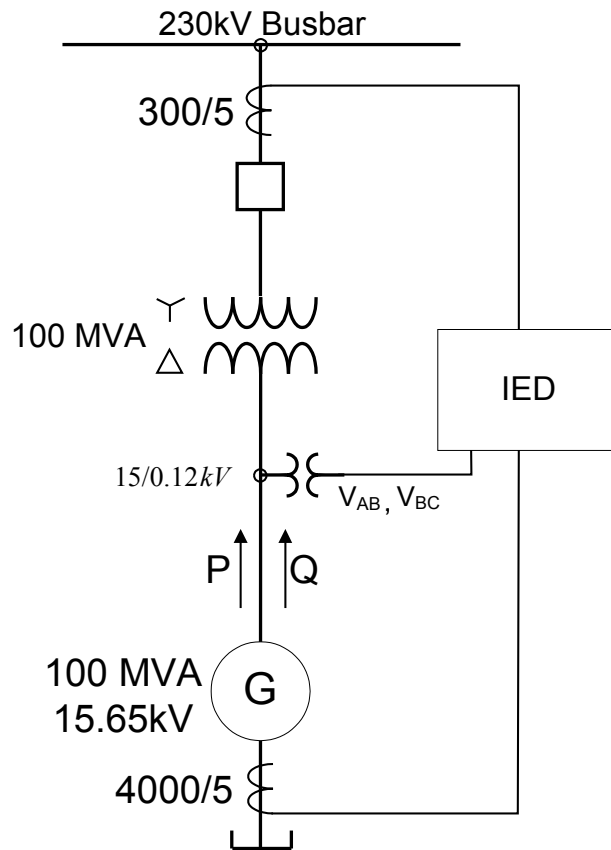
1. Set correctly all CT and VT and phase angle reference channel *PhaseAngleRef* data using PCM600 for analog input channels
2. Connect, in PCM600, measurement function to LV side CT & VT inputs
3. Set the setting parameters for relevant Measurement function as shown in the following table 28:

Table 28: *General settings parameters for the Measurement function*

Setting	Short description	Selected value	Comment
<i>Operation</i>	<i>Operation Disabled/Enabled</i>	<i>Enabled</i>	Function must be <i>Enabled</i>
<i>PowAmpFact</i>	Magnitude factor to scale power calculations	1.000	Typically no scaling is required
<i>PowAngComp</i>	Angle compensation for phase shift between measured I & V	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 alimnt with the required direction.
<i>Mode</i>	Selection of measured current and voltage	L1L2	Only UL1L2 phase-to-phase voltage is available
k	Low pass filter coefficient for power measurement, V and I	0.00	Typically no additional filtering is required
VGenZeroDb	Zero point clamping in % of Vbase	25	Set minimum voltage level to 25%
IGenZeroDb	Zero point clamping in % of Ibase	3	Set minimum current level to 3%
VBase (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

Measurement function application for a generator

Single line diagram for this application is given in figure [89](#).



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Figure 89: Single line diagram for generator application

In order to measure the active and reactive power as indicated in figure 89, it is necessary to do the following:

1. Set correctly all CT and VT data and phase angle reference channel *PhaseAngleRef* using PCM600 for analog input channels
2. Connect, in PCM600, measurement function to the generator CT & VT inputs
3. Set the setting parameters for relevant Measurement function as shown in the following table:

Table 29: General settings parameters for the Measurement function

Setting	Short description	Selected value	Comment
Operation	Operation Off/On	On	Function must be <i>On</i>
PowAmpFact	Amplitude factor to scale power calculations	1.000	Typically no scaling is required
PowAngComp	Angle compensation for phase shift between measured I & V	0.0	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	Arone	Generator VTs are connected between phases (V-connected)
k	Low pass filter coefficient for power measurement, V and I	0.00	Typically no additional filtering is required
VGenZeroDb	Zero point clamping in % of Vbase	25%	Set minimum voltage level to 25%
IGenZeroDb	Zero point clamping in % of Ibase	3	Set minimum current level to 3%
VBase (set in Global base)	Base setting for voltage level in kV	15,65	Set generator rated phase-to-phase voltage
IBase (set in Global base)	Base setting for current level in A	3690	Set generator rated current

16.2 Gas medium supervision SSIMG (63)

16.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Insulation gas monitoring function	SSIMG	-	63

16.2.2 Application

Gas medium supervision (SSIMG ,63) 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. 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.

16.2.3 Setting guidelines

The parameters for Gas medium supervision SSIMG can be set via local HMI or Protection and Control Manager PCM600.

Operation: This is used to disable/enable the operation of gas medium supervision i.e. Off/On.

PresAlmLimit: This is used to set the limit for a pressure alarm condition in the circuit breaker.

PresLOLimit: This is used to set the limit for a pressure lockout condition in the circuit breaker.

TempAlarmLimit: This is used to set the limit for a temperature alarm condition in the circuit breaker.

TempLOLimit: This is used to set the limit for a temperature lockout condition in the circuit breaker.

tPressureAlarm: This is used to set the time delay for a pressure alarm indication, given in s.

tPressureLO: This is used to set the time delay for a pressure lockout indication, given in s.

tTempAlarm: This is used to set the time delay for a temperature alarm indication, given in s.

tTempLockOut: This is used to set the time delay for a temperature lockout indication, given in s.

tResetPressAlm: This is used for the pressure alarm indication to reset after a set time delay in s.

tResetPressLO: This is used for the pressure lockout indication to reset after a set time delay in s.

tResetTempLO: This is used for the temperature lockout indication to reset after a set time delay in s.

tResetTempAlm: This is used for the temperature alarm indication to reset after a set time delay in s.

16.3 Liquid medium supervision SSIML (71)

16.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Insulation liquid monitoring function	SSIML	-	71

16.3.2 Application

Liquid medium supervision (SSIML ,71) 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. Binary information based on the oil level in the oil insulated devices are used as input signals to the function. In addition, the function generates alarms based on the received information.

16.3.3 Setting guidelines

The parameters for Liquid medium supervision SSIML can be set via local HMI or Protection and Control Manager PCM600.

Operation: This is used to disable/enable the operation of liquid medium supervision i.e. *Off/On*.

LevelAlmLimit: This is used to set the limit for a level alarm condition in the oil insulated device.

LevelLOLimit: This is used to set the limit for a level lockout condition in the oil insulated device.

TempAlarmLimit: This is used to set the limit for a temperature alarm condition in the oil insulated device.

TempLOLimit: This is used to set the limit for a temperature lockout condition in the oil insulated device.

tLevelAlarm: This is used to set the time delay for a level alarm indication, given in s.

tLevelLockOut: This is used to set the time delay for a level lockout indication, given in s.

tTempAlarm: This is used to set the time delay for a temperature alarm indication, given in s.

tTempLockOut: This is used to set the time delay for a temperature lockout indication, given in s.

tResetLevelAlm: This is used for the level alarm indication to reset after a set time delay in s.

tResetLevelLO: This is used for the level lockout indication to reset after a set time delay in s.

tResetTempLO: This is used for the temperature lockout indication to reset after a set time delay in s.

tResetTempAlm: This is used for the temperature alarm indication to reset after a set time delay in s.

16.4 Breaker monitoring SSCBR

16.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Breaker monitoring	SSCBR	-	-

16.4.2 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 travel time

Auxiliary contacts provide information about the mechanical operation, opening time and closing time of a breaker. Detecting an excessive traveling time is essential to indicate the need for maintenance of the circuit breaker mechanism. The excessive travel 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 [90](#).

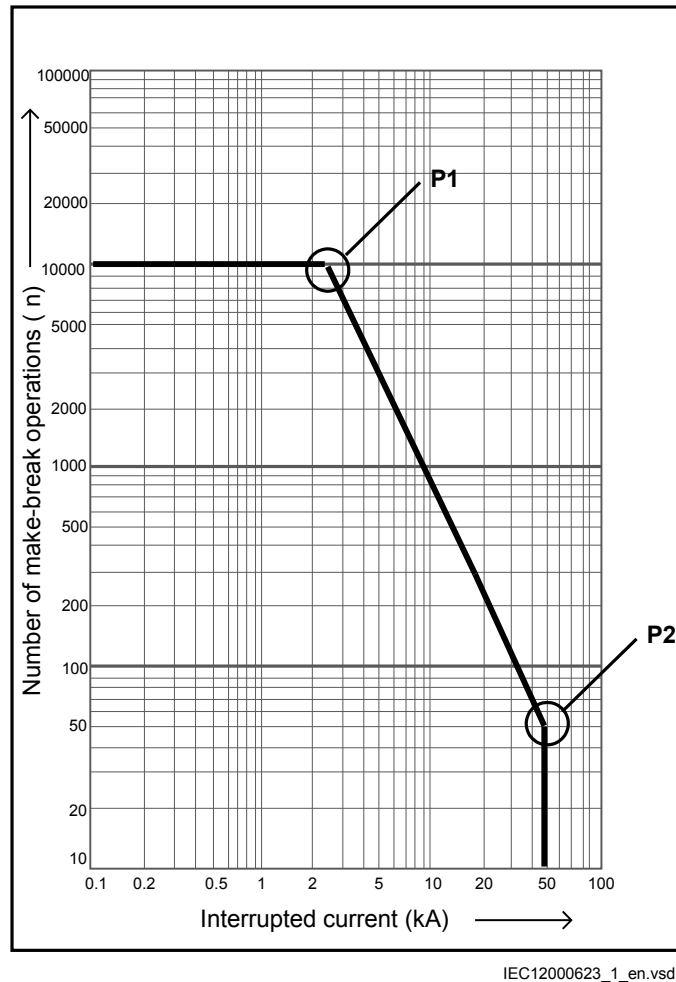


Figure 90: An example for estimating the remaining life of a circuit breaker

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 energy

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 energy value can be reset to initial accumulation energy value by using the Reset accumulating energy input, RSTI POW.

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.

16.4.3 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, 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 OPENPOS, CLOSEPOS, INVDPOS, CBLIFEAL, IPOWALPH, IPOWLOPH, TRVTOPAL and TRVTCLAL signals are not used in SAM600-IO.

16.4.3.1 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 (I_{Base}), primary voltage (V_{Base}) and primary power (S_{Base}) are set in Global base values for settings function GBASVAL.

GlobalBaseSel: It is used to select a GBASVAL function for reference of base values.

Operation: Enabled or Disabled.

I_{Base}: Base phase current in primary A. This current is used as reference for current settings.

OpenTimeCorr: Correction factor for circuit breaker opening travel time.

CloseTimeCorr: Correction factor for circuit breaker closing travel time.

t_{TrOpenAlm}: Setting of alarm level for opening travel time.

t_{TrCloseAlm}: Setting of alarm level for closing travel time.

OperAlmLevel: Alarm limit for number of mechanical operations.

OperLOLevel: Lockout limit for number of mechanical operations.

CurrExponent: Current exponent setting for energy calculation. It varies for different types of circuit breakers. This factor ranges from 0.5 to 3.0.

AccStopCurr: RMS current setting below which calculation of energy accumulation stops. It is given as a percentage of *IBase*.

ContTrCorr: Correction factor for time difference in auxiliary and main contacts' opening time.

AlmAccCurrPwr: Setting of alarm level for accumulated energy.

LOAccCurrPwr: Lockout limit setting for accumulated energy.

SpChAlmTime: Time delay for spring charging time alarm.

tDGasPresAlm: Time delay for gas pressure alarm.

tDGasPresLO: Time delay for gas pressure lockout.

DirCoef: Directional coefficient for circuit breaker life calculation.

RatedOperCurr: Rated operating current of the circuit breaker.

RatedFltCurr: Rated fault current of the circuit breaker.

OperNoRated: Number of operations possible at rated current.

OperNoFault: Number of operations possible at rated fault current.

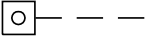
CBLifeAlmLevel: Alarm level for circuit breaker remaining life.

AccSelCal: Selection between the method of calculation of accumulated energy.

OperTimeDelay: Time delay between change of status of trip output and start of main contact separation.

16.5 Event function EVENT

16.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Event function	EVENT		-

16.5.2 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 remote communication.

Analog, integer and double indication values are also transferred through the EVENT function.

16.5.3 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 SPACchannelMask

Definition of which part of the event function block that shall generate events:

- *Disabled*
- *Channel 1-8*
- *Channel 9-16*
- *Channel 1-16*

***MinReplntVal* (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.

16.6 Disturbance report DRPRDRE

16.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Disturbance report	DRPRDRE	-	-
Disturbance report	A1RADR - A4RADR	-	-
Disturbance report	B1RBDR - B22RBDR	-	-

16.6.2 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), Sequential of events (SOE), Trip value recorder (TVR), Disturbance recorder (DR).

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.

16.6.3 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 Sequential of events (SOE) 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 Sequential of events (SOE)).

Figure 91 shows the relations between Disturbance report, included functions and function blocks. Sequential of events (SOE), 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). Disturbance report function acquires information from both AxRADR and BxRBDR.

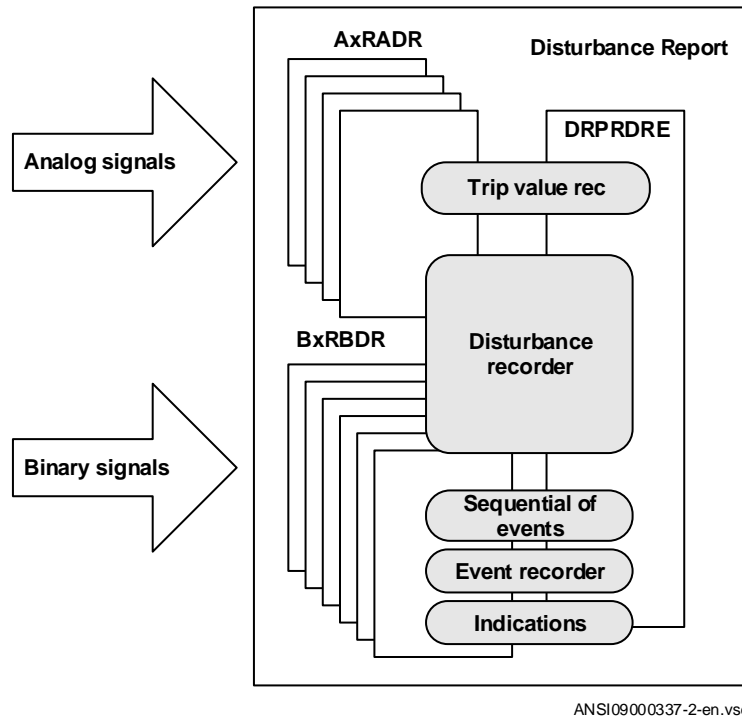


Figure 91: Disturbance report functions and related function blocks

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)

Flashing light

The IED is in test mode

Table continues on next page

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 *Enabled* or *Disabled*. If *Disabled* is selected, note that no disturbance report is registered, and none sub-function will operate (the only general parameter that influences Sequential of events (SOE)).

Operation = Disabled:

- Disturbance reports are not stored.
- LED information (yellow - pickup, red - trip) is not stored or changed.

Operation = Enabled:

- Disturbance reports are stored, disturbance data can be read from the local HMI and from a PC for example using PCM600.
- LED information (yellow - pickup, 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 100. The oldest recording will be overwritten when a new recording arrives (FIFO).



To be able to delete disturbance records, *Operation* parameter has to be *Enabled*.



The maximum number of recordings depend on each recordings total recording time. Long recording time will reduce the number of recordings to less than 100.



The IED flash disk should NOT be used to store any user files. This might cause disturbance recordings to be deleted due to lack of disk space.

16.6.3.1

Recording times

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 = Disabled*. Disturbance report function does not save any recordings and no LED information is displayed.

If the IED is in test mode and *OpModeTest = Enabled*. 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 = Enabled*) during the post-fault time. In this case a new, complete recording will pickup and, during a period, run in parallel with the initial recording.

When the retrigger parameter is disabled (*PostRetrig = Disabled*), a new recording will not pickup 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.

16.6.3.2 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.

TrigDRN: Disturbance report may trig for binary input N (*Enabled*) or not (*Disabled*).

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.

16.6.3.3 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.

The analog trigger of Disturbance report is not affected if analog input M is to be included in the disturbance recording or not (*OperationM = Enabled/Disabled*).

If *OperationM = Disabled*, 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 = Enabled*, 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 (*Enabled*) or not (*Disabled*).

OverTrigLeM, UnderTrigLeM: Over or under trig level, Trig high/low level relative nominal value for analog input M in percent of nominal value.

16.6.3.4 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 (*Enabled*) or not (*Disabled*).

If *OperationM = Disabled*, 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 = Enabled*, 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).

Sequential of events

function has no dedicated parameters.

16.6.3.5 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 pickup 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.

16.7 Logical signal status report BINSTATREP

16.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Logical signal status report	BINSTATREP	-	-

16.7.2 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.

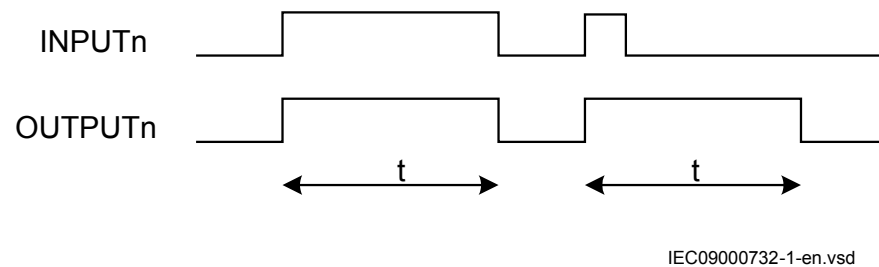


Figure 92: BINSTATREP logical diagram

16.7.3 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.

16.8 Limit counter L4UFCNT

16.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Limit counter	L4UFCNT		-

16.8.2 Application

Limit counter (L4UFCNT) is intended for applications where positive and/or negative sides 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.

16.8.3 Setting guidelines

The parameters for Limit counter L4UFCNT are set via the local HMI or PCM600.

16.9 Running hour-meter TEILGAPC

16.9.1 Identification

Function Description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Running hour-meter	TEILGAPC	-	-

16.9.2 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.

16.9.3 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 $tAlarm > tWarning$.

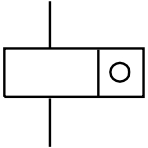
The limit for the overflow supervision is fixed at 99999.9 hours.

The setting *tAddToTime* is a user settable time parameter in hours.

Section 17 Metering

17.1 Pulse-counter logic PCFCNT

17.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Pulse-counter logic	PCFCNT		-

17.1.2 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.

17.1.3 Setting guidelines

Parameters that can be set individually for each pulse counter from PCM600:

- *Operation: Disabled/Enabled*
- *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 1 ms, that is, the counter suppresses pulses with a pulse length less than 1 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/I/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.

17.2 Function for energy calculation and demand handling ETPMMTR

17.2.1 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	-

17.2.2 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 [93](#).

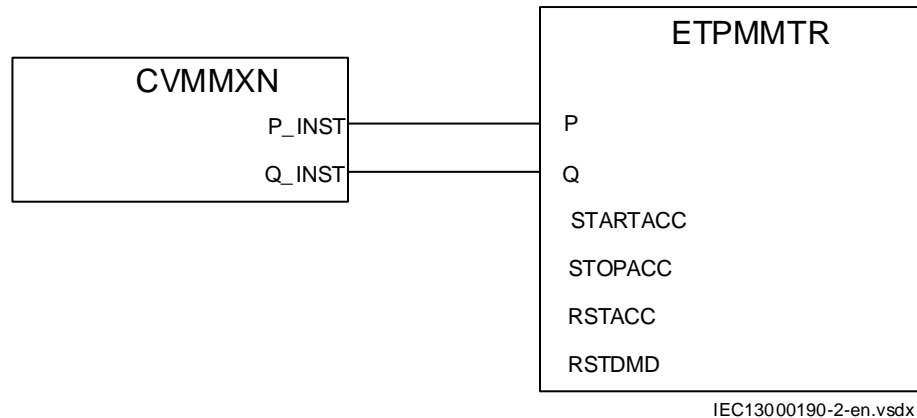


Figure 93: Connection of energy calculation and demand handling function ETPMMTR to the measurements function (CVMMXN)

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 *EAFAccPlsQty*, *EARAccPlsQty*, *ERFAccPlsQty* and *ERVAccPlsQty* 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.

17.2.3

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*, *VBase* and *SBase* as applicable.

Operation: Disabled/Enabled

EnaAcc: Disabled/Enabled 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 18 Ethernet-based communication

18.1 Access point

18.1.1 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).

18.1.2 Setting guidelines



The physical ports allocated to access points 2–6 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 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 IEC61850 Ed2 IEDs and not editable for IEC61850 Ed1 IEDs because in IEC61850 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**

18.2 Redundant communication

18.2.1 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	-	-

18.2.2 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.

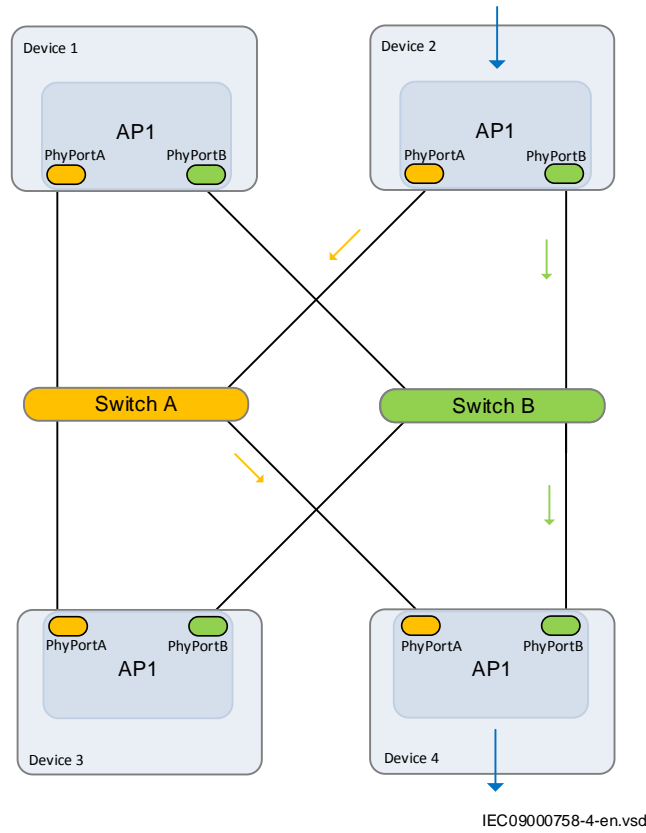


Figure 94: Parallel Redundancy Protocol (PRP)

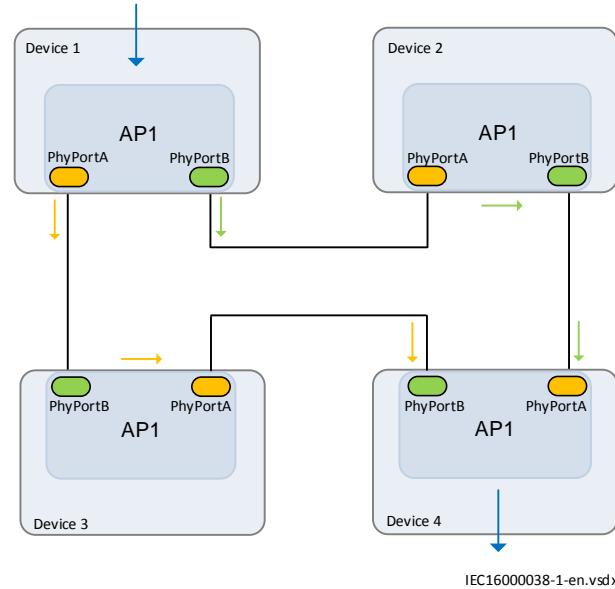


Figure 95: High-availability Seamless Redundancy (HSR)

18.2.3 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	<input checked="" type="checkbox"/>	None	ETH_Front	
1	Station bus	<input checked="" type="checkbox"/>	PRP-1	SFP_301	SFP_302
3	Accesspoint 3	<input checked="" type="checkbox"/>	HSR	SFP_303	SFP_304

IEC16000039-1-en.vsdX

Figure 96: ECT screen with Redundancy set to PRP-1 on Access point 1 and HSR Access point 3

18.3 Merging unit

18.3.1 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.

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

Figure 97: Merging unit

18.3.2 Setting guidelines

For information on the merging unit setting guidelines, see section [IEC/UCA 61850-9-2LE communication protocol](#).

18.4 Routes

18.4.1 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.

18.4.2 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 checkbox 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 19 Station communication

19.1 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
- C37.118 communication protocol

Several protocols can be combined in the same IED.

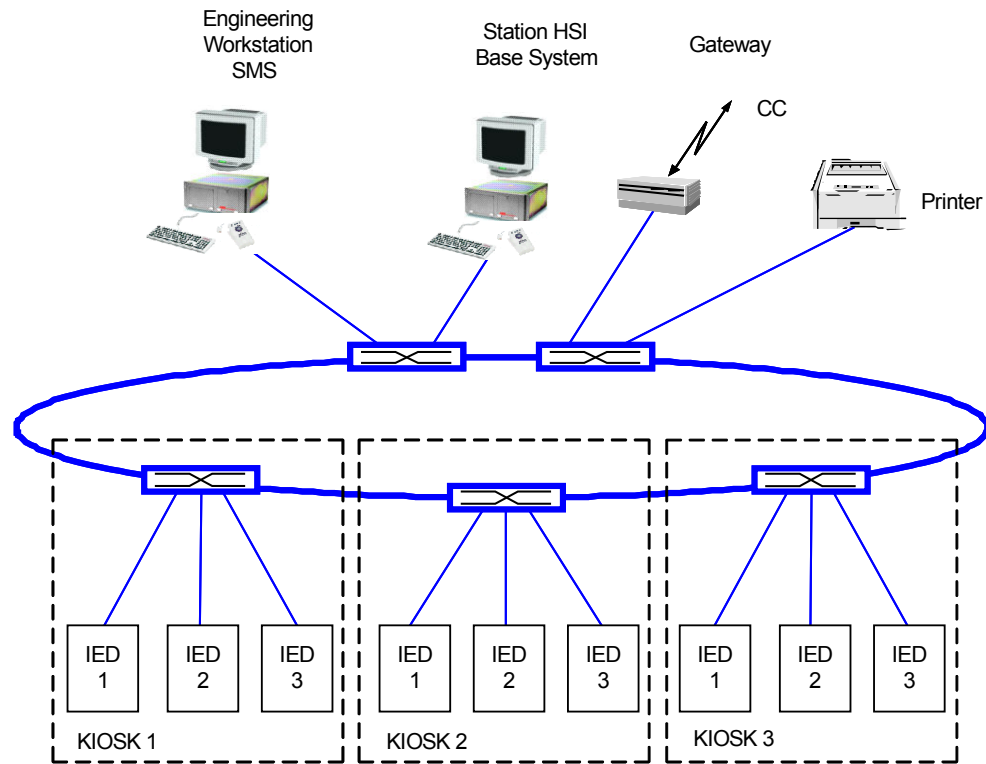
19.2 IEC 61850-8-1 communication protocol

19.2.1 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 [98](#) 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.



IEC09000135_en.v
sd

Figure 98: SA system with IEC 61850-8-1

Figure 99 shows the GOOSE peer-to-peer communication.

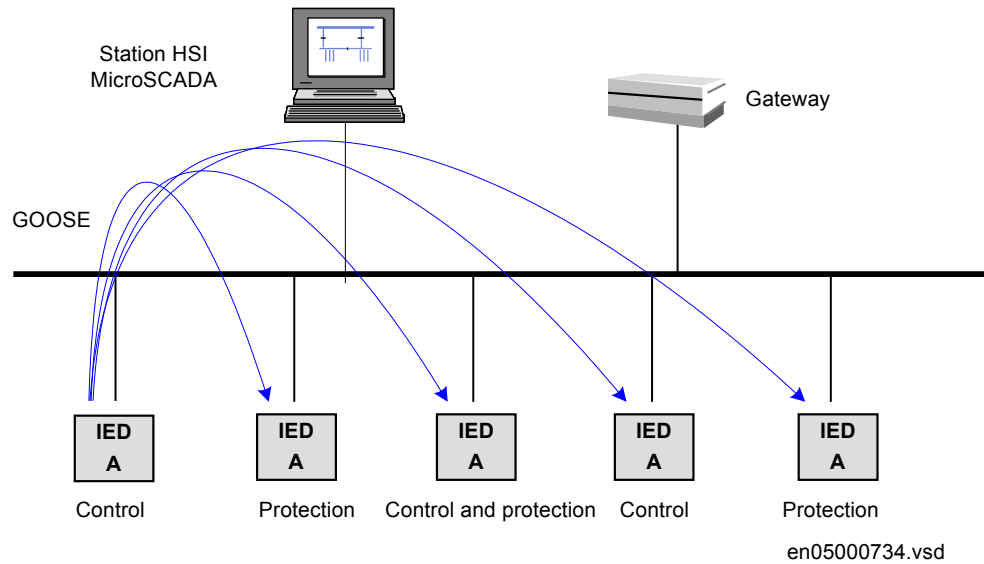


Figure 99: Example of a broadcasted GOOSE message

19.2.2 Setting guidelines

There are two settings related to the IEC 61850–8–1 protocol:

Operation: User can set IEC 61850 communication to *Enabled* or *Disabled*.

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.

19.2.3 Horizontal communication via GOOSE

19.2.3.1 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.

19.2.3.2

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
GOOSEMVRVCV	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 GOOSEPRCV 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.

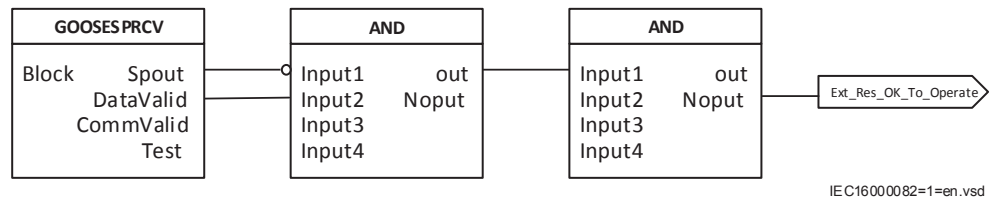


Figure 100: GOOSEPRCV and AND function blocks - checking the validity of the received data

19.3 IEC/UCA 61850-9-2LE communication protocol

19.3.1 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.

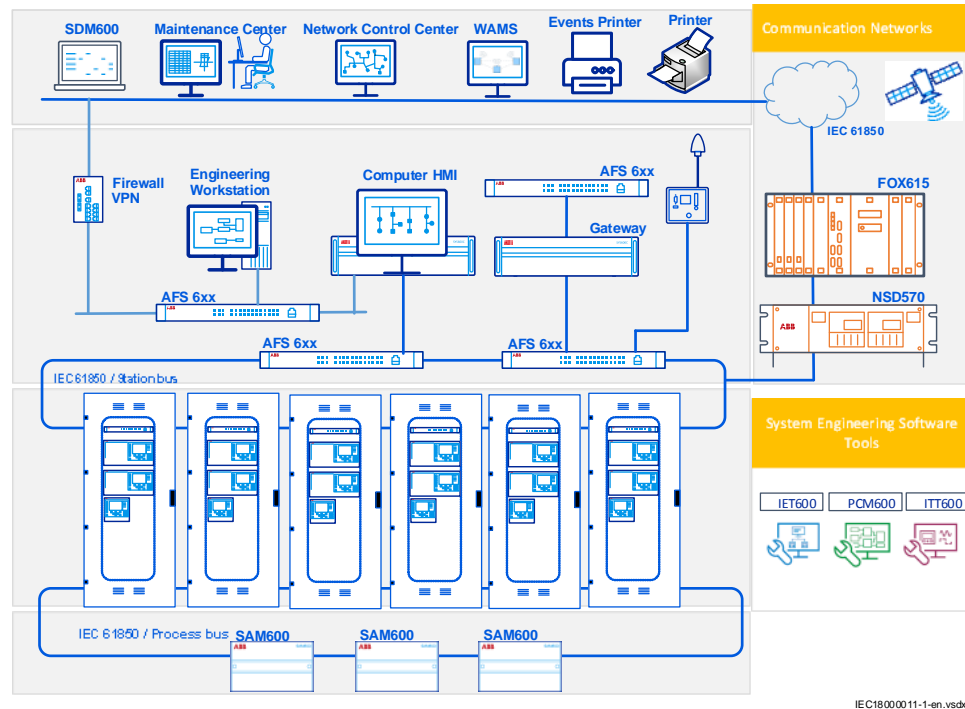


Figure 101: Example of a station configuration with separated process bus and station bus

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.

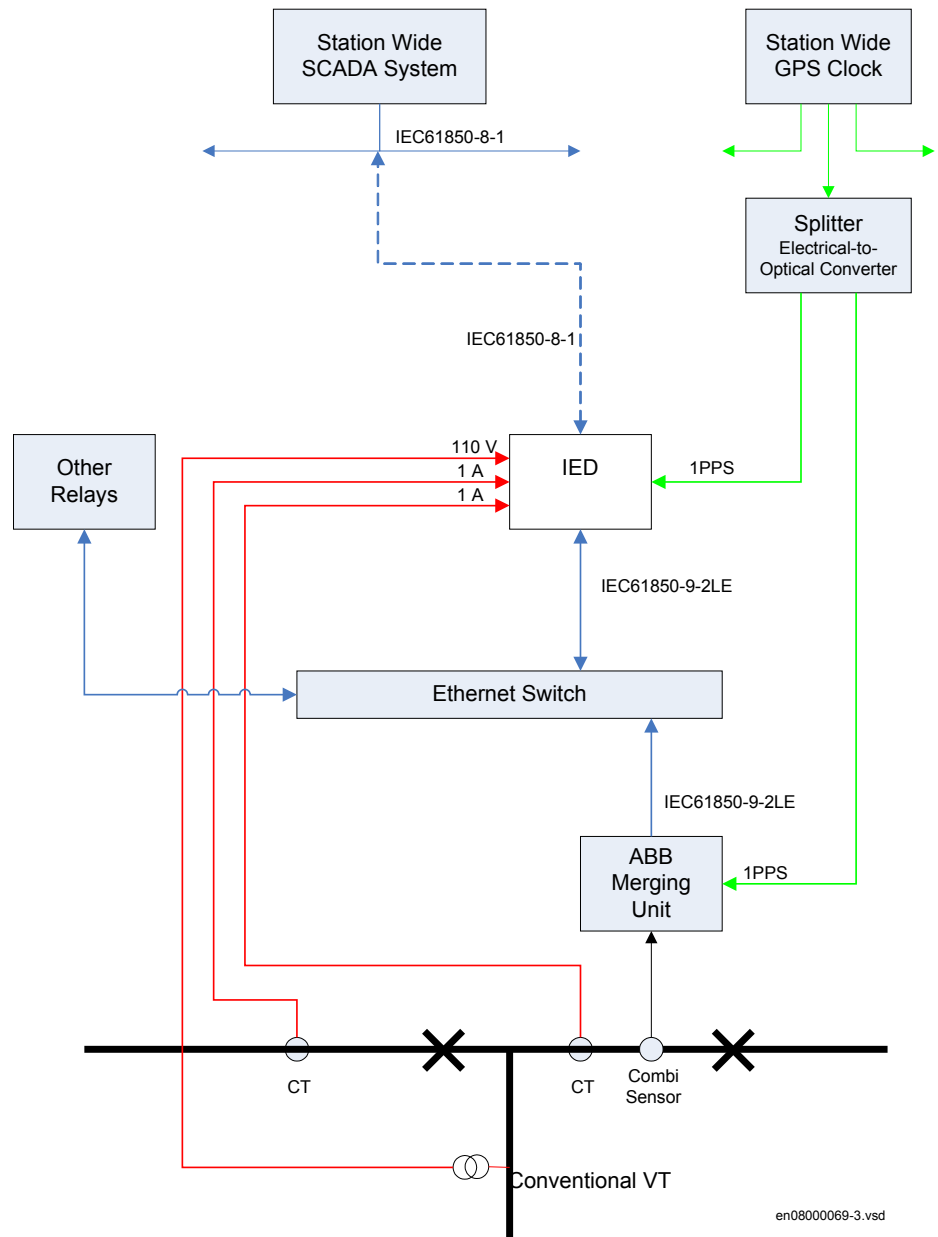


Figure 102: Example of a station configuration with the IED receiving analog values from both classical measuring transformers and merging units.

19.3.2 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 01–12.

19.3.2.1 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 [30](#) will be blocked due to conditional blocking. If this parameter is set to *BlockOnLostUTC*, the protection functions in list [30](#) 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.

19.3.2.2 Loss of communication when used with LDCM

If IEC/UCA 61850-9-2LE communication is lost, see examples in figures [103](#), [104](#) and [105](#), the protection functions in table [30](#) are blocked as per graceful degradation.

Case 1:

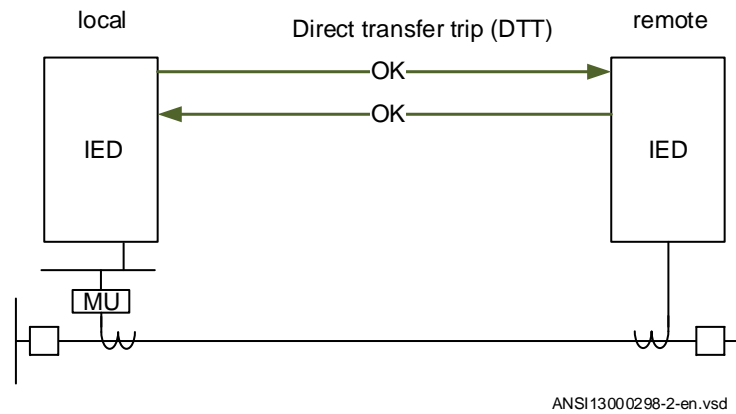


Figure 103: Normal operation

Case 2:

Failure of the MU (sample lost) blocks the sending of binary signals through LDCM. The received binary signals are not blocked and processed normally.

→DTT from the remote end is still processed.

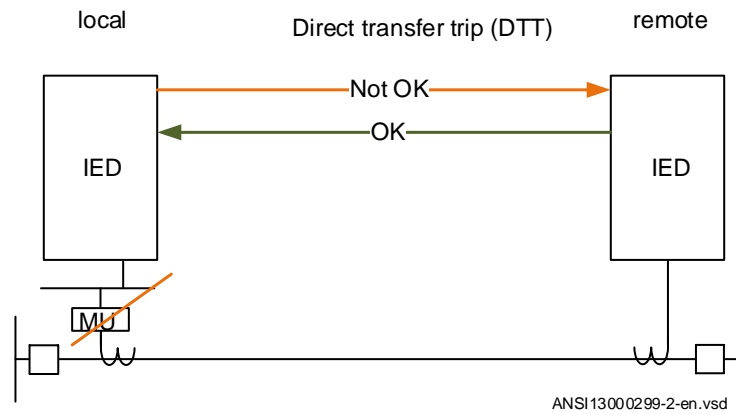


Figure 104: MU failed, mixed system

Case 3:

Failure of one MU (sample lost) blocks the sending and receiving of binary signals through LDCM.

→DTT from the remote end is not working.

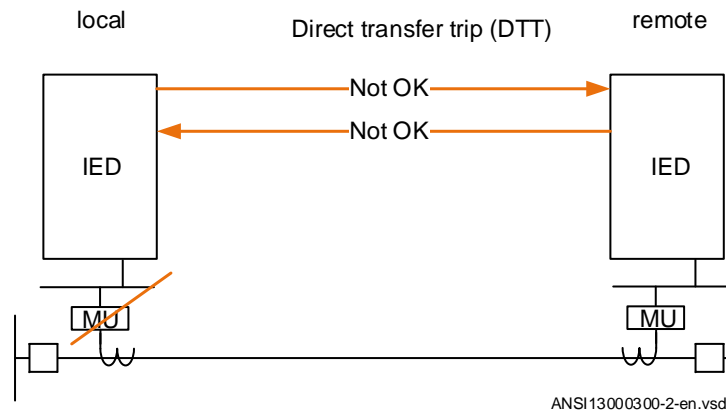


Figure 105: MU failed, 9-2 system

Table 30: Blocked protection functions if IEC/UCA 61850-9-2LE communication is interrupted and functions are connected to specific MUs

Function description	IEC 61850 identification	Function description	IEC 61850 identification
Accidental energizing protection for synchronous generator	AEGPVOG	Two step overvoltage protection	OV2PTOV
Broken conductor check	BRCPTOC	Four step single phase overcurrent protection	PH4SPTOC
Capacitor bank protection	CBPGAPC	Radial feeder protection	PAPGAPC
Pole discordance protection	CCPDSC	Instantaneous phase overcurrent protection	PHPIOC
Breaker failure protection	CCRBRF	PoleSlip/Out-of-step protection	PSPPPAM
Breaker failure protection, single phase version	CCSRBRF	Restricted earth fault protection, low impedance	REFPDIF
Current circuit supervision	CCSSPVC	Two step residual overvoltage protection	ROV2PTOV
Compensated over- and undervoltage protection	COUVGAPC	Rate-of-change frequency protection	SAPFRC
General current and voltage protection	CVGAPC	Overfrequency protection	SAPTOF
Current reversal and weakend infeed logic for residual overcurrent protection	ECRWPSCH	Underfrequency protection	SAPTUF
Four step residual overcurrent protection	EF4PTOC	Sudden change in current variation	SCCVPTOC

Table continues on next page

Function description	IEC 61850 identification	Function description	IEC 61850 identification
Instantaneous residual overcurrent protection	EFPIOC	Sensitive Directional residual over current and power protection	SDEPSDE
Phase selection, quadrilateral characteristic with fixed angle	FDSPDIS	Synchrocheck, energizing check, and synchronizing	SESRSYN
Faulty phase identification with load encroachment	FMPSPDIS	Circuit breaker condition monitoring	SSCBR
Phase selection, quadrilateral characteristic with settable angle	FRSPDIS	Insulation gas monitoring	SSIMG
Frequency time accumulation protection	FTAQFVR	Insulation liquid monitoring	SSIML
Fuse failure supervision	FUFSPVC	Stub protection	STBPTOC
Generator differential protection	GENPDIF	Transformer differential protection, two winding	T2WPDIF
Directional Overpower protection	GOPPDOP	Transformer differential protection, three winding	T3WPDIF
Generator rotor overload protection	GRPTTR	Automatic voltage control for tapchanger, single control	TR1ATCC
Generator stator overload protection	GSPTR	Automatic voltage control for tapchanger, parallel control	TR8ATCC
Directional Underpower protection	GUPPDUP	Thermal overload protection, two time constants	TRPTTR
1Ph High impedance differential protection	HZPDIF	Two step undervoltage protection	UV2PTUV
Line differential protection, 3 CT sets, 2-3 line ends	L3CPDIF	Voltage differential protection	VDCPTOV
Line differential protection, 6 CT sets, 3-5 line ends	L6CPDIF	Fuse failure supervision	VDRFUF
Low active power and power factor protection	LAPPGAPC	Voltage-restrained time overcurrent protection	VRPVOG
Negative sequence overcurrent protection	LCNSPTOC	Local acceleration logic	ZCLCPSCH
Negative sequence overvoltage protection	LCNSPTOV	Scheme communication logic for distance or overcurrent protection	ZCPSCH
Table continues on next page			

Function description	IEC 61850 identification	Function description	IEC 61850 identification
Three phase overcurrent	LCP3PTOC	Current reversal and weak-end infeed logic for distance protection	ZCRWPSCH
Three phase undercurrent	LCP3PTUC	Automatic switch onto fault logic, voltage and current based	ZCVPSOF
Thermal overload protection, one time constant	LCPTTR	Under impedance protection for generator	ZGVPDIS
Zero sequence overcurrent protection	LCZSPTOC	Fast distance protection	ZMFCPDIS
Zero sequence overvoltage protection	LCZSPTOV	High speed distance protection	ZMFPDIS
Line differential coordination	LDLPSCCH	Distance measuring zone, quadrilateral characteristic for series compensated lines	ZMCAPDIS
Additional security logic for differential protection	LDRGFC	Distance measuring zone, quadrilateral characteristic for series compensated lines	ZMCPDIS
Loss of excitation	LEXPDIS	Fullscheme distance protection, mho characteristic	ZMHPDIS
Thermal overload protection, one time constant	LFPTTR	Fullscheme distance protection, quadrilateral for earth faults	ZMMAPDIS
Loss of voltage check	LOVPTUV	Fullscheme distance protection, quadrilateral for earth faults	ZMMPDIS
Line differential protection 3 CT sets, with inzone transformers, 2-3 line ends	LT3CPDIF	Distance protection zone, quadrilateral characteristic	ZMQAPDIS
Line differential protection 6 CT sets, with inzone transformers, 3-5 line ends	LT6CPDIF	Distance protection zone, quadrilateral characteristic	ZMQPDIS
Negativ sequence time overcurrent protection for machines	NS2PTOC	Distance protection zone, quadrilateral characteristic, separate settings	ZMRAPDIS
Four step directional negative phase sequence overcurrent protection	NS4PTOC	Distance protection zone, quadrilateral characteristic, separate settings	ZMRPDIS
Four step phase overcurrent protection	OC4PTOC	Power swing detection	ZMRPSB
Table continues on next page			

Function description	IEC 61850 identification	Function description	IEC 61850 identification
Overexcitation protection	OEXPVPH	Mho Impedance supervision logic	ZSMGAPC
Out-of-step protection	OOSPPAM	Transformer tank overcurrent protection	TPPIOC
Busbar differential protection, check zone	BCZPDIF	Busbar differential protection, bus interconnection xx	BICPTRC_x, (1≤x≤5)
Busbar differential protection, dynamic zone selection	BDZSGAPC	Busbar differential protection, zone 1	BZNPDIF_Zx, (1≤x≤6)
Busbar differential protection, single phase feeder xx	BFPTRC_Fx, (1≤x≤24)		
Voltage delta supervision, 2 phase	DELVSPVC	Current delta supervision, 2 phase	DELISPVC
DELSPVC	Current harmonic monitoring, 2 phase	CHMMHAN	

19.3.2.3

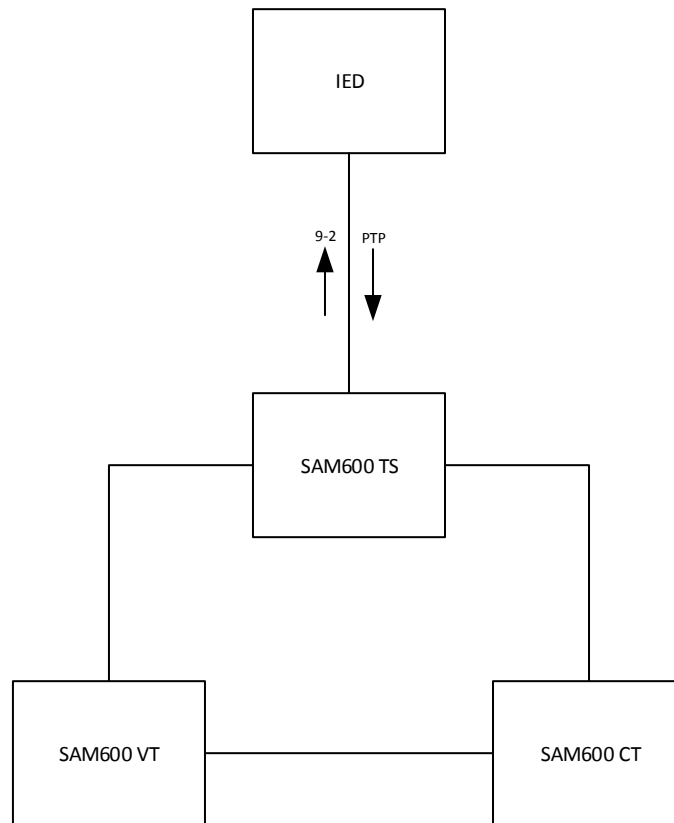
Setting examples for IEC/UCA 61850-9-2LE and time synchronization

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 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 106: 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 external clock for time synchronization



This example is not valid when GPS time is used for differential protection, when PTP is enabled or when the PMU report is used.

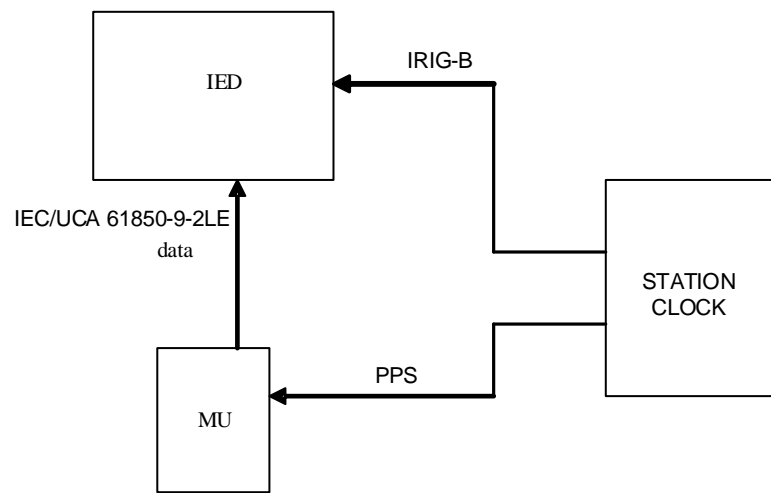


Figure 107: Setting example with external synchronization

Settings on the local HMI under **Main menu/Configuration/Time/Synchronization/TIMESYNCHGEN:1/IEC61850-9-2:**

- *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.

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, when PTP is enabled or when the PMU report is used.

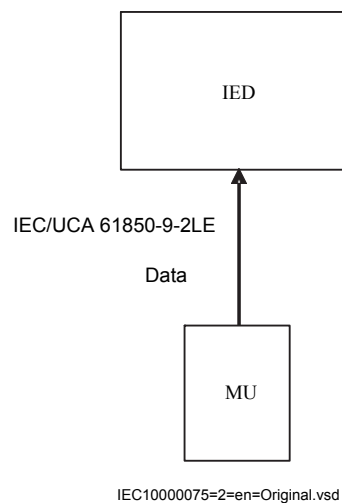


Figure 108: Setting example without time synchronization

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*

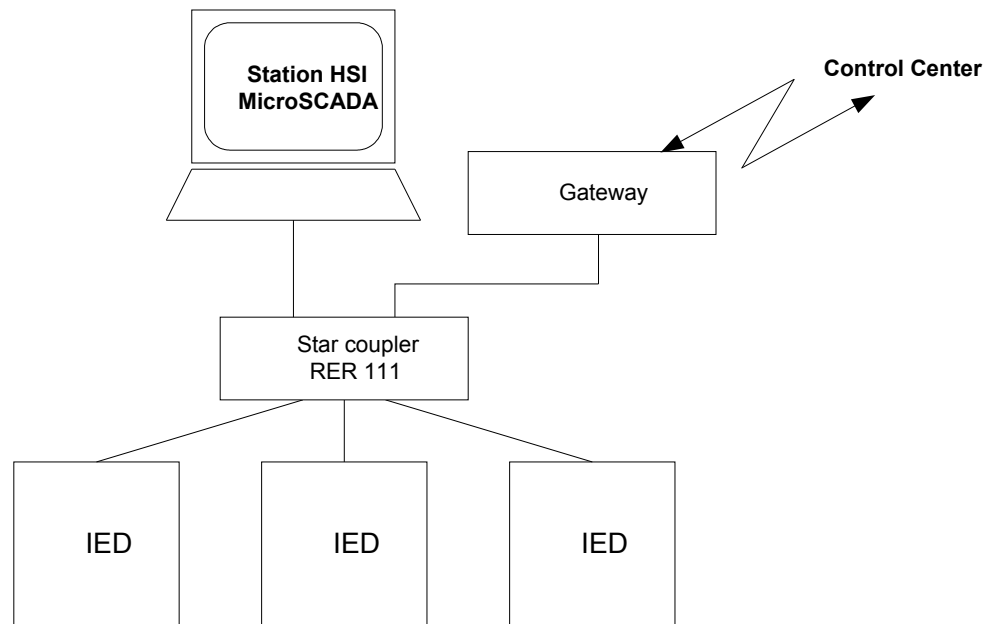
Two status monitoring signals with no time synchronization:

- 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.

19.4 LON communication protocol

19.4.1 Application



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Figure 109: Example of LON communication structure for a substation automation system

An optical network can be used within the substation 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 31: *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.

19.4.2 MULTICMDRCV and MULTICMDSND

19.4.2.1 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	-	-

19.4.2.2 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.

19.4.2.3 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.

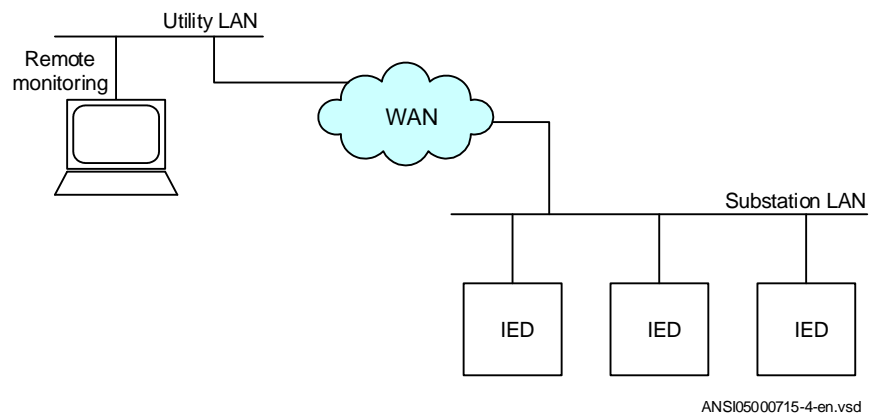
19.5 SPA communication protocol

19.5.1 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 110), 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



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Figure 110: 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.

19.5.2

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).

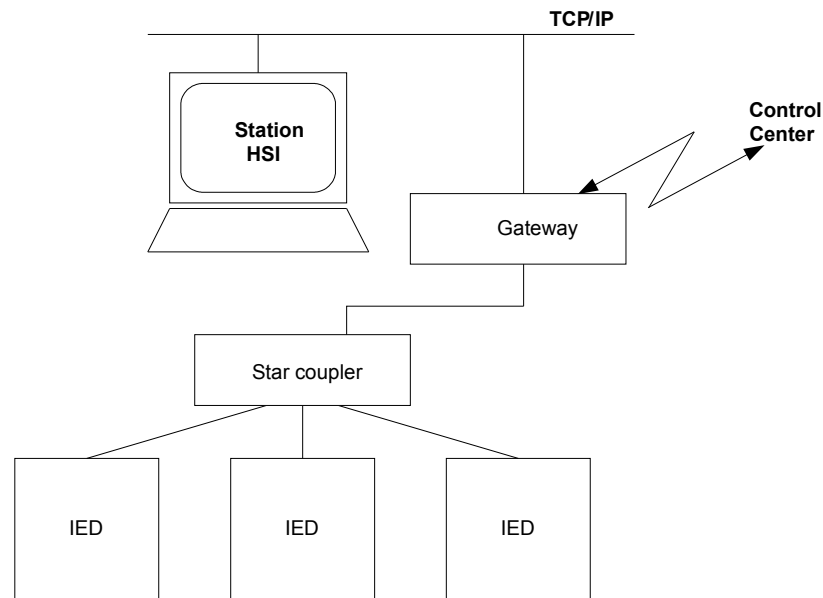
With local fiber optic communication, communication speed is usually set to 19200 or 38400 baud. With telephone communication, the speed setting depends on the quality of the connection and the type of modem used. Refer to technical data to determine the rated communication speed for the selected communication interfaces.



The IED does not adapt its speed to the actual communication conditions because the communication speed is set on the local HMI.

19.6 IEC 60870-5-103 communication protocol

19.6.1 Application



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Figure 111: 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.

19.6.1.1 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.

19.6.1.2

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, I103UserCMD. 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.

- Ground fault indications in monitor direction

Function block with defined functions for ground 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 ground-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.

19.6.2 Settings

19.6.2.1 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.

1. 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

2. 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	1800.0
MasterTimeDomain		UTC			
TimeSyncMode		IEDTime			
✓ EvalTimeAccuracy		Sens			
EventRepMode		SeqOfEvent			

Figure 112: 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 *Enabled*.
- *CycMeasRepTime*: See I103MEAS function block for more information.
- *EventRepMode*: Defines the mode for how events are reported. The event buffer size is 1000 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.

19.6.2.2

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 32.

Table 32: Channels on disturbance recorder sent with a given ACC

DRA#-Input	ACC	IEC103 meaning
1	1	IA
2	2	IB
3	3	IC
4	4	IG
5	5	VA
6	6	VB
7	7	VC
8	8	VG
9	64	Private range
10	65	Private range
11	66	Private range
12	67	Private range
13	68	Private range
14	69	Private range

Table continues on next page

DRA#-Input	ACC	IEC103 meaning
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

19.6.3

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

REG 150 Private range

REQ 245 Private range

RER 152 Private range

RES 118 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.

19.7 DNP3 Communication protocol

19.7.1 Application

For more information on the application and setting guidelines for the DNP3 communication protocol refer to the DNP3 Communication protocol manual.

Section 20 Remote communication

20.1 Binary signal transfer

20.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Binary signal transfer, receive	BinSignRec1_1 BinSignRec1_2 BinSignReceive2	-	-
Binary signal transfer, 2Mbit receive	BinSigRec1_12M BinSigRec1_22M	-	-
Binary signal transfer, transmit	BinSignTrans1_1 BinSignTrans1_2 BinSignTransm2	-	-
Binary signal transfer, 2Mbit transmit	BinSigTran1_12M BinSigTran1_22M	-	-

20.1.2 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.

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.

Link forwarding

If it is not possible to have a communication link between each station, the solution has been to set the protection up in a slave-master-slave configuration. This means that in Figure [113](#), only IED-B has access to all currents and, therefore, this is the only place

where the differential current is evaluated. If the evaluation results in a trip, the trip signal will be sent over the two communication links.

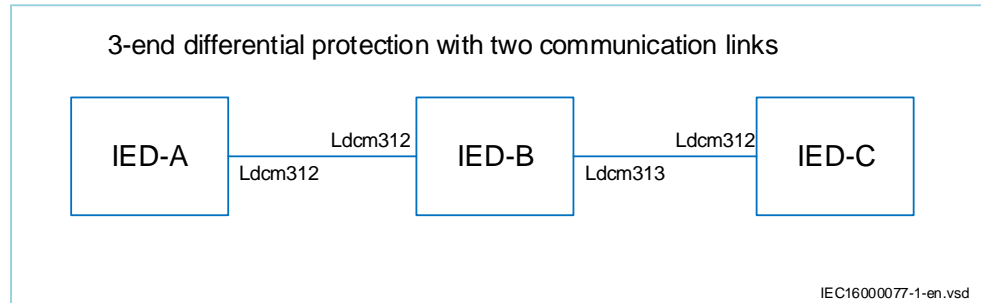


Figure 113: Three-end differential protection with two communication links

If the LDCM is in 2Mbit mode, you can send the three local currents as well as the three remote currents from the other links by configuring the transmitters in IED-B:

1. Ldcm312 transmitter sends the local currents and the three currents received by Ldcm313.
2. Ldcm313 transmitter sends the three local currents and the three currents received from Ldcm312.

As a result, six currents are received in IED-A and IED-C. These currents can be connected to the protection function together with the local three currents.



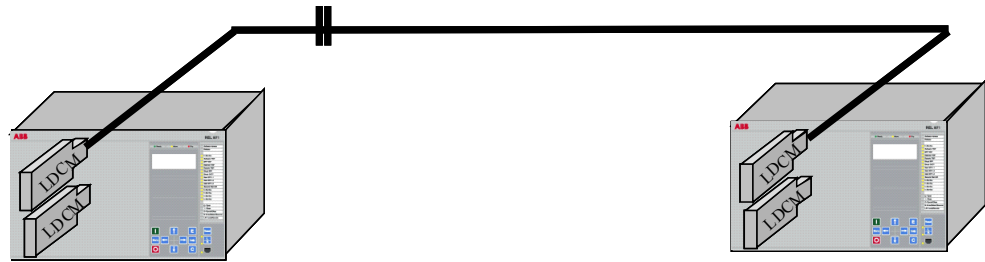
In order to forward the logic signals (for example, inter-trip or inter-block) between IED-A and IED-C, the setting *LinkForwarded* should be defined. In IED-B, it is set to *LDCM313* for Ldcm312 and to *LDCM312* for ldc313.

This setup results in a master-master-master configuration, but without the benefit of reverting to a slave-master-slave configuration in case of a communication link interruption. In case of a communication link interruption, all three IEDs would be blocked.

20.1.2.1

Communication hardware solutions

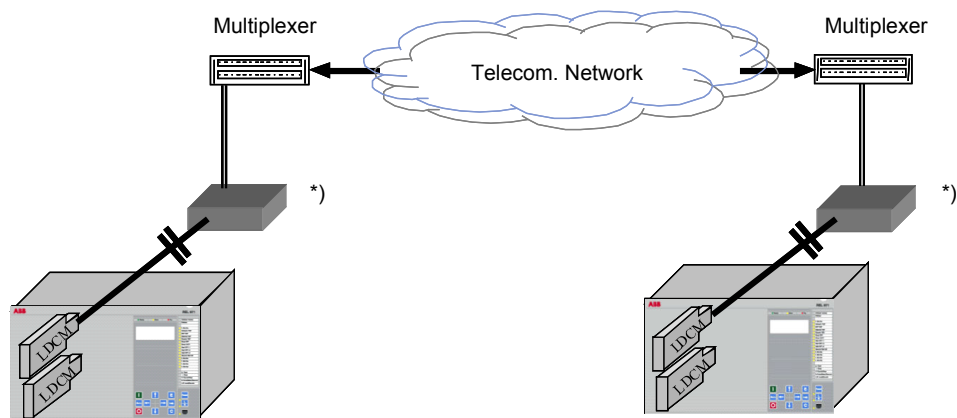
The LDCM (Line Data Communication Module) has an optical connection such that two IEDs can be connected over a direct fiber (multimode), as shown in figure 114. The protocol used is IEEE/ANSI C37.94. The distance with this solution is typical 110 km/68 miles.



en06000519-2.vsd

Figure 114: 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 115. 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

en05000527-2.vsd

Figure 115: 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/2 mile length. The IEEE/ANSI C37.94 protocol is always used between LDCM and the modem.

20.1.3

Setting guidelines

64 kbit and 2 Mbit mode common settings

ChannelMode defines how an IED discards the LDCM information when one of the IEDs in the system is out of service: it can either be done on the IED out of service by setting all local LDCMs to channel mode *OutOfService* or at the remote end by setting the corresponding LDCM to channel mode *Blocked*. If *OutOfService* is selected, the IED should have active communication to the remote end during the whole maintenance process, that is, no restart or removal of the fiber can be done.

This setting does not apply to two-end communication.

<i>Blocked</i>	IED does not use data from the LDCM
<i>OutOfService</i>	IED informs the remote end that it is out of service

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

In multiterminal current differential applications, with 4 LDCMs in each IED, up to 20 unique addresses must be set.



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 and slot 322-323.

DiffSync defines the method of time synchronization for the line differential function: *Echo* or *GPS*.



Using *Echo* in this case is safe only if there is no risk of varying transmission asymmetry.

GPSSyncErr: when GPS synchronization is lost, synchronization of the line differential function continues for 16 s based on the stability in the local IED clocks. After that, setting *Block* blocks the line differential function or setting *Echo* keeps it on by using the *Echo* synchronization method.



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* and *HighPower*.

Short-range LDCM: Use *LowPower* for fibres 0 – 1 km and *HighPower* for fibers greater than 1 km.

Medium-range LDCM: Typical distance 80 km for both *LowPower* and *HighPower*.

Long-range LDCM: Typical distance 120 km for both *LowPower* and *HighPower*.

An optical budget calculation should be made for the actual case. For medium range LDCM and long range LDCM the recommendation is to use the *LowPower* setting to minimize the power consumption and keep the heat dissipation at minimum.

The *HighPower* setting adds 3 dBm extra optical power and can be used to increase the margin at distances close to maximum.

Table 33: *Optical budgets with C37.94 protocol*

Type of LDCM	Short range (SR)	Short range (SR)	Medium range (MR)	Long range (LR)
Type of fibre	Multi-mode fiber glass 50/125 µm	Multi-mode fiber glass 62.5/125 µm	Single-mode fiber glass 9/125 µm	Single-mode fiber glass 9/125 µm
Modem type	1MRK0002122-AB	1MRK0002122-AB	1MRK002311-AA	1MRK002311-BA
Contact type	ST	ST	FC/PC	FC/PC
Minimum output power ¹⁾	-21 dBm	-13.7 dBm	-3.2 dBm	-1.3 dBm
Minimum receiver sensitivity	-32.5 dBm	-32.5 dBm	-30 dBm	-30 dBm
Optical link budget ²⁾	11.5 dB	18.8 dB	26.8 dB	28.7 dB

- 1) Minimum output power is measured with 1 m of the selected fiber and the high power mode.
 2) The optical budget includes a satisfactory margin for aging in transmitter and receiver during 20–30 years.

Table 34: *Example of input data for calculating the optical budget (maximum distance)*

Type of LDCM	Short range (SR)	Short range (SR)	Medium range (MR)	Long range (LR)
Type of fibre	Multi-mode fiber glass 50/125 µm	Multi-mode fiber glass 62.5/125 µm	Single-mode fiber glass 9/125 µm	Single-mode fiber glass 9/125 µm
Modem type	1MRK0002122-AB	1MRK0002122-AB	1MRK002311-AA	1MRK002311-BA
Typical attenuation in fibre-optic cables	3 dB/km	3 dB/km	0.32 dB/km	0.21 dB/km
Attenuation/Contact	1.5 dB/ST	1.5 dB/ST	0.3 dB/FC/PC	0.3 dB/FC/PC
Factory splice attenuation	0.5 dB/splice 0.3 splices/km	0.5 dB/splice 0.1 splices/km	0.08 dB/splice 0.1 splices/km	0.08 dB/splice 0.1 splices/km
Repair splices	0.25 dB/splice 0.1 splices/km	0.25 dB/splice 0.1 splices/km	0.1 dB/splice 0.05 splices/km	0.1 dB/splice 0.05 splices/km
Fiber margin for aging	0.1 dB/km	0.1 dB/km	0.01 dB/km	0.01 dB/km

Table 35: *Example of calculating the optical budget (maximum distance)*

Type of LDCM	Short range (SR)	Short range (SR)	Medium range (MR)	Long range (LR)
Type of fibre	Multi-mode fiber glass 50/125 µm	Multi-mode fiber glass 62.5/125 µm	Single-mode fiber glass 9/125 µm	Single-mode fiber glass 9/125 µm
Modem type	1MRK0002122-AB	1MRK0002122-AB	1MRK002311-AA	1MRK002311-BA
Maximum distance	2 km	3 km	80 km	120 km
Table continues on next page				

Type of LDCM	Short range (SR)	Short range (SR)	Medium range (MR)	Long range (LR)
Attenuation in fibre-optic cables	6 dB	9 dB	25.6 dB	25.2 dB
2 contacts	2 dB	3 dB	0.6 dB	0.6 dB
Factory splice attenuation	0.3 dB	0.45 dB	0.64 dB	0.96 dB
Repair splices	0.1 dB	0.3 dB	0.8 dB	1.2 dB
Fiber margin for aging	0.2 dB	0.3 dB	0.8 dB	1.2 dB
Total attenuation	8.6 dB	12.05 dB	26.04 dB	28.56 dB
Optical link budget	9 dB	13 dB	26.8 dB	28.7 dB
Link margin	0.4 dB	0.95 dB	0.76 dB	0.14 dB

ComAlarmDel 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.

ComAlrmResDel 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.

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.

64 kbit mode specific settings

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

breaker-and-a-half arrangement has two local currents, and the Current Transformer (CT) grounding 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.

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. When a merging unit according to IEC 61850-9-2 is used instead of the TRM, this parameter shall be set to 5.

CompRange value indicates the current peak value over which truncation is made. To set this value, knowledge of fault current levels is required. It is recommended to set the minimum range that will cover the expected fault current value. For example, if a 40kA fault level is expected on the network, the 0-50kA settings range should be chosen.

2 Mbit mode specific settings

RedundantCh is used to set the channel as a redundant backup channel. The redundant channel takes the CT group setting of the main channel, and ignores the CT group configured in its own transmit block.

LinkForwarded is used to configure the LDCM to merge the inter-trip and block signals from another LDCM-receiver. This is used when the analog signals for the LDCM-transmitter is connected to the receiver of another LDCM.

Section 21 Security

21.1 Authority status ATHSTAT

21.1.1 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.

21.2 Self supervision with internal event list INTERRSIG

21.2.1 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.

21.3 Change lock CHNGLCK

21.3.1 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.



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 ABB representative for remedial action.

21.4 Denial of service SCHLCCH/RCHLCCH

21.4.1 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

21.4.2

Setting guidelines

The function does not have any parameters available in the local HMI or PCM600.

Section 22 Basic IED functions

22.1 IED identifiers TERMINALID

22.1.1 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.

22.2 Product information PRODINF

22.2.1 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 116: IED summary

This information is very helpful when interacting with ABB product support (for example during repair and maintenance).

22.2.2 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: *REL670*
- 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

22.3 Measured value expander block RANGE_XP

22.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Measured value expander block	RANGE_XP	-	-

22.3.2 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.

22.3.3 Setting guidelines

There are no settable parameters for the measured value expander block function.

22.4 Parameter setting groups

22.4.1 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.

22.4.2 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 GRP_CHGD 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.

22.5 Rated system frequency PRIMVAL

22.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Primary system values	PRIMVAL	-	-

22.5.2 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.

22.5.3 Setting guidelines

Set the system rated frequency. Refer to section ["Signal matrix for analog inputs SMAI"](#) for description on frequency tracking.

22.6 Summation block 3 phase 3PHSUM

22.6.1 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.

22.6.2 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 *VBase* voltage setting (for each instance x).

GlobalBaseSel: Selects the global base value group used by the function to define (*IBase*), (*VBase*) and (*SBase*).

22.7 Global base values GBASVAL

22.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Global base values	GBASVAL	-	-

22.7.2 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.

22.7.3 Setting guidelines

VBase: 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 $SBase = \sqrt{3} \cdot VBase \cdot IBase$.

22.8 Signal matrix for binary inputs SMBI

22.8.1 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.

22.8.2 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.

22.9 Signal matrix for binary outputs SMBO

22.9.1 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.

22.9.2 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.

22.10 Signal matrix for mA inputs SMMI

22.10.1 Application

The Signal matrix for mA inputs function SMMI is used within the Application Configuration tool in direct relation with the Signal Matrix tool. SMMI represents the way milliamp (mA) inputs are brought in for one IED configuration.

22.10.2 Setting guidelines

There are no setting parameters for the Signal matrix for mA inputs SMMI available to the user in the Parameter Setting tool. However, the user must give a name to SMMI instance and SMMI inputs, directly in the Application Configuration tool.

22.11 Signal matrix for analog inputs SMAI

22.11.1 Application

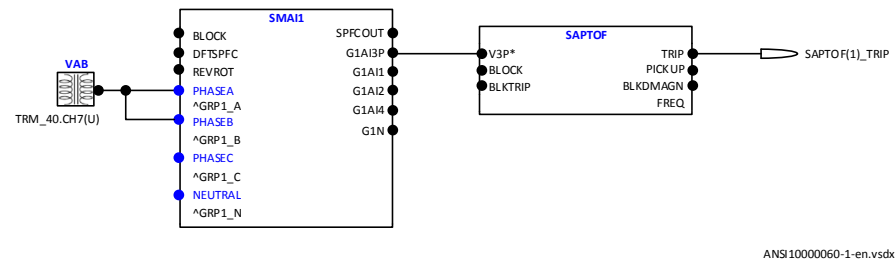
Signal matrix for analog inputs (SMAI), also known as the preprocessor function block, analyses the connected four analog signals (three phases and neutral) and calculates all relevant information from them like the phasor magnitude, phase angle, frequency, true RMS value, harmonics, sequence components 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).

22.11.2 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 $V_{Base}/\sqrt{3}$

If SMAI setting *ConnectionType* is *Ph-Ph*, at least two of the inputs GRP_x_A, GRP_x_B and GRP_x_C, 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: A-B to GRP_xA, B-C to GRP_xB, C-A to GRP_xC. If SMAI setting *ConnectionType* is *Ph-N*, all three inputs GRP_x_A, GRP_x_B and GRP_x_C 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 GRP_x_A, GRP_x_B and GRP_x_C to the same voltage input as shown in figure [117](#) to make SMAI calculate a positive sequence voltage.



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Figure 117: Connection example



The above described scenario does not work if SMAI setting *ConnectionType* is *Ph-N*. If only one phase-ground 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, 81), Underfrequency protection (SAPTUF, 81) and Rate-of-change frequency protection (SAPFRC, 81) due to that all other information except frequency and positive sequence voltage might be wrongly calculated.

22.11.3

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 that 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 A, B and C will be calculated for use in symmetrical situations. If N component should be used respectively the phase component during faults I_N/V_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*), (*VBase*) and (*SBase*).

MinValFreqMeas: The minimum value of the voltage for which the frequency is calculated, expressed as percent of *VBase* (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 utmost importance that parameter setting DFTRreference 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

AdDFTRefCh7

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

AdDFTRefCh4

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

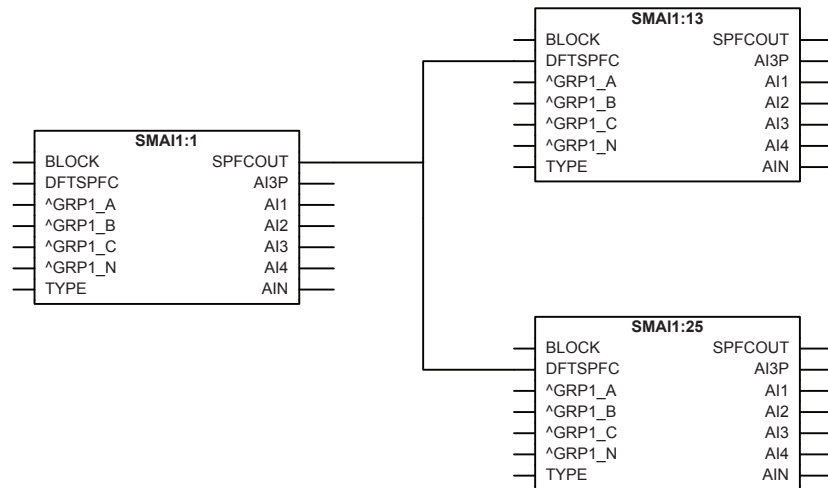
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Figure 118: Twelve SMAI instances are grouped within one task time. SMAI blocks are available in three different task times in the IED. Two pointed instances are used in the following examples.

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. In other application the usual setting of the parameter *DFTReference* of SMAI is *InternalDFTRef*.

Example 1



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Figure 119: 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 118 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 119) SMAI2:2 – SMAI12:12: *DFTReference* = *DFTRefGrp7* for SMAI2:2 – SMAI12:12 to use SMAI7:7 as reference.

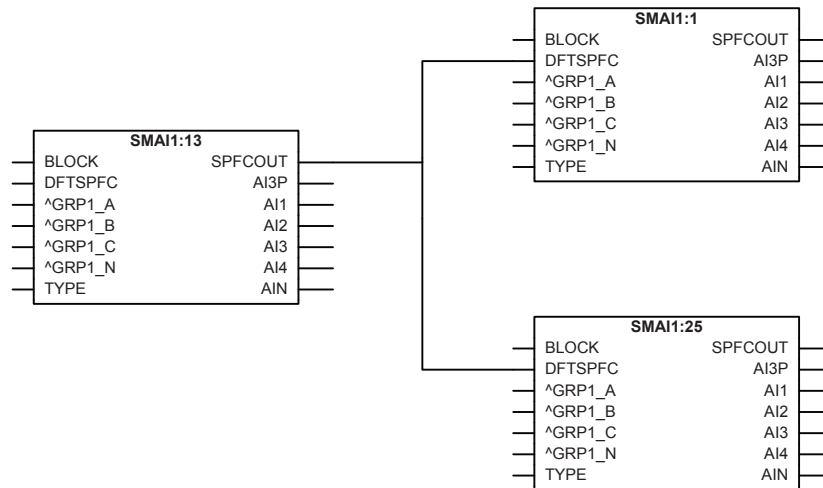
For task time group 2 this gives the following settings:

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)

Example 2



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Figure 120: 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 118 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 120) SMAI12:14 – 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)

22.12 Test mode functionality TESTMODE

22.12.1 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.

22.12.1.1 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/IEC61850-8-1:1RemoteModControl** 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 IEC61850-7-4. 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 IEC61850-8-1 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.

22.12.2 Setting guidelines

Remember always that there are two possible ways to place the IED in the *TestMode=Enabled* state. If, the IED is set to normal operation (*TestMode = Disabled*), 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.

22.13 Time synchronization TIMESYNCHGEN

22.13.1 Setting guidelines

All the parameters related to time are divided into two categories: System time and Synchronization.

22.13.1.1 System time

The system time can be set manually via the local HMI under **Main menu/Configuration/Time/System time**. The time is set with years, month, day, hour, minute, second and millisecond. In addition, there are also settings for Day-Light-Saving and adjustment of Time-Zones.

22.13.1.2 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.

Time Synchronization

The time synchronization (TIMESYNCHGEN) parameters are divided in two categories, "general" and "IEC61850-9-2" parameters.

The general parameters are as follows:

- *FineSynchSource*
- *SynchMaster*

FineSynchSource: This parameter is used to select the time synchronization source. The options are "Off", "GPS", "IRIG-B", or "GPS+IRIG-B". In case that both GPS and IRIG-B are used (GPS+IRIG-B) for redundant time synchronization, the PMU will automatically select the most accurate time synchronization source.

SynchMaster: This parameter defines if the IED shall be used as a master clock (SNTP Server) for time synchronization within a Substation Automation System for IEDs connected on a communication network (IEC61850-8-1). The options are "Off" or "SNTP-Server".

The IEC61850-9-2 parameters are as follows:

- *SyncLostMode*
- *SynchAccLevel*

SyncLostMode: This parameter defines the time synchronization mode when using process bus applications (IEC61850-9-2). The options are *NoBlock*, *Block*, and *BlockOnLostUTC*. If the parameter is set to *Block* or *BlockOnLostUTC*, then if the time quality is worse than the limit set by *SynchAccLevel*, some functions will be blocked in the IED.

SynchAccLevel: This parameter is to define the required time synchronization accuracy for process bus applications. The options are "Class T5 (1 μ s)", "Class T4 (4 μ s)", or "Unspecified". If it is set to "Unspecified", the time quality will be always accepted and application functions will not be blocked due to the time quality.

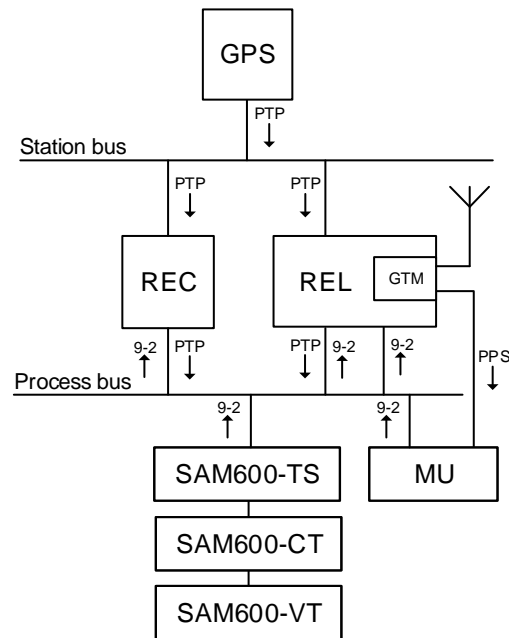
IRIG-B

The IRIG-B parameters have to be set according to the external clock providing the IRIG-B signal to the IED. The IRIG-B parameters (IRIG-B:1) are as follows:

- *SynchType*
- *TimeDomain*
- *Encoding*
- *TimeZoneAs1344*

SynchType: This parameter is used to select the type of IRIG-B synchronization. The options are "BNC" or "Opto". The IRIG-B module has two inputs. One input is for the electrical IRIG-B (BNC connector) that can handle both a pulse-width modulated signal (also called unmodulated) and an amplitude modulated signal (also called sine wave modulated). The other is an optical input type ST for optical pulse-width modulated signal (IRIG-B 00X). The recommended IRIG-B signal for PMU time synchronization is IRIG-B optical (IRIG-B 00X) with IEEE1344 support. If the optical

Setting example



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Figure 122: Example system

Figure 122 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. The REL contains a GTM card, which has a PPS output that is used to synchronize merging units that are not PTP compliant. As a side effect, the GTM contains a GPS receiver and the REL acts as a backup of the GPS on the station bus.

On all access points, the *PTP* parameter is “ON”.

On the REL, the parameter *FineSynchSource* (under **Configuration/Time/Synchronization/TIMESYNCHGEN:1/General**) is set to “GPS” if there is a GPS antenna attached.

If the GTM is used as a PPS output only, the *FineSynchSource* is not set.

22.13.1.3

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 is not PTP capable, then synchronize the merging unit from the IED via a PPS out from the GTM. 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 synch as well as sync to the merging unit.

If synchronization of the IED and the merging unit is based on GPS, set the parameter *LostSyncMode* 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 either PMU or 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. Either *FineSyncSource* is set to the same source that the merging unit uses, or the PPS output from the GTM module is used to synchronize the merging unit. If the PPS output from the GTM module is used to synchronize the merging unit and PTP is not used, the IED does not know how the merging unit is synchronized and the parameter *LostSyncMode* must be set to *NoBlock*.

Section 23 Requirements

23.1 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.

23.1.1 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 ABB 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 ABB 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.

23.1.2

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-ground, 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.

23.1.3 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-ground faults. The current for a single phase-to-ground 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.

23.1.4 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 ground 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-ground 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-ground faults it is important to consider both cases. Even in a case where the phase-to-ground fault current is smaller than the three-phase fault current the phase-to-ground fault can be dimensioning for the CT depending on the higher burden.

In isolated or high impedance grounded systems the phase-to-ground 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.

23.1.5 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.

23.1.6 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 ABB 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.

23.1.7 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.

23.1.7.1 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 102)

23.1.7.2 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 V_{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:

$$S = TD \cdot S_{Old} + (1 - TD) \cdot S_{Calculated}$$

(Equation 103)

23.1.7.3

Current transformers according to ANSI/IEEE

Current transformers according to ANSI/IEEE are partly specified in different ways. A rated secondary terminal voltage V_{ANSI} is specified for a CT of class C. V_{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 V_{ANSI} values for example, V_{ANSI} is 400 V for a C400 CT. A corresponding rated equivalent limiting secondary e.m.f. E_{alANSI} can be estimated as follows:

$$E_{alANSI} = |20 \cdot I_{SN} \cdot R_{CT} + V_{ANSI}| = |20 \cdot I_{SN} \cdot R_{CT} + 20 \cdot I_{SN} \cdot Z_{bANSI}|$$

(Equation 104)

where:

Z_{bANSI} The impedance (that is, with a complex quantity) of the standard ANSI burden for the specific C class (Ω)

V_{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 105)

A CT according to ANSI/IEEE is also specified by the knee point voltage $V_{kneeANSI}$ that is graphically defined from an excitation curve. The knee point voltage $V_{kneeANSI}$ normally has a lower value than the knee-point e.m.f. according to IEC and BS. $V_{kneeANSI}$ 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 $V_{kneeANSI}$ that fulfils the following:

$$V_{kneeANSI} > 0.75 \cdot (\text{maximum of } E_{alreq})$$

(Equation 106)

The following guide may also be referred for some more application aspects of ANSI class CTs: IEEE C37.110 (2007), IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes.

23.2 Voltage transformer requirements

The performance of a protection function will depend on the quality of the measured input signal. Transients caused by capacitive Coupled voltage transformers (CCVTs) can affect some protection functions.

Magnetic or capacitive voltage transformers can be used.

The capacitive voltage transformers (CCVTs) should fulfill the requirements according to the IEC 61869-5 standard regarding ferro-resonance and transients. The ferro-resonance requirements of the CCVTs 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. CCVTs according to all classes can be used.

The protection IED has effective filters for these transients, which gives secure and correct operation with CCVTs.

23.3 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.

23.4 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.

23.5 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 $<250 \mu\text{s}$, $<100 \mu\text{s}$ 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 $<100 \mu\text{s}$

- 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).

IED with GPS clock

- Independent of asymmetry.

23.6

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 24 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
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
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
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	<ol style="list-style-type: none"> 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 IP20- Protected against solid foreign objects of 12.5mm diameter and greater.
IP 40	Ingression protection, according to IEC 60529, level IP40- Protected against solid foreign objects of 1mm diameter and greater.
IP 54	Ingression protection, according to IEC 60529, level IP54-Dust-protected, protected against splashing water.
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
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
MIM	Milli-ampere 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
OCP	Overcurrent protection
OEM	Optical Ethernet module
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.
SRV	Switch for CB ready condition
ST	Switch or push button to trip
Starpoint	Neutral/Wye 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 ground-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
X.21	A digital signalling interface primarily used for telecom equipment
3I₀	Three times zero-sequence current. Often referred to as the residual or the ground-fault current

$3V_0$

Three times the zero sequence voltage. Often referred to as the residual voltage or the neutral point voltage



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