Relion® 650 SERIES

Line distance protection REL650 Version 1.1 ANSI

Application manual

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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 standards EN 50263 and 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 IED 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 be used when 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 communication and protocols.

1.3 Product documentation

1.3.1 Product documentation set

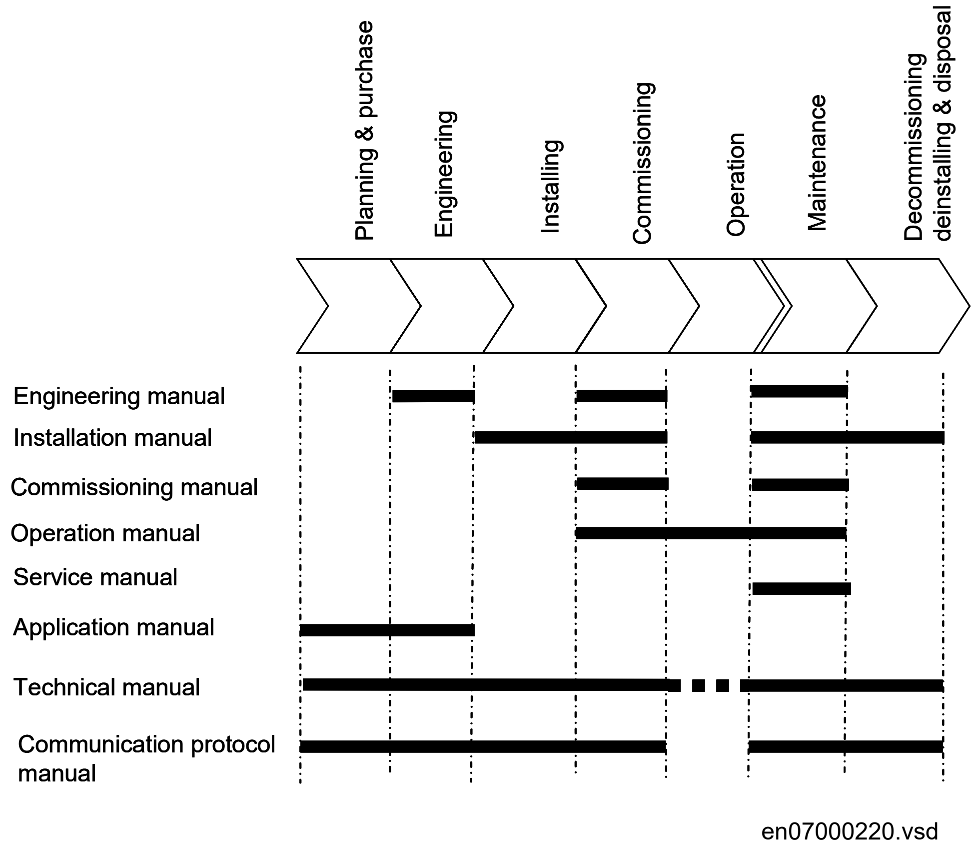


Figure 1: The intended use of manuals in different lifecycles

The engineering manual contains instructions on how to engineer the IEDs using the different tools in PCM600. 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 engineering of protection and control functions, LHMI functions as well as communication engineering for IEC 60870-5-103, IEC 61850 and DNP3.

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 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 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 chronological order in which the IED should be commissioned.

The operation manual contains instructions on how to operate the IED once it has been commissioned. The manual provides instructions for monitoring, controlling and setting 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 service manual contains instructions on how to service and maintain the IED. The manual also provides procedures for de-energizing, de-commissioning and disposal of the IED.

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 be used when calculating settings.

The technical manual contains application and functionality 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 a communication protocol supported by the IED. The manual concentrates on 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 service manual is not available yet.

1.3.2 Document revision history

Document revision/date	Product series version	History
-/April 2011	1.1	First release
A/November 2019	1.1	Maintenance release - Updated safety information and bug corrections

1.3.3 Related documents

Documents related to REL650	Identity number
Application manual	1MRK 506 325-UUS
Technical manual	1MRK 506 326-UUS
Commissioning manual	1MRK 506 327-UUS
Product Guide, configured	1MRK 506 328-BUS
Type test certificate	1MRK 506 328-TUS

650 series manuals	Identity number
Communication protocol manual, DNP3	1MRK 511 241-UUS
Communication protocol manual, IEC 61850	1MRK 511 242-UUS
Communication protocol manual, IEC 60870-5-103	1MRK 511 243-UUS
Point list manual, DNP3	1MRK 511 244-UUS

Table continues on next page

650 series manuals	Identity number
Engineering manual	1MRK 511 245-UUS
Operation manual	1MRK 500 093-UUS
Installation manual	1MRK 514 014-UUS

1.4 Symbols and conventions

1.4.1 Safety indication 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 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. Therefore, comply fully with all warning and caution notices.

1.4.2 Manual conventions

Conventions used in IED manuals. A particular convention may not be used in this manual.

- 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.
- The ^ character in front of an input or output signal name in the function block symbol given for a function, indicates that the user can set an own signal name in PCM600.
- The * character after an input or output signal name in the function block symbol given for a function, 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 mm. If it is not specifically mentioned then the dimension is in mm.

Section 2 Application

2.1 REL650 application

REL650 is used for the protection, control and monitoring of overhead lines and cables in solidly or impedance grounded networks. The IED can be used up to the high voltage levels. It is suitable for the protection of heavily loaded lines and multi-terminal lines where the requirement for fast three-pole tripping is wanted.

The full scheme distance protection provides protection of power lines with high sensitivity and low requirement on remote end communication. The five zones have fully independent measuring and setting which gives high flexibility for all types of lines.

The modern technical solution offers fast operating time of typically 1.5 cycles.

The autoreclose includes priority features for single-breaker arrangements. It co-operates with the synchronism check function with high-speed or delayed reclosing.

High set instantaneous phase and ground overcurrent, four step directional or non-directional delayed phase and ground overcurrent, thermal overload and two step under and overvoltage protection are examples of the available functions allowing the user to fulfill any application requirement.

The distance phase and ground fault protection can communicate with remote end in any teleprotection communication scheme.

The advanced logic capability, where the user logic is prepared with a graphical tool, allows special applications.

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

Three packages has been defined for following applications:

- Five zone distance protection with quadrilateral characteristic (A01A)
- Five zone distance protection with mho characteristic (A05A)
- Five zone distance protection with quadrilateral characteristic, single pole tripping (A11A)

The packages are configured and ready for direct use. Analog and tripping IO has been pre-defined for basic use.

Add binary I/O as required for the application when ordering. Other signals need to be applied as required for each application.

The graphical configuration tool ensures simple and fast testing and commissioning.

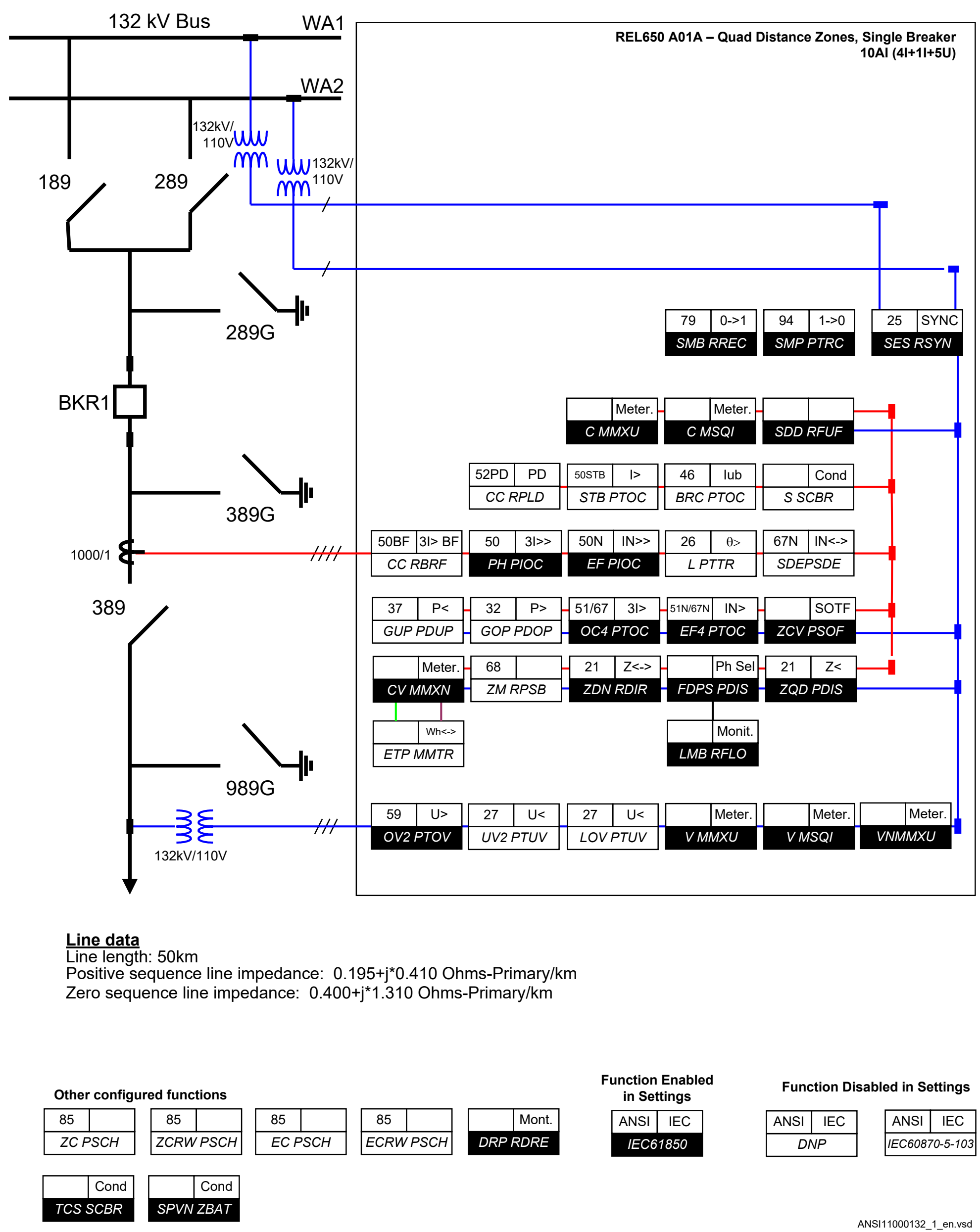


Figure 2: A typical protection application for quadrilateral distance zones in a single breaker arrangement

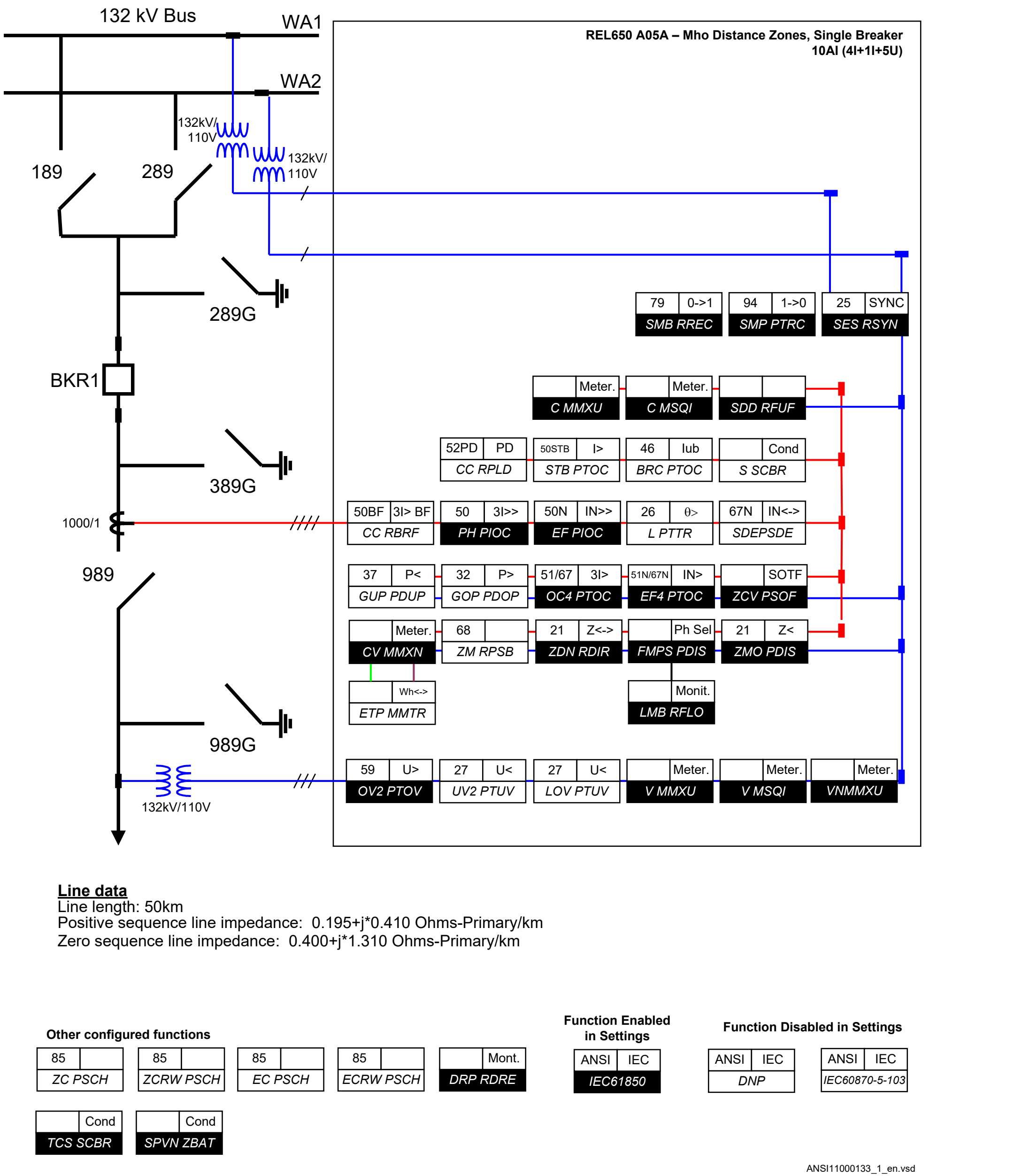


Figure 3: A typical protection application for mho distance zones in a single breaker arrangement

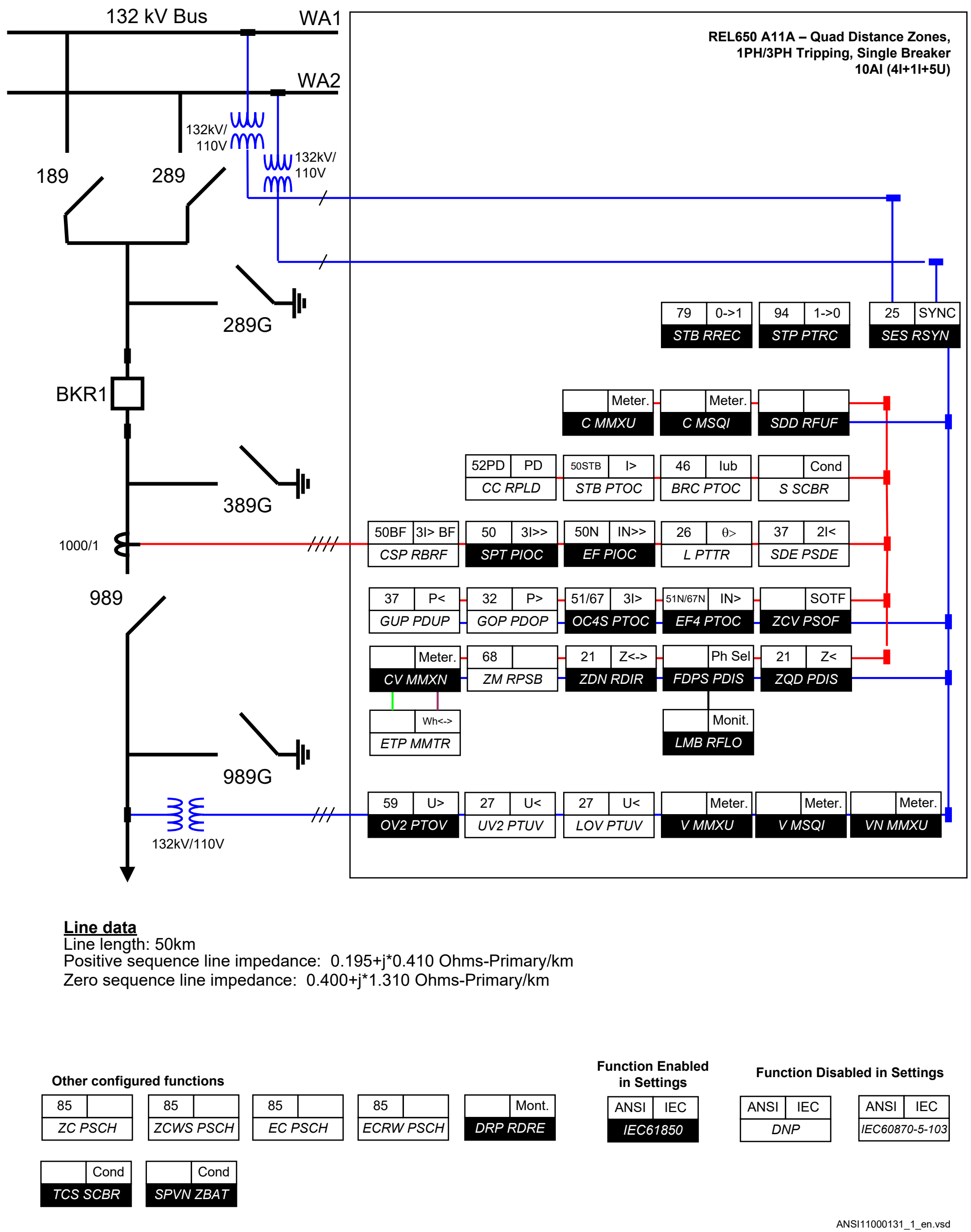


Figure 4: A typical protection application for quadrilateral characteristic distance zones in a single breaker arrangement, single pole tripping

2.2 Available functions

2.2.1 Main protection functions

IEC 61850/ Function block name	ANSI	Function description	Line Distance		
			REL650 (A01A) 3Ph/1CB, quad	REL650 (A05A) 3Ph/1CB, mho	REL650 (A11A) 1Ph/1CB
Impedance protection					
ZQDPDIS	21	Five zone distance protection, quadrilateral characteristic	1		1
FDPSPDIS	21	Phase selection with load enchroachment, quadrilateral characteristic	1		1
ZMOPDIS	21	Five zone distance protection, mho characteristic		1	
FMPSPDIS	21	Faulty phase identification with load enchroachment for mho		1	
ZDNRDIR	21	Directional impedance quadrilateral and mho	1	1	1
PPLPHIZ		Phase preference logic	1	1	1
ZMRPSB	68	Power swing detection	1	1	1
ZCVPSOF		Automatic switch onto fault logic, voltage and current based	1	1	1

2.2.2 Back-up protection functions

IEC 61850/ Function block name	ANSI	Function description	Line Distance		
			REL650 (A01A) 3Ph/1CB, quad	REL650 (A05A) 3Ph/1CB, mho	REL650 (A11A) 1Ph/1CB
Current protection					
PHPIOC	50	Instantaneous phase overcurrent protection	1	1	
SPTPIOC	50	Instantaneous phase overcurrent protection			1
OC4PTOC	51/67	Four step directional phase overcurrent protection	1	1	
OC4SPTOC	51/67	Four step phase overcurrent protection			1
EFPIOC	50N	Instantaneous residual overcurrent protection	1	1	1
EF4PTOC	51N/67N	Four step directional residual overcurrent protection	1	1	1
SDEPSDE	67N	Sensitive directional residual overcurrent and power protection	1	1	1
UC2PTUC	37	Time delayed 2-step undercurrent protection	1	1	1
LPTTR	26	Thermal overload protection, one time constant	1	1	1

Table continues on next page

IEC 61850/ Function block name	ANSI	Function description	Line Distance		
			REL650 (A01A) 3Ph/1CB, quad	REL650 (A05A) 3Ph/1CB, mho	REL650 (A11A) 1Ph/1CB
CCRBRF	50BF	Breaker failure protection	1	1	
CSPRBRF	50BF	Breaker failure protection			1
STBPTOC	50STB	Stub protection	1	1	1
CCRPLD	52PD	Pole discordance protection	1	1	1
BRCPTOC	46	Broken conductor check	1	1	1
GUPPDUP	37	Directional underpower protection	1	1	1
GOPPDOP	32	Directional overpower protection	1	1	1
DNSPTOC	46	Negative sequence based overcurrent function	1	1	1
Voltage protection					
UV2PTUV	27	Two step undervoltage protection	1	1	1
OV2PTOV	59	Two step overvoltage protection	1	1	1
ROV2PTOV	59N	Two step residual overvoltage protection	1	1	1
LOVPTUV	27	Loss of voltage check	1	1	1
Frequency protection					
SAPTUF	81	Underfrequency function	2	2	2
SAPTOF	81	Overfrequency function	2	2	2
SAPFRC	81	Rate-of-change frequency protection	2	2	2

2.2.3 Control and monitoring functions

IEC 61850/Function block name	ANSI	Function description	Line Distance		
			REL650 (A01A) 3Ph/1CB, quad	REL650 (A05A) 3Ph/1CB, mho	REL650 (A11A) 1Ph/1CB
Control					
SESRSYN	25	Synchrocheck, energizing check, and synchronizing	1	1	1
SMBRREC	79	Autorecloser	1	1	
STBRREC	79	Autorecloser			1
QCBAY		Bay control	1	1	1
LOCREM		Handling of LR-switch positions	1	1	1
LOCREMCTRL		LHMI control of Permitted Source To Operate (PSTO)	1	1	1
SLGGIO		Logic Rotating Switch for function selection and LHMI presentation	15	15	15

Table continues on next page

IEC 61850/Function block name	ANSI	Function description	Line Distance		
			REL650 (A01A) 3Ph/1CB, quad	REL650 (A05A) 3Ph/1CB, mho	REL650 (A11A) 1Ph/1CB
VSGGIO		Selector mini switch extension	20	20	20
DPGGIO		IEC 61850 generic communication I/O functions double point	16	16	16
SPC8GGIO		Single point generic control 8 signals	5	5	5
AUTOBITS		AutomationBits, command function for DNP3.0	3	3	3
I103CMD		Function commands for IEC60870-5-103	1	1	1
I103IEDCMD		IED commands for IEC60870-5-103	1	1	1
I103USRCMD		Function commands user defined for IEC60870-5-103	4	4	4
I103GENCMD		Function commands generic for IEC60870-5-103	50	50	50
I103POSCMD		IED commands with position and select for IEC60870-5-103	50	50	50
Secondary system supervision					
CCSRDIF	87	Current circuit supervision	1	1	1
SDDRFUF		Fuse failure supervision	1	1	1
TCSSCBR		Breaker close/trip circuit monitoring	3	3	3
Logic					
SMPPTRC	94	Tripping logic	1	1	
SPTPTRC	94	Tripping logic			1
TMAGGIO		Trip matrix logic	12	12	12
OR		Configurable logic blocks, OR gate	283	283	283
INVERTER		Configurable logic blocks, Inverter gate	140	140	140
PULSETIMER		Configurable logic blocks, Pulse timer	40	40	40
GATE		Configurable logic blocks, Controllable gate	40	40	40
XOR		Configurable logic blocks, exclusive OR gate	40	40	40
LOOPDELAY		Configurable logic blocks, loop delay	40	40	40
TIMERSET		Configurable logic blocks, timer function block	40	40	40
AND		Configurable logic blocks, AND gate	280	280	280
SRMEMORY		Configurable logic blocks, set-reset memory flip-flop gate	40	40	40
RSMEMORY		Configurable logic blocks, reset-set memory flip-flop gate	40	40	40
FXDSIGN		Fixed signal function block	1	1	1
B16I		Boolean 16 to Integer conversion	16	16	16
B16IFCVI		Boolean 16 to Integer conversion with logic node representation	16	16	16
IB16A		Integer to Boolean 16 conversion	16	16	16
IB16FCVB		Integer to Boolean 16 conversion with logic node representation	16	16	16

Table continues on next page

IEC 61850/Function block name	ANSI	Function description	Line Distance		
			REL650 (A01A) 3Ph/1CB, quad	REL650 (A05A) 3Ph/1CB, mho	REL650 (A11A) 1Ph/1CB
Monitoring					
CVMMXN		Measurements	6	6	6
CMMXU		Phase current measurement	10	10	10
VMMXU		Phase-phase voltage measurement	6	6	6
CMSQI		Current sequence component measurement	6	6	6
VMSQI		Voltage sequence measurement	6	6	6
VNMMXU		Phase-neutral voltage measurement	6	6	6
CNTGGIO		Event counter	5	5	5
DRPRDRE		Disturbance report	1	1	1
AxRADR		Analog input signals	4	4	4
BxRBDR		Binary input signals	6	6	6
SPGGIO		IEC 61850 generic communication I/O functions	64	64	64
SP16GGIO		IEC 61850 generic communication I/O functions 16 inputs	16	16	16
MVGGIO		IEC 61850 generic communication I/O functions	16	16	16
MVEXP		Measured value expander block	66	66	66
LMBRFLO		Fault locator	1	1	1
SPVNZBAT		Station battery supervision	1	1	1
SSIMG	63	Insulation gas monitoring function	1	1	1
SSIML	71	Insulation liquid monitoring function	1	1	1
SSCBR		Circuit breaker condition monitoring	1	1	1
I103MEAS		Measurands for IEC60870-5-103	1	1	1
I103MEASUSR		Measurands user defined signals for IEC60870-5-103	3	3	3
I103AR		Function status auto-recloser for IEC60870-5-103	1	1	1
I103EF		Function status ground-fault for IEC60870-5-103	1	1	1
I103FLTPROT		Function status fault protection for IEC60870-5-103	1	1	1
I103IED		IED status for IEC60870-5-103	1	1	1
I103SUPERV		Supervison status for IEC60870-5-103	1	1	1
I103USRDEF		Status for user defined signals for IEC60870-5-103	20	20	20
Metering					
PCGGIO		Pulse counter logic	16	16	16
ETPMMTR		Function for energy calculation and demand handling	3	3	3

2.2.4 Designed to communicate

IEC 61850/Function block name	ANSI	Function description	Line Distance		
			REL650 (A01A) 3Ph/1CB, quad	REL650 (A05A) 3Ph/1CB, mho	REL650 (A11A) 1Ph/1CB
Station communication					
		IEC 61850 communication protocol, LAN1	1	1	1
		DNP3.0 for TCP/IP communication protocol, LAN1	1	1	1
IEC61870-5-103		IEC60870-5-103 serial communication via ST	1	1	1
GOOSEINTLKRCV		Horizontal communication via GOOSE for interlocking	59	59	59
GOOSEBINRCV		GOOSE binary receive	4	4	4
ETHFRNT ETHLAN1 GATEWAY		Ethernet configuration of front port, LAN1 port and gateway			
GOOSEDPRCV		GOOSE function block to receive a double point value	32	32	32
GOOSEINTRCV		GOOSE function block to receive an integer value	32	32	32
GOOSEMVRCV		GOOSE function block to receive a mesurand value	16	16	16
GOOSESPRCV		GOOSE function block to receive a single point value	64	64	64
Scheme communication					
ZCPSCH	85	Scheme communication logic for distance or overcurrent protection	1	1	1
ZCRWPSCH	85	Current reversal and weak-end infeed logic for distance protection	1	1	
ZCWSPSCH	85	Current reversal and weak-end infeed logic for distance protection			1
ZCLCPLAL		Local acceleration logic	1	1	1
ECPSCH	85	Scheme communication logic for residual overcurrent protection	1	1	1
ECRWPSCH	85	Current reversal and weak-end infeed logic for residual overcurrent protection	1	1	1

2.2.5 Basic IED functions

IEC 61850/Function block name	Function description	
Basic functions included in all products		
INTERRSIG	Self supervision with internal event list	1
SELFSUPEVLST	Self supervision with internal event list	1
SNTP	Time synchronization	1
TIMESYNCHGEN	Time synchronization	1
Table continues on next page		

IEC 61850/Function block name	Function description	
DTSBEGIN, DTSEND, TIMEZONE	Time synchronization, daylight saving	1
IRIG-B	Time synchronization	1
SETGRPS	Setting group handling	1
ACTVGRP	Parameter setting groups	1
TESTMODE	Test mode functionality	1
CHNGLCK	Change lock function	1
TERMINALID	IED identifiers	1
PRODINF	Product information	1
PRIMVAL	Primary system values	1
SMAI_20_1-12	Signal matrix for analog inputs	2
3PHSUM	Summation block 3 phase	12
GBASVAL	Global base values for settings	6
ATHSTAT	Authority status	1
ATHCHCK	Authority check	1
FTPACCS	FTP access with password	1
DOSFRNT	Denial of service, frame rate control for front port	1
DOSLAN1	Denial of service, frame rate control for LAN1	1
DOSSCKT	Denial of service, socket flow control	1

2.3 REL650 application examples

2.3.1 Adaptation to different applications

The IED is provided in a variant for a pre-defined configuration to be used with quadrilateral distance protection characteristic.

The IED is provided in a variant for a pre-defined configuration to be used with mho distance protection characteristic.

The IED can be used in a wide range of applications. This is done by selecting from the comprehensive function library in the IED.

A selection of common applications are described below.

- Application 1: Two-ended over-head transmission line in a solidly grounded network
- Application 2: Two-ended cable transmission line in a solidly grounded network
- Application 3: Double circuit over-head transmission line in a solidly grounded network
- Application 4: Two-ended over-head line with transformer in a solidly grounded network
- Application 5: Two-ended over-head transmission line in a high impedance grounded network

2.3.2 Two-ended over-head transmission line in a solidly grounded network

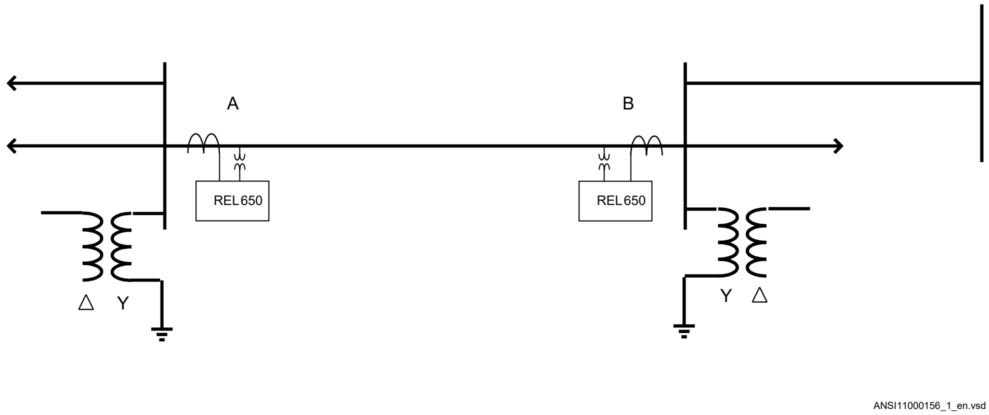


Figure 5: Two-ended over-head line in a solidly grounded network

Table 1: Data for the line application example

Parameter	Value
System voltage	110 – 220 kV
Line length	10 – 150 km
Short circuit power level infeed at both line ends	500 – 10 000 MVA
Line R/X	≈ 0.25

2.3.3 Two-ended cable transmission line in a solidly grounded network

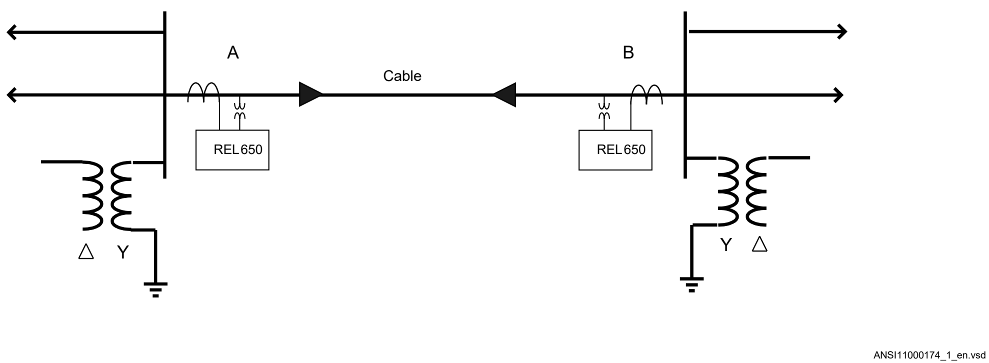


Figure 6: Two-ended cable line in a solidly grounded network

Table 2: Data for the line application example

Parameter	Value
System voltage	110 – 220 kV
Line length:	2 – 10 km
Short circuit power level infeed at both line ends	500 – 10 000 MVA
Line R/X	≈ 1.0

2.3.4 Double circuit over-head transmission line in a solidly grounded network

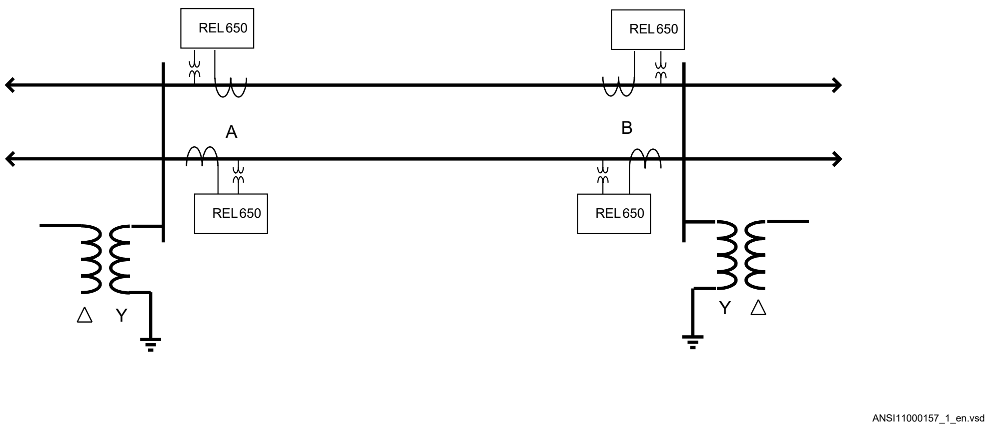


Figure 7: Double circuit over-head line in a solidly grounded network

Table 3: Data for the line application example

Parameter	Value
System voltage	110 – 220 kV
Line length	10 – 150 km
Short circuit power level infeed at both line ends	500 – 10 000 MVA
Line R/X	≈ 0.25

2.3.5 Two-ended over-head line with transformer in a solidly grounded network

Figure 8: Two-ended over-head line with transformer in a solidly grounded network

Table 4: Data for the line application example

Parameter	Value
System voltage	110 – 220 kV
Line length	10 – 20 km
Short circuit power level infeed from one line end	500 – 10 000 MVA
Line R/X	≈ 0.25

2.3.6 Two-ended over-head transmission line in a high-impedance grounded network

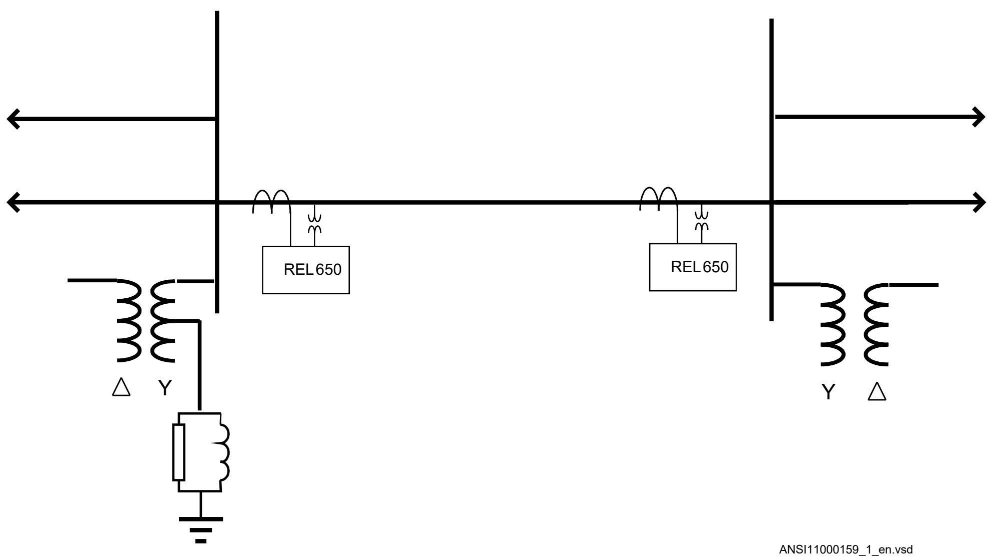


Figure 9: Two-ended over-head line in a high-impedance grounded network

Table 5: Data for the line application example

Parameter	Value
System voltage	40 – 110 kV
Line length	5 – 80 km
Short circuit power level infeed at both line ends	200 – 7 000 MVA
Line R/X	≈ 0.25

2.3.7 Functionality table

The proposal for functionality choice for the different application cases are shown in table 6. The recommendations have the following meaning:

- Enabled: It is recommended to have the function activated in the application
- Disabled: It is recommended to have the function deactivated in the application
- Application dependent: The decision to have the function activated or not is dependent on the specific conditions in each case

Application 1- 5 in table 6 are according to application examples given in previous sections.

Table 6: Selection of functions in different applications

Function	Application 1	Application 2	Application 3	Application 4	Application 5
Five zone distance protection, quadrilateral characteristic ZQDPDIS (21)	Enabled	Enabled	Enabled	Enabled	Enabled
Phase selection with load enchroachment, quadrilateral characteristic FDPSPDIS (21)	Enabled	Enabled	Enabled	Enabled	Enabled
Faulty phase identification with load enchroachment for mho FMPSPDIS	Enabled	Enabled	Enabled	Enabled	Enabled
Local acceleration logic ZCLCPLAL	Application dependent	Application dependent	Application dependent	Application dependent	Application dependent
Phase preference logic PPLPHIZ	Disabled	Disabled	Disabled	Disabled	Enabled
Power swing detection ZMRPSB (68)	Application dependent	Application dependent	Application dependent	Disabled	Application dependent
Automatic switch onto fault logic, voltage and current based ZCVPSOF	Enabled	Enabled	Enabled	Enabled	Enabled
Instantaneous phase overcurrent protection PHPIOC (50)	Application dependent	Application dependent	Application dependent	Application dependent	Application dependent
Four step phase overcurrent protection OC4PTOC (51_67)	Enabled	Enabled	Enabled	Enabled	Enabled
Instantaneous residual overcurrent protection EFPIOC (50N)	Enabled	Enabled	Enabled	Enabled	Disabled
Four step residual overcurrent protection EF4PTOC (51N_67N)	Enabled	Enabled	Enabled	Enabled	Disabled
Scheme communication logic for distance or overcurrent protection ZCPSCH (85)	Application dependent	Enabled	Enabled	Disabled	Application dependent
Table continues on next page					

Function	Application 1	Application 2	Application 3	Application 4	Application 5
Current reversal and weak-end infeed logic for distance protection ZCRWPSCH (85)	Application dependent	Enabled	Enabled	Disabled	Application dependent
Scheme communication logic for residual overcurrent protection ECPSCH (85)	Application dependent	Enabled	Enabled	Disabled	Disabled
Current reversal and weak-end infeed logic for residual overcurrent protection ECRWPSCH (85)	Application dependent	Application dependent	Enabled	Disabled	Disabled
Sensitive directional residual over current and power protection SDEPSDE (67N)	Disabled	Disabled	Disabled	Disabled	Enabled
Thermal overload protection, one time constant LPTTR (26)	Application dependent	Enabled	Application dependent	Application dependent	Application dependent
Breaker failure protection CCRBRF (50BF)	Enabled	Enabled	Enabled	Enabled	Enabled
Pole discordance protection CCRPLD (52PD)	Application dependent	Application dependent	Application dependent	Application dependent	Application dependent
Broken conductor check BRCPTOC (46)	Application dependent	Application dependent	Application dependent	Application dependent	Enabled
Directional under-power protection GUPPDUP (37)	Application dependent	Application dependent	Application dependent	Application dependent	Application dependent
Directional over-power protection GOPPDOP (32)	Application dependent	Application dependent	Application dependent	Application dependent	Application dependent
Negative sequence based overcurrent protection DNSPTOC (46)	Application dependent	Application dependent	Application dependent	Application dependent	Application dependent
Two step undervoltage protection UV2PTUV (27)	Application dependent	Application dependent	Application dependent	Application dependent	Application dependent
Two step overvoltage protection OV2PTOV (59)	Application dependent	Application dependent	Application dependent	Application dependent	Application dependent
Two step residual overvoltage protection ROV2PTOV (59N)	Application dependent	Application dependent	Application dependent	Application dependent	Enabled
Loss of voltage check LOVPTUV (27)	Application dependent	Application dependent	Application dependent	Application dependent	Application dependent
Under-frequency protection SAPTUF (81)	Application dependent	Application dependent	Application dependent	Application dependent	Application dependent
Over-frequency protection SAPTOF (81)	Application dependent	Application dependent	Application dependent	Application dependent	Application dependent
Rate of change of frequency protection SAPFRC (81)	Application dependent	Application dependent	Application dependent	Application dependent	Application dependent
Current circuit supervision CCSRDIF (87)	Enabled	Enabled	Enabled	Enabled	Enabled
Fuse failure supervision SDDRFUF	Enabled	Enabled	Enabled	Enabled	Enabled
Breaker close/trip circuit monitoring TCSSCBR	Enabled	Enabled	Enabled	Enabled	Enabled
Autorecloser SMBRREC (79)	Enabled	Off	Enabled	Enabled	Enabled

Section 3 REL650 setting examples

3.1 Setting example for a two-ended overhead transmission line in a solidly grounded network

The application example: a 138 kV line as shown in figure 9

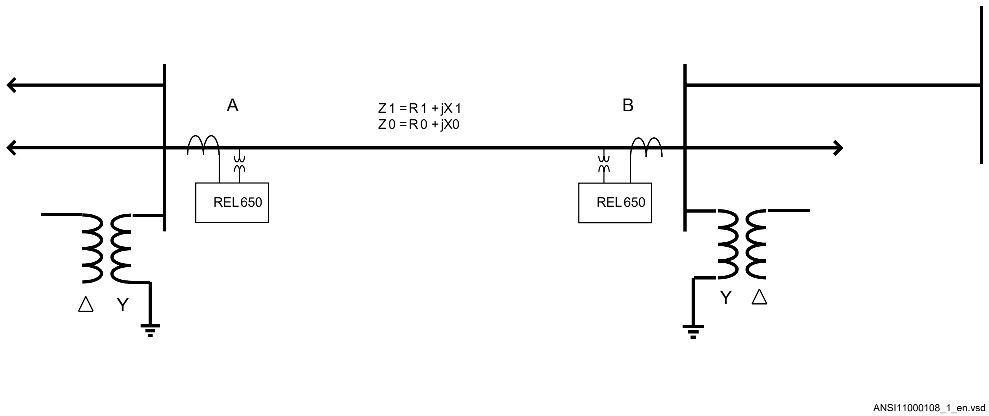


Figure 10: Two-ended overhead transmission line in a solidly grounded network

The following data is assumed:

Table 7: Data for the line application example

Entity	Value
Line length	50 km
Positive sequence impedance	0.05 + j 0.35 Ω/km ⇒ 2.5 + j17.5 Ω
Zero sequence impedance	0.15 + j 1.00 Ω/km ⇒ 7.5 + j50 Ω
High positive sequence source impedance at A	j10 Ω (about 1 900 MVA)
Low positive sequence source impedance at A	j3.2 Ω (about 6 000 MVA)
High zero sequence source impedance at A	j8 Ω
Low zero sequence source impedance at A	j5 Ω
High positive sequence source impedance at B	j10 Ω (about 1 900 MVA)
Low positive sequence source impedance at B	j3.2 Ω (about 6 000 MVA)
High zero sequence source impedance at B	j8 Ω
Low zero sequence source impedance at B	j5 Ω
CT ratio at A and B	1 000/1 A
VT ratio at A and B	$\frac{143}{\sqrt{3}} / \frac{0.11}{\sqrt{3}}$ kV
Maximum power transfer on the line	180 MVA

Only settings that need adjustment due to the specific application are described in setting examples. It is recommended to keep the default values for all settings that are not described. Refer to Technical manual for setting tables for each protection and control function.

Refer to setting guideline section in Application manual for guidelines on how to set functions that are not presented in setting examples.

Use parameter setting tool in PCM600 to set the IED according to calculations for the particular application.

3.1.1 Calculating general settings for analogue TRM inputs 4I 1I 5U

The transformer module (TRM) has the capability of 4 current inputs (tapped to 1 or 5 A), one current input (tapped 0.1 or 0.5 A) and 5 voltage inputs.

The line phase current CTs (three phase current transformer group) are connected to inputs 1 – 3 (A,B,C).

The residual current CT of a parallel line can be connected to input 4 (IN, COMP).

The residual current CT of the protected line can be connected to input 5 (IN). This input has lower rated current enabling sensitive ground fault detection.

The line voltage transformer VTs are connected to inputs 6 – 8 (A,B,C).

The busbar voltage transformers (busbar 1 and 2) can be connected to inputs 9 – 10 (one phase input phase-to-ground or phase-to-phase)

Set the current transformers inputs as follows:

1. Set the primary and secondary values for current transformer input 1.
    1.1. Set *CT_WyePoint1* to *ToObject*
    (The CT secondary is grounded towards the protected line)
    1.2. Set *CTSec1* to *1 A*
    (The rated secondary current of the CT)
    1.3. Set *CTPrim1* to *1000 A*
    (The rated primary current of the CT)
2. Set the same values for the current inputs 2 and 3.

Current input 4 can be used for residual on a parallel line. The aim of this current is for compensation of the fault locator function influence from the parallel line. In this application the input is not used.

Current input 5 can be used for connection of a current transformer dedicated for residual current protection. A special current transformer with a ratio adapted to achieve high sensitivity of the protection. In this application the input is not used.

3. Set the primary and secondary values for voltage transformer inputs 6.
   3.1. Set *VTSec6* to *110 V*
   (The rated secondary voltage of the VT, given as phase-phase voltage)
   3.2. Set *VTPrim6* to *143 kV*
   (The rated secondary voltage of the VT, given as phase-phase voltage)
4. Set the same values for inputs 7 and 8.

Voltage inputs 9 and 10 can be used for busbar voltage measurement to enable the synchronism check function. In this application the inputs are not used.

3.1.2 Calculating settings for Global base values for setting function GBASVAL

Each function uses primary base values for reference of settings. The base vaules are defined in Global base values for settings function. It is possible to include up to six Global base values for settings functions. Only one Global base values for settings functions is needed in the Two-ended over-head transmission line in a solidly grounded network application.

For line protection, set the parameters for the Global base values for settings functions according to instrument transformer primary rated values (recommended):

1. Set *IBase* to *1 000 A*
2. Set *VBase* to *143 kV*
3. Set *SBase* to *247.7 MVA* ($SBase = \sqrt{3} \cdot VBase \cdot IBase$)

The *GlobalBaseSel* setting in a protection and control function references a Global base values for setting function for reference of primary values.

3.1.3 Calculating settings for five zone distance protection, quadrilateral characteristic ZQDPDIS (21)

The purpose of distance protection is:

- Main protection for short circuits on the line
- Main protection for phase-to-ground faults on the line
- Main protection for short circuits on the adjacent 138 kV busbar (no busbar protection)
- Main protection for phase-to-ground faults on the adjacent 138 kV busbar (no busbar protection)
- Remote back-up protection for short circuits on the 138 kV lines out from the adjacent busbar

- Remote back-up protection for phase-to-ground faults on the 138 kV lines out from the adjacent busbar
- Remote back-up protection for short circuits in the transformer connected to the adjacent 138 kV busbar
- Remote back-up protection for phase-to-ground faults in the transformer connected to the adjacent 138 kV busbar

The function of the zones for the distance protection A can be seen in figure 11.

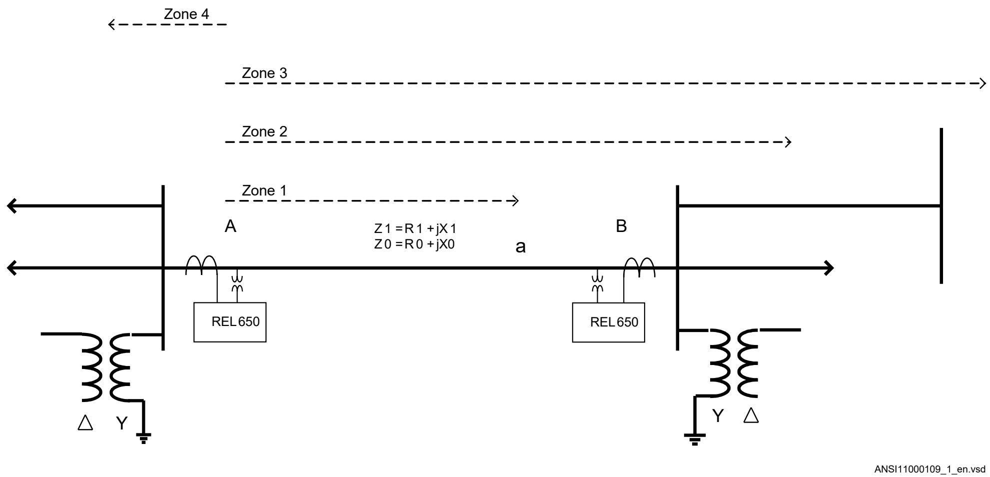


Figure 11: Reach of the distance protection zones

Zone 1, with instantaneous operation, detects most short circuits and phase-to-ground faults on the protected line. At the same time the selectivity must be assured. Therefore the most remote part of the line is not covered by zone 1.

Zone 2, with a short delay, detects short circuits and phase-to-ground faults on part of the protected line not covered by zone 1. The delay shall be sufficient to assure selectivity. This means that faults cleared by instantaneous protection function at other objects connected to the remote 138 kV busbar shall not cause unwanted trip at A.

Zone 3, together with zone 2, serves as remote back-up protection for short circuits and phase-to-ground faults on the lines out from the remote 138 kV busbar. Zone 3 shall, if possible, cover the whole length of these lines. The delay of zone 3 shall be sufficient to assure selectivity. This means that faults cleared by delayed zone 2 protection function at other objects connected to the remote 138 kV busbar shall not cause unwanted trip at A.

Zone 4 serves as back-up for short circuits and phase-to-ground faults on the 138 kV busbar in substation A. Zone 4 has a delay to assure selectivity. The directional start signal for the zone can also be used for additional functions related to distance protection: weak end infeed logic and fault current reversal logic.

The calculations and choice of the settings are shown in the following instructions, General settings, Zone 1– 4 settings. Zone 5 is not used.

3.1.3.1 Calculating general settings

1. Set *GlobalBaseSel* to *1*
2. Set *LineAng* to *81.9º*
   The positive sequence impedance line angle for the protected line is calculated as

$$LineAng = \arctan\left(\frac{X_{line}}{R_{line}}\right) = \arctan\left(\frac{17.5}{2.5}\right) = 81.9°$$

(Equation 1)

3. Set KN-factors
   3.1. Set *KNMag1* to *0.62*
        for Zone 1
   3.2. Set *KNAng1* to *-0.6º*
        for Zone 1
   3.3. Set *KNMag2* to *0.62*
        For Zones 2, 3, 4, 5
   3.4. Set *KNAng2* to *-0.6º*
        for Zones 2,3,4 and 5

the KN-factor is calculated for correct reach for phase-to-ground faults . The definition of the KN-factor is:

$$KN = \frac{Z_{0,line} - Z_{1,line}}{3 \cdot Z_{1,line}}$$

(Equation 2)

For phase-to-ground fault loops the apparent impedance is defined as:

$$Z_{ph-ea} = \frac{V_{ph,Ln}}{I_{ph,Ln} + KN \cdot 3 \cdot I_0}$$

(Equation 3)

The magnitude and phase angle are set separately as KN is a complex value. The KN-factor can be set separately for zone 1 and for the other zones. This is mainly for application for double circuit lines where zone 1 should be set to assure underreach and the other zones should be set to assure overreach. For a single circuit line it is recommended to set the KN-factors to the same values.

$$KN = \frac{Z_{0,line} - Z_{1,line}}{3 \cdot Z_{1,line}} = \frac{7.5 + j50.0 - (2.5 + j17.5)}{3 \cdot (2.5 + j17.5)} = \frac{5 + j32.5}{7.5 + j52.5} = \frac{32.9\angle 81.2°}{53.0\angle 81.8°} = 0.62\angle -0.6°$$

(Equation 4)

3.1.3.2 Calculating settings for zone 1

1. Set *DirModeSel1* to *Forward*
2. Set *Z1* to *15.000 Ω*
   The reach of zone 1 is normally set to 85 % of the line impedance. See figure 12.

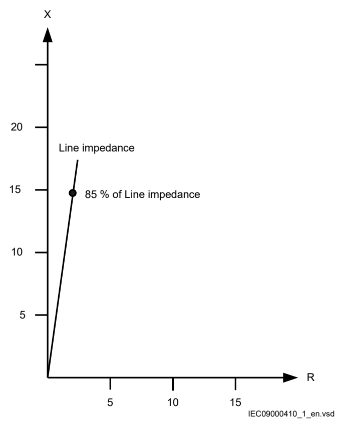


Figure 12: Line impedance diagram

The setting *Z1* is calculated as:

$$Z1 = 0.85 \cdot \left| Z_{Line,posseq} \right| = 0.85 \cdot \left| 2.5 + j17.5 \right| = 15.0\ \Omega$$

(Equation 5)

3. Set *RFPP1* to *15 Ω*
The fault resistance setting for phase-to-phase faults is normally the resistance arc between the faulty phases. The fault resistance can approximately be calculated by using the van Warrington expression:

$$R_{arc} \approx \frac{28700}{I^{1.4}} \cdot L$$

(Equation 6)

where:

- *I* is the arc current in A
- *L* is the length of the arc in m

The length of the arc is equal to the distance between the phases. For this line the distance between the phases is 5 m.
The fault current for a phase-to-phase fault at the open line end and minimum short circuit capacity is:

$$I = \frac{V_{ph-ph} / \sqrt{3}}{Z_{1,Line} + Z_{1,Source}} = \frac{138 / \sqrt{3}}{2.5 + j17.5 + j10} = 2.9\angle -84.8^{\circ}\ kA$$

(Equation 7)

This gives the following arc resistance:

$$R_{arc} \approx \frac{28700}{2900^{1.4}} \cdot 5 = 2.0\,\Omega$$

(Equation 8)

This is the minimum value for the fault resistance reach *RFPP1* setting. It can be valuable to have much higher *RFPP1* setting. *RFPP1* = *Z1* setting is proposed.

4. Set *RFPE1* to *30.00 Ω*

For phase-to-ground faults the fault current flows to ground via ground wires and the tower foots. The resistance is thus depending on the ground resistivity (tower footing resistance) and the resistance of grounded shield wires, if existing.
The fault resistance can be written:
$R \approx R_{arc} + R_{towerfoot}$
The fault current for a single phase-to-ground fault at the open line end and minimum short circuit capacity is:

$$3I_0 = \frac{3 \cdot V_{ph-ph} / \sqrt{3}}{2 \cdot \left(Z_{1,Line} + Z_{1,Source}\right) + Z_{0,Line} + Z_{0,Source}} = \frac{3 \cdot 138 / \sqrt{3}}{2 \cdot \left(2.5 + j17.5 + j10\right) + \left(12.5 + j37.5 + j8\right)} =$$
$$= 2.3 \angle -80.1° \; kA$$

(Equation 9)

This gives the following arc resistance (arc length: 2m):

$$R_{arc} \approx \frac{28700}{2300^{1.4}} \cdot 2 = 1.1 \, \Omega$$

(Equation 10)

Each individual tower foot has a resistance to ground up to 100 Ω, as the soil has very high resistivity. The towers are however connected to each other via the shield wire at the top of the towers, grounded to every tower. The effective tower footing resistance is thus maximum 10 Ω.
$R \approx R_{arc} + R_{towerfoot} = 1{,}1 + 10\ \Omega$
This is the minimum value for the fault resistance reach *RFPE1* setting. It can be valuable to have much higher *RFPE1* setting. it is proposed to set *RFPE1* to 2 · *Z1* (should never be larger than 4.5 · X1, where X1 is the reactive part of Z1):
In case of load transfer at the line there is a risk of phase shift of the fault resistance that moves the apparent impedance into the zone 1 characteristic even if the fault is external.

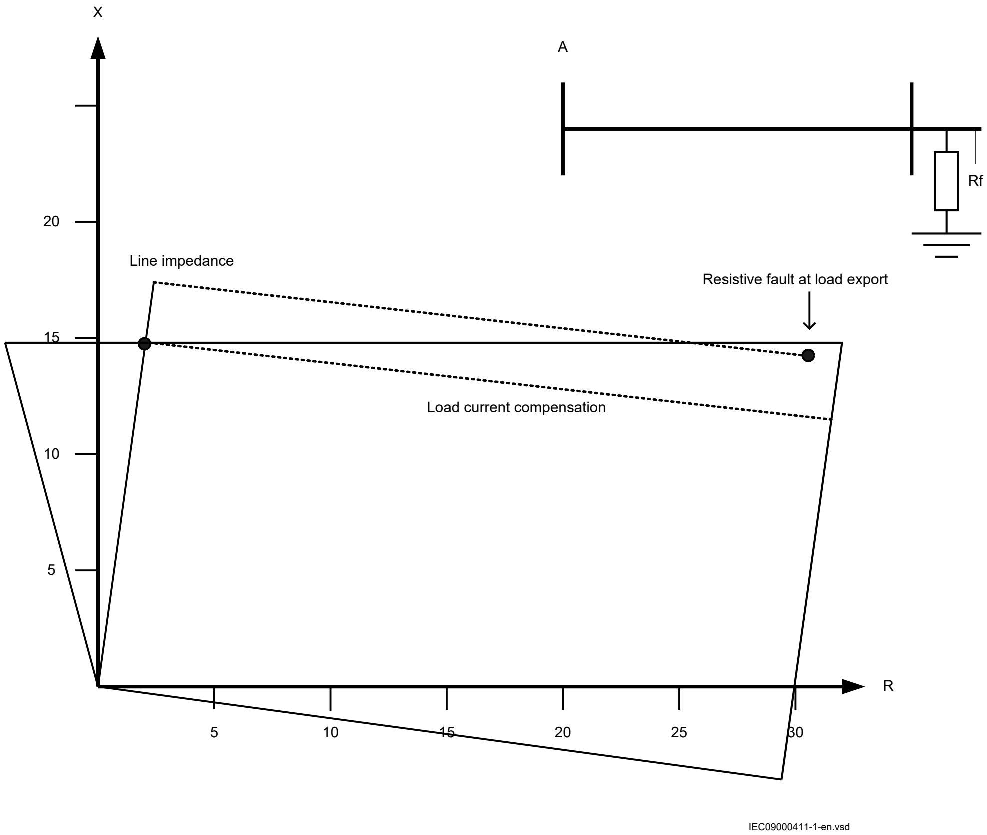


Figure 13: Load current compensation for zone 1

The built in load current compensation of the zone 1 characteristic prevents unwanted trip. see figure "".

5. Set *OpMode1* to *Enable Ph-E PhPh* (Zone 1 is activated)
6. Set *OpModetPP1* to *Enabled* (Zone 1 phase-phase loops gives trip)
7. Set time delays to trip
(Zone 1 phase-ground loops gives trip)
   7.1. Set *tPP1* to *0.000 s*
   Zone 1 phase-phase loops gives instantaneous trip
   7.2. Set *tPE1* to *0.000 s*
   Zone 1 phase-ground loops gives instantaneous trip

3.1.3.3 Calculating settings for zone 2

1. Set *DirModeSel2* to *Forward*
2. Set *Z2* to *44.200 Ω*
The reach of zone 2 is minimum set to 120 % of the line impedance to guarantee that the adjacent 138 kV busbar is covered by the zone.
Zone 2 must be set so that there is no risk for unselective trip on faults out on adjacent lines. Zone 2 must not overreach zone 1 of the line B – C as shown in figure 14.

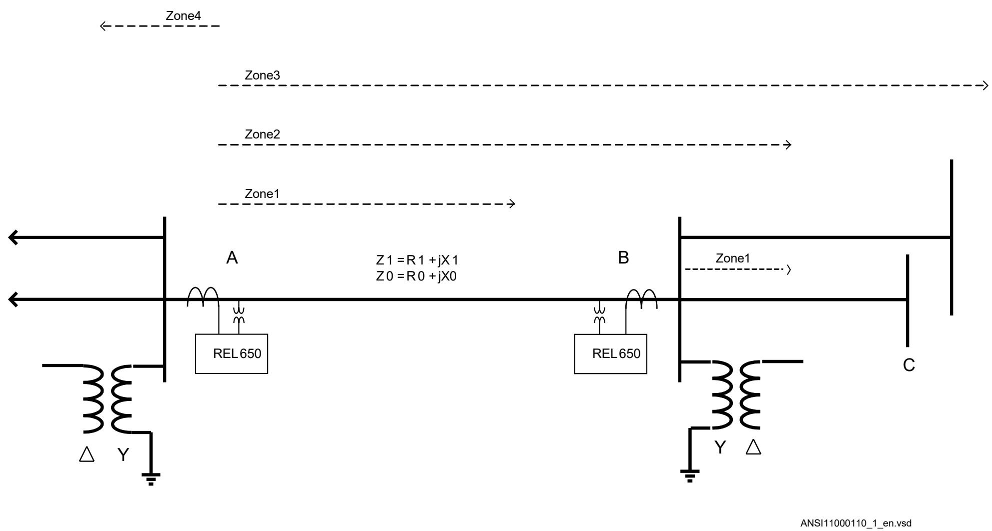


Figure 14: Distance protection zones reach for zone 2

The reactive reach of zone 1 B-C is 10 Ω
The minimum set reach is $Z2 \geq 1.2 \cdot 17.7 = 21.2\ \Omega$
The maximum set reach can approximately be calculated as (B: high source impedance, A: low source impedance):

$$
\begin{aligned}
Z2 &\leq Z1_{A-B} + 0.85 \cdot Z_{set}(B-C) \cdot \frac{I_{B-C}}{I_{A-B}} = \\
&= Z1_{A-B} + 0.85 \cdot Z1_{set}(B-C) \cdot \frac{Z_{source,B} + Z_{source,A} + Z1_{A-B}}{Z_{source,B}} = \\
&= 17.5 + 0.85 \cdot 10 \cdot \frac{8 + 3.2 + 17.5}{8} = 48.0\ \Omega
\end{aligned}
$$

(Equation 11)

This corresponds to about 2.7 times the line reactance.
An alternative way is to set *Z2* according to:
$Z2 \geq Z1_{A-B} + 0.85 \cdot Z_{set}(B-C) = 17.5 + 0.85 \cdot 10 = 26.0\ \Omega$
If remote back–up protection is used in the network it is desirable to maximize reach of zone 2.
If local back-up protection is used it is better to minimize the zone 2 reach.
The settings can be chosen:

$$
Z2 = 2.5 \cdot \left| Z_{Line,posseq} \right| = 2.5 \cdot \left| 2.5 + j17.5 \right| = 44.2\ \Omega
$$

(Equation 12)

3. Set *RFPP2* to *44.00 Ω*
   It is assumed that the fault resistance is equal to the fault resistances calculated for zone 1. At a fault on an adjacent line also the fault resistance is influenced by the fault current infeed from the other lines connected to B. The apparent value of the fault resistance at A can approximately be calculated as:

$$RFPP = R_f \cdot \frac{I_{B-C}}{I_{A-B}} = R_f \cdot \frac{X_{source,B} + X_{source,A} + X1_{A-B}}{X_{source,B}} =$$
$$= 2 \cdot \frac{3.2 + 8 + 17.5}{3.2} = 17.9\ \Omega$$

(Equation 13)

This is the minimum value for the fault resistance reach *RFPP2* setting. It can be valuable to have much higher *RFPP* setting. *RFPP2* ≈ *Z2* setting is proposed:

4. Set *RFPE2* to *100 Ω*

$$RFPE = R_f \cdot \frac{I_{B-C}}{I_{A-B}} = R_f \cdot \frac{X_{source,B} + X_{source,A} + X1_{A-B}}{X_{source,B}} =$$
$$= 11.1 \cdot \frac{3.2 + 8 + 17.5}{3.2} = 99.6\ \Omega$$

(Equation 14)

This is the minimum value for the fault resistance reach *RFPE2* setting. It can be valuable to have much higher *RFPE2* setting. *RFPE2* ≈ 2.3 · Z2 setting is proposed (should never be larger than 4.5 · X2 where X2 is the reactive part of Z2):

5. Set *OpMode2* to *Enable Ph-E PhPh*
   Zone 2 is activated
6. Set *OpModetPP2* to *Enabled*
   Zone 2 phase-phase loops gives trip
7. Set time delays to trip
   Zone 2 phase-ground loops gives trip
   7.1. Set *tPP2* to *0.400 s*
   Zone 2 phase-phase loops gives trip after a short delay
   7.2. Set *tPE2* to *0.400 s*
   Zone 2 phase-ground loops gives trip after a short delay

Choose the time delay for zone 2 with margin to assure selectivity to zone 1 of adjacent lines. A delay time difference of 0.4 s between the zones is sufficient. The time delay for zone 2 is therefore chosen to 0 s (delay zone 1) + 0.4 s.

3.1.3.4 Calculating settings for zone 3

Zone 3 should preferably be set so that the required back-up zones are covered. See figure "".

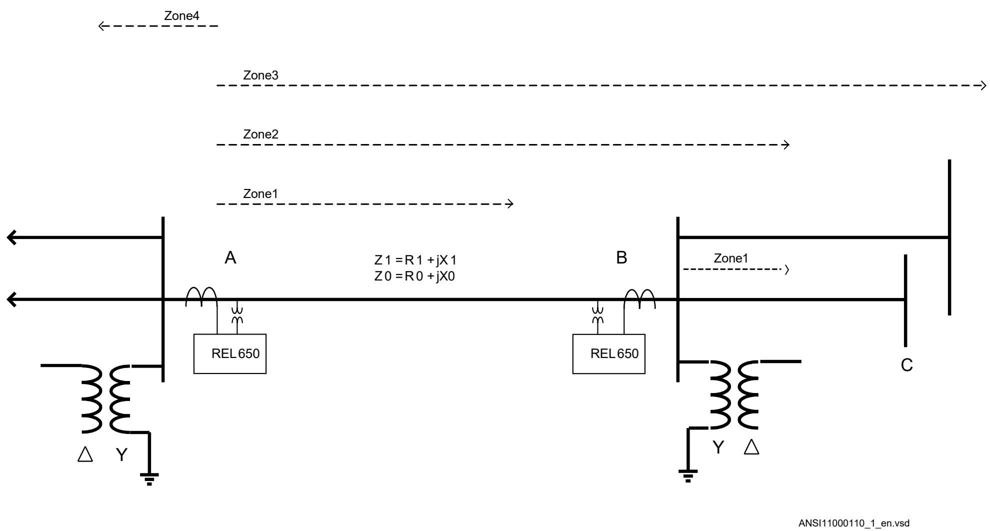


Figure 15: Impedance zones reach for zone 3

The reach of zone 3 might come into conflict with the apparent impedance due to the maximum load current out on the line. This current mainly influences the resistive reach. In order to prevent unwanted operation due to the load current the load encroachment function with load encroachment, quadrilateral characteristic function (FMPSPDIS) (setting below is used).

The reactance of the longest line adjacent out from substation B is 20 Ω. The reactance of the transformer in substation B is 30 Ω (60 MVA transformer, 10 % short circuit voltage).

The minimum reactive reach is can approximately be calculated as:

$$X3 \geq X_{\max} \frac{I_{Fault}}{I_{A-B}} = 30 \cdot \frac{X_{source,B} + X_{source,A} + X1_{A-B}}{X_{source,B}} = 30 \cdot \frac{3.2 + 8 + 17.5}{3.2} \approx 269\ \Omega$$

(Equation 15)

This corresponds to 21 times the line reactance.

$$R \leq 0.8 \cdot \frac{V_{\min}^2}{P_{ext,\max}} = \frac{(0.9 \cdot 138)^2}{180} = 85.7\ \Omega$$

(Equation 16)

1. Set *DirModeSel3* to *Forward*
2. Set *Z3* to *368 Ω*
   Z3 = 21 · $Z_{Line,posseq}$ = 21 · 17.5 = 368 Ω
3. Set *RFPP3* to *150 Ω*
   RFPP3 ≈ 0.5 · *Z3* setting is proposed
4. Set *RFPE3* to *150 Ω*
   RFPE3 ≈ 0.5 · *Z3* setting is proposed
5. Set *OpMode3* to *Enable Ph-E PhPh*
   Zone 3 is activated
6. Set *OpModetPP3* to *Enabled*
   Zone 3 phase-phase loops gives trip
7. Set time delays to trip

7.1. Set *tPP3* to *0.800 s*
Zone 3 phase-phase loops gives trip after a short delay
7.2. Set *tPE3* to *0.800 s*
Zone 3 phase-ground loops gives trip after a short delay

The time delay for zone 3 is chosen with margin to assure selectivity to zone 2 of adjacent lines. A delay time difference of 0.4 s between the zones is sufficient. The time delay for zone 3 is therefore chosen to 0.4 s (delay zone 2) + 0.4 s = 0.8 s.

3.1.3.5 Calculating settings for zone 4

The reach of zone 4 can be set to 85 % of the distance protection zone 1 reach of the shortest line from A. This reactance reach is 5 Ω. This corresponds to 28 % of the reactance of the protected line (A-B).

1. Set *DirModeSel4* to *Reverse*
2. Set *Z1* to *4.2 Ω*
   $Z1 = 0.85 \cdot Z_{Line, posseq} = 0.85 \cdot 0.28 \cdot 17.5 = 4.2\ \Omega$
3. Set *RFPP4* to *4 Ω*
   Setting *RFPP4* ≈ *Z4* is proposed
4. Set *RFPE4* to *8 Ω*
   RFPE4 ≈ *2 · Z4* setting is proposed (should never be larger than 4.5 · X4 where X4 is the reactive part of Z4)
5. Set *OpMode4* to *Enable Ph-E PhPh* (Zone 4 is activated)
6. Set *OpModetPP4* to *Enabled*
   Zone 4 phase-phase loops gives trip.
7. Set time delays to trip
   7.1. Set *tPP4* to *0.400 s*
   Zone 4 phase-phase loops give trip after a short delay.
   7.2. Set *tPE4* to *0.400 s*
   Zone 3 phase-ground loops give trip after a short delay.

   The time delay for zone 4 need margin to assure selectivity to zone 1 of lines out from substation A. A delay time difference of 0.4 s between the zones is sufficient.

3.1.4 Calculating settings for phase selection with load encroachment FDPSPDIS (21)

Correct phase selection for faults within zone 1 and 2 is required.

1. Set *GlobalBaseSel* to *1*
2. Set the minimum apparent resistance during non-faulted conditions:
   2.1. Set *RLdFwd* to *70 Ω*
   2.2. Set *RldRev* to *70 Ω*

   The minimum apparent resistance during non-faulted conditions is calculated as:

$$RLdFwd, Rld\,\mathrm{Rev} \le 0.8 \cdot \frac{V_{\min}^2}{P_{ext,\max}} = \frac{(0.9 \cdot 138)^2}{180} = 85.7\ \Omega$$

(Equation 17)

3. Set *LdAngle* to *30º*
   It is normally considered that the apparent impedance during non-faulted condition has a phase angle in the range ± 30º.
4. Set the zero and positive sequence reactance reach
   4.1. Set *X1* to *50 Ω*
   *X*1 ≥ 1.1 · *X*1 (*Zone*2) = 1.1 · 44.2 = 48.5 *Ω*
   4.2. Set *X0* to *140 Ω*
   X0 ≥ 1.1 · *X0* (Zone2) = 138.9 Ω
5. Set the fault resistance reach (phase-phase)
   5.1. Set *RFltFwdPP* to *70* Ω
   5.2. Set *RFltRevPP* to *70* Ω

   The setting *RFltFwdPP*, *RFltRevPP*, *RFltFwdPG* and *RFltRevPG* shall cover zone 2 both for phase-to-phase short circuits and three-phase short circuits.
   RFltFwdPP ≥ 1.1 · *RFPP* (Zone2) = 1.1 · 44 = 48.4 *Ω*
   It shall also be clarified that zone 2 is covered also for three-phase short circuits where the phase selection has a phase shift of 30º and an amplitude increase of $2/\sqrt{3}$. The characteristic are shown in figure 16:

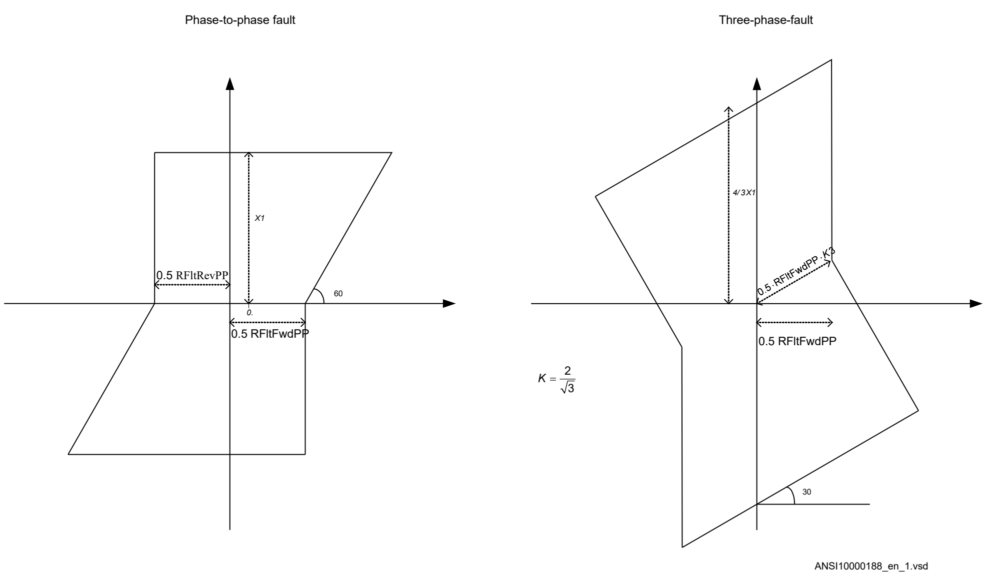


Figure 16: Phase selection impedance characteristic for two phase and three phase short circuits

   The figure shows that 0.5 · *RFltFwdPP* is larger than zone 2 maximum reach.
   This gives:

$$0.5 \cdot RFltFwdPP \ge 48 \cdot \cos(81.9^{\circ}) + \frac{44}{2} = 28.8 \Rightarrow RFltFwdPP \ge 57.6\Omega$$

(Equation 18)

6. Set the fault resistance reach (phase-ground)

6.1. Set *RFltFwdPG* to *110* Ω
6.2. Set *RFltRevPG* to *110* Ω

$$RFltFwdPG \geq 1.1 \cdot RFPE\,(Zone\,2) = 1.1 \cdot 100 = 110\ \Omega$$

3.1.5 Distance protection setting ZMOPDIS (21)

The purpose of distance protection is:

- Main protection for short circuits on the line
- Main protection for phase-to-ground faults on the line
- Main protection for short circuits on the adjacent 138 kV busbar (no busbar protection)
- Main protection for phase-to-ground faults on the adjacent 138 kV busbar (no busbar protection)
- Remote back-up protection for short circuits on the 138 kV lines out from the adjacent busbar
- Remote back-up protection for phase-to-ground faults on the 138 kV lines out from the adjacent busbar
- Remote back-up protection for short circuits in the transformer connected to the adjacent 138 kV busbar
- Remote back-up protection for phase-to-ground faults in the transformer connected to the adjacent 138 kV busbar

The function of the zones for the distance protection A can be seen in figure 11.

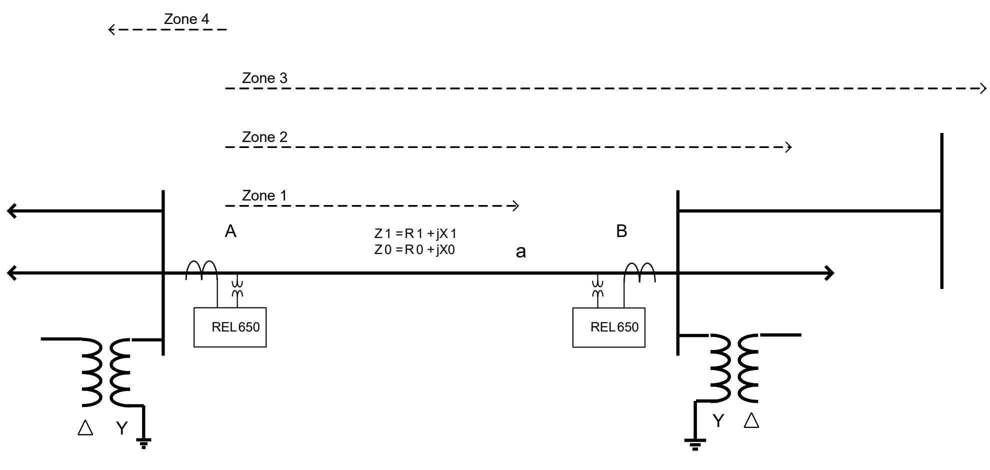


Figure 17: Reach of the distance protection zones

Zone 1, with instantaneous operation, detects most short circuits and phase-to-ground faults on the protected line. At the same time the selectivity must be assured. Therefore the most remote part of the line is not covered by zone 1.

Zone 2, with a short delay, detects short circuits and phase-to-ground faults on part of the protected line not covered by zone 1. The delay shall be sufficient to assure selectivity. This means that faults cleared by instantaneous protection function at other objects connected to the remote 138 kV busbar shall not cause unwanted trip at A.

Zone 3, together with zone 2, serves as remote back-up protection for short circuits and phase-to-ground faults on the lines out from the remote 138 kV busbar. Zone 3 shall, if possible, cover the whole length of these lines. The delay of zone 3 shall be sufficient to assure selectivity. This means that faults cleared by delayed zone 2 protection function at other objects connected to the remote 138 kV busbar shall not cause unwanted trip at A.

Zone 4 serves as back-up for short circuits and phase-to-ground faults on the 138 kV busbar in substation A. Zone 4 has a delay to assure selectivity. The directional start signal for the zone can also be used for additional functions related to distance protection: weak end infeed logic and fault current reversal logic.

The calculations and choice of the settings are shown in the following instructions, General settings, Zone 1– 4 settings. Zone 5 is not used.

3.1.5.1 Calculating general settings

1. Set *GlobalBaseSel* to *1*
2. Set *LineAng* to *81º*
   The positive sequence impedance line angle for the protected line is calculated as

$$LineAng = \arctan\left(\frac{X_{line}}{R_{line}}\right) = \arctan\left(\frac{17.5}{2.5}\right) = 81.9°$$

(Equation 19)

3. Set KN-factors
   - 3.1. Set *KNMag1* to *0.62*
     for Zone 1
   - 3.2. Set *KNAng1* to *-0.6º*
     for Zone 1
   - 3.3. Set *KNMag2* to *0.62*
     For Zones 2, 3, 4, 5
   - 3.4. Set *KNAng2* to *-0.6º*
     for Zones 2,3,4 and 5

   the KN-factor is calculated for correct reach for phase-to-ground faults . The definition of the KN-factor is:

$$KN = \frac{Z_{0,line} - Z_{1,line}}{3 \cdot Z_{1,line}}$$

(Equation 20)

   For phase-to-ground fault loops the apparent impedance is defined as:

$$Z_{ph-ea} = \frac{V_{ph,Ln}}{I_{ph,Ln} + KN \cdot 3 \cdot I_0}$$

(Equation 21)

   The magnitude and phase angle are set separately as KN is a complex value. The KN-factor can be set separately for zone 1 and for the other zones. This is mainly for application for double circuit lines where zone 1 should be set to assure underreach and the other zones should be set to assure overreach. For a single circuit line it is recommended to set the KN-factors to the same values.

$$KN = \frac{Z_{0,line} - Z_{1,line}}{3 \cdot Z_{1,line}} = \frac{7.5 + j50.0 - (2.5 + j17.5)}{3 \cdot (2.5 + j17.5)} = \frac{5 + j32.5}{7.5 + j52.5} = \frac{32.9\angle 81.2°}{53.0\angle 81.8°} = 0.62\angle -0.6°$$

(Equation 22)

3.1.5.2 Calculating settings for zone 1

1. Set *DirModeSel1* to *Forward*
2. Set *Z1* to *15.000 Ω*
   The reach of zone 1 is normally set to 85 % of the line impedance. See figure 12.

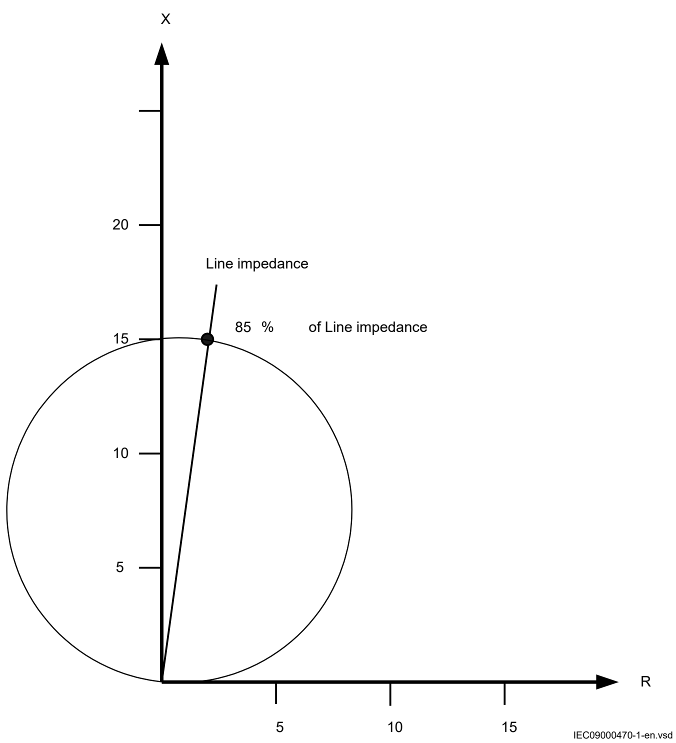


Figure 18: Zone 1 mho characteristic

The setting *Z1* is calculated as:

$$Z1 = 0.85 \cdot \left| Z_{Line,posseq} \right| = 0.85 \cdot \left| 2.5 + j17.5 \right| = 15.0\ \Omega$$

(Equation 23)

3. Set *OpMode1* to *Enable PhG PhPh*
   Zone 1 is activated
4. Set *OpModetPP1* to *Enabled*
   Zone 1 phase-phase loops gives trip
5. Set time delays to trip
   Zone 1 phase-ground loops gives trip
   5.1. Set *tPP1* to *0.000 s*
   Zone 1 phase-phase loops gives instantaneous trip
   5.2. Set *tPE1* to *0.000 s*

Zone 1 phase-ground loops gives instantaneous trip

3.1.5.3 Calculating settings for zone 2

1. Set *DirModeSel2* to *Forward*
2. Set *Z2* to *44.200 Ω*
   The reach of zone 2 is minimum set to 120 % of the line impedance to guarantee that the adjacent 138 kV busbar is covered by the zone.
   Zone 2 must be set so that there is no risk for unselective trip on faults out on adjacent lines. Zone 2 must not overreach zone 1 of the line B – C as shown in figure 14.

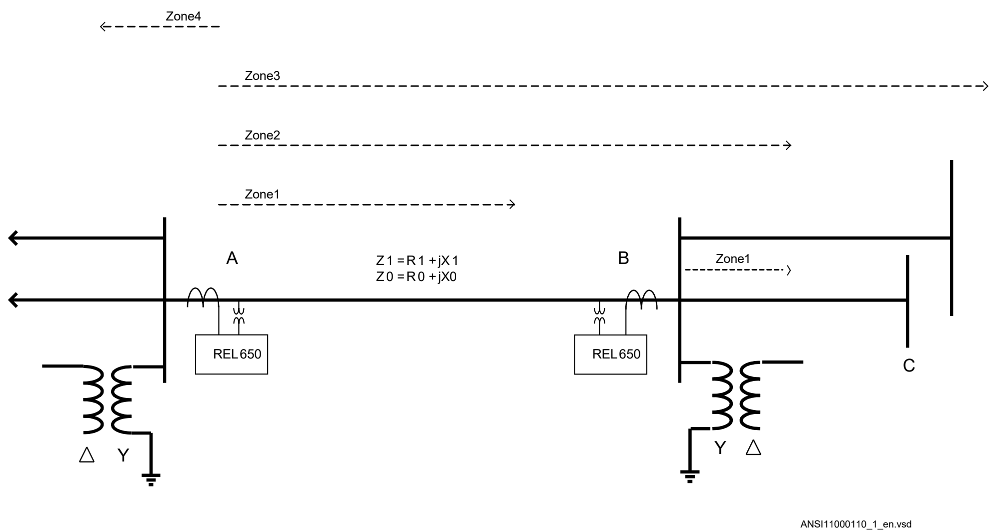


Figure 19: Distance protection zones reach for zone 2

The reactive reach of zone 1 B-C is 10 Ω
The minimum set reach is $Z2 \geq 1.2 \cdot 17.7 = 21.2\ \Omega$
The maximum set reach can approximately be calculated as (B: high source impedance, A: low source impedance):

$$Z2 \leq Z1_{A-B} + 0.85 \cdot Z_{set}(B-C) \cdot \frac{I_{B-C}}{I_{A-B}} =$$
$$= Z1_{A-B} + 0.85 \cdot Z1_{set}(B-C) \cdot \frac{Z_{source,B} + Z_{source,A} + Z1_{A-B}}{Z_{source,B}} =$$
$$= 17.5 + 0.85 \cdot 10 \cdot \frac{8 + 3.2 + 17.5}{8} = 48.0\ \Omega$$

(Equation 24)

This corresponds to about 2.7 times the line reactance.
An alternative way is to set *Z2* according to:
$Z2 \geq Z1_{A-B} + 0.85 \cdot Z_{set}(B-C) = 17.5 + 0.85 \cdot 10 = 26.0\ \Omega$
If remote back–up protection is used in the network is desirable to maximum reach of zone 2. If local back-up protection is used it is better to minimize the zone 2 reach.
The settings can be chosen:

$$Z2 = 2.5 \cdot \left| Z_{Line,posseq} \right| = 2.5 \cdot \left| 2.5 + j17.5 \right| = 44.2\ \Omega$$

(Equation 25)

3. Set *OpMode2* to *Enable Ph-E PhPh* (Zone 2 is activated)
4. Set *OpModetPP2* to *Enabled* (Zone 2 phase-phase loops gives trip)
5. Set time delays to trip (Zone 2 phase-ground loops gives trip)
   5.1. Set *tPP2* to *0.400 s* (Zone 2 phase-phase loops gives trip after a short delay)
   5.2. Set *tLG2* to *0.400 s* (Zone 2 phase-ground loops gives trip after a short delay)

   Choose the time delay for zone 2 with margin to assure selectivity to zone 1 of adjacent lines. A delay time difference of 0.4 s between the zones is sufficient. The time delay for zone 2 will therefore be chosen to 0 s (delay zone 1) + 0.4 s.

3.1.5.4 Calculating settings for zone 3

Zone 3 should preferably be set so that the required back-up zones are covered. See figure "".

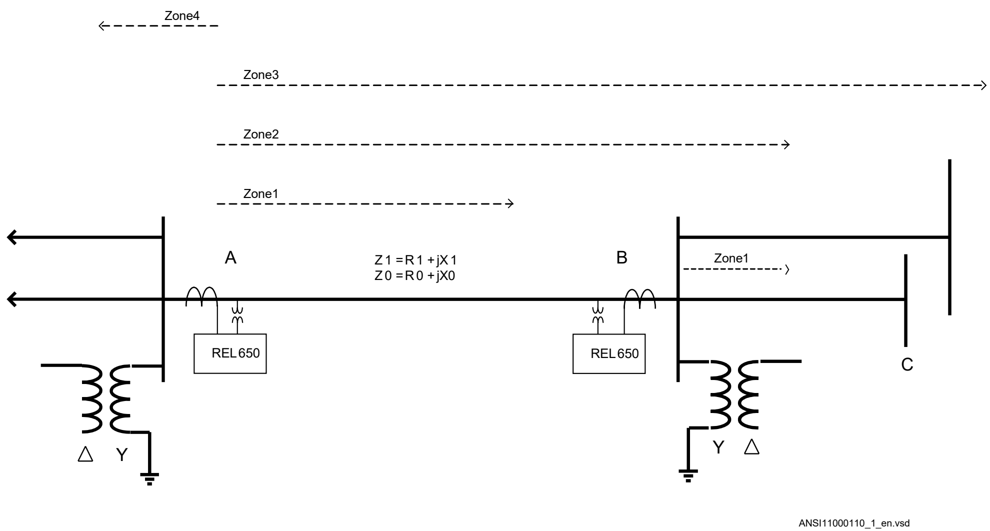


Figure 20: Impedance zones reach for zone 3

The reach of zone 3 might come into conflict with the apparent impedance due to the maximum load current out on the line. This current mainly influences the resistive reach. In order to prevent unwanted operation due to the load current the load encroachment function with load encroachment, quadrilateral characteristic function (FMPSPDIS) (setting below).

The reactance of the longest line adjacent out from substation B is 20 Ω. The reactance of the transformer in substation B is 30 Ω (60 MVA transformer, 10 % short circuit voltage).

The minimum reactive reach is can approximately be calculated as:

$$X3 \geq X_{\max} \frac{I_{Fault}}{I_{A-B}} = 30 \cdot \frac{X_{source,B} + X_{source,A} + X1_{A-B}}{X_{source,B}} = 30 \cdot \frac{3.2 + 8 + 17.5}{3.2} \approx 269\ \Omega$$

(Equation 26)

This corresponds to 21 times the line reactance.

$$R \leq 0.8 \cdot \frac{V_{\min}^{2}}{P_{ext,\max}} = \frac{(0.9 \cdot 138)^{2}}{180} = 85.7\ \Omega$$

(Equation 27)

1. Set *DirModeSel3* to *Forward*
2. Set *Z3* to *368 Ω*
   Z3 = 21 · $Z_{Line,posseq}$ = 21 · 17.5 = 368 Ω
3. Set *OpMode3* to *enable PhG PhPh* (Zone 3 is activated)
4. Set *OpModetPP3* to *Enabled* (Zone 3 phase-phase loops gives trip)
5. Set time delays to trip
   5.1. Set *tPP3* to *0.800 s* (Zone 3 phase-phase loops gives trip after a short delay)
   5.2. Set *tLG3* to *0.800 s*
   Zone 3 phase-ground loops gives trip after a short delay.

   The time delay for zone 3 is chosen with margin to assure selectivity to zone 2 of adjacent lines. A delay time difference of 0.4 s between the zones is sufficient.

3.1.5.5 Calculating settings for zone 4

The reach of zone 4 can be set to 85 % of the distance protection zone 1 reach of the shortest line from A. This reactance reach is 5 Ω. This corresponds to 28 % of the reactance of the protected line (A-B).

1. Set *DirModeSel4* to *Reverse*
2. Set *Z1* to *4.2 Ω*
   Z1 = 0.85 · $Z_{Line,\ posseq}$ = 0.85 · 0.28 · 17.5 = 4.2 Ω
3. Set *RFPP4* to *4 Ω*
   Setting *RFPP4* ≈ *Z4* is proposed
4. Set *RFPE4* to *8 Ω*
   RFPE4 ≈ *2 · Z4* setting is proposed (should never be larger than 4.5 · X4 where X4 is the reactive part of Z4)
5. Set *OpMode4* to *Enable Ph-E PhPh* (Zone 4 is activated)
6. Set *OpModetPP4* to *Enabled*
   Zone 4 phase-phase loops gives trip.
7. Set time delays to trip
   7.1. Set *tPP4* to *0.400 s*
   Zone 4 phase-phase loops give trip after a short delay.
   7.2. Set *tPE4* to *0.400 s*
   Zone 3 phase-ground loops give trip after a short delay.

   The time delay for zone 4 need margin to assure selectivity to zone 1 of lines out from substation A. A delay time difference of 0.4 s between the zones is sufficient.

3.1.6 Faulty phase identification with load encroachment for mho FMPSPDIS

The function is based of different principles to identify the fault type. The signals from the different fault identification algorithms are combined in selection logic.

The advanced parameters for faulty phase identification are chosen to the default setting values.

1. Set *IMaxLoad* to *90 %* of *IBase* 1000 A
   The maximum load current for identification of three phase fault is calculated as:

$$IMaxLoad \geq \frac{1.2 \cdot 180}{\sqrt{3} \cdot 138} = 0.90\ kA$$

(Equation 28)

2. Set *RLd* to *70 Ω*
   The minimum apparent resistance during non-faulted conditions is calculated as:

$$RLd \leq 0.8 \cdot \frac{V_{min}^2}{P_{ext,max}} = \frac{(0.9 \cdot 138)^2}{180} = 85.7\ \Omega$$

(Equation 29)

3. Set *LdAngle* to *30º*
   It is normally considered that the apparent impedance during non-faulted condition has a phase angle in the range ± 30º.

3.1.7 Calculating settings for scheme communication logic for distance or overcurrent protection ZCPSCH (85)

The communication logic is used to assure fast fault clearance for all faults along the line, that is also for faults outside the zone 1 reach of the distance protection. The logic for the communication schemes requires a communication link between the distance protection on the two line ends. The communication link alternatives are:

- Power line carrier (PLC)
- Microwave link (radio)
- Optic fibre link

The following alternatives for communication scheme are possible:

- Under-reach permissive logic
- Over-reach permissive logic
- Blocking scheme

1. Set *Scheme Type* to *Permissive OR*
   This corresponds to over-reach permissive scheme. The choice is based on the following:

Permissive over-reach scheme is chosen because it is considered as the weak end infeed logic shall be used as there is a risk of small current infeed. The WEI function requires permissive over-reach communication scheme.

2. Set *tCoord* to *0.000 s*
3. Set *tSendMin* to *0.100 s*

3.1.7.1 Principles for over-reach permissive communication logic

The principle of the logic can be explained as shown in figure 21.

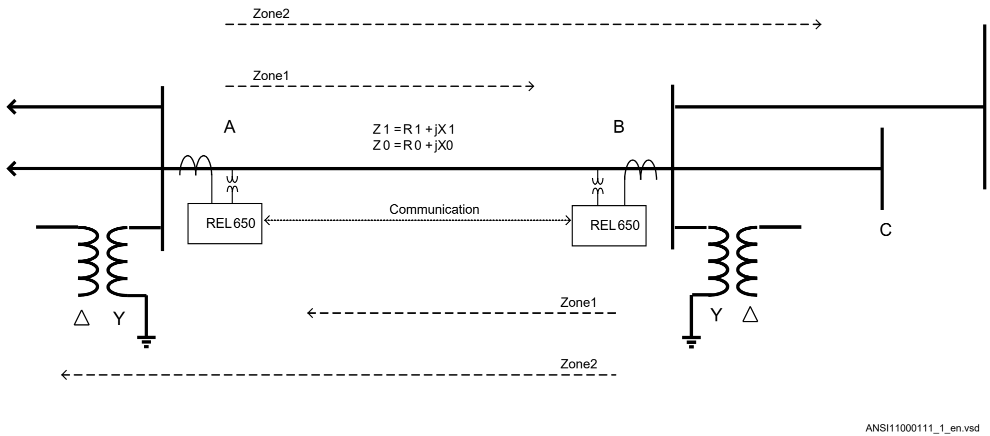


Figure 21: Principle of over-reach communication scheme

A communication signal is sent (CS) if a fault is detected by zone 2 (overreach zone). When a communication signal is received (CR) zone 2 operates instantaneously. The logic is shown in figure 22.

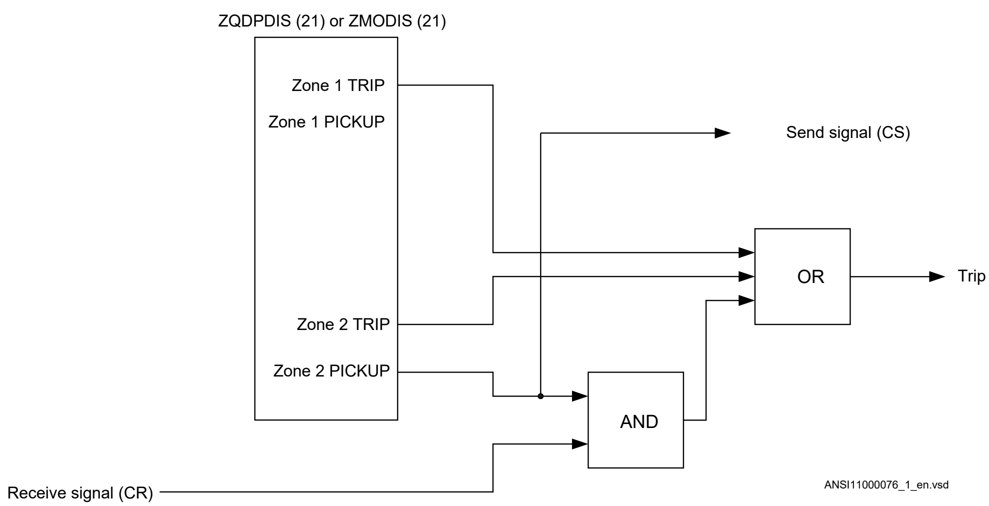


Figure 22: Logic of over-reach communication scheme

This scheme is used for short lines where it can not be assured that the zone 1 reach from both line ends overlap each other. The scheme should also be used for lines where the fault current infeed from one of the line ends is small and the weak end infeed logic is used.

3.1.7.2 Principles for under-reach permissive communication logic

The principle of the logic can be explained as shown in figure 23.

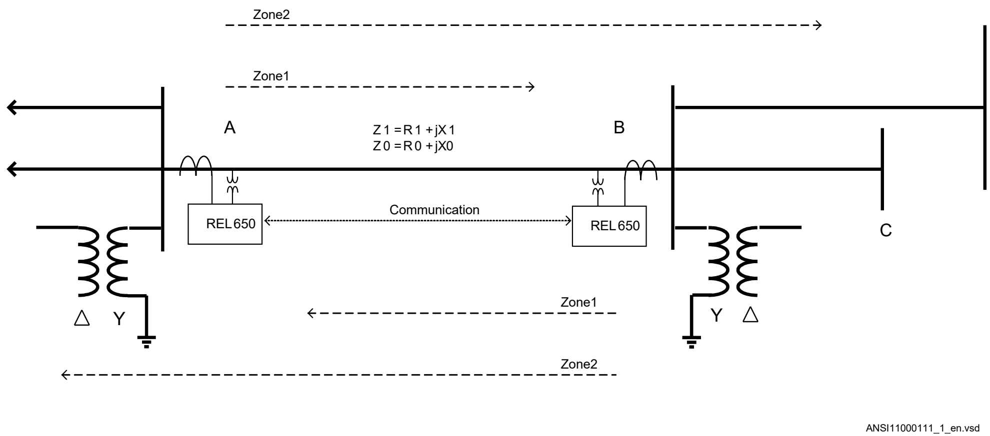


Figure 23: Principle of under-reach communication scheme

A communication signal is sent (CS) if a fault is detected by zone 1 (underreach zone). When a communication signal is received (CR) zone 2 operates instantaneously. The logic is shown in figure 24.

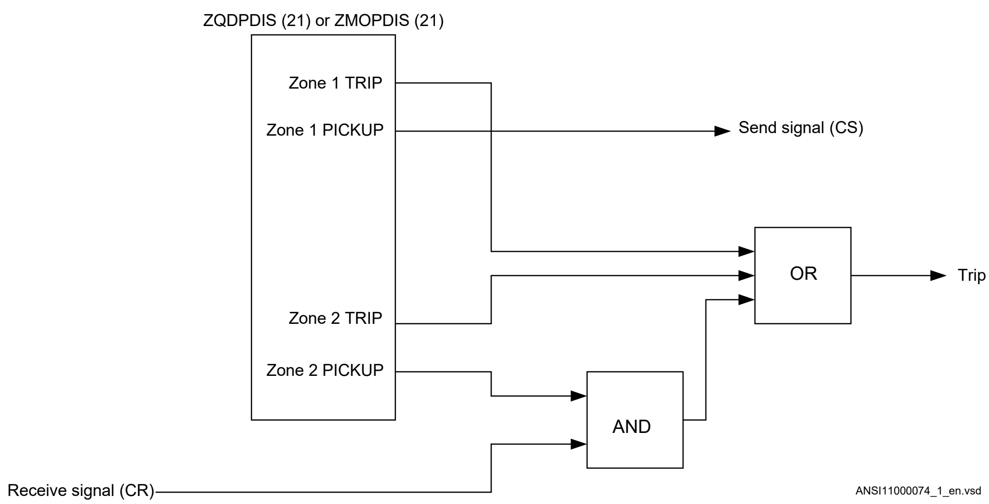


Figure 24: Logic of under-reach communication scheme

This scheme is used for long lines where it can be assured that the zone 1 reach from both line ends overlap each other.

3.1.7.3 Principle for blocking scheme

The principle of the logic can be explained as shown in figure 25.

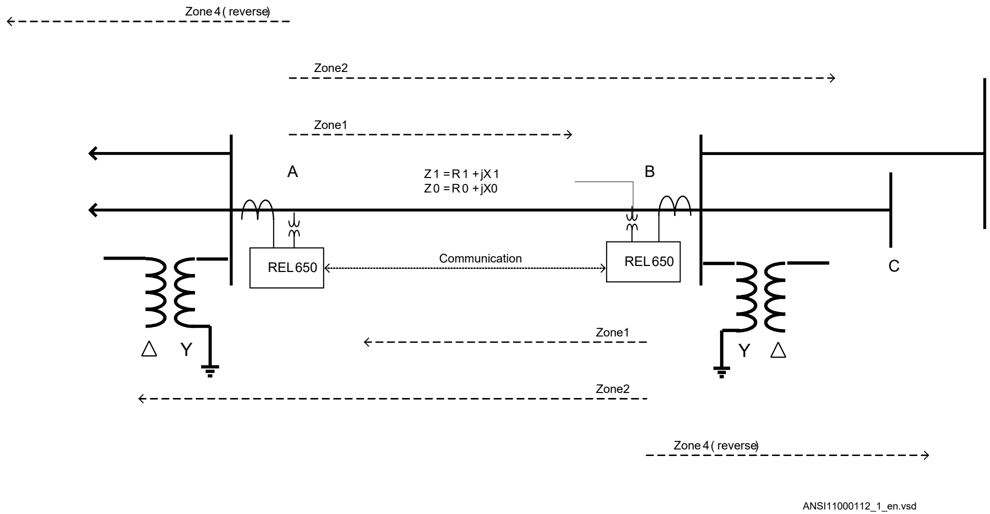


Figure 25: Principle of blocking communication scheme

A communication signal is sent (CS) if a fault is detected by zone 4 (reverse zone). When a communication signal is received (CR) the fast zone 2 is blocked. The logic is shown in figure 26.

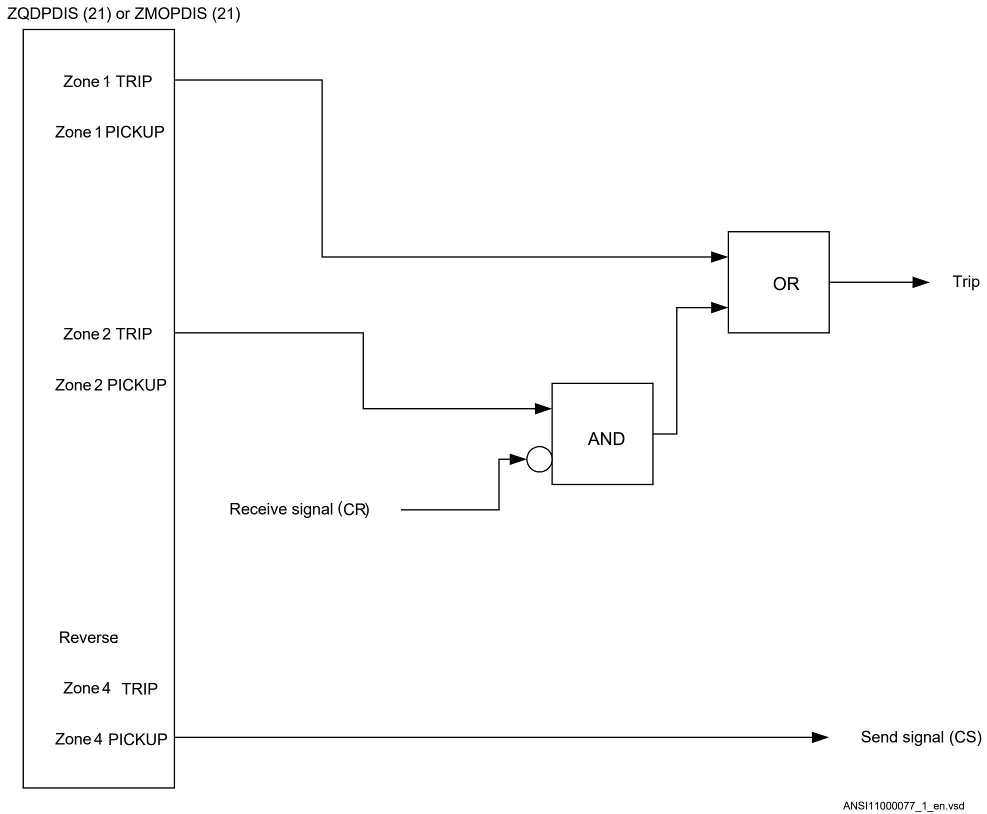


Figure 26: Logic of blocking communication scheme

The trip signal from zone 2 must be delayed so that the blocking signal has enough time for blocking at external faults.

3.1.8 Calculating setting for current reversal and weak end infeed logic for distance protection ZCRWPSCH (85)

The distance protection can only operate if the fault current fed to the protection is larger than 10 – 30 % of the rated current (settable). There is a risk that the fault current infeed from one of the line ends is very small, but not zero. In such case the following can be the consequence of a short circuit close to the line end with small fault current infeed.

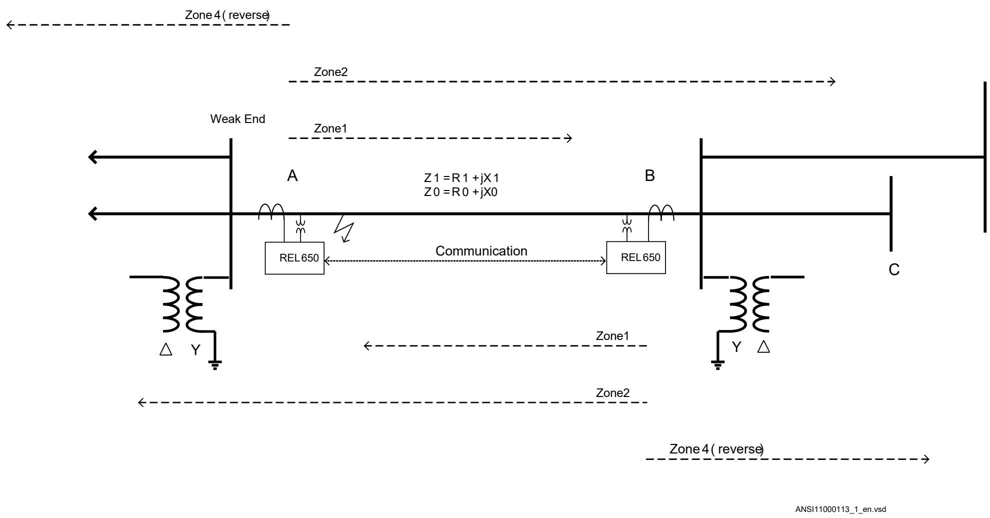


Figure 27: Line fault for fast fault clearance by means of WEI logic

For the fault shown in the figure 27 there is a risk that we get the following consequences if the WEI logic is not used:

- Zone 1 in the line end A (weak end) will not start due to the small fault current infeed. This means that the line breaker will not open.
- The fault detection in line end B will be done by means of zone 2 distance protection function. As there will be no acceleration signal (CR) from line end A, the communication scheme cannot be activated. The fault clearance will thus be delayed (zone 2 time delay).

To overcome this shortcoming of the protection scheme the weak end infeed logic (WEI) is activated.

The function at internal line fault can be described as:

- For an internal fault zone 2 in line end B will pick up and send a signal to line end A (CS).
- If zone 4 (reverse) or none of the forward zones in line end A does not pick up the received signal from line end B (CR) will be sent back (echo).
- If the voltage in line end A is low and the distance protection zones do not pick up the circuit breaker is tripped (if this feature is set).
- In line end B the echo signal is received (CR) and the communication scheme will give an undelayed trip to the circuit breaker.

The function at external fault can be described as:

- For an external fault zone 2 in line end B will pick up and send a signal to line end A (CS).
- Zone 4 (reverse) in line end A will pick up and prevent the received signal to be sent back to line end B.
- None of the line ends will be tripped.

1. Set *WEI* to *Echo & Trip*
   Echoes the CR signal as well as, trip locally.
2. Set *tPickUpWEI* to *0.01 s*

The shortest duration of the CR signal.

3. Set *PU27PP* to 70%
   Should be set lower than the lowest possible phase-to-phase voltage at non-faulted operation. The setting is done in % of rated phase-to-phase voltage. Default setting is 70%.
4. Set *PU27PN* to 70%
   Should be set lower than the lowest possible phase-to-ground voltage at non-faulted operation. The setting is done in % of rated phase-to-ground voltage. Default setting is 70%.

3.1.9 Calculating setting for switch into fault logic voltage and current based ZCVPSOF

The settings are made in primary values. These values are given in the base settings in Global base 1.

1. Set *GlobalBaseSel* to *1*
2. Set *Mode* to *VILvl&Imp*
3. Set *AutoInit* to *Enabled*
   No BC signal available
4. Set *IphPickup* to *20 %* of *IBase*
   Default value
5. Set *UVPickup* to *70 %* of *VBase*
   Default value that must be lower than the voltage at normal operation
6. Set *tDuration* to *0.020 s*
   Default value for time delay of UI detection
7. Set *tSOTF* to *1.0 s*
   Default value for drop off delay of SOTF function
8. Set *tDLD* to *0.2 s*
   Default value for drop off delay of Dead Line Detection
   The switch onto fault logic is aimed to give fast trip of faults energized by switching in of the line circuit breaker. There are two different modes for operation:
   - *Impedance*: meaning that ZCVPSOF is released by a non-directional start signal from the distance protection function (normally zone 2).
   - *VILevel*: meaning that ZCVPSOF is released by a combination of low voltage (lower than setting*UVPickup*) and current higher than a set value (*IphPickup*).

   It is possible to set the mode of operation to the combination: *Impedance* and *VILevel*. The function can be initiated by a binary input signal BC: (closing of the circuit breaker). If this signal is not available there can be an automatic initiation based on the voltage and current measurement.

3.1.10 Calculating settings for four step phase overcurrent protection OC4PTOC 51_67

The phase overcurrent protection is more difficult to set as the short circuit current is highly dependent of the switching state in the power system as well as of the fault type. In order to achieve setting that assure selective fault clearance a large number of calculations have to be made with different fault locations, different switching states in the system and different fault types. Below one example of setting of phase overcurrent protection for a line in a meshed solidly grounded system is given.

The phase overcurrent protection has the following purpose:

- Backup protection for short circuits on the line in case the distance protection is unavailable (after fuse failure blocking)
- Backup protection for short circuits on the adjacent busbar in case the distance protection is unavailable (after fuse failure blocking)
- Backup protection for short circuits on the local busbar
- Protection for short circuits between the line circuit breaker and the line current transformer

The reach of phase overcurrent line protection is dependent of the operation state and the fault type. Therefore the setting must be based on fault calculations made for different faults, fault points and switching states in the network. Although it is possible to make hand calculations of the different faults it is recommended to use computer based fault calculations. Different time delay principles can be used. This is due to different praxis.

The following principle for the phase overcurrent protection is proposed:

- Step 1 (I>>>) with high current setting and zero delay. This step gives fast trip for the line short circuits close to the nearest line end.
- Step 2 (I>>) with a current setting that enables detection of all short circuits on the protected line and on the local and remote busbars. The function has a short delay to enable selectivity.
- Step 3 (I>) with a current setting that enables detection of all short circuits on the adjacent lines connected to the local and remote busbars. The function has a longer delay to enable selectivity.

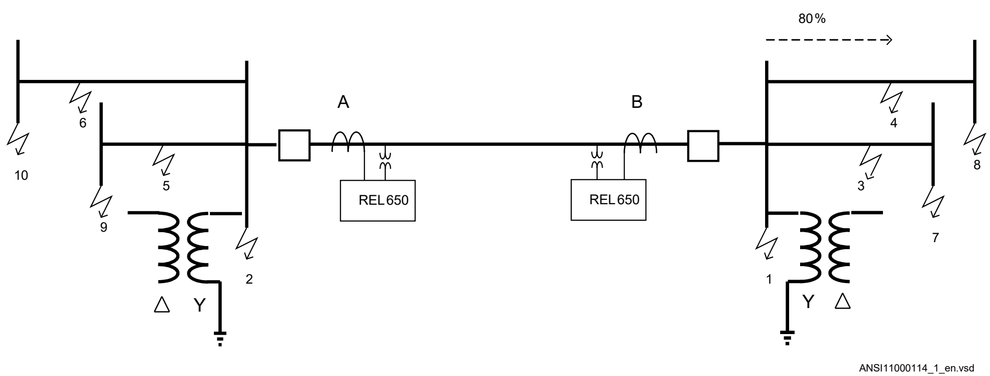


Figure 28: Fault points for phase overcurrent setting calculations

The phase overcurrent protection in line end A is considered in this example. The same principle can be used for line end B.

3.1.10.1 Calculating general settings

1. Set *GlobalBaseSel* to *1*
   The settings are made in primary values. These values are given in the base settings in Global base 1.
2. Set *DirModeSel1(2,3)* to *Non-directional*

It is assumed that the phase overcurrent protection shall operate also when the distance protection is deactivated due to fuse failure. Therefore the function shall be non-directional as the directional function must use voltage measurement.

3.1.10.2 Calculating settings for step 1

1. Set *Pickup1* to *490 %* of *IBase*
   The calculations show the largest phase current I_{max} = 3.84 kA
   To assure selectivity the setting must fulfil:
   $I_{high, set} \geq 1{,}2 \cdot k \cdot I_{max}$
   where k is the transient overreach (due to fault current DC-component) of the overcurrent function. For the four step overcurrent function in the IED k = 1.05.
   This gives: $I_{high, set} \geq 1{,}2 \cdot 1.05 \cdot 3\,840 = 4\,840\ A$
   Setting: *Pickup1= 490 %* of *IBase* which corresponds to *4 900 A*
2. Set *t1* to *0 s*
   Faults are applied at points 1 and 2 (busbar faults at both line ends). The following fault types are applied: 3-phase short circuit, phase-phase-ground short circuit and phase-ground fault. For the faults at fault point 1 the source impedance at line end A should be minimized (maximum short circuit power). For the faults at fault point 2 the source impedance at line end B should be minimized (maximum short circuit power).

3.1.10.3 Calculating settings for step 2

1. Set *Pickup2* to *190 %* of *IBase*
   To assure that step 2 will detect all short circuits on the line a phase-phase short circuit is applied at point 1 (the adjacent busbar). The source impedance at line end A should be maximized (minimum short circuit power) at this calculation. We get the phase current $I_{AB,min} = 2.50\ kA$ (phase-to-phase short circuit).

   To assure that step 2 will detect all short circuits on the local busbar a phase-phase short circuit is applied at point 2 (the local busbar). The source impedance at line end B should be maximized (minimum short circuit power) at this calculation. We get the phase current $I_{BA,min} = 2.50\ kA$ (phase-to-phase short circuit).

   If possible the delay of step 2 should be set equal to the distance protection zone 2 (normally 0.4 s). To assure selectivity with this time delay the function should not overreach adjacent lines out from the remote busbar and out from the local busbar.

   The fault current fed to the protection shall be calculated for the fault points 3, 4, 5 and 6 (faults about 80 % out on the adjacent lines connected to the local and remote busbar).

   The fault at point 3 is calculated with minimum source impedance at substation A and with one line out from substation B taken out of service. This results in the current $I_{fault3,max.} = 1.56\ kA$.

The fault at point 4 is calculated with minimum source impedance at substation A and with one line out from substation B taken out of service. This gives the current $I_{fault4,max.} = 1.4\ kA$.

The fault at point 5 is calculated with minimum source impedance at substation B and with one line out from substation A taken out of service. This gives the current $I_{fault5,max.} = 1.56\ kA$

The fault at point 6 is calculated with minimum source impedance at substation B and with one line out from substation A taken out of service. This gives the current $I_{fault6,max.} = 1.35\ kA$.
The current setting of step 2 is, if possible, chosen as:
$1.2 \cdot max(I_{fault3,4,5,6max}) \leq I_{step2} \leq 0,7 \cdot min(I_{AB,min}, I_{BA,min})$
$1.2 \cdot 1.56 \leq I_{step2} \leq 0.7 \cdot 2.50$ or $1.9 \leq I_{step2} \leq 1.75$

In this case, it is not possible to fulfil the requirement above. Priority is given to selectivity, choosing setting 1900 A and accepting a small risk that short circuits close to the remote busbar are not tripped. This is acceptable as the distance protection normally gives sufficient coverage of the whole line and remote busbar from zone 2.

Setting: *Pickup2= 190 %* of *IBase* which corresponds to *1 900 A*.

2. Set *t2* to *0.4 s*
   If possible the delay of step 2 should be set equal to the distance protection zone 2 (normally 0.4 s). To assure selectivity with this time delay the function should not overreach adjacent lines out from the remote busbar and out from the local busbar.

3.1.10.4 Calculating settings for step 3

1. Set *Pickup3* to *110 %* of *IBase*
   To assure that step 3 detects all short circuits on the adjacent lines out from the remote busbar a phase-phase short circuit is applied at fault points 7 and 8. The source impedance at line end A should be maximized (minimum short circuit power) for this calculation. We get the phase current $I_{fault7,8,min} = 0.46\ kA$
   To assure that step 3 detects all short circuits on the adjacent lines out from the local busbar a phase-phase short circuit is applied at fault points 9 and 10. The source impedance at line end B should be maximized (minimum short circuit power) at this calculation. Resulting phase current is $I_{fault9,10,min} = 0.46\ kA$
   Delay of I> should be set larger than the delay of distance protection zone 2 (normally 0.4 s), this means normally at least 0.8 s.
   Step 3 should be set so that the maximum load current out on the line does not give unwanted trip.
   The maximum load current can be estimated as:

$$I_{Load,\max} = \frac{S_{\max}}{\sqrt{3} \cdot V_{\min}} = \frac{180}{\sqrt{3} \cdot 0.9 \cdot 138} = 0.84\ kA$$

(Equation 30)

The current setting of step 2 is, if possible, chosen as:

$$1.2 \cdot \frac{I_{Load,\max}}{\eta} \leq I_{step3} \leq 0.7 \cdot \min(I_{fault7,8,9,10\min})$$

(Equation 31)

$$1.2 \cdot \frac{840}{0.95} \leq I_{step3} \leq 0.7 \cdot 460 \quad or \quad 1061 \leq I_{step3} \leq 322$$

(Equation 32)

where η is the reset ratio of the overcurrent function. For the overcurrent function in the IED, η = 0.95.
In this case it is not possible to fulfil the requirement above. Priority is given to selectivity, choosing setting 1100 A and accepting that the phase overcurrent protection cannot act as remote back-up protection for the remote lines.

2. Set *t3* to *0.8 s*

3.1.11 Calculating settings for four step residual overcurrent protection EF4PTOC (51N_67N)

The residual overcurrent protection is more difficult to set as the ground-fault current is highly dependent of the switching state in the power system. In order to achieve setting that assure selective fault clearance a large number of calculations have to be made with different fault locations, different switching states in the system and different ground-fault types. Below one example of setting of four step residual overcurrent protection for a line in a meshed solidly grounded system is given.

The four step residual overcurrent protection has the following purpose:

- Fast and sensitive protection for ground-faults on the protected line.
- Backup protection for ground-faults on the adjacent busbar in case the distance protection is unavailable (after fuse failure blocking)
- Sensitive detection of high resistive ground-faults and series faults on the protected line.

The reach of four step residual overcurrent protection depends on the operation state and the fault type. Therefore the setting must be based on fault calculations made for different faults, fault points and switching states in the network. Although it is possible to make hand calculations of the different faults use of computer based fault calculations is recommended. Different time delay principles can be used. This is due to different praxis.

The following principle for the four step residual phase overcurrent protection is proposed:

- Step 1 ($3I_0$>>>) with high current setting and zero delay. Step 1 has directional function with the residual voltage as directional reference. This step gives a fast trip for the line ground-faults close on approximately 70 % out on the line.
- Step 2 ($3I_0$>>) with a current setting that enables detection of all short circuits on the protected line. Step 2 has directional function with the residual voltage as directional reference. The function has a short delay to enable selectivity. The step is also used for sending acceleration signals in under- or overreach communication schemes. In this example an overreach scheme is used.
- Step 4 ($3I_0$>) with a current setting that enables detection of high resistive ground-faults and series faults on the protected line. Step 4 has non-directional function. The function has a longer delay to enable selectivity.

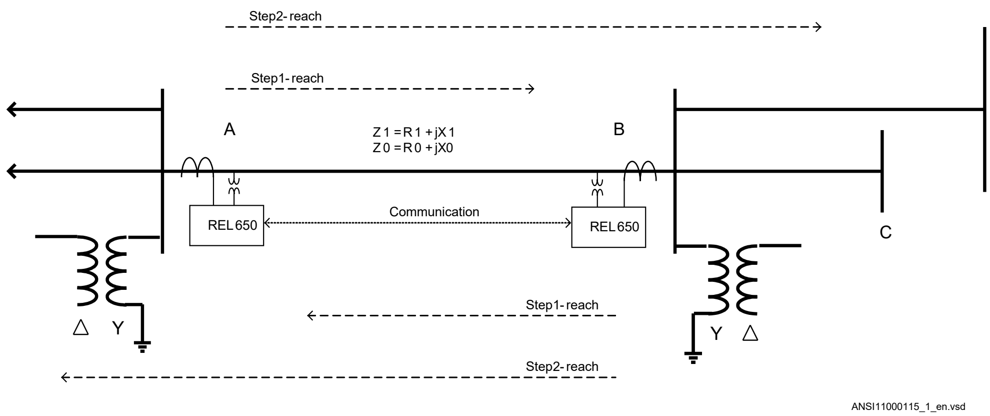


Figure 29: Residual overcurrent protection combined with communication scheme

The residual overcurrent protection in line end A is considered. See figure 29. The same principle can be used for the other line end.

3.1.11.1 Calculating general settings

1. Set *GlobalBaseSel* to *1*
   The settings are made in primary values. These values are given in the base settings in Global base 1.
2. Set *DirModeSel1* and *DirModeSel2* to *Forward*
   The function shall be directional as the directional forward function for steps 1 and 2.
3. Set *DirModeSel3* to *Non-directional*

3.1.11.2 Calculating settings for step 1

1. Set *Pickup1* to *300 %* of *IBase*
   Faults are applied at points 1 (busbar faults at the remote line end), see figure 30. The following fault types are applied: phase-phase-ground short circuit and phase-ground-fault. For the faults at fault point 1 the source impedance (both positive sequence and zero sequence) at line end A should be minimized (maximum short circuit power). For the faults at fault point 2 the source impedance at line end B should be minimized (maximum short circuit power). Calculations shall be done for cases where one of the lines out from the remote busbar is out of service, so that the settings are valid also during un-normal switching states, for example due to line maintenance.

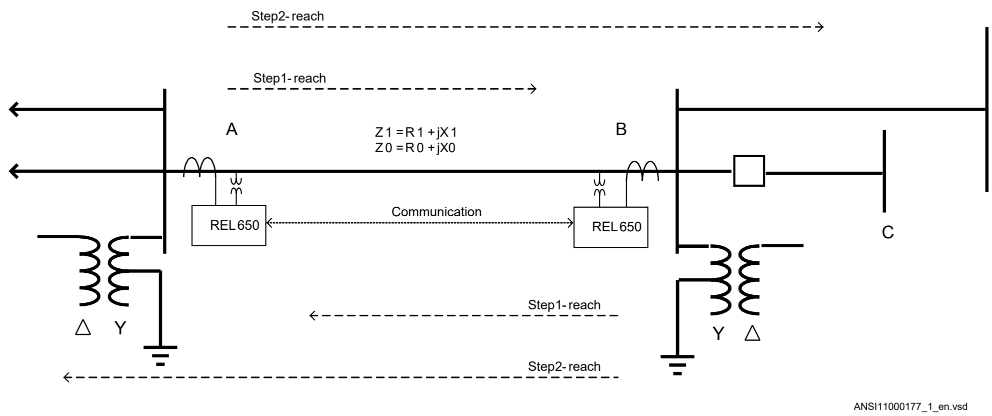


Figure 30: Fault case for step 1 calculation

The calculations provide the largest residual current to the protection $3I_{0max}$ = 2.39 kA.

To assure selectivity the setting must fulfil:

$I_{high,set} = 1.2 \cdot k \cdot 3_{I0max}$

where k is the transient overreach (due to fault current DC-component) of the overcurrent function. For step 4, k is 1.05

2. Set *t1* to *0 s*

3.1.11.3 Calculating settings for step 2

1. Set *Pickup2* to *140 %* of *IBase*

   To assure that step 2 detects all short circuits on the line a phase-phase short circuit is applied at point 1 (the adjacent busbar), see figure 31. The source impedance at line end A should be maximized (minimum short circuit power) at this calculation. The phase current works out as

   $3I_{0AB,min} = 2.39\ kA$

   If possible the delay of $3I_0$>> should be set equal to the distance protection zone 2 (normally 0.4 s). To assure selectivity with this time delay the function should not overreach adjacent lines out from the remote busbar and out from the local busbar.

   To assure selectivity to ground-fault current protections of the other lines going out from the remote busbar the following calculations shall be made.

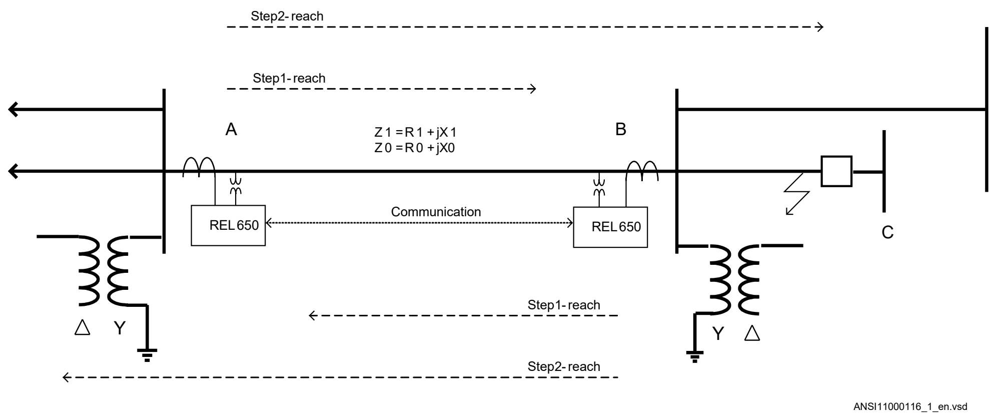


Figure 31: Fault case for step 2 calculation

The calculated fault current fed to the protection is $3I_{0,AB}$. The calculated total fault current fed to the fault point is $3I_{0,BC}$. The step 1 setting of the four step residual overcurrent protection at line B – C is $3I_{0BC,step1}$. The current measured by the ground-fault protection at an ground-fault at step 1 reach can be calculated:

$$3I_{0,sel} = 3I_{0BC,step1} \cdot \frac{3I_{0,AB}}{3I_{0,BC}}$$

(Equation 33)

$3I_{0BC,step1}$ = 4 000 A and we get

$$3I_{0,sel} = 4000 \cdot \frac{790}{2980} = 1060\ A$$

(Equation 34)

This calculation is made for fault out on each of the lines out from the remote busbar.
To assure both sufficient reach of step 2 and selectivity the setting of step 2 must be chosen:
$1.2 \cdot max(3I_{0,sel}) \le IN_{step2} \le 0.7 \cdot 3I_{0ABmin}$
$1.2 \cdot 1\,060 \le IN_{step2} \le 0.7 \cdot 2\,390$ or $1\,272 \le N_{step2} \le 1\,673$
Setting: *Pickup2= 140 %* of *IBase* which corresponds to *1400 A*

2. Set *t2* to *0.4 s*

3.1.11.4 Calculating settings for step 4

The current setting of step 4 should be chosen according to standard procedure in the grid. From experience it can be concluded that the setting down to about *100 A* can be used. This setting is however highly dependent on the line configuration, manly if the line is transposed or not.

If definite time delay is used there is some risk of unselective tip at high resistive ground-faults or series faults. If dependent time delay (inverse time) is used some degree of selectivity can be achieved.

1. Set *Pickup4* to *10 %* of *IBase* which corresponds to 100 A

Characteristic 4: RD Type.
2. Set *TD4* to *0.3*
3. Set: *t4Min* to *1.2 s*

3.1.12 Calculating settings for scheme communication for residual overcurrent protection ECPSCH (85)

The communication logic is used to assure fast fault clearance for all ground-faults along the line, that is also for faults outside the reach of step 1 of the four step residual overcurrent protection. The logic for the communication schemes requires a communication link between the four step residual overcurrent protections on the two line ends. The communication link alternatives are:

- Power line carrier (PLC)
- Microwave link (radio)
- Optic fibre link

There are the following alternatives for communication scheme:

- Under-reach permissive logic
- Over-reach permissive logic
- Blocking scheme

1. Set *SchemeType* to *Permissive OR*
   This corresponds to over-reach permissive scheme. The choice is based on the following: Permissive over-reach scheme is chosen because it is considered as the weak end infeed logic shall be used as there is a risk of small current infeed. Th WEI function requires permissive over-reach communication scheme.
2. Set *tCoord* to *0.000 s*
3. Set *tSendMin* to *0.100 s*

3.1.12.1 Over-reach permissive logic

The principle of the logic can be explained as shown in figure 32.

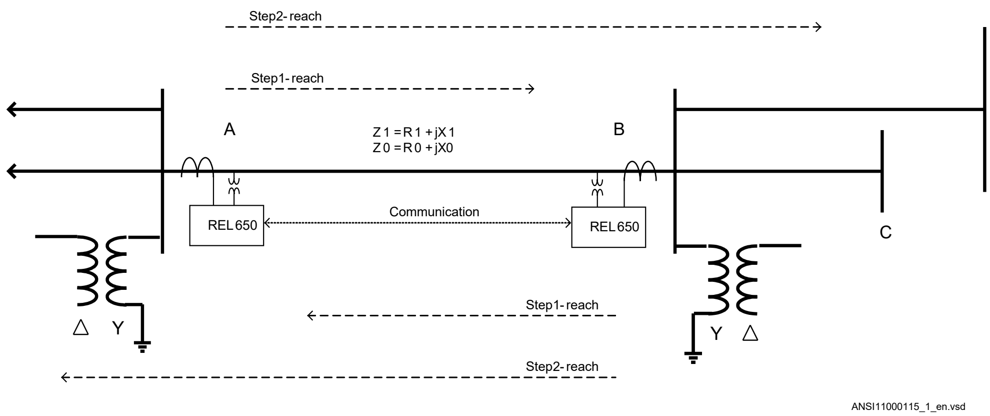


Figure 32: Principle for four step residual overcurrent protection overreach communication scheme

A communication signal is sent (CS) if a fault is detected by step 2 ($3I_0$>> overreach step). When a communication signal is received (CR) Step 2 ($3I_0$>>) operates instantaneously. The logic is shown in figure 33.

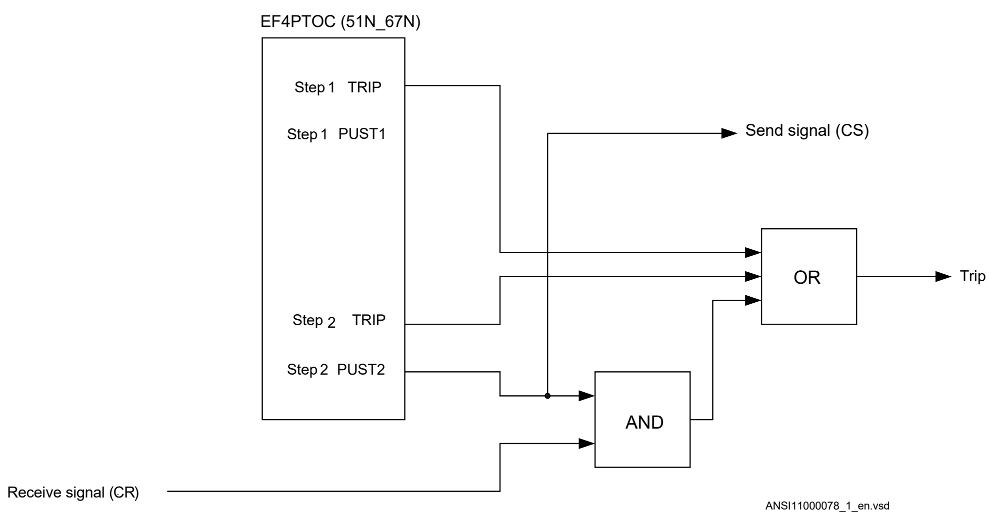


Figure 33: Logic for four step residual overcurrent protection overreach communication scheme

This scheme is used for short lines where it can not be assured that the zone 1 reach from both line ends overlap each other. The scheme should also be used for lines where the fault current infeed from one of the line ends is small and the weak end infeed logic is used.

3.1.12.2 Under-reach permissive logic

The principle of the logic can be explained as shown in figure 34.

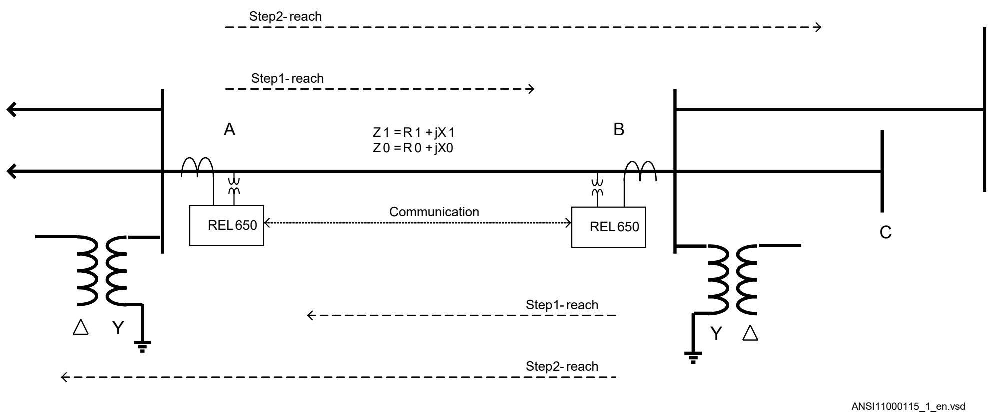


Figure 34: Principle for four step residual overcurrent protection underreach communication scheme

A communication signal is sent (CS) if a fault is detected by step 1 ($3I_0$>>> underreach step). When a communication signal is received (CR) Step 2 ($3I_0$>>) will operate instantaneously. The logic can be described as shown in figure 35.

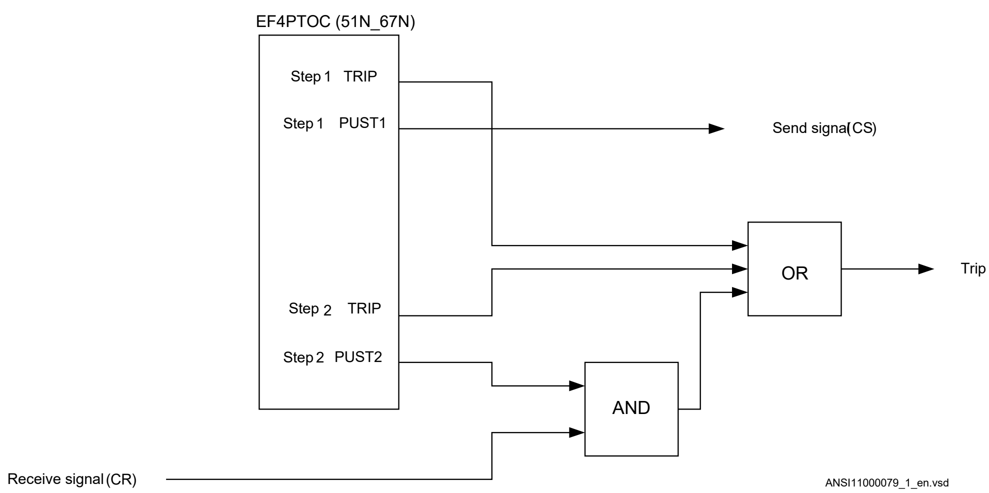


Figure 35: Logic for four step residual overcurrent protection underreach communication scheme

This scheme is used for long lines where it can be assured that the zone 1 reach from both line ends will overlap each other.

3.1.12.3 Blocking scheme

The principle of the logic can be explained as shown in figure 36.

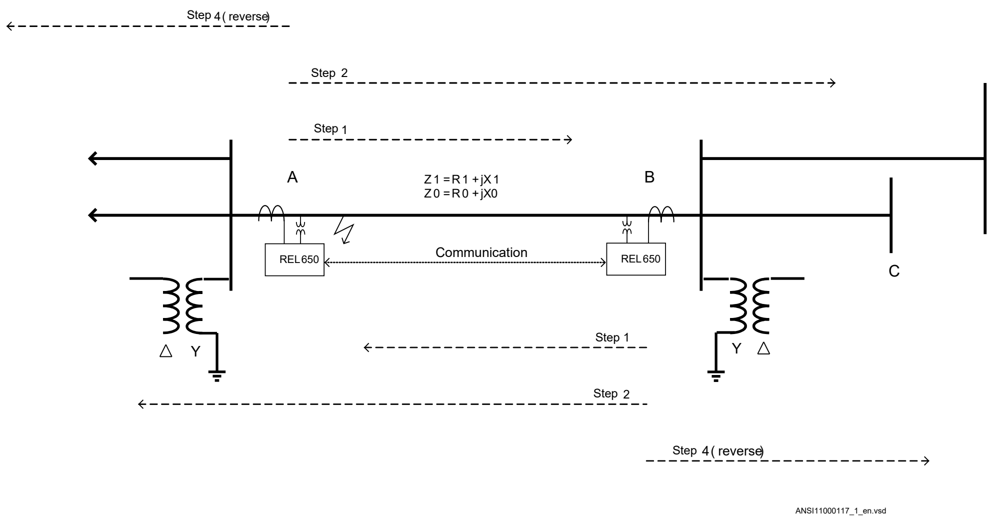


Figure 36: Principle for four step residual overcurrent protection blocking communication scheme

A communication signal is sent (CS) if a fault is detected by step 4 (reverse direction). When a communication signal is received (CR) the fast overreaching step 2 will be blocked. The logic is shown in figure 37.

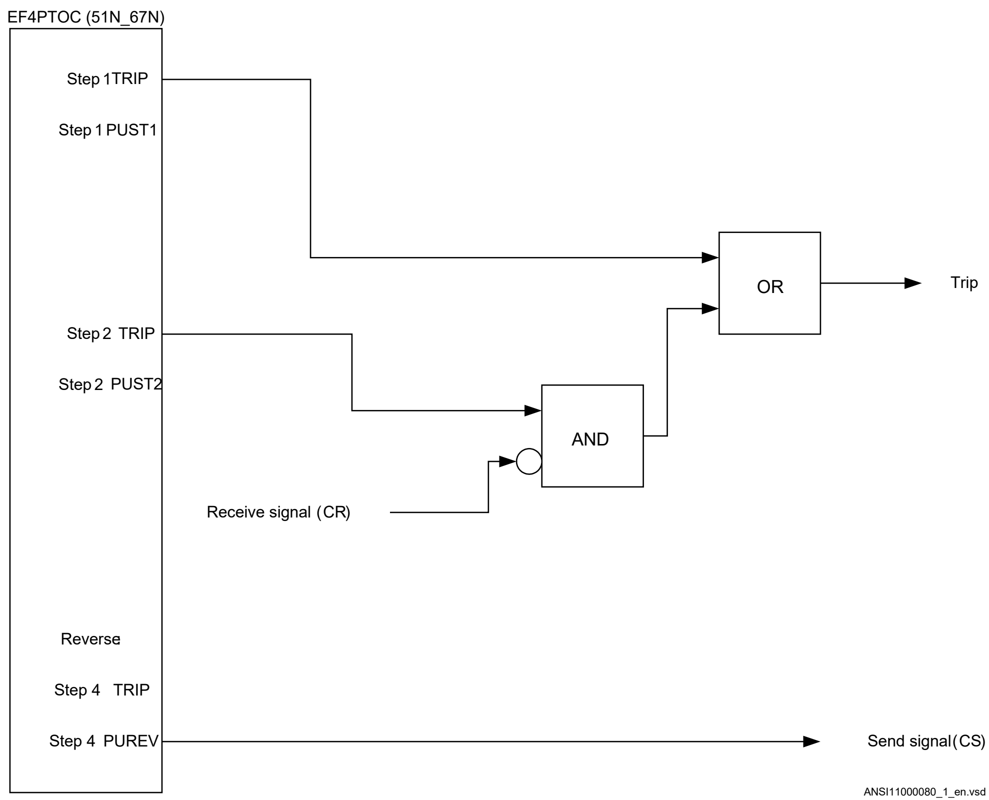


Figure 37: Logic for four step residual overcurrent protection blocking communication scheme

The trip signal from step 2 must be delayed so that the blocking signal has enough time for blocking at external faults.

3.1.13 Calculating settings for current reversal and weak-end infeed logic for residual overcurrent protection ECRWPSCH (85)

The four step residual overcurrent protection can only operate if the fault current to the fed to the protection is larger than about 3% of the rated current (settable). There is a risk that the fault current infeed from one of the line ends is very small, but not zero. In such case the following can be the consequence of a short circuit close to the line end with small fault current infeed.

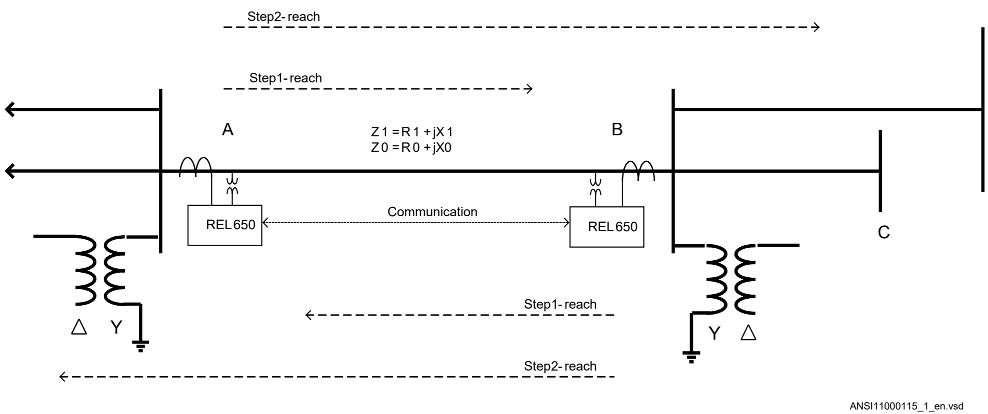


Figure 38: Residual overcurrent protection WEI scheme

For the fault shown in figure 38 there is a risk of the following consequences if the weak end infeed logic is not used:

- Step 1 in the line end A (weak end) does not start due to the small fault current infeed or too low residual voltage level. This means that the line breaker does not open.
- The fault detection in line end B is done by means of four step residual overcurrent protection function step 2. As there is no acceleration signal (CR) from line end A, the communication scheme cannot be activated. The fault clearance is thus be delayed (step 2 time delay).

To overcome this shortcoming of the protection scheme the weak end infeed logic (WEI) is activated. The function at internal line fault can be described as:

- For an internal fault step 2 in line end B picks up and sends a signal to line end A (CS)
- If none of the non-directional start signals of step 1 or 2 in line end A does not pick up the received signal from line end B (CR) is sent back (echo).
- If the voltage in line end A is low and the four step residual overcurrent protection steps do not pick up the circuit breaker is tripped (if this feature is set).
- In line end B the echo signal is received (CR) and the communication scheme gives an undelayed trip to the circuit breaker.

The function at external fault can be described as:

- For an external fault step 2 in line end B is activated and sends a signal to line end A (CS)
- When the non-directional start signals of step 1 or 2 in line end A are activated, they prevent the received signal to be sent back to line end B.
- None of the line ends is tripped.

1. Set *WEI* to *Echo & Trip*
   This echoes CR signal as well as trip locally.
2. Set *tPickUpWEI* to *0.01 s*
   Shortest duration of CR signal.
3. Set *UPP<* to lower than the lowest possible phase-to-phase voltage at non-faulted operation. The setting is done in % of rated phase-to-phase voltage.
   Default setting is *70 %*.
4. Set *UPN<* to lower than the lowest possible phase-to-ground voltage at non-faulted operation. The setting is done in % of rated phase-to-ground voltage.
   Default setting is *70 %*.

3.1.14 Calculating settings for breaker failure protection CCRBRF (50BF)

Breaker failure protection (CCRBRF , 50BF) can use either contact function in the circuit breaker or current measurement to detect correct breaker function. For line protections the most suitable way is to use current measurement breaker check.

1. Set *GlobalBaseSel* to *1*
   The settings are made in primary values. These values are given in the base settings in Global base 1.
2. Set *FunctionMode* to *Current*
3. Set *BuTripMode* to *1 out of 4*
   In the current measurement the three-phase currents out on the line is used. It is also possible to measure the residual current (analogue input 4). The logics to detect failure of the circuit breaker can be chosen:
   1 out of 3: at least one of the three-phase current shall be larger than the set level to detect failure to break
   1 out of 4: at least one of the three-phase current and the residual current shall be larger than the set level to detect failure to break
   2 out of 4: at least two of the three-phase current and the residual current shall be larger than the set level to detect failure to break.
   As the residual current protection is one of the protection functions to initiate the breaker failure protection the setting *1 out of 4* is chosen.
4. Set *Pickup_PH* to *10 %* of *IBase*
   Pickup_PH should be set lower than the smallest current to be detected by the distance protection ($I_{Min}O_{p}PP$) which is set 20 % of *IBase*.
5. Set *Pickup_N* to *10 %* of *IBase*
   Pickup_N should be set lower than the smallest current to be detected by the most sensitive step of the residual ovecurrent protection which is 100 A.
6. Set *t1* to *0 s*
   Re-tip time delay: t1
7. Set *t2* to *0.17 s*
   The delay time of the breaker failure protection BuTrip is chosen according to figure 39.
   The maximum open time of the circuit breaker is considered to be 100 ms.

The BFP reset time is maximum 15 ms.
The margin should be chosen to about 2 cycles. This gives about 155 ms minimum setting of back-up trip delay *t2*.

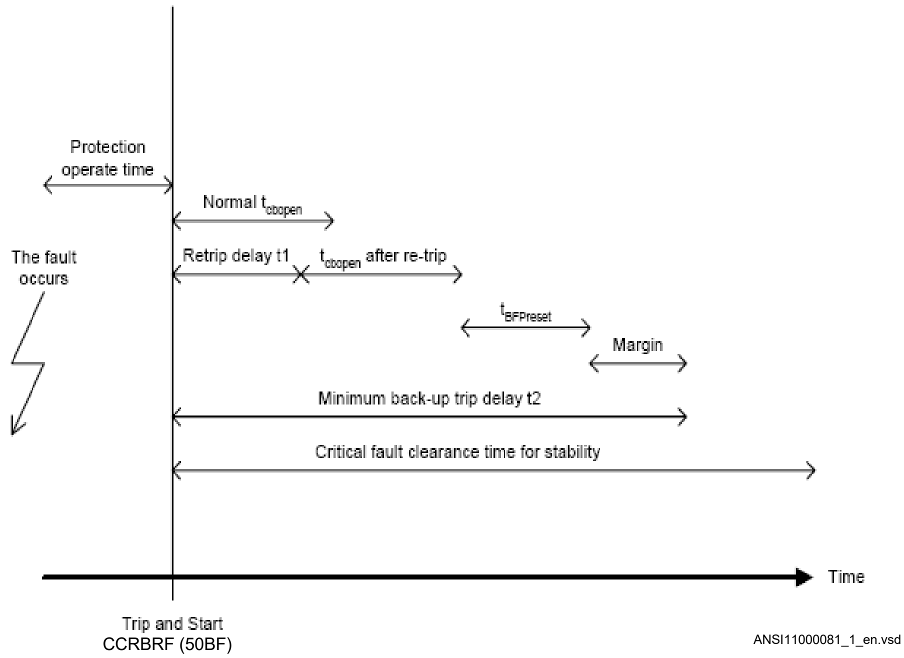


Figure 39: Time sequences for breaker failure protection setting

3.2 Setting example for a two-ended over-head transmission line in a high impedance network

Setting calculations given for functions in the two-ended overhead transmission line in a solidly grounded network are also valid for the two-ended over-head transmission line in a high impedance network application, except the phase preference logic and sensitive directional residual overcurrent protection which are used in high impedance networks.

3.2.1 Calculating settings for phase preference logic PPLPHIZ

The phase preference logic is only to be used if it is allowed to operate the network with single phase-to-ground fault. In case of a “cross-country fault” as shown in the figure the fault will be seen as a single phase-to-ground fault for each of the distance protections as long as both faults are fed from the station. The faults are within zone 1.

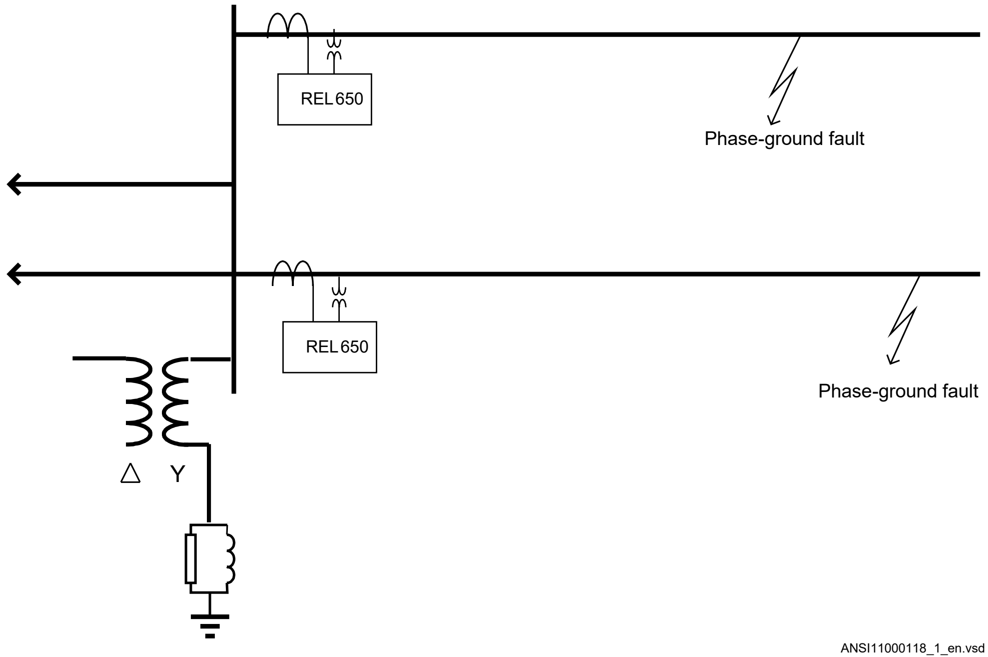


Figure 40: Cross country fault

The aim of the phase preference function is to release distance protection trip one of the faulted lines so that the other line can remain in service with the single phase-to-ground fault.

The phase preference logic will identify the faulted phases on each of the faulted lines by measurement of the phase-to-ground voltages (setting *PU27PN*), the phase-to-phase voltages (setting *PU27PP*), the residual voltage (setting *3V0PU*) and the residual current out on the protected line (setting *Pickup_N*).

1. Set *OperMode* to *1231c*
   When a cross-country fault has been detected the trip is made according to a chosen priority: *OperMode*.
   This setting shall be identical for all distance protections in the system. In this case a cyclic order is used: A– B– C– A.
   Setting *OperMode: 1231c*
2. Set *PU27PN* to *70 %*
   The setting *PU27PN* is used to identify faulted phases. The setting shall be less than the lowest possible voltage at normal operation. The default value 70 % of *VBase* is recommended.
   Setting *PU27PN* to *70 %*
3. Set *PU27PP* to *40 %*
   The setting *PU27PP* is used in the logic to evaluate if a fault exists in two or more phases. The setting must be chosen so that pick-up at phase-to-phase fault in another fault loop is avoided. The default value 40 % of *VBase* is recommended.
   Setting *PU27PP* to *40 %*
4. Set *3V0PU* to *20 %*
   The setting *3V0PU* is used in the logic to evaluate if a phase-to-ground fault exists. The setting must be chosen so that pick-up at unfaulted conditions is avoided. The default value 20 % of *VBase* is recommended.
5. Set *Pickup_N* to *7 %* (70 A)

The setting *Pickup_N* is used in the logic to evaluate if a cross-country fault exists. The setting must be chosen larger than the maximum residual current out on the line at single phase-to-ground fault. In case of a single phase-to-ground fault out on the protected line the fault current will be according to the figure 41: $3I_{0line} \geq 25 + j50$. The setting $\geq 56 \cdot 1.25 = 70$ A is proposed.

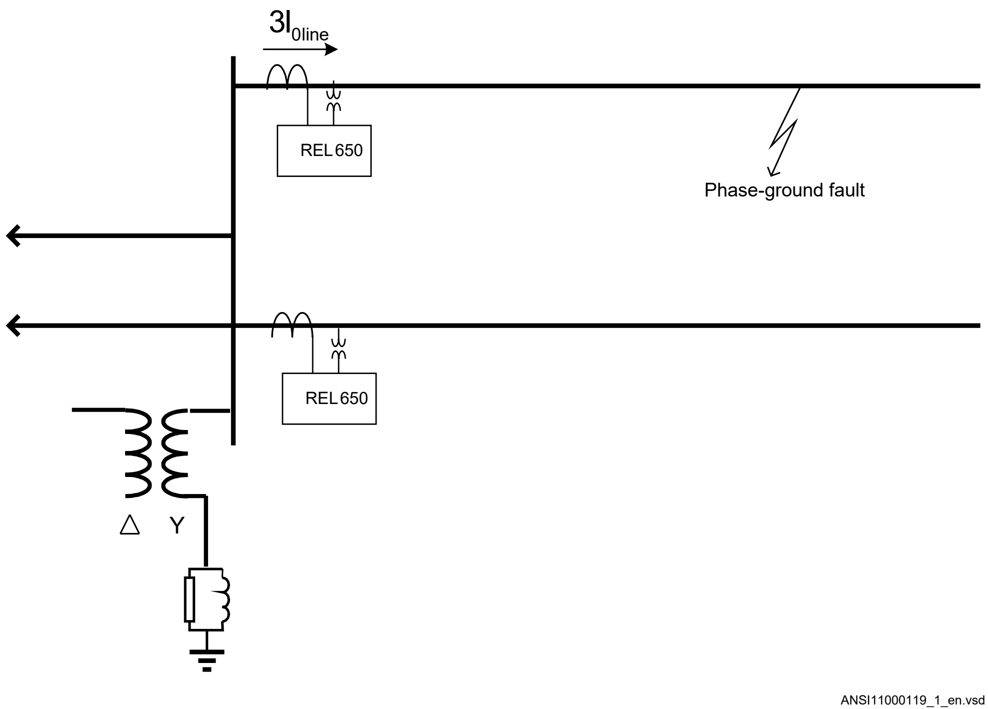


Figure 41: Single phase-to-ground fault

6. Set *tVN* to *0.001 s*
   Setting *tVN* gives the pick-up delay for residual voltage. The default value *0.001 s* is proposed.
7. Set *tOffVN* to *0.1 s*
   Setting *tOffVN* gives the drop-off delay for residual voltage. The default value 0.1 s is proposed.
   Set *tOffVN* to *0.1 s*
8. Set *tIN* to *0.15 s*
   Setting *tIN* gives the pick-up delay for residual current. The default value *0.15 s* is proposed.

3.2.2 Calculating settings for sensitive directional residual overcurrent protection SDEPSDE 67N

In high impedance grounded system the ground fault current, at single phase-to-ground fault, is small compared to the fault current at phase-to-phase short circuit. Therefore it is difficult and normally not possible to use distance protection as ground fault protection. In many networks it is also required to detect and clear phase-to-ground faults with a high resistance to ground in the fault point. The ground fault current is limited by the capacitance between the phase conductors and ground and the impedance of equipment connected between the transformer neutral point and ground. In this network a Petersen coil parallel with a neutral point resistor is connected to the transformer neutral. The active ground fault current, that is, the residual current in phase with the residual voltage, is used for line fault detection. The active residual current only flows on the connection from the neutral point resistor and the fault point on the faulted line.

1. Set *OpModeSel* to *3I0Cosfi* if the current component is related to the set characteristic angle relative to the reference voltage, or *3I03V0Cosfi* if the power component is related to the set characteristic angle relative to the reference voltage, or *3I0 and fi,* if measuring the total residual current if the angle fi is within the set range.
   The active ground fault current, out on the faulted feeder, can be calculated by first to calculate the residual voltage at required sensitivity (fault resistance).

   $$V_o = \frac{V_{Phase}}{1 + \frac{3 \cdot R_f}{Z_0}}$$

   (Equation 35)

   where

   $$Z_0 = -jX_c\ //3R_n\ //\ j3X_n = \frac{9R_N X_N X_C}{3X_N X_C + j3R_N \cdot (3X_N - X_C)}$$

   (Equation 36)

   The active ground fault current component can now be calculated according to

   $$I_{j,active} = \frac{V_0}{V_{Phase}} \cdot I_{Rn}$$

   (Equation 37)

   where I_{Rn} is the rated current of the neutral point resistor.
   In the network the following conditions applies:
   The Petersen coil is perfectly tuned: $3X_n = X_c$
   The neutral point resistor provides 25 A at ground fault without resistance. This gives the value of R_n.

   $$R_n = \frac{13800/\sqrt{3}}{25} = 3187\ \Omega$$

   (Equation 38)

   The zero sequence network impedance works out as:

   $$Z_0 = -jX_c\ //3R_n\ //\ j3X_n = \frac{9R_N X_N X_C}{3X_N X_C + j3R_N \cdot (3X_N - X_C)} = 3R_n = 9561\ \Omega$$

   (Equation 39)

   The requirement in this network is that the ground fault protection shall have sensitivity so that ground faults with resistance up to 3 000 Ω shall be detected and cleared.
   The residual voltage at 3 000 Ω works out as:

   $$V_o = \frac{V_{Phase}}{1 + \frac{3 \cdot R_f}{Z_0}} = \frac{138000/\sqrt{3}}{1 + \frac{3 \cdot 3000}{9561}} = 0.52 \cdot 79674 = 41431\ V$$

   (Equation 40)

   This corresponds to 52 % of residual voltage at non-resistive (solid) phase-to-ground fault.
   The active current works out as:

$$I_{j,active} = \frac{V_0}{V_{Phase}} \cdot I_{Rn} = 0.52 \cdot 25 = 13\ A$$

(Equation 41)

This corresponds to 52 % of the neutral point resistor rated current. The setting *OpModeSel* can be set to:

- *3I0Cosfi* where the current component is related to the set characteristic angle relative to the reference voltage.
- *3I03V0Cosfi* where the power component is related to the set characteristic angle relative to the reference voltage
- *3I0 and fi*, measuring the total residual current if the angle *fi* is within the set range.

In this case *3I0Cosfi* is chosen.

2. Set *DirMode* to *Forward*
   The setting *DirMode* can be set *Forward* or *Reverse*. *Forward* is chosen.
3. Set *RCADir* to *0°*
   The setting *RCADir* (Relay Characteristic Angle) determines the angle between the residual current and voltage giving maximum sensitivity. If a neutral point resistor is used the setting *0°* is used. If capacitive residual current is measured (isolated networks) the setting *-90°* is used.
4. Set *RCAComp* to *0°*
   The setting *RCAComp* (Relay Characteristic Angle Compensation) can be used for compensation of instrument transformer angle error.
5. Set *ROADir* to *90°*
   The setting *ROADir* (Relay Open Angle) is the angle sector where the protection can operate. Normally 90° is used. In special cases with very large capacitive current fed from the line this sector can be limited to avoid unwanted trip at fault on another line.
6. Set *INCosPhiPU* to *1.3 %* (corresponds to 13 A primary current)
   The setting *INCosPhiPU* provides the sensitivity of the protection. Above, the required current sensitivity (active ground fault current) is calculated to 13 A.
7. Use the setting *INDirPU* when *OpModeSel* is set to *3I0 and fi*
8. Use the setting *SN_PU* when *OpModeSel* is set to *3I03V0Cosfi*
9. Set *TimeChar* to *IEC Def.Time*
   The setting *TimeChar* gives the time characteristic of the sensitive residual overcurrent protection. Definite time delay as well as different types of time inverse time delay characteristics can be chosen. Definite time delay is chosen.
10. Use the setting *tDef* for the definite time delay of the protection function.
    The setting is depending on the setting of other sensitive residual current protections in the system. Often pure time selectivity is used. As the fault current is relative small and independent of the fault point relatively long trip delay can be accepted.
11. If required for the protection, use the available non-directional residual overcurrent function EF4PTOC (51N_67N) as well as the residual overvoltage function ROV2PTOV (59N).

Section 4 Analog inputs

4.1 Introduction

Analog input channels are already configured inside the IED. However the IED has to be set properly to get correct measurement results and correct protection operations. For power measuring and all directional and differential functions the directions of the input currents must be defined properly. Measuring and protection algorithms in the IED use primary system quantities. Set values are done in primary quantities as well and it is important to set the data about the connected current and voltage transformers properly.

The availability of CT and VT inputs, as well as setting parameters depends on the ordered IED.

A reference *PhaseAngleRef*must be defined to facilitate service values reading. This analog channels phase angle will always be fixed to zero degree and all other 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.

4.2 Setting guidelines

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

The setting shall be used if a phase-to-ground voltage (usually the A phase-to-ground voltage connected to VT channel number of the analog card) is selected to be the phase reference.

4.2.1.2 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 42

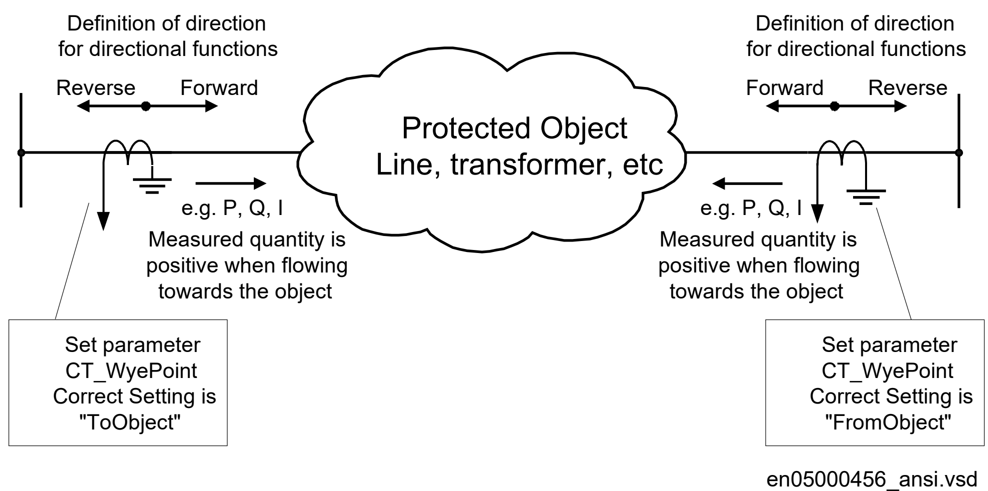


Figure 42: Internal convention of the directionality in the IED

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

4.2.1.3 Example 1

Two IEDs used for protection of two objects.

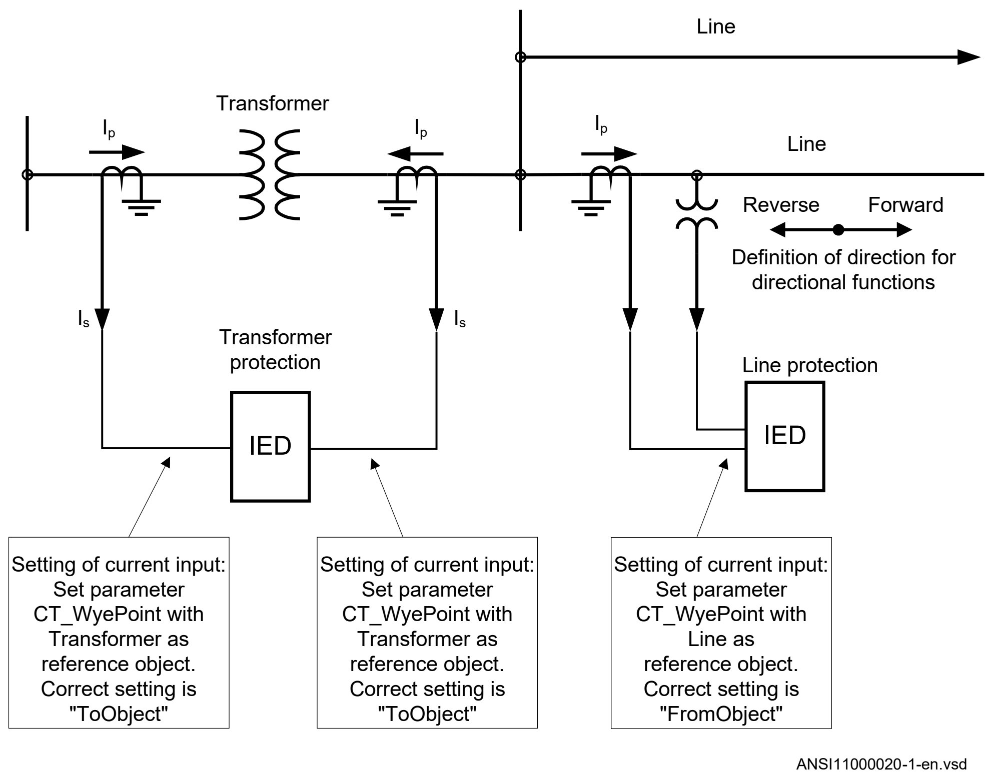
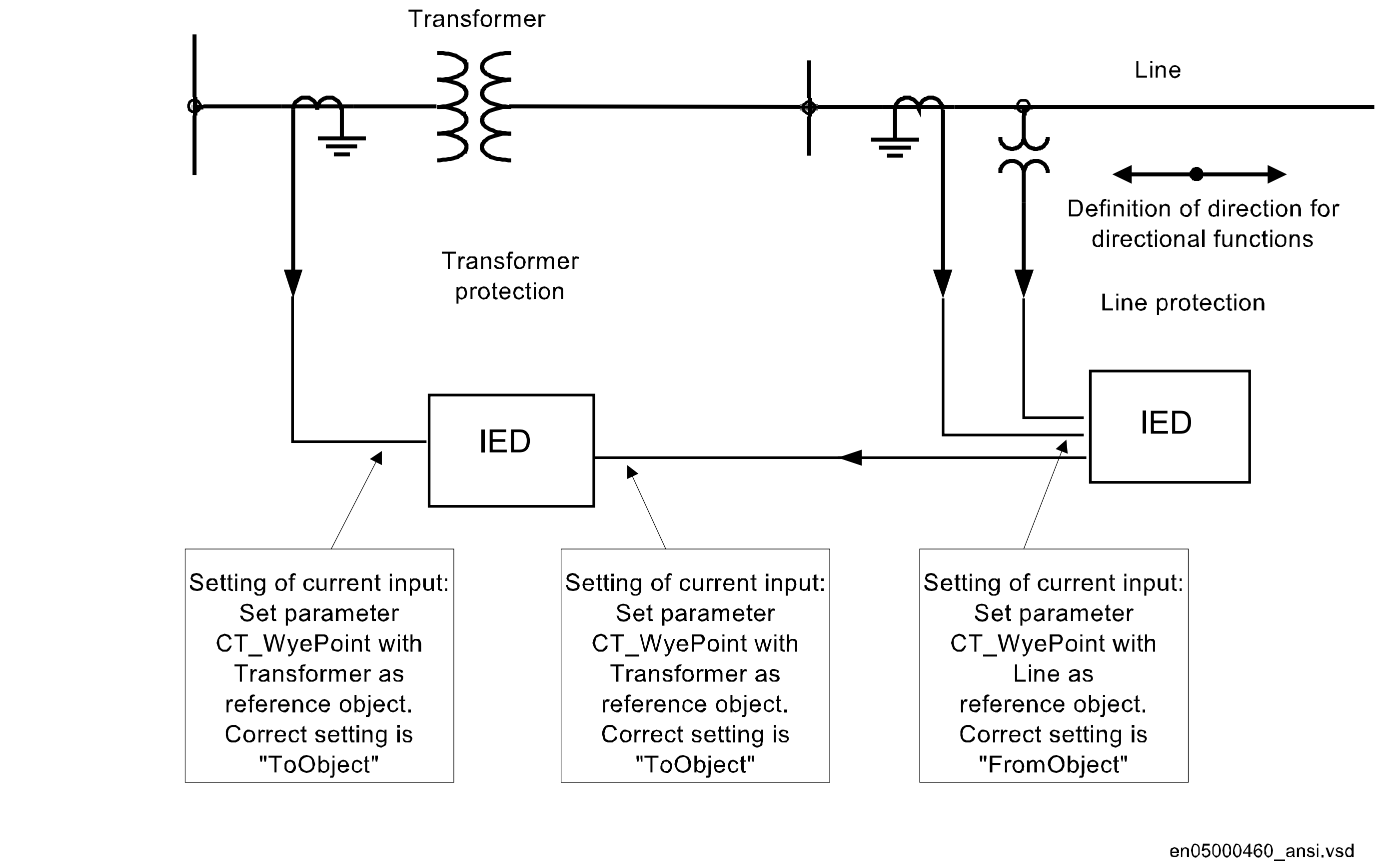


Figure 43: Example how to set CT_WyePoint parameters in the IED

The figure 43 shows the most 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 the direction of the directional functions of the line protection shall be set to *Forward*. This means that the protection is looking towards the line.

4.2.1.4 Example 2

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



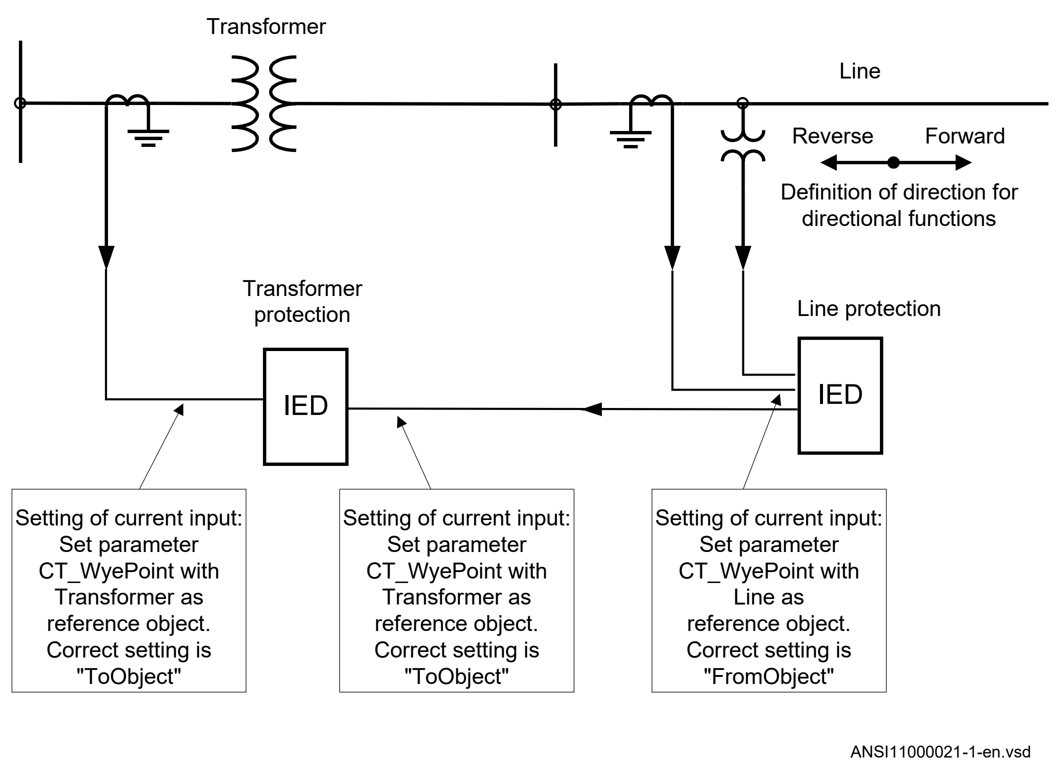


Figure 44: Example how to set CT_WyePoint parameters in the IED

This example is similar to example 1 but 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 two IEDs. With these settings the directional functions of the line protection shall be set to *Forward* to look towards the line.

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

Figure 45 defines the marking of current transformers terminals commonly used around the world:

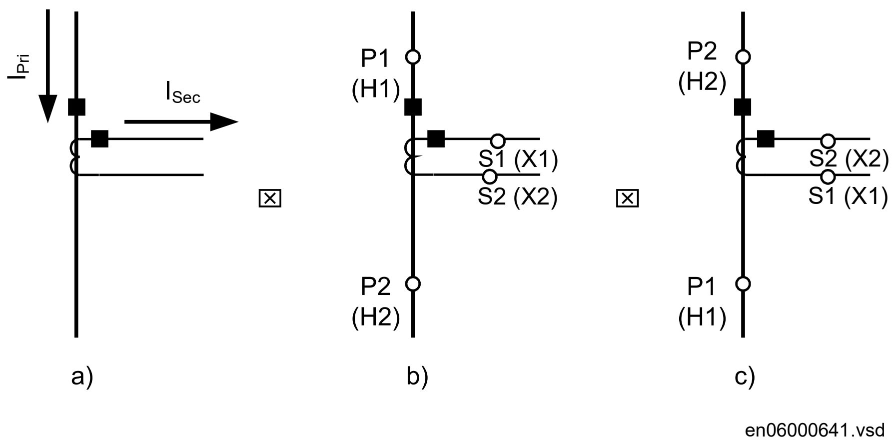


Figure 45: Commonly used markings of CT terminals

Where:

a)	is symbol and terminal marking used in this document. Terminals marked with a dot 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 this two cases the CT polarity marking is correct!

It shall be noted that depending on national standard and utility practices 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 as well used:

- 2A
- 10A

The IED fully supports all of these rated secondary values.

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

Figure 46 gives an example how to connect the wye connected three-phase CT set to the IED. It as well 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.

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

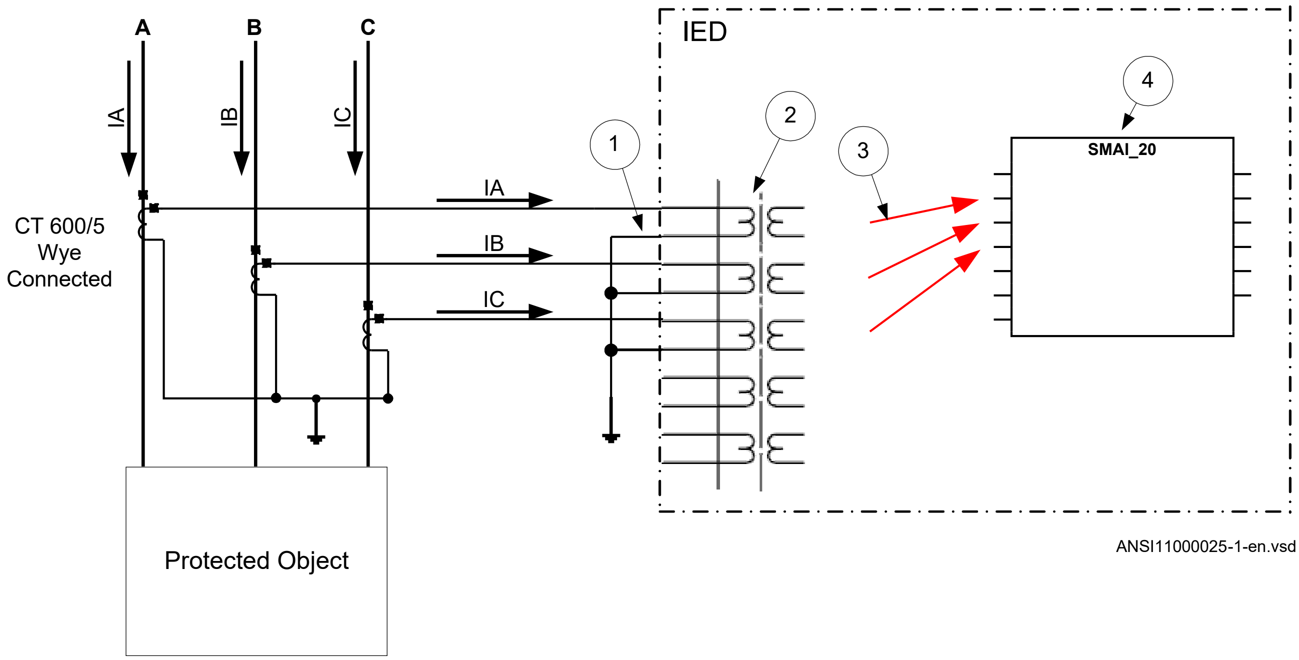


Figure 46: Wye connected three-phase CT set with wye point towards the protected object

Where:

1) shows how to connect three individual phase currents from wye connected three-phase CT set to three CT inputs in the IED.

2) is TRM or AIM where these current inputs are located. It shall be noted that for all these current inputs the following setting values shall be entered.

- CTprim=600A
- CTsec=5A
- CTStarPoint=ToObject

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

3) are three connections, which connects these three current inputs to three input channels of 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.

4) 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. 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 star point of the three-phase CT set as shown in figure 47:

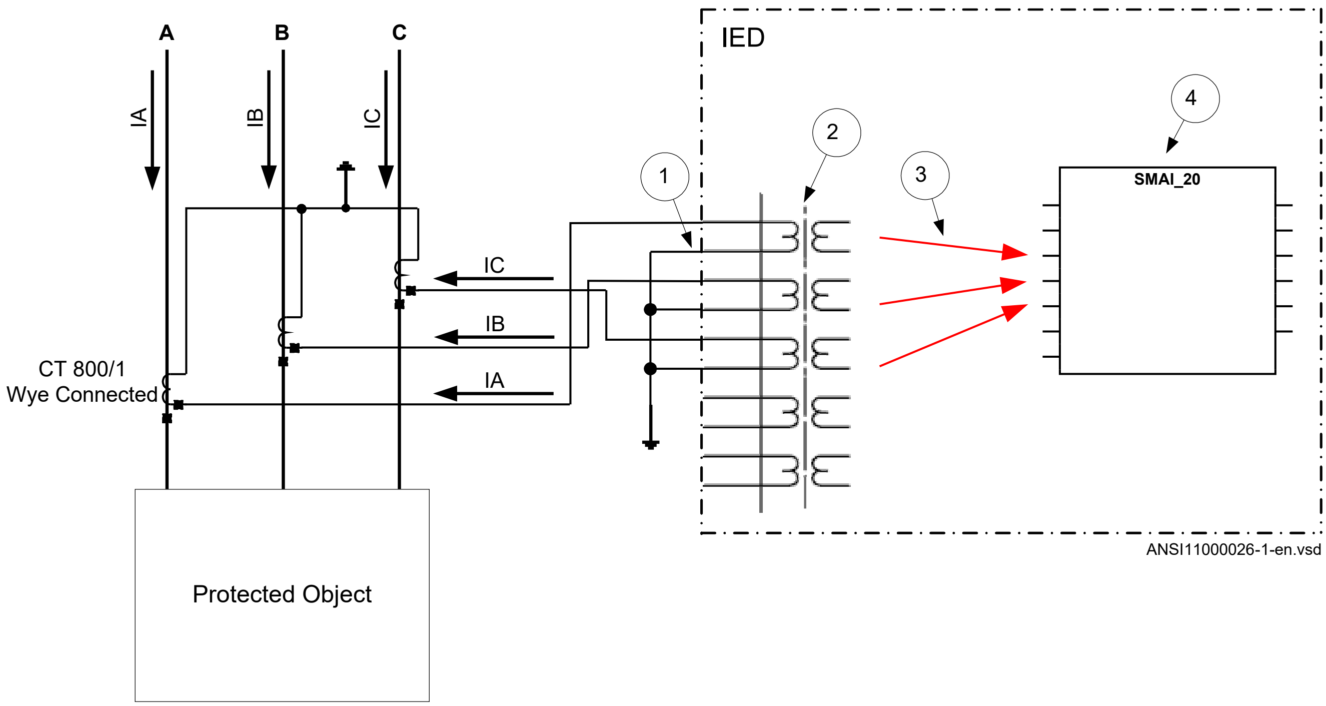


Figure 47: Wye connected three-phase CT set with star point from the protected object

Please note that 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:

- *CTprim*=800A
- *CTsec*=1A
- *CTWyePoint*=FromObject

Inside the IED only the ratio of the first two parameters is used. The third parameter as set in this example will reverse the measured currents (that is, turn the currents by 180°) in order to ensure that the currents within the IED are measured towards the protected object.

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

Figure 48 gives an example how to connect the single-phase CT to the IED. It as well 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.

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

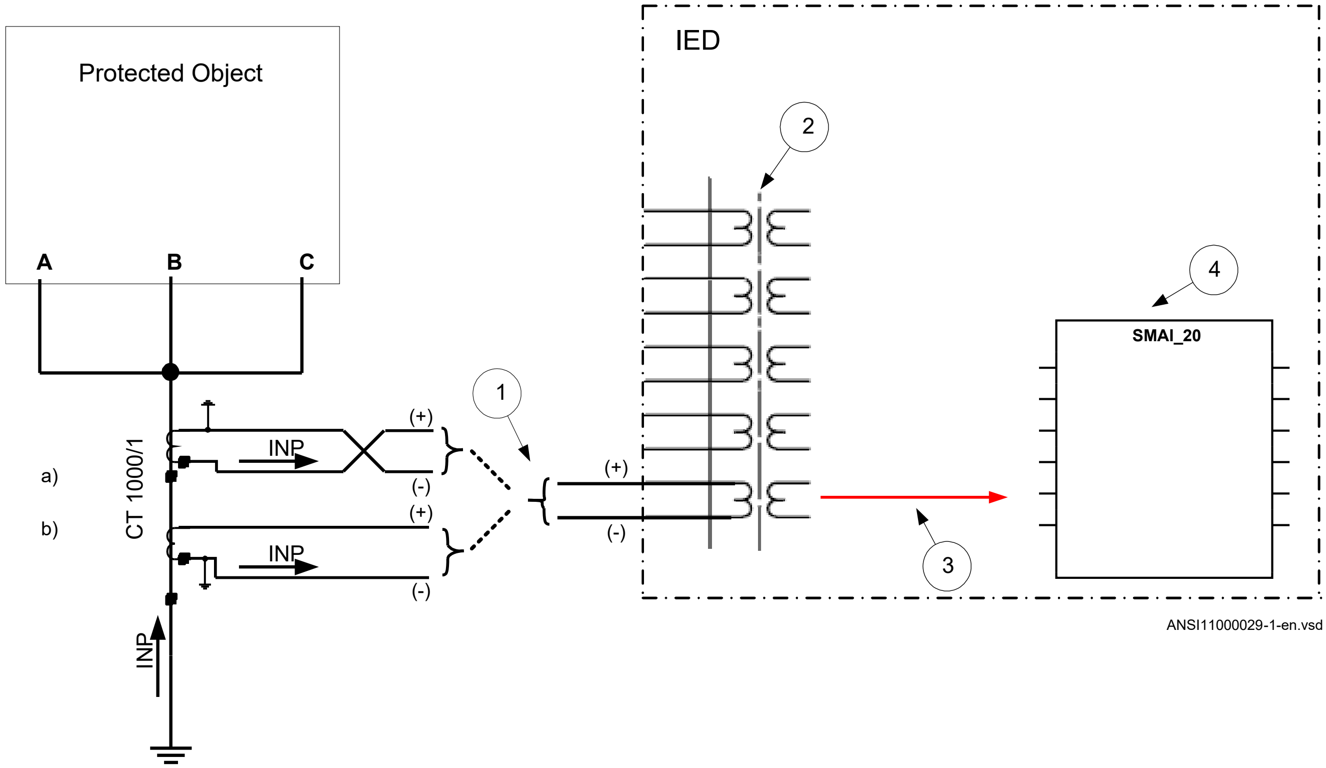


Figure 48: Connections for single-phase CT input

Where:

1) shows how to connect single-phase CT input in the IED.

2) is TRM or AIM 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 48:
  - *CTprim*=1000A
  - *CTsec*=1A
  - *CTWyePoint*=*ToObject*

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

- For connection b) shown in figure 48:
  - *CTprim*=1000A
  - *CTsec*=1A
  - *CTWyePoint*=*FromObject*

Inside the IED only the ratio of the first two parameters is used. The third parameter as set in this example will invert the measured currents (that is, turn the currents by 180°) in order to ensure that the currents within the IED are measured towards the protected object.

3) shows the connection, which connect this CT input to the input channel of the preprocessing function block 5).

4) 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. 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.

4.2.1.8 Setting of voltage channels

As the IED uses primary system quantities the main VT ratios must be known. This is done by setting the two parameters *VTsec* and *VTprim* 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.

4.2.1.9 Example

Consider a VT with the following data:

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

(Equation 42)

The following setting should be used: *VTprim=132* (value in kV) *VTsec=120* (value in V)

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

Figure 49 defines the marking of voltage transformers terminals commonly used around the world.

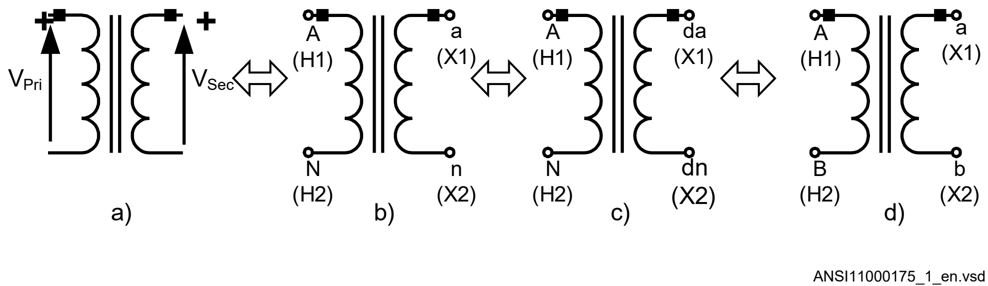


Figure 49: Commonly used markings of VT terminals

Where:

a)	is symbol and terminal marking used in this document. Terminals marked with a dot indicates the primary and secondary winding terminals with the same (that is, positive) polarity
b)	is equivalent symbol and terminal marking used by IEC (ANSI) standard for phase-to-ground connected VT
c)	is equivalent symbol and terminal marking used by IEC (ANSI) standard for open delta connected VT
d)	is equivalent symbol and terminal marking used by IEC (ANSI) standard for phase-to-phase connected VT

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

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

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

4.2.1.11 Examples how to connect three phase-to-ground connected VTs to the IED

Figure 50 gives an example how to connect the three phase-to-ground connected VTs to the IED. It as well 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.

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

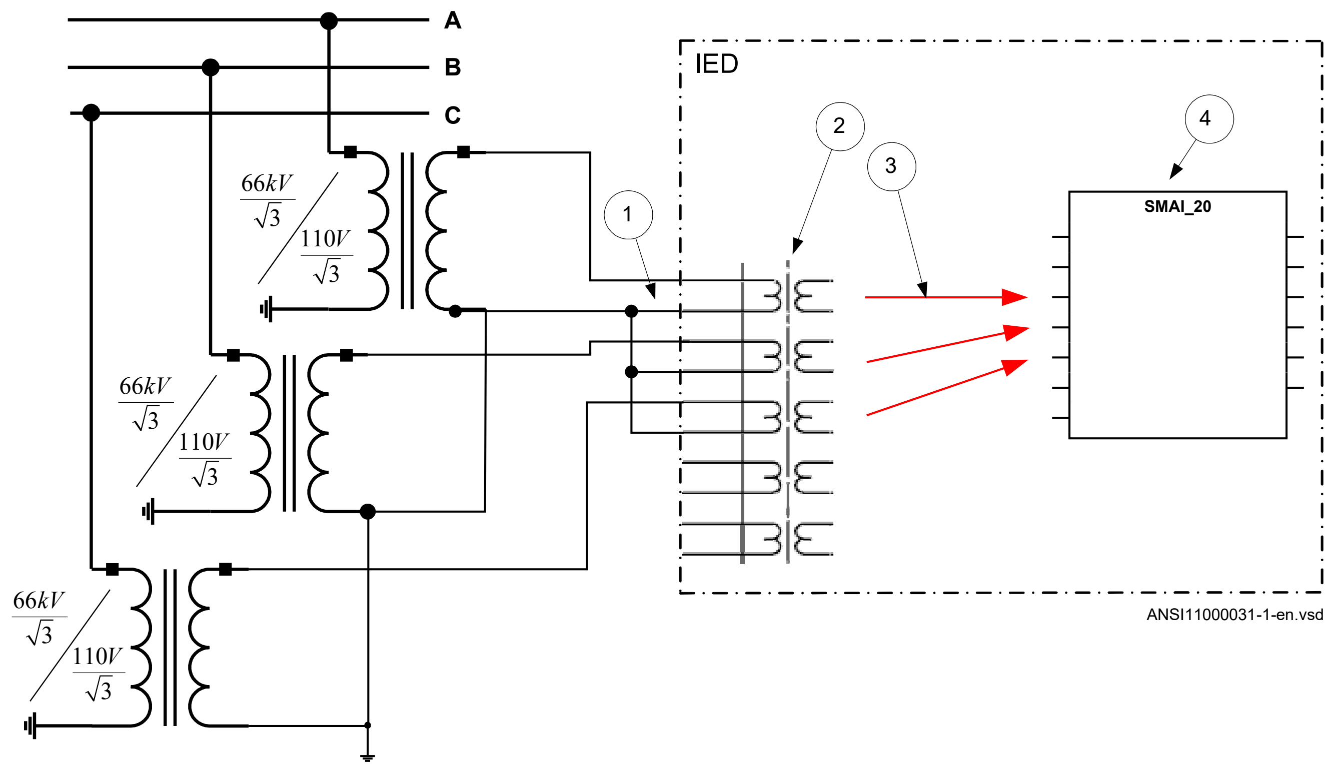


Figure 50: Three phase-to-ground connected VTs

Where
:

1)

2) is TRM or AIM where these three voltage inputs are located. It shall be noted that for these three voltage inputs the following setting values shall be entered:
VTprim=66 kV
VTsec= 110 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 43)

3) are three connections, which connect these three voltage inputs to three input channels of the preprocessing function block 5). Depending on type of functions which need this voltage information, more then one preprocessing block might be connected in parallel to these three VT inputs

4) 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. 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:
VBase=66 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.

Section 5 Local human-machine interface

5.1 Local HMI

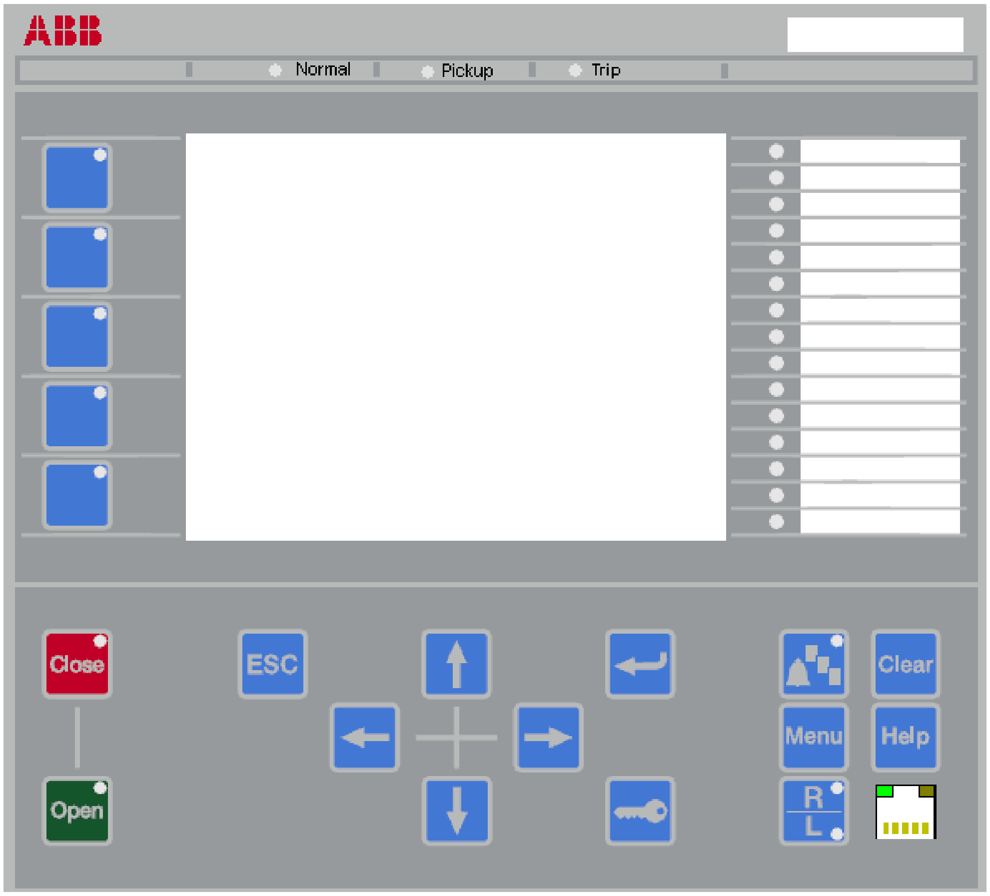


Figure 51: Local human-machine interface

The LHMI of the IED contains the following elements:

- Display (LCD)
- Buttons
- LED indicators
- Communication port

The LHMI is used for setting, monitoring and controlling .

5.1.1 Display

The LHMI includes a graphical monochrome display with a resolution of 320 x 240 pixels. The character size can vary.

The display view is divided into four basic areas.

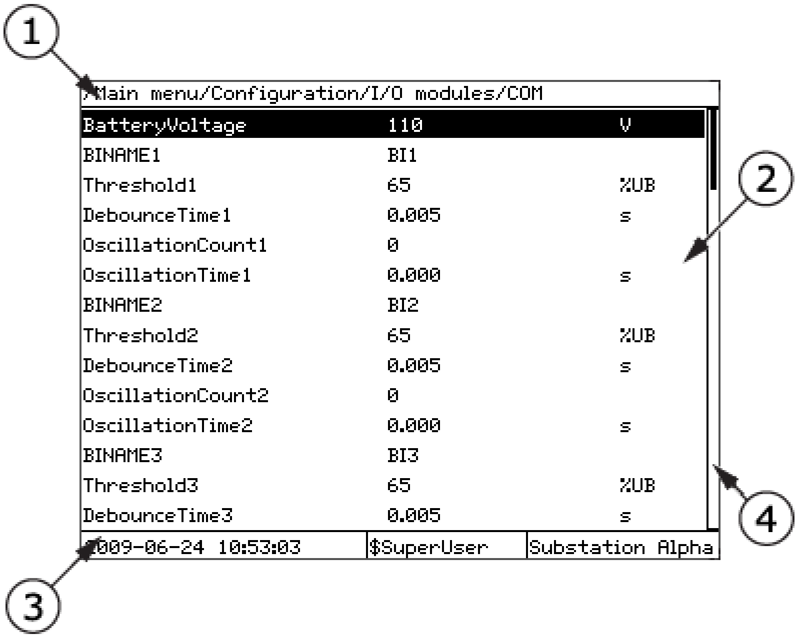


Figure 52: Display layout

1 Path

2 Content

3 Status

4 Scroll bar (appears when needed)

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

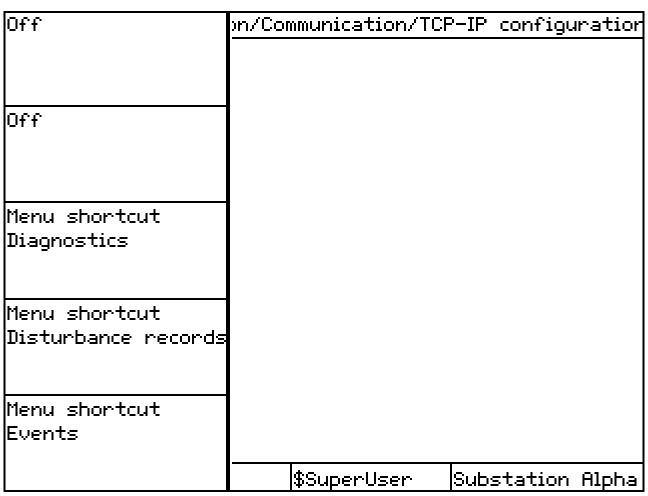


Figure 53: Function button panel

The alarm LED panel shows on request the alarm text labels for the alarm LEDs.

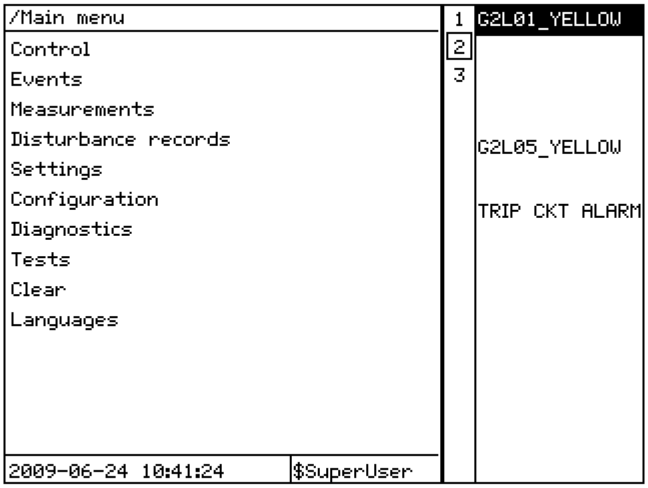


Figure 54: Alarm LED panel

The function button and alarm 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 the panels have dynamic width that depends on the label string length that the panel contains.

5.1.2 LEDs

The LHMI includes three protection indicators above the display: Normal, Pickup and Trip.

There are also 15 matrix programmable alarm LEDs on front of the LHMI. Each LED can indicate three states with the colors: green, yellow and red. The alarm texts related to each three-color LED are divided into three pages.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 can be configured with PCM600 and the operation mode can be selected with the LHMI or PCM600.

There are two additional LEDs which are embedded into the control buttons 

and 

. They represent the status of the circuit breaker.

5.1.3 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.

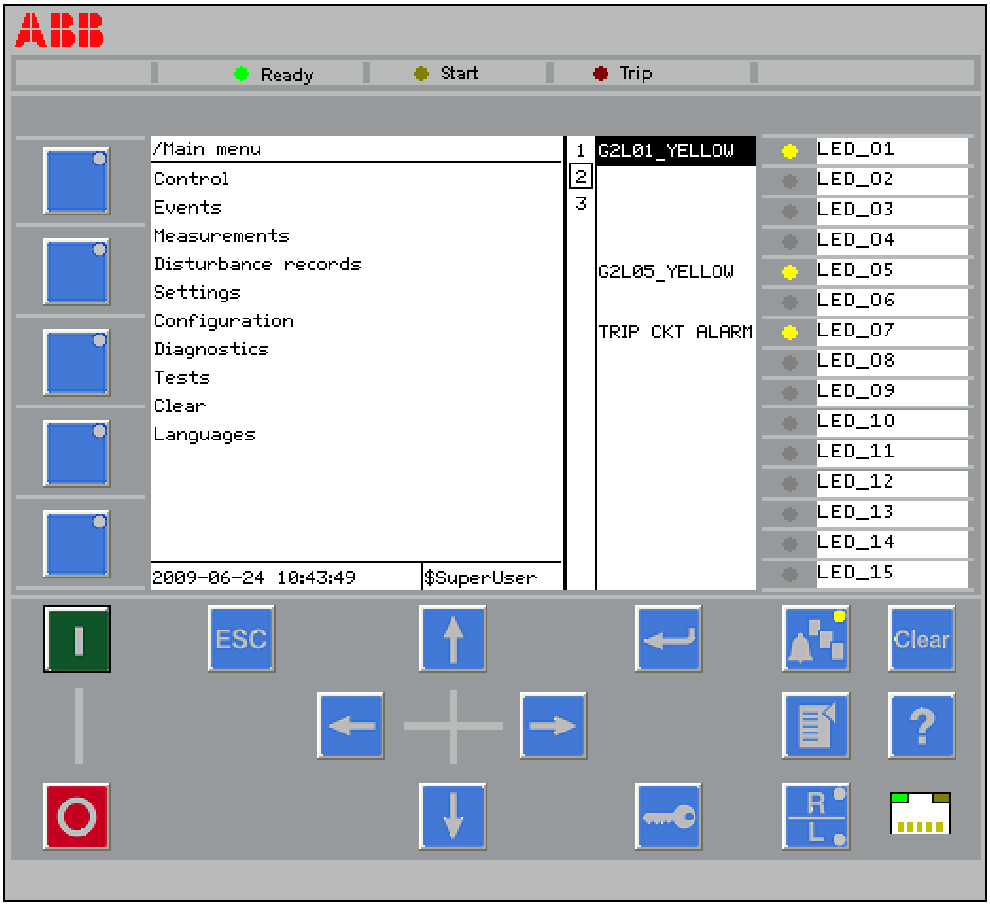


Figure 55: LHMI keypad

5.1.4 Local HMI functionality

5.1.4.1 Protection and alarm indication

Protection indicators

The protection indicator LEDs are Normal, Pickup and Trip.

Table 8: Normal LED (green)

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

Table 9: PickUp LED (yellow)

LED state	Description
Off	Normal operation.
On	A protection function has picked up and an indication message is displayed. • If several protection functions Pickup within a short time, the last Pickup is indicated on the display.
Flashing	A flashing yellow LED has a higher priority than a steady yellow LED. The IED is in test mode and protection functions are blocked. • The indication disappears when the IED is no longer in test mode and blocking is removed.

Table 10: Trip LED (red)

LED state	Description
Off	Normal operation.
On	A protection function has tripped and an indication message is displayed. • The trip indication is latching and must be reset via communication or by pressing Clear.

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 11: Alarm indications

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

Alarm indications for REL650

Table 12: Alarm group 1 indications in REL650 (A05A) configuration

Alarm group 1 LEDs	LED color	Label
GRP1_LED1	Red LED	21 PROT TRIP
GRP1_LED2	Red LED	OC PROT TRIP
GRP1_LED3	Red LED	GND PROT TRIP
GRP1_LED4	Red LED	85 PROT TRIP
GRP1_LED5	Red LED	59/27 PROT TRIP
GRP1_LED6	Red LED	50BF PROT TRIP
GRP1_LED7	-	-
GRP1_LED8	-	-
GRP1_LED9	Yellow LED	46 ALARM
GRP1_LED10	-	-
GRP1_LED11	-	-
GRP1_LED12	-	-
GRP1_LED13	-	-
GRP1_LED14	-	-
GRP1_LED15	-	-

Table 13: Alarm group 2 indications in REL650 (A05A) configuration

Alarm group 2 LEDs	LED color	Label
GRP2_LED1	Yellow LED	GEN PICKUP 21
GRP2_LED2	Yellow LED	GEN PICKUP OC
GRP2_LED3	Yellow LED	GEN PICKUP GND
GRP2_LED4	-	-
GRP2_LED5	Yellow LED	GEN PICKUP 59
GRP2_LED6	Yellow LED	GEN PICKUP A
GRP2_LED7	Yellow LED	GEN PICKUP B
GRP2_LED8	Yellow LED	GEN PICKUP C
GRP2_LED9	-	-
GRP2_LED10	-	-
GRP2_LED11	-	-
GRP2_LED12	-	-
GRP2_LED13	-	-
GRP2_LED14	-	-
GRP2_LED15	-	-

Table 14: Alarm group 3 indications in REL650 (A05A) configuration

Alarm group 3 LEDs	LED color	Label
GRP3_LED1 - GRP3_LED9	-	-
GRP3_LED10	Yellow LED	Z BLOCK
GRP3_LED11	Yellow LED	V BLOCK
GRP3_LED12	-	-
GRP3_LED13	Yellow LED	BKR ALARMS
GRP3_LED14	Yellow LED	TCS ALARM
GRP3_LED15	Red LED	BAT SUP ALARM
	Yellow LED	BAT SUP PICKUP

5.1.4.2 Parameter management

The LHMI is used to access the IED 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.

5.1.4.3 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.

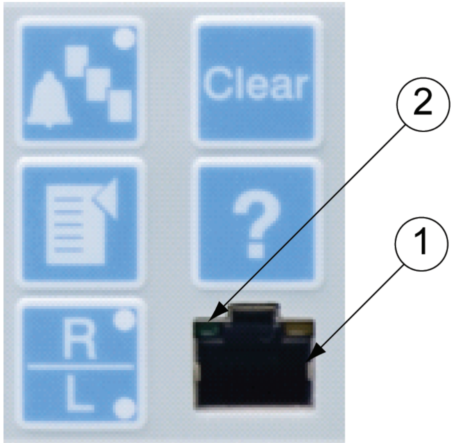


Figure 56: RJ-45 communication port and green indicator LED

1 RJ-45 connector

2 Green indicator LED

When a computer is connected to the IED front port with a crossed-over cable, the IED's DHCP server for the front interface assigns an IP address to the computer if *DHCPServer* = *Enabled*. The default IP address for the front port is 10.1.150.3.

Do not connect the IED front port to LAN. Connect only a single local PC with PCM600 to front port.

5.1.4.4 Single-line diagram

Single-line diagram for REL650

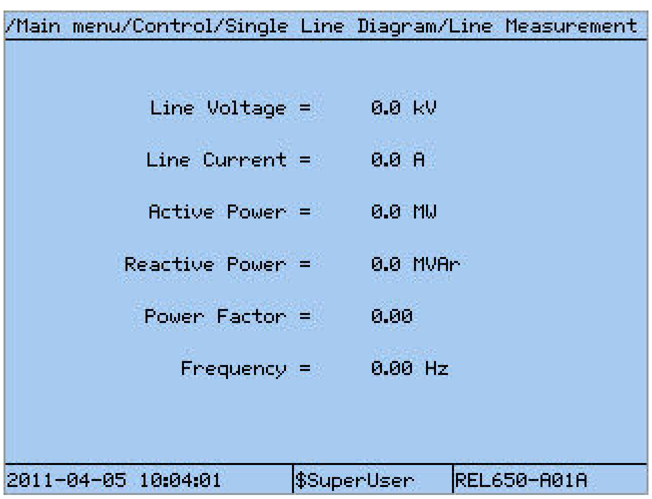


Figure 57: Single-line diagram for REL650(A01A)

Section 6 Impedance protection

6.1 Five zone distance protection, quadrilateral characteristic ZQDPDIS (21)

6.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Five zone distance protection, quadrilateral characteristic	ZQDPDIS	Z<	21

6.1.2 Application

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

Five zone distance protection, quadrilateral characteristic function (ZQDPDIS, 21) is designed to meet basic requirements for application on transmission and sub-transmission lines although it also can be used on distribution levels.

6.1.2.1 System grounding

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

Solid grounded networks
In solidly grounded systems, the transformer neutrals are connected solidly to ground without any impedance between the transformer neutral and ground.

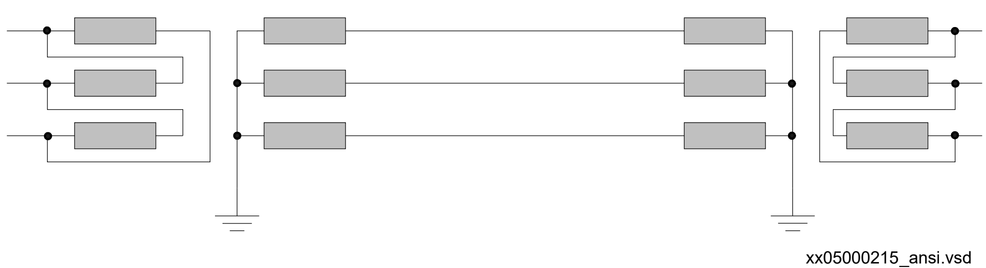


Figure 58: Solidly grounded network

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

The ground-fault current at single phase-to-ground in phase A can be calculated as equation 44:

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

(Equation 44)

Where:

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

The voltage on the healthy phases is generally lower than 140% of the nominal phase-to-ground voltage. This corresponds to about 80% of the nominal phase-to-phase voltage.

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

Effectively grounded networks

A network is defined as effectively grounded if the ground-fault factor f_e is less than 1.4. The ground-fault factor is defined according to equation 45.

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

(Equation 45)

Where:

V_{max}	is the highest fundamental frequency voltage on one of the healthy phases at single phase-to-ground fault.
V_{pn}	is the phase-to-ground fundamental frequency voltage before fault.

Another definition for effectively grounded network is when the following relationships between the symmetrical components of the network impedances are valid, see equation 46 and equation 47.

$$X_0 < 3 \cdot X_1$$

(Equation 46)

$$R_0 \leq R_1$$

(Equation 47)

Where

R_0	is the resistive zero sequence reach
X_0	is the reactive zero sequence reach
R_1	is the resistive positive sequence reach
X_1	is the reactive positive sequence reach

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

High impedance grounded networks

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

This type of network is many times operated in radial, but can also be found operating meshed networks.

What is typical for this type of network is that the magnitude of the ground-fault current is very low compared to the short circuit current. The voltage on the healthy phases will get a magnitude of √3 times the phase voltage during the fault. The zero sequence voltage ($3V_0$) will have the same magnitude in different places in the network due to low voltage drop distribution.

The magnitude of the total fault current can be calculated according to equation 48.

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

(Equation 48)

Where:

$3I_0$	is the ground-fault current (A)
IR	is the current through the neutral point resistor (A)
IL	is the current through the neutral point reactor (A)
IC	is the total capacitive ground-fault current (A)

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

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

(Equation 49)

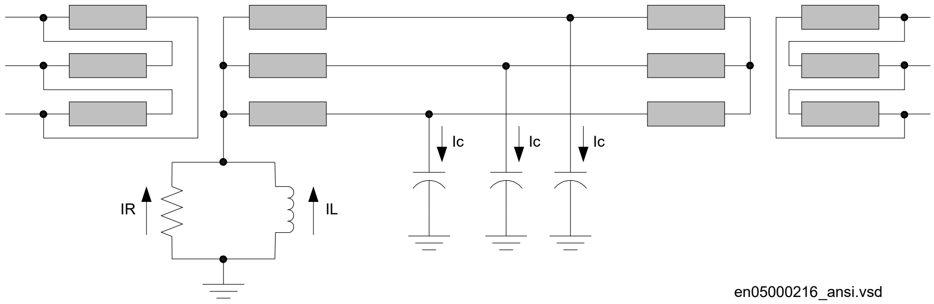


Figure 59: High impedance grounded network

The operation of high impedance grounded networks is different compared to solid grounded networks where all major faults have to be cleared very fast. In high impedance grounded networks, some system operators do not clear single phase-to-ground faults immediately; they clear the line later when it is more convenient. In case of cross-country faults, many network operators want to selectively clear one of the two ground faults. To handle this type phenomenon, a separate function called Phase preference logic (PPLPHIZ) is needed, which is not common to be used in transmission applications.

In this type of network, it is mostly not possible to use distance protection for detection and clearance of ground faults. The low magnitude of the ground-fault current might not give pickup of the zero-sequence measurement elements or the sensitivity will be too low for acceptance. For this reason a separate high sensitive ground-fault protection is necessary to carry out the fault clearance for single phase-to-ground fault.

6.1.2.2 Fault infeed from remote end

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

With reference to figure 60, the equation for the bus voltage V_A at A side is:

$$\overline{V}_A = \overline{I}_A \cdot p \cdot Z_L + (\overline{I}_A + \overline{I}_B) \cdot R_f$$

(Equation 50)

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

$$\overline{Z}_A = \frac{\overline{V}_a}{\overline{I}_A} = p \cdot \overline{Z}_L + \frac{\overline{I}_A + \overline{I}_B}{\overline{I}_A} \cdot R_f$$

(Equation 51)

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

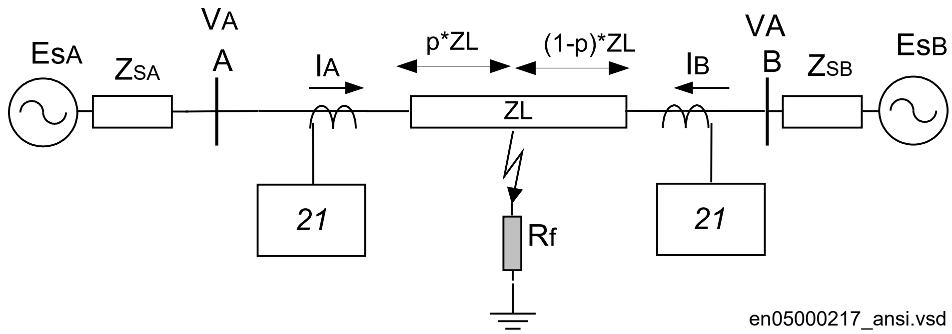


Figure 60: Influence of fault current infeed from remote line end

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

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

6.1.2.3 Load encroachment

In some cases the load impedance might enter the zone characteristic without any fault on the protected line. The phenomenon is called load encroachment and it might occur when an external fault is cleared and high emergency load is transferred on the protected line. The effect of load encroachment is illustrated to the left in figure 61. The entrance of the load impedance inside the characteristic is of course not allowed and the way to handle this with conventional distance protection is to consider this with the settings, that is, to have a security margin between the distance zone and the minimum load impedance. This has the drawback that it will reduce the sensitivity of the protection, that is, the ability to detect resistive faults.

The IED has a built in function which shapes the characteristic according to the right figure of figure 61. The load encroachment algorithm will increase the possibility to detect high fault resistances, especially for phase-to-ground faults at remote line end. For example, for a given setting of the load angle *LdAngle* for Phase selection with load encroachment, quadrilateral characteristic function (FDPSPDIS, 21), the resistive blinder for the zone measurement can be expanded according to the figure 61 given higher fault resistance coverage without risk for unwanted operation due to load encroachment. This is valid in both directions.

The use of the load encroachment feature is essential for long heavy loaded lines, where there might be a conflict between the necessary emergency load transfer and necessary sensitivity of the distance protection. The function can also preferably be used on heavy loaded medium long lines. For short lines, the major concern is to get sufficient fault resistance coverage and load encroachment is not a major problem. So, for short lines, the load encroachment function could preferably be switched off. See section "Load impedance limitation, without load encroachment function".

The settings of the parameters for load encroachment are done in FDPSPDIS (21) function.

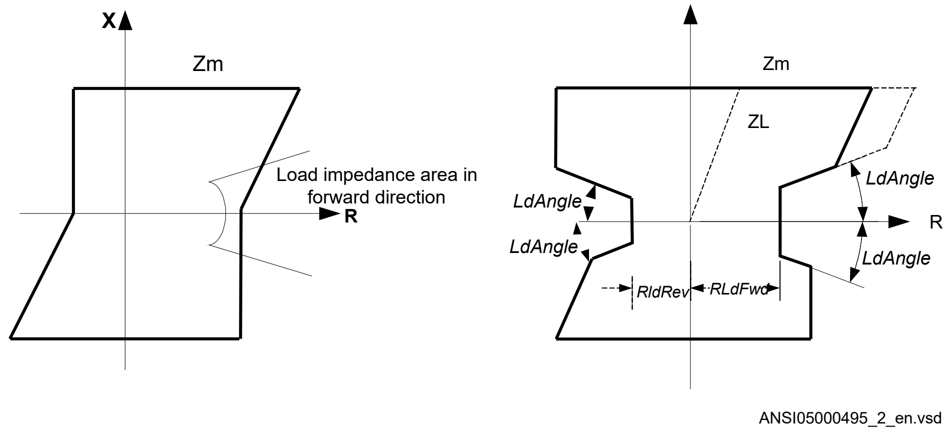


Figure 61: Load encroachment phenomena and shaped load encroachment characteristic defined in Phase selection with load encroachment function FDPSPDIS (21)

6.1.2.4 Short line application

Transmission line lengths for protection application purposes are classified as short, medium and long. The definition of short, medium and long lines is found in IEEE Std C37.113-1999.). The length classification is defined by the ratio of the source impedance at the protected line's terminal to the protected line's impedance (SIR). SIR's of about 4 or greater generally define a short line. Medium lines are those with SIR's greater than 0.5 and less than 4

In short line applications, the major concern is to get sufficient fault resistance coverage. Load encroachment is not so common. The line length that can be recognized as a short line is not a fixed length; it depends on system parameters such as voltage and source impedance, see table 15.

Table 15: Definition of short and very short line

Line category	Vn 110 kV	Vn 500 kV
Very short line	0.75 -3.5mile	3-15 miles
Short line	4-7 miles	15-30 miles

The IED's ability to set individual fault resistance settings for phase-to-phase and phase-to-ground fault together with load encroachment algorithm improves the possibility to detect high resistive faults without conflict with the load impedance, see figure 61.

For very short line applications, the underreaching zone 1 can not be used due to the voltage drop distribution throughout the line will be too low causing risk for overreaching. It is difficult, if not impossible, to apply distance protection for short lines. It is possible to apply an overreaching pilot communication based POTT or Blocking scheme protection for such lines to have fast tripping along the entire line. Usually a unit protection, based on comparison of currents at the ends of the lines is applied for such lines.

Load encroachment is normally no problem for short line applications.

6.1.2.5 Long transmission line application

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

What can be recognized as long lines with respect to the performance of distance protection can generally be described as in table 16, long lines have Source impedance ratio (SIR's) less than 0.5.

Table 16: Definition of long and very long lines

Line category	**Vn 110 kV**	**Vn 500 kV**
Long lines	45-60 miles	200-250 miles
Very long lines	>60 miles	>250 miles

The IED's ability to set individual fault resistance settings for phase-to-phase and phase-to-ground fault together with load encroachment algorithm improves the possibility to detect high resistive faults at the same time as the security is improved (risk for unwanted trip due to load encroachment is eliminated), see figure 61.

6.1.2.6 Parallel line application with mutual coupling

General

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

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

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

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

The different network configuration classes are:

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

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

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

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

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

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

Most multi circuit lines have two parallel operating circuits.

Parallel line applications

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

The three most common operation modes are:

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

Parallel line in service

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

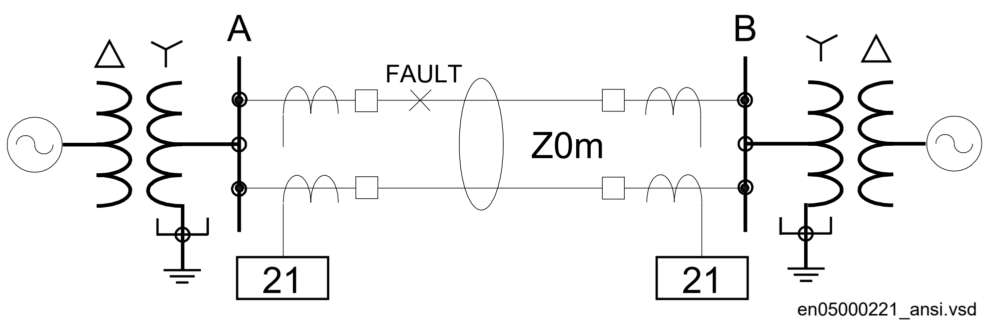


Figure 62: Class 1, parallel line in service

The equivalent circuit of the lines can be simplified, see figure 63.

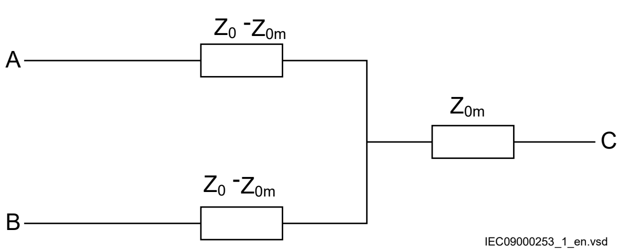


Figure 63: Equivalent zero sequence impedance circuit of the double-circuit, parallel, operating line with a single phase-to-ground fault at the remote busbar

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

Maximum overreach will occur if the fault current infeed from remote line end is weak. If considering a single phase-to-ground fault at 'p' unit of the line length from A to B on the parallel line for the case when the fault current infeed from remote line end is zero, the voltage V_A in the faulty phase at A side as in equation 52.

$$V_A = p \cdot Z1_L \left(I_{ph} + K_N \cdot 3I_0 + K_{Nm} \cdot 3I_{0p} \right)$$

(Equation 52)

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

Parallel line out of service and grounded

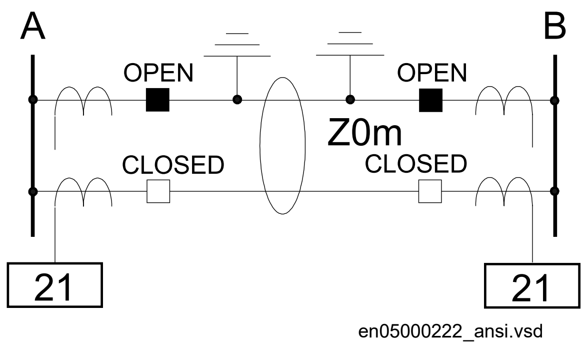


Figure 64: The parallel line is out of service and grounded

When the parallel line is out of service and grounded at both line ends on the bus bar side of the line CTs so that zero sequence current can flow on the parallel line, the equivalent zero sequence circuit of the parallel lines will be according to figure 65.

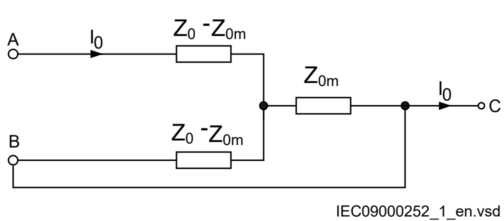


Figure 65: Equivalent zero sequence impedance circuit for the double-circuit line that operates with one circuit disconnected and grounded at both ends

Here the equivalent zero-sequence impedance is equal to Z_0-Z_0m in parallel with (Z_0-Z_{0m})/Z_0-Z_{0m} +Z_{0m} which is equal to equation 53.

$$\overline{Z}_{0E} = \frac{\overline{Z}_0^2 - \overline{Z0}_m^2}{\overline{Z}_0}$$

(Equation 53)

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

Parallel line out of service and not grounded

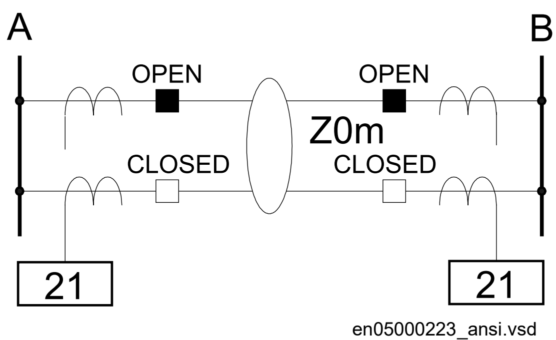


Figure 66: Parallel line is out of service and not grounded

When the parallel line is out of service and not grounded, the zero sequence on that line can only flow through the line admittance to the ground. The line admittance is high which limits the zero-sequence current on the parallel line to very low values. In practice, the equivalent zero-sequence impedance circuit for faults at the remote bus bar can be simplified to the circuit shown in figure 66

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

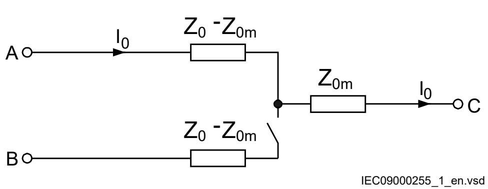


Figure 67: Equivalent zero-sequence impedance circuit for a double-circuit line with one circuit disconnected and not grounded

The reduction of the reach is equal to equation 54.

$$\overline{K}_U = \frac{\frac{1}{3}\cdot\left(2\cdot\overline{Z_1}+\overline{Z_{0E}}\right)+R_f}{\frac{1}{3}\cdot\left(2\cdot\overline{Z_1}+\overline{Z_0}\right)+R_f} = 1-\frac{\overline{Z_{m0}}^2}{\overline{Z_0}\cdot\left(2\cdot\overline{Z}_1+\overline{Z}_0+3R_f\right)}$$

(Equation 54)

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

6.1.2.7 Tapped line application

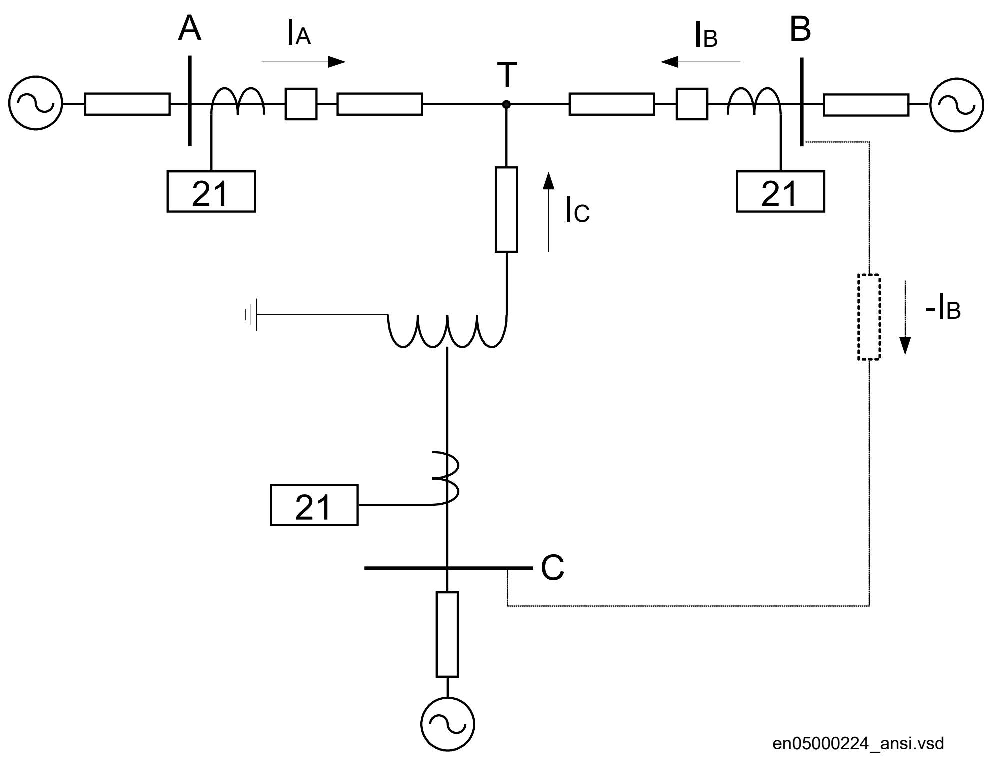


Figure 68: Example of tapped line with Auto transformer

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

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

(Equation 55)

$$\overline{Z}_C = \overline{Z}_{Trf} + (\overline{Z}_{CT} + \frac{\dot{I}_A + \dot{I}_C}{\dot{I}_C} \cdot \overline{Z}_{TB}) \cdot (\frac{V2}{V1})^2$$

(Equation 56)

Where:

Z_{AT} and Z_{CT}	is the line impedance from the A respective C station to the T point.
I_A and I_C	is fault current from A respective C station for fault between T and B.
V2/V1	Transformation ratio for transformation of impedance at V1 side of the transformer to the measuring side V2 (it is assumed that current and voltage distance function is taken from V2 side of the transformer).
Z_{TF}	is the line impedance from the T point to the fault (F).
Z_{Trf}	Transformer impedance

For this example with a fault between T and B, the measured impedance from the T point to the fault will be increased by a factor defined as the sum of the currents from T point to the fault divided by the IED current. For the IED at C, the impedance on the high voltage side V1 has to be transferred to the measuring voltage level by the transformer ratio.

Another complication that might occur depending on the topology is that the current from one end can have a reverse direction for fault on the protected line. For example, for faults at T the current from B might go in reverse direction from B to C depending on the system parameters (see the dotted line in figure 68), given that the distance protection in B to T will measure wrong direction.

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

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

Fault resistance

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

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

(Equation 57)

where:

L	represents the length of the arc (in meters). This equation applies for the distance protection zone 1. Consider approximately three times arc foot spacing for the zone 2 and wind speed of approximately 30 m/h
I	is the actual fault current in A.

In practice, the setting of fault resistance for both phase-to-ground *RFPEx* and phase-to-phase *RFPPx* (where *x* is 1-5 depending on selected zone) should be as high as possible without interfering with the load impedance in order to obtain reliable fault detection.

6.1.3 Setting guidelines

6.1.3.1 General

The settings for Five zone distance protection, quadrilateral characteristic function (ZQDPDIS, 21) are done in primary values. The instrument transformer ratio that has been set for the analogue input card is used to automatically convert the measured secondary input signals to primary values used in ZQDPDIS (21).

The settings for the function are done in primary values. The instrument transformer ratio that has been set for the analogue input card is used to automatically convert the measured secondary input signals to primary values used in ZGPDIS(21G).

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

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

The setting values of all parameters that belong to ZGPDIS (21G) must correspond to the parameters of the protected object and be coordinated to the selectivity plan for the network.

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

6.1.3.2 Setting of zone 1

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

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

6.1.3.3 Setting of overreaching zone

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

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

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

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

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

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

If a fault occurs at point F see figure 69, the IED at point A senses the impedance:

$$\overline{Z}_{AF} = \overline{Z}_{AC} + \frac{\overline{I}_A + \overline{I}_B}{\overline{I}_A} \cdot \overline{Z}_{CF} = \overline{Z}_{AC} + \left(1 + \frac{\overline{I}_B}{\overline{I}_A}\right) \cdot \overline{Z}_{CF}$$

(Equation 58)

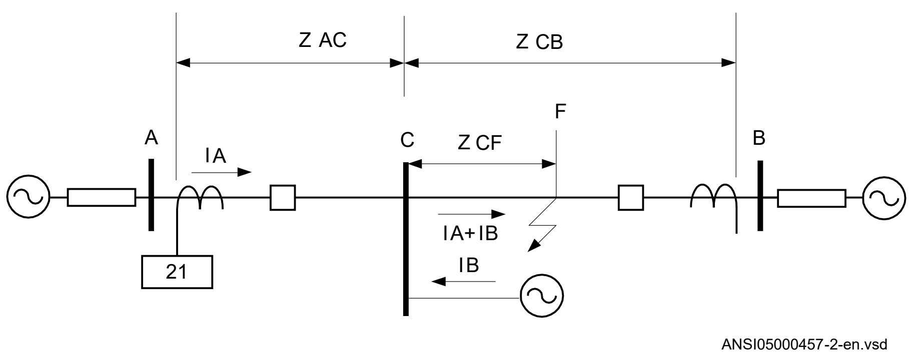


Figure 69: Setting of overreaching zone

6.1.3.4 Setting of reverse zone

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

Consider the possible enlarging factor that might exist due to fault infeed from adjacent lines. Equation 59 can be used to calculate the reach in reverse direction when the zone is used for blocking scheme, weak-end infeed, and so on.

$$Zrev \geq 1.2 \cdot \left| ZL \quad Z2rem \right|$$

(Equation 59)

Where:

ZL	is the protected line impedance
Z2rem	is zone 2 setting at remote end of protected line.

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

6.1.3.5 Setting of zones for parallel line application

Parallel line in service – Setting of zone 1
With reference to section "Parallel line applications", the zone reach can be set to 85% of protected line.

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

Parallel line in service – setting of zone 2
Overreaching zones (in general, zones 2 and 3) must overreach the protected circuit in all cases. The greatest reduction of a reach occurs in cases when both parallel circuits are in service with a single phase-to-ground fault located at the end of a protected line. The equivalent zero sequence impedance circuit for this case is equal to the one in figure 63 in section "Parallel line in service".

Parallel line is out of service and grounded in both ends
Apply the same measures as in the case with a single set of setting parameters. This means that an underreaching zone must not overreach the end of a protected circuit for the single phase-to-ground faults.

6.1.3.6 Setting of reach in resistive direction

Set separately the expected fault resistance for phase-to-phase faults *RFPPx* and for the phase-to-ground faults *RFPEx* (where *x* is 1-5 depending on selected zone) for each zone. For each distance zone, set all remaining reach setting parameters independently of each other.

6.1.3.7 Load impedance limitation, without load encroachment function

The following instructions are valid when Phase selection with load encroachment, quadrilateral characteristic function FDPSPDIS (21) is not activated. To deactivate the function, the setting of the load resistance *RLdFwd* and *RldRev* in FDPSPDIS (21) must be set to max value (3000). Check the maximum permissible resistive reach for any zone to ensure that there is a sufficient setting margin between the boundary and the minimum load impedance. The minimum load impedance (Ω/phase) is calculated as:

$$Z_{load\,min} = \frac{V^2}{S}$$

(Equation 60)

Where:

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

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

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

(Equation 61)

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

As a safety margin is required to avoid load encroachment under three-phase conditions and to guarantee correct healthy phase IED operation under combined heavy three-phase load and ground faults, consider both: phase-to-phase and phase-to-ground fault operating characteristics.

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

$$RFPE \leq 0.8 \cdot Z_{load}$$

(Equation 62)

This equation is applicable only when the loop characteristic angle for the single phase-to-ground faults is more than three times as large as the maximum expected load-impedance angle. For the case when the loop characteristic angle is less than three times the load-impedance angle, more accurate calculations are necessary according to equation 63.

$$RFPE \leq 0.8 \cdot Z_{load\,min} \cdot \left[\cos\partial - \frac{2 \cdot R1 + R0}{2 \cdot X1 + X0} \cdot \sin\partial \right]$$

(Equation 63)

Where:

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

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

$$RFPP \leq 1.6 \cdot \mathrm{Z}_{\mathrm{load}}$$

(Equation 64)

Equation 64 is applicable only when the loop characteristic angle for the phase-to-phase faults is more than three times as large as the maximum expected load-impedance angle. More accurate calculations are necessary according to equation 65.

$$\mathrm{RFPP} \leq 1.6 \cdot \mathrm{Z}_{\mathrm{load\,min}} \cdot \left[\cos\vartheta - \frac{\mathrm{R1}}{\mathrm{X1}} \cdot \sin\vartheta \right]$$

(Equation 65)

All this is applicable for all measuring zones when no Power swing detection function ZMRPSB (68) is activated in the IED. Use an additional safety margin of approximately 20% in cases when a ZMRPSB (68) function is activated in the IED, refer to the description of Power swing detection function ZMRPSB (68).

6.1.3.8 Load impedance limitation, with Phase selection with load encroachment, quadrilateral characteristic function activated

The parameters for shaping of the load encroachment characteristic are found in the description of Phase selection with load encroachment, quadrilateral characteristic function (FDPSPDIS, 21).

6.1.3.9 Setting of minimum operating currents

The operation of Five zone distance protection, quadrilateral characteristic function (ZQDPDIS, 21) can be blocked if the magnitude of the currents is below the set value of the parameter *IMinPUPP* and *IMinPUPG*.

The default setting of *IMinPUPP* and *IMinPUPG* is 20% of *IBase* where *IBase* is the chosen current for the analogue input channels. The value has been proven in practice to be suitable in most of the applications. However, there might be applications where it is necessary to increase the sensitivity by reducing the minimum operating current down to 10% of *IBase*. This happens especially in cases, when the IED serves as a remote back-up protection on series of very long transmission lines.

Setting *IMinOpIR* blocks the phase-to-ground loop if $3I_0$<*IMinOpIR*. The default setting of *IMinOpIR* is 5% of *IBase*.

The minimum operating fault current is automatically reduced to 75% of its set value, if the distance protection zone has been set for the operation in reverse direction.

6.1.3.10 Setting of timers for distance protection zones

The required time delays for different distance protection zones are independent of each other. Distance protection zone 1 can also have a time delay, if so required for selectivity reasons. Time delays for all zones can be set in a range of 0 to 60 seconds. The tripping function of each particular zone can be inhibited by setting the corresponding *OpModetLGx* and *OpModePPx* parameter to *Disabled*. Different time delays are possible for the phase-to-ground *tLGx* and for the phase-to-phase *tPPx* measuring loops in each distance protection zone separately, to further increase the total flexibility of a distance protection. *OpModeLGx* and *OpModetPPx* must be set *Enabled* even if the time delays *tLGx* and *tPPx* are set to 0 s.

6.2 Phase selection with load enchroachment, quadrilateral characteristic FDPSPDIS (21)

6.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Phase selection with load encroachment, quadrilateral characteristic	FDPSPDIS	*Z<phs*	21

6.2.2 Application

The operation of transmission networks today is in many cases close to the stability limit. The ability to accurately and reliably classify the different types of fault, so that autoreclosing can be used plays an important role in this matter. The Phase selection with load encroachment function (FDPSPDIS, 21) is designed to accurately select the proper fault loop in the distance measuring function depending on the fault type.

The heavy load transfer that is common in many transmission networks may in some cases be in opposite to the wanted fault resistance coverage. Therefore, the function has a built in algorithm for load encroachment, which gives the possibility to enlarge the resistive setting of both the Phase selection with load encroachment and the measuring zones without interfering with the load.

A current-based phase selection is also included. The measuring elements continuously measure three phase currents and the residual current and, compare them with the set values.

The extensive output signals from FDPSPDIS (21) give also important information about faulty phase(s), which can be used for fault analysis.

6.2.3 Setting guidelines

6.2.3.1 Load encroachment characteristics

The phase selector must at least cover the overreaching zone 2 in order to achieve correct phase selection for utilizing autoreclosing for faults on the entire line. It is not necessary to cover all distance protection zones. A safety margin of at least 10% is recommended. In order to get operation from distance zones (ZQDPDIS , 21), the phase selection outputs STCNDZI or DLECND must be connected to input STCNDZI on ZMQPDIS (21), distance measuring block.

For normal overhead lines, the angle for the loop impedance ϕ for phase-to-ground fault is defined according to equation 66.

$$\arctan \varphi = \frac{X1_L + XN}{R1_L + RN}$$

(Equation 66)

In some applications, for instance cable lines, the angle of the loop might be less than 60°. In these applications, the settings of fault resistance coverage in forward and reverse direction, *RFltFwdPG* and *RFltRevPG* for phase-to-ground faults and *RFltRevPP* and *RFltRevPP* for phase-to-phase faults have to be increased to avoid that FDPSPDIS (21) characteristic shall cut off some part of the zone characteristic. The necessary increased setting of the fault resistance coverage can be derived from trigonometric evaluation of the basic characteristic for respectively fault type.

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Phase-to-ground fault in forward direction
With reference to figure 70, the following equations for the setting calculations can be obtained.

Index PHS in images and equations reference settings for Phase selection with load encroachment function FDPSPDIS (21) and index Zm reference settings for Distance protection function (ZQDPDIS, 21).

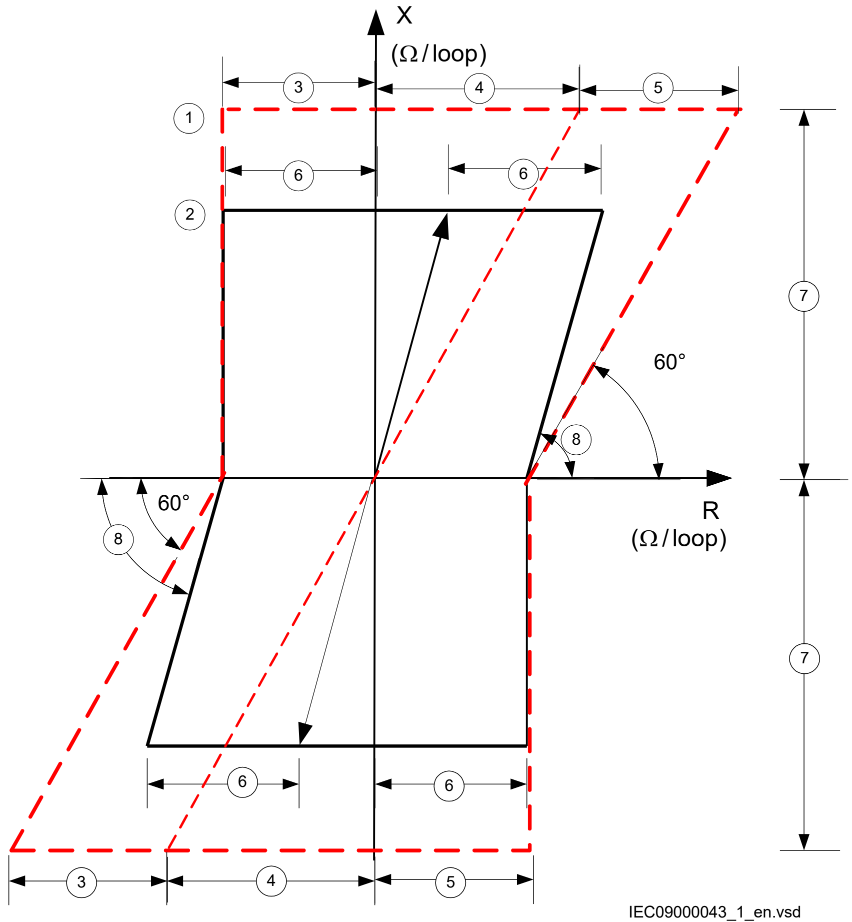


Figure 70: Relation between distance protection ZQDPDIS (21) and FDPSPDIS (21) for phase-to-ground fault ϕloop>60° (setting parameters in italic)

1 FDPSPDIS (21) (red line)

2 ZQDPDIS(21)

3

4 $(X1_{PHS}+XN)/\tan(60°)$

5

6

7 $X1_{PHS}+XN$

8 ϕloop

9 $X1_{ZM}+XN$

Reactive reach

The reactive reach in forward direction must as minimum be set to cover the measuring zone used in the Teleprotection schemes, mostly zone 2. Equation 67 and equation 68 gives the minimum recommended reactive reach.

$$X1_{PHS} \geq 1.44 \cdot X1_{Zm}$$

(Equation 67)

$$X0_{PHS} \geq 1.44 \cdot X0_{Zm}$$

(Equation 68)

where:

$X1_{Zm}$	is the reactive reach for the zone to be covered by FDPSPDIS (21), and the constant
1.44	is a safety margin
$X0_{Zm}$	is the zero-sequence reactive reach for the zone to be covered by FDPSPDIS (21)

The reactive reach in reverse direction is automatically set to the same reach as for forward direction. No additional setting is required.

Fault resistance reach
The resistive reach must cover *RFPG* for the overreaching zone to be covered, mostly zone 2. Consider the longest overreaching zone if correct fault selection is important in the application. Equation 69 gives the minimum recommended resistive reach.

$$RFltFwdPG_{\min} \geq 1.1 \cdot RFPG_{zm}$$

(Equation 69)

where:

$RFPG_{Zm}$	is the setting *RFPG* for the longest overreaching zone to be covered by FDPSPDIS (21).

The security margin has to be increased to at least 1.2° in the case where ϕloop<60° to avoid that FDPSPDIS (21) characteristic shall cut off some part of the zone measurement characteristic.

Phase-to-ground fault in reverse direction

Reactive reach
The reactive reach in reverse direction is the same as for forward so no additional setting is required.

Resistive reach
The resistive reach in reverse direction must be set longer than the longest reverse zones. In blocking schemes it must be set longer than the overreaching zone at remote end that is used in the communication scheme. In equation 70 the index ZmRv references the specific zone to be coordinated to.

$$RFltREvPG \geq 1.2 \cdot RFPG_{ZmRv}$$

(Equation 70)

Phase-to-phase fault in forward direction

Reactive reach
The reach in reactive direction is determined by phase-to-ground reach setting *X1*. No extra setting is required.

Resistive reach
In the same way as for phase-to-ground fault, the reach is automatically calculated based on setting *X1*. The reach will be X1/tan(60°) =X1/√(3).

Fault resistance reach
The fault resistance reaches in forward direction *RFltFwdPP*, must cover $RFPP_{Zm}$ with at least 25% margin. $RFPP_{Zm}$ is the setting of fault resistance for phase-to-phase fault for the longest overreaching zone to be covered by FDPSPDIS (21), see figure 71. The minimum recommended reach can be calculated according to equation 71.

$$RFltFwdPP \geq 1.25 \cdot RFPP_{zm}$$

(Equation 71)

where:

$RFPP_{Zm}$	is the setting of the longest reach of the overreaching zones that must be covered by FDPSPDIS (21).

Equation 71 modified is applicable also for the *RFltRevPP* as follows:

$$RFlt\,\mathrm{Re}\,vPP_{\min} \geq 1.25 \cdot RFPP_{zmRv}$$

Equation 71 is also valid for three-phase fault. The proposed margin of 25% will cater for the risk of cut off of the zone measuring characteristic that might occur at three-phase fault when FDPSPDIS (21) characteristic angle is changed from 60 degrees to 90 degrees (rotated 30° anti-clock wise).

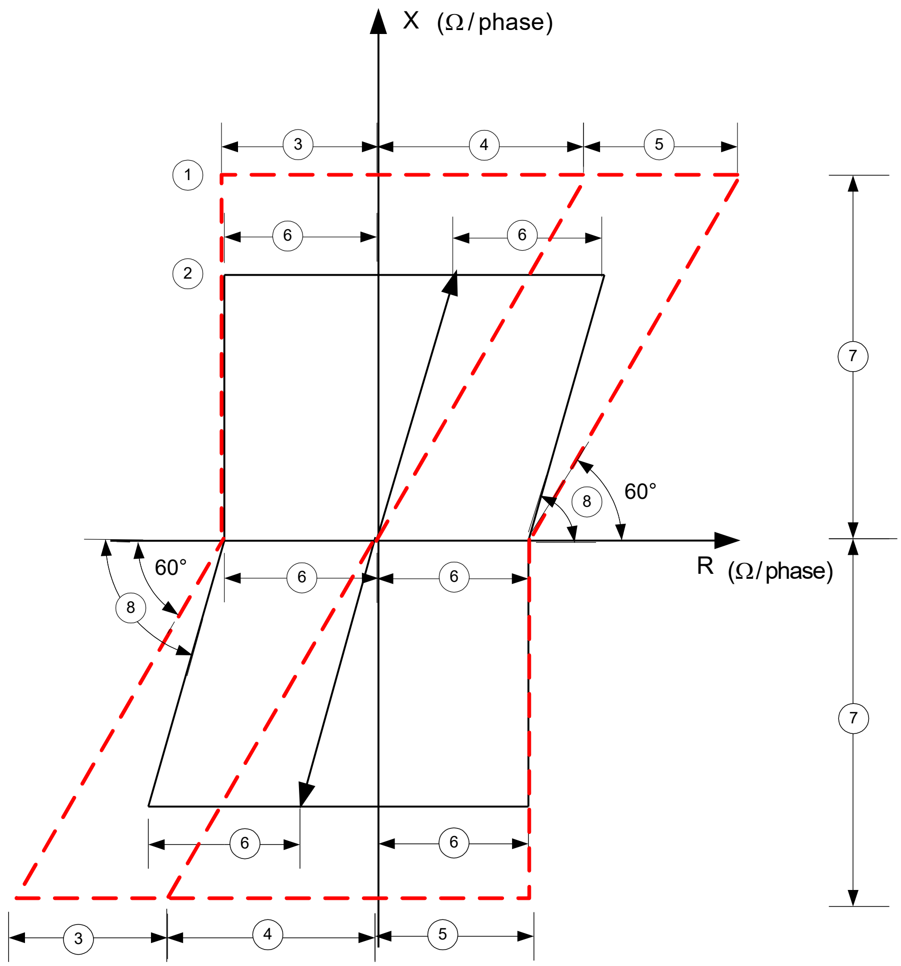


Figure 71: Relation between distance protection (ZQDPDIS) (21) and FDPSPDIS (21) characteristic for phase-to-phase fault for ϕline>60° (setting parameters in italic)

1 FDPSPDIS (21)(red line)

2 ZQDPDIS(21)

3 0.5 ·

4 $\frac{X1_{PHS}}{\tan(60°)}$

5 0.5 ·

6 0.5 · $RFPP_{Zm}$

7 $X1_{PHS}$

8 $X1_{Zm}$

6.2.3.2 Resistive reach with load encroachment characteristic

The procedure for calculating the settings for the load encroachment consist basically to define the load angle *LdAngle*, the blinder *RLdFwd* in forward direction and blinder *RLdRev* in reverse direction, as shown in figure 72.

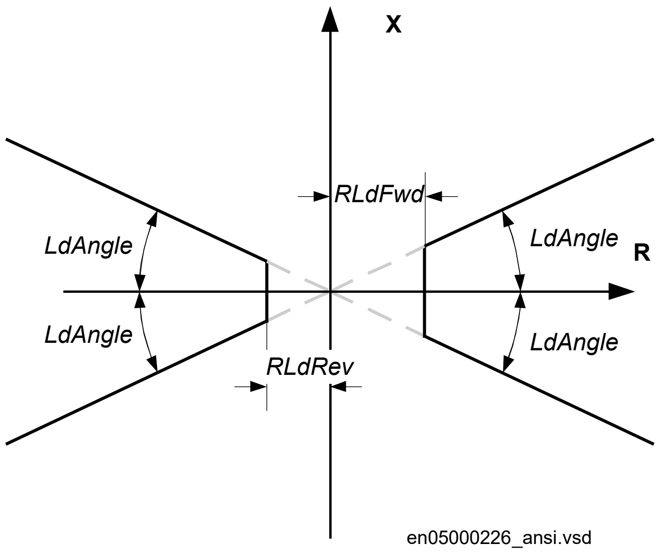


Figure 72: Load encroachment characteristic

The load angle *LdAngle* is the same in forward and reverse direction, so it could be suitable to begin to calculate the setting for that parameter. Set the parameter to the maximum possible load angle at maximum active load. A value bigger than 20° must be used.

The blinder in forward direction, *RLdFwd*, can be calculated according to equation 72.

$$RLdFwd = 0.8 \cdot \frac{V^2 \min}{P \exp \max}$$

where:

*P*exp max	is the maximum exporting active power
*V*min	is the minimum voltage for which the Pexp max occurs
0.8	is a security factor to ensure that the setting of *RLdFwd* can be lesser than the calculated minimal resistive load.

The resistive boundary *RLdRev* for load encroachment characteristic in reverse direction can be calculated in the same way as *RLdFwd*, but use maximum importing power that might occur instead of maximum exporting power and the relevant Vmin voltage for this condition.

6.2.3.3 Minimum operate currents

FDPSPDIS (21) has two current setting parameters which blocks the respective phase-to-ground loop and phase-to-phase loop if the RMS value of the phase current (ILn) and phase difference current (ILmILn) is below the settable threshold.

The threshold to activate the phase selector for phase-to-ground (*IMinPUPG*) is set to securely detect a single phase-to-ground fault at the furthest reach of the phase selection. It is recommended to set *IMinPUPP* to double value of *IMinPUPG*.

The threshold for opening the measuring loop for phase-to-ground fault (*3I0Enable_PG*) is set securely detect single line-to-ground fault at remote end on the protected line. It is recommended to set *3I0BLK_PP* to double value of *3I0Enable_PG*.

6.3 Five zone distance protection, mho characteristic ZMOPDIS(21)

6.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Five zone distance protection, mho characteristic	ZMOPDIS	Z<	21

6.3.2 Application

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

Five zone distance protection, mho characteristic function (ZMOPDIS, 21) in the IED is designed to meet basic requirements for application on transmission and sub-transmission lines (solid grounded systems) although it also can be used on distribution levels.

6.3.2.1 System grounding

The type of system grounding plays an important role when designing the protection system. In the following some hints with respect to distance protection are highlighted.

Solid grounded networks
In solid grounded systems the transformer neutrals are connected solidly to ground without any impedance between the transformer neutral and ground.

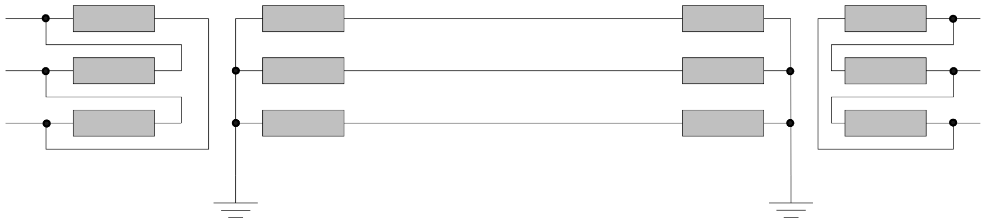


Figure 73: Solidly grounded network

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

The ground-fault current at single phase-to-ground in phase A can be calculated as equation 73:

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

(Equation 73)

Where:

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

The voltage on the healthy phases is generally lower than 140% of the nominal phase-to-ground voltage. This corresponds to about 80% of the nominal phase-to-phase voltage.

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

Effectively grounded networks

A network is defined as effectively grounded if the ground-fault factor f_e is less than 1.4. The ground-fault factor is defined according to equation 74.

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

(Equation 74)

Where:

V_{max}	is the highest fundamental frequency voltage on one of the healthy phases at single phase-to-ground fault.
V_{pn}	is the phase-to-ground fundamental frequency voltage before fault.

Another definition for effectively grounded network is when the following relationships between the symmetrical components of the network impedances are valid, see equation 75 and equation 76.

$$X_0 = 3 \cdot X_1$$

(Equation 75)

$$R_0 \leq R_1$$

(Equation 76)

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

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

This type of network is many times operated in radial, but can also be found operating meshed networks.

What is typical for this type of network is that the magnitude of the ground-fault current is very low compared to the short-circuit current. The voltage on the healthy phases will get a magnitude of √3 times the phase voltage during the fault. The zero-sequence voltage (3V0) will have the same magnitude in different places in the network due to low voltage drop distribution.

The magnitude of the total fault current can be calculated according to equation 77.

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

(Equation 77)

where

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

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

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

(Equation 78)

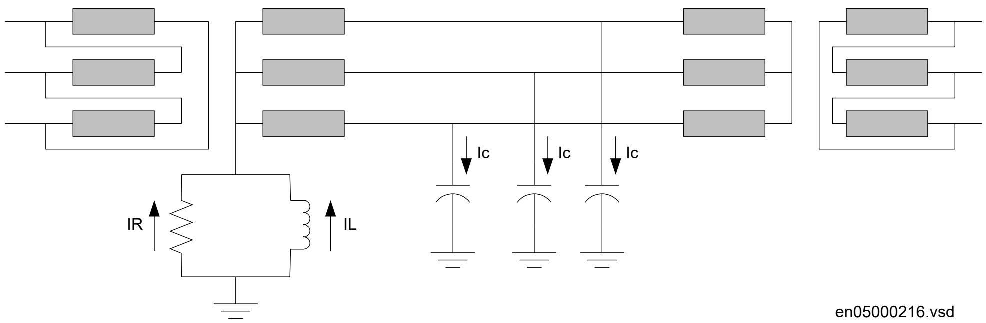


Figure 74: High impedance grounding network

The operation of high impedance grounded networks is different compared to solid grounded networks where all major faults have to be cleared very fast. In high impedance grounded networks, some system operators do not clear single phase-to-ground faults immediately; they clear the line later when it is more convenient. In case of cross-country faults, many network operators want to selectively clear one of the two ground faults. To handle this type phenomena Phase preference logic function (PPLPHIZ) is needed, which is not common to be used in transmission applications.

In this type of network, it is mostly not possible to use distance protection for detection and clearance of ground faults. The low magnitude of the ground-fault current might not give pickup of the zero-sequence measurement element or the sensitivity will be too low for acceptance. For this reason a separate high sensitive ground-fault protection is necessary to carry out the fault clearance for single phase-to-ground fault.

6.3.2.2 Fault infeed from remote end

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

With reference to figure 75, we can draw the equation for the bus voltage U_A at left side as:

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

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

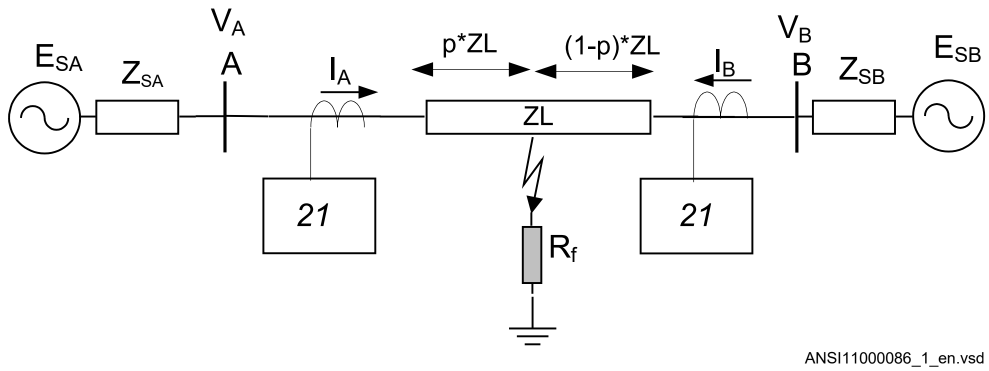


Figure 75: Influence of fault current infeed from remote end.

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

6.3.2.3 Load encroachment

In some cases the load impedance might enter the zone characteristic without any fault on the protected line. The phenomenon is called load encroachment and it might occur when an external fault is cleared and high emergency load is transferred on the protected line. The effect of load encroachment for the mho circle is illustrated to the left in figure 76. The entrance of the load impedance inside the characteristic is of course not allowed and the way to handle this with conventional distance protection is to consider this with the settings, that is, to have a security margin between the distance zone and the minimum load impedance. This has the drawback that it will reduce the sensitivity of the protection, that is, the ability to detect resistive faults.

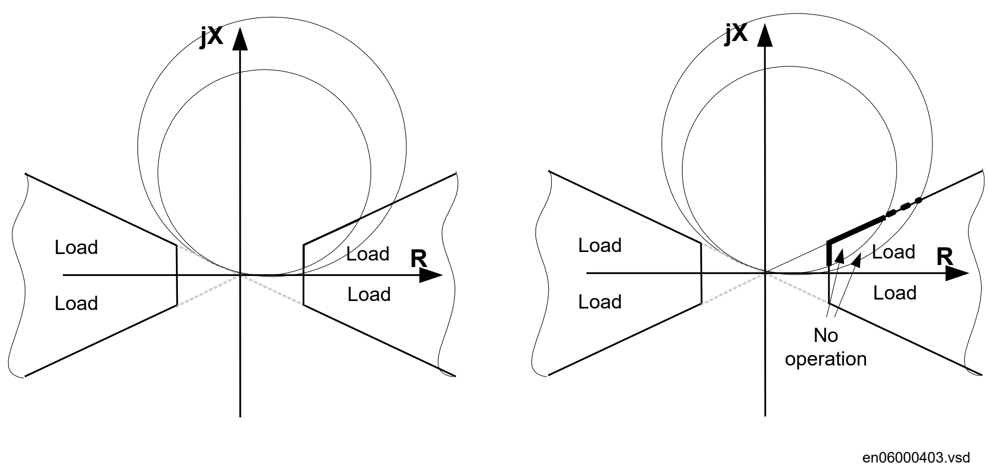


Figure 76: Load encroachment phenomena and shaped load encroachment characteristic

The Faulty phase identification with load encroachment for mho (FMPSPDIS, 21) function shapes the characteristic according to the diagram on the right in figure 76. The load encroachment algorithm will increase the possibility to detect high fault resistances, especially for phase-to-ground faults at remote line end. For example, for a given setting of the load angle *LdAngle* (see figure 77) for the Faulty phase identification with load encroachment for mho function (FMPSPDIS, 21), the zone reach can be expanded according to the diagram on the right in figure 76 given higher fault resistance coverage without risk for unwanted operation due to load encroachment.

The part of the load encroachment sector that comes inside the mho circle will not cause a trip if FMPSPDIS (21) is activated for the zone measurement. This is valid in both directions.

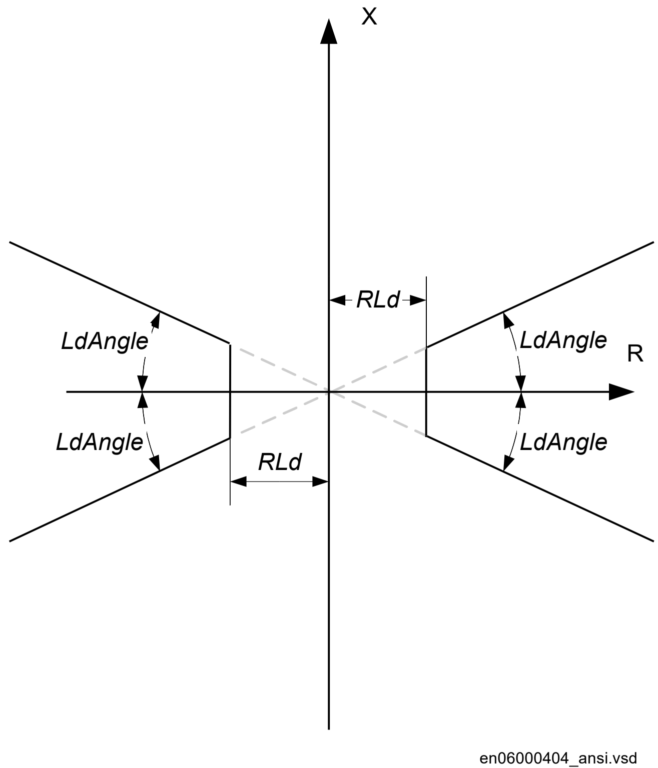


Figure 77: Load encroachment of Faulty phase identification with load encroachment for mho function FMPSPDIS (21) characteristic

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

The main settings of the parameters for load encroachment are done in Faulty phase identification with load encroachment for mho function FMPSPDIS (21). The operation of load encroachment function is always activated. To deactivate the function, setting *LoadEnchModex* (where *x* is 1-5 depending on selected zone) should be set off or the setting of *RLdFw* and *RLdRv* must be set to a value much higher than the maximal load impedance.

6.3.2.4 Short line application

The definition of short, medium and long lines is found in IEEE Std C37.113-1999. The length classification is defined by the ratio of the source impedance at the protected line's terminal to the protected line's impedance (SIR). SIR's of about 4 or greater generally define a short line. Medium lines are those with SIR's greater than 0.5 and less than 4.

In short line applications, the major concern is to get sufficient fault resistance coverage. Load encroachment is not so common. The line length that can be recognized as a short line is not a fixed length; it depends on system parameters such as voltage and source impedance, see table 17.

Table 17: Definition of short and very short line

Line category	Vn 110 kV	Vn 500 kV
Very short line	0.75–3.6 miles	3–15 miles
Short line	4–7 miles	15–30 miles

The use of load encroachment algorithm in Five zone distance protection, mho characteristic function (ZMOPDIS, 21) improves the possibility to detect high resistive faults without conflict with the load impedance (see to the right of figure 76).

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

Load encroachment is normally no problems for short line applications so the load encroachment function could be switched off meaning *LoadEnchModex* (where *x* is 1-5 depending on selected zone) = *Disabled*. This will increase the possibility to detect resistive close-in faults.

6.3.2.5 Long transmission line application

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

What can be recognized as long lines with respect to the performance of distance protection is noted in table 18.

Table 18: Definition of long lines

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

The possibility to use the binary information from the load encroachment algorithm improves the possibility to detect high resistive faults at the same time as the security is improved (risk for unwanted trip due to load encroachment is eliminated). The possibility to also use blinder together with load encroachment algorithm will considerable increase the security but might also lower the dependability since the blinder might cut off a larger part of the operating area of the circle (see to the right of figure 76).

It is recommended to use at least one of the load discrimination functions for long heavy loaded transmission lines.

6.3.2.6 Parallel line application with mutual coupling

General

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

Parallel lines introduce an error in the measurement due to the mutual coupling between the lines. The lines need not to be of the same voltage in order to experience mutual coupling, and some coupling exists even for lines that are separated by 100 meters or more. The reason to the introduced error in measuring due to mutual coupling is the zero sequence voltage inversion that occurs.

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

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

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

One example of class3 networks could be the mutual coupling between a 400 kV line and rail road overhead lines. This type of mutual coupling is not so common although it exists and is not treated any further in this manual.

For each type of network class we can have three different topologies; the parallel line can be in service, out of service, out of service and grounded in both ends.

The reach of the distance protection zone 1 will be different depending on the operation condition of the parallel line. It is therefore recommended to use the different setting groups to handle the cases when the parallel line is in operation and out of service and grounded at both ends.

Five zone distance protection, mho characteristic function (ZMOPDIS, 21) can compensate for the influence of a zero sequence mutual coupling on the measurement at single phase-to-ground faults in the following ways, by using:

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

Most multi circuit lines have two parallel operating circuits. The application guide mentioned below recommends in more detail the setting practice for this particular type of line. The basic principles also apply to other multi circuit lines.

Parallel line applications

In this type of networks, the parallel transmission lines terminate at common nodes at both ends. We consider the three most common operation modes:

1. parallel line in service.
2. parallel line out of service and grounded.
3. parallel line out of service and not grounded.

Parallel line in service

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

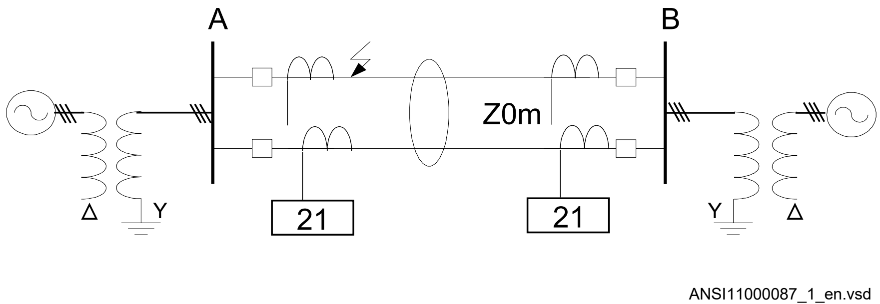


Figure 78: Class 1, parallel line in service.

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

Calculation for a 400 kV line, where the resistance is excluded, gives with X1L=0.303 Ω/km, X0L=0.88 Ω/km, zone 1 reach is set to 90% of the line reactance p=71%, that is, the protection is underreaching with approximately 20%.

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

Parallel line out of service and grounded

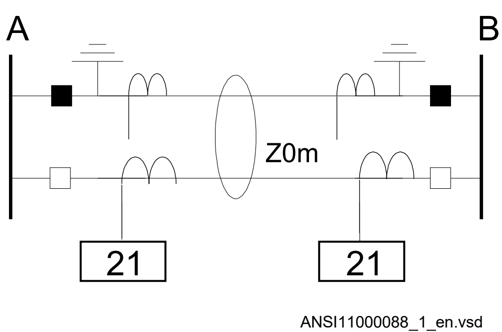


Figure 79: The parallel line is out of service and grounded

When the parallel line is out of service and grounded at both ends on the bus bar side of the line CT so that zero sequence current can flow on the parallel line.

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

Parallel line out of service and not grounded

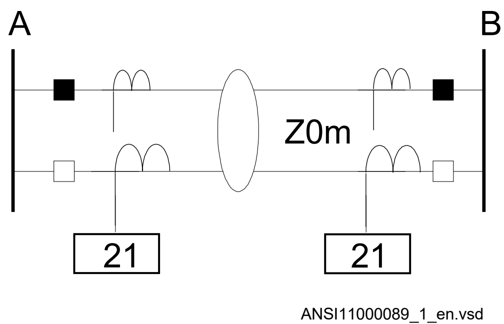


Figure 80: Parallel line is out of service and not grounded.

When the parallel line is out of service and not grounded, the zero sequence on that line can only flow through the line admittance to the ground. The line admittance is high which limits the zero sequence current on the parallel line to very low values.

The line zero sequence mutual impedance does not influence the measurement of the distance protection in a faulty circuit.

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

6.3.2.7 Tapped line application

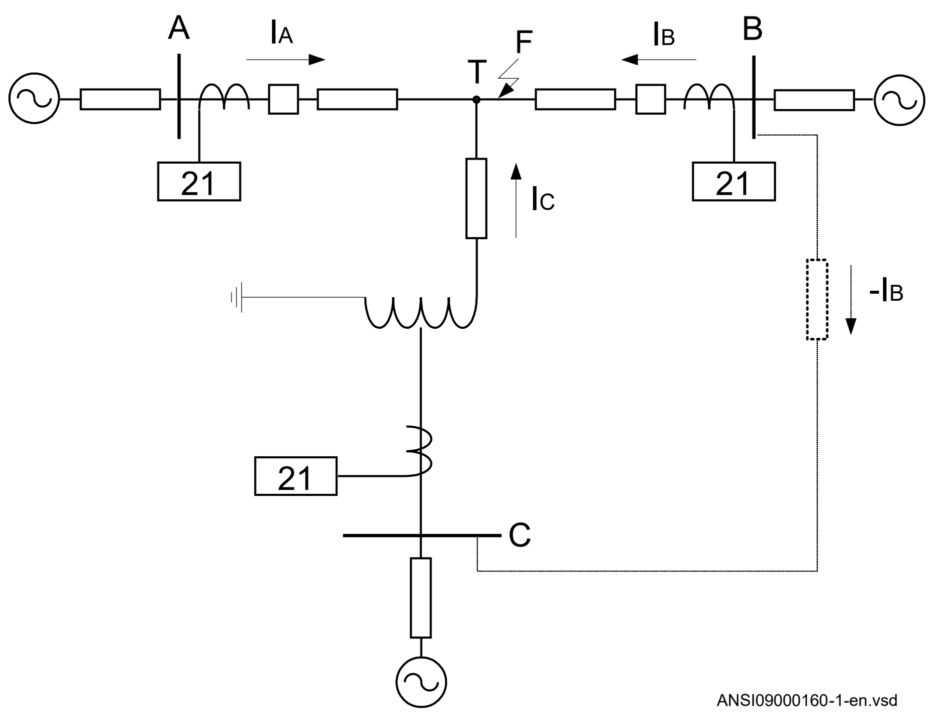


Figure 81: Example of tapped line with Auto transformer

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

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

(Equation 81)

$$\bar{Z}_C = \bar{Z}_{Trf} + \left(\bar{Z}_{CT} + \frac{I_A + I_C}{I_C} \cdot \bar{Z}_{TF} \right) \cdot \left(\frac{V2}{V1} \right)^2$$

(Equation 82)

where

Z_{AT} and Z_{CT}	is the line impedance from the A respective C station to the T point.
I_A and I_C	is fault current from A respective C station for fault between T and B.
V2/V1	Transformation ratio for transformation of impedance at U1 side of the transformer to the measuring side U2 (it is assumed that current and voltage distance function is taken from U2 side of the transformer).

For this example with a fault between T and B, the measured impedance from the T point to the fault will be increased by a factor defined as the sum of the currents from T point to the fault divided by the IED current. For the IED at C, the impedance on the high voltage side V1 has to be transferred to the measuring voltage level by the transformer ratio.

Another complication that might occur depending on the topology is that the current from one end can have a reverse direction for fault on the protected line. For example, for faults at T the current from B might go in reverse direction from B to C depending on the system parameters (see the dotted line in figure 81), given that the distance protection in B to T will measure wrong direction.

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

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

6.3.3 Setting guidelines

6.3.3.1 General

The settings for Five zone distance protection, mho characteristic function (ZMOPDIS, 21) are done in primary values. The instrument transformer ratio that has been set for the analog input card is used to automatically convert the measured secondary input signals to primary values used in ZMOPDIS (21).

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

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

The setting values of all parameters that belong to ZMOPDIS (21) must correspond to the parameters of the protected line and be coordinated to the selectivity plan for the network.

Use different setting groups for the cases when the parallel line is in operation, out of service and not grounded and out of service and grounded in both ends. In this way it is possible to optimize the settings for each system condition.

When Directional impedance element for mho characteristic (ZDMRDIR, 21D) is used together with Fullscheme distance protection, mho characteristic (ZMHPDIS) the following settings for parameter *DirEvalType* in ZDMRDIR is vital:

- alternative *Comparator* is strongly recommended
- alternative *Imp/Comp* should generally not be used
- alternative Impedance should not be used. This alternative is intended for use together with Distance protection zone, quadrilateral characteristic (ZMQPDIS)

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

6.3.3.2 Setting of zone 1

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

In case of parallel lines, consider the influence of the mutual coupling according to section "Parallel line application with mutual coupling" and select the case(s) that are valid in your application. We recommend to compensating the setting for the cases when the parallel line is in operation, out of service and not grounded and out of service and grounded in both ends. The setting of ground-fault reach should be selected to be <95% also when parallel line is out of service and grounded at both ends (worst case).

6.3.3.3 Setting of overreaching zone

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

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

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

If the requirements in the bullet list above gives a zone 2 reach that gives non-selectivity between the overreaching zone and the shortest outgoing line at the remote end, the time delay of zone 2 must be increased by approximately 200ms to avoid unwanted operation in cases when the telecommunication for the short adjacent line at remote end is down during faults. The zone 2 must not be reduced below 120% of the protected line section. The whole line must be covered under all conditions.

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

If a fault occurs at point F (see figure 82, also for the explanation of all abbreviations used), the IED at point A senses the impedance:

$$\bar{Z}_{AF} = \bar{Z}_{AC} + \frac{\bar{I}_A + \bar{I}_B}{\bar{I}_A} \cdot \bar{Z}_{CF} = \bar{Z}_{AC} + \left(1 + \frac{\bar{I}_B}{\bar{I}_A}\right) \cdot \bar{Z}_{CF}$$

(Equation 83)

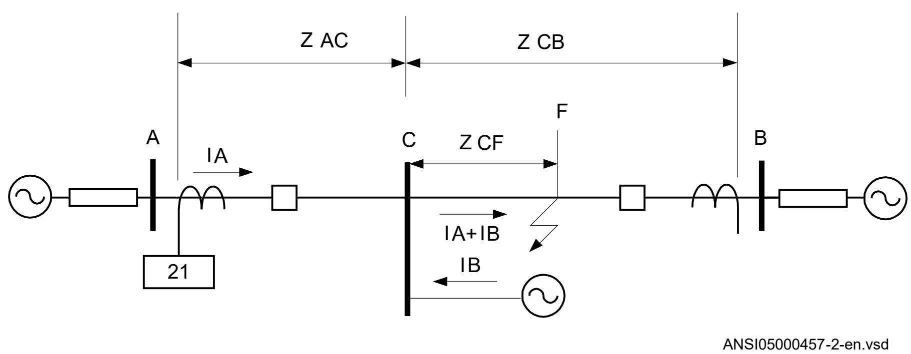


Figure 82: Setting of overreaching zone

6.3.3.4 Setting of reverse zone

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

Consider the possible enlarging factor that might exist due to fault infeed from adjacent lines. Equation 84 can be used to calculate the reach in reverse direction when the zone is used for blocking scheme, weak-end infeed, and so on.

$$Zrev \geq 1.2 \cdot \left| ZL \quad Z2rem \right|$$

(Equation 84)

Where:

ZL	is the protected line impedance
Z2rem	is zone 2 setting at remote end of protected line.

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

6.3.3.5 Setting of zones for parallel line application

Parallel line in service – Setting of zone 1
With reference to section "Parallel line application with mutual coupling", the zone reach can be set to 85% of protected line.

Parallel line in service – Setting of zone 2
Overreaching zones (in general, zones 2 and 3) must overreach the protected circuit in all cases. The greatest reduction of a reach occurs in cases when both parallel circuits are in service with a single phase-to-ground fault located at the end of a protected line.

Parallel line is out of service and grounded in both ends
Apply the same measures as in the case with a single set of setting parameters. This means that an underreaching zone must not overreach the end of a protected circuit for the single phase-to-ground faults.

6.3.3.6 Load impedance limitation, without load encroachment function

The following instruction is valid when the load encroachment function or blinder function is not activated (*BlinderMode*=*Disabled*). If the load encroachment or blinder function is to be used for all or some of the measuring zones, the load limitation for those zones according to this chapter can be omitted. Check the maximum permissible resistive reach for any zone to ensure that there is a sufficient setting margin between the relay boundary and the minimum load impedance. The minimum load impedance (Ω/phase) is calculated as:

$$Zload\ \min = \frac{V^2}{S}$$

(Equation 85)

Where:

V is the minimum phase-to-phase voltage in kV

S is the maximum apparent power in MVA.

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

$$Zload = \frac{V_{\min}}{\sqrt{3} \cdot I_{\max}}$$

(Equation 86)

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

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

6.3.3.7 Load impedance limitation, with load encroachment function activated

The parameters for load encroachment shaping of the characteristic are found in the description of Faulty phase identification with load encroachment for mho (FMPSPDIS).

6.3.3.8 Setting of minimum operating currents

The operation of the distance function will be blocked if the magnitude of the currents is below the set value of the parameter *IMinPUPP* and *IMinPUPG*.

The default setting of *IMinOpPP* and *IMinPUPG* is 20% of *IBase*. The values have been proven in practice to be suitable in most of the applications. However, there might be applications where it is necessary to increase the sensitivity by reducing the minimum operating current down to 10% of *IBase*.

The minimum operating fault current is automatically reduced to 75% of its set value, if the distance protection zone has been set for the operation in reverse direction.

6.3.3.9 Setting of directional mode

Setting of the directional mode is by default set to forward by setting the parameter *DirModeSelx* (where *x* is 1-5 depending on selected zone) to *Forward*.

The selection of *Offset* can be used for sending block signal in blocking teleprotection scheme, switch onto fault application and so on.

The *Reverse* mode might be use in comparison schemes where it is necessary to absolute discriminate between forward and reverse fault.

6.3.3.10 Setting of direction for offset mho

If offset mho has been selected, one can select if the offset mho shall be *Non-Directional*, *Forward* or *Reverse* by setting the parameter *OfffsetMhoDir*.

When forward or reverse operation is selected, then the operation characteristic will be cut off by the directional lines used for the mho characteristic. The setting is by default set to *Non-Directional*.

6.3.3.11 Setting of timers for distance protection zones

The required time delays for different distance protection zones are independent of each other. Distance protection zone 1 can also have a time delay, if so required for selectivity reasons. One can set the time delays for all zones in a range of 0 to 60 seconds. The tripping function of each particular zone can be inhibited by setting the corresponding *OpModeZx* or *OpModetzx*(where *x* is 1-5 depending on selected zone) parameter to *Disable-Zone*.

6.4 Faulty phase identification with load enchroachment for mho FMPSPDIS

6.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Faulty phase identification with load encroachment for mho	FMPSPDIS	Z<	-

6.4.2 Application

Faulty phase identification with load encroachment for mho (FMPSPDIS) function is designed to accurately select the proper fault loop in the Distance protection function (ZMOPDIS, 21) dependent on the fault type.

The heavy load transfer that is common in many transmission networks may in some cases be in opposite to the wanted fault resistance coverage. Therefore, FMPSPDIS has an built-in algorithm for load encroachment, which gives the possibility to enlarge the resistive setting of both the Phase selection with load encroachment and the measuring zones Five zone distance protection, mho characteristic (ZMOPDIS, 21) without interfering with the load.

The load encroachment algorithm and the blinder functions are always activated in the phase selector. The influence from these functions on the zone measurement characteristic has to be activated by switching the setting parameter *LoadEnchMode* in ZMOPDIS (21) for the respective measuring zone(s) to *Enabled*.

6.4.3 Setting guidelines

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

INRelPG: The setting of *INRelPG* for release of the phase-to-ground loop is by default set to 20% of *IBase*. The default setting is suitable in most applications.

The setting must normally be set to at least 10% lower than the setting of *3I0BLK_PP* to give priority to open phase-to-ground loop. *INRelPG* must be above the normal un-balance current ($3I_0$) that might exist due to un-transposed lines.

3I0BLK_PP: The setting of *3I0BLK_PP* is by default set to 40% of *VBase*, which is suitable in most applications.

I1LowLevel: The setting of the positive current threshold *I1LowLevel* used in the sequence based part of the phase selector for identifying three-phase fault, is by default set to 10% of *IBase*.

The default setting is suitable in most cases, but must be checked against the minimum three-phase current that occurs at remote end of the line with reasonable fault resistance.

IMaxLoad: The setting *IMaxLoad* must be set higher than the maximum load current transfer during emergency conditions including a safety margin of at least 20%. The setting is proposed to be according to equation 87:

$$IMaxLoad = 1.2\ \mathrm{ILoad}$$

(Equation 87)

where:

1.2	is the security margin against the load current and
ILoad	is the maximal load current during emergency conditions.

The current ILoad can be defined according to equation 88.

$$ILoad = \frac{S\max}{\sqrt{3} \cdot VLmn}$$

(Equation 88)

where:

Smax	is the maximal apparent power transfer during emergency conditions and
VLmn	is the phase-to-phase voltage during the emergency conditions at the IED location.

6.4.3.1 Load encroachment

The load encroachment function has two setting parameters, *RLd* for the load resistance and *LdAngle* for the inclination of the load sector (see figure 83).

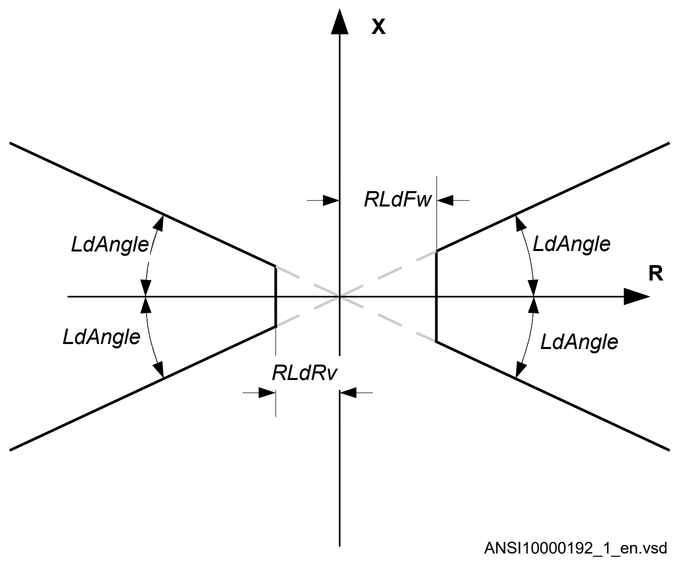


Figure 83: Load encroachment characteristic

$$Zload = \frac{V_{\min}}{\sqrt{3} \cdot I_{\max}}$$

(Equation 89)

$$Zload\,\min = \frac{V^2}{S}$$

(Equation 90)

Where:

V is the minimum phase-to-phase voltage in kV

S is the maximum apparent power in MVA.

The load angle *LdAngle* can be derived according to equation 91:

$$LdAngle = a\cos\left(\frac{P\max}{S\max}\right)$$

(Equation 91)

where:

Pmax is the maximal active power transfer during emergency conditions and

Smax is the maximal apparent power transfer during emergency conditions.

The *RLd* can be calculated according to equation 92:

$$RLd = ZLoad \cdot \cos(LdAngle)$$

(Equation 92)

The setting of *RLd* and *LdAngle* is by default set to 80 ohm/phase and 20 degrees. Those values must be adapted to the specific application.

6.5 Phase preference logic PPLPHIZ

6.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Phase preference logic	PPLPHIZ	-	-

6.5.2 Application

Phase preference logic function PPLPHIZ is an auxiliary function to Five zone distance protection, quadrilateral characteristic (ZQDPDIS, 21) and Phase selection with load encroachment, quadrilateral characteristic function FDPSPDIS (21). The purpose is to create the logic in resonance or high resistive grounded systems (normally sub-transmission) to achieve the correct phase selective tripping during two simultaneous single-phase ground-faults in different phases on different line sections.

Due to the resonance/high resistive grounding principle, the ground faults in the system gives very low fault currents, typically below 25 A. At the same time, the occurring system voltages on the healthy phases will increase to line voltage level as the neutral displacement is equal to the phase voltage level at a fully developed ground fault. This increase of the healthy phase voltage, together with slow tripping, gives a considerable increase of the risk of a second fault in a healthy phase and the second fault can occur at any location. When it occurs on another feeder, the fault is commonly called cross-country fault.

Different practices for tripping is used by different utilities. The main use of this logic is in systems where single phase-to-ground faults are not automatically cleared, only alarm is given and the fault is left on until a suitable time to send people to track down and repair the fault. When cross-country faults occur, the practice is to trip only one of the faulty lines. In other cases, a sensitive, directional ground-fault protection is provided to trip, but due to the low fault currents long tripping times are utilized.

Figure 84 shows an occurring cross-country fault. Figure 85 shows the achievement of line voltage on healthy phases and an occurring cross-country fault.

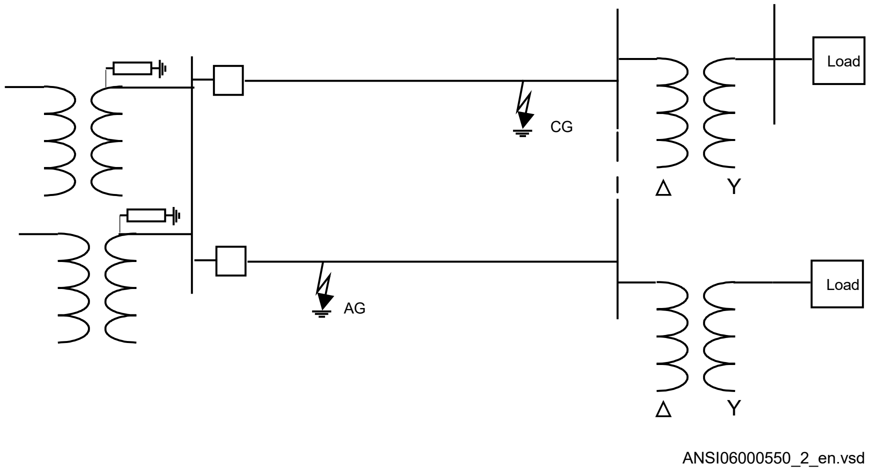


Figure 84: An occurring cross-country fault on different feeders in a sub-transmission network, high impedance (resistance, reactance) grounded

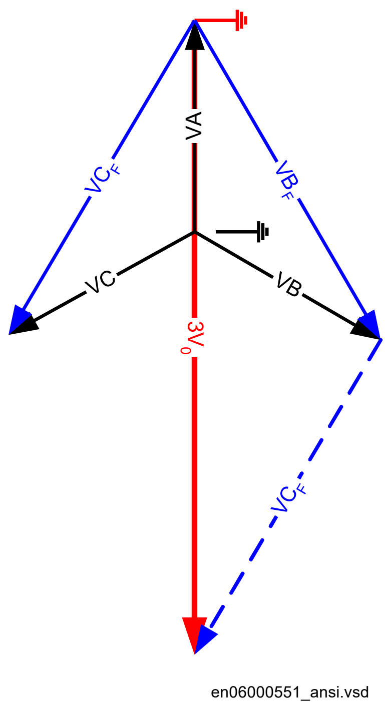


Figure 85: The voltage increase on healthy phases and occurring neutral point voltage (3V0) at a single phase-to-ground fault and an occurring cross-country fault on different feeders in a sub-transmission network, high impedance (resistance, reactance) grounded

PPLPHIZ is connected between Five zone distance protection, quadrilateral characteristic function (ZQDPDIS, 21) and Phase selection with load encroachment, quadrilateral characteristic function FDPSPDIS (21) as shown in figure 86. The integer from the phase selection function, which gives the type of fault undergoes a check and will release the distance protection zones as decided by the logic. The logic includes a check of the fault loops given by the phase selection and if the fault type indicates a two or three phase fault the integer releasing the zone is not changed.

If the fault indicates and ground-fault checks are done which mode of tripping to be used, for example ABCAc, which means that fault in the phases are tripped in the cyclic order A before B before C before A. Local conditions to check the phase-to-ground voltage levels and occurring zero sequence current and voltages completes the logic.

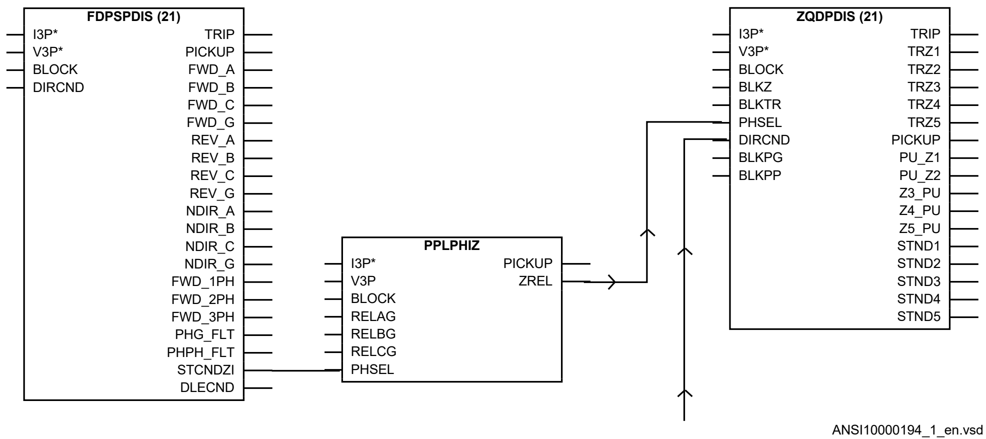


Figure 86: The connection of Phase preference logic function (PPLPHIZ) between Five zone distance protection, quadrilateral characteristic (ZQDPDIS, 21) and Phase selection with load encroachment, quadrilateral characteristic function (FDPSPDIS, 21)

As the fault is a double ground-faults at different locations of the network, the fault current in the faulty phase on each of the lines will be seen as a phase current and at the same time as a neutral current as the remaining phases on each feeder virtually carries no (load) current. Any current through the grounding impedance does not exist. It is limited by the impedance to below the typical, say 25 to 40 A. Occurring neutral current is thus a sign of a cross-country fault (a double ground- fault)

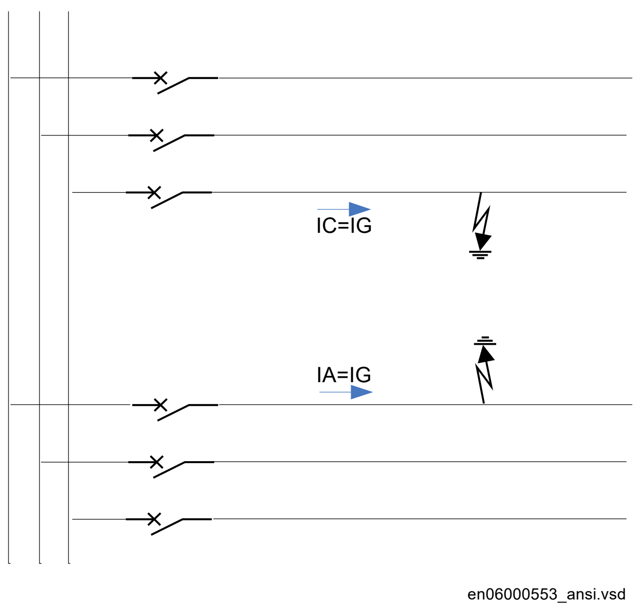


Figure 87: The currents in the phases at a double ground fault

The function has a block input (BLOCK) to block start from the function if required in certain conditions.

6.5.3 Setting guidelines

The parameters for the Phase preference logic function PPLPHIZ are set via the local HMI or PCM600.

Phase preference logic function is an intermediate logic between Distance protection zone, quadrilateral characteristic function Five zone distance protection, quadrilateral characteristic (ZQDPDIS, 21) and Phase selection with load encroachment, quadrilateral characteristic function FDPSPDIS (21). Phase selection and zones are set according to normal praxis, including ground-fault loops, although ground-fault loops will only be active during a cross-country fault.

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

OperMode: The operating mode is selected. Choices includes cyclic or acyclic phase selection in the preferred mode. This setting must be identical for all IEDs in the same galvanic connected network part.

PU27PN: The setting of the phase-to- ground voltage level (phase voltage) which is used by the evaluation logic to verify that a fault exists in the phase. Normally in a high impedance grounded system, the voltage drop is big and the setting can typically be set to 70% of base voltage (*VBase*)

PU27PP: The setting of the phase-to-phase voltage level (line voltage) which is used by the evaluation logic to verify that a fault exists in two or more phases. The voltage must be set to avoid that a partly healthy phase-to-phase voltage, for example, B-C for a A-B fault, picks-up and gives an incorrect release of all loops. The setting can typically be 70% of base voltage (*VBase*) divided by √3, that is 40%.

3V0PU: The setting of the residual voltage level (neutral voltage) which is used by the evaluation logic to verify that an ground-fault exists. The setting can typically be 20% of base voltage (*VBase*).

Pickup_N: The setting of the residual current level (neutral current) which is used by the evaluation logic to verify that a cross-country fault exists. The setting can typically be 20% of base current (*IBase*) but the setting shall be above the maximum current generated by the system grounding. Note that the systems are high impedance grounded which means that the ground-fault currents at ground-faults are limited and the occurring IN above this level shows that there exists a two-phase fault on this line and a parallel line where the IN is the fault current level in the faulty phase. A high sensitivity need not to be achieved as the two-phase fault level normally is well above base current.

tIN: The time delay for detecting that the fault is cross-country. Normal time setting is 0.1 - 0.15 s.

tVN: The time delay for a secure VN detecting that the fault is an ground-fault or double ground-fault with residual voltage. Normal time setting is 0.1 - 0.15 s.

tOffVN: The VN voltage has a reset drop-off to ensure correct function without timing problems. Normal time setting is 0.1 s

6.6 Power swing detection ZMRPSB (68)

6.6.1 Identification

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

6.6.2 Application

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

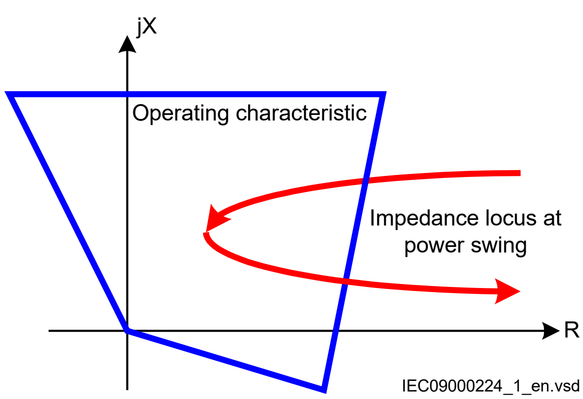


Figure 88: Impedance plane with Power swing detection operating characteristic and impedance locus at power swing

6.6.2.2 Basic characteristics

Power swing detection function (ZMRPSB) (68) 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 operating conditions.

ZMRPSB (68) function is able to secure selective operation for internal faults during power. 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 (68) function is easily adjustable to the selected impedance operate characteristics of the corresponding controlled distance protection zones as well as to the maximum possible load conditions of the protected power lines.

6.6.3 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 89.

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

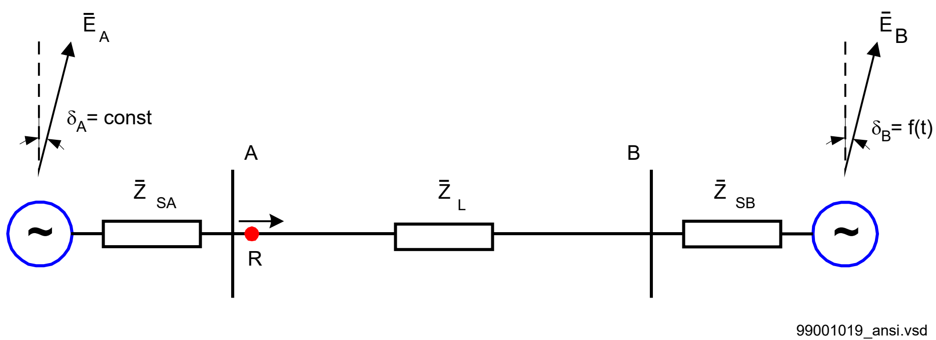


Figure 89: Protected power line as part of a two-machine system

Reduce the power system with protected power line into equivalent two-machine system with positive sequence source impedances Z_{SA} behind the IED and Z_{SB} behind the remote end bus B. Observe a fact that these impedances can not 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

Table continues on next page

$V_p = \dfrac{400}{\sqrt{3}} kV$	Rated primary voltage of voltage protection transformers used
$V_s = \dfrac{0.115}{\sqrt{3}} kV$	Rated secondary voltage of voltage instrument transformers used
$I_p = 1200 A$	Rated primary current of current protection transformers used
$I_s = 5A$	Rated secondary current of current protection transformers used
$\bar{Z}_{L1} = (10.71 + j75.6)\Omega$	Line positive sequence impedance
$\bar{Z}_{SA1} = (1.15 + j43.5)\Omega$	Positive sequence source impedance behind A bus
$\bar{Z}_{SB1} = (5.3 + j35.7)\Omega$	Positive sequence source impedance behind B bus
$S_{\max} = 1000 MVA$	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
$\varphi_{\max} = 25°$	Maximum expected load angle
$f_{si} = 2.5 Hz$	Maximum possible initial frequency of power oscillation
$f_{sc} = 7.0 Hz$	Maximum possible consecutive frequency of power oscillation

The impedance transformation factor, which transforms the primary impedances to the corresponding secondary values is calculated according to equation 93. Consider a fact that all settings are performed in primary values. The impedance transformation factor is presented for orientation and testing purposes only.

$$KIMP = \frac{I_p}{I_s} \cdot \frac{V_s}{V_p} = \frac{1200}{5} \cdot \frac{0.115}{400} = 0.069$$

(Equation 93)

The minimum load impedance at minimum expected system voltage is equal to equation 94.

$$\left|\overline{Z}_{L\min}\right| = \frac{V^2{}_{\min}}{S_{\max}} = \frac{380^2}{1000} = 144.4\Omega$$

(Equation 94)

The minimum load resistance R_{Lmin} at maximum load and minimum system voltage is equal to equation 95.

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

(Equation 95)

The system impedance Z_S is determined as a sum of all impedance in an equivalent two-machine system, see figure 89. Its value is calculated according to equation 96.

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

(Equation 96)

The calculated value of the system impedance is of informative nature and helps determining the position of oscillation center, see figure 90, which is for general case calculated according to equation 97.

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

(Equation 97)

In particular cases, when

$$\left|\overline{E}_A\right| = \left|\overline{E}_B\right|$$

(Equation 98)

resides the center of oscillation on impedance point, see equation 99.

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

(Equation 99)

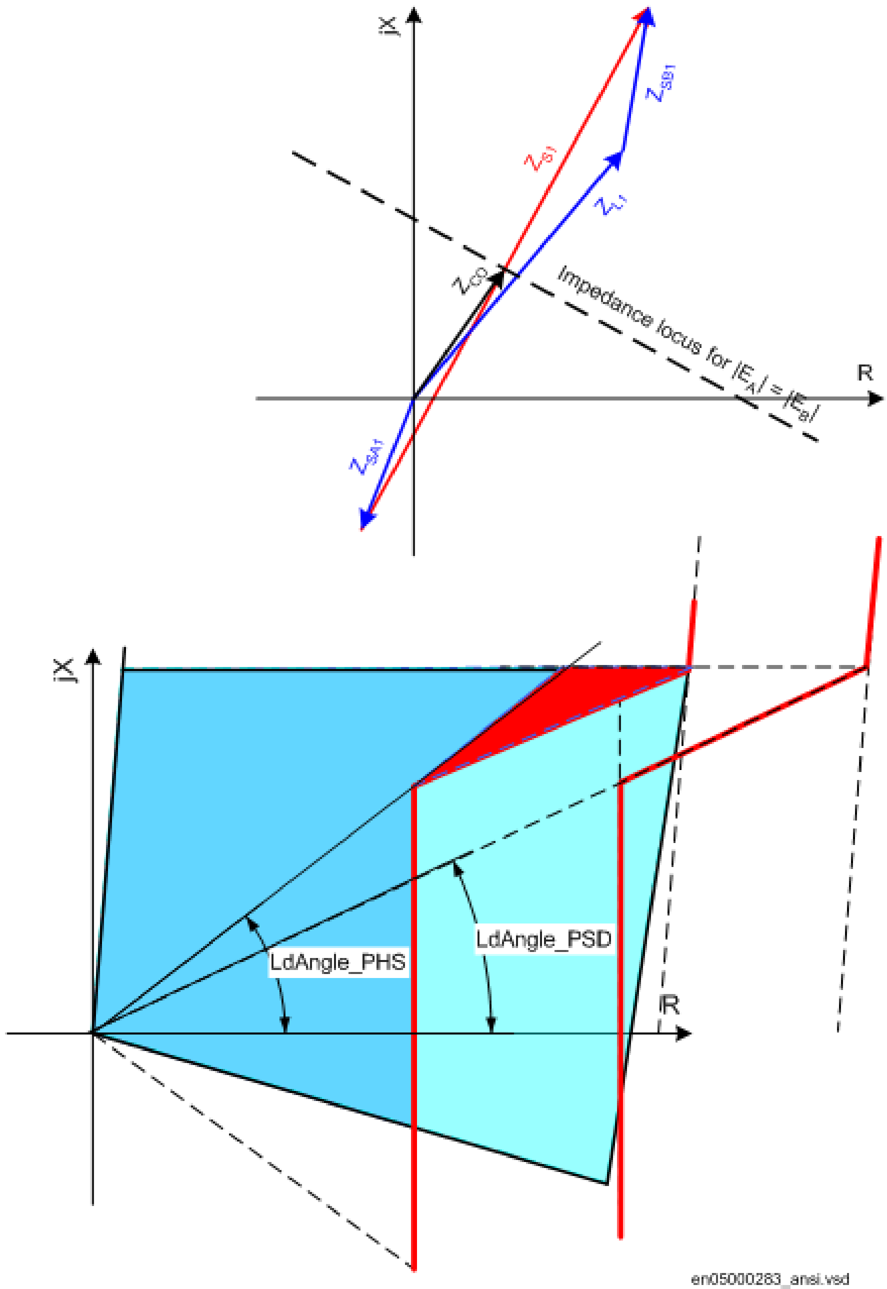


Figure 90: Impedance diagrams with corresponding impedances under consideration

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 rated voltage 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 100.

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

(Equation 100)

It is a general recommendation to set the inner boundary *RLdInFw* of the oscillation detection characteristic to 80% or less of its outer boundary. Exceptions are always possible, but must be considered with special care especially when it comes to settings of timers *tP1* and *tP2* included in oscillation detection logic. This requires the maximum permitted setting values of factor *kLdRFw* = 0.8. Equation 101 presents the corresponding maximum possible value of *RLdInFw*.

$$\mathrm{RLdInFw} = kLdRFw \cdot RLdOutFw = 98.8\Omega$$

(Equation 101)

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 102 and 103 respectively.

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

(Equation 102)

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

(Equation 103)

The required setting *tP1* of the initial oscillation detection timer depends on the load angle difference according to equation 104.

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

(Equation 104)

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 105, 106, 107 and 108.

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

(Equation 105)

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

(Equation 106)

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

(Equation 107)

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

(Equation 108)

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 109.

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

(Equation 109)

The final proposed settings are as follows:

RLdOutFw = 123.5Ω

kLdRFw = 0.61

tP1 = 30 ms

tP2 = 10 ms

Consider RLdInFw = 75.0Ω.

Do not forget to adjust the setting of load encroachment resistance *RLdFwd* in Phase selection with load encroachment (FDPSPDIS, 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 FDPSPDIS (21) to follow the condition presented in equation 110.

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

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

(Equation 110)

Consider equation 111,

$$LdAngle_{PSD} = \varphi_{\max} = 25°$$

(Equation 111)

then it is necessary to set the load angle in FDPSPDIS (21) function to not less than equation 112.

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

(Equation 112)

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, requires 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 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.

6.7 Automatic switch onto fault logic, voltage and current based ZCVPSOF

6.7.1 Identification

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

6.7.2 Application

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

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

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

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

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

6.7.3 Setting guidelines

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

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

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: The operation of Automatic switch onto fault logic, voltage and current based function is by default set to *Enabled*. Set the parameter to *Disabled* if the function is not to be used.

IphPickup is used to set current level for detection of dead line.*IphPickup* is by default set to 20% of *IBase*. It shall be set with sufficient margin (15 - 20%) under the minimum expected load current. In many cases the minimum load current of a line is close to 0 and even 0. The operate value must exceed the maximum charging current of an overhead line, when only one phase is disconnected (mutual coupling the other phases).

UVPickup is used to set voltage level for detection of dead line. *UVPickup* is by default set to 70% of *VBase*. This is a suitable setting in most cases, but it is recommended to checking the suitability in the actual application.

Mode: The operation of ZCVPSOF has three modes for defining the criteria for trip. The setting of the *Mode* is by default set to *VILevel*, which means that the tripping criteria is based on the setting of *IPhPickup* and *UVPickup*. The choice of *VILevel* gives faster and more sensitive operation of the function, which is important to reduce the stress that might occur when energizing onto a fault. On the other hand the risk for over function might be higher due to that the voltage recovery in some systems can be slow given unwanted operation at energizing the line if the timer *tDuration* is set too short.

When *Mode* is set to *Impedance*, the operation criteria is based on the start of overeaching zone from impedance zone measurement. A non-directional output signal should be used from an overreaching zone. The selection of Impedance mode gives increased security.

In operation mode *VILvl&Imp* the condition for trip is an OR-gate between *VILevel* and *VILvl&Imp*.

The setting of the timer for release of the *VILevel*, *tDuration* is by default set to 0.1 sec, which have been proven to be suitable in most cases from field experience. If shorter time delay is to be set, it is necessary to consider the voltage recovery time at energizing the line.

AutoInit: Automatic activating of the ZCVPSOF function is by default set to *Disabled*. If automatic activation Deadline detection is required, set the parameter *Autoinit* to *Enabled*. Otherwise the logic will be activated by an external BC input.

tSOTF: The drop delay of ZCVPSOF function is by default set to 1 second, which is suitable for most applications.

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

Section 7 Current protection

7.1 Instantaneous phase overcurrent protection PHPIOC (50)

7.1.1 Identification

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

7.1.2 Application

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

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

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

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

The instantaneous phase overcurrent protection PHPIOC (50) can operate in 10 ms for faults characterized by very high currents.

7.1.3 Setting guidelines

The parameters for instantaneous phase overcurrent protection PHPIOC (50) are set via the local HMI or PCM600.

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

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

Also study transients that could cause a high increase of the line current for short times. A typical example is a transmission line with a power transformer at the remote end, which can cause high inrush current when connected to the network and can thus also cause the operation of the built-in, instantaneous, overcurrent protection.

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Pickup: Set operate current in % of *IBase*.

7.1.3.1 Meshed network without parallel line

The following fault calculations have to be done for three-phase, single-phase-to-ground and two-phase-to-ground faults. With reference to figure 91, apply a fault in B and then calculate the current through-fault phase current I_{fB}. The calculation should be done using the minimum source impedance values for Z_A and the maximum source impedance values for Z_B in order to get the maximum through fault current from A to B.

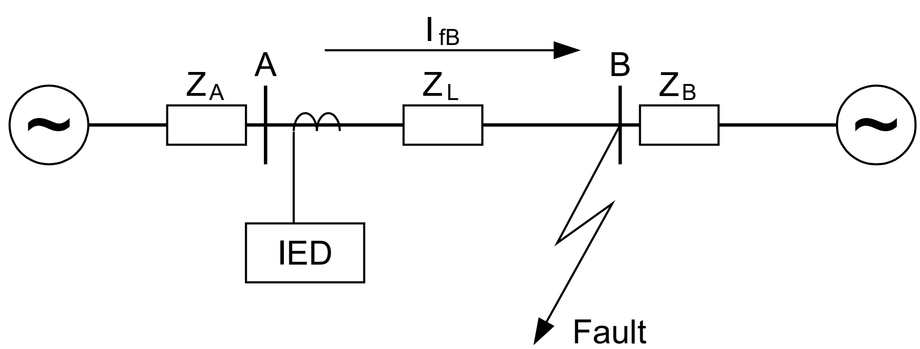


Figure 91: Through fault current from A to B: I_{fB}

Then a fault in A has to be applied and the through fault current I_{fA} has to be calculated, figure 92. In order to get the maximum through fault current, the minimum value for Z_B and the maximum value for Z_A have to be considered.

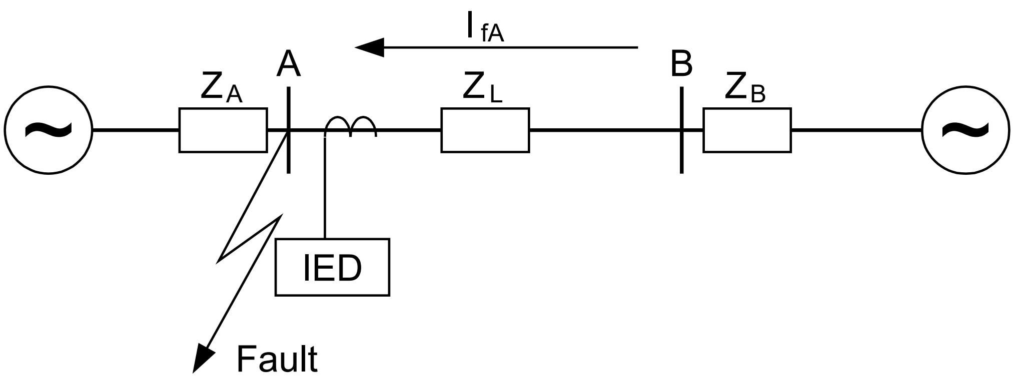


Figure 92: Through fault current from B to A: I_{fA}

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

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

(Equation 113)

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

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

$$Is \geq 1,3 \cdot Imin$$

(Equation 114)

The protection function can be used for the specific application only if this setting value is equal to or less than the maximum fault current that the IED has to clear, I_F in figure 93.

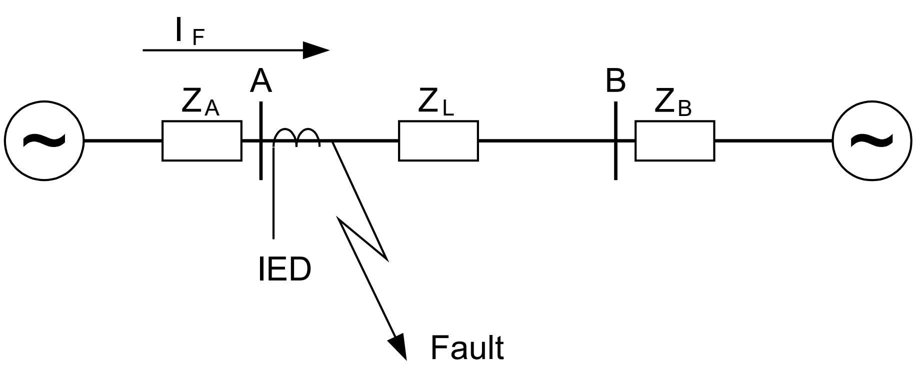


Figure 93: Fault current: I_F

The IED setting value *Pickup* is given in percentage of the primary base current value, *IBase*. The value for *Pickup* is given from this formula:

$$Pickup = \frac{Is}{IBase} \cdot 100$$

(Equation 115)

7.1.3.2 Meshed network with parallel line

In case of parallel lines, the influence of the induced current from the parallel line to the protected line has to be considered. One example is given in figure 94 where the two lines are connected to the same busbars. In this case the influence of the induced fault current from the faulty line (line 1) to the healthy line (line 2) is considered together with the two through fault currents I_{fA} and I_{fB} mentioned previously. The maximal influence from the parallel line for the IED in figure 94 will be with a fault at the C point with the C breaker open.

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

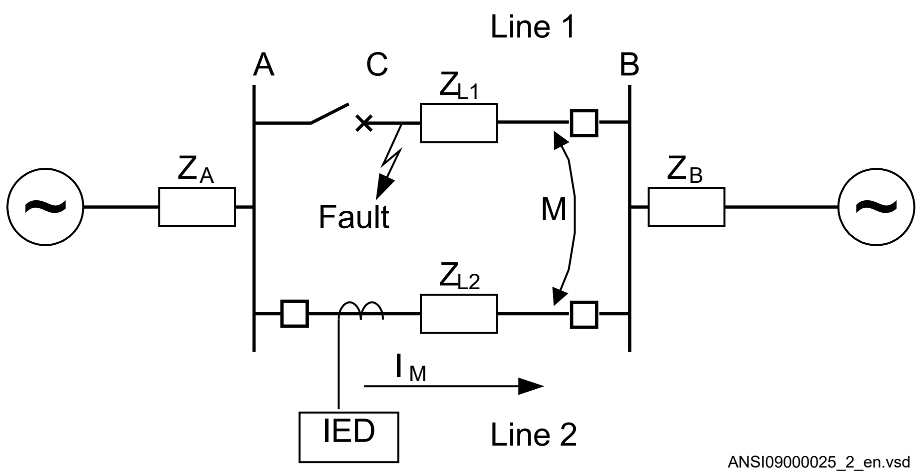


Figure 94: Two parallel lines. Influence from parallel line to the through fault current: I_M

The minimum theoretical current setting for the overcurrent protection function (Imin) will be:

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

(Equation 116)

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

$$\text{Is} \geq 1.3 \cdot \text{Imin}$$

(Equation 117)

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

The IED setting value *Pickup* is given in percentage of the primary base current value, *IBase*. The value for *Pickup* is given from this formula:

$$Pickup = \frac{Is}{IBase} \cdot 100$$

(Equation 118)

7.2 Instantaneous phase overcurrent protection SPTPIOC (50)

7.2.1 Identification

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

7.2.2 Application

Long transmission lines often transfer great quantities of electric power from production to consumption areas. The unbalance of the produced and consumed electric power at each end of the transmission line is very large. This means that a fault on the line can easily endanger the stability of a complete system. The transient stability of a power system depends mostly on three parameters (at constant amount of transmitted electric power):

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

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

The instantaneous phase overcurrent protection SPTPIOC (50) can operate in 10 ms for faults characterized by very high currents.

7.2.3 Setting guidelines

The parameters for Instantaneous phase overcurrent protection SPTPIOC (50) are set via the local HMI or Protection and Control Manager (PCM600). This protection function must operate only in a selective way. So check all system and transient conditions that could cause its unwanted operation.

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

Also, study transients that could cause a high increase of the line current for short times. A typical example is a transmission line with a power transformer at the remote end, which can cause high inrush current when connected to the network and can thus also cause the operation of the built-in, instantaneous, overcurrent protection.

Common base IED values for primary current (*IBase*), primary voltage (setting *VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Pickup: Set operate current in % of *IBase*.

7.2.3.1 Meshed network without parallel line

The following fault calculations have to be done for three-phase, single-phase-to ground and two-phase-to-ground faults. With reference to figure 95, apply a fault in B and then calculate the current through fault phase current I_{fB}. The calculation should be done using the minimum source impedance values for Z_A and the maximum source impedance values for ZB in order to get the maximum through fault current from A to B.

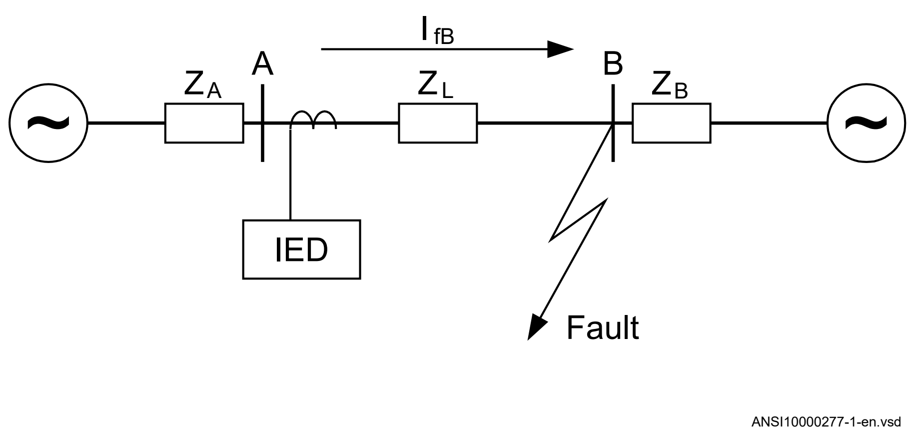


Figure 95: Through fault current from A to B: I_{fB}

Then a fault in A has to be applied and the through fault current I_{fA} has to be calculated, figure 96. In order to get the maximum through fault current, the minimum value for Z_B and the maximum value for Z_A have to be considered.

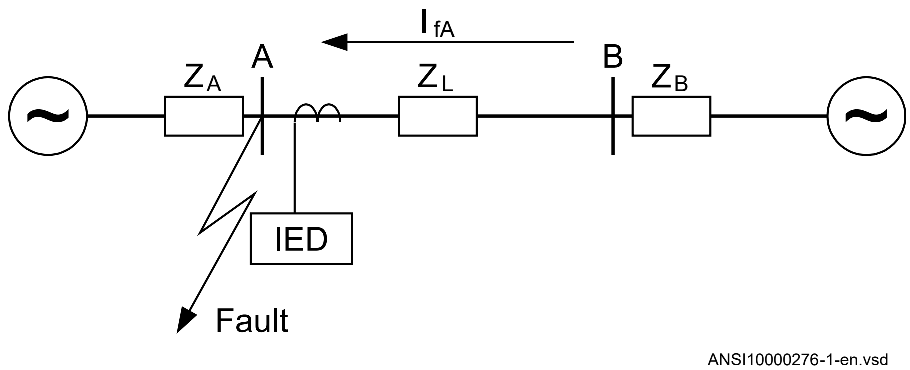


Figure 96: Through fault current from B to A: I_{fA}

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

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

(Equation 119)

A safety margin of 5% for the maximum protection static inaccuracy and a safety margin of 5% for the maximum possible transient overreach have to be introduced. An additional 20% is suggested due to the inaccuracy of the instrument transformers under transient conditions and inaccuracy in the system data. The minimum primary setting (Is) for SPTPIOC (50) is then:

$$I_s \geq 1.3 \cdot Imin$$

(Equation 120)

The protection function can be used for the specific application only if this setting value is equal to or less than the maximum fault current that the IED has to clear, fault current (I_F) in figure 97.

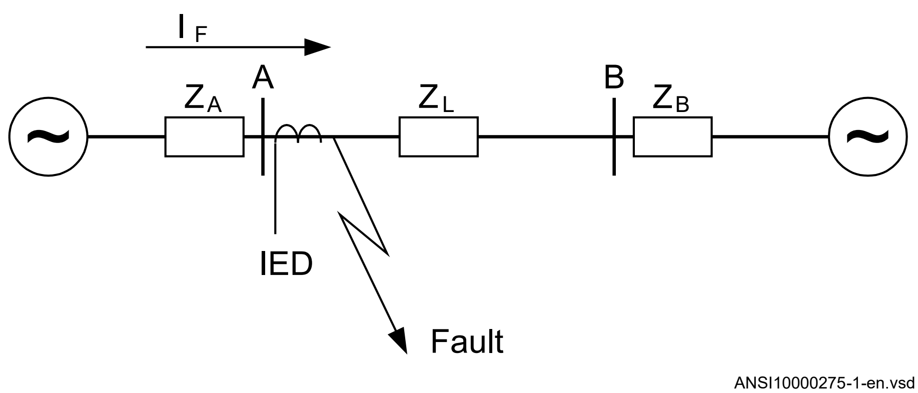


Figure 97: Fault current: I_F

The IED setting value *Pickup* is given in percentage of the primary base current value, *IBase*. The value for *Pickup* is given from this formula:

$$Pickup = \frac{Is}{IBase} \cdot 100$$

(Equation 121)

7.2.3.2 Meshed network with parallel line

In case of parallel lines, the influence of the induced current from the parallel line to the protected line has to be considered. One example is given in figure 98 where the two lines are connected to the same busbars. In this case the influence of the induced fault current from the faulty line (line 1) to the healthy line (line 2) is considered together with the two through fault currents I_{fA} and I_{fB} mentioned previously. The maximal influence from the parallel line for the IED in figure 98 will be with a fault at the C point with the C breaker open.

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

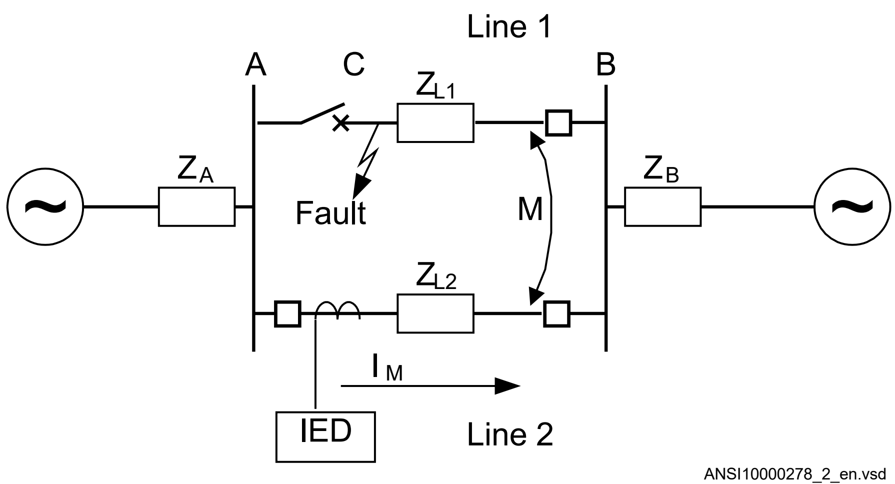


Figure 98: Two parallel lines Influence form parallel line to the through fault current: I_M

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

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

(Equation 122)

Where I_{fA} and I_{fB} have been described in the previous paragraph. Considering the safety margins mentioned previously, the minimum setting Is as given in equation below:

$$Is \geq 1.3 \cdot Imin$$

(Equation 123)

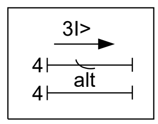
The protection function can be used for the specific application only if this setting value is equal or less than the maximum phase fault current that the IED has to clear. The IED setting value *Pickup* is given in percentage of the primary base current value, *IBase*. The value for *Pickup* is given from this formula:

$$Pickup = \frac{Is}{IBase} \cdot 100$$

(Equation 124)

7.3 Four step phase overcurrent protection OC4PTOC (51/67)

7.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Four step phase overcurrent protection	OC4PTOC		51/67

7.3.2 Application

The Four step phase overcurrent protection 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 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.

If VT inputs are not available or not connected, setting parameter *DirModeSelx* (*x* = step 1, 2, 3 or 4) shall be left to default value *Non-directional*or set to *Disabled*.

In many applications several steps with different current pick up levels and time delays are needed. OC4PTOC (51_67) can have up to four different, individual settable, steps. The flexibility of each step of OC4PTOC (51_67) is great. 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.

Choice of delay time characteristics: There are several types of delay time 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: IEC and ANSI.

The time characteristic for step 1 and 4 can be chosen as definite time delay or inverse time characteristic. Step 2 and 3 are always definite time delayed and are used in system where IDMT is not needed.

7.3.3 Setting guidelines

The parameters for Four step phase overcurrent protection 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 primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

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 *Disabled* or *Enabled*

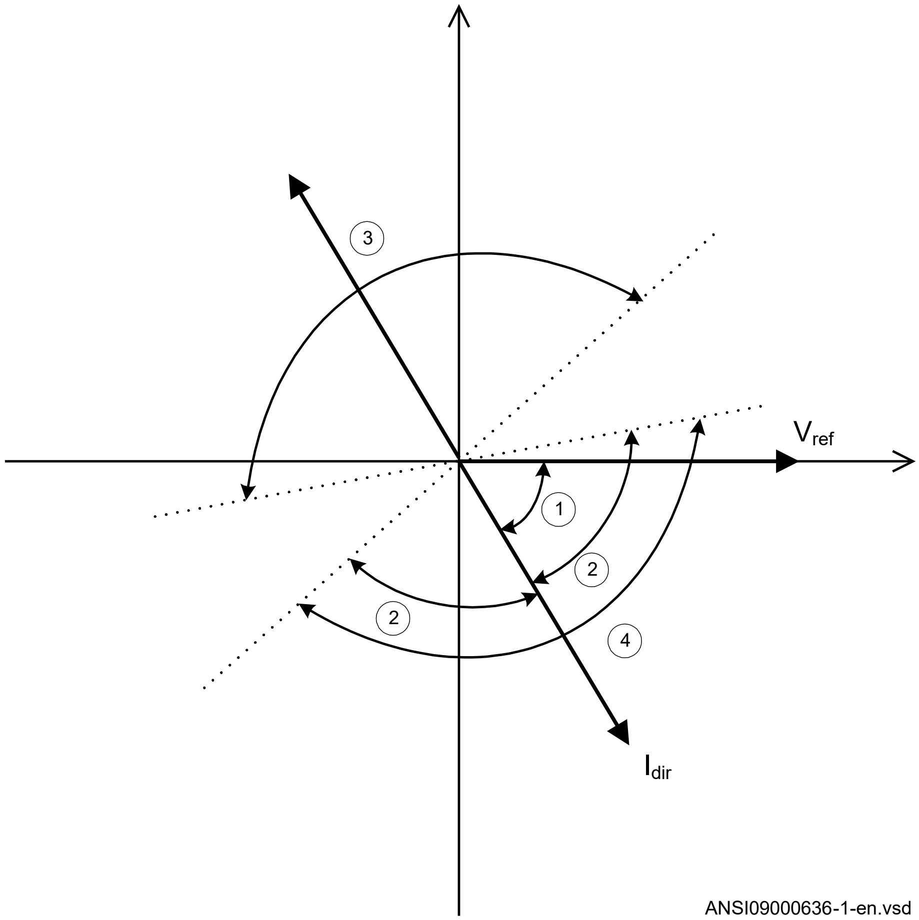


Figure 99: Directional function characteristic

1. RCA = Relay characteristic angle 55°
2. ROA = Relay operating angle 80°
3. Reverse
4. Forward

7.3.3.1 Settings for steps 1 to 4

n means step 1 and 4. *x* means step 1, 2, 3 and 4.

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

Characteristn: Selection of time characteristic for step *n*. Definite time delay and different types of inverse time characteristics are available according to table 19. Step 2 and 3 are always definite time delayed.

Table 19: 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
ASEA RI
RXIDG (logarithmic)

The different characteristics are described in Technical manual.

Pickupx: Operation phase current level for step *x* given in % of *IBase*.

tx: Definite time delay for step *x*. Used if definite time characteristic is chosen.

TDn: Time multiplier for inverse time delay for step *n*.

IMinn: Minimum operate current for step *n* in % of *IBase*. Set *IMinn* below *Pickupx* for every step to achieve ANSI reset characteristic according to standard. If *IMinn* is set above *Pickupx* for any step the ANSI reset works as if current is zero when current drops below *IMinn*.

tnMin: Minimum operation 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.

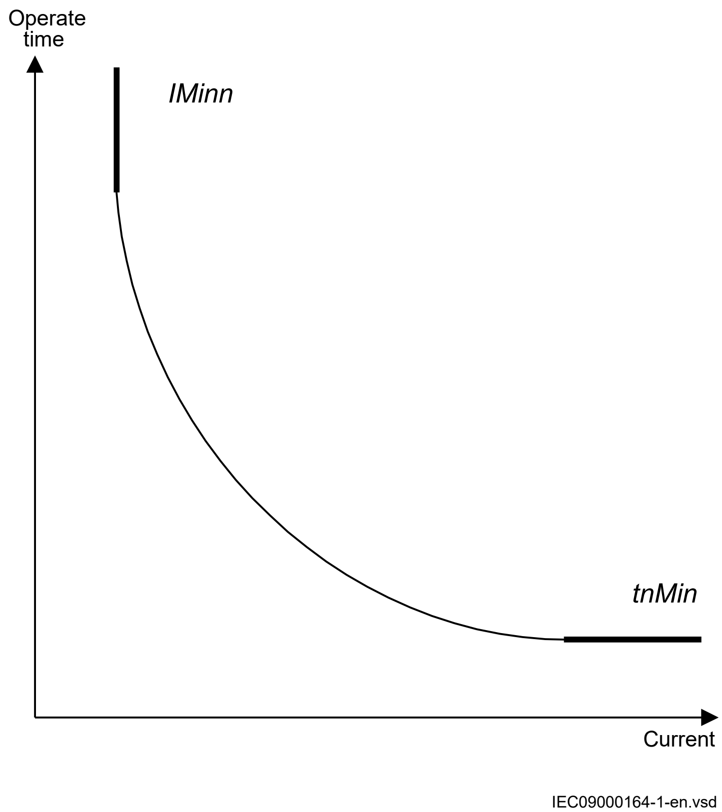


Figure 100: Minimum operate current and operation time for inverse time characteristics

In order to fully comply with curves definition setting parameter *tnMin* shall be set to the value, which is equal to the operating time of the selected inverse curve for measured current of twenty times the set current pickup value. Note that the operating time value is dependent on the selected setting value for time multiplier *TDn*.

7.3.3.2 Current applications

The four step phase overcurrent protection 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 inverse time protection or the lowest current step constant inverse time protection must be given a current setting so that the highest possible load current does not cause protection operation. Here consideration also has to be taken to the protection reset current, so that a short peak of overcurrent does not cause operation of the protection even when the overcurrent has ceased. This phenomenon is described in figure 101.

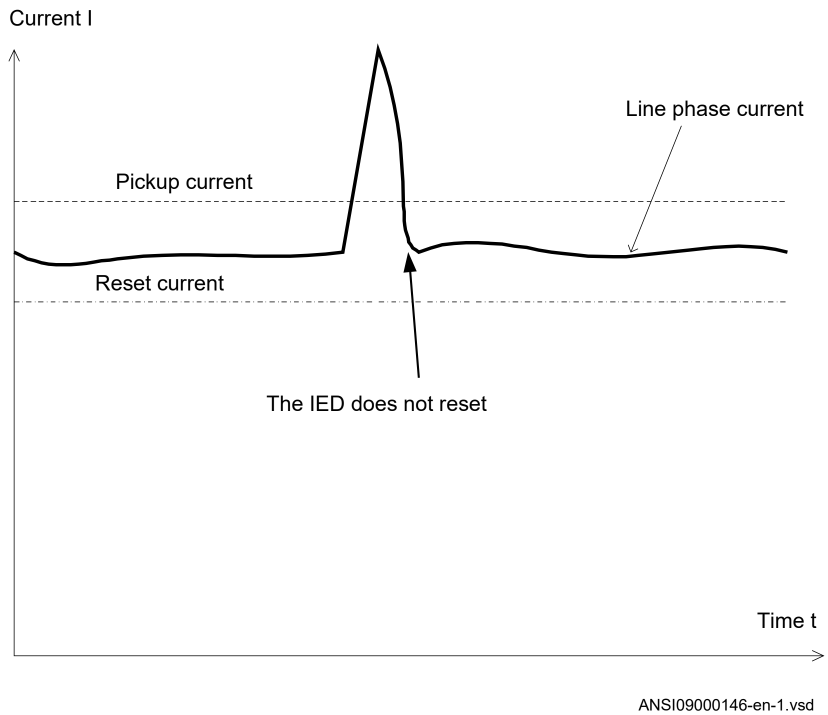


Figure 101: Pickup and reset current for an overcurrent protection

The lowest setting value can be written according to equation 125.

$$Ipu \geq 1.2 \cdot \frac{Imax}{k}$$

(Equation 125)

where:

1.2	is a safety factor,
k	is the resetting ratio of the protection, and
Imax	is the maximum load current.

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 Iscmin, to be detected by the protection, must be calculated. Taking this value as a base, the highest pick up current setting can be written according to equation 126.

$$Ipu \leq 0.7 \cdot Iscmin$$

(Equation 126)

where:

0.7	is a safety factor and
Iscmin	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 127.

$$1.2 \cdot \frac{\mathrm{Im\,ax}}{\mathrm{k}} \leq \mathrm{Ipu} \leq 0.7 \cdot \mathrm{Isc\,min}$$

(Equation 127)

The high current function of the overcurrent protection, which only has a short delay of the operation, must be given a current setting so that the protection is selective to other protection in the power system. It is desirable to have a rapid tripping of faults within as large portion as possible of the part of the power system to be protected by the protection (primary protected zone). A fault current calculation gives the largest current of faults, Iscmax, at the most remote part of the primary protected zone. Considerations have to be made to the risk of transient overreach, due to a possible DC component of the short circuit current. The lowest current setting of the most rapid stage, of the phase overcurrent protection, can be written according to

$$I_{high} \geq 1.2 \cdot k_t \cdot I_{sc\max}$$

(Equation 128)

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 1.1
Iscmax	is the largest fault current at a fault at the most remote point of the primary protection zone.

The operate times of the phase overcurrent protection has to be chosen so that the fault time is so short that protected equipment will not be destroyed due to thermal overload, at the same time as 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 102 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.

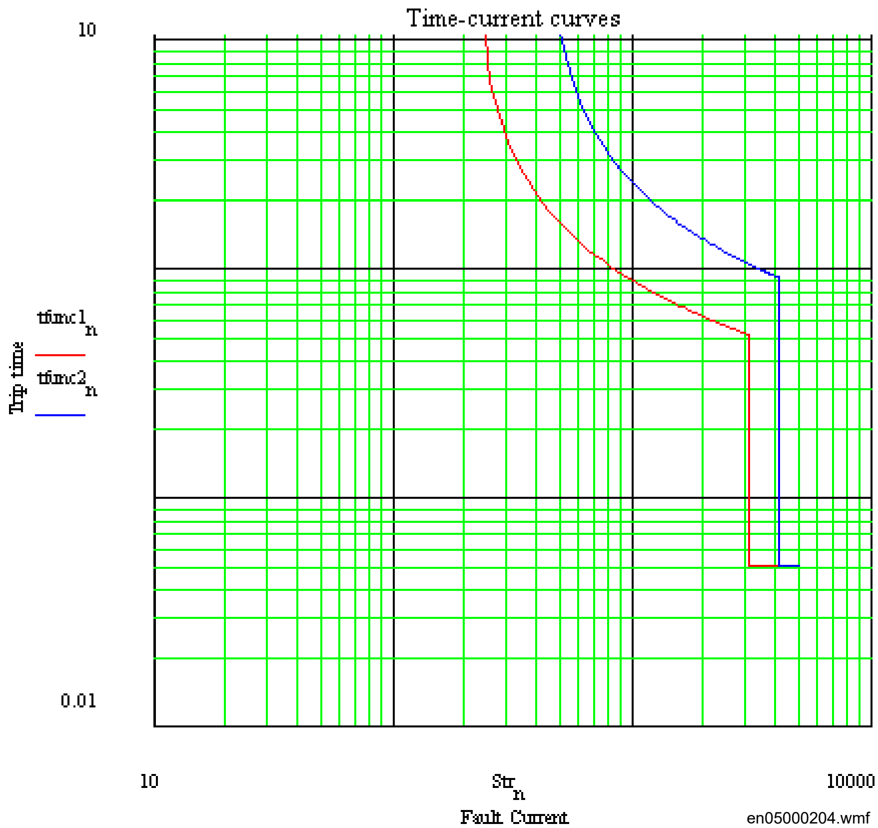


Figure 102: Fault time with maintained selectivity

To assure selectivity between different protections, in the radial network, there have to be a minimum time difference Δt between the time delays of two protections. The minimum time difference can be determined for different cases. 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 operation time:	15-60 ms
Protection resetting time:	15-60 ms
Breaker opening time:	20-120 ms

Example

Assume two substations A and B directly connected to each other via one line, as shown in the figure 103. 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 protection will have instantaneous function. The overcurrent protection of IED A1 must have a delayed function. The sequence of events during the fault can be described using a time axis, see figure 103.

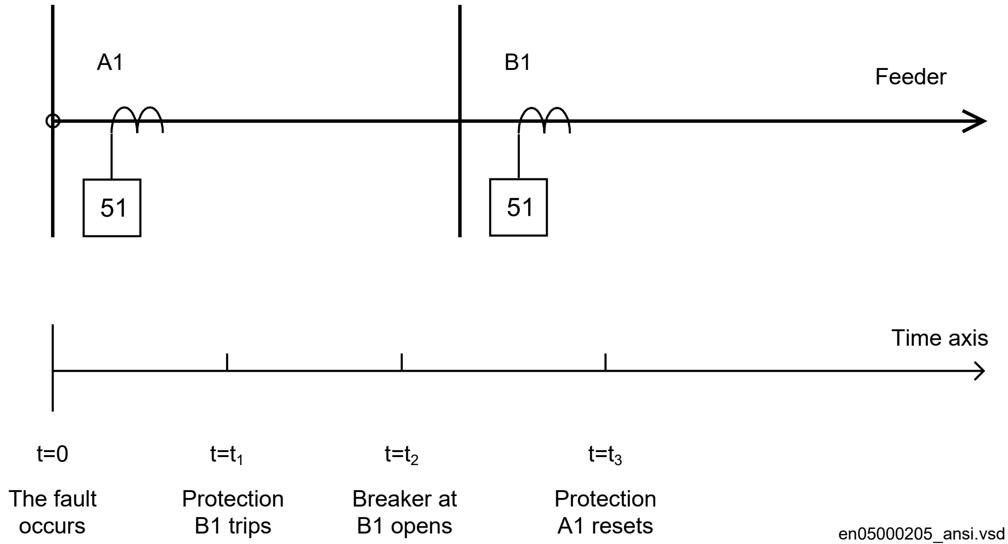


Figure 103: Sequence of events during fault

where:

t=0	is when the fault occurs,
$t=t_1$	is when the trip signal from the overcurrent protection at IED B1 is sent to the circuit breaker. The operation time of this protection is t_1,
$t=t_2$	is when the circuit breaker at IED B1 opens. The circuit breaker opening time is t_2 - t_1 and
$t=t_3$	is when the overcurrent protection at IED A1 resets. The protection resetting time is t_3 - t_2.

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 129.

$$\Delta t \geq 40\,ms + 100\,ms + 40\,ms + 40\,ms = 220\,ms$$

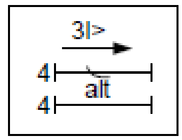
(Equation 129)

where it is considered that:

the operation 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

7.4 Four step phase overcurrent protection OC4SPTOC 51_67

7.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Four step phase overcurrent protection	OC4SPTOC		51/67

7.4.2 Application

The four step phase overcurrent protection OC4SPTOC (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 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.

If VT inputs are not available or not connected, setting parameter *DirModeSelx* (x=step 1, 2, 3 or 4) shall be left to default value, *Nondirectional*, or set to *Disabled*.

In many applications several steps with different current pick up levels and time delays are needed. OC4SPTOC (51_67) can have up to four different, individual settable, steps. The flexibility of each step of the OC4SPTOC (51_67) function is great. 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.

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

The time characteristic for step 1 and 4 can be chosen as definite time delay or inverse time characteristic. Step 2 and 3 are always definite time delayed and are used in system where IDMT is not needed.

7.4.3 Setting guidelines

The parameters for four step phase overcurrent protection OC4SPTOC (51_67) are set via the local HMI or Protection and Control IED Manager (PCM600).

The following settings can be done for the four step phase overcurrent protection.

- Common base IED values for primary current (setting *IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL.
- Setting *GlobalBaseSel*:
  Used to select a GBASVAL function for reference of base values.
- *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 *Disabled* or *Enabled*

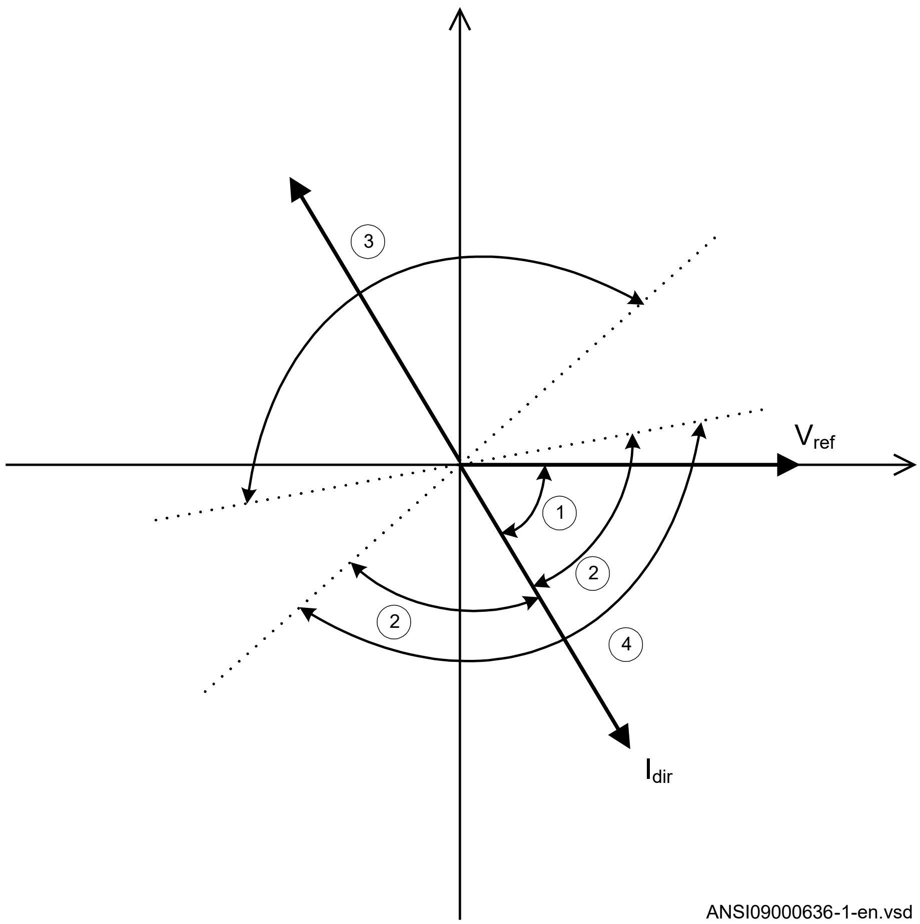


Figure 104: Directional function characteristic

1. RCA = Relay characteristic angle 55°
2. ROA = Relay operating angle 80°
3. Reverse
4. Forward

7.4.3.1 Settings for steps 1 to 4

- *n*: means
  step 1 and *4*. *x* means *step 1,2, 3* and *4*.
- DirModeSelx:
  The directional mode of step *x*. Possible settings are *Disabled/Non-directional/ Forward/ Reverse*
- *Characteristn*:
  Selection of time characteristic for step *n*. Definite time delay and different types of inverse time characteristics are available according to table 14. Step 2 and 3 are always definite time delayed.

Table 20: 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
ASEA RI
RXIDG (logarithmic)

The different characteristics are described in the Technical manual.

- *Pickupx*:
  Operation phase current level for step x given in % of *IBase*.
- *tx*:
  Definite time delay for step *x*. Used if definite time characteristic is chosen.
- *TDn*:
  Time multiplier for inverse time delay for step *n*.
- *IMinn*:
  Minimum operate current for step *n* in % of *IBase*.
  Set *IMinn* below *Pickupx* for every step to achieve ANSI reset characteristic according to standard. If *IMinn* is set above *Pickupx* for any step the ANSI reset works as if current is zero when current drops below *IMinn*.
- *tnMin*: Minimum operation 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.

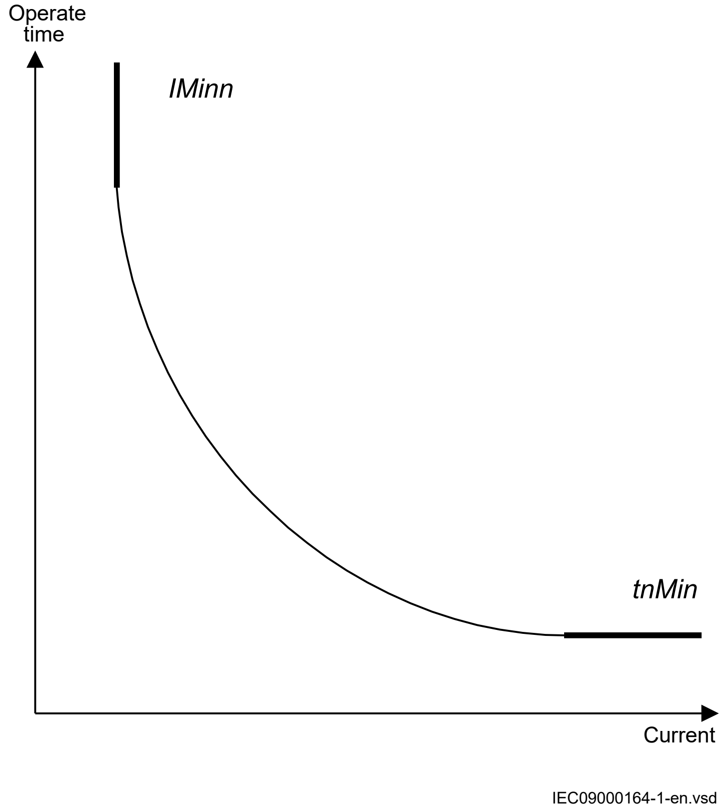


Figure 105: Minimum operating current and operation time for inverse time characteristics

In order to fully comply with curves definition setting parameter *tnMin* shall be set to the value which is equal to the operating time of the selected inverse curve for measured current of twenty times the set current pickup value. Note that the operating time value is dependent on the selected setting value for time multiplier *TDn*.

7.4.3.2 Current application

OC4SPTOC (51_67) function 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 inverse time protection or the lowest current step constant inverse time protection must be given a current setting so that the highest possible load current does not cause protection operation. Here consideration also has to be taken to the protection reset current, so that a short peak of overcurrent does not cause operation of the protection even when the overcurrent has ceased. This phenomenon is described in figure 106.

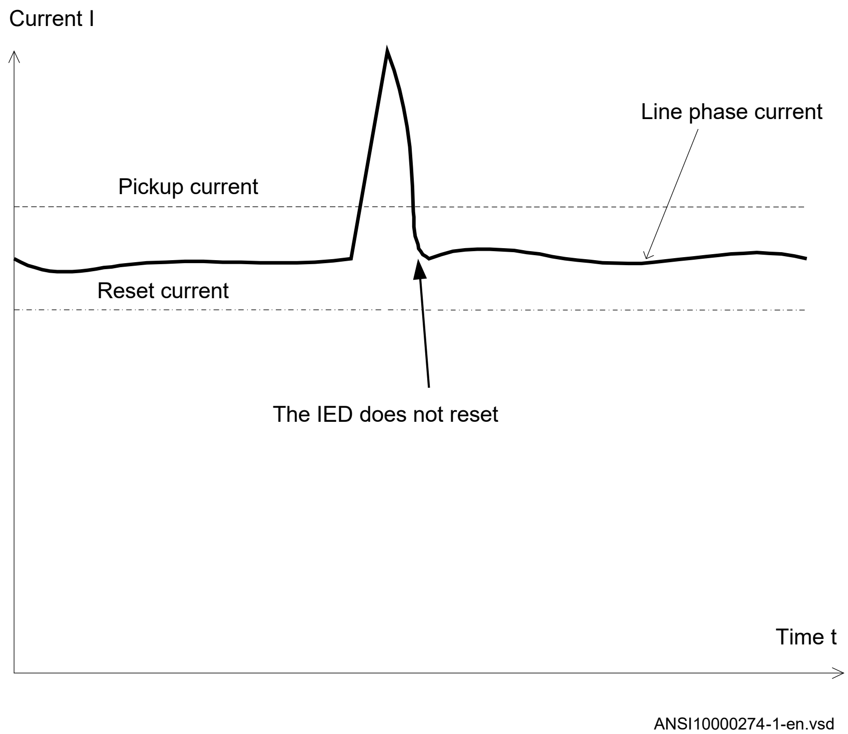


Figure 106: Pickup and reset current for an overcurrent protection

The lowest setting value can be written according to equation 130.

$$Ipu \geq 1.2 \cdot \frac{Imax}{k}$$

(Equation 130)

where:

- *1.2* is a safety factor,
- *k* is the resetting ratio of the protection, and
- *Imax* is the maximum load current.

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 *Iscmin*, to be detected by the protection, must be calculated. Taking this value as a base, the highest pick up current setting can be written according to equation 131.

$$Ipu \leq 0.7 \cdot Iscmin$$

(Equation 131)

where:

- 0.7 is a safety factor
- Iscmin is the smallest fault current to be detected by the overcurrent protection

$$1.2 \cdot \frac{\mathrm{Imax}}{\mathrm{k}} \leq \mathrm{Ipu} \leq 0.7 \cdot \mathrm{Iscmin}$$

(Equation 132)

The *high current function* of the overcurrent protection, which only has a short delay of the operation, must be given a current setting so that the protection is selective to other protection in the power system. It is desirable to have a rapid tripping of faults within as large portion as possible of the part of the power system to be protected by the protection (primary protected zone). A fault current calculation gives the largest current of faults, Iscmax, at the most remote part of the primary protected zone. Considerations have to be made to the risk of transient overreach, due to a possible DC component of the short circuit current. The lowest current setting of the most rapid stage, of the phase overcurrent protection, can be written according to

$$I_{high} \geq 1.2 \cdot k_t \cdot I_{sc\max}$$

(Equation 133)

where:

- 1.2 is a safety factor
- kt 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 1.1
- Iscmax is the largest fault current at a fault at the most remote point of the primary protection zone

The operate times of the phase overcurrent protection has to be chosen so that the fault time is so short that protected equipment will not be destroyed due to thermal overload, at the same time as 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 107 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.

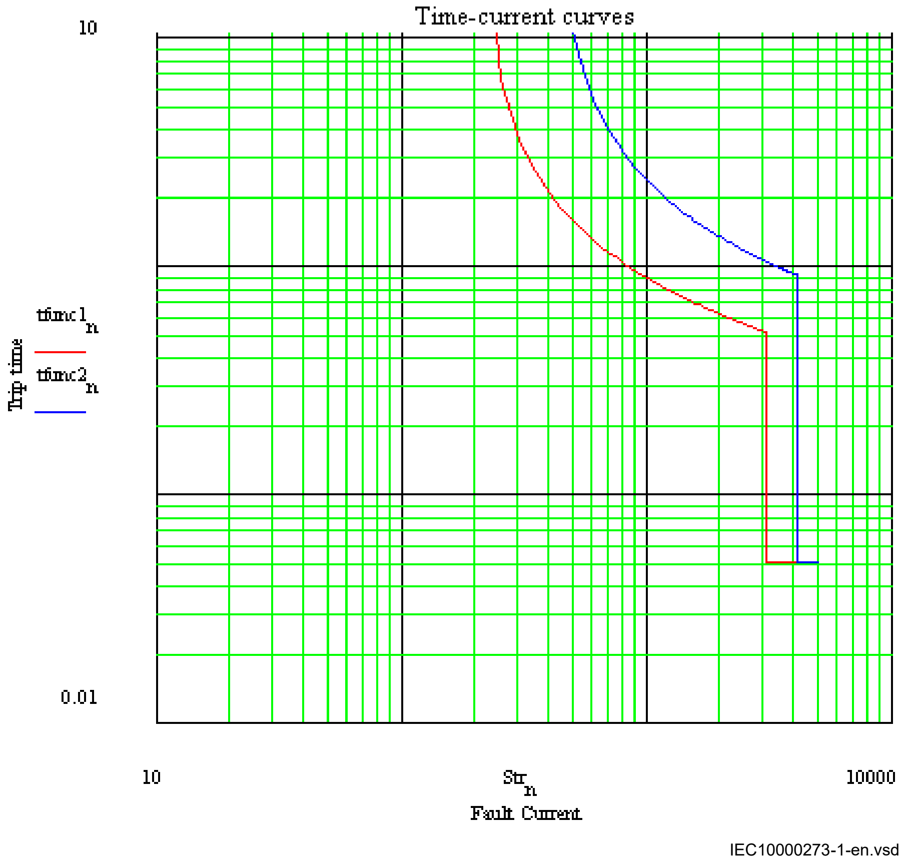


Figure 107: Fault time with maintained selectivity

To assure selectivity between different protections, in the radial network, there have to be a minimum time difference Δt between the time delays of two protections. The minimum time difference can be determined for different cases. 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 operation time: *15-60 ms*
- Protection resetting time: *15-60 ms*
- Breaker opening time: *20-120 ms*

7.4.3.3 Example

Assume two substations A and B directly connected to each other via one line, as shown in the figure 108. 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 protection will have instantaneous function. The overcurrent protection of IED A1 must have a delayed function. The sequence of events during the fault can be described using a time axis, see figure 108.

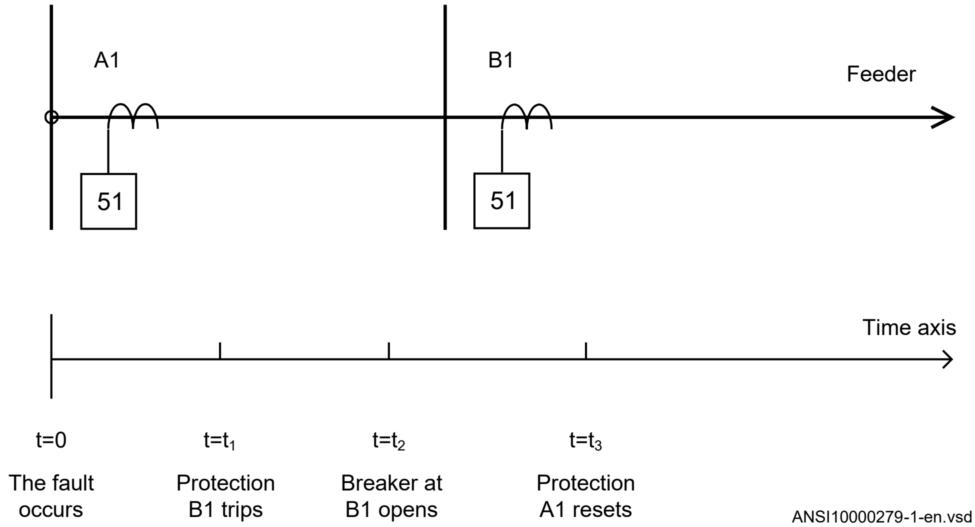


Figure 108: Sequence of events during fault

where:

- t=0 is when the fault occurs.
- t=t1 is when the trip signal from the overcurrent protection at IED B1 is sent to the circuit breaker. The operation time of this protection is
- t1, t=t2 is when the circuit breaker at IED B1 opens. The circuit breaker opening time is t2 - t1.
- t=t3 is when the overcurrent protection at IED A1 resets. The protection resetting time is t3 - t2.

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 134.

$$\Delta t \geq 40\,ms + 100\,ms + 40\,ms + 40\,ms = 220\,ms$$

(Equation 134)

where it is considered that:

- the operation time of overcurrent protection B1 is 40 ms
- the breaker open time is 100 ms
- the resetting time of protection A1 is 40 ms
- the additional margin is 40 ms

7.5 Instantaneous residual overcurrent protection EFPIOC (50N)

7.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Instantaneous residual overcurrent protection	EFPIOC	*IN>>*	50N

7.5.2 Application

In many applications, when fault current is limited to a defined value by the object impedance, an instantaneous ground-fault protection can provide fast and selective tripping.

The Instantaneous residual overcurrent EFPIOC (50N), which can operate in 15 ms (50 Hz nominal system frequency) for faults characterized by very high currents, is included in the IED.

7.5.3 Setting guidelines

The parameters for the Instantaneous residual overcurrent protection EFPIOC (50N) are set via the local HMI or PCM600.

Some guidelines for the choice of setting parameter for EFPIOC (50N) is given.

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

The setting of the function is limited to the operation residual current to the protection (*Pickup*).

The basic requirement is to assure selectivity, that is EFPIOC (50N) shall not be allowed to operate for faults at other objects than the protected object (line).

For a normal line in a meshed system single phase-to-ground faults and phase-to-phase-to-ground faults shall be calculated as shown in figure 109 and figure 110. The residual currents ($3I_0$) to the protection are calculated. For a fault at the remote line end this fault current is I_{fB}. In this calculation the operational state with high source impedance Z_A and low source impedance Z_B should be used. For the fault at the home busbar this fault current is I_{fA}. In this calculation the operational state with low source impedance Z_A and high source impedance Z_B should be used.

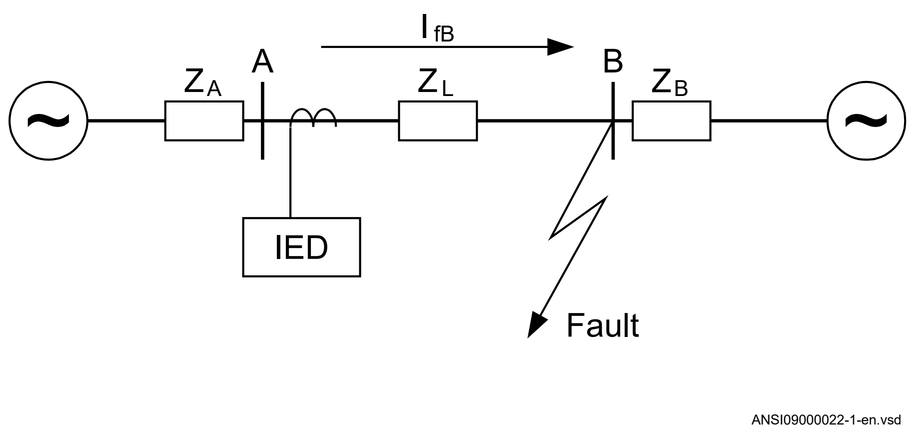


Figure 109: Through fault current from A to B: I_{fB}

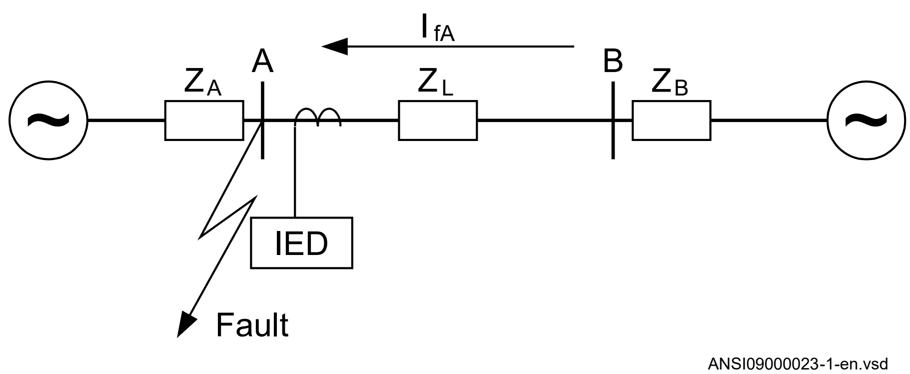


Figure 110: Through fault current from B to A: I_{fA}

The function shall not operate for any of the calculated currents to the protection. The minimum theoretical current setting (Imin) will be:

$$Imin \geq MAX(I_{fA}, I_{fA})$$

(Equation 135)

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

The minimum primary current setting (Is) is:

$$Is \geq 1,3 \cdot Imin$$

(Equation 136)

In case of parallel lines with zero sequence mutual coupling a fault on the parallel line, as shown in figure 111, should be calculated.

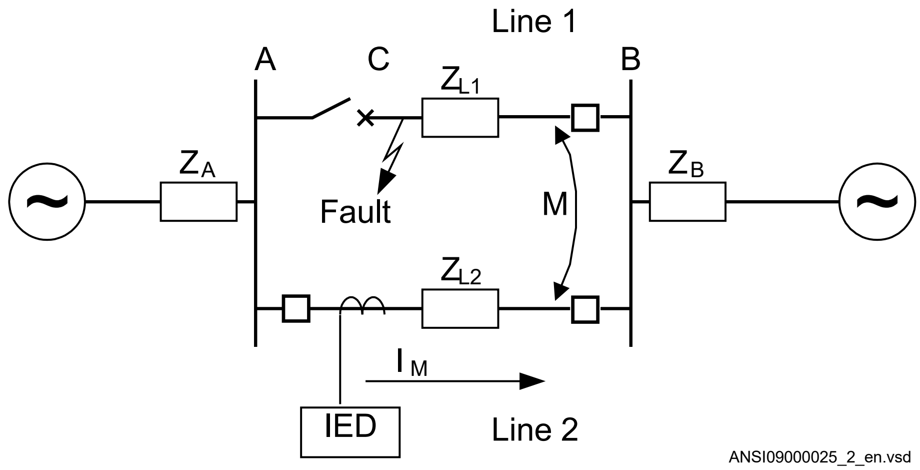


Figure 111: Two parallel lines. Influence from parallel line to the through fault current: I_M

The minimum theoretical current setting (Imin) will in this case be:

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

(Equation 137)

Where:

I_{fA} and I_{fB} have been described for the single line case.

Considering the safety margins mentioned previously, the minimum setting (Is) is:

$$Is \geq 1,3 \cdot Imin$$

(Equation 138)

Transformer inrush current shall be considered.

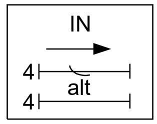
The setting of the protection is set as a percentage of the base current (*IBase*).

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

Pickup: Set operate current in % of *IBase*. *IBase* is a global parameter valid for all functions in the IED.

7.6 Four step residual overcurrent protection EF4PTOC (51N/67N)

7.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Four step residual overcurrent protection	EF4PTOC		51N/67N

7.6.2 Application

The four step residual overcurrent protection EF4PTOC (51N_67N) is used in several applications in the power system. Some applications are:

- Ground-fault protection of feeders in effectively grounded distribution and subtransmission systems. Normally these feeders have radial structure.
- Back-up ground-fault protection of transmission lines.
- Sensitive ground-fault protection of transmission lines. EF4PTOC (51N_67N) can have better sensitivity to detect resistive phase-to-ground-faults compared to distance protection.
- Back-up ground-fault protection of power transformers.
- Ground-fault protection of different kinds of equipment connected to the power system such as shunt capacitor banks, shunt reactors and others.

In many applications several steps with different current pickup levels and time delays are needed. EF4PTOC (51N_67N) can have up to four, individual settable steps. The flexibility of each step of EF4PTOC (51N_67N) 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 ground-fault protection in meshed and effectively grounded transmission systems. The directional residual overcurrent protection is also well suited to operate in teleprotection communication schemes, which enables fast clearance of ground faults on transmission lines. The directional function uses the polarizing quantity as decided by setting. Voltage polarizing ($-3V_0$) is most commonly used but alternatively current polarizing where currents in transformer neutrals providing the neutral (zero sequence) source (ZN) is used to polarize (IN · ZN) the function. Dual polarizing where the sum of both voltage and current components is allowed to polarize can also be selected.

Choice of time characteristics: There are several types of time characteristics available such as definite time delay and different types of inverse time characteristics. The selectivity between different overcurrent protections is normally enabled by co-ordination between the operating time of the different protections. To enable optimal co-ordination all overcurrent protections, to be co-ordinated against each other, should have the same time characteristic. Therefore a wide range of standardized inverse time characteristics are available: IEC and ANSI. The time characteristic for step 1 and 4 can be chosen as definite time delay or inverse time characteristic. Step 2 and 3 are always definite time delayed and are used in system where IDMT is not needed.

Table 21: 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
ASEA RI
RXIDG (logarithmic)

Power transformers can have a large inrush current, when being energized. This inrush current can have residual current components. The phenomenon is due to saturation of the transformer magnetic core during parts of the cycle. There is a risk that inrush current will give a residual current that reaches level above the pickup current of the residual overcurrent protection. The inrush current has a large second harmonic content. This can be used to avoid unwanted operation of the protection. Therefore, EF4PTOC (51N_67N) has a possibility of second harmonic restrain *2ndHarmStab* if the level of this harmonic current reaches a value above a set percentage of the fundamental current.

7.6.3 Setting guidelines

The parameters for the four step residual overcurrent protection EF4PTOC (51N/67N) are set via the local HMI or PCM600.

The following settings can be done for the four step residual overcurrent protection.

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

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

7.6.3.1 Settings for steps 1 and 4

n means step 1 and 4.

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

Characteristx: 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 have to be a minimum time difference Δt between the time delays of two protections. The minimum time difference can be determined for different cases. 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 operation time:	15-60 ms
Protection resetting time:	15-60 ms
Breaker opening time:	20-120 ms

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

Pickup"x": Operation residual current level for step *x* given in % of *IBase*.

TDn: Time multiplier for the dependent (inverse) characteristic for step *n*.

IMinn: Minimum operate current for step *n* in % of *IBase*. Set *IMinn* below *Pickupx* for every step to achieve ANSI reset characteristic according to standard. If *IMinn* is set above *Pickupx* for any step the ANSI reset works as if current is zero when current drops below *IMinn*.

tnMin: 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 *n* can never be shorter than the setting.

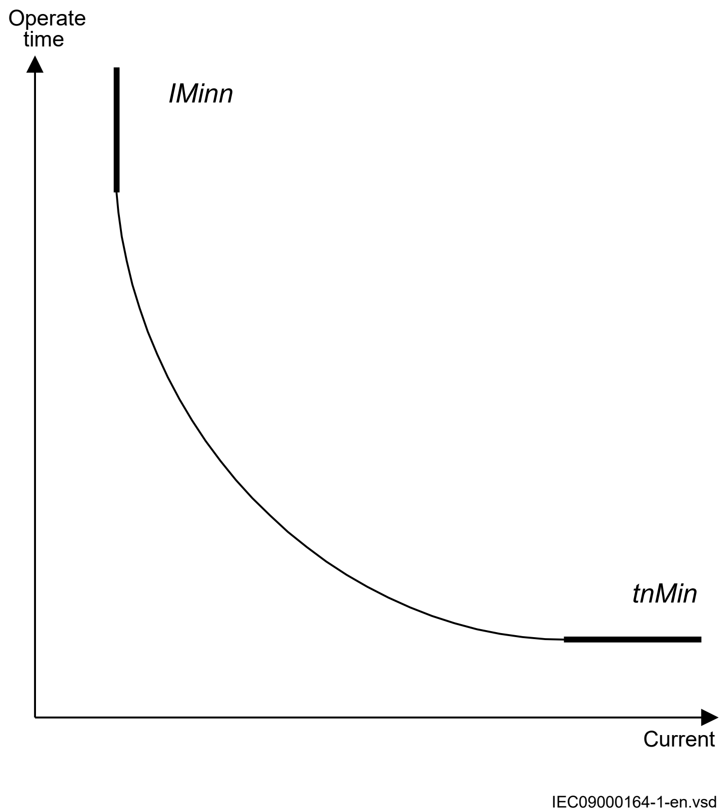


Figure 112: Minimum operate current and operation time for inverse time characteristics

In order to fully comply with curves definition the setting parameter *txMin* shall be set to the value which is equal to the operating time of the selected IEC inverse curve for measured current of twenty times the set current pickup value. Note that the operating time value is dependent on the selected setting value for time multiplier *TDn*.

7.6.3.2 Common settings for all steps

tx: Definite time delay for step *x*. Used if definite time characteristic is chosen.

AngleRCA: Relay characteristic angle given in degree. This angle is defined as shown in figure 113. The angle is defined positive when the residual current lags the reference voltage (Vpol = -3V_0)

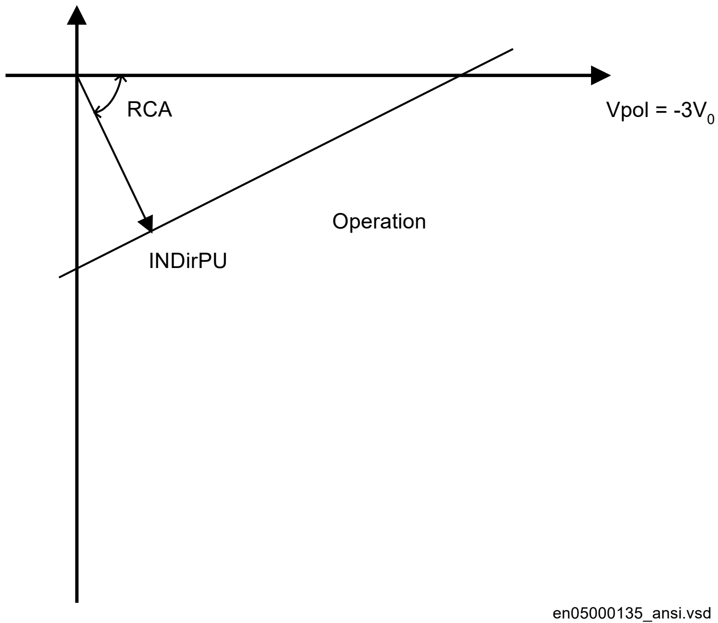


Figure 113: Relay characteristic angle given in degree

In a normal transmission network a normal value of RCA is about 65°. The setting range is -180° to +180°.

polMethod: Defines if the directional polarization is from

- *Voltage* ($-3V_0$)
- *Current* ($3I_0 \cdot$ ZNpol where ZNpol is RNpol + jXNpol), or
- both currents and voltage, *Dual* (dual polarizing, -3U0 + $3I_0 \cdot$ ZNpol).

Normally voltage polarizing from the 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 (ZNpol) and check that the percentage of the phase-to-ground voltage is definitely higher than 1% (minimum $3V_0$> *VPolMin* 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 $3I_0 \cdot$ ZNpol. The ZNpol can be defined as (ZS_1-ZS_0)/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 ZN as V/(√3 · $3I_0$) Typically, the minimum ZNPol (3 · zero sequence source) is set. Setting is in primary ohms.

When the dual polarizing method is used it is important that the setting *Pickupx* or the product $3I_0$ · ZNpol is not greater than $3U_0$. If so, there is a risk for incorrect operation for faults in the reverse direction.

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

VPolMin: Minimum polarization (reference) residual voltage for the directional function, given in % of *VBase*/√3.

INDirPU: Operating residual current release level in % of *IBase* for directional comparison scheme. The setting is given in % of *IBase*. The output signals, PUFW and PUREV can be used in a teleprotection scheme. The appropriate signal should be configured to the communication scheme block.

7.6.3.3 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 an inrush transformer 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. Also here the 2^{nd} harmonic restrain can prevent unwanted operation.

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.

HarmRestrainx: Enable block of step *x* from the harmonic restrain function.

7.6.3.4 Line application example

The Four step residual overcurrent protection EF4PTOC (51N67N) can be used in different ways. Below is described one application possibility to be used in meshed effectively grounded systems.

The protection measures the residual current out on the protected line. The protection function has a directional function where the residual voltage (zero-sequence voltage) is the polarizing quantity.

The residual voltage can be internally generated when a three-phase set of voltage transformers are used.

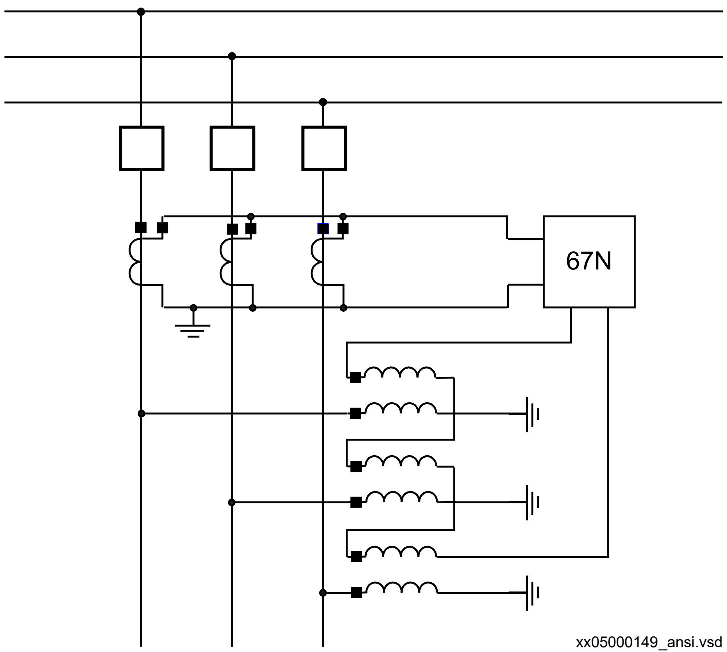


Figure 114: Connection of polarizing voltage from an open (ANSI-broken) delta

The different steps can be described as follows.

Step 1

This step has directional instantaneous function. The requirement is that overreaching of the protected line is not allowed.

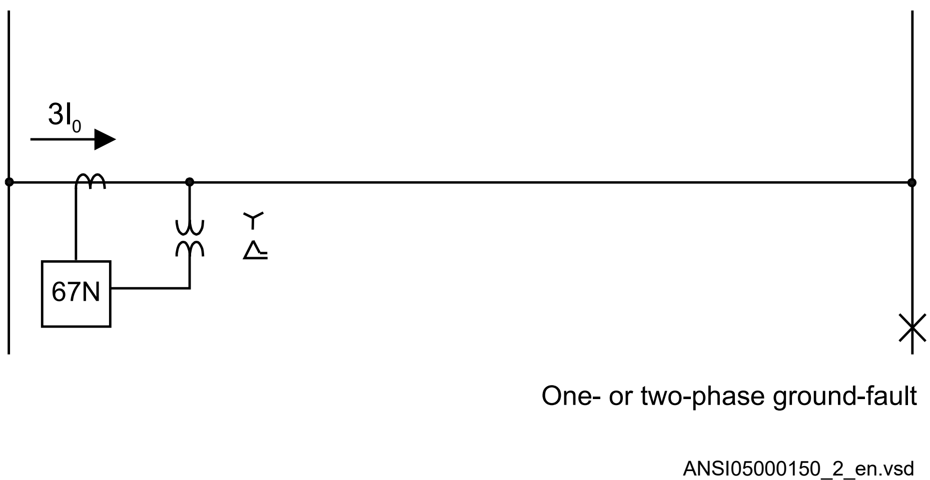


Figure 115: Step 1, first calculation

The residual current out on the line is calculated at a fault on the remote busbar (one- or two-phase-to-ground fault). To assure selectivity it is required that step 1 shall not give a trip at this fault. The requirement can be formulated according to equation 139.

$$I_{step1} \geq 1.2 \cdot 3I_0 \text{ (remote busbar)}$$

(Equation 139)

As a consequence of the distribution of zero sequence current in the power system, the current to the protection might be larger if one line out from the remote busbar is taken out of service, see figure 116.

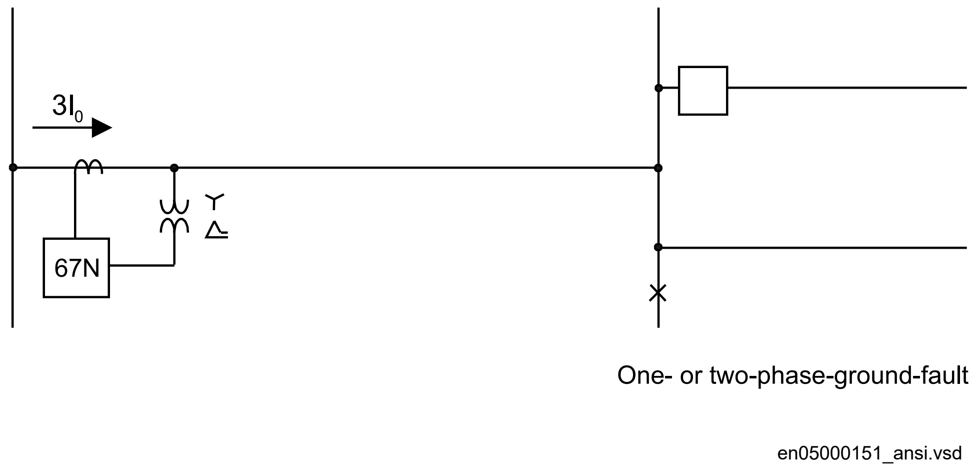


Figure 116: Step 1, second calculation. Remote busbar with, one line taken out of service

The requirement is now according to equation 140.

$$I_{step1} \geq 1.2 \cdot 3I_0 \text{ (remote busbar with one line out)}$$

(Equation 140)

A higher value of step 1 might occur if a big power transformer (Y0/D) at remote bus bar is disconnected.

A special case occurs at double circuit lines, with mutual zero-sequence impedance between the parallel lines, see figure 117.

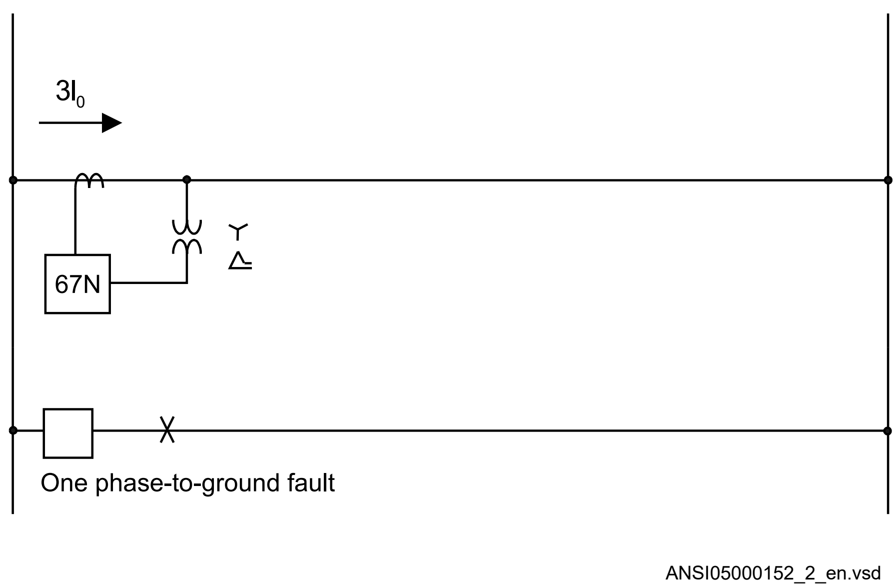


Figure 117: Step 1, third calculation

In this case the residual current out on the line can be larger than in the case of ground fault on the remote busbar.

$$I_{step1} \geq 1.2 \cdot 3I_0$$

(Equation 141)

The current setting for step 1 is chosen as the largest of the above calculated residual currents, measured by the protection.

Step 2

This step has directional function and a short time delay, often about 0.4 s. Step 2 shall securely detect all ground faults on the line, not detected by step 1.

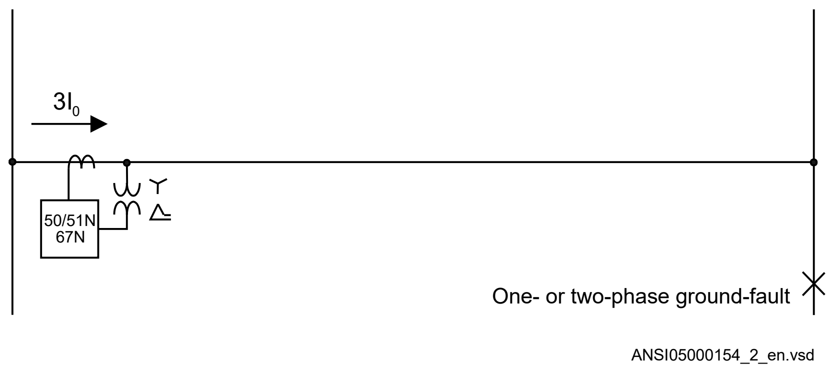


Figure 118: Step 2, check of reach calculation

The residual current, out on the line, is calculated at an operational case with minimal ground-fault current. The requirement that the whole line shall be covered by step 2 can be formulated according to equation 142.

$$I_{step1} \geq 0.7 \cdot 3I_0 \text{ (at remote busbar)}$$

(Equation 142)

To assure selectivity the current setting must be chosen so that step 2 does not operate at step 2 for faults on the next line from the remote substation. Consider a fault as shown in figure 119.

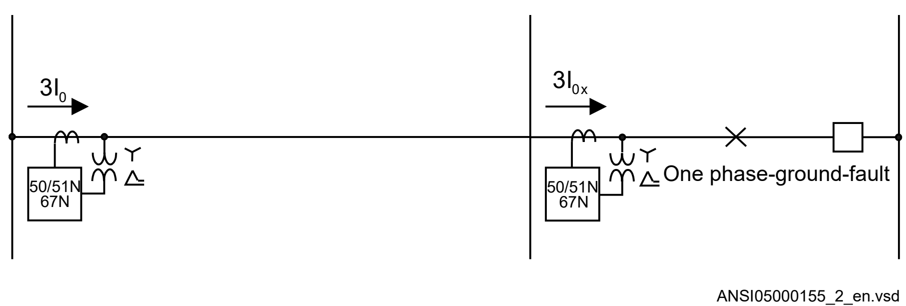


Figure 119: Step 2, selectivity calculation

A second criterion for step 2 is according to equation 143.

$$I_{step2} \geq 1.2 \cdot \frac{3I_0}{3I_{0x}} \cdot I_{step1x}$$

(Equation 143)

where:

Istep1x is the current setting for step 1 on the faulted line.

Step 3

This step has directional function and a time delay slightly larger than step 2, often 0.8 s. Step 3 shall enable selective trip of ground faults having some fault resistance to ground, so that step 2 is not activated. The requirement on step 3 is selectivity to other ground-fault protections in the network. One criterion for setting is shown in figure 120.

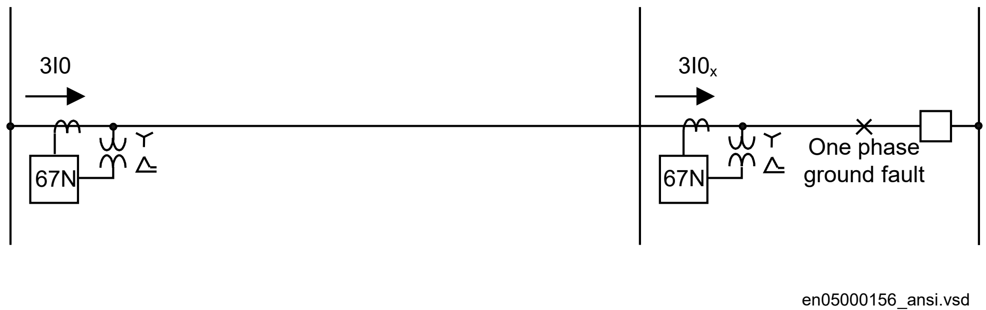


Figure 120: Step 3, Selectivity calculation

$$I_{step3} \geq 1.2 \cdot \frac{3I_0}{3I_{0x}} \cdot I_{step2x}$$

(Equation 144)

where:

Istep2x is the chosen current setting for step 2 on the faulted line.

Step 4

This step normally has non-directional function and a relatively long time delay. The task for step 4 is to detect and initiate trip for ground faults with large fault resistance, for example tree faults. Step 4 shall also detect series faults where one or two poles, of a breaker or other switching device, are open while the other poles are closed.

Both high resistance ground faults and series faults give zero-sequence current flow in the network. Such currents give disturbances on telecommunication systems and current to ground. It is important to clear such faults both concerning personal security as well as risk of fire.

The current setting for step 4 is often set down to about 100 A (primary $3I_0$). In many applications definite time delay in the range 1.2 - 2.0 s is used. In other applications a current dependent inverse time characteristic is used. This enables a higher degree of selectivity also for sensitive ground-fault current protection.

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

7.7.1 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

7.7.2 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 $3I_0 \cdot \cos \phi$, where φ is the angle between the residual current and the residual voltage (-3U0), compensated with a characteristic angle. Alternatively, the function can be set to strict $3I_0$ level with an check of angle $3I_0$ and cos 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 $3I_0 \cdot 3V_0 \cdot \cos \phi$, 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 back-up neutral point voltage function is also available for non-directional sensitive back-up 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 -90º phase shift compared to the reference residual voltage. The characteristic angle is chosen to -90º 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 0º.

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 facts:

- Sensitive directional residual overcurrent protection gives possibility for better sensitivity
- 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 current
- In some power systems a medium size neutral point resistor is used, for example, in low impedance grounded system. Such a resistor will give a resistive ground-fault current component of about 200 - 400 A at a zero resistive phase-to-ground fault. In such a system the directional residual power protection gives better possibilities for selectivity enabled by inverse time power characteristics.

7.7.3 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:

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

(Equation 145)

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:

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

(Equation 146)

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:

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

(Equation 147)

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 148)

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:

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

(Equation 149)

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 121.

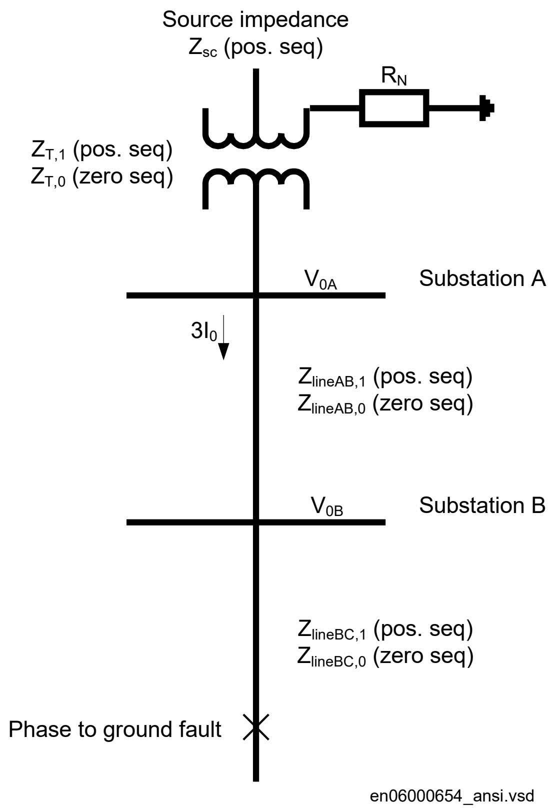


Figure 121: Equivalent of power system for calculation of setting

The residual fault current can be written:

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

(Equation 150)

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. $Z_1 = Z_{sc}+Z_{T,1}+Z_{lineAB,1}+Z_{lineBC,1}$

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

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 151)

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

(Equation 152)

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

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

(Equation 153)

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

(Equation 154)

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:

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

(Equation 155)

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

(Equation 156)

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:

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

(Equation 157)

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

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

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* is measured. The characteristic for *RCADir* is equal to 0° is shown in figure 122.

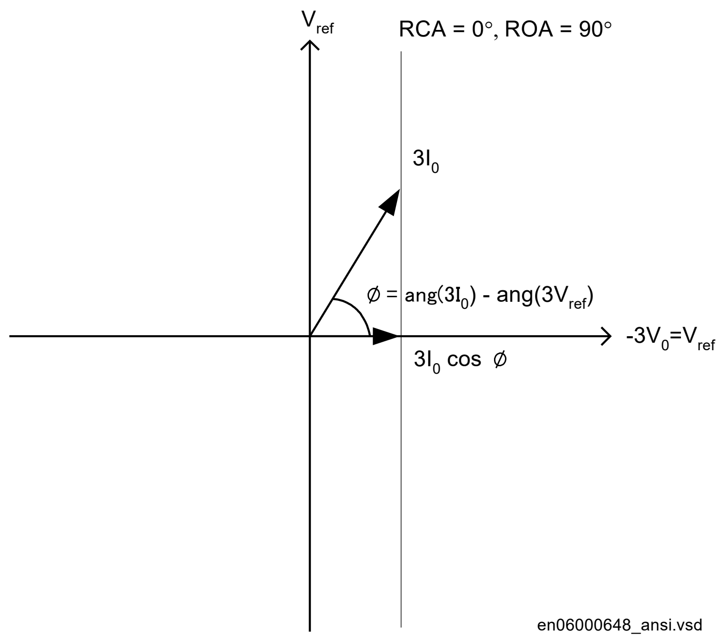


Figure 122: Characteristic for RCADir equal to 0°

The characteristic is for *RCADir* equal to -90° is shown in figure 123.

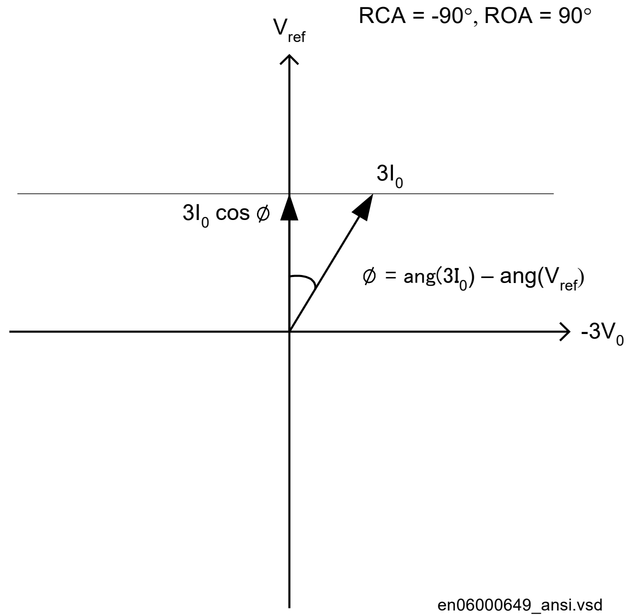


Figure 123: Characteristic for RCADir equal to -90°

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* ± *ROADir*.

The characteristic for *RCADir* = 0° and *ROADir* = 80° is shown in figure 124.

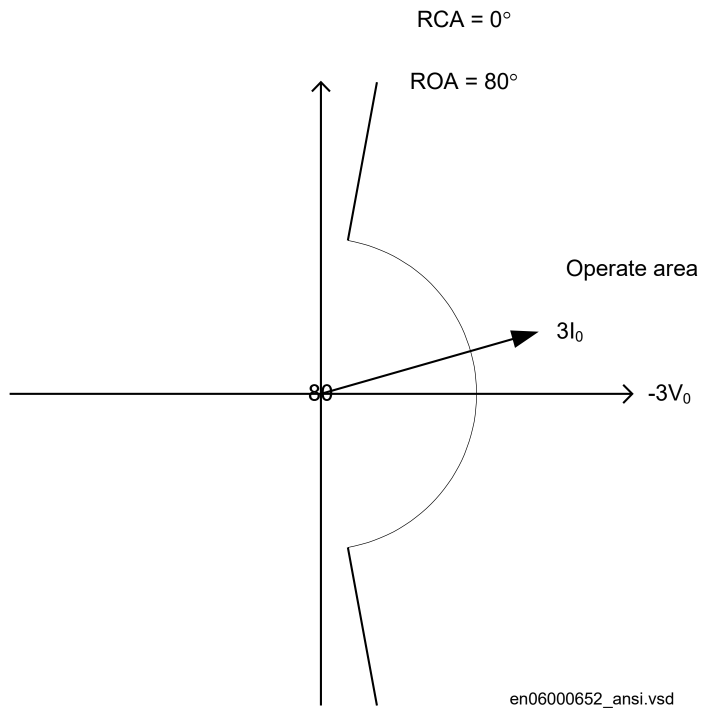


Figure 124: Characteristic for RCADir = 0° and ROADir = 80°

DirMode is set *Forward* or *Reverse* to set the direction of the trip function from the directional residual current function.

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 if definite time delay is chosen.

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.

The relay open angle *ROADir* is set in degrees. For angles differing more than *ROADir* from*RCADir* the function from the protection is blocked. The setting can be used to prevent unwanted function for non-faulted feeders, with large capacitive ground-fault current contributions, due to CT phase angle error.

INCosPhiPU is the operate 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 operate power level for the directional function when *OpModeSel* is set *3I03V0Cosfi*. The setting is given in % of *IBase*. 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.

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:

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

(Equation 158)

INDirPU is the operate 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 operate 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 out 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:

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
ASEA RI
RXIDG (logarithmic)

The different characteristics are described in Technical Manual.

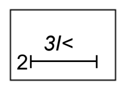
tINNonDir is the definite time delay for the non directional ground-fault current protection, given in s.

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

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

7.8 Time delayed 2-step undercurrent protection UC2PTUC (37)

7.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time delayed 2-step undercurrent protection	UC2PTUC		37

7.8.2 Application

Time delayed 2-step undercurrent protection (UC2PTUC ,37) can be used wherever a “low current” signal is needed. The main application is as a local criterion to increase security when transfer trip schemes are used. Two different application examples for the undercurrent protection function are given below. The examples are a power transformer directly connected to the feeding line and a line connected shunt reactor operating on a circuit breaker in another substation. Both examples involve a transfer trip scheme, to which a local low current criterion is added, to avoid unwanted trips, caused by false transfer trip signals.

Power transformer, directly connected to the feeding line

The main purpose of UC2PTUC (37) is to provide a local criterion, which is added to a received transfer trip signal, in order to increase the security of the overall tripping functionality. A typical application for this function is a power transformer directly connected to the feeding line, as shown in figure 125.

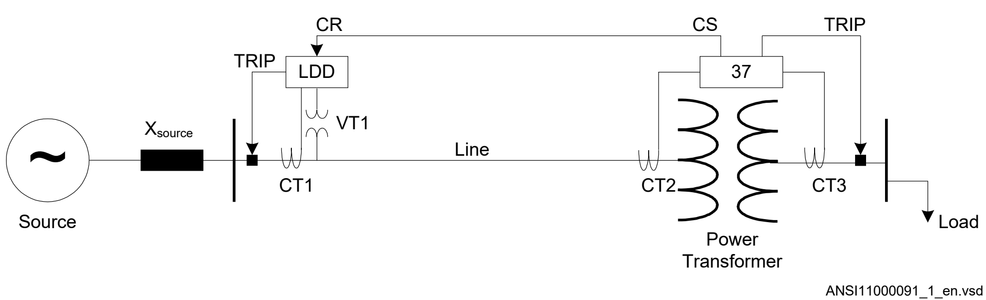


Figure 125: Power transformer, directly connected to the feeding line

Suppose that an internal non-symmetrical transformer fault appears within the protective area of the transformer differential protection. In most cases, the line protection will not recognize the fault. The transformer differential protection operates for the internal fault and initiates a trip of the secondary side circuit breaker. It addition to that, it sends the carrier signal CS to the remote line end, in order to open the line circuit breaker in that substation.

The carrier receive (CR) signal could trip the line circuit breaker directly, according to a so called direct transfer trip scheme (DTT), but in such cases security would be compromised, due to the bad quality of the communication link. A false CR signal could unnecessarily trip the line. Therefore, a local detection device (LDD) is used, to provide an additional trip criterion, at the same location as the line circuit breaker. The LDD must detect the abnormal conditions at the end of the protected line and transformer and permit the CR signal to trip the circuit breaker. The current in at least one of the phases at the sending end of the line decreases, when the differential protection of the transformer trips the circuit breaker on the secondary side, and the breaker contacts open. This means, that an undercurrent function, properly set, could provide a good criterion to increase the security of the protection for the line and the transformer, with basically unchanged dependability.

Line connected shunt reactor

The main purpose of UC2PTUC (37) is to provide a local criterion, which is added to a received transfer trip signal, in order to increase the security of the overall tripping functionality. A typical application for UC2PTUC (37) function is a line connected shunt reactor, as shown in figure 126.

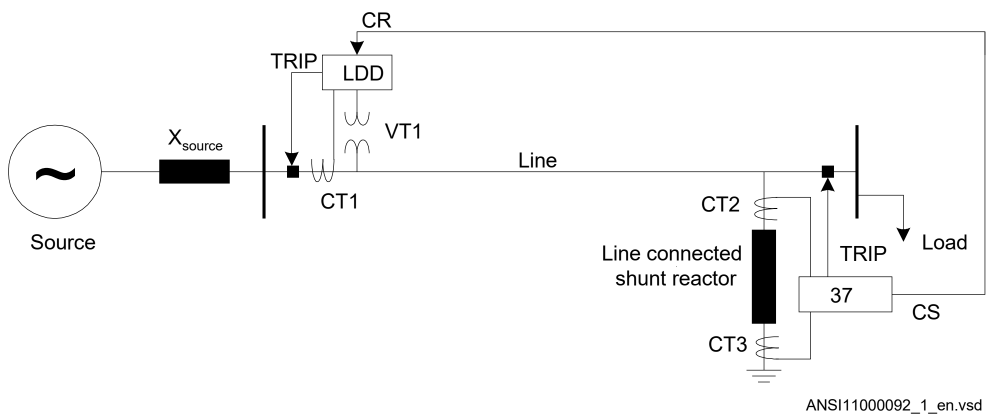


Figure 126: High voltage power line with solidly connected shunt reactor

Shunt reactors are generally protected by differential protection, which operates the local line circuit breaker and sends a transfer trip command to the remote line end. The line protection in the remote end is much less sensitive than the differential protection, and operates only for low impedance reactor faults very close to the high voltage terminal. To avoid line trips at the remote end due to false transfer trip signals, a local criterion can be added at the remote end. Low current in at least two of the phases is, therefore, found to be a very useful criterion to increase security.

7.8.3 Setting guidelines

The parameters for the undercurrent protection function are set via the local HMI or PCM600.

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: operation of the entire undercurrent protection function has to be set to either *Enabled* or *Disabled*.

I1Mode: number of phases involved for operation for step1.

I1<: low-set level of the current. If the current decreases below this limit, the function picks up and issue start signals PU_ST1 and RI.

t1: time delay of *I1<* from pick-up to the issue of trip signals TRST1 and TRIP.

tReset1: instantaneous or time delayed reset of RI and PU_ST1 signals.

I2Mode: number of phases involved for operation for step2.

I2<: high-set level of the current. If the current decreases below this limit the function picks up and issue start signals PU_ST2 and RI.

t2: time delay of *I2<* from the pick-up to the issue of trip signals TRST2 and TRIP.

tReset2: instantaneous or time delayed reset of RI and PU_ST2 signals.

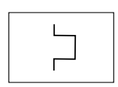
tPulse: duration of all TRIP signals.

IBlk: set level of the currents. If all three phase currents are below this limit the function blocks the undercurrent protection.

The pick-up level for *I1<* and *I2<* should be set with some margin to the lowest current level, that can appear during normal operation conditions.

7.9 Thermal overload protection, one time constant LPTTR (26)

7.9.1 Identification

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

7.9.2 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, get 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 without risks.

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. 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.

7.9.3 Setting guidelines

The parameters for the Thermal overload protection LPTTR (26) are set via the local HMI or PCM600.

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

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: *Disabled*/*Enabled*

IRef: Reference, steady state current, given in % of *IBase* that will give a steady state (end) temperature *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 (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 90°C. For overhead lines the critical temperature for aluminium conductor is about 90 - 100°C. For a copper conductor a normal figure is 70°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 65°C. Similar values are stated for overhead lines. A suitable setting can be about 15°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.

7.10 Breaker failure protection CCRBRF (50BF)

7.10.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Breaker failure protection	CCRBRF	3I>BF	50BF

7.10.2 Application

In the design of the fault clearance system the N-1 criterion is often used. This means that a fault needs to be cleared even if any component in the fault clearance system is faulty. One necessary component in the fault clearance system is the circuit breaker. It is from practical and economical reason not feasible to duplicate the circuit breaker for the protected component. Instead a breaker failure protection is used.

Breaker failure protection (CCRBRF, 50BF) will issue a back-up trip command to adjacent circuit breakers in case of failure to trip of the “normal” circuit breaker for the protected component. The detection of failure to break the current through the breaker is made by means of current measurement or as detection of remaining trip signal (unconditional).

CCRBRF (50BF) can also give a re-trip. This means that a second trip signal is sent to the protected circuit breaker. The re-trip function can be used to increase the probability of operation of the breaker, or it can be used to avoid back-up trip of many breakers in case of mistakes during relay maintenance and test.

7.10.3 Setting guidelines

The parameters for Breaker failure protection CCRBRF (50BF) are set via the local HMI or PCM600.

The following settings can be done for the breaker failure protection.

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: *Disabled*/ *Enabled*

FunctionMode This parameter can be set *Current* or *Contact*. This states the way the detection of failure of the breaker is performed. In the mode current the current measurement is used for the detection. In the mode *Contact* the long duration of breaker position signal is used as indicator of failure of the breaker. The mode *Current&Contact* means that both ways of detections are activated. *Contact* mode can be usable in applications where the fault current through the circuit breaker is small. This can be the case for some generator protection application (for example reverse power protection) or in case of line ends with weak end infeed.

RetripMode: This setting states how the re-trip function shall operate. *Retrip Off* means that the re-trip function is not activated. *CB Pos Check* (circuit breaker position check) and *Current* means that a phase current must be larger than the operate level to allow re-trip. *CB Pos Check* (circuit breaker position check) and *Contact* means re-trip is done when circuit breaker is closed (breaker position is used). *No CBPos Check* means re-trip is done without check of breaker position.

Table 22: Dependencies between parameters RetripMode and FunctionMode

RetripMode	***FunctionMode***	**Description**
Retrip Off	N/A	the re-trip function is not activated
CB Pos Check	*Current*	a phase current must be larger than the operate level to allow re-trip
	Contact	re-trip is done when breaker position indicates that breaker is still closed after re-trip time has elapsed
	Current&Contact	both methods are used
No CBPos Check	*Current*	re-trip is done without check of breaker position
	Contact	re-trip is done without check of breaker position
	Current&Contact	both methods are used

BuTripMode: Back-up trip mode is given to state sufficient current criteria to detect failure to break. For *Current* operation *2 out of 4* means that at least two currents, of the three-phase currents and the residual current, shall be high to indicate breaker failure. *1 out of 3* means that at least one current of the three-phase currents shall be high to indicate breaker failure. *1 out of 4* means that at least one current of the three-phase currents or the residual current shall be high to indicate breaker failure. In most applications *1 out of 3* is sufficient. For *Contact* operation means back-up trip is done when circuit breaker is closed (breaker position is used).

Pickup_PH: Current level for detection of breaker failure, set in % of *IBase*. This parameter should be set so that faults with small fault current can be detected. The setting can be chosen in accordance with the most sensitive protection function to start the breaker failure protection. Typical setting is 10% of *IBase*.

Pickup_BlkCont: If any contact based detection of breaker failure is used this function can be blocked if any phase current is larger than this setting level. If the *FunctionMode* is set *Current&Contact* breaker failure for high current faults are safely detected by the current measurement function. To increase security the contact based function should be disabled for high currents. The setting can be given within the range 5 – 200% of *IBase*.

Pickup_N: Residual current level for detection of breaker failure set in % of *IBase*. In high impedance grounded systems the residual current at phase- to-ground faults are normally much smaller than the short circuit currents. In order to detect breaker failure at single-phase-ground faults in these systems it is necessary to measure the residual current separately. Also in effectively grounded systems the setting of the ground-fault current protection can be chosen to relatively low current level. The *BuTripMode* is set *1 out of 4*. The current setting should be chosen in accordance to the setting of the sensitive ground-fault protection. The setting can be given within the range 2 – 200 % of *IBase*.

t1: Time delay of the re-trip. The setting can be given within the range 0 – 60s in steps of 0.001 s. Typical setting is 0 – 50ms.

t2: Time delay of the back-up trip. The choice of this setting is made as short as possible at the same time as unwanted operation must be avoided. Typical setting is 90 – 200ms (also dependent of re-trip timer).

The minimum time delay for the re-trip can be estimated as:

$$t2 \geq t1 + t_{cbopen} + t_{BFP\_reset} + t_{margin}$$

(Equation 159)

where:

t_{cbopen}	is the maximum opening time for the circuit breaker
t_{BFP_reset}	is the maximum time for breaker failure protection to detect correct breaker function (the current criteria reset)
t_{margin}	is a safety margin

It is often required that the total fault clearance time shall be less than a given critical time. This time is often dependent of the ability to maintain transient stability in case of a fault close to a power plant.

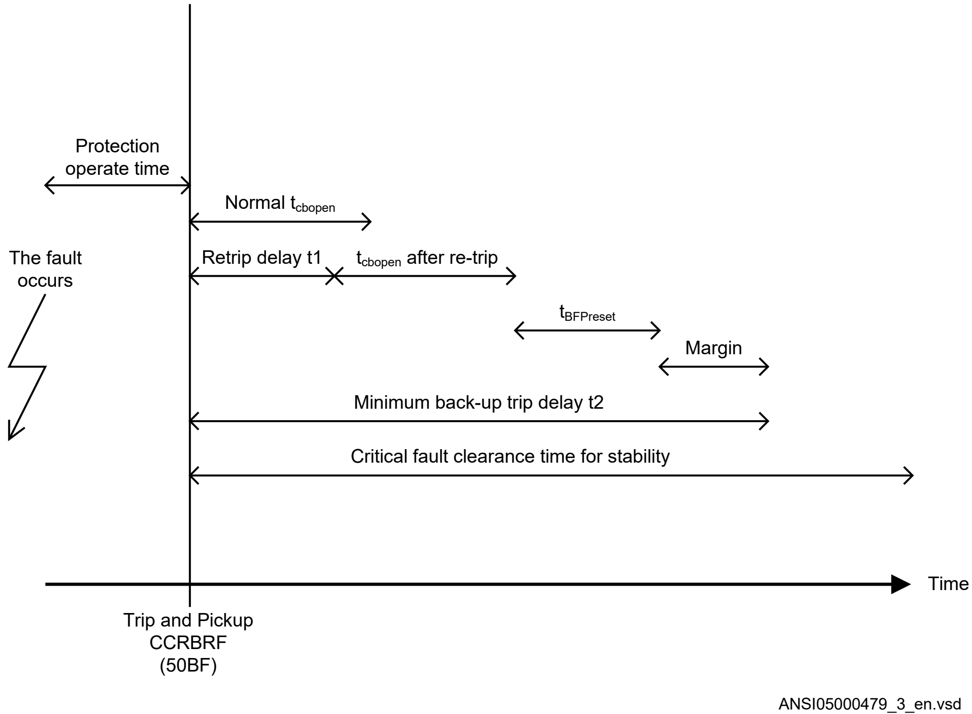


Figure 127: Time sequence

7.11 Breaker failure protection CSPRBRF (50BF)

7.11.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Breaker failure protection	CSPRBRF	3I>BF	50BF

7.11.2 Application

In the design of the fault clearance system the N-1 criterion is often used. This means that a fault needs to be cleared even if any component in the fault clearance system is faulty. One necessary component in the fault clearance system is the circuit breaker. It is from practical and economical reason not feasible to duplicate the circuit breaker for the protected component. Instead a breaker failure protection is used.

The Breaker failure protection (CSPRBRF, 50BF) issues a back-up trip command to adjacent circuit breakers in case of failure to trip of the "normal" circuit breaker for the protected component. The detection of failure to break the current through the breaker is made by means of current measurement or as detection of remaining trip signal (unconditional).

CSPRBRF (50BF) can also give a re-trip. This means that a second trip signal is sent to the protected circuit breaker. The re-trip function can be used to increase the probability of operation of the breaker, or it can be used to avoid back-up trip of many breakers in case of mistakes during relay maintenance and test.

7.11.3 Setting guidelines

The parameters for Breaker failure protection CSPRBRF (50BF) are set via the local HMI or PCM600.

The following settings can be done for the breaker failure protection. Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: Disabled/*Enabled*

FunctionMode: This parameter can be set *Current/Contact*. This states the way the detection of failure of the breaker is performed. In the mode current the current measurement is used for the detection. In the mode *Contact* the long duration of breaker position signal is used as indicator of failure of the breaker. The mode *Current&Contact* means that both ways of detections are activated. *Contact* mode can be usable in applications where the fault current through the circuit breaker is small. This can be the case for some generator protection application (for example reverse power protection) or in case of line ends with weak end infeed.

RetripMode: This setting states how the re-trip function shall operate. *Retrip Off* means that the re-trip function is not activated. *CB Pos Check* (circuit breaker position check) and Current means that a phase current must be larger than the operate level to allow re-trip. *CB Pos Check* (circuit breaker position check) and *Contact* means re-trip is done when circuit breaker is closed (breaker position is used). *No CB Pos Check* means re-trip is done without check of breaker position.

Table 23: Dependencies between parameters RetripMode and FunctionMode

RetripMode	***FunctionMode***	**Description**
Retrip Off	N/A	The re-trip function is not activated
CB Pos Check	*Current*	A phase current must be larger than the operate level to allow re-trip
	Contact	Re-trip is done when circuit breaker is closed (breaker position is used) and a long duration of a trip signal indicates breaker failure
	Current&Contact	Both methods are used
No CB Pos Check	*Current*	Re-trip is done without check of breaker position
	Contact	Re-trip is done without check of breaker position
	Current&Contact	Both methods are used

BuTripMode: Back-up trip mode is given to state sufficient current criteria to detect failure to break. For Current operation *2 out of 4* means that at least two currents, of the three phase-currents and the residual current, shall be high to indicate breaker failure. *1 out of 3* means that at least one current of the three phase-currents shall be high to indicate breaker failure. *1 out of 4* means that at least one current of the three phase currents or the residual current shall be high to indicate breaker failure. In most applications *1 out of 3* is sufficient. For *Contact* operation means back-up trip is done when circuit breaker is closed (breaker position is used).

Pickup_PH: Current level for detection of breaker failure, set in % of *IBase*. This parameter should be set so that faults with small fault current can be detected. The setting can be chosen in accordance with the most sensitive protection function to start the breaker failure protection. Typical setting is 10% of *IBase*.

Pickup_BlkCont: If any contact based detection of breaker failure is used this function can be blocked if any phase current is larger than this setting level. If the *FunctionMode* is set *Current and Contact* breaker failure for high current faults are safely detected by the current measurement function. To increase security the contact based function should be disabled for high currents. The setting can be given within the range 5 – 200% of *IBase*.

Pickup_N: Residual current level for detection of breaker failure set in % of *IBase*. In high impedance grounded systems the residual current at phase to ground faults are normally much smaller than the short circuit currents. In order to detect breaker failure at single-phase ground faults in these systems it is necessary to measure the residual current separately. Also in effectively grounded systems the setting of the ground-fault current protection can be chosen to relatively low current level. The *BuTripMode* is set *1 out of 4*. The current setting should be chosen in accordance to the setting of the sensitive ground fault protection. The setting can be given within the range 2 – 200 % of *IBase*.

t1: Time delay of the re-trip. The setting can be given within the range 0 – 60 s in steps of 0.001 s. Typical setting is 0 – 50 ms.

t2: Time delay of the back-up trip. The choice of this setting is made as short as possible at the same time as unwanted operation must be avoided. Typical setting is 90 – 200 ms (also dependent of re-trip timer).

The minimum time delay for the re-trip can be estimated as:

$$t2 \geq t1 + t_{cbopen} + t_{BFP\_reset} + t_{margin}$$

(Equation 160)

where:

t_{cbopen} is the maximum opening time for the circuit breaker

t_{BFP_reset} is the maximum time for breaker failure protection to detect correct breaker function (the current criteria reset)

t_{margin} is the safety margin

It is often required that the total fault clearance time shall be less than a given critical time. This time is often dependent of the ability to maintain transient stability in case of a fault close to a power plant.

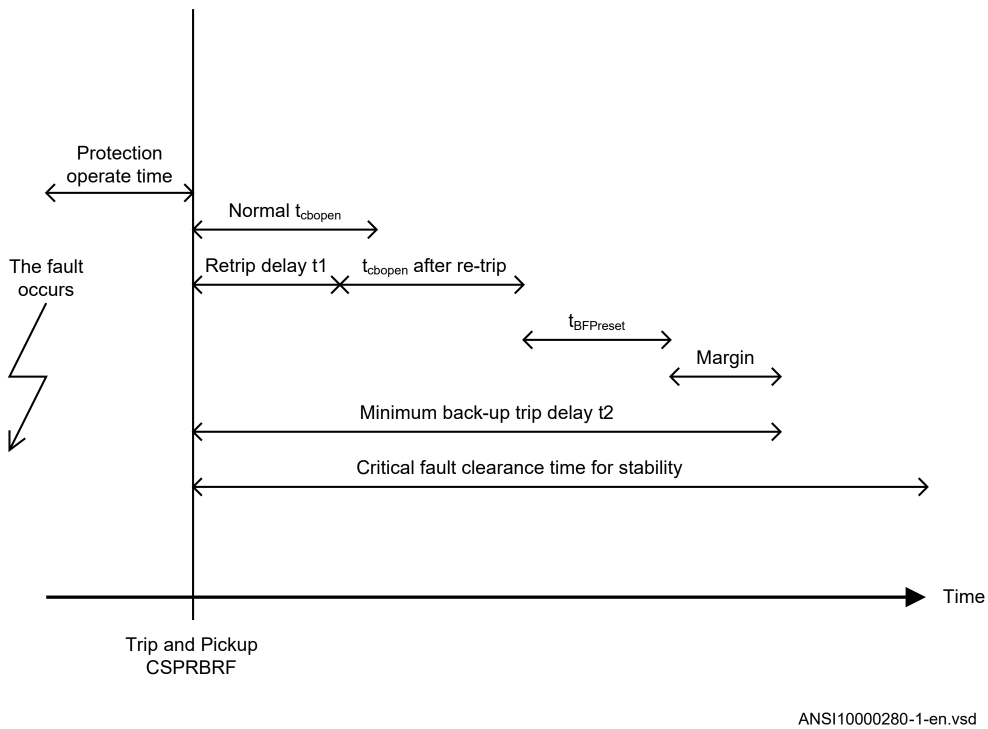


Figure 128: Time Sequence

7.12 Stub protection STBPTOC (50STB)

7.12.1 Identification

Function description	**IEC 61850 identification**	**IEC 60617 identification**	**ANSI/IEEE C37.2 device number**
Stub protection	STBPTOC	3I>STUB	50STB

7.12.2 Application

Stub protection STBPTOC (50STB) is a simple phase overcurrent protection, fed from the two current transformer groups feeding the object taken out of service. The stub protection is only activated when the disconnector of the object is open. STBPTOC (50STB) enables fast fault clearance of faults at the section between the CTs and the open disconnector.

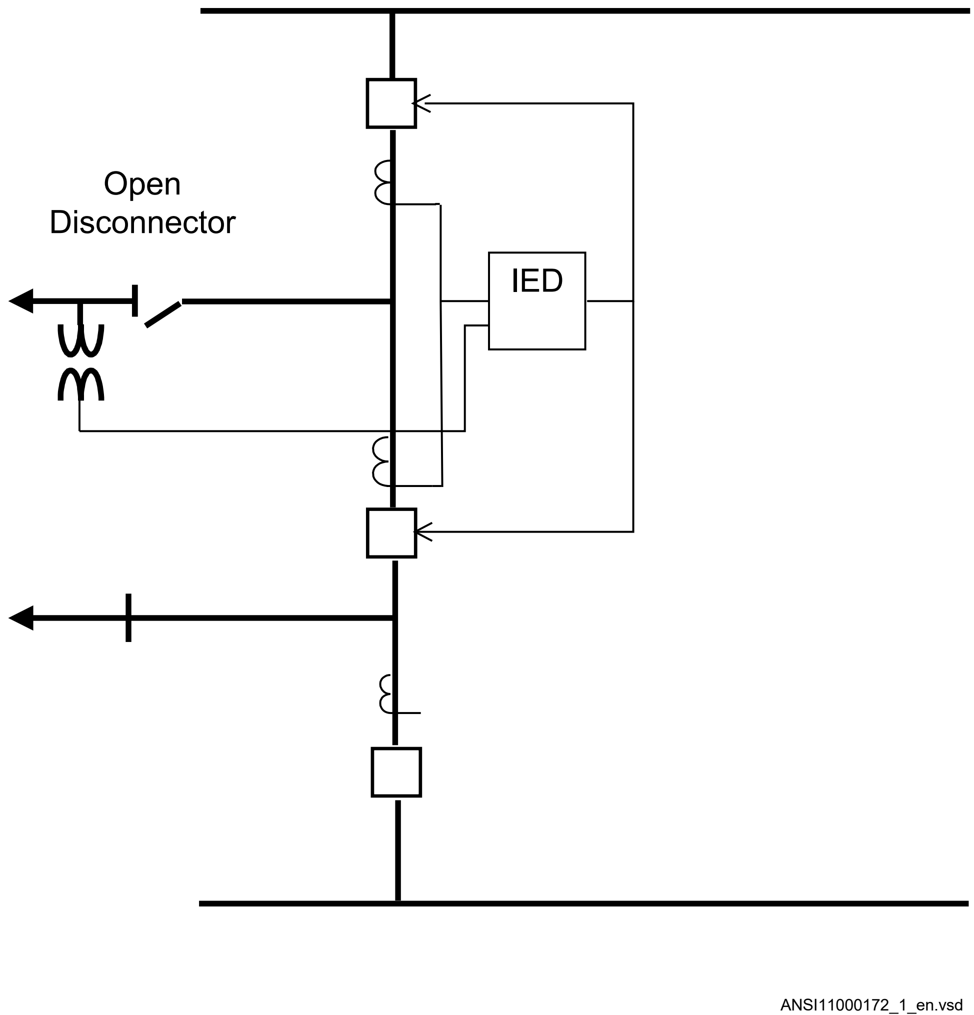


Figure 129: Typical connection for stub protection in breaker-and-a-half arrangement.

7.12.3 Setting guidelines

The parameters for Stub protection STBPTOC (50STB) are set via the local HMI or PCM600.

The following settings can be done for the stub protection.

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: *Disabled*/ *Enabled*

IPickup: Current level for the Stub protection, set in % of *IBase*. This parameter should be set so that all faults on the stub can be detected. The setting should thus be based on fault calculations.

7.13 Pole discrepancy protection CCRPLD (52PD)

7.13.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Pole discrepancy protection	CCRPLD	PD	52PD

7.13.2 Application

There is a risk that a circuit breaker will get discrepancy between the poles at circuit breaker operation: closing or opening. One pole can be open and the other two closed, or two poles can be open and one closed. Pole discrepancy of a circuit breaker will cause unsymmetrical currents in the power system. The consequence of this can be:

- Negative sequence currents that will give stress on rotating machines
- Zero sequence currents that might give unwanted operation of sensitive ground-fault protections in the power system.

It is therefore important to detect situations with pole discrepancy of circuit breakers. When this is detected the breaker should be tripped directly.

Pole discordance protection CCRPLD (52PD) will detect situation with deviating positions of the poles of the protected circuit breaker. The protection has two different options to make this detection:

- By connecting the auxiliary contacts in the circuit breaker so that logic is created and a signal can be sent to the pole discrepancy protection, indicating pole discrepancy.
- Each phase current through the circuit breaker is measured. If the difference between the phase currents is larger than a *CurrUnsymPU* this is an indication of pole discrepancy, and the protection will operate.

7.13.3 Setting guidelines

The parameters for the Pole discordance protection CCRPLD (52PD) are set via the local HMI or PCM600.

The following settings can be done for the pole discrepancy protection.

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: *Disabled* or *Enabled*

tTrip: Time delay of the operation.

ContactSel: Operation of the contact based pole discrepancy protection. Can be set: *Disabled*/ *PD signal from CB*. If *PD signal from CB* is chosen the logic to detect pole discrepancy is made in the vicinity to the breaker auxiliary contacts and only one signal is connected to the pole discrepancy function.

CurrentSel: Operation of the current based pole discrepancy protection. Can be set: *Disabled*/ *CB oper monitor*/ *Continuous monitor*. In the alternative *CB oper monitor* the function is activated only directly in connection to breaker open or close command (during 200 ms). In the alternative *Continuous monitor* function is continuously activated.

CurrUnsymPU: Unsymmetrical magnitude of lowest phase current compared to the highest, set in % of the highest phase current.

CurrRelPU: Current magnitude for release of the function in % of *IBase*.

7.14 Broken conductor check BRCPTOC (46)

7.14.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Broken conductor check	BRCPTOC	-	46

7.14.2 Application

Conventional protection functions can not detect the broken conductor condition. Broken conductor check (BRCPTOC, 46) function, consisting of continuous current unsymmetrical check on the line where the IED connected will give alarm or trip at detecting broken conductors.

7.14.3 Setting guidelines

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Broken conductor check BRCPTOC (46) must be set to detect open phase/s (series faults) with different loads on the line. BRCPTOC (46) must at the same time be set to not operate for maximum asymmetry which can exist due to, for example, not transposed power lines.

All settings are in primary values or percentage.

Set minimum operating level per phase *Pickup_PH* to typically 10-20% of rated current.

Set the unsymmetrical current, which is relation between the difference of the minimum and maximum phase currents to the maximum phase current to typical *Pickup_ub = 50%*.

Note that it must be set to avoid problem with asymmetry under minimum operating conditions.

Set the time delay *tOper* = *5 - 60* seconds and reset time *tReset* = *0.010 - 60.000* seconds.

7.15 Directional over-/under-power protection GOPPDOP/ GUPPDUP (32/37)

7.15.1 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 130 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 to trip if the active power from the generator is less than about 2%. One should set the overpower protection to trip if the power flow from the network to the generator is higher than 1%.

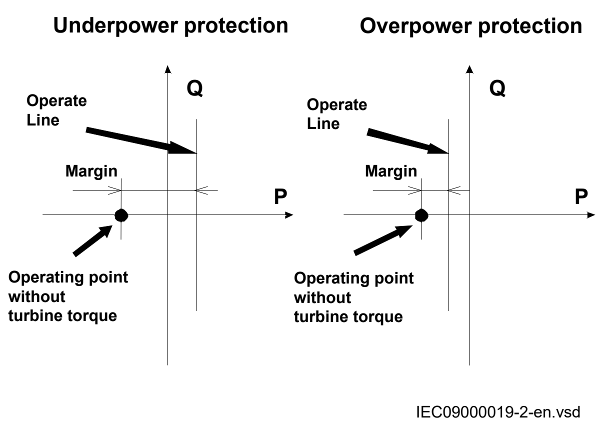


Figure 130: Reverse power protection with underpower or overpower protection

7.15.2 Directional overpower protection GOPPDOP (32)

7.15.2.1 Identification

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

7.15.2.2 Setting guidelines

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

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 24.

For reverse power applications *PosSeq* or *Arone* modes are strongly recommended.

Table 24: Complex power calculation

Set value *Mode*	Formula used for complex power calculation
A,B,C	$\overline{S} = \overline{V}_A \cdot \overline{I}_A^{*} + \overline{V}_B \cdot \overline{I}_B^{*} + \overline{V}_C \cdot \overline{I}_C^{*}$ (Equation 161)
Arone	$\overline{S} = \overline{V}_{AB} \cdot \overline{I}_A^{*} - \overline{V}_{BC} \cdot \overline{I}_C^{*}$ (Equation 162)
PosSeq	$\overline{S} = 3 \cdot \overline{V}_{PosSeq} \cdot \overline{I}_{PosSeq}^{*}$ (Equation 163)
A,B	$\overline{S} = \overline{V}_{AB} \cdot (\overline{I}_A^{*} - \overline{I}_B^{*})$ (Equation 164)
B,C	$\overline{S} = \overline{V}_{BC} \cdot (\overline{I}_B^{*} - \overline{I}_C^{*})$ (Equation 165)
C,A	$\overline{S} = \overline{V}_{CA} \cdot (\overline{I}_C^{*} - \overline{I}_A^{*})$ (Equation 166)
Table continues on next page	

Set value *Mode*	Formula used for complex power calculation
A	$$\overline{S} = 3 \cdot \overline{V}_A \cdot \overline{I}_A^{\,*}$$ (Equation 167)
B	$$\overline{S} = 3 \cdot \overline{V}_B \cdot \overline{I}_B^{\,*}$$ (Equation 168)
C	$$\overline{S} = 3 \cdot \overline{V}_C \cdot \overline{I}_C^{\,*}$$ (Equation 169)

The function has two stages with the same setting parameters.

OpMode1(2) is set to define the function of the stage. Possible settings are:

Enabled: the stage is activated *Disabled*: the stage is 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)*

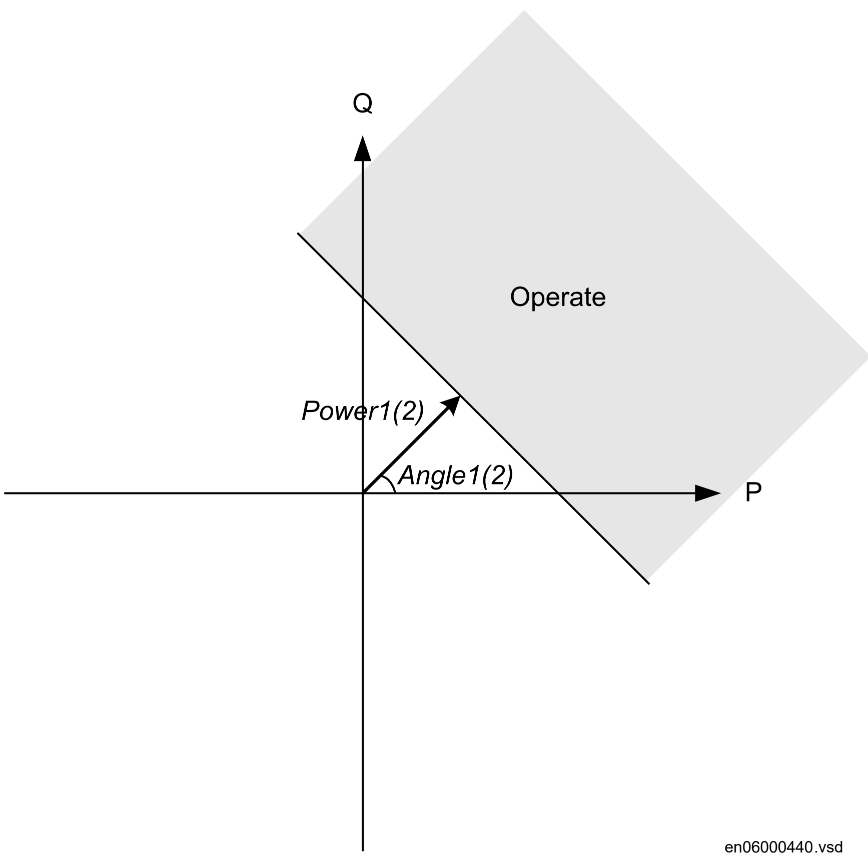


Figure 131: Overpower mode

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 170.

Minimum recommended setting is 1.0% of S_N. Note also that at the same time the minimum IED pickup current shall be bigger than 9mA secondary.

$$S_N = \sqrt{3} \cdot \mathrm{VBase} \cdot \mathrm{IBase}$$

(Equation 170)

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 in 50Hz network while -179.5° should be used for generator reverse power protection in 60Hz network. This angle adjustment in 60Hz networks will improve accuracy of the power function.

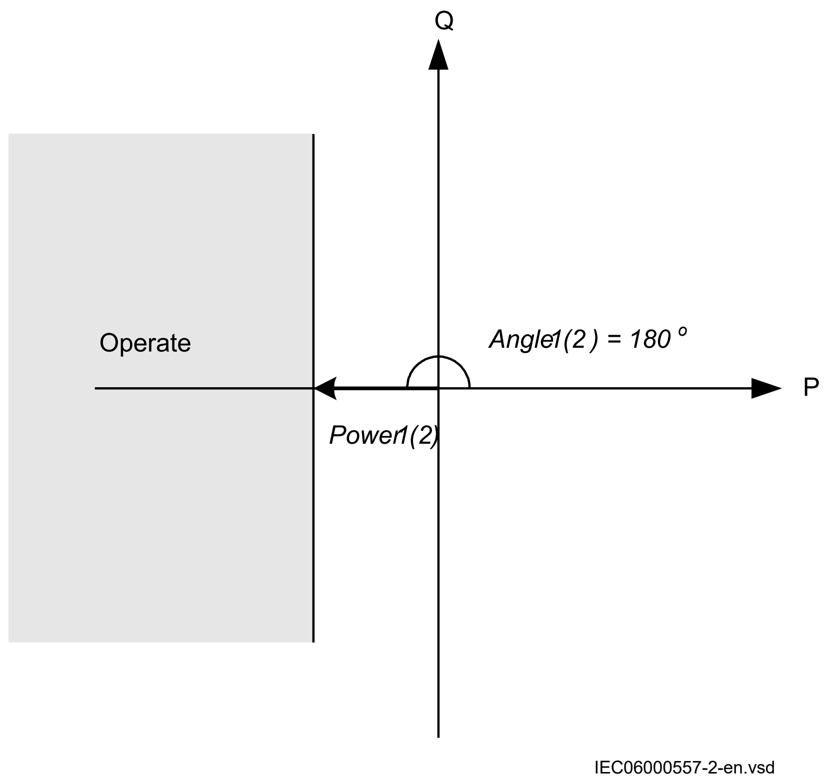


Figure 132: For reverse power the set angle should be 180° in the overpower function

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

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 171)

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=0.98* or even *TD=0.99* is recommended in generator reverse power applications as the trip delay is normally quite long. This filtering will improve accuracy of the power function.

7.15.3 Directional underpower protection GUPPDUP (37)

7.15.3.1 Identification

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

7.15.3.2 Setting guidelines

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

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 25.

For reverse power applications *PosSeq* or *Arone* modes are strongly recommended.

Table 25: Complex power calculation

Set value *Mode*	Formula used for complex power calculation
A, B, C	$\overline{S} = \overline{V}_A \cdot \overline{I}_A^* + \overline{V}_B \cdot \overline{I}_B^* + \overline{V}_C \cdot \overline{I}_C^*$ (Equation 172)
Arone	$\overline{S} = \overline{V}_{AB} \cdot \overline{I}_A^* - \overline{V}_{BC} \cdot \overline{I}_C^*$ (Equation 173)
PosSeq	$\overline{S} = 3 \cdot \overline{V}_{PosSeq} \cdot \overline{I}_{PosSeq}^*$ (Equation 174)
AB	$\overline{S} = \overline{V}_{AB} \cdot (\overline{I}_A^* - \overline{I}_B^*)$ (Equation 175)
BC	$\overline{S} = \overline{V}_{BC} \cdot (\overline{I}_B^* - \overline{I}_C^*)$ (Equation 176)
CA	$\overline{S} = \overline{V}_{CA} \cdot (\overline{I}_C^* - \overline{I}_A^*)$ (Equation 177)
A	$\overline{S} = 3 \cdot \overline{V}_A \cdot \overline{I}_A^*$ (Equation 178)
B	$\overline{S} = 3 \cdot \overline{V}_B \cdot \overline{I}_B^*$ (Equation 179)
C	$\overline{S} = 3 \cdot \overline{V}_C \cdot \overline{I}_C^*$ (Equation 180)

The function has two stages with the same setting parameters.

OpMode1(2) is set to define the function of the stage. Possible settings are:

Enabled: the stage is activated. *Disabled*: the stage is 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)*

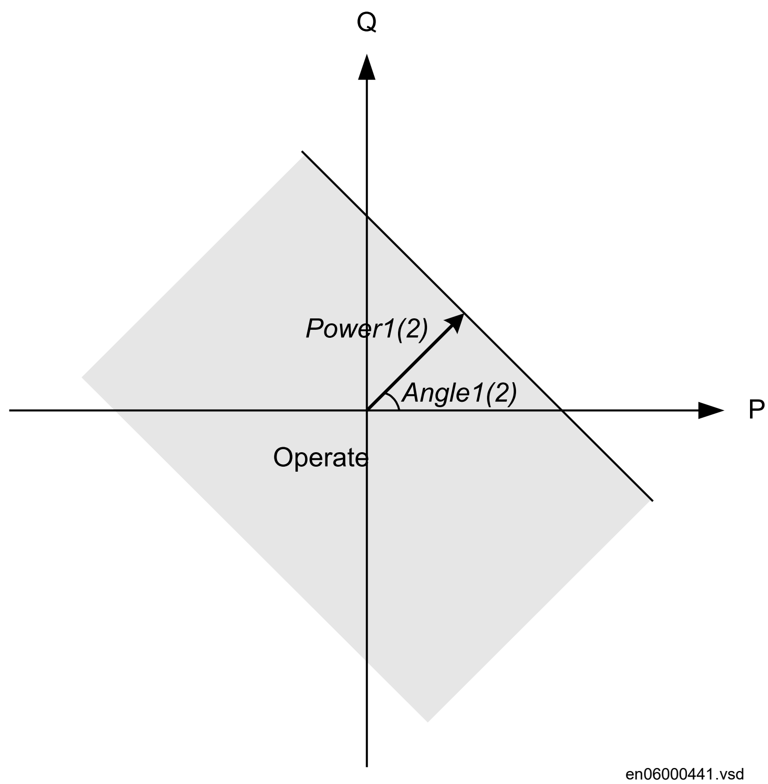


Figure 133: Underpower mode

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 181.

Minimum recommended setting is 1.0% of S_N. At the same time the minimum IED pickup current shall be bigger than 9mA secondary.

$$S_N = \sqrt{3} \cdot VBase \cdot IBase$$

(Equation 181)

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.

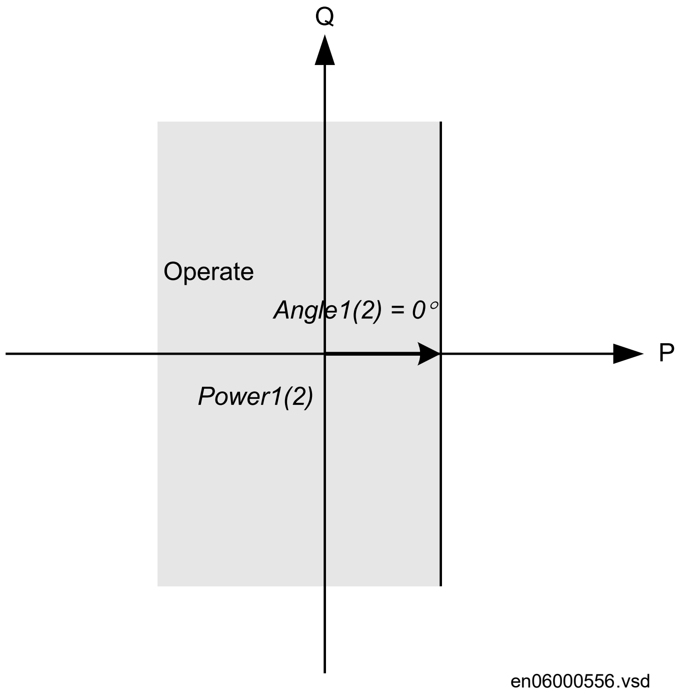


Figure 134: For low forward power the set angle should be 0° in the underpower function

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

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 182)

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=0.98* or even *TD=0.99* is recommended in generator low forward power applications as the trip delay is normally quite long. This filtering will improve accuracy of the power function.

7.16 Negative sequence based overcurrent function DNSPTOC (46)

7.16.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Negative sequence based overcurrent function	DNSPTOC	3I2>	46

7.16.2 Application

Negative sequence based overcurrent function (DNSPTOC, 46) may be used in power line applications where the reverse zero sequence source is weak or open, the forward source impedance is strong and it is desired to detect forward ground faults.

Additionally, it is applied 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.

The directional function is current and voltage polarized. The function can be set to forward, reverse or non-directional independently for each step.

DNSPTOC (46) protects against all unbalanced faults including phase-to-phase faults. The minimum pickup current of the function must be set to above the normal system unbalance level in order to avoid unintentional tripping.

7.16.3 Setting guidelines

Below is an example of Negative sequence based overcurrent function (DNSPTOC ,46) used as a sensitive ground-fault protection for power lines. The following settings must be done in order to ensure proper operation of the protection:

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

- setting *RCADir* to value *+65 degrees*, that is, the negative sequence current typically lags the inverted negative sequence voltage for this angle during the fault
- setting *ROADir* to value *90 degrees*
- setting *LowVolt_VM* to value *2%*, that is, the negative sequence voltage level above which the directional element will be enabled
- setting *Operation_OC1* to *Enabled*
- setting *PickupCurr_OC1* to value between *3-10%*, (typical values)
- setting *tDef_OC1* to insure proper time coordination with other ground-fault protections installed in the vicinity of this power line

- setting *DirMode_OC1* to *Forward*
- setting *DirPrinc_OC1* to *IcosPhi&V*
- setting *ActLowVolt1_VM* to *Block*

DNSPTOC (46) is used in directional comparison protection scheme for the power line protection, when communication channels to the remote end of this power line are available. In that case, two negative sequence overcurrent steps are required - one in forward and another in reverse direction. The OC1 stage is used to detect faults in forward direction and the OC2 stage is used to detect faults in reverse direction.

However, the following must be noted for such application:

- setting *RCADir* and *ROADir* are applicable for both steps OC1 and OC2
- setting *DirMode_OC1* must be set to *Forward*
- setting *DirMode_OC2* must be set to *Reverse*
- setting *PickupCurr_OC2* must be made more sensitive than *pickup* value of the forward OC1 element, that is, typically 60% of *PickupCurr_OC1* set pickup level in order to insure proper operation of the directional comparison scheme during current reversal situations
- the start signals PU_OC1 and PU_OC2 from OC1 and OC2 elements is used to send forward and reverse signals to the remote end of the power line
- the available scheme communications function block within IED is used between the protection function and the teleprotection communication equipment, in order to insure proper conditioning of the above two start signals.

Section 8 Voltage protection

8.1 Two step undervoltage protection UV2PTUV (27)

8.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Two step undervoltage protection	UV2PTUV	*2U<*	27

8.1.2 Application

Two-step undervoltage protection function (UV2PTUV ,27) is applicable in all situations, where reliable detection of low phase voltages is necessary. It is used also as a supervision and fault detection function for other protection functions, to increase the security of a complete protection system.

UV2PTUV (27) is applied to power system elements, such as generators, transformers, motors and power lines in order to detect low voltage conditions. Low voltage conditions are caused by abnormal operation or fault in the power system. 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. Other applications are the detection of "no voltage" condition, for example, before the energization of a HV line or for automatic breaker trip in case of a blackout. UV2PTUV (27) is also used to initiate voltage correction measures, like insertion of shunt capacitor banks to compensate for reactive load and thereby increasing the voltage. The function has a high measuring accuracy to allow applications to control reactive load.

UV2PTUV (27) is used to disconnect from the network apparatuses, like electric motors, which will be damaged when subject to service under low voltage conditions. UV2PTUV (27) deals with low voltage conditions at power system frequency, which can be caused by the following reasons:

1. Malfunctioning of a voltage regulator or wrong settings under manual control (symmetrical voltage decrease).
2. Overload (symmetrical voltage decrease).
3. Short circuits, often as phase-to-ground faults (unsymmetrical voltage decrease).

UV2PTUV (27) prevents sensitive equipment from running under conditions that could cause their overheating 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.

8.1.3 Setting guidelines

The parameters for Two step undervoltage protection UV2PTUV (27) are set via the local HMI or PCM600.

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 settings base voltage *VBase*, which normally is set to the primary nominal voltage level (phase-to-phase) of the power system or the high voltage equipment under consideration.

The setting for UV2PTUV (27) is normally not critical, since there must be enough time available for the main protection to clear short circuits andground faults.

Some applications and related setting guidelines for the voltage level are described in the following sections.

8.1.3.1 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.

8.1.3.2 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.

8.1.3.3 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.

8.1.3.4 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.

8.1.3.5 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.

8.1.3.6 Settings for Two step undervoltage protection

The following settings can be done for two step undervoltage protection (UV2PTUV ,27).

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

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*.

UV2PTUV (27) measures selectively phase-to-ground voltages, or phase-to-phase voltage chosen by the setting *ConnType*.

This means operation for phase-to-ground voltage if:

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

(Equation 183)

and operation for phase-to-phase voltage if:

$$\mathrm{Vpickup} < (\%) \cdot \mathrm{VBase(kV)}$$

(Equation 184)

Characteristic1: This parameter gives the type of time delay to be used for step 1. The setting can be. *Definite time/Inverse Curve A/Inverse Curve B*. The choice is highly dependent of the protection application.

OpModen: This parameter describes how many of the three measured voltages that should be below the set level to give operation for step *n* (*n*=step 1 and 2). 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 the function shall be insensitive for single phase-to-ground faults *2 out of 3* can be chosen.

Pickupn: Set operate undervoltage operation value for step *n* (*n*=step 1 and 2), given as % of the global parameter *VBase*. The setting is highly dependent of the protection application. Here it is essential to consider the minimum voltage at non-faulted situations. Normally this voltage is larger than 90% of nominal voltage.

tn: time delay for step *n* (*n*=step 1 and 2), given in s. The setting is highly dependent of the protection application. In many applications the protection function shall not directly trip in case of short circuits or ground faults in the system. The time delay must be coordinated to the short circuit protections.

t1Min: Minimum operation time for inverse time characteristic for step 1, given in s. For very low voltages the undervoltage function, using inverse time characteristic, can give very short operation time. This might lead to unselective trip. By setting *t1Min* longer than the operation time for other protections such unselective tripping can be avoided.

TD1: Time multiplier for inverse time characteristic. This parameter is used for coordination between different inverse time delayed undervoltage protections.

The function must be externally blocked when the protected object is disconnected.

8.2 Two step overvoltage protection OV2PTOV (59)

8.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Two step overvoltage protection	OV2PTOV	2U>	59

8.2.2 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 voltage 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 setting hysteresis to allow applications to control reactive load.

OV2PTOV (59) is used to disconnect, from the network, 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.

8.2.3 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 is a very wide application area where general overvoltage functions are used. All voltage related settings are made as a percentage of a settable base primary voltage, which normally is 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:

Equipment protection, such as for motors, generators, reactors and transformers

High voltage can cause overexcitation of the core and deteriorate the winding insulation. The setting must be above the highest occurring "normal" voltage and below the highest acceptable voltage for the equipment.

Equipment protection, capacitors

High voltage can deteriorate the dielectricum and the insulation. The setting must be above the highest occurring "normal" voltage and below the highest acceptable voltage for the capacitor.

High impedance grounded systems

In high impedance grounded systems, ground-faults cause a voltage increase in the non-faulty phases. OV2PTOV (59) can be 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 √3.

The following settings can be done for Two step overvoltage protection

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

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 .

OV2PTOV (59) measures the phase-to-ground voltages, or phase-to-phase voltages as selected. The function will operate if the voltage gets higher than the set percentage of the global set base voltage *VBase*. This means operation for phase-to-ground voltage over:

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

(Equation 185)

and operation for phase-to-phase voltage over:

$$\mathrm{Vpickup} > (\%) \cdot \mathrm{VBase(kV)}$$

(Equation 186)

Characteristic1: 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*. 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 for step n (n=step 1 and 2). 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 high to give operation. If the function shall be insensitive for single phase-to-ground faults *3 out of 3* can be chosen, because the voltage will normally rise in the non-faulted phases at single phase-to-ground faults.

Pickupn: Set operate overvoltage operation value for step n (n=step 1 and 2), given as % of the global parameter *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 for step n (n=step 1 and 2), given in s. The setting is highly dependent of the protection application. In many applications the protection function has the task 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.

t1Min: Minimum operation time for inverse time characteristic for step 1, given in s. For very high voltages the overvoltage function, using inverse time characteristic, can give very short operation time. This might lead to unselective trip. By setting *t1Min* longer than the operation time for other protections such unselective tripping can be avoided.

TD1: Time multiplier for inverse time characteristic. This parameter is used for co-ordination between different inverse time delayed undervoltage protections.

8.3 Two step residual overvoltage protection ROV2PTOV (59N)

8.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Two step residual overvoltage protection	ROV2PTOV	*3U0>*	59N

8.3.2 Application

Two step residual overvoltage protection ROV2PTOV (59N) is primarily used in high impedancegrounded distribution networks, mainly as a backup for the primary ground-fault protection of the feeders and the transformer. To increase the security for different ground-fault related functions, the residual overvoltage signal can be used as a release signal. The residual voltage can be measured either at the transformer neutral or from a voltage transformer open delta connection. The residual voltage can also be calculated internally, based on measurement of the three-phase voltages.

In high impedance grounded systems the system neutral voltage, that is, the residual voltage, will increase in case of any fault connected to ground. Depending on the type of fault and fault resistance the residual voltage will reach different values. The highest residual voltage, equal to three times the phase-to-ground voltage, is achieved for a single phase-to-ground fault. The residual voltage increases approximately the same amount in the whole system and does not provide any guidance in finding the faulted component. Therefore, ROV2PTOV (59N) is often used as a backup protection or as a release signal for the feeder ground-fault protection.

8.3.3 Setting guidelines

The parameters for Two step residual overvoltage protection ROV2PTOV (59N) are set via the local HMI or PCM600.

All the voltage conditions in the system where ROV2PTOV (59N) 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 single input or residual overvoltage functions are used. All voltage related settings are made as a percentage of a settable base voltage, which can be set to the primary nominal voltage (phase-phase) level of the power system or the high voltage equipment under consideration.

The time delay for ROV2PTOV (59N) are seldom critical, since residual voltage is related to ground-faults in a high impedance grounded system, and enough time must normally be given for the primary protection to clear the fault. In some more specific situations, where the single overvoltage protection is used to protect some specific equipment, the time delay is shorter.

Some applications and related setting guidelines for the residual voltage level are given below.

8.3.3.1 Power supply quality

The setting must be above the highest occurring "normal" residual voltage and below the highest acceptable residual voltage, due to regulation, good practice or other agreements.

8.3.3.2 High impedance grounded systems

In high impedance grounded systems, ground faults cause a neutral voltage in the feeding transformer neutral. Two step residual overvoltage protection ROV2PTOV (59N) is used to trip the transformer, as a backup protection for the feeder ground-fault protection, and as a backup for the transformer primary ground-fault protection. The setting must be above the highest occurring "normal" residual voltage, and below the lowest occurring residual voltage during the faults under consideration. A metallic single-phase ground fault causes a transformer neutral to reach a voltage equal to the normal phase-to-ground voltage.

The voltage transformers measuring the phase-to-ground voltages measure zero voltage in the faulty phase. The two healthy phases will measure full phase-to-phase voltage, as the ground is available on the faulty phase and the neutral has a full phase-to-ground voltage. The residual overvoltage will be three times the phase-to-ground voltage. See Figure 135.

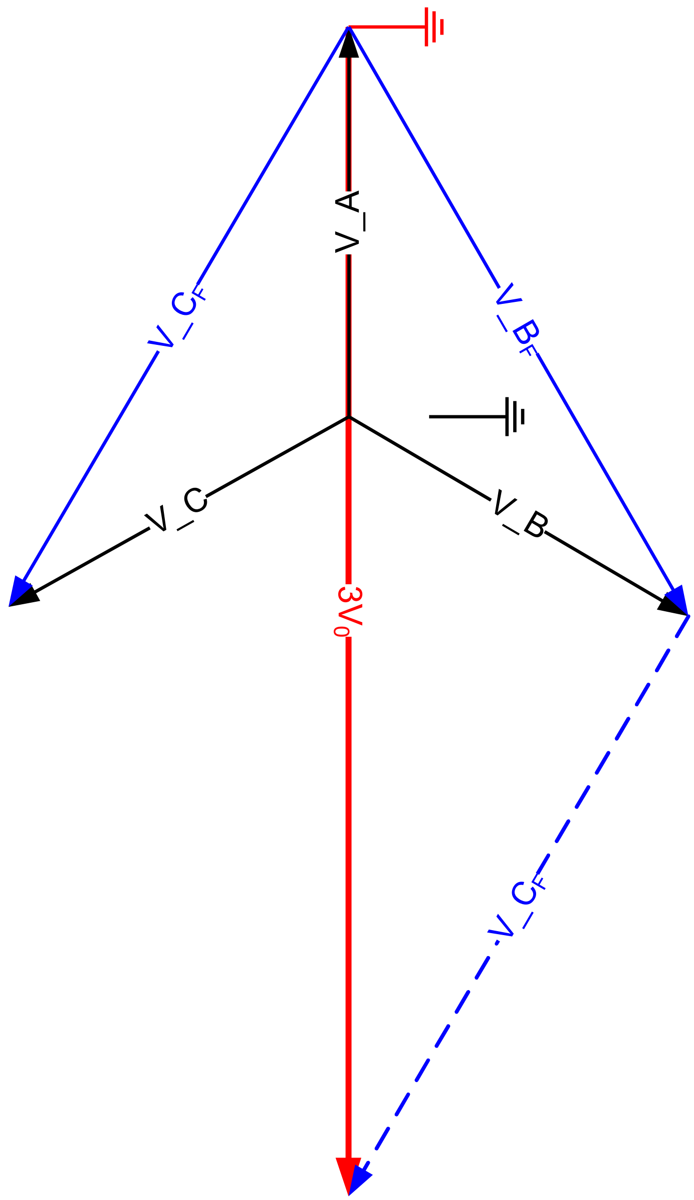


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Figure 135: Non-effectivelygroundedsystems

8.3.3.3 Direct grounded system

In direct grounded systems, an ground-fault on one phase indicates a voltage collapse in that phase. The two healthy phases will have normal phase-to-ground voltages. The residual sum will have the same value as phase-to-ground voltage. See Figure 136.

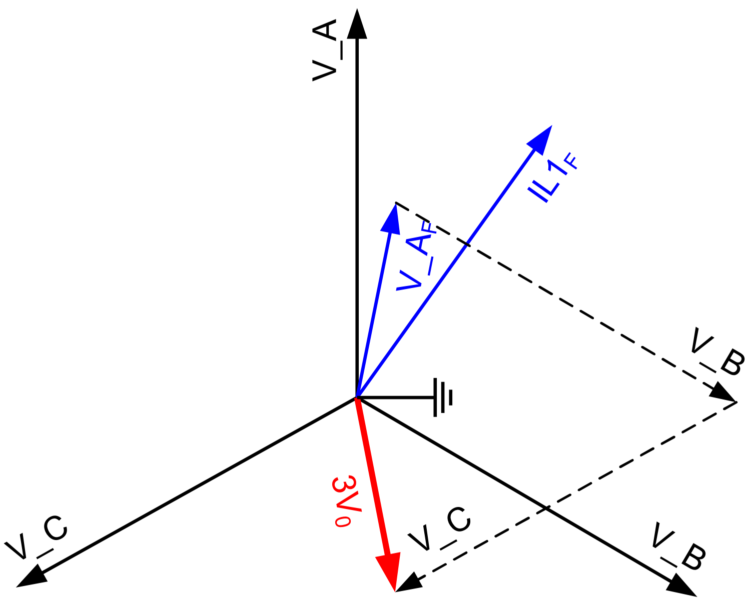


Figure 136: Direct grounded system

8.3.3.4 Settings for Two step residual overvoltage protection

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: *Disabled* or *Enabled*

VBase is used as voltage reference for the voltage. The voltage can be fed to the IED in different ways:

1. The IED is fed from a normal voltage transformer group where the residual voltage is created from the phase-to-ground voltages within the protection software.
2. The IED is fed from a broken delta connection normal voltage transformer group. In a open delta connection the protection is fed by the voltage 3V0 (single input). The setting chapter in the application manual explains how the analog input needs to be set.
3. The IED is fed from a single voltage transformer connected to the neutral point of a power transformer in the power system. In this connection the protection is fed by the voltage VN=V0 (single input). The setting chapter in the application manual explains how the analog input needs to be set. ROV2PTOV (59N) will measure the residual voltage corresponding nominal phase-to-ground voltage for high impedance grounded system. The measurement will be based on the neutral voltage displacement .

Characteristic1: This parameter gives the type of time delay to be used. The setting can be, *Definite time* or *Inverse curve A* or *Inverse curve B* or *Inverse curve C*. The choice is highly dependent of the protection application.

Pickupn: Set operate overvoltage operation value for step *n* (*n*=step 1 and 2), given as % of residual voltage corresponding to global set parameter *VBase*:

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

The setting is dependent of the required sensitivity of the protection and the system grounding. In non-effectively grounded systems the residual voltage can be maximum the rated phase-to-ground voltage, which should correspond to 100%.

In effectively grounded systems this value is dependent of the ratio Z0/Z1. The required setting to detect high resistive ground-faults must be based on network calculations.

tn: time delay of step *n* (*n*=step 1 and 2), given in s. The setting is highly dependent of the protection application. In many applications, the protection function has the task 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.

t1Min: Minimum operation time for inverse time characteristic for step 1, given in s. For very high voltages the overvoltage function, using inverse time characteristic, can give very short operation time. This might lead to unselective trip. By setting *t1Min* longer than the operation time for other protections such unselective tripping can be avoided.

TD1: Time multiplier for inverse time characteristic. This parameter is used for co-ordination between different inverse time delayed undervoltage protections.

8.4 Loss of voltage check LOVPTUV (27)

8.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Loss of voltage check	LOVPTUV	-	27

8.4.2 Application

The trip of the circuit breaker at a prolonged loss of voltage at all the three phases is normally used in automatic restoration systems to facilitate the system restoration after a major blackout. Loss of voltage check (LOVPTUV, 27) generates a TRIP signal only if the voltage in all the three phases is low for more than the set time. If the trip to the circuit breaker is not required, LOVPTUV (27) is used for signallization only through an output contact or through the event recording function.

8.4.3 Setting guidelines

Loss of voltage check (LOVPTUV, 27) is in principle independent of the protection functions. It requires to be set to open the circuit breaker in order to allow a simple system restoration following a main voltage loss of a big part of the network and only when the voltage is lost with breakers still closed.

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

All settings are in primary values or per unit. Set operating level per phase to typically 70% of the global parameter *VBase* level. Set the time delay *tTrip*=5-20 seconds.

8.4.4 Advanced users settings

For advanced users the following parameters need also to be set. Set the length of the trip pulse to typical *tPulse*=0.15 sec. Set the blocking time *tBlock* to block Loss of voltage check (LOVPTUV, 27), if some but not all voltage are low, to typical 5.0 seconds and set the time delay for enabling the function after restoration *tRestore* to 3 - 40 seconds.

Section 9 Frequency protection

9.1 Underfrequency protection SAPTUF (81)

9.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Underfrequency protection	SAPTUF	f <	81

9.1.2 Application

Underfrequency protection SAPTUF (81) is applicable in all situations, where reliable detection of low fundamental power system voltage 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. 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.

9.1.3 Setting guidelines

The parameters for underfrequency protection SAPTUF (81) are set via the local HMI or Protection and Control IED Manager (PCM600).

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 especially two 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.

SAPTUF (81) is not instantaneous, since the frequency is related to movements of the system inertia, but the time and frequency steps between different actions might be critical, and sometimes a rather short operation time is required, for example, down to 70 ms.

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.

9.2 Overfrequency protection SAPTOF (81)

9.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Overfrequency protection	SAPTOF	$f >$	81

9.2.2 Application

Overfrequency protection function SAPTOF (81) is applicable in all situations, where reliable detection of high fundamental power system voltage 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.

9.2.3 Setting guidelines

The parameters for Overfrequency protection (SAPTOF ,81) are set via local HMI or PCM600.

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 especially 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 generation surplus 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*.

SAPTOF (81) is not instantaneous, since the frequency is related to movements of the system inertia, but the time and frequency steps between different actions might be critical, and sometimes a rather short operation time is required, for example, down to 70 ms.

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.

9.3 Rate-of-change frequency protection SAPFRC (81)

9.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Rate-of-change frequency protection	SAPFRC	df/dt ≷	81

9.3.2 Application

Rate-of-change 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. 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.

9.3.3 Setting guidelines

The parameters for Rate-of-change frequency protection SAPFRC (81) are set via the local HMI or 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 especially two application areas for SAPFRC (81):

1. to protect equipment against damage due to high or to 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).

SAPFRC (81)PICKUP value 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.

Section 10 Secondary system supervision

10.1 Current circuit supervision CCSRDIF (87)

10.1.1 Identification

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

10.1.2 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 CCSRDIF (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 may damage the insulation and cause new problems.
The application shall, thus, be done with this in consideration, especially if protection functions are blocked.

10.1.3 Setting guidelines

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Current circuit supervision CCSRDIF (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.

The minimum operate current, *IMinOp*, must be set as a minimum to twice the residual current in the supervised CT circuits under normal service conditions and rated primary current.

The parameter *Pickup_Block* is normally set at *150%* to block the function during transient conditions.

The FAIL output is connected in the PCM configuration to the blocking input of the protection function to be blocked at faulty CT secondary circuits.

10.2 Fuse failure supervision SDDRFUF

10.2.1 Identification

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

10.2.2 Application

Different protection functions within the protection IED, operates on the basis of the measured voltage in the relay point. Examples are:

- distance protection function
- under/over-voltage function
- synchronism check function and voltage check for the weak infeed logic.

These functions can operate unintensionally 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, located as close as possible to the voltage instrument transformers, are one of them. 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 (SDDRFUF).

SDDRFUF function built into the IED products can operate on the basis of external binary signals from the miniature circuit breaker or from the line disconnector. The first case influences the operation of all voltage-dependent functions while the second one does not affect the impedance measuring functions.

The negative sequence detection algorithm, based on the negative-sequence measuring quantities, a high value of voltage $3V_2$ without the presence of the negative-sequence current $3I_2$, is recommended for use in isolated or high-impedance grounded networks.

The zero sequence detection algorithm, based on the zero sequence measuring quantities, a high value of voltage $3V_0$ without the presence of the residual current $3I_0$, is recommended for use in directly or low impedance grounded networks. 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, which in practice is more associated with voltage transformer switching during station operations.

10.2.3 Setting guidelines

10.2.3.1 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 longer 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, *VBase* and *IBase* respectively. Set *VBase* to the primary rated phase-phase voltage of the potential voltage transformer and *IBase* to the primary rated current of the current transformer.

10.2.3.2 Setting of common parameters

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

The settings of negative sequence, zero sequence and delta algorithm are in percent of the global base voltage and global base current for the function, *VBase* and *IBase* respectively.

The voltage threshold *VSealInPU* is used to identify low voltage condition in the system. Set *VSealInPU* below the minimum operating voltage that might occur during emergency conditions. We propose a setting of approximately 70% of the global parameter *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 makes it possible to select 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 the negative and zero sequence based algorithm is activated and working in an OR-condition. Also in mode *OptimZsNs* both the negative and zero sequence algorithm are activated and the one that has the highest magnitude of measured negative 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 algorithm is activated working in an AND-condition, that is, both algorithm must give condition for block in order to activate the output signals BLKV or BLKZ.

10.2.3.3 Negative sequence based

The relay setting value *3V2PU* is given in percentage of the base voltage *VBase* and should not be set lower than according to equation 187.

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

(Equation 187)

where:

3V2PU	is maximal negative sequence voltage during normal operation condition
VBase	is setting of the global base voltage for all functions in the IED.

The setting of the current limit *3I2PU* is in percentage of global 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 188.

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

(Equation 188)

where:

3I2	is maximal negative sequence current during normal operating condition
IBase	is setting of base current for the function

10.2.3.4 Zero sequence based

The relay setting value *3V0PU* is given in percentage of the global parameter *VBase*. The setting of *3V0PU* should not be set lower than according to equation 189.

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

(Equation 189)

where:

3V0	is maximal zero sequence voltage during normal operation condition
VBase	is setting of global base voltage all functions in the IED.

The setting of the current limit *3I0PU* is done in percentage of the global parameter *IBase*. The setting of *3I0PU* must be higher than the normal unbalance current that might exist in the system. The setting can be calculated according to equation 190.

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

(Equation 190)

where:

3I0PU	is maximal zero sequence current during normal operating condition
IBase	is setting of global base current all functions in the IED.

10.2.3.5 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 *VSetprim* is the primary voltage for operation of dU/dt and *ISetprim* the primary current for operation of dI/dt, the setting of *DVPU* and *DIPU* will be given according to equation 191and equation 192.

$$\mathrm{DVPU} = \frac{\mathrm{VSetprim}}{\mathrm{VBase}} \cdot 100$$

(Equation 191)

$$DIPU = \frac{ISetprim}{IBase} \cdot 100$$

(Equation 192)

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. We propose a setting of approximately 70% of *VB*.

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

10.2.3.6 Dead line detection

The condition for operation of the dead line detection is set by the parameters *IDLDPU* for the current threshold and *VDLDPU* 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 *VDLDPU* with a sufficient margin below the minimum expected operating voltage. A safety margin of at least 15% is recommended.

10.3 Breaker close/trip circuit monitoring TCSSCBR

10.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Breaker close/trip circuit monitoring	TCSSCBR	-	-

10.3.2 Application

TCSSCBR detects faults in the electrical control circuit of the circuit breaker. The function can supervise both open and closed coil circuits. This kind of monitoring is necessary to find out the vitality of the control circuits continuously.

Trip circuit supervision generates a current of approximately 1.0 mA through the supervised circuit. It must be ensured that this current will not cause a latch up of the controlled object.

To protect the trip circuit supervision circuits in the IED, the output contacts are provided with parallel transient voltage suppressors. The breakdown voltage of these suppressors is 400 +/– 20 V DC.

The following figure shows an application of the trip-circuit monitoring function usage. The best solution is to connect an external R_{ext} shunt resistor in parallel with the circuit breaker internal contact. Although the circuit breaker internal contact is open, TCSSCBR can see the trip circuit through R_{ext}. The R_{ext} resistor should have such a resistance that the current through the resistance remains small, that is, it does not harm or overload the circuit breaker's trip coil.

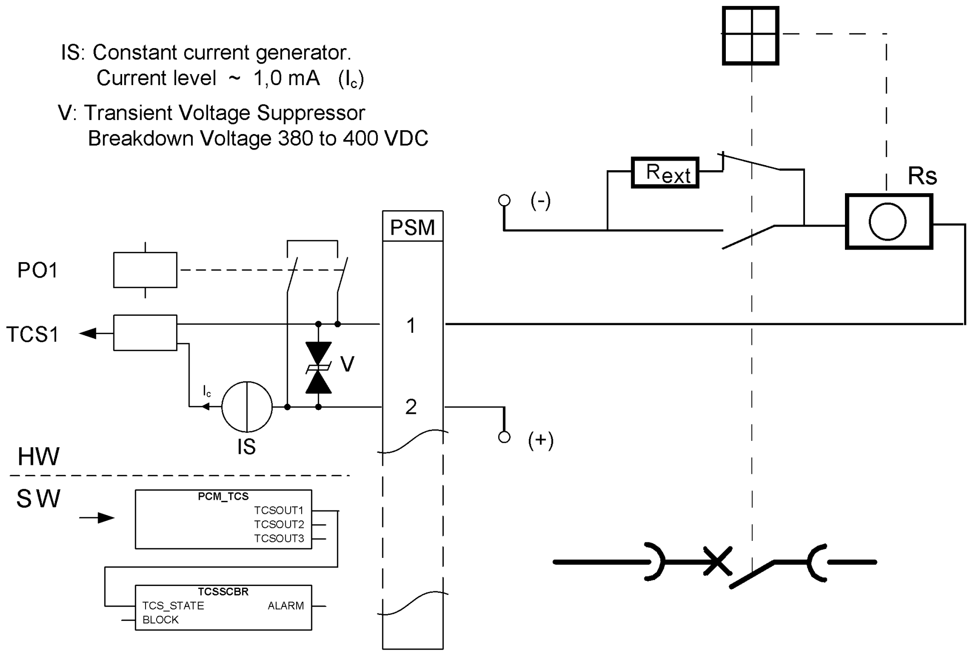


Figure 137: Operating principle of the trip-circuit supervision with an external resistor. The TCSSCBR blocking switch is not required since the external resistor is used.

If the TCSSCBR is required only in a closed position, the external shunt resistance may be omitted. When the circuit breaker is in the open position, the TCSSCBR sees the situation as a faulty circuit. One way to avoid TCSSCBR operation in this situation would be to block the monitoring function whenever the circuit breaker is open.

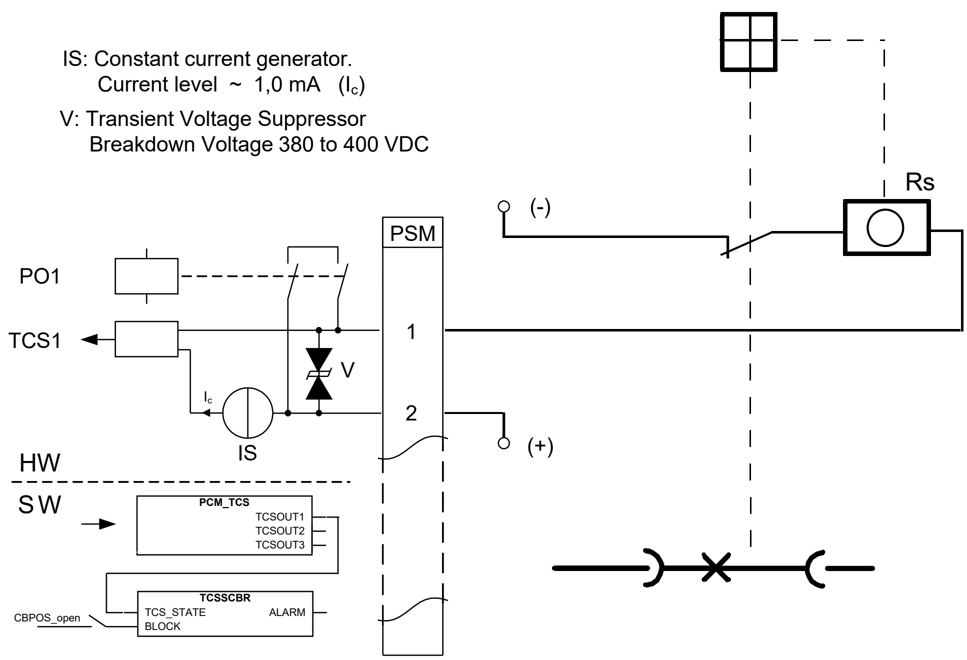


Figure 138: Operating principle of the trip-circuit supervision without an external resistor. The circuit breaker open indication is set to block TCSSCBR when the circuit breaker is open.

Trip-circuit monitoring and other trip contacts

It is typical that the trip circuit contains more than one trip contact in parallel, for example in transformer feeders where the trip of a Buchholz relay is connected in parallel with the feeder terminal and other relays involved.

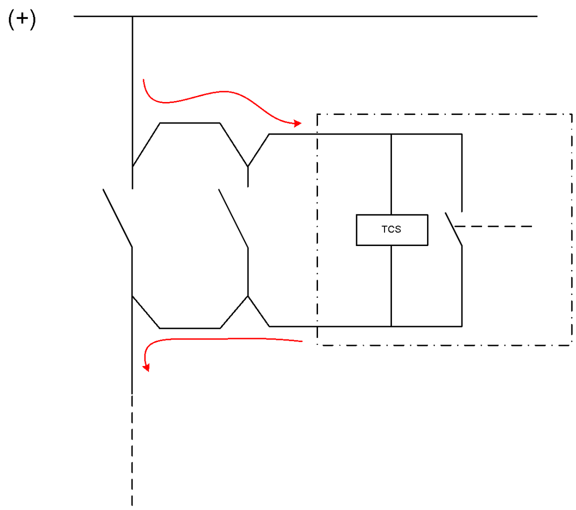


Figure 139: Constant test current flow in parallel trip contacts and trip-circuit supervision

Several trip-circuit monitoring functions parallel in circuit

Not only the trip circuit often have parallel trip contacts, it is also possible that the circuit has multiple TCSSCBR circuits in parallel. Each TCSSCBR circuit causes its own supervising current to flow through the monitored coil and the actual coil current is a sum of all TCSSCBR currents. This must be taken into consideration when determining the resistance of R_{ext}.

Setting the TCSSCBR function in a protection IED not-in-use does not typically affect the supervising current injection.

Trip-circuit monitoring with auxiliary relays

Many retrofit projects are carried out partially, that is, the old electromechanical relays are replaced with new ones but the circuit breaker is not replaced. This creates a problem that the coil current of an old type circuit breaker can be too high for the protection IED trip contact to break.

The circuit breaker coil current is normally cut by an internal contact of the circuit breaker. In case of a circuit breaker failure, there is a risk that the protection IED trip contact is destroyed since the contact is obliged to disconnect high level of electromagnetic energy accumulated in the trip coil.

An auxiliary relay can be used between the protection IED trip contact and the circuit breaker coil. This way the breaking capacity question is solved, but the TCSSCBR circuit in the protection IED monitors the healthy auxiliary relay coil, not the circuit breaker coil. The separate trip circuit monitoring relay is applicable for this to supervise the trip coil of the circuit breaker.

Dimensioning of the external resistor

Under normal operating conditions, the applied external voltage is divided between the relay's internal circuit and the external trip circuit so that at the minimum 20 V (3...20 V) remains over the relay's internal circuit. Should the external circuit's resistance be too high or the internal circuit's too low, for example due to welded relay contacts, the fault is detected.

Mathematically, the operation condition can be expressed as:

$$V_C - \left(R_{ext} + R_S\right) \times I_C \geq 20V\ \ DC$$

(Equation 193)

V_c	Operating voltage over the supervised trip circuit
I_c	Measuring current through the trip circuit, appr. 1.0 mA (0.85...1.20 mA)
R_{ext}	external shunt resistance
R_s	trip coil resistance

If the external shunt resistance is used, it has to be calculated not to interfere with the functionality of the supervision or the trip coil. Too high a resistance causes too high a voltage drop, jeopardizing the requirement of at least 20 V over the internal circuit, while a resistance too low can enable false operations of the trip coil.

Table 26: Values recommended for the external resistor R_{ext}

Operating voltage U_c	**Shunt resistor R_{ext}**
48 V DC	10 kΩ, 5 W
60 V DC	22 kΩ, 5 W
110 V DC	33 kΩ, 5 W
220 V DC	68 kΩ, 5 W

Due to the requirement that the voltage over the TCSSCBR contact must be 20V or higher, the correct operation is not guaranteed with auxiliary operating voltages lower than 48V DC because of the voltage drop in the R_{ext} and operating coil or even voltage drop of the feeding auxiliary voltage system which can cause too low voltage values over the TCSSCBR contact. In this case, erroneous alarming can occur.

At lower (<48V DC) auxiliary circuit operating voltages, it is recommended to use the circuit breaker position to block unintentional operation of TCSSCBR. The use of the position indication is described earlier in this chapter.

Section 11 Control

11.1 Synchronism check, energizing check, and synchronizing SESRSYN (25)

11.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Synchrocheck, energizing check, and synchronizing	SESRSYN	sc/vc	25

11.1.2 Application

11.1.2.1 Synchronizing

To allow closing of breakers between asynchronous networks a synchronizing function is provided. The breaker close command is issued at the optimum time when conditions across the breaker are satisfied in order to avoid stress on the network and its components.

The systems are defined to be asynchronous when the frequency difference between bus and line is larger than an adjustable parameter. If the frequency difference is less than this threshold value the system is defined to have a parallel circuit and the synchronism check function is used.

The synchronizing function measures the difference between the V-Line and the V-Bus. It operates and enables a closing command to the circuit breaker when the calculated closing angle is equal to the measured phase angle and the following conditions are simultaneously fulfilled:

- The measured voltage V-Line is higher than 80% of *GblBaseSelLine* and the measured voltage V-Bus is higher than 80% of *GblBaseSelBus*.
- The voltage difference is smaller than 0.10 p.u, that is (V-Bus/*GblBaseSelBus*) - (V-Line/*GblBaseSelLine*) < 0.10.
- The difference in frequency is less than the set value of *FreqDiffMax* and larger than the set value of *FreqDiffMin*. If the frequency is less than *FreqDiffMin* the synchronism check is used and the value of *FreqDiffMin* must thus be identical to the value *FreqDiffM* resp *FreqDiffA* for synchronism check function. The bus and line frequencies must also be within a range of +/- 5 Hz from the rated frequency. When the synchronizing option is included also for autoreclose there is no reason to have different frequency setting for the manual and automatic reclosing and the frequency difference values for synchronism check should be kept low.
- The frequency rate of change is less than set value for both V-Bus and V-Line.
- The closing angle is decided by the calculation of slip frequency and required pre-closing time.

The synchronizing function compensates for measured slip frequency as well as the circuit breaker closing delay. The phase angle advance is calculated continuously. Closing angle is the change in angle during the set breaker closing operate time *tBreaker*.

The reference voltage can be phase-neutral A, B, C or phase-phase A-B, B-C, C-A or positive sequence. The bus voltage must then be connected to the same phase or phases as are chosen for the line. If different phases voltages are used for the reference voltage, the phase shift has to be compensated with the parameter *PhaseShift*, and the voltage amplitude has to be compensated by the factor *URatio*. Positive sequence selection setting requires that both reference voltages are three phase voltages.

11.1.2.2 Synchronism check

The main purpose of the synchronism check function is to provide control over the closing of circuit breakers in power networks in order to prevent closing if conditions for synchronism are not detected. It is also used to prevent the re-connection of two systems, which are divided after islanding and after a three pole reclosing.

Single pole auto-reclosing does not require any synchronism check since the system is tied together by two phases.

SESRSYN (25) function block includes both the synchronism check function and the energizing function to allow closing when one side of the breaker is dead. SESRSYN (25) function also includes a built in voltage selection scheme which allows simple application in busbar arrangements.

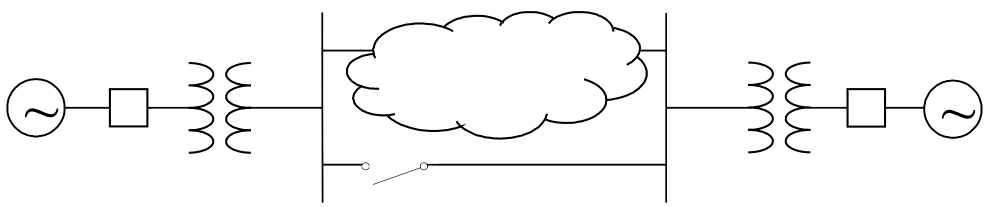


Figure 140: Two interconnected power systems

Figure 140 shows two interconnected power systems. The cloud means that the interconnection can be further away, that is, a weak connection through other stations. The need for a check of synchronization increases as the meshed system decreases since the risk of the two networks being out of synchronization at manual or automatic closing is greater.

The synchronism check function measures the conditions across the circuit breaker and compares them to set limits. Output is generated only when all measured conditions are within their set limits simultaneously. The check consists of:

- Live line and live bus.
- Voltage level difference.
- Frequency difference (slip). The bus and line frequency must also be within a range of ±5 Hz from rated frequency.
- Phase angle difference.

A time delay is available to ensure that the conditions are fulfilled for a minimum period of time.

In very stable power systems the frequency difference is insignificant or zero for manually initiated closing or closing by automatic restoration. In steady conditions a bigger phase angle difference can be allowed as this is sometimes the case in a long and loaded parallel power line. For this application we accept a synchronism check with a long operation time and high sensitivity regarding the frequency difference. The phase angle difference setting can be set for steady state conditions.

Another example, is when the operation of the power net is disturbed and high-speed auto-reclosing after fault clearance takes place. This can cause a power swing in the net and the phase angle difference may begin to oscillate. Generally, the frequency difference is the time derivative of the phase angle difference and will, typically oscillate between positive and negative values. When the circuit breaker needs to be closed by auto-reclosing after fault-clearance some frequency difference should be tolerated, to a greater extent than in the steady condition mentioned in the case above. But if a big phase angle difference is allowed at the same time, there is some risk that auto-reclosing will take place when the phase angle difference is big and increasing. In this case it should be safer to close when the phase angle difference is smaller.

To fulfill the above requirements the synchronism check function is provided with duplicate settings, one for steady (Manual) conditions and one for operation under disturbed conditions (Auto).

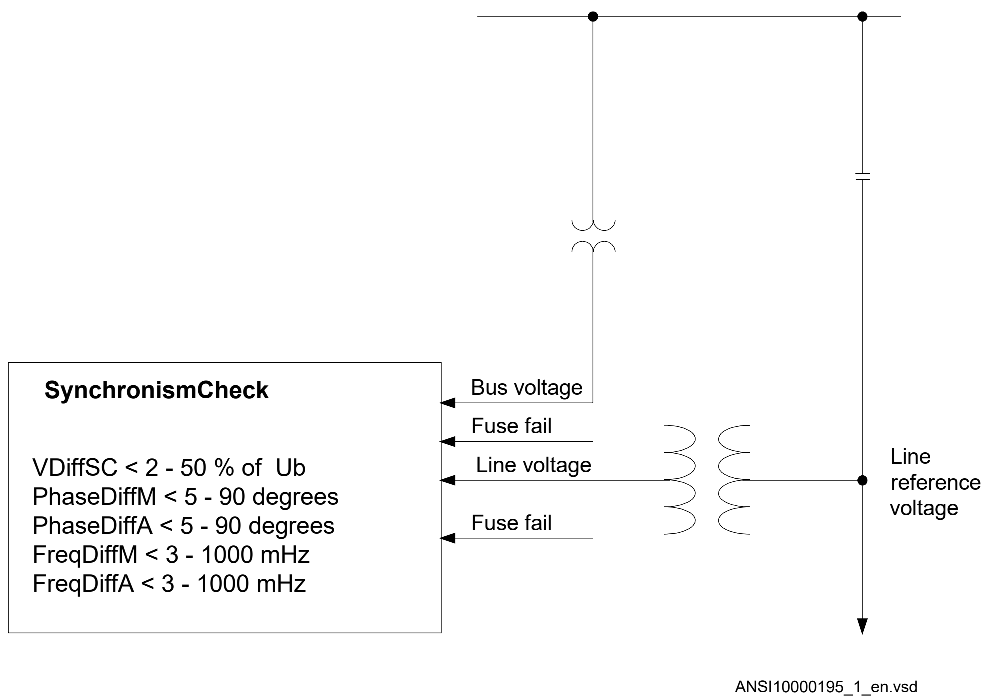


Figure 141: Principle for the synchronism check function

11.1.2.3 Energizing check

The main purpose of the energizing check function is to facilitate the controlled re-connection of disconnected lines and buses to energized lines and buses.

The energizing check function measures the bus and line voltages and compares them to both high and low threshold values. The output is given only when the actual measured conditions match the set conditions. Figure 142 shows two power systems, where one (1) is energized and the other (2) is not energized. Power system 2 is energized (DLLB) from system 1 via the circuit breaker A.

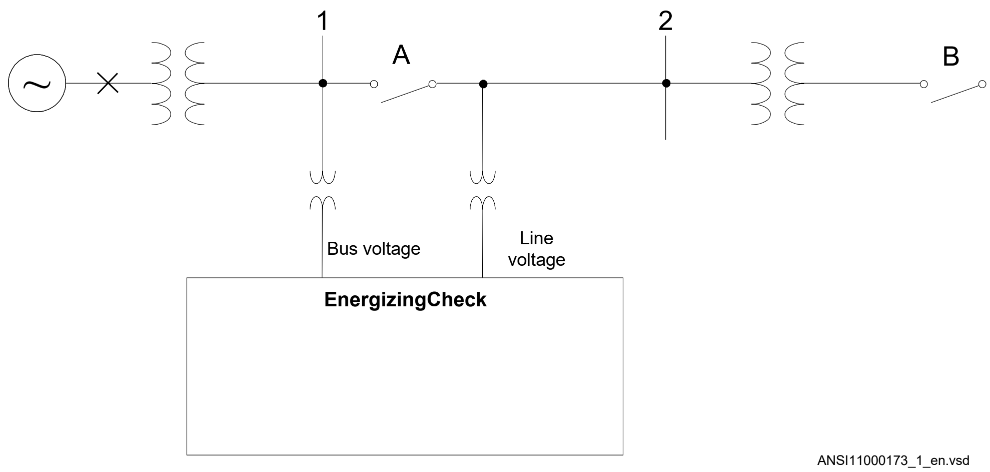


Figure 142: Principle for the energizing check function

The energizing operation can operate in the dead line live bus (DLLB) direction, dead bus live line (DBLL) direction, or in both directions over the circuit breaker. Energizing from different directions can be different for automatic reclosing and manual closing of the circuit breaker. For manual closing it is also possible to allow closing when both sides of the breaker are dead, Dead Bus Dead Line (DBDL).

The equipment is considered energized if the voltage is above a set value, for example, 80% of the base voltage, and non-energized if it is below a set value, for example, 30% of the base voltage. A disconnected line can have a considerable potential because of factors such as induction from a line running in parallel, or feeding via extinguishing capacitors in the circuit breakers. This voltage can be as high as 50% or more of the base voltage of the line. Normally, for breakers with single breaking elements (<330kV) the level is well below 30%.

When the energizing direction corresponds to the settings, the situation has to remain constant for a certain period of time before the close signal is permitted. The purpose of the delayed operate time is to ensure that the dead side remains de-energized and that the condition is not due to temporary interference.

11.1.2.4 Voltage selection

The voltage selection function is used for the connection of appropriate voltages to the synchronism check and energizing check functions. For example, when the IED is used in a double bus arrangement, the voltage that should be selected depends on the status of the breakers and/or disconnectors. By checking the status of the disconnectors auxiliary contacts, the right voltages for the synchronism check and energizing check functions can be selected.

The voltages from busbars and lines must be physically connected to the voltage inputs in the IED and connected, using the control software, to each of the maximum two SESRSYN(25) functions available in the IED.

11.1.2.5 External fuse failure

External fuse-failure signals or signals from a tripped fuse switch/MCB are connected to binary inputs that are configured to inputs of SESRSYN(25) function in the IED. The internal fuse failure supervision function can also be used, for at least the line voltage supply. The signal VTSU is then used and connected to the blocking input of the energizing check function block. In case of a fuse failure, SESRSYN(25) and energizing check functions are blocked.

The VB1OK/VB2OK and VB1FF inputs are related to the busbar voltage and the ULNOK and ULNFF inputs are related to the line voltage.

External selection of energizing direction
The energizing can be selected by use of the available logic function blocks. Below is an example where the choice of mode is done from a symbol on the local HMI through selector switch function block, but alternatively there can for example, be a physical selector switch on the front of the panel which is connected to a binary to integer function block (B16I).

If the PSTO input is used, connected to the Local-Remote switch on the local HMI, the choice can also be from the station HMI system, typically ABB Microscada through IEC 61850 communication.

The connection example for selection of the manual energizing mode is shown in figure 143. Selected names are just examples but note that the symbol on the local HMI can only show three signs.

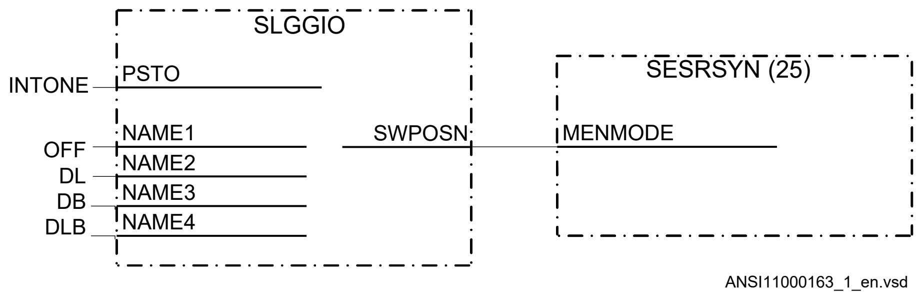


Figure 143: Selection of the energizing direction from a local HMI symbol through a selector switch function block.

11.1.3 Application examples

SESRSYN (25) function block can also be used in some switchyard arrangements, but with different parameter settings. Below are some examples of how different arrangements are connected to the IED analog inputs and to the function block SESRSYN(25). One function block is used per circuit breaker.

The input used below in example are typical and can be changed by use of configuration and signal matrix tools.

The SESRSYN and connected SMAI function block instances must have the same cycle time in the application configuration.

11.1.3.1 Single circuit breaker with single busbar

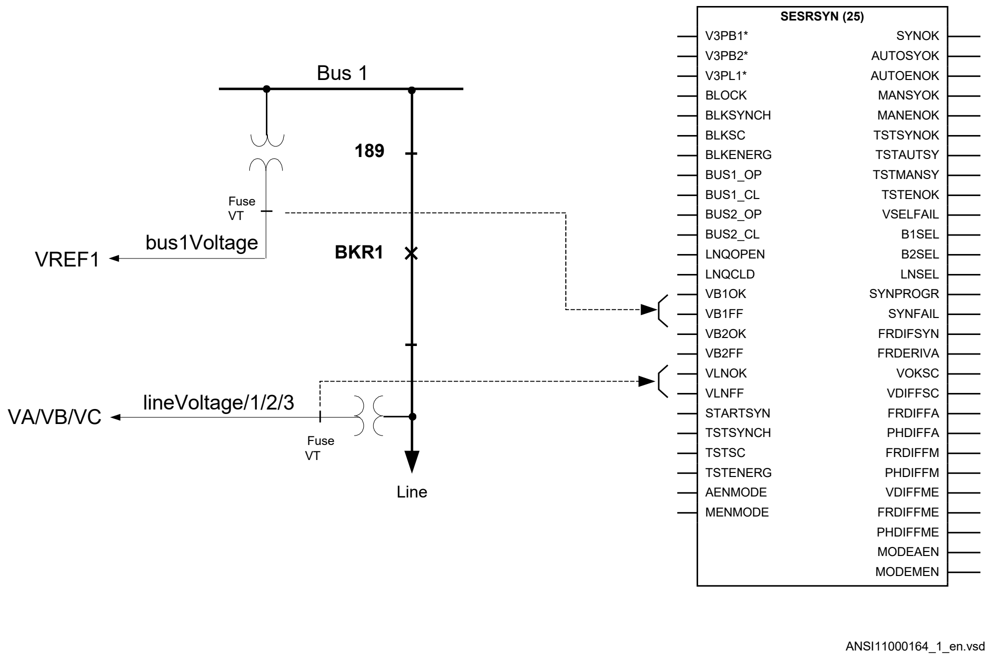


Figure 144: Connection of SESRSYN (25) function block in a single busbar arrangement

Figure 144 illustrates connection principles. For the SESRSYN (25) function there is one voltage transformer on each side of the circuit breaker. The voltage transformer circuit connections are straightforward; no special voltage selection is necessary. For SESRSYN (25), the voltage from the busbar VT is connected to analog input VREF1 on the analog input module. The line voltage is connected as a three-phase voltage to the analog inputs VA, VB and VC.

11.1.3.2 Single circuit breaker with double busbar, external voltage selection

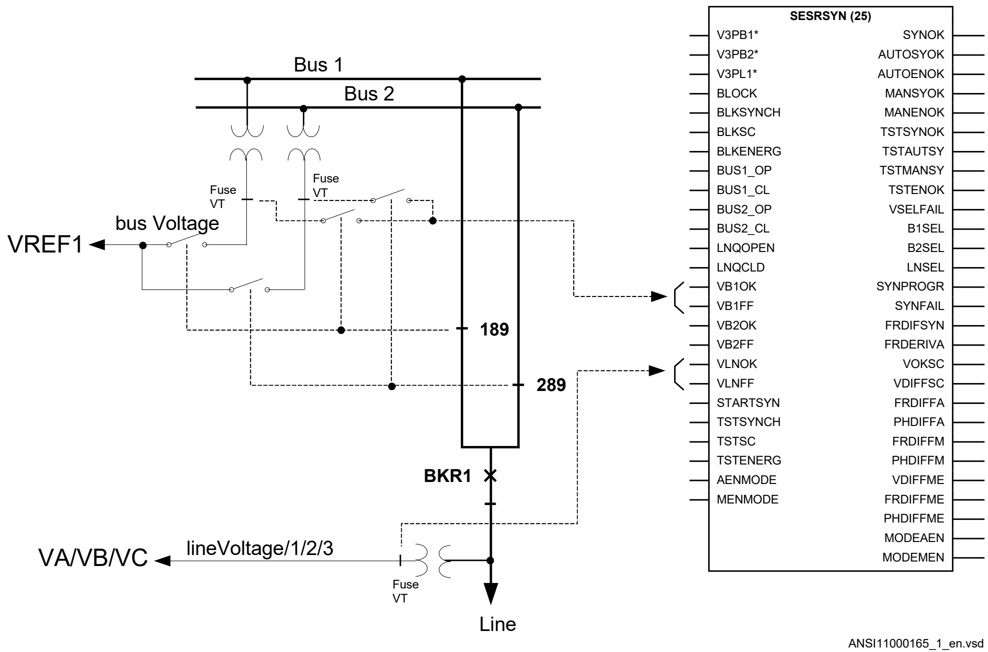


Figure 145: Connection of SESRSYN (25) function block in a single breaker, double busbar arrangement with external voltage selection.

In this type of arrangement no internal voltage selection is required. The voltage selection is made by external relays typically connected according to figure 145. Suitable voltage and VT fuse failure supervision from the two busbars are selected based on the position of the busbar disconnectors. That means that the connections to the function block will be the same as for the single busbar arrangement.

11.1.3.3 Single circuit breaker with double busbar, internal voltage selection

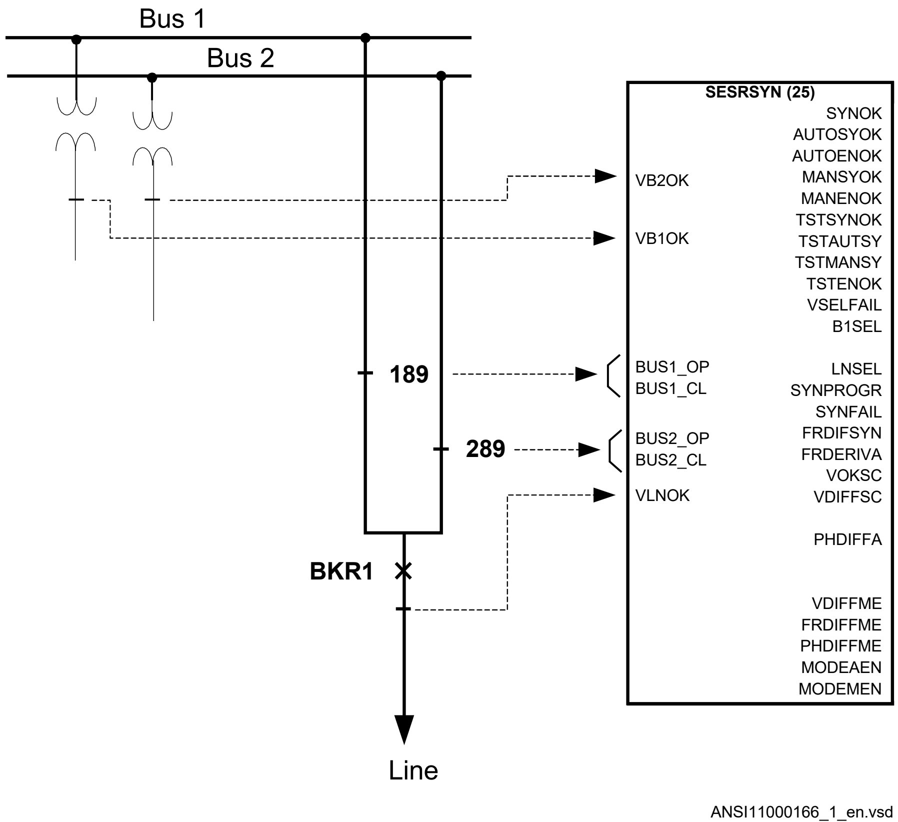


Figure 146: Connection of the Synchrocheck function block in a single breaker, double busbar arrangement with internal selection.

With the configuration according to figure 146, the voltage selection is made internally based on the signals from 189 and 289.

11.1.4 Setting guidelines

The setting parameters for the synchronizing, synchronism check and energizing check function (SESRSYN) are set via the local HMI, or Protection and Control IED Manager (PCM600).

Common base IED value for primary voltage (*VBase*) is set in a Global base value function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: The operation mode can be set *Enabled* or *Disabled* from PST. The setting *Disabled* disables the whole function.

MeasVoltBus1 and *MeasVoltBus2*

Configuration parameters for selection of measuring phase of the voltage for the busbar 1 and 2 respectively, which can be single-phase (*UL1*), two-phase (*UL1L2*) or positive sequence voltage.

MeasVoltBus1 and *MeasVoltBus2* must always be set to measure the same type of voltage, either single-phase (*UL1*), two-phase (*UL1L2*) or positive sequence voltage.

MeasVoltLine1

Configuration parameters for selection of measuring phase of the voltage for the line, which can be a single-phase (*UL1*), two-phase (*UL1L2*) or positive sequence voltage.

MeasVoltLine1 must always be set to measure the same type of voltage as *MeasVoltBus1* and *MeasVoltBus2* , either single-phase (*UL1*), two-phase (*UL1L2*) or positive sequence voltage.

PhaseShift

This setting is used to compensate for a phase shift caused by a line transformer between the two measurement points for bus voltage and line voltage, or one voltage is measured phase-phase and the other phase-neutral. The set value is added to the measured line phase angle. The bus voltage is reference voltage.

VRatio

The *VRatio* is defined as *VRatio=bus voltage/line voltage*. A typical use of the setting is to compensate for the voltage difference caused if one wishes to connect the bus voltage phase-phase and line voltage phase-neutral. The *MeasVoltBus1* setting should then be set to phase-phase and the *VRatio* setting to *√3=1.73*. This setting scales up the line voltage to equal level with the bus voltage.

OperationSynch

The setting *Disabled* disables the Synchronizing function. With the setting *Enabled*, the function is in service and the output signal depends on the input conditions.

FreqDiffMax

The setting *FreqDiffMax* is the maximum slip frequency at which synchronizing is accepted. 1/FreqDiffMax shows the time for the vector to move 360 degrees, one turn on the synchronoscope and is called the Beat time. A typical value for the *FreqDiffMax* is 200-250 mHz which gives beat times on 4-5 seconds. Higher values should be avoided as the two networks normally are regulated to nominal frequency independent of each other so the frequency difference shall be small.

FreqDiffMin

The setting *FreqDiffMin* is the minimum frequency difference where the system are defined to be asynchronous. For frequency difference lower than this value the systems are considered to be in parallel. A typical value for the *FreqDiffMin* is 10 mHz. Generally the value should be low if both synchronizing and synchronism check function is provided as it is better to let synchronizing function close as it will close at the exact right instance if the networks runs with a frequency difference. The synchronism check function will at such a case close to the set phase angle difference value which can be 35 degrees from the correct angle.

The *FreqDiffMin* shall be set to the same value as *FreqDiffM* resp *FreqDiffA* for the synchronism check function dependent of whether the functions are used for manual operation, auto-reclosing or both.

FreqRateChange

The maximum allowed rate of change for the frequency.

tBreaker

The *tBreaker* shall be set to match the closing time for the circuit breaker and should also include the possible auxiliary relays in the closing circuit. It is important to check that no slow logic components are used in the configuration of the IED as there then can be big variations in closing time due to those components. Typical setting is 80-150 ms depending on the breaker closing time.

tClosePulse

Setting for the duration of the breaker close pulse.

tMinSynch

The *tMinSynch* is set to limit the minimum time at which synchronizing closing attempt is given. The setting will not give a closing should a condition fulfilled occur within this time from the synchronizing function is started. Typical setting is 200 ms.

tMaxSynch

The *tMaxSynch* is set to reset the operation of the synchronizing function if the operation does not take place within this time. The setting must allow for the setting of *FreqDiffMin* which will decide how long it will take maximum to reach phase equality. At a setting of 10ms the beat time is 100 seconds and the setting would thus need to be at least *tMinSynch* plus 100 seconds. If the network frequencies are expected to be outside the limits from start a margin needs to be added. Typical setting 300 seconds.

OperationSC

The *OperationSC* setting *Disabled* disables thesynchronsim check function and sets the outputs AUTOSYOK, MANSYOK, TSTAUTSY and TSTMANSY to low.

With the setting *Enabled*, the function is in service and the output signal depends on the input conditions.

VDiffSC

Setting for voltage difference between line and bus.

FreqDiffM and FreqDiffA

The frequency difference level settings, *FreqDiffM* and *FreqDiffA*, shall be chosen depending on the condition in the network. At steady conditions a low frequency difference setting is needed, where the *FreqDiffM* setting is used. For auto-reclosing a bigger frequency difference setting is preferable, where the *FreqDiffA* setting is used. A typical value for the *FreqDiffM* can be 10 mHz and a typical value for the *FreqDiffA* can be 100-200 mHz.

PhaseDiffM and PhaseDiffA

The phase angle difference level settings, *PhaseDiffM* and *PhaseDiffA*, shall also be chosen depending on conditions in the network. The phase angle setting must be chosen to allow closing under maximum load condition. A typical maximum value in heavy loaded networks can be 45 degrees whereas in most networks the maximum occurring angle is below 25 degrees.

tSCM and tSCA

The purpose of the timer delay settings, *tSCM* and *tSCA*, is to ensure that the synchronism check conditions remains constant and that the situation is not due to a temporary interference. Should the conditions not persist for the specified time, the delay timer is reset and the procedure is restarted when the conditions are fulfilled again. Circuit breaker closing is thus not permitted until the synchronism check situation has remained constant throughout the set delay setting time. Under stable conditions a longer operation time delay setting is needed, where the *tSCM* setting is used. During auto-reclosing a shorter operation time delay setting is preferable, where the *tSCA* setting is used. A typical value for the *tSCM* may be 1 second and a typical value for the *tSCA* may be 0.1 second.

AutoEnerg and *ManEnerg*

Two different settings can be used for automatic and manual closing of the circuit breaker. The settings for each of them are:

- *Disabled*, the energizing function is disabled.
- *DLLB*, Dead Line Live Bus, the line voltage is below a standard value.
- *DBLL*, Dead Bus Live Line, the bus voltage is below a standard value.
- *Both*, energizing can be done in both directions, *DLLB* or *DBLL*.

tAutoEnerg and *tManEnerg*

The purpose of the timer delay settings, *tAutoEnerg* and *tManEnerg*, is to ensure that the dead side remains de-energized and that the condition is not due to a temporary interference. Should the conditions not persist for the specified time, the delay timer is reset and the procedure is restarted when the conditions are fulfilled again. Circuit breaker closing is thus not permitted until the energizing condition has remained constant throughout the set delay setting time.

ManEnergDBDL

If the parameter is set to *Enabled*, manual energizing is enabled.

11.2 Autorecloser SMBRREC (79)

11.2.1 Identification

Function Description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Autorecloser	SMBRREC	*O->I*	79

11.2.2 Application

Automatic reclosing is a well-established method for the restoration of service in a power system after a transient line fault. The majority of line faults are flashover arcs, which are transient by nature. When the power line is switched off by the operation of line protection and line breakers, the arc de-ionizes and recovers its ability to withstand voltage at a somewhat variable rate. Thus, a certain dead time with a de-energized line is necessary. Line service can then be resumed by automatic reclosing of the line breakers. The dead time selected should be long enough to ensure a high probability of arc de-ionization and successful reclosing.

For individual line breakers, auto-reclosing equipment or functions, the auto-reclosing open time is used to determine line “dead time”. When simultaneous tripping and reclosing at the two line ends occurs, auto-reclosing open time is approximately equal to the line “dead time”. If the open time and dead time differ then, the line will be energized until the breakers at both ends have opened.

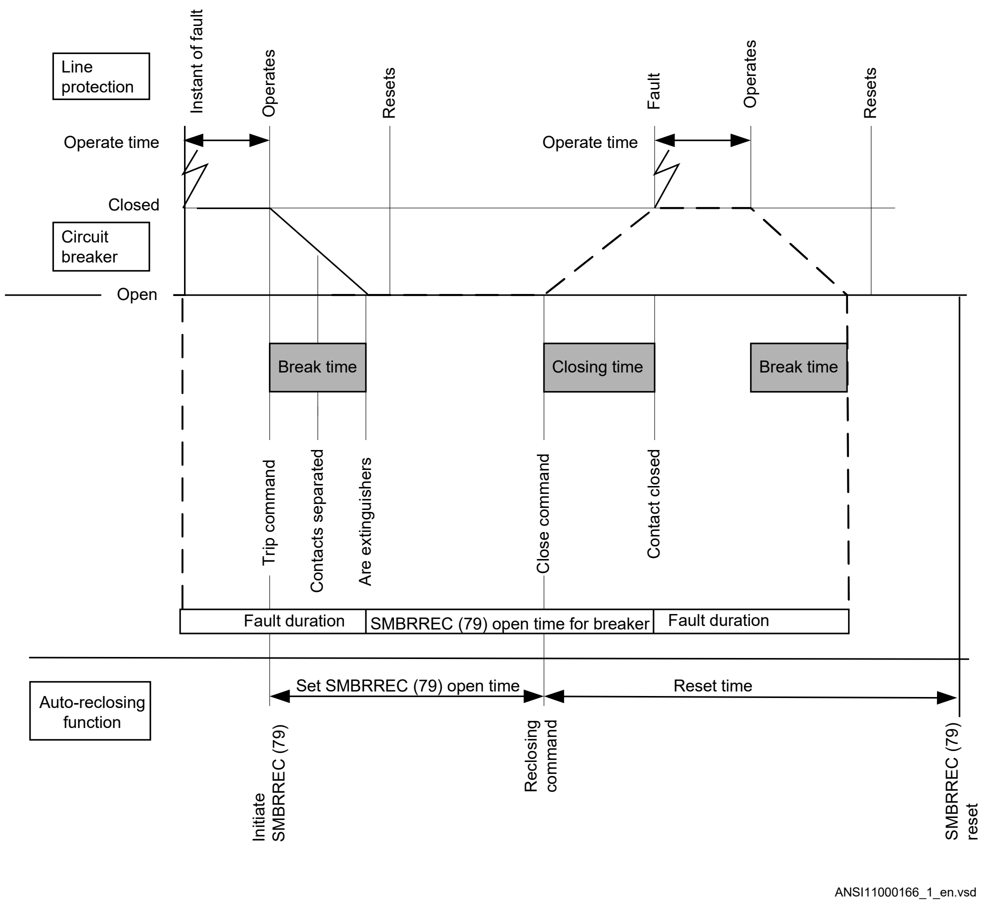


Figure 147: Single-shot automatic reclosing at a permanent fault

Three-phase automatic reclosing can be performed with or without the use of a synchronism check, and an energizing check, such as dead line or dead busbar check.

For the individual line breakers and auto-reclosing equipment, the ”auto-reclosing open time” expression is used. This is the dead time setting for the Auto-Recloser. During simultaneous tripping and reclosing at the two line ends, auto-reclosing open time is approximately equal to the line dead time. Otherwise these two times may differ as one line end might have a slower trip than the other end which means that the line will not be dead until both ends have opened.

If the fault is permanent, the line protection will trip again when reclosing is attempted in order to clear the fault.

It is common to use one automatic reclosing function per line circuit-breaker (CB). When one CB per line end is used, then there is one auto-reclosing function per line end. If auto-reclosing functions are included in duplicated line protection, which means two auto-reclosing functions per CB, one should take measures to avoid uncoordinated reclosing commands. In breaker-and-a-half, double-breaker and ring bus arrangements, two CBs per line end are operated. One auto-reclosing function per CB is recommended. Arranged in such a way, sequential reclosing of the two CBs can be arranged with a priority circuit available in the auto-reclose function. In case of a permanent fault and unsuccessful reclosing of the first CB, reclosing of the second CB is cancelled and thus the stress on the power system is limited. Another advantage with the breaker connected auto-recloser is that checking that the breaker closed before the sequence, breaker prepared for an auto-reclose sequence and so on. is much simpler.

The auto-reclosing function performs three-phase automatic-reclosing with single-shot or multiple-shots.

In power transmission systems it is common practise to apply single and/or three phase, single-shot Auto-Reclosing. In Sub-transmission and Distribution systems tripping and auto-reclosing are usually three-phase. The mode of automatic-reclosing varies however. Single-shot and multi-shot are in use. The first shot can have a short delay, HSAR, or a longer delay, DAR. The second and following reclosing shots have a rather long delay. When multiple shots are used the dead time must harmonize with the breaker duty-cycle capacity.

Automatic-reclosing is usually started by the line protection and in particular by instantaneous tripping of such protection. The auto-reclosing function can be inhibited (blocked) when certain protection functions detecting permanent faults, such as shunt reactor, cable or busbar protection are in operation. Back-up protection zones indicating faults outside the own line are also connected to inhibit the Auto-Reclose.

Automatic-reclosing should not be attempted when closing a CB and energizing a line onto a fault (SOTF), except when multiple-shots are used where shots 2 etc. will be started at SOTF. Likewise a CB in a multi-breaker busbar arrangement which was not closed when a fault occurred should not be closed by operation of the Auto-Reclosing function. Auto-Reclosing is often combined with a release condition from synchronism check and dead line or dead busbar check. In order to limit the stress on turbo-generator sets from Auto-Reclosing onto a permanent fault, one can arrange to combine Auto-Reclosing with a synchronism check on line terminals close to such power stations and attempt energizing from the side furthest away from the power station and perform the synchronism check at the local end if the energizing was successful.

Transmission protection systems are usually sub-divided and provided with two redundant protection IEDs. In such systems it is common to provide auto-reclosing in only one of the sub-systems as the requirement is for fault clearance and a failure to reclose because of the auto-recloser being out of service is not considered a major disturbance. If two auto-reclosers are provided on the same breaker, the application must be carefully checked and normally one must be the master and be connected to inhibit the other auto-recloser if it has started. This inhibit can for example be done from Autorecloser (SMBRREC ,79) In progress.

A permanent fault will cause the line protection to trip again when it recloses in an attempt to clear the fault.

The auto-reclosing function allows a number of parameters to be adjusted.

Examples:

- number of auto-reclosing shots
- auto-reclosing open times (dead time) for each shot

11.2.2.1 Auto-reclosing operation OFF and ON

Operation of the automatic reclosing can be set OFF and ON by a setting parameter and by external control. Parameter *Operation*= *Disabled*, or *Enabled* sets the function OFF and ON. In setting *Operation*=*ExternalCtrl*, OFF and ON control is made by input signal pulses, for example, from the control system or from the binary input (and other systems).

When the function is set ON and operative (other conditions such as CB closed and CB Ready are also fulfilled), the output SETON is activated (high). When the function is ready to accept a reclosing start.

11.2.2.2 Initiate auto-reclosing and conditions for initiation of a reclosing cycle

The usual way to start a reclosing cycle, or sequence, is to start it at tripping by line protection by applying a signal to the input RI. Starting signals can be either, General Trip signals or, only the conditions for Differential, Distance protection Zone 1 and Distance protection Aided trip. In some cases also Directional Ground fault function Aided trip can be connected to start an Auto-Reclose attempt.

A number of conditions need to be fulfilled for the start to be accepted and a new auto-reclosing cycle to be started. They are linked to dedicated inputs. The inputs are:

- CBREADY, CB ready for a reclosing cycle, for example, charged operating gear.
- 52a to ensure that the CB was closed when the line fault occurred and start was applied.
- No signal at input INHIBIT that is, no blocking or inhibit signal present. After the start has been accepted, it is latched in and an internal signal “Started” is set. It can be interrupted by certain events, like an “Inhibit” signal.

11.2.2.3 Initiate auto-reclosing from CB open information

If a user wants to initiate auto-reclosing from the "CB open" position instead of from protection trip signals, the function offers such a possibility. This starting mode is selected with the setting parameter *StartByCBOpen*=*Enabled*. It is then necessary to block reclosing for all manual trip operations. Typically *CBAuxContType*=*NormClosed* is also set and a CB auxiliary contact of type NC (normally closed, 52b) is connected to inputs 52a and RI. When the signal changes from “CB closed” to “CB open” an auto-reclosing start pulse is generated and latched in the function, subject to the usual checks. Then the reclosing sequence continues as usual. One needs to connect signals from manual tripping and other functions, which shall prevent reclosing, to the input INHIBIT.

11.2.2.4 Blocking of the autorecloser

Auto-Reclose attempts are expected to take place only in the event of transient faults on the own line. The Auto-Recloser must be blocked for the following conditions:

- Tripping from Delayed Distance protection zones
- Tripping from Back-up protection functions
- Tripping from Breaker failure function
- Intertrip received from remote end Breaker failure function
- Busbar protection tripping

Depending of the starting principle (General Trip or only Instantaneous trip) adopted above the delayed and back-up zones might not be required. Breaker failure local and remote must however always be connected.

11.2.2.5 Control of the auto-reclosing open time

There are settings for the three-phase auto-reclosing open time, *t1 3Ph to t5 3Ph*.

11.2.2.6 Long trip signal

In normal circumstances the trip command resets quickly because of fault clearance. The user can set a maximum trip pulse duration *tTrip*. A long trip signal interrupts the reclosing sequence in the same way as a signal to input INHIBIT.

11.2.2.7 Maximum number of reclosing shots

The maximum number of reclosing shots in an auto-reclosing cycle is selected by the setting parameter *NoOfShots*.

11.2.2.8 3-phase reclosing, one to five shots according to setting NoOfShots.

A trip operation is made as a three-phase trip at all types of fault. The reclosing is as a three-phase. Here, the auto-reclosing function is assumed to be "On" and "Ready". The breaker is closed and the operation gear ready (operating energy stored). Input RI is received and sealed-in. The output READY is reset (set to false). Output ACTIVE is set. The timer for 3-phase auto-reclosing open time is started.

While any of the auto-reclosing open time timers are running, the output INPROGR is activated. When the "open reset" timer runs out, the respective internal signal is transmitted to the output module for further checks and to issue a closing command to the circuit breaker.

When issuing a CB closing command a “reset” timer *tReset* is started. If no tripping takes place during that time the auto-reclosing function resets to the “Ready” state and the signal ACTIVE resets. If the first reclosing shot fails, 2nd to 5th reclosing shots will follow, if selected.

11.2.2.9 Reclosing reset timer

The reset timer *tReset* defines the time it takes from issue of the reclosing command, until the reclosing function resets. Should a new trip occur during this time, it is treated as a continuation of the first fault. The reclaim timer is started when the CB closing command is given.

11.2.2.10 Transient fault

After the Reclosing command the reset timer keeps running for the set time. If no tripping occurs within this time, *tReset*, the Auto-Reclosing will reset. The CB remains closed and the operating gear recharges. The input signals 52a and CBREADY will be set

11.2.2.11 Permanent fault and reclosing unsuccessful signal

If a new trip occurs, and a new input signal RI or TRSOTF appears, after the CB closing command, the output UNSUCCL (unsuccessful closing) is set high. The timer for the first shot can no longer be started. Depending on the set number of Reclosing shots further shots may be made or the Reclosing sequence is ended. After reset timer time-out the Auto-Reclosing function resets, but the CB remains open. The “CB closed” information through the input 52a is missing. Thus, the reclosing function is not ready for a new reclosing cycle.

Normally, the signal UNSUCCL appears when a new trip and start is received after the last reclosing shot has been made and the auto-reclosing function is blocked. The signal resets after reset time. The “unsuccessful” signal can also be made to depend on CB position input. The parameter *UnsucClByCBChk* should then be set to *CBCheck*, and a timer *tUnsucCl* should be set too. If the CB does not respond to the closing command and does not close, but remains open, the output UNSUCCL is set high after time *tUnsucCl*. The Unsuccessful output can for example, be used in Multi-Breaker arrangement to cancel the auto-reclosing function for the second breaker, if the first breaker closed onto a persistent fault. It can also be used to generate a Lock-out of manual closing until the operator has reset the Lock-out, see separate section.

11.2.2.12 Lock-out initiation

In many cases there is a requirement that a Lock-out is generated when the auto-reclosing attempt fails. This is done with logic connected to the in- and outputs of the Autoreclose function and connected to Binary IO as required. Many alternative ways of performing the logic exist depending on whether manual closing is interlocked in the IED, whether an external physical Lock-out relay exists and whether the reset is hardwired, or carried out by means of communication. There are also different alternatives regarding what shall generate Lock-out. Examples of questions are:

- Shall back-up time delayed trip give Lock-out (normally yes)
- Shall Lock-out be generated when closing onto a fault (mostly)
- Shall Lock-out be generated when the Auto-Recloser was OFF at the fault
- Shall Lock-out be generated if the Breaker did not have sufficient operating power for an auto-reclosing sequence (normally not as no closing attempt has been given)

In figures 148 and 149 the logic shows how a closing Lock-out logic can be designed with the Lock-out relay as an external relay alternatively with the Lock-out created internally with the manual closing going through the Synchro-check function. An example of Lock-out logic.

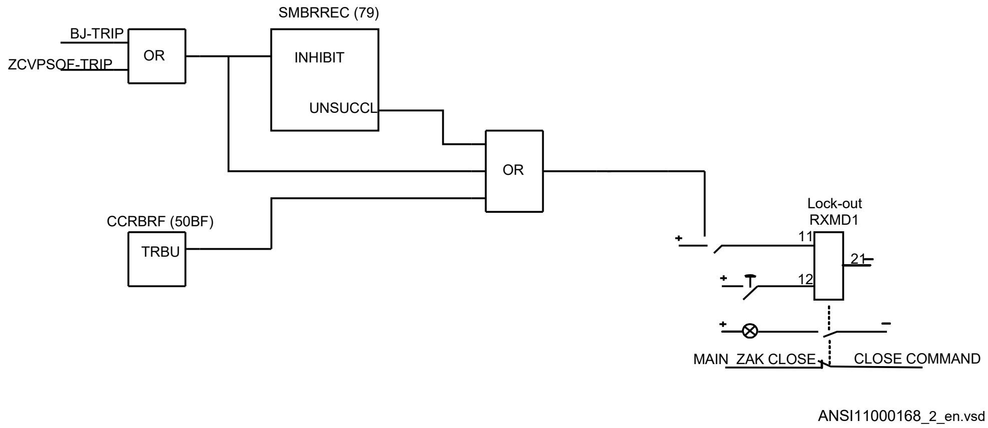


Figure 148: Lock-out arranged with an external Lock-out relay

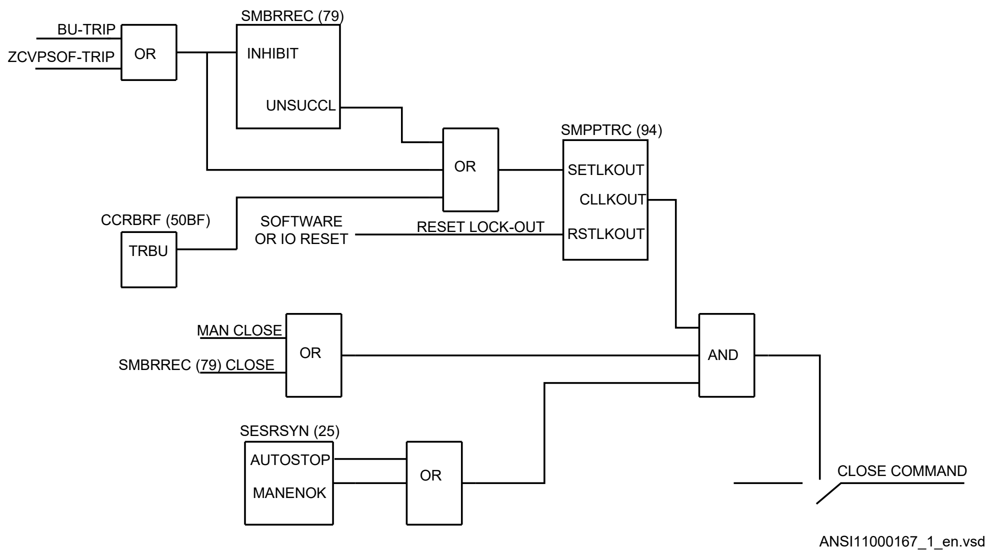


Figure 149: Lock-out arranged with internal logic with manual closing going through in IED

11.2.2.13 Automatic continuation of the reclosing sequence

SMBRREC (79) function can be programmed to proceed to the following reclosing shots (if multiple shots are selected) even if start signals are not received from the protection functions, but the breaker is still not closed. This is done by setting parameter *AutoCont* = *Enabled* and *tAutoContWait* to the required delay for the function to proceed without a new start.

11.2.2.14 Thermal overload protection holding the auto-reclosing function back

If the input THOLHOLD (thermal overload protection holding reclosing back) is activated, it will keep the reclosing function on a hold until it is reset. There may thus be a considerable delay between start of Auto-Reclosing and reclosing command to the circuit-breaker. An external logic limiting the time and sending an inhibit to the INHIBIT input can be used. The input can also be used to set the Auto-Reclosing on hold for a longer or shorter period.

11.2.3 Setting guidelines

11.2.3.1 Configuration

Use the PCM600 configuration tool to configure signals.

Autorecloser function parameters are set via the local HMI or Parameter Setting Tool (PST). Parameter Setting Tool is a part of PCM600.

Recommendations for input signals
Please see examples in figure 150.

ON and OFF

These inputs can be connected to binary inputs or to a communication interface block for external control.

RI

It should be connected to the trip output protection function, which starts the autorecloser (SMBRREC ,79) function. It can also be connected to a binary input for start from an external contact. A logical OR-gate can be used to combine the number of start sources.

If *StartByCBOpen* is used, the CB Open condition shall also be connected to the input RI.

INHIBIT

To this input shall be connected signals that interrupt a reclosing cycle or prevent a start from being accepted. Such signals can come from protection for a line connected shunt reactor, from transfer trip receive, from back-up protection functions, busbar protection trip or from breaker failure protection. When the CB open position is set to start SMBRREC(79) , then manual opening must also be connected here. The inhibit is often a combination of signals from external IEDs via the IO and internal functions. An OR gate is then used for the combination.

52a and CBREADY

These should be connected to binary inputs to pick-up information from the CB. The 52a input is interpreted as CB Closed, if parameter *CBAuxContType* is set *NormOpen*, which is the default setting. At three operating gears in the breaker (single pole operated breakers) the connection should be “All poles closed” (series connection of the NO contacts) or “At least one pole open” (parallel connection of NC contacts) if the *CBAuxContType* is set to *NormClosed*. The “CB Ready” is a signal meaning that the CB is ready for a reclosing operation, either Close-Open (CO), or Open-Close-Open (OCO). If the available signal is of type “CB not charged” or “not ready”, an inverter can be inserted in front of the CBREADY input.

SYNC

This is connected to the internal synchronism check function when required. It can also be connected to a binary input for synchronization from an external device. If neither internal nor external synchronism or energizing check is required, it can be connected to a permanently high source, TRUE. The signal is required for three phase shots 1-5 to proceed .

TRSOTF

This is the signal “Trip by Switch Onto Fault”. It is usually connected to the “switch onto fault” output of line protection if multi-shot Auto-Reclose attempts are used. The input will start the shots 2-5. For single shot applications the input is set to FALSE.

THOLHOLD

Signal “Thermal overload protection holding back Auto-Reclosing”. It is normally set to FALSE. It can be connected to a thermal overload protection trip signal which resets only when the thermal content has gone down to an acceptable level, for example, 70%. As long as the signal is high, indicating that the line is hot, the Auto-Reclosing is held back. When the signal resets, a reclosing cycle will continue. Please observe that this have a considerable delay. Input can also be used for other purposes if for some reason the Auto-Reclose shot is halted.

WAIT

Used to hold back reclosing of the “low priority unit” during sequential reclosing. See “Recommendation for multi-breaker arrangement” below. The signal is activated from output WFMASTER on the second breaker Auto-Recloser in multi-breaker arrangements.

BLKON

Used to block the autorecloser (SMBRREC ,79) function for example, when certain special service conditions arise. Input is normally set to FALSE. When used, blocking must be reset with BLOCKOFF.

BLOCKOFF

Used to Unblock SMBRREC (79) function when it has gone to Block due to activating input BLKON or by an unsuccessful Auto-Reclose attempt if the setting *BlockByUnsucCl* is set to *Enabled*. Input is normally set to FALSE.

RESET

Used to Reset SMBRREC (79) to start condition. Possible Thermal overload Hold will be reset. Positions, setting On-Off. will be started and checked with set times. Input is normally set to FALSE.

Recommendations for output signals
Please see figure 150.

SETON

Indicates that Autorecloser (SMBRREC ,79) function is switched on and operative.

BLOCKED

Indicates that SMRREC (79) function is temporarily or permanently blocked.

ACTIVE

Indicates that SMBRREC (79) is active, from start until end of Reset time.

INPROGR

Indicates that a sequence is in progress, from start until reclosing command.

UNSUCCL

Indicates unsuccessful reclosing.

CLOSECMD

Connect to a binary output for circuit-breaker closing command.

READY

Indicates that SMBRREC (79) function is ready for a new and complete reclosing sequence. It can be connected to the zone extension of a line protection should extended zone reach before automatic reclosing be necessary.

3PT1,-3PT2,-3PT3,-3PT4 and -3PT5

Indicates that three-phase automatic reclosing shots 1-5 are in progress. The signals can be used as an indication of progress or for own logic.

WFMASTER

Wait from master is used in high priority units to hold back reclosing of the low priority unit during sequential reclosing.

Other outputs

The other outputs can be connected for indication, disturbance recording, as required.

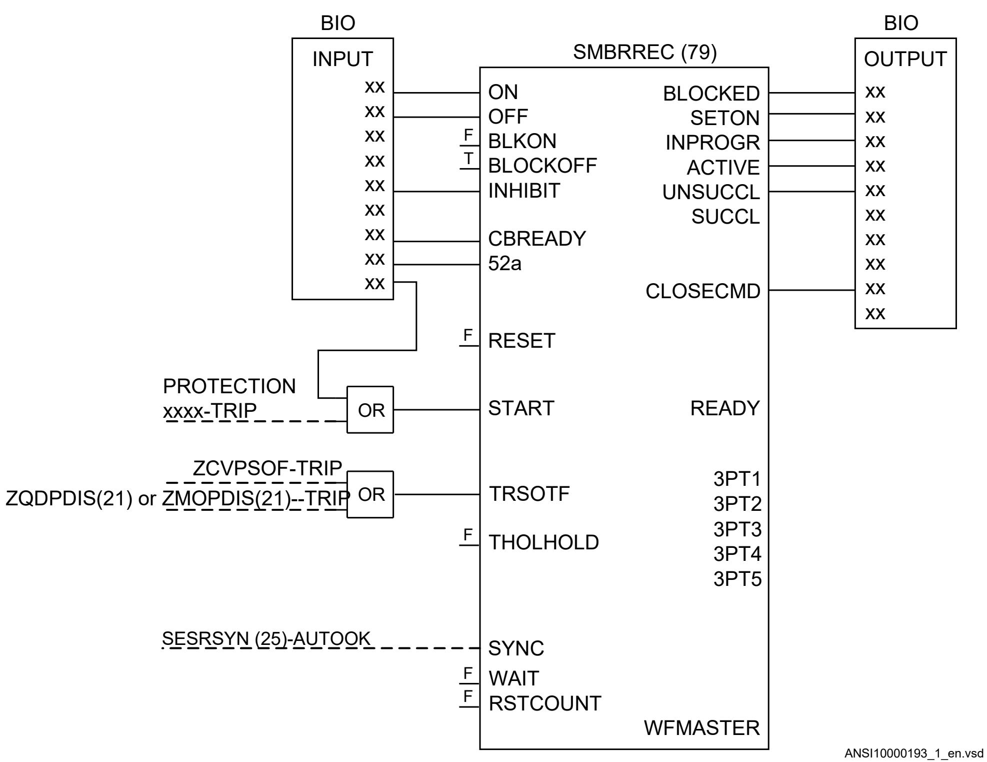


Figure 150: Example of I/O-signal connections at a three-phase reclosing function

11.2.3.2 Auto-recloser parameter settings

The operation of the Autorecloser (SMBRREC ,79) function can be switched *Enabled* and *Disabled*. The setting makes it possible to switch it *Enabled* or *Disabled* using an external switch via IO or communication ports.

, Number of reclosing shots

In sub-transmission 1 shot is mostly used. In most cases one reclosing shot is sufficient as the majority of arcing faults will cease after the first reclosing shot. In power systems with many other types of faults caused by other phenomena, for example wind, a greater number of reclose attempts (shots) can be motivated.

Auto-reclosing open times, dead times

Three-phase shot 1 delay: For three-phase High-Speed Auto-Reclosing (HSAR) a typical open time is 400ms. Different local phenomena, such as moisture, salt, pollution etc. can influence the required dead time. Some users apply Delayed Auto-Reclosing (DAR) with delays of 10s or more. The delay of reclosing shot 2 and possible later shots are usually set at 30s or more. A check that the CB duty cycle can manage the selected setting must be done. The setting can in some cases be restricted by national regulations. For multiple shots the setting of shots 2-5 must be longer than the circuit breaker duty cycle time.

tSync, Maximum wait time for synchronismcheck

The time window should be coordinated with the operate time and other settings of the synchronism check function. Attention should also be paid to the possibility of a power swing when reclosing after a line fault. Too short a time may prevent a potentially successful reclosing. A typical setting may be 2.0 s.

tTrip, Long trip pulse

Usually the trip command and initiate auto-reclosing signal reset quickly as the fault is cleared. A prolonged trip command may depend on a CB failing to clear the fault. A trip signal present when the CB is reclosed will result in a new trip. At a setting somewhat longer than the auto-reclosing open time, this facility will not influence the reclosing. A typical setting of *tTrip* could be close to the auto-reclosing open time.

tInhibit, Inhibit resetting delay

A typical setting is *tInhibit = 5.0 s* to ensure reliable interruption and temporary blocking of the function. Function will be blocked during this time after the *tinhibit* has been activated.

tReset, Reset time

The Reset time sets the time for resetting the function to its original state, after which a line fault and tripping will be treated as an independent new case with a new reclosing cycle. One may consider a nominal CB duty cycle of for instance, O-0.3sec CO- 3 min. – CO. However the 3 minute (180 s) recovery time is usually not critical as fault levels are mostly lower than rated value and the risk of a new fault within a short time is negligible. A typical time may be *tReset = 60 or 180 s* dependent of the fault level and breaker duty cycle.

StartByCBOpen

The normal setting is *Disabled*. It is used when the function is started by protection trip signals.

FollowCB

The usual setting is *Follow CB* = *Disabled*. The setting *Enabled* can be used for delayed reclosing with long delay, to cover the case when a CB is being manually closed during the “auto-reclosing open time” before the auto-reclosing function has issued its CB closing command.

tCBClosedMin

A typical setting is 5.0 s. If the CB has not been closed for at least this minimum time, a reclosing start will not be accepted.

CBAuxContType, CB auxiliary contact type

It shall be set to correspond to the CB auxiliary contact used. A *NormOpen* contact is recommended in order to generate a positive signal when the CB is in the closed position.

CBReadyType, Type of CB ready signal connected

The selection depends on the type of performance available from the CB operating gear. At setting *OCO* (CB ready for an Open – Close – Open cycle), the condition is checked only at the start of the reclosing cycle. The signal will disappear after tripping, but the CB will still be able to perform the C-O sequence. For the selection *CO* (CB ready for a Close – Open cycle) the condition is also checked after the set auto-reclosing dead time. This selection has a value first of all at multi-shot reclosing to ensure that the CB is ready for a C-O sequence at shot 2 and further shots. During single-shot reclosing, the *OCO* selection can be used. A breaker shall according to its duty cycle always have storing energy for a CO operation after the first trip. (IEC 56 duty cycle is O-0.3sec CO-3minCO).

tPulse, Breaker closing command pulse duration

The pulse should be long enough to ensure reliable operation of the CB. A typical setting may be *tPulse=200 ms*. A longer pulse setting may facilitate dynamic indication at testing, for example in “Debug” mode of PCM600 Application Configuration Tool (ACT) .

BlockByUnsucCl

Setting of whether an unsuccessful auto-reclose attempt shall set the Auto-Reclose in block. If used the inputs BLKOFF must be configured to unblock the function after an unsuccessful Reclosing attempt. Normal setting is *Disabled*.

UnsucClByCBCheck, Unsuccessful closing by CB check

The normal setting is *NoCBCheck*. The “auto-reclosing unsuccessful” event is then decided by a new trip within the reset time after the last reclosing shot. If one wants to get the UNSUCCL (Unsuccessful closing) signal in the case the CB does not respond to the closing command, CLOSECMD, one can set *UnsucClByCBCheck*= *CB Check* and set *tUnsucCl* for instance to 1.0 s.

Priority and time *tWaitForMaster*

In single CB applications, one sets *Priority* = *None*. At sequential reclosing the function of the first CB, e.g. near the busbar, is set *Priority* = *High* and for the second CB *Priority* = *Low*. The maximum waiting time, *tWaitForMaster* of the second CB is set longer than the “auto-reclosing open time” and a margin for synchronism check at the first CB. Typical setting is *tWaitForMaster=2sec*.

AutoCont and *tAutoContWait*, Automatic continuation to the next shot if the CB is not closed within the set time

The normal setting is *AutoCont* = *Disabled*. The *tAutoContWait* is the length of time SMBRREC (79) waits to see if the breaker is closed when *AutoCont* is set to *Enabled*. Normally, the setting can be *tAutoContWait = 2 sec*.

11.3 Autorecloser STBRREC (79)

11.3.1 Identification

Function Description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Autorecloser	STBRREC	*O->I*	79

11.3.2 Application

Automatic reclosing is a well-established method for the restoration of service in a power system after a transient line fault. The majority of line faults are flashover arcs, which are transient by nature. When the power line is switched off by the operation of line protection and line breakers, the arc de-ionizes and recovers its ability to withstand voltage at a somewhat variable rate. Thus, a certain dead time with a de-energized line is necessary. Line service can then be resumed by automatic reclosing of the line breakers. The dead time selected should be long enough to ensure a high probability of arc de-ionization and successful reclosing.

For individual line breakers, auto-reclosing equipment or functions, the autoreclosing open time is used to determine line “dead time”. When simultaneous tripping and reclosing at the two line ends occurs, auto-reclosing open time is approximately equal to the line “dead time”. If the open time and dead time differ then, the line will be energized until the breakers at both ends have opened.

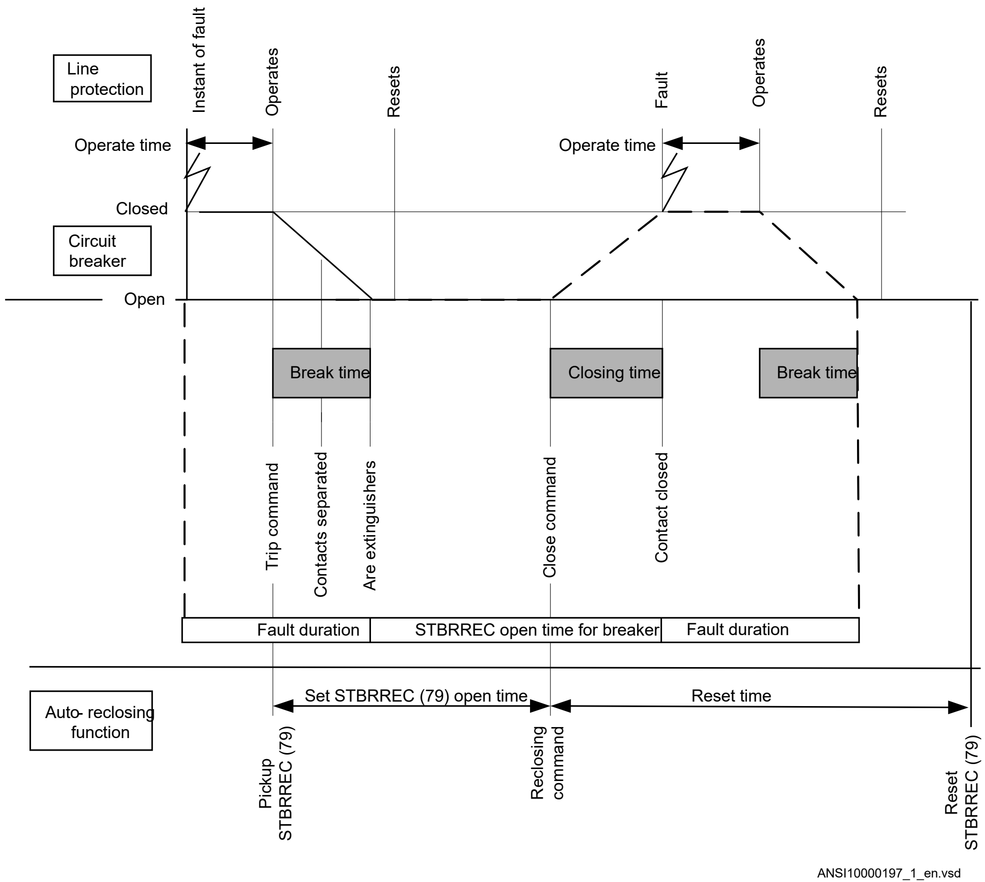


Figure 151: Single-shot automatic reclosing at a permanent fault

Single-pole tripping and single-pole automatic reclosing is a way of limiting the effect of a single-phase line fault on power system operation. Especially at higher voltage levels, the majority of faults are of single-phase type (around 90%). To maintain system stability in power systems with limited meshing or parallel routing single phase auto reclosing is of particular value. During the single phase dead time the system is still capable of transmitting load on the two healthy phases and the system is still synchronized. It requires that each phase breaker operates individually, which is usually the case for higher transmission voltages.

A somewhat longer dead time may be required for single-phase reclosing compared to high-speed three-phase reclosing. This is due to the influence on the fault arc from the voltage and the current in the non-tripped phases.

To maximize the availability of the power system it is possible to choose single pole tripping and automatic reclosing during single-phase faults and three pole tripping and automatic reclosing during multi-phase faults. Three-phase automatic reclosing can be performed with or without the use of a synchronism check, and an energizing check, such as dead line or dead busbar check.

During the single-pole open time there is an equivalent "series"-fault in the system resulting in a flow of zero sequence current. It is therefore necessary to coordinate the residual current protections (ground fault protection) with the single pole tripping and the auto-reclosing function. Attention shall also be paid to “pole discordance” (pole discordance) that arises when circuit breakers are provided with single pole operating devices. These breakers need pole discordance protection. They must also be coordinated with the single pole auto-recloser and blocked during the dead time when a normal discordance occurs. Alternatively they should use a trip time longer than the set single phase dead time.

For the individual line breakers and auto-reclosing equipment, the “auto-reclosing open time” expression is used. This is the dead time setting for the Auto-Recloser. During simultaneous tripping and reclosing at the two line ends, auto-reclosing open time is approximately equal to the line dead time. Otherwise these two times may differ as one line end might have a slower trip than the other end which means that the line will not be dead until both ends have opened.

If the fault is permanent, the line protection will trip again when reclosing is attempted in order to clear the fault.

It is common to use one automatic reclosing function per line circuit-breaker (CB). When one CB per line end is used, then there is one auto-reclosing function per line end. If auto-reclosing functions are included in duplicated line protection, which means two auto-reclosing functions per CB, one should take measures to avoid uncoordinated reclosing commands. In breaker-and-a-half, double-breaker and ring bus arrangements, two CBs per line end are operated. One auto-reclosing function per CB is recommended. Arranged in such a way, sequential reclosing of the two CBs can be arranged with a priority circuit available in the auto-reclose function. In case of a permanent fault and unsuccessful reclosing of the first CB, reclosing of the second CB is cancelled and thus the stress on the power system is limited. Another advantage with the breaker connected auto-recloser is that checking that the breaker closed before the sequence, breaker prepared for an autoreclose sequence and so on is much simpler.

The auto-reclosing function can be selected to perform single-phase and/or three phase automatic-reclosing from several single-shot to multiple-shot reclosing programs.

In power transmission systems it is common practice to apply single and/or three phase, single-shot Auto-Reclosing. In Sub-transmission and Distribution systems tripping and auto-reclosing are usually three-phase. The mode of automaticreclosing varies however. Single-shot and multi-shot are in use. The first shot can have a short delay, HSAR, or a longer delay, DAR. The second and following reclosing shots have a rather long delay. When multiple shots are used the dead time must harmonize with the breaker duty-cycle capacity.

Automatic-reclosing is usually started by the line protection and in particular by instantaneous tripping of such protection. The auto-reclosing function can be inhibited (blocked) when certain protection functions detecting permanent faults, such as shunt reactor, cable or bus bar protection are in operation. Back-up protection zones indicating faults outside the own line are also connected to inhibit the Auto-Reclose.

Automatic-reclosing should not be attempted when closing a CB and energizing a line onto a fault (SOTF), except when multiple-shots are used where shots 2 etc. will be started at SOTF. Likewise a CB in a multi-breaker bus bar arrangement which was not closed when a fault occurred should not be closed by operation of the Auto-Reclosing function. Auto-Reclosing is often combined with a release condition from synchronism check and dead line or dead bus bar check. In order to limit the stress on turbo-generator sets from Auto-Reclosing onto a permanent fault, one can arrange to combine Auto-Reclosing with a synchronism check on line terminals close to such power stations and attempt energizing from the side furthest away from the power station and perform the synchronism check at the local end if the energizing was successful.

Transmission protection systems are usually sub-divided and provided with two redundant protection IEDs. In such systems it is common to provide auto-reclosing in only one of the sub-systems as the requirement is for fault clearance and a failure to reclose because of the auto-recloser being out of service is not considered a major disturbance. If two auto-reclosers are provided on the same breaker, the application must be carefully checked and normally one must be the master and be connected to inhibit the other auto-recloser if it has started. This inhibit can, for example, be done from STBRREC (79) In progress.

When Single and/or three phase auto-reclosing is used there are a number of cases where the tripping shall be three phase anyway. Some examples are:

When Single and/or three phase auto-reclosing is used there are a number of cases where the tripping shall be three phase anyway. Some examples are:

- Evolving fault where the fault during the dead-time spreads to another phase. The other two phases must then be tripped and a three phase dead-time and autoreclose initiated
- Permanent fault
- Fault during three phase dead-time
- Auto-reclose out of service or CB not ready for an auto-reclosing cycle

Prepare three phase tripping is then used to switch the tripping to three phase. This signal is generated by the auto-recloser and connected to the trip function block and also connected outside the IED through IO when a common auto-recloser is provided for two sub-systems. An alternative signal *Prepare 1 Phase tripping* is also provided and can be used as an alternative when the autorecloser is shared with another subsystem. This provides a fail safe connection so that even a failure in the IED with the auto-recloser will mean that the other sub-system will start a three-phase trip.

A permanent fault will cause the line protection to trip again when it recloses in an attempt to clear the fault.

The auto-reclosing function allows a number of parameters to be adjusted.

Examples:

- number of auto-reclosing shots
- auto-reclosing program
- auto-reclosing open times (dead time) for each shot.

11.3.2.1 Auto-reclosing operation Disabled and Enabled

Operation of the automatic reclosing can be set OFF and ON by a setting parameter and by external control. Parameter *Operation* = *Disabled*, or *Enabled* sets the function OFF and ON. In setting *Operation=ExternalCtrl*= *Disabled* and *Enabled* control is made by input signal pulses, for example, from the control system or from the binary input (and other systems).

When the function is set *Enabled* and operative (other conditions such as CB closed and CB Ready are also fulfilled), the output SETON is activated (high) when the function is ready to accept a reclosing start.

11.3.2.2 Initiate auto-reclosing and conditions for initiation of a reclosing cycle

The usual way to start a reclosing cycle, or sequence, is to start it at tripping by line protection by applying a signal to the input PICKUP. Starting signals can be either, General Trip signals or, only the conditions for Differential, Distance protection Zone 1 and Distance protection Aided trip. In some cases also Directional Ground fault function Aided trip can be connected to start an Auto-Reclose attempt.

A number of conditions need to be fulfilled for the start to be accepted and a new auto-reclosing cycle to be started. They are linked to dedicated inputs. The inputs are:

- CBREADY, CB ready for a reclosing cycle, for example, charged operating gear
- 52a to ensure that the CB was closed when the line fault occurred and start was applied.
- No signal at input INHIBIT that is, no blocking or inhibit signal present. After the start has been accepted, it is latched in and an internal signal *Started* is set. It can be interrupted by certain events, like an *Inhibit* signal.

11.3.2.3 Initiate auto-reclosing from CB open information

If a user wants to initiate auto-reclosing from the "CB open" position instead of from protection trip signals, the function offers such a possibility. This starting mode is selected with the setting parameter *StartByCBOpen*=*Enabled*. It is then necessary to block reclosing for all manual trip operations. Typically *CBAuxContType=NormClosed* is also set and a CB auxiliary contact of type NC (normally closed, 52b) is connected to inputs 52a and PICKUP. When the signal changes from “CB closed” to “CB open” an auto-reclosing start pulse is generated and latched in the function, subject to the usual checks. Then the reclosing sequence continues as usual. One needs to connect signals from manual tripping and other functions, which shall prevent reclosing, to the input INHIBIT.

11.3.2.4 Blocking of the autorecloser

Auto-Reclose attempts are expected to take place only in the event of transient faults on the own line. The Auto-Recloser must be blocked for the following conditions:

- Tripping from Delayed Distance protection zones
- Tripping from Back-up protection functions
- Tripping from Breaker failure function
- Intertrip received from remote end Breaker failure function
- Busbar protection tripping

Depending of the starting principle (General Trip or only Instantaneous trip) adopted above the delayed and back-up zones might not be required. Breaker failure local and remote must however always be connected.

11.3.2.5 Control of the auto-reclosing open time for shot 1

Up to four different time settings can be used for the first shot, and one extension time. There are separate settings for single- and three-phase auto-reclosing open time, *t1 1Ph*, *t1 3Ph*. If no particular input signal is applied, and an autoreclosing program with single-phase reclosing is selected, the auto-reclosing open time *t1 1Ph* will be used. If input signal TR3P is activated in connection with start, the auto-reclosing open time for three-phase reclosing is used.

An auto-reclosing open time extension delay, *tExtended t1*, can be added to the normal shot 1 delay. It is intended to come into use if the communication channel for permissive line protection is lost. In such a case there can be a significant time difference in fault clearance at the two ends of the line. A longer “auto-reclosing open time” can then be useful. This extension time is controlled by setting parameter *Extended t1* = *Disabled* and the input PLCLOST.

11.3.2.6 Long trip signal

In normal circumstances the trip command resets quickly due to fault clearing. The user can set a maximum trip pulse duration *tTrip*. When trip signals are longer, the auto-reclosing open time is extended by *tExtended t1*. If *Extended t1* = *Disabled*, a long trip signal interrupts the reclosing sequence in the same way as a signal to input INHIBIT.

11.3.2.7 Reclosing programs

The maximum number of reclosing shots in an auto-reclosing cycle is selected by the setting parameter *NoOfShots*. The type of reclosing used at the first reclosing shot is set by parameter *FirstShot*. The first alternative is three-phase reclosing. The other alternatives include some single-phase or two-phase reclosing. Usually there is no two-phase tripping arranged, and then there will be no two-phase reclosing.

The decision is also made in the tripping function block (TR) where the setting *3Ph,1/3Ph* is selected.

11.3.2.8 FirstShot=3ph (normal setting for a single 3 phase shot)

3-phase reclosing, one to five shots according to setting *NoOfShots*. The output three-phase trip PREP3P is always set (high). A trip operation is made as a three-phase trip at all types of fault. The reclosing is as a three-phase Reclosing as in mode 1/3ph described below. All signals, blockings, inhibits, timers, requirements etc. are the same as for FirstShot=1/3ph .

11.3.2.9 3-phase reclosing, one to five shots according to setting NoOfShots

1-phase or 3-phase reclosing first shot, followed by 3-phase reclosing shots, if selected. Here, the auto-reclosing function is assumed to be "On" and "Ready". The breaker is closed and the operation gear ready (operating energy stored). Input START is received and sealed-in. The output READY is reset (set to false). Output ACTIVE is set.

- If TR3P is low (1-phase trip): The timer for 1-phase reclosing open time is started and the output 1PT1 (1-phase reclosing in progress) is activated. It can be used to suppress pole disagreement trip and ground-fault protection during the 1-phase open interval. •
- If TR3P is high (3-phase trip): The timer for 3-phase auto-reclosing open time, t1 3Ph or t1 3PhHS is started and output 3PT1 (3-phase auto-reclosing shot 1 in progress) is set.

While any of the auto-reclosing open time timers are running, the output INPROGR is activated. When the "open time" timer runs out, the respective internal signal is transmitted to the output module for further checks and to issue a closing command to the circuit breaker.

When a CB closing command is issued the output prepare 3-phase trip is set. When issuing a CB closing command a resettimer tReset is started. If no tripping takes place during that time the auto-reclosing function resets to the “Ready” state and the signal ACTIVE resets. If the first reclosing shot fails, a 3-phase trip will be initiated and 3-phase reclosing can follow, if selected.

11.3.2.10 FirstShot=1ph 1-phase reclosing in the first shot

The 1-phase reclosing attempt can be followed by 3-phase reclosing, if selected. If the first trip is a 3-phase trip the auto-reclosing will be blocked. In the event of a 1-phase trip, the operation is as in the example described above, program mode 1/3ph. If the first reclosing shot fails, a 3-phase trip will be initiated and 3-phase reclosing can follow, if selected. A maximum of four additional shots can be done (according to the *NoOfShots* parameter). During 3-phase trip (TR2P low and TR3P high) the auto-reclosing will be blocked and no reclosing takes place.

11.3.2.11 FirstShot=1ph + 1*3ph 1-phase or 3-phase reclosing in the first shot

At 1-phase trip, the operation is as described above. If the first reclosing shot fails, a 3-phase trip will be issued and 3-phase reclosing will follow, if selected. At 3-phase trip, the operation is similar to the above. But, if the first reclosing shot fails, a 3-phase trip command will be issued and the auto-reclosing will be blocked. No more shots take place! *1*3ph* should be understood as “Just one shot at 3-phase reclosing”.

11.3.2.12 FirstShot=1ph + 1*2/3ph 1-phase, 2-phase or 3-phase reclosing in the first shot

At 1-phase trip, the operation is as described above. If the first reclosing shot fails, a 3-phase trip will be issued and 3-phase reclosing will follow, if selected. At 3-phase trip, the operation is similar as above. But, if the first reclosing shot fails, a 3-phase trip will be issued and the auto-reclosing will be blocked. No more shots take place! “1*3ph”should be understood as “Just one shot at 3-phase reclosing”.

A start of a new reclosing cycle is blocked during the set “reclaim time” after the selected number of reclosing shots have been made.

11.3.2.13 Evolving fault

An evolving fault starts as a single-phase fault which leads to single-pole tripping and then the fault spreads to another pole. The second fault is then cleared by three-pole tripping.

The Auto-Reclosing function will first receive a trip and start signal (START) without any three-phase signal (TR3P). The Auto-Reclosing function will start a single-phase reclosing, if programmed to do so. At the evolving fault clearance there will be a new signal PICKUP and three-pole trip information, TR3P. The single-phase reclosing sequence will then be stopped, and instead the timer, *t1 3Ph*, for three-phase reclosing will be started from zero. The sequence will continue as a three-phase reclosing sequence, if it is a selected alternative reclosing mode.

The second fault which can be single phase is tripped three phase because trip module (TR) in the IED has an evolving fault timer which ensures that second fault is always tripped three phase. For other types of relays where the relays do not include this function the output PREP3PH is used to prepare the other sub-system for three pole tripping. This signal will, for evolving fault situations be activated a short time after the first trip has reset and will thus ensure that new trips will be three phase.

11.3.2.14 Reclosing reset timer

The reset timer *tReset* defines the time it takes from issue of the reclosing command, until the reclosing function resets. Should a new trip occur during this time, it is treated as a continuation of the first fault. The reclaim timer is started when the CB closing command is given.

11.3.2.15 Transient fault

After the Reclosing command the reset timer keeps running for the set time. If no tripping occurs within this time, *tReset*, the Auto-Reclosing will reset. The CB remains closed and the operating gear recharges. The input signals 52A and CBREADY will be set

11.3.2.16 Permanent fault and reclosing unsuccessful signal

If a new trip occurs, and a new input signal PICKUP or TRSOTF appears, after the CB closing command, the output UNSUCCL (unsuccessful closing) is set high. The timer for the first shot can no longer be started. Depending on the set number of Reclosing shots further shots may be made or the Reclosing sequence is ended. After reset timer time-out the Auto-Reclosing function resets, but the CB remains open. The “CB closed” information through the input 52A is missing. Thus, the reclosing function is not ready for a new reclosing cycle.

Normally, the signal UNSUCCL appears when a new trip and start is received after the last reclosing shot has been made and the auto-reclosing function is blocked. The signal resets after reclaim reset time. The “unsuccessful” signal can also be made to depend on CB position input. The parameter *UnsucClByCBChk* should then be set to *CB Check*, and a timer *tUnsucCl* should be set too. If the CB does not respond to the closing command and does not close, but remains open, the output UNSUCCL is set high after time *tUnsucCl*. The Unsuccessful output can for example, be used in Multi-Breaker arrangement to cancel the auto-reclosing function for the second breaker, if the first breaker closed onto a persistent fault. It can also be used to generate a Lock-out of manual closing until the operator has reset the Lock-out, see separate section.

11.3.2.17 Lock-out initiation

In many cases there is a requirement that a Lock-out is generated when the Auto- Reclosing attempt fails. This is done with logic connected to the in- and outputs of the Auto-Reclose function and connected to Binary IO as required. Many alternative ways of performing the logic exist depending on whether manual closing is interlocked in the IED, whether an external physical Lock-out relay exists and whether the reset is hardwired, or carried out by means of communication.

There are also different alternatives regarding what shall generate Lock-out. Examples of questions are:

- Shall back-up time delayed trip give Lock-out (normally yes)
- Shall Lock-out be generated when closing onto a fault (mostly)
- Shall Lock-out generated when the Auto-Recloser was OFF at the fault
- Shall Lock-out be generated if the Breaker did not have sufficient operating power for an Auto-Reclosing sequence (normally not as no closing attempt has been given)

In figure 152 and figure 153 the logic shows how a closing Lock-out logic can be designed with the Lock-out relay as an external relay alternatively with the Lock-out created internally with the Manual closing going through the Synchro-check function. Lock-out arranged with an external Lock-out relay.

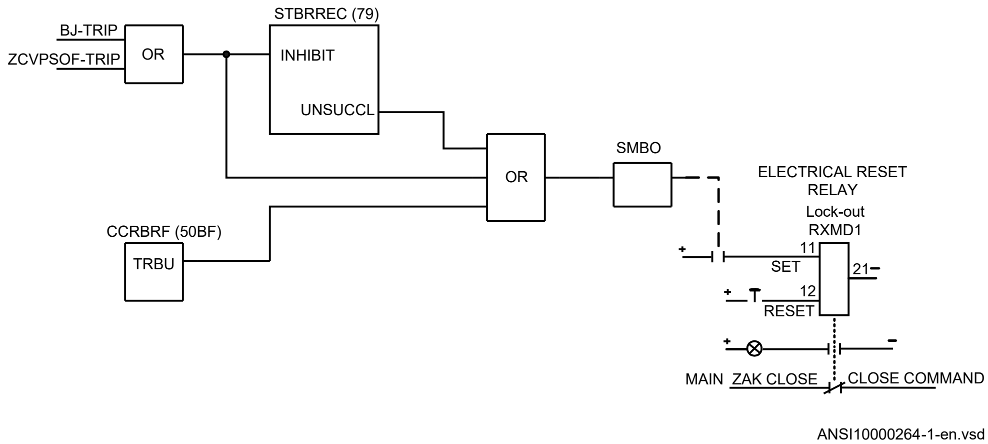


Figure 152: Lock-out arranged with an external Lock-out relay

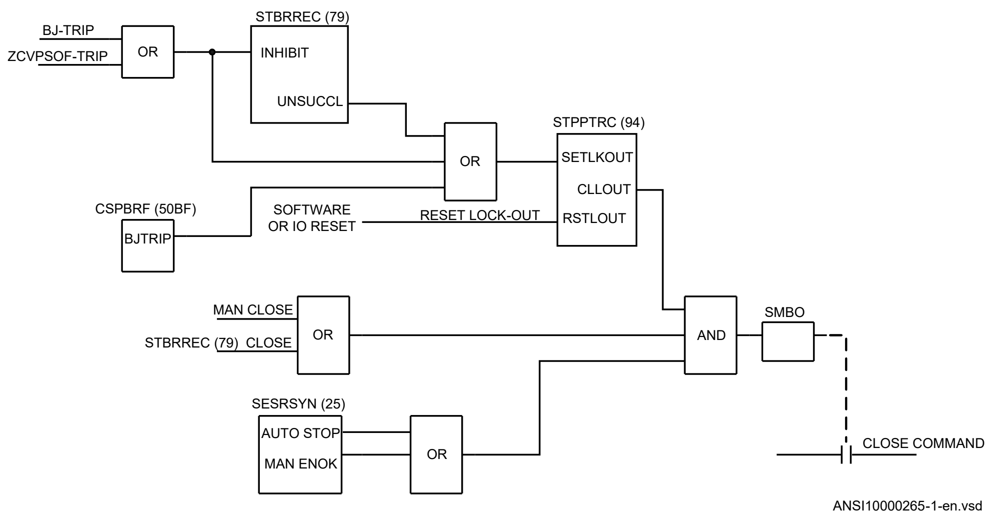


Figure 153: Lock-out arranged with internal logic with manual closing going through in IED

11.3.2.18 Automatic continuation of the reclosing sequence

The auto-reclosing function can be programmed to proceed to the following reclosing shots (if selected) even if the start signals are not received from the protection functions, but the breaker is still not closed. This is done by setting parameter *AutoCont* = *Enabled* and *tAutoContWait* to the required delay for the function to proceed without a new start.

11.3.2.19 Thermal overload protection holding the auto-reclosing function back

If the input THOLHOLD (thermal overload protection holding reclosing back) is activated, it will keep the reclosing function on a hold until it is reset. There may thus be a considerable delay between start of Auto-Reclosing and reclosing command to the circuit-breaker. An external logic limiting the time and sending an inhibit to the INHIBIT input can be used. The input can also be used to set the Auto- Reclosing on hold for a longer or shorter period.

11.3.3 Setting guidelines

11.3.3.1 Configuration

Use the PCM600 configuration tool to configure signals.

Autorecloser function parameters are set via the local HMI or Parameter Setting Tool (PST). Parameter Setting Tool is a part of PCM600.

11.3.3.2 Recommendations for input signals

Please see examples in figure 154. The figure is also valid for output signals.

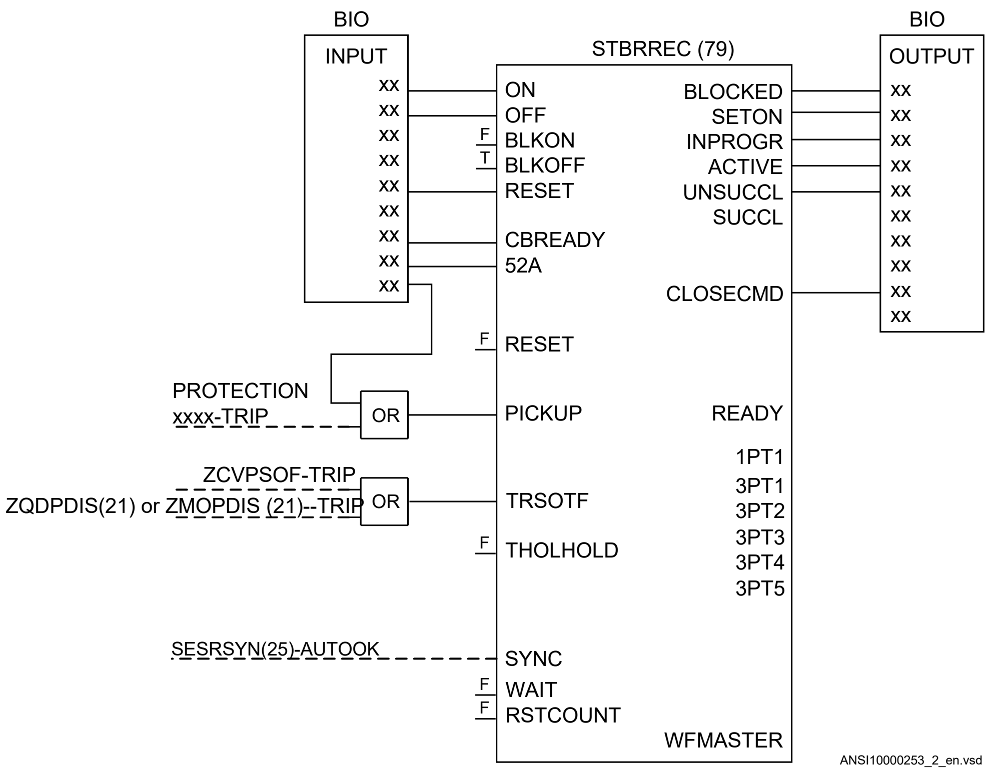


Figure 154: Connection diagram Example of I/O-signal connections at a three-phase reclosing function

ON and OFF

These inputs can be connected to binary inputs or to a communication interface block for external control.

PICKUP

It should be connected to the trip output protection function, which starts the auto-reclosing function. It can also be connected to a binary input for start from an external contact. A logical OR-gate can be used to combine the number of start sources.

If *StartByCBOpen* is used, the CB Open condition shall also be connected to the input PICKUP.

INHIBIT

Signals that interpret a reclosing cycle or prevent start from being accepted are connected to this input. Such signals can come from protection for a line connected shunt reactor, from transfer trip receive, from back-up protection functions, busbar protection trip or from breaker failure protection. When the CB open position is set to start the Auto-Recloser, then manual opening must also be connected here. The inhibit is often a combination of signals from external IEDs via the IO and internal functions. An OR gate is then used for the combination.

52A and CBREADY

These should be connected to binary inputs to pick-up information from the CB. The CBREADY input is interpreted as CB Closed, if parameter *CBAuxContType* is set *NormOpen*, which is the default setting. At three operating gears in the breaker (single pole operated breakers) the connection should be “All poles closed” (series connection of the NO contacts) or “At least one pole open” (parallel connection of NC contacts) if the *CBAuxContType* is set to *NormClosed*. The “CB Ready” is a signal meaning that the CB is ready for a reclosing operation, either Close-Open (CO), or Open-Close-Open (OCO). If the available signal is of type “CB not charged” or “not ready”, an inverter can be inserted in front of the CBREADY input.

SYNC

This is connected to the internal synchronism check function when required. It can also be connected to a binary input for synchronization from an external device. If neither internal nor external synchronism or energizing check is required, it can be connected to a permanently high source, TRUE. The signal is required for three phase shots 1-5 to proceed .

TRSOTF

This is the signal “Trip by Switch Onto Fault”. It is usually connected to the “switch onto fault” output of line protection if multi-shot Auto-Reclose attempts are used. The input will start the shots 2-5. For single shot applications the input is set to FALSE.

THOLHOLD

Signal “Thermal overload protection holding back Auto-Reclosing”. It is normally set to FALSE. It can be connected to a thermal overload protection trip signal which resets only when the thermal content has gone down to an acceptable level, for example, 70%. As long as the signal is high, indicating that the line is hot, the Auto-Reclosing is held back. When the signal resets, a reclosing cycle will continue. Please observe that this have a considerable delay. Input can also be used for other purposes if for some reason the Auto-Reclose shot is halted.

WAIT

Used to hold back reclosing of the “low priority unit” during sequential reclosing. See “Recommendation for multi-breaker arrangement” below. The signal is activated from output WFMASTER on the second breaker Auto-Recloser in multi-breaker arrangements.

BLKON

Used to block the Auto-Reclosing function for example, when certain special service conditions arise. Input is normally set to FALSE. When used, blocking must be reset with BLOCKOFF.

BLOCKOFF

Used to Unblock the Auto-Reclosing function when it has gone to Block due to activating input BLKON or by an unsuccessful Auto-Reclose attempt if the setting *BlockByUnsucCl* is set to *Enabled*. Input is normally set to FALSE.

RESET

Used to Reset the Auto-Recloser to start condition. Possible Thermal overload Hold and so on will be reset. Positions, setting *Enabled*-*Disabled* and so on will be started and checked with set times. Input is normally set to FALSE.

Recommendations for output signals

SETON

Indicates that the auto-reclose function is switched ON and operative.

BLOCKED

Indicates that the auto-reclose function is temporarily or permanently blocked.

ACTIVE

Indicates that STBRREC (79) is active, from start until end of reset time.

INPROGR

Indicates that a sequence is in progress, from start until reclosing command.

UNSUCCL

Indicates unsuccessful reclosing.

CLOSEDCMD

Connect to a binary output for circuit-breaker closing command.

READY

Indicates that the Auto-reclosing function is ready for a new and complete reclosing sequence. It can be connected to the zone extension of a line protection should extended zone reach before automatic reclosing be necessary.

1PT1

Indicates that 1-phase automatic reclosing is in progress. It is used to temporarily block an ground-fault and/or pole disagreement function during the 1-phase open interval

3PT1, 3PT2, 3PT3, 3PT4 and 3PT5

Indicates that three-pole automatic reclosing shots 1-5 are in progress. The signals can be used as an indication of progress or for own logic.

PREP3P

Prepare three-pole trip is usually connected to the trip block to force a coming trip to be a three-pole one. If the function cannot make a single- or two-pole reclosing, the tripping should be three-pole.

WFMASTER

Wait from master is used in high priority units to hold back reclosing of the low priority unit during sequential reclosing.

Other outputs

The other outputs can be connected for indication, disturbance recording and so on as required.

11.3.3.3 STBRREC- Auto-recloser parameter settings

Auto-recloser parameter settings

Operation

The operation of the Autorecloser (STBRREC, 79) function can be switched *Enabled* and *Disabled*. The setting makes it possible to switch it *Enabled* or *Disabled* using an external switch via IO or communication ports.

NoOfShots, Number of reclosing shots

In power transmission 1 shot is mostly used. In most cases one reclosing shot is sufficient as the majority of arcing faults will cease after the first reclosing shot. In power systems with many other types of faults caused by other phenomena, for example wind, a greater number of reclose attempts (shots) can be motivated.

First shot and reclosing program

There are six different possibilities in the selection of reclosing programs. What type of reclosing to use for the different kinds of faults depends on the power system configuration and on the users practices and preferences. When the circuit-breakers only have three-pole operation, then three-pole reclosing has to be chosen. This is usually the case in subtransmission and distribution lines. Three-phase tripping and reclosing for all types of faults is also widely accepted in completely meshed power systems. In transmission systems with few parallel circuits, single-phase reclosing for single-phase faults is an attractive alternative for maintaining service and system stability.

Auto-reclosing open times, dead times

Three-phase shot 1 delay: For three-phase High-Speed Auto-Reclosing (HSAR) a typical open time is 400 ms. Different local phenomena, such as moisture, salt, pollution etc. can influence the required dead time. Some users apply Delayed Auto- Reclosing (DAR) with delays of 10 s or more. The delay of reclosing shot 2 and possible later shots are usually set at 30 s or more. A check that the CB duty cycle can manage the selected setting must be done. The setting can in some cases be restricted by national regulations. For multiple shots the setting of shots 2-5 must be longer than the circuit breaker duty cycle time.

Extended t1 and *tExtended t1*

Extended auto-reclosing open time for shot 1.

The communication link in a permissive (not strict) line protection scheme, for instance a power line carrier (PLC) link, may not always be available. If lost, it can result in delayed tripping at one end of a line. There is a possibility to extend the autoreclosing open time in such a case by use of an input to PLCLOST, and the setting parameters. Typical setting in such a case: *Extended t1* = *Enabled* and *tExtended t1* = *0.5 s*.

tTrip, Long trip pulse

Usually the trip command and initiate auto-reclosing signal reset quickly as the fault is cleared. A prolonged trip command may depend on a CB failing to clear the fault. A trip signal present when the CB is reclosed will result in a new trip. Depending on the setting *Extended t1* = *Disabled* or *Enabled* a trip/ initiate pulse longer than the set time *tTrip* will either block the reclosing or extend the auto-reclosing open time. At a setting somewhat longer than the auto-reclosing open time, this facility will not influence the reclosing. A typical setting of *tTrip* could be close to the autoreclosing open time.

tInhibit, Inhibit resetting delay

A typical setting is *tInhibit = 5.0 s* to ensure reliable interruption and temporary blocking of the function. Function will be blocked during this time after the *tInhibit* has been activated.

timetReset, Reset time

The Reset time sets the time for resetting the function to its original state, after which a line fault and tripping will be treated as an independent new case with a new reclosing cycle. One may consider a nominal CB duty cycle of for instance, O-0.3 s CO- 3 min. – CO. However the 3 minute (180 s) recovery time is usually not critical as fault levels are mostly lower than rated value and the risk of a new fault within a short time is negligible. A typical time may be *tReset* = 60 or 180 s dependent of the fault level and breaker duty cycle.

StartByCBOpen

The normal setting is *Disabled*. It is used when the function is started by protection trip signals *Follow CB* = *Disabled*. *Follow CB* = *Enabled*.

Follow CB

The usual setting is *Follow CB* = *Disabled*. The setting *Enabled* can be used for delayed reclosing with long delay, to cover the case when a CB is being manually closed during the “auto-reclosing open time” before the auto-reclosing function has issued its CB closing command.

tCBClosedMin

A typical setting is 5.0 s. If the CB has not been closed for at least this minimum time, a reclosing start will not be accepted.

CBAuxContType, CB auxiliary contact type

It shall be set to correspond to the CB auxiliary contact used. A *NormOpen* contact is recommended in order to generate a positive signal when the CB is in the closed position.

CBReadyType, Type of CB ready signal connected

The selection depends on the type of performance available from the CB operating gear. At setting *OCO* (CB ready for an Open – Close – Open cycle), the condition is checked only at the start of the reclosing cycle. The signal will disappear after tripping, but the CB will still be able to perform the C-O sequence. For the selection *CO* (CB ready for a Close – Open cycle) the condition is also checked after the set auto-reclosing dead time. This selection has a value first of all at multi-shot reclosing to ensure that the CB is ready for a C-O sequence at shot 2 and further shots. During single-shot reclosing, the *OCO* selection can be used. A breaker shall according to its duty cycle always have storing energy for a CO operation after the first trip. (IEC 56 duty cycle is O-0.3 secCO-3minCO).

tPulse, Breaker closing command pulse duration

The pulse should be long enough to ensure reliable operation of the CB. A typical setting may be *tPulse*=200 ms. A longer pulse setting may facilitate dynamic indication at testing, for example in “Debug” mode of PCM600 Application Configuration Tool (ACT).

BlockByUnsucCl

Setting of whether an Unsuccessful Auto-Reclose attempt shall set the Auto- Reclose in Block. If used the inputs BLKOFF must be configured to unblock the function after an unsuccessful Reclosing attempt. Normal setting is *Disabled*.

UnsucClByCBChk, Unsuccessful closing by CB check

The normal setting is *NoCBCheck*. The “auto-reclosing unsuccessful” event is then decided by a new trip within the reclaim reclaimreset time after the last reclosing shot. If one wants to get the UNSUCCL (Unsuccessful closing) signal in the case the CB does not respond to the closing command, CLOSECMD, one can set *UnsucClByCBChk* = *CB check* and set *tUnsucCl* for instance to *1.0* s.

Priority and time *tWaitForMaster*

In single CB applications, one sets *Priority = None*. At sequential reclosing the function of the first CB, for example near the busbar, is set *Priority = High* and for the second CB *Priority = Low*. The maximum waiting time, *tWaitForMaster* of the second CB is set longer than the “auto-reclosing open time” and a margin for synchronism check at the first CB. Typical setting is *tWaitForMaster* =*2s*.

AutoCont and *tAutoContWait*, Automatic continuation to the next shot if the CB is not closed within the set time

The normal setting is *AutoCont* = *Disabled*. The *tAutoContWait* is the length of time STBRREC (79) waits to see if the breaker is closed when *AutoCont* is set to *Enabled*. Normally the setting can be *tAutoContWait*=*2 s*.

11.4 Apparatus control

11.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Bay control	QCBAY	-	-
Local remote	LOCREM	-	-
Local remote control	LOCREMCTRL	-	-

11.4.2 Application

The apparatus control is a function for control and supervising of circuit breakers, disconnectors, and grounding switches within a bay. Permission to operate is given after evaluation of conditions from other functions such as interlocking, synchronism check, operator place selection and external or internal blockings.

The complete apparatus control function is not included in this product, and the information below is included for understanding of the principle for the use of QCBAY, LOCREM, and LOCREMCTRL for the selection of the operator place.

Figure 155 gives an overview from what places the apparatus control function receive commands. Commands to an apparatus can be initiated from the Control Centre (CC), the station HMI or the local HMI on the IED front.

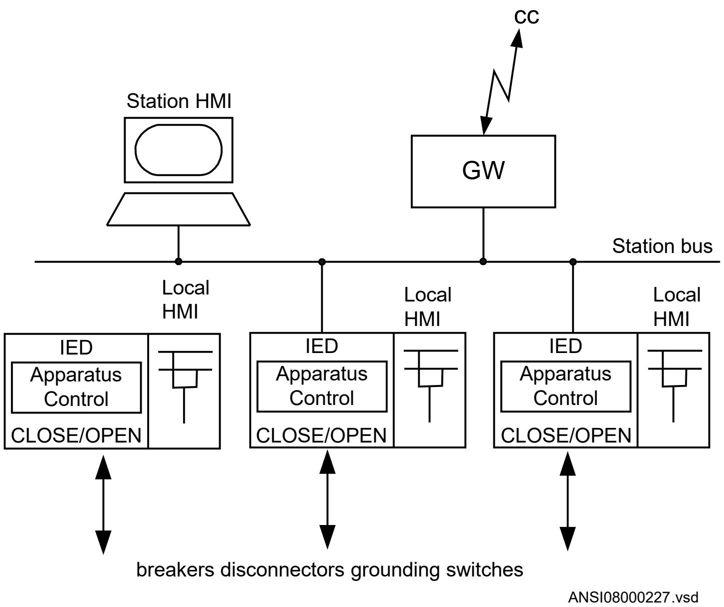


Figure 155: Overview of the apparatus control functions

Features in the apparatus control function:

- Operation of primary apparatuses
- Select-Execute principle to give high security
- Selection function to prevent simultaneous operation
- Selection and supervision of operator place
- Command supervision
- Block/deblock of operation
- Block/deblock of updating of position indications
- Substitution of position indications
- Overriding of interlocking functions
- Overriding of synchronism check
- Operation counter
- Suppression of Mid position

The apparatus control function is realized by means of a number of function blocks designated:

- Switch controller SCSWI
- Circuit breaker SXCBR
- Circuit switch SXSWI
- Position evaluation POS_EVAL
- Select release SELGGIO

- Bay control QCBAY
- Local remote LOCREM
- Local remote control LOCREMCTRL

SCSWI, SXCBR, QCBAY, SXSWI and SELGGIO are logical nodes according to IEC 61850. The signal flow between these function blocks appears in figure 156. The function Logical node Interlocking (SCILO) in the figure 156 is the logical node for interlocking.

Control operation can be performed from the local HMI. If the administrator has defined users with the UM tool, then the local/remote switch is under authority control. If not, the default (factory) user is the SuperUser that can perform control operations from the local HMI without LogOn. The default position of the local/remote switch is on remote.

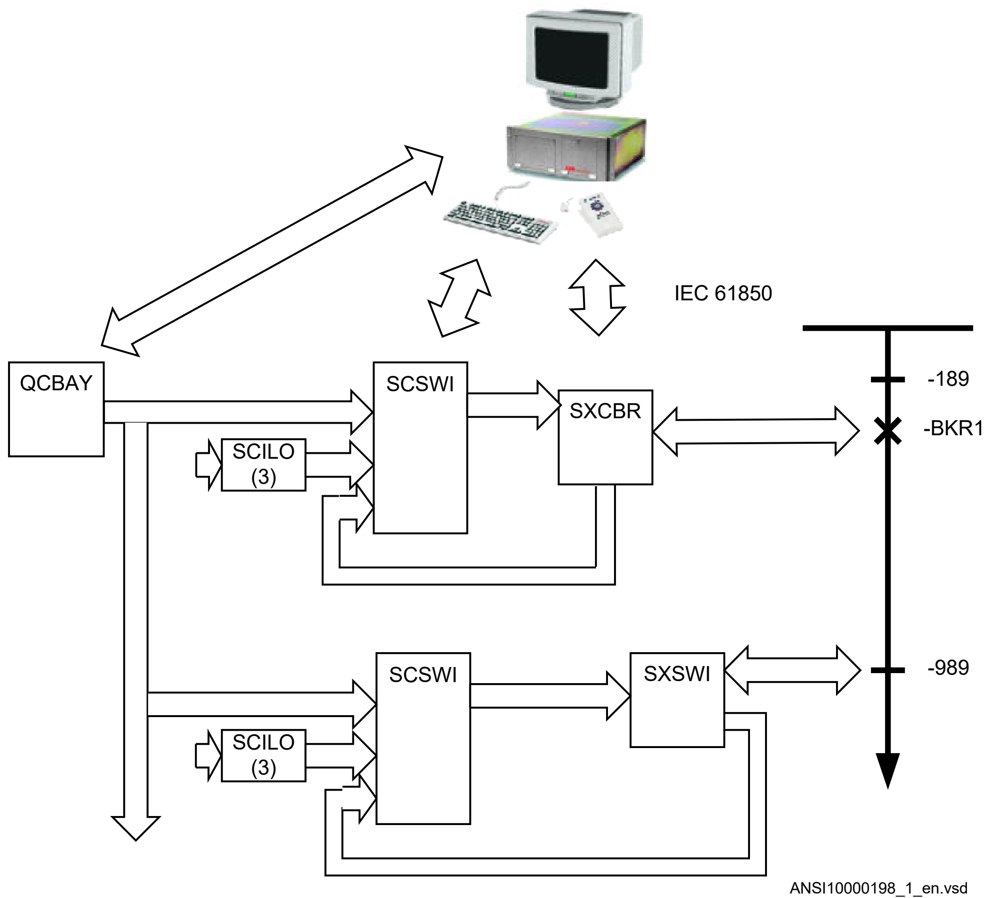


Figure 156: Signal flow between apparatus control function blocks

Bay control (QCBAY)

The Bay control (QCBAY) is used to handle the selection of the operator place for the bay. The function gives permission to operate from two types of locations either from Remote (for example, control centre or station HMI) or from Local (local HMI on the IED) or from all (Local and Remote). The Local/Remote switch position can also be set to Off, which means no operator place selected that is, operation is not possible neither from local nor from remote.

QCBAY also provides blocking functions that can be distributed to different apparatuses within the bay. There are two different blocking alternatives:

- Blocking of update of positions
- Blocking of commands

The function does not have a corresponding functionality defined in the IEC 61850 standard, which means that this function is included as a vendor specific logical node.

11.4.3 Interaction between modules

A typical bay with apparatus control function consists of a combination of logical nodes or functions that are described here:

- The Switch controller (SCSWI) initializes all operations for one apparatus and performs the actual switching and is more or less the interface to the drive of one apparatus. It includes the position handling as well as the control of the position.
- The Circuit breaker (SXCBR) is the process interface to the circuit breaker for the apparatus control function.
- The Circuit switch (SXSWI) is the process interface to the disconnector or the grounding switch for the apparatus control function.
- The Bay control (QCBAY) fulfils the bay-level functions for the apparatuses, such as operator place selection and blockings for the complete bay.
- The function (SELGGIO), deals with reservation of the bay.
- The Four step overcurrent protection (OC4PTOC, 51/67) trips the breaker.
- The Protection trip logic (SMPPTRC, 94) connects the "trip" outputs of one or more protection functions to a common "trip" to be transmitted to SXCBR.
- The Autorecloser (SMBRREC, 79) consists of the facilities to automatically close a tripped breaker with respect to a number of configurable conditions.
- The logical node Interlocking (SCILO, 3) provides the information to SCSWI whether it is permitted to operate due to the switchyard topology. The interlocking conditions are evaluated with separate logic and connected to SCILO (3).
- The Synchronism, energizing check, and synchronizing (SESRSYN, 25) calculates and compares the voltage phasor difference from both sides of an open breaker with predefined switching conditions (synchronism check). Also the case that one side is dead (energizing-check) is included.
- The logical node Generic Automatic Process Control, GAPC, is an automatic function that reduces the interaction between the operator and the system. With one command, the operator can start a sequence that will end with a connection of a process object (for example a line) to one of the possible busbars.

The overview of the interaction between these functions is shown in figure 157 below.

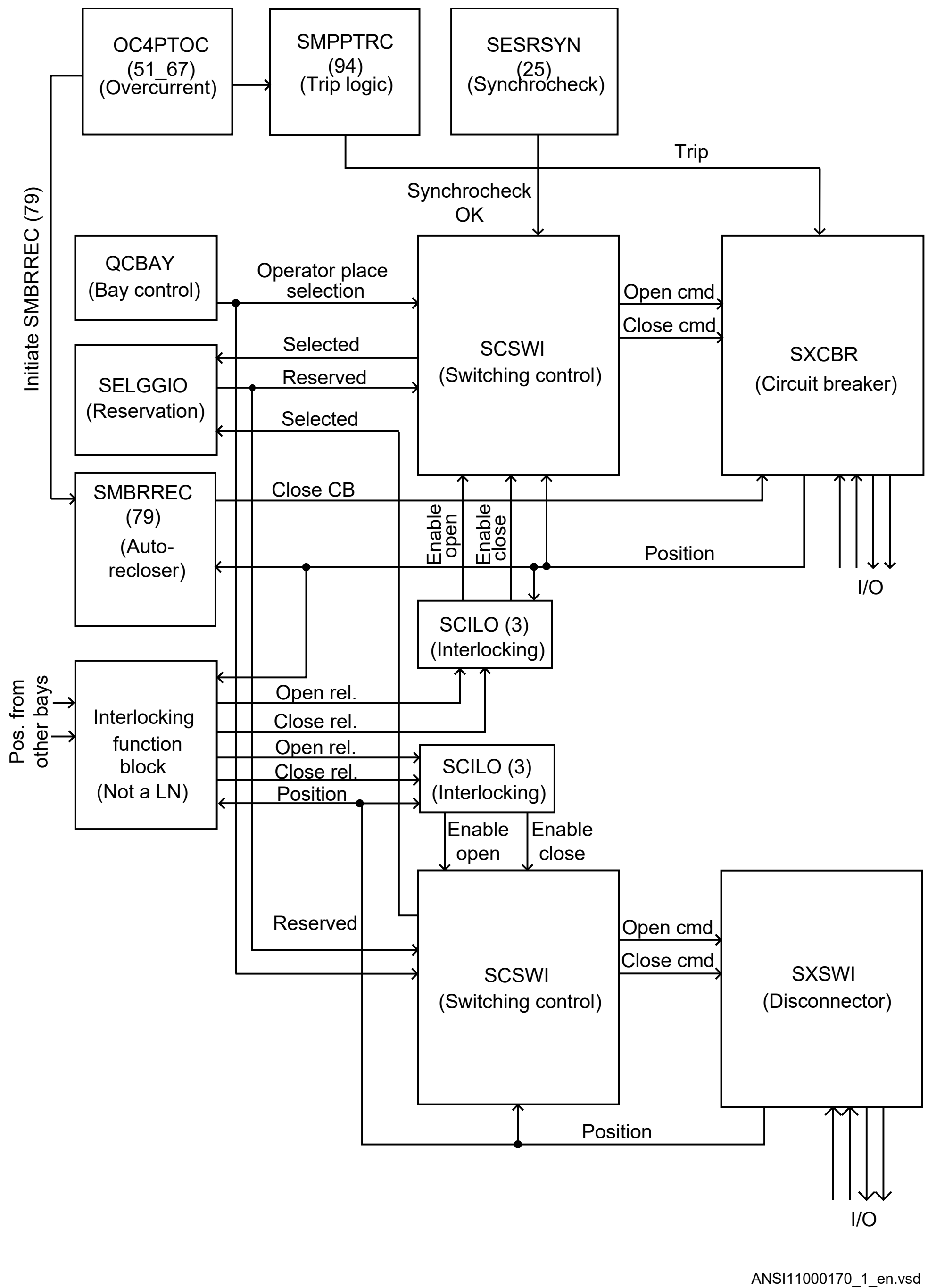


Figure 157: Example overview of the interactions between functions in a typical bay

11.4.4 Setting guidelines

The setting parameters for the apparatus control function are set via the local HMI or PCM600.

11.4.4.1 Bay control (QCBAY)

If the parameter *AllPSTOValid* is set to *No priority*, all originators from local and remote are accepted without any priority.

11.5 Logic rotating switch for function selection and LHMI presentation SLGGIO

11.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Logic rotating switch for function selection and LHMI presentation	SLGGIO	-	-

11.5.2 Application

The logic rotating switch for function selection and LHMI presentation function (SLGGIO) (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 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.

SLGGIO function block has two operating inputs (UP and DOWN), one blocking input (BLOCK) and one operator position input (PSTO).

SLGGIO 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, there are two modes of operating the switch: from the menu and from the Single-line diagram (SLD).

11.5.3 Setting guidelines

The following settings are available for the Logic rotating switch for function selection and LHMI presentation (SLGGIO) function:

Operation: Sets the operation of the function *Enabled* or *Disabled*.

NrPos: Sets the number of positions in the switch (max. 32). This setting influence the behavior of the switch when changes from the last to the first position.

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.

11.6 Selector mini switch VSGGIO

11.6.1 Identification

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

11.6.2 Application

Selector mini switch (VSGGIO) function is a multipurpose function used in the configuration tool in PCM600 for a variety of applications, as a general purpose switch. VSGGIO 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.

An example where VSGGIO is configured to switch Autorecloser enabled–disabled from a button symbol on the local HMI is shown in Figure 158. The Close and Open buttons on the local HMI are normally used for enable–disable operations of the circuit breaker.

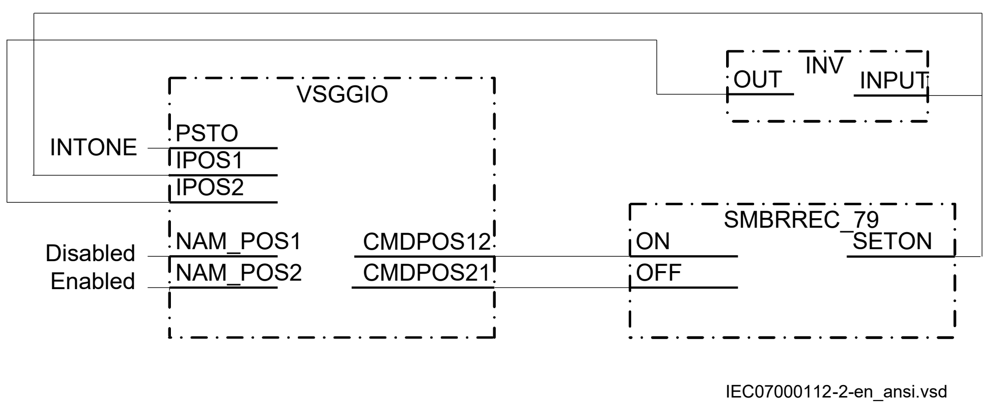


Figure 158: Control of Autorecloser from local HMI through Selector mini switch

11.6.3 Setting guidelines

Selector mini switch (VSGGIO) 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*.

11.7 IEC61850 generic communication I/O functions DPGGIO

11.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IEC 61850 generic communication I/O functions	DPGGIO	-	-

11.7.2 Application

The IEC61850 generic communication I/O functions (DPGGIO) function block is used to send three logical outputs to other systems or equipment in the substation. The three inputs are named OPEN, CLOSE and VALID, since this function block is intended to be used as a position indicator block in interlocking and reservation station-wide logics.

11.7.3 Setting guidelines

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

11.8 Single point generic control 8 signals SPC8GGIO

11.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Single point generic control 8 signals	SPC8GGIO	-	-

11.8.2 Application

The Single point generic control 8 signals (SPC8GGIO) function block is a collection of 8 single point commands, designed to bring in commands from REMOTE (SCADA) to those parts of the logic configuration that do not need complicated function blocks that have the capability to receive commands (for example SCSWI). 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 SPGGIO 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 SPC8GGIO function block is REMOTE.

11.8.3 Setting guidelines

The parameters for the single point generic control 8 signals (SPC8GGIO) 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):

Latchedx: decides if the command signal for output *x* is *Latched* (steady) or *Pulsed*.

tPulsex: if *Latchedx* is set to *Pulsed*, then *tPulsex* will set the length of the pulse (in seconds).

11.9 Automation bits AUTOBITS

11.9.1 Identification

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

11.9.2 Application

The AUTOBITS function block (or the automation bits function block) is used within PCM600 in order to get into the configuration the commands coming through the DNP3 protocol.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.

See the communication protocol manual for a detailed description of the DNP3 protocol

11.9.3 Setting guidelines

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

Section 12 Scheme communication

12.1 Scheme communication logic for distance or overcurrent protection ZCPSCH (85)

12.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Scheme communication logic for distance or overcurrent protection	ZCPSCH	-	85

12.1.2 Application

To achieve fast fault clearing for a fault on the part of the line not covered by the instantaneous zone 1, the stepped distance protection function can be supported with logic, that uses communication channels.

One communication channel in each direction, which can transmit an on/off signal is required. The performance and security of this function is directly related to the transmission channel speed, and security against false or lost signals. For this reason special channels are used for this purpose. When power line carrier is used for communication, these special channels are strongly recommended due to the communication disturbance caused by the primary fault.

Communication speed, or minimum time delay, is always of utmost importance because the purpose for using communication is to improve the tripping speed of the scheme.

To avoid false signals that could cause false tripping, it is necessary to pay attention to the security of the communication channel. At the same time it is important pay attention to the communication channel dependability to ensure that proper signals are communicated during power system faults, the time during which the protection schemes must perform their tasks flawlessly.

The logic supports the following communications schemes; blocking scheme, permissive schemes (overreaching and underreaching), unblocking scheme and direct intertrip.

A permissive scheme is inherently faster and has better security against false tripping than a blocking scheme. On the other hand, permissive scheme depends on a received CR signal for a fast trip, so its dependability is lower than that of a blocking scheme.

12.1.2.1 Blocking schemes

In blocking scheme a reverse looking zone is used to send a block signal to remote end to block an overreaching zone.

Since the scheme is sending the blocking signal during conditions where the protected line is healthy, it is common to use the line itself as communication media (PLC). The scheme can be used on all line lengths.

The blocking scheme is very dependable because it will operate for faults anywhere on the protected line if the communication channel is out of service. Conversely, it is less secure than permissive schemes because it will trip for external faults within the reach of the tripping function if the communication channel is out of service.

Inadequate speed or dependability can cause spurious tripping for external faults. Inadequate security can cause delayed tripping for internal faults.

To secure that the send signal will arrive before the zone used in the communication scheme will trip, the trip is released first after the time delay *tCoord* has elapsed. The setting of *tCoord* must be set longer than the maximal transmission time of the channel. A security margin of at least 10 ms should be considered.

The timer *tSendMin* for prolonging the send signal is proposed to set to zero.

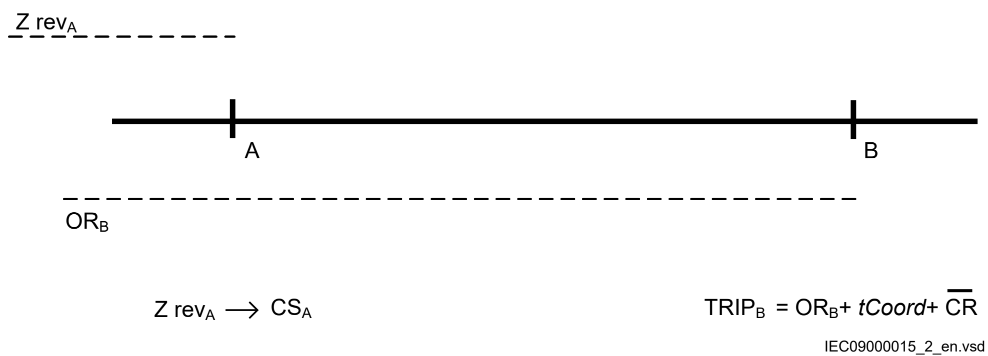


Figure 159: Principle of blocking scheme

OR:	Overreaching
CR:	Communication signal received
CS:	Communication signal send
Z rev_A:	Reverse zone

12.1.2.2 Permissive schemes

In permissive scheme permission to trip is sent from local end to remote end(s), that is protection at local end have detected a fault on the protected object. The received signal(s) is combined with an overreaching zone and gives an instantaneous trip if the received signal is present during the time the chosen zone is detected a fault in forward direction.

Either end may send a permissive (or command) signal to trip to the other end(s), and the teleprotection equipment need to be able to receive while transmitting.

A general requirement on permissive schemes is that it shall be fast and secure.

Depending on if the sending signal(s) is issued by underreaching or overreaching zone, it is divided into Permissive underreach or Permissive overreach scheme.

Permissive underreaching scheme

Permissive underreaching scheme is not suitable to use on short line length due to difficulties for distance protection measurement in general to distinguish between internal and external faults in those applications.

The underreaching zones at local and remote end(s) must overlap in reach to prevent a gap between the protection zones where faults would not be detected. If the underreaching zone do not meet required sensitivity due to for instance fault infeed from remote end blocking or permissive overreaching scheme should be considered.

The received signal (CR) must be received when the overreaching zone is still activated to achieve an instantaneous trip. In some cases, due to the fault current distribution, the overreaching zone can operate only after the fault has been cleared at the terminal nearest to the fault. There is a certain risk that in case of a trip from an independent tripping zone, the zone issuing the send signal (CS) resets before the overreaching zone has operated at the remote terminal. To assure a sufficient duration of the received signal (CR), the send signal (CS), can be prolonged by a *tSendMin* reset timer. The recommended setting of *tSendMin* is 100 ms.

Since the received communication signal is combined with the output from an overreaching zone, there is less concern about false signal causing an incorrect trip. Therefore set the timer *tCoord* to zero.

Failure of the communication channel does not affect the selectivity, but delays tripping at one end(s) for certain fault locations.

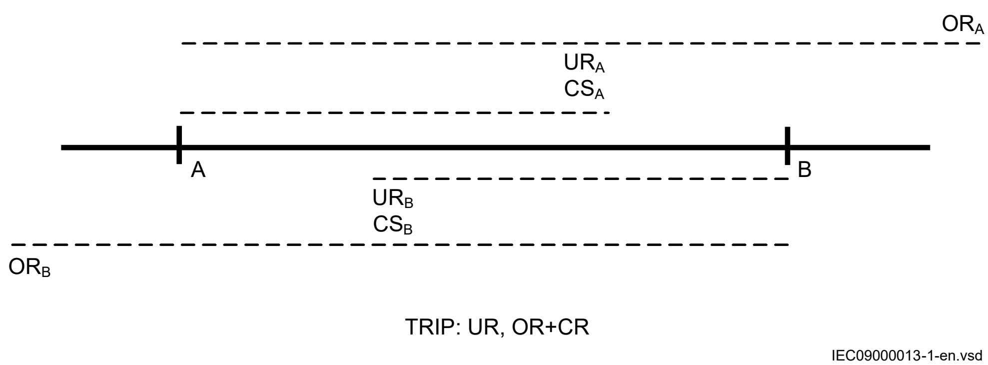


Figure 160: Principle of Permissive underreaching scheme

UR: Underreaching

OR: Overreaching

CR: Communication signal received

CS: Communication signal send

Permissive overreaching scheme

In permissive overreaching scheme there is an overreaching zone that issues the send signal. At remote end the received signal together with activating of an overreaching zone gives instantaneous trip of the protected object. The overreaching zone used in the teleprotection scheme must be activated at the same time as the received signal is present. The scheme can be used for all line lengths.

In permissive overreaching schemes, the communication channel plays an essential roll to obtain fast tripping at both ends. Failure of the communication channel may affect the selectivity and delay tripping at one end at least, for faults anywhere along the protected circuit.

Teleprotection operating in permissive overreaching scheme must beside the general requirement of fast and secure operation also consider requirement on dependability. Inadequate security can cause unwanted tripping for external faults. Inadequate speed or dependability can cause delayed tripping for internal faults or even unwanted operations.

At the permissive overreaching scheme, the send signal (CS) might be issued in parallel both from an overreaching zone and an underreaching, independent tripping zone. The CS signal from the overreaching zone must not be prolonged while the CS signal from zone 1 can be prolonged.

There is no need to delay the trip at receipt of the signal, so set the timer *tCoord* to zero.

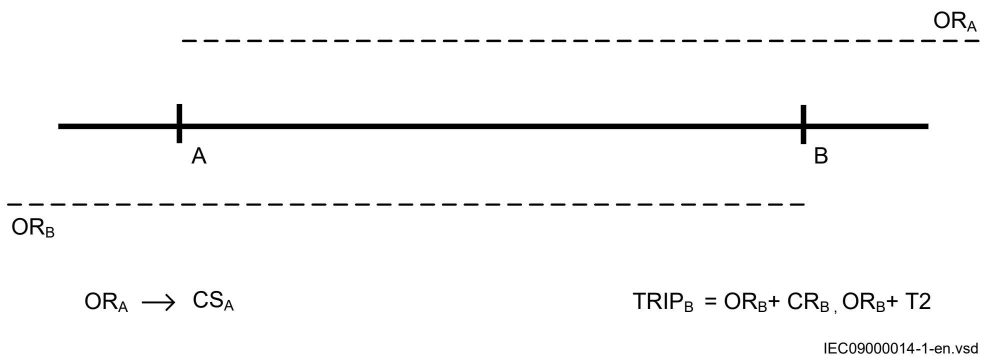


Figure 161: Principle of Permissive overreaching scheme

OR: Overreaching

CR: Communication signal received

CS: Communication signal send

T2: Timer step 2

Unblocking scheme

Metallic communication paths adversely affected by fault generated noise may not be suitable for conventional permissive schemes that rely on signal transmitted during a protected line fault. With power line carrier, for example, the communication signal may be attenuated by the fault, especially when the fault is close to the line end, thereby disabling the communication channel.

To overcome the lower dependability in permissive schemes, an unblocking function can be used. Use this function at older, less reliable, power-line carrier (PLC) communication, where the signal has to be sent through the primary fault. The unblocking function uses a guard signal CR_GUARD, which must always be present, even when no CR signal is received. The absence of the CR_GUARD signal during the security time is used as a CR signal. This also enables a permissive scheme to operate when the line fault blocks the signal transmission. Set the *tSecurity* to 35 ms.

12.1.2.3 Intertrip scheme

In some power system applications, there is a need to trip the remote end breaker immediately from local protections. This applies, for instance, when transformers or reactors are connected to the system without circuit-breakers or for remote tripping following operation of breaker failure protection.

In intertrip scheme, the send signal is initiated by an underreaching zone or from an external protection (transformer or reactor protection). At remote end, the received signals initiate a trip without any further protection criteria. To limit the risk for unwanted trip due to spurious sending of signals, the timer *tCoord* should be set to 10-30 ms dependant on type of communication channel.

12.1.3 Setting guidelines

The parameters for the scheme communication logic function are set via the local HMI or PCM600.

Configure the zones used for the CS send and for scheme communication tripping by using the ACT configuration tool.

The recommended settings of *tCoord* timer are based on maximal recommended transmission time for analogue channels according to IEC 60834-1. It is recommended to coordinate the proposed settings with actual performance for the teleprotection equipment to get optimized settings.

12.1.3.1 Blocking scheme

Set *Operation*	= *Enabled*
Set *SchemeType*	= *Blocking*
Set *tCoord*	25 ms (10 ms + maximal transmission time)
Set *tSendMin*	= 0 s
Set *Unblock*	= *Disable* (Set to *NoRestart* if Unblocking scheme with no alarm for loss of guard is to be used. Set to *Restart* if Unblocking scheme with alarm for loss of guard is to be used)
Set *tSecurity*	= 0.035 s

12.1.3.2 Permissive underreaching scheme

Set *Operation*	= *Enabled*
Set *SchemeType*	= *Permissive UR*
Set *tCoord*	= 0 ms
Set *tSendMin*	= 0.1 s
Set *Unblock*	= *Disable*
Set *tSecurity*	= 0.035 s

12.1.3.3 Permissive overreaching scheme

Set *Operation*	= *Enabled*
Set *Scheme type*	= *Permissive OR*
Set *tCoord*	= 0 ms
Set *tSendMin*	= 0.1 s (0 s in parallel line applications)
Set *Unblock*	= *Disable*
Set *tSecurity*	= 0.035 s

12.1.3.4 Unblocking scheme

Set *Unblock*	= *Restart* (Loss of guard signal will give both trip and alarm Choose *NoRestart* if only trip is required)
Set *tSecurity*	= 0.035 s

12.1.3.5 Intertrip scheme

Set *Operation*	= *Enabled*
Set *SchemeType*	= *Intertrip*
Set *tCoord*	50 ms (10 ms + maximal transmission time)
Set *tSendMin*	= 0.1 s (0 s in parallel line applications)
Set *Unblock*	= *Disable*
Set *tSecurity*	= 0.015 s

12.2 Current reversal and weak-end infeed logic for distance protection ZCRWPSCH (85)

12.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Current reversal and weak-end infeed logic for distance protection	ZCRWPSCH	-	85

12.2.2 Application

12.2.2.1 Current reversal logic

If parallel lines are connected to common buses at both terminals, overreaching permissive communication schemes can trip unselectable due to current reversal. The unwanted tripping affects the healthy line when a fault is cleared on the other line. This lack of security results in a total loss of inter-connection between the two buses.

To avoid this kind of disturbances, a fault current reversal logic (transient blocking logic) can be used.

The unwanted operations that might occur can be explained by looking into figure 162 and figure 163. Initially the protection A:2 at A side will detect a fault in forward direction and send a communication signal to the protection B:2 at remote end, which is measuring a fault in reverse direction.

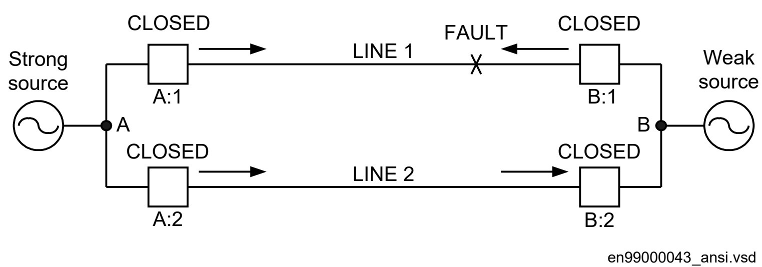


Figure 162: Current distribution for a fault close to B side when all breakers are closed

When the breaker B:1 opens for clearing the fault, the fault current through B:2 bay will invert. If the communication signal has not reset at the same time as the distance protection function used in the Teleprotection scheme has switched on to forward direction, we will have an unwanted operation of breaker B:2 at B side.

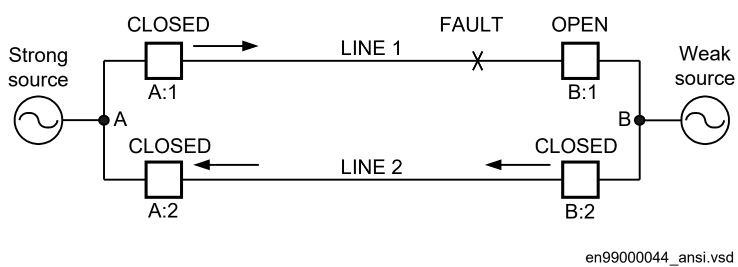


Figure 163: Current distribution for a fault close to B side when breaker B:1 has opened

To handle this the send signal CS from B:2 is held back until the reverse zone IRVL has reset and the *tDelayRev* time has elapsed. To achieve this the reverse zone on the distance protection shall be connected to input IRV and the output IRVL shall be connected to input BLKCS on the communication function block ZCPSCH.

The function can be blocked by activating the input IRVBLK or the general BLOCK input.

12.2.2.2 Weak-end infeed logic

Permissive communication schemes can basically operate only when the protection in the remote IED can detect the fault. The detection requires a sufficient minimum fault current, normally >20% of In. The fault current can be too low due to an open breaker or low short-circuit power of the source. To overcome these conditions, weak-end infeed (WEI) echo logic is used. The fault current can also be initially too low due to the fault current distribution. Here, the fault current increases when the breaker opens in the strong terminal, and a sequential tripping is achieved. This requires a detection of the fault by an independent tripping zone 1. To avoid sequential tripping as described, and when zone 1 is not available, weak-end infeed tripping logic is used.

The WEI function sends back (echoes) the received signal under the condition that no fault has been detected on the weak-end by different fault detection elements (distance protection in forward and reverse direction).

The WEI function can be extended to trip also the breaker in the weak side. The trip is achieved when one or more phase voltages are low during an echo function.

Together with the blocking Teleprotection scheme some limitations apply:

- Only the trip part of the function can be used together with the blocking scheme. It is not possible to use the echo function to send the echo signal to the remote line IED. The echo signal would block the operation of the distance protection at the remote line end and in this way prevent the correct operation of a complete protection scheme.
- A separate direct intertrip channel must be arranged from remote end when a trip or accelerated trip is given there. The intertrip receive signal is connect to input CRL.

Avoid using WEI function at both line ends. It shall only be activated at the weak-end.

12.2.3 Setting guidelines

The parameters for the current reversal logic and the weak-end infeed logic (WEI) function are set via the local HMI or PCM600.

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

12.2.3.1 Current reversal logic

Set *CurrRev* to *Enabled* to activate the function.

Set *tDelayRev* timer at the maximum reset time for the communication equipment that gives the carrier receive (CRL) signal plus 30 ms. A minimum setting of 40 ms is recommended, typical 60 ms.

A long *tDelayRev* setting increases security against unwanted tripping, but delay the fault clearing in case of a fault developing from one line to involve the other one. The probability of this type of fault is small. Therefore set *tDelayRev* with a good margin.

Set the pick-up delay *tPickUpRev* to <80% of the breaker operate time, but with a minimum of 20 ms.

12.2.3.2 Weak-end infeed logic

Set *WEI* to *Echo*, to activate the weak-end infeed function with only echo function.

Set *WEI* to *Echo&Trip* to obtain echo with trip.

Set *tPickUpWEI* to *10* ms, a short delay is recommended to avoid that spurious carrier received signals will activate WEI and cause unwanted communications.

Set the voltage criterion *PU27PP* and *PU27PN* for the weak-end trip to 70% of the system base voltage *VBase*. The setting should be below the minimum operate voltage of the system but above the voltage that occurs for fault on the protected line. The phase-to-phase elements must be verified to not operate for phase to ground faults.

12.3 Current reversal and weak-end infeed logic for distance protection ZCWSPSCH (85)

12.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Current reversal and weak-end infeed logic for distance protection	ZCWSPSCH	-	85

12.3.2 Application

12.3.2.1 Current reversal logic

If parallel lines are connected to common buses at both terminals, overreaching permissive communication schemes can trip unselectable due to current reversal. The unwanted tripping affects the healthy line when a fault is cleared on the other line. This lack of security results in a total loss of inter-connection between the two buses.

To avoid this kind of disturbances, fault current reversal logic (transient blocking logic) can be used.

The unwanted operations that might occur can be explained by looking into figure 164 and figure 165. Initially the protection A:2 at A side will detect a fault in forward direction and send a communication signal to the protection B:2 at remote end, which is measuring a fault in reverse direction.

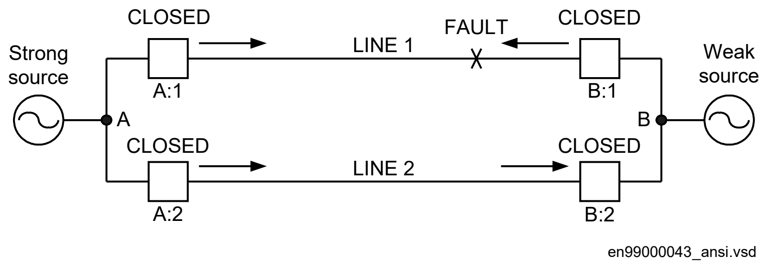


Figure 164: Current distribution for a fault close to B side when all breakers are closed

When the breaker B: 1 opens for clearing the fault, the fault current through B: 2 bay will invert. If the communication signal has not reset at the same time as the distance protection function used in the Teleprotection scheme has switched on to forward direction, we will have an unwanted operation of breaker B:2 at B side.

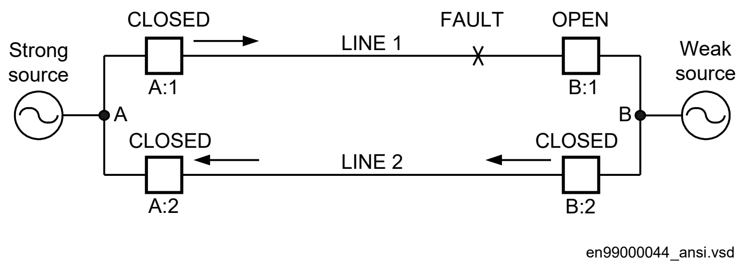


Figure 165: Current distribution for a fault close to B side when breaker B: 1 has opened

To handle this the send signal CS from B: 2 is held back until the reverse zone IRVL has reset and the *tDelayRev* time has elapsed. To achieve this reverse zone on the distance protection shall be connected to input IREV and the output IRVL shall be connected to input BLKCS on the communication function block ZCPSCH. The function can be blocked by activating the input IFWD or the general BLOCK input.

12.3.2.2 Weak-end infeed logic

Permissive communication schemes can basically operate only when the protection in the remote terminal can detect the fault. The detection requires a sufficient minimum fault current, normally >20% of In. The fault current can be too low due to an open breaker or low short-circuit power of the source. To overcome these conditions, weak-end infeed (WEI) echo logic is used. The fault current can also be initially too low due to the fault current distribution. Here, the fault current increases when the breaker opens in the strong terminal, and a sequential tripping is achieved. This requires a detection of the fault by an independent tripping zone 1.

To avoid sequential tripping as described, and when zone 1 is not available, weakend infeed tripping logic is used. The WEI function sends back (echoes) the received signal under the condition that no fault has been detected on the weak-end by different fault detection elements (distance protection in forward and reverse direction).

The WEI function can be extended to trip also the breaker in the weak side. The trip is achieved when one or more phase voltages are low during an echo function.

Together with the blocking Teleprotection scheme some limitations apply:

- Only the trip part of the function can be used together with the blocking scheme. It is not possible to use the echo function to send the echo signal to the remote line IED. The echo signal would block the operation of the distance protection at the remote line end and in this way prevent the correct operation of a complete protection scheme.
- A separate direct intertrip channel must be arranged from remote end when a trip or accelerated trip is given there. The intertrip receive signal is connect to input CRL.

Avoid using WEI function at both line ends. It shall only be activated at the weak end.

12.3.3 Setting guidelines

The parameters for the current reversal logic and the weak-end infeed logic (WEI) function are set via the local HMI or Protection and Control Manager (PCM600). Common base IED values for primary current (setting *IBase*), primary voltage (setting *VBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting GlobalBaseSel is used to select a GBASVAL function for reference of base values.

12.3.3.1 Current reverse logic

CurrRev: Sets *CurrRev* to *Enabled* to activate current reversal logic.

tDelayRev: Sets *tDelayRev* timer at the maximum reset time for the communication equipment that gives the carrier receive (CRL) signal plus 30 ms. A minimum setting of 40 ms is recommended, typical 60 ms.

A long *tDelayRev* setting increases security against unwanted tripping, but delay the fault clearing in case of a fault developing from one line to involve the other one. The probability of this type of fault is small. Therefore set *tDelayRev* with a good margin.

tPickUpRev: Sets the pick-up delay *tPickUpRev* to *<80%* of the breaker operate time, but with a minimum of 20 ms.

12.3.3.2 Weak-end infeed logic

WEI: Set *WEI* to *Echo*, to activate the weak-end infeed function with only echo function. To activate echo with trip set *WEI* to *Echo & Trip*.

tPickUpWEI: Set *tPickUpWEI = 10* ms, a short delay is recommended to avoid that spurious carrier received signals will activate WEI and cause unwanted communications.

PU27PP and *PU27PN*: Set the voltage criterion *PU27PP* and *PU27PN* for the weak-end trip to *70%* of the system base voltage *VBase*. The setting should be below the minimum operate voltage of the system but above the voltage that occurs for fault on the protected line. The phase-to-phase elements must be verified to not operate for phase-to-ground faults.

12.4 Local acceleration logic ZCLCPLAL

12.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Local acceleration logic	ZCLCPLAL	-	-

12.4.2 Application

The local acceleration logic (ZCLCPLAL) is used in those applications where conventional teleprotection scheme is not available (no communication channel), but the user still require fast clearance for faults on the whole line.

This logic enables fast fault clearing during certain conditions, but naturally, it can not fully replace a teleprotection scheme.

The logic can be controlled either by the autorecloser (zone extension) or by the loss-of-load current (loss-of-load acceleration).

The loss-of-load acceleration gives selected overreach zone permission to operate instantaneously after check of the different current criteria. It can not operate for three-phase faults.

12.4.3 Setting guidelines

The parameters for the local acceleration logic functions are set via the local HMI or PCM600.

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Set *ZoneExtension* to *Enabled* when the first trip from selected overreaching zone shall be instantaneous and the definitive trip after autoreclosure a normal time-delayed trip.

Set *LossOfLoad* to *Enabled* when the acceleration shall be controlled by loss-of-load in healthy phase(s).

LoadCurr must be set below the current that will flow on the healthy phase when one or two of the other phases are faulty and the breaker has opened at remote end (three-phase). Calculate the setting according to equation 194.

$$LoadCurr = \frac{0.5 \cdot I_{Load\ \min}}{I_{Base}}$$

(Equation 194)

where:

ILoadmin is the minimum load current on the line during normal operation conditions.

The timer *tLoadOn* is used to increase the security of the loss-of-load function for example to avoid unwanted release due to transient inrush current when energizing the line power transformer. The loss-of-load function will be released after the timer *tLoadOn* has elapsed at the same time as the load current in all three phases are above the setting *LoadCurr*. In normal acceleration applications there is no need for delaying the release, so set the *tLoadOn* to zero.

The drop-out timer *tLoadOff* is used to determine the window for the current release conditions for Loss-of-load. The timer is by default set to 300ms, which is judged to be enough to secure the current release.

The setting of the minimum current detector, *MinCurr*, should be set higher than the unsymmetrical current that might flow on the non faulty line, when the breaker at remote end has opened (three-phase). At the same time it should be set below the minimum load current transfer during normal operations that the line can be subjected to. By default, *MinCurr* is set to 5% of *IBase*.

The pick-up timer *tLowCurr* determine the window needed for pick-up of the minimum current value used to release the function. The timer is by default set to 200 ms, which is judged to be enough to avoid unwanted release of the function (avoid unwanted trip).

12.5 Scheme communication logic for residual overcurrent protection ECPSCH (85)

12.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Scheme communication logic for residual overcurrent protection	ECPSCH	-	85

12.5.2 Application

To achieve fast fault clearance of ground faults on the part of the line not covered by the instantaneous step of the residual overcurrent protection, the directional residual overcurrent protection can be supported with a logic that uses communication channels.

One communication channel is used in each direction, which can transmit an on/off signal if required. The performance and security of this function is directly related to the transmission channel speed and security against false or lost signals.

In the directional scheme, information of the fault current direction must be transmitted to the other line end.

With directional, comparison in permissive schemes, a short operate time of the protection including a channel transmission time, can be achieved. This short operate time enables rapid autoreclosing function after the fault clearance.

The communication logic module enables blocking as well as permissive under/overreaching schemes. The logic can also be supported by additional logic for weak-end infeed and current reversal, included in the Current reversal and weak-end infeed logic for residual overcurrent protection (ECRWPSCH, 85) function.

Metallic communication paths adversely affected by fault generated noise may not be suitable for conventional permissive schemes that rely on signal transmitted during a protected line fault. With power line carrier, for example, the communication signal may be attenuated by the fault, especially when the fault is close to the line end, thereby disabling the communication channel.

To overcome the lower dependability in permissive schemes, an unblocking function can be used. Use this function at older, less reliable, power line carrier (PLC) communication, where the signal has to be sent through the primary fault. The unblocking function uses a guard signal CRG, which must always be present, even when no CR signal is received. The absence of the CRG signal during the security time is used as a CR signal. This also enables a permissive scheme to operate when the line fault blocks the signal transmission. Set the *tSecurity* to 35 ms.

12.5.3 Setting guidelines

The parameters for the scheme communication logic for residual overcurrent protection function are set via the local HMI or PCM600.

The following settings can be done for the scheme communication logic for residual overcurrent protection function:

Operation: *Disabled* or *Enabled*.

SchemeType: This parameter can be set to *Off* , *Intertrip*, *Permissive UR*, *Permissive OR* or *Blocking*.

tCoord: Delay time for trip from ECPSCH (85) function. For Permissive under/overreaching schemes, this timer can be set to 0. For Blocking scheme, the setting should be minimum: the maximum signal transmission time +10 ms.

Unblock: Select *Off* if unblocking scheme with no alarm for loss of guard is used. Set to *Restart* if unblocking scheme with alarm for loss of guard is used.

12.6 Current reversal and weak-end infeed logic for residual overcurrent protection ECRWPSCH (85)

12.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Current reversal and weak-end infeed logic for residual overcurrent protection	ECRWPSCH	-	85

12.6.2 Application

12.6.2.1 Fault current reversal logic

Figure 166 and figure 167 show a typical system condition, which can result in a fault current reversal.

This can cause an unselective trip on line L2 if the current reversal logic does not block the permissive overreaching scheme in the IED at B:2.

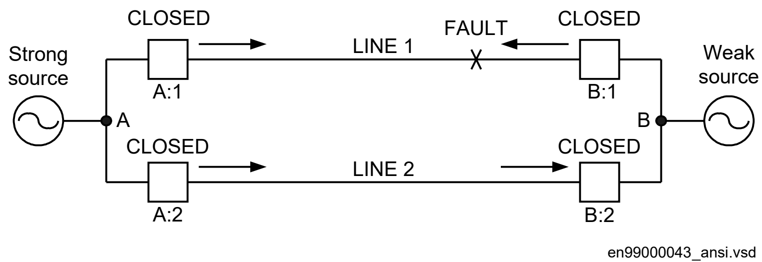


Figure 166: Initial condition

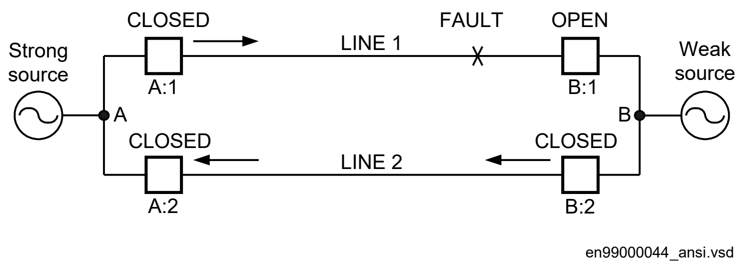


Figure 167: Current distribution after the breaker at B:1 is opened

When breaker on the parallel line operates, the fault current on the non faulty line is reversed. The IED at B:2 recognizes now the fault in forward direction. Together with the remaining received signal it will trip the breaker in B:2. To ensure that this does not occur, the permissive overreaching function needs to be blocked by IRVL, until the received signal is reset.

The IED at remote end, where the forward direction element was initially activated, must reset before the send signal is initiated from B:2. The delayed reset of output signal IRVL also ensures the send signal from IED B:2 is held back until the forward direction element is reset in IED A:2.

12.6.2.2 Weak-end infeed logic

Figure 168 shows a typical system condition that can result in a missing operation. Note that there is no fault current from node B. This causes that the IED at B cannot detect the fault and trip the breaker in B. To cope with this situation, a selectable weak-end infeed logic is provided for the permissive overreaching scheme.

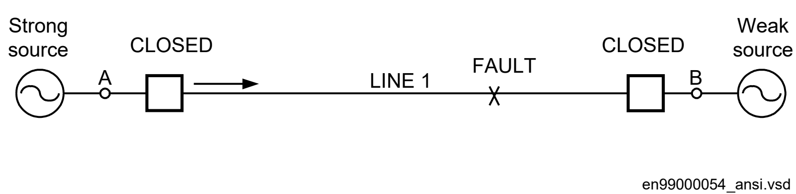


Figure 168: Initial condition

12.6.3 Setting guidelines

The parameters for the current reversal and weak-end infeed logic for residual overcurrent protection function are set via the local HMI or PCM600.

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

12.6.3.1 Current reversal

The current reversal function is set on or off by setting the parameter *CurrRev* to *Enabled* or *Disabled*. Time delays shall be set for the timers *tPickUpRev* and *tDelayRev*.

tPickUpRev is chosen shorter (<80%) than the breaker opening time, but minimum 20 ms.

tDelayRev is chosen at a minimum to the sum of protection reset time and the communication reset time. A minimum *tDelayRev* setting of 40 ms is recommended.

The reset time of the directional residual overcurrent protection (EF4PTOC) is typically 25 ms. If other type of residual overcurrent protection is used in the remote line end, its reset time should be used.

The signal propagation time is in the range 3 – 10 ms/km for most types of communication media. In communication networks small additional time delays are added in multiplexers and repeaters. Theses delays are less than 1 ms per process. It is often stated that the total propagation time is less than 5 ms.

When a signal arrives or ends there is a decision time to be added. This decision time is highly dependent on the interface between communication and protection used. In many cases external interface (teleprotection equipment) is used. This equipment makes a decision and gives a binary signal to the protection device. In case of analog teleprotection equipment typical decision time is in the range 10 – 30 ms. For digital teleprotection equipment this time is in the range 2 – 10 ms.

If the teleprotection equipment is integrated in the protection IED the decision time can be slightly reduced.

Below the principle time sequence of signaling at current reversal is shown.

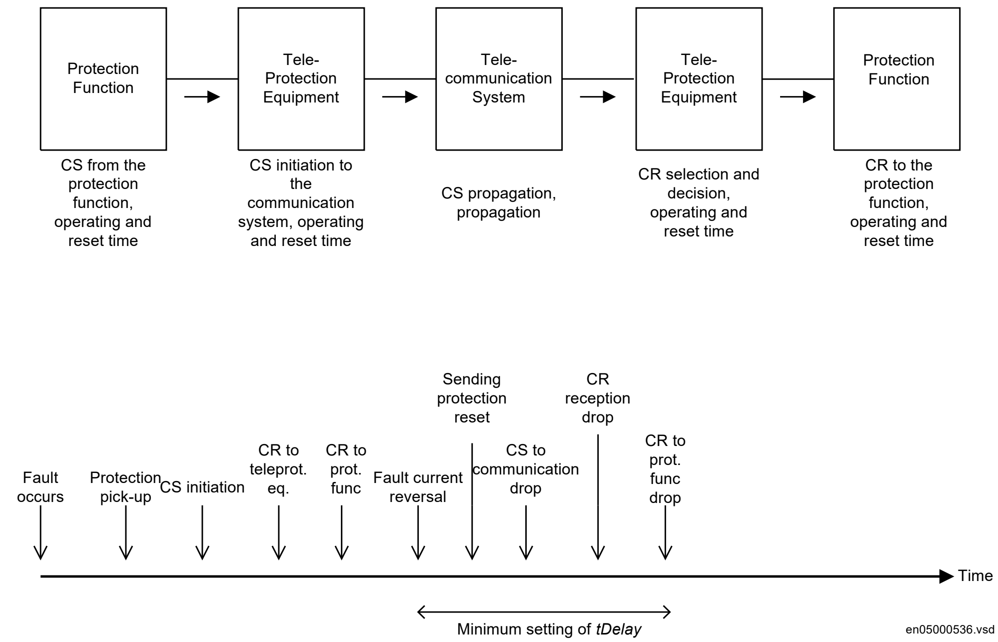


Figure 169: Time sequence of signaling at current reversal

12.6.3.2 Weak-end infeed

The weak-end infeed can be set by setting the parameter *WEI* to *Off*, *Echo* or *Echo & Trip*. Operating zero sequence voltage when parameter *WEI* is set to *Echo & Trip* is set with 3V0PU.

The zero sequence voltage for a fault at the remote line end and appropriate fault resistance is calculated.

To avoid unwanted trip from the weak-end infeed logic (if spurious signals should occur), set the operate value of the broken delta voltage level detector ($3V_0$) higher than the maximum false network frequency residual voltage that can occur during normal service conditions. The recommended minimum setting is two times the false zero-sequence voltage during normal service conditions.

Section 13 Logic

13.1 Tripping logic SMPPTRC (94)

13.1.1 Identification

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

13.1.2 Application

All trip signals from the different protection functions shall be routed through the trip logic. In its simplest alternative the logic will only link the TRIP signal and make sure that it is long enough.

Tripping logic (SMPPTRC ,94) in the IED for protection, control and monitoring offers three-pole tripping.

The three-pole trip for all faults offers a simple solution and is often sufficient in well meshed transmission systems and in High Voltage (HV) systems.

One SMPPTRC (94) function block should be used for each breaker, if the line is connected to the substation via more than one breaker.

To prevent closing of a circuit breaker after a trip the function can block the closing.

13.1.2.1 Three-pole tripping

A simple application with three-pole tripping from the logic block utilizes a part of the function block. Connect the inputs from the protection function blocks to the input TRINP_3P. If necessary (normally the case) use a logic OR block to combine the different function outputs to this input. Connect the output TRIP to the digital Output/s on the IO board.

For special applications such as Lock-out refer to the separate section below. The typical connection is shown below in figure 170. Signals that are not used are dimmed.

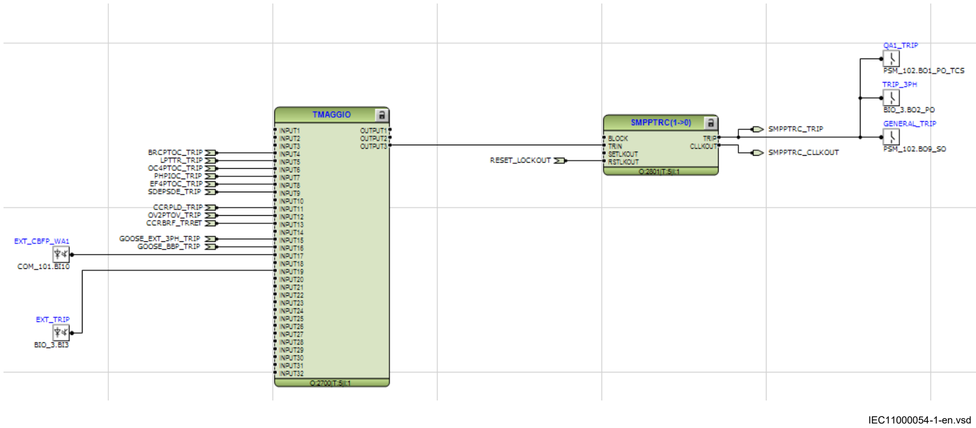


Figure 170: Tripping logic SMPPTRC (94) is used for a simple three-pole tripping application

13.1.2.2 Lock-out

This 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 (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 Lock-out but not initiate 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.

13.1.2.3 Blocking of the function block

Blocking can be initiated internally by logic, or by the operator using a communication channel. Total blockage of Tripping logic (SMPPTRC ,94) function is done by activating the input BLOCK and can be used to block the output of SMPPTRC (94) in the event of internal failures.

13.1.3 Setting guidelines

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

The following trip parameters can be set to regulate tripping.

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

TripLockout: Sets the scheme for lock-out. *Disabled* only activates lock-out output. *Enabled* activates the lock-out output and latching output contacts. The normal selection is *Disabled*.

AutoLock: Sets the scheme for lock-out. *Disabled* only activates lock-out through the input SETLKOUT. *Enabled* also allows activation from trip function itself and activates the lockout output. The normal selection is *Disabled*.

tTripMin: Sets the required minimum duration of the trip pulse. It should be set to ensure that the breaker is tripped and if a signal is used to initiate Breaker failure protection CCRBRF (50BF) longer than the back-up trip timer in CCRBRF (50BF). Normal setting is *0.150s*.

13.2 Tripping logic SPTPTRC 94

13.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Tripping logic	SPTPTRC	*I->O*	94

13.2.2 Application

All trip signals from the different protection functions shall be routed through the trip logic. In its simplest alternative the logic will only link the TRIP signal and make sure that it is long enough.

Tripping logic (SPTPTRC, 94) in the IED for protection, control and monitoring offers three-phase tripping. two different operating modes:

- Three-pole tripping for all fault types (3ph operating mode)
- Single-pole tripping for single-pole faults and three-pole tripping for multiphase and evolving faults (1ph/3ph 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.

The three-pole trip for all faults offers a simple solution and is often sufficient in well meshed transmission systems and in High Voltage (HV) systems. Since most faults, especially at the highest voltage levels, are single pole to ground faults, single pole tripping can be of great value. If only the faulty pole is tripped, power can still be transferred on the line during the dead time that arises before reclosing. Single pole tripping during single phase faults must be combined with single pole reclosing.

13.2.2.1 Single- and/or three-pole tripping

The single-/three-pole tripping will give single-pole tripping for single-phase faults and three-pole tripping for multi-phase fault. The 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.

The inputs 1PTRZ and 1PTREF are used for single-pole tripping for distance protection and directional ground fault protection as required.

The inputs are combined with the phase selection logic and the pickup signals from the 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 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 is normally connected to the respective output on the Auto- Recloser but can also be connected to other signals, for example an external logic signal.If two breakers are involved, one TR block instance and one Auto-Recloser instance is used for each breaker. This will ensure correct operation and behavior of each breaker.

The output Trip 3 Phase TR3P must be connected to the respective input in SESRSYN (25) to switch SESRSYN (25) to three-phase reclosing. If this signal is not activated SESRSYN (25) will use single-phase reclosing dead time.

Note also that if a second line protection is utilizing the same SESRSYN (25) the three-pole trip signal must be generated, for example by using the three-trip relays contacts in series and connecting them in parallel to the TR3P output from the trip block.

The trip logic also has inputs TRIN_A, TRIN_B and TRIN_C where phase-selected trip signals can be connected. Examples can be individual phase inter-trips from remote end or internal/external phase selected trip signals, which are routed through the IED to achieve, for example SESRSYN (25), Breaker failure, and so on. Other back-up functions are connected to the input TRIN as described above. A typical connection for a single-pole tripping scheme is shown in figure 171.

Figure 171: The trip logic function SPTPTRC (94) used for single-pole tripping application

13.2.2.2 Lock out

This 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 (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 Lock-out but not initiate trip this can be achieved by activating input SETLKOUT. The setting *AutoLock* = *Disabled* will mean 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 auto-reclose and back-up zone tripping can in such cases be connected to initiate Lock-out by activating the input SETLKOUT.

13.2.2.3 Blocking of the function block

Blocking can be initiated internally by logic, or by the operator using a communication channel. Total blockage of the Tripping logic SPTPTRC (94) function is done by activating the input BLOCK and can be used to block the output of SPTPTRC (94) in the event of internal failures.

13.2.3 Setting guidelines

The parameters for Tripping logic SPTPTRC (94) function are set via the local HMI or PCM600.

The following trip parameters can be set to regulate tripping.

Program

Set the required tripping scheme depending on value selected *3 phase* or *1p/3p*.

Operation

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

TripLockout

Sets the scheme for lock-out. *Disabled* only activates lock-out output. *Enabled* activates the lock-out output and latching output contacts. The normal selection is *Disabled*.

AutoLock

Sets the scheme for lock-out. *Disabled* only activates lock-out through the input SETLKOUT. *Enabled* also allows activation from trip function itself and activates the lockout output. The normal selection is *Disabled*.

tTripMin

Sets the required minimum duration of the trip pulse. It should be set to ensure that the breaker is tripped and if a signal is used to initiate the Breaker failure protection CSPRBRF (50BF) function longer than the back-up trip timer in CSPRBRF (50BF). Normal setting is *0.150s*.

13.3 Trip matrix logic TMAGGIO

13.3.1 Identification

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

13.3.2 Application

Trip matrix logic TMAGGIO function is used to route trip signals and other logical output signals to different output contacts on the IED.

TMAGGIO output signals and the physical outputs allows the user to adapt the signals to the physical tripping outputs according to the specific application needs.

13.3.3 Setting guidelines

Operation: Operation of function *Enabled/ Disabled*.

PulseTime: Defines the pulse time delay. When used for direct tripping of circuit breaker(s) the pulse time delay shall be set to approximately 0.150 seconds in order to obtain satisfactory minimum duration of the trip pulse to the circuit breaker trip coils.

OnDelay: Used to prevent output signals to be given for spurious inputs. Normally set to 0 or a low value.

OffDelay: Defines a minimum on time for the outputs. When used for direct tripping of circuit breaker(s) the off delay time shall be set to approximately 0.150 seconds in order to obtain satisfactory minimum duration of the trip pulse to the circuit breaker trip coils.

ModeOutputx: Defines if output signal OUTPUTx (where x=1-3) is *Steady* or *Pulsed*.

13.4 Configurable logic blocks

13.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
OR Function block	OR	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Inverter function block	INVERTER	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
PULSETIMER function block	PULSETIMER	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Controllable gate function block	GATE	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Exclusive OR function block	XOR	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Logic loop delay function block	LOOPDELAY	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Timer function block	TIMERSET	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
AND function block	AND	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Set-reset memory function block	SRMEMORY	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Reset-set with memory function block	RSMEMORY	-	-

13.4.2 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.

There are no settings for AND gates, OR gates, inverters or XOR gates.

For normal On/Off delay and pulse timers the time delays and pulse lengths are set from the local HMI or via the PST tool.

Both timers in the same logic block (the one delayed on pick-up and the one delayed on drop-out) always have a common setting value.

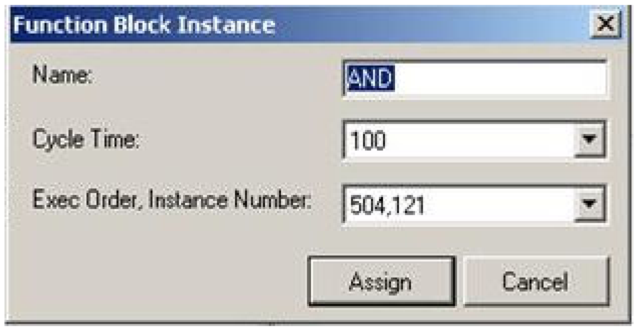
For controllable gates, settable timers and SR flip-flops with memory, the setting parameters are accessible via the local HMI or via the PST tool.

13.4.3.1 Configuration

Logic is configured using the ACT configuration tool.

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

The execution of different function blocks within the same cycle is determined by the order of their serial execution numbers. Always remember this when connecting two or more logical function blocks in series.

Always be careful when connecting function blocks with a fast cycle time to function blocks with a slow cycle time.
Remember to design the logic circuits carefully and always check the execution sequence for different functions. In other cases, additional time delays must be introduced into the logic schemes to prevent errors, for example, race between functions.
Default value on all four inputs of the AND gate are logical 1 which makes it possible for the user to just use the required number of inputs and leave the rest un-connected. The output OUT has a default value 0 initially, which will suppress one cycle pulse if the function has been put in the wrong execution order.

13.5 Fixed signals FXDSIGN

13.5.1 Identification

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

13.5.2 Application

The Fixed signals function (FXDSIGN) generates a number of 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.

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.

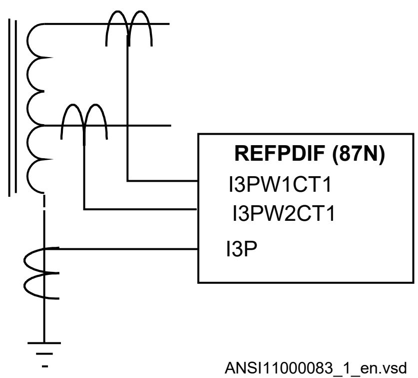


Figure 173: REFPDIF (87N) function inputs for autotransformer application

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.

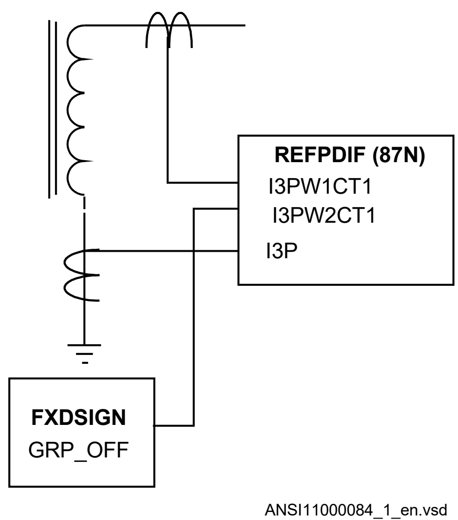


Figure 174: REFPDIF (87N) function inputs for normal transformer application

13.6 Boolean 16 to integer conversion B16I

13.6.1 Identification

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

13.6.2 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.

13.6.3 Setting guidelines

The function does not have any parameters available in Local HMI or Protection and Control IED Manager (PCM600).

13.7 Boolean 16 to integer conversion with logic node representation B16IFCVI

13.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Boolean 16 to integer conversion with logic node representation	B16IFCVI	-	-

13.7.2 Application

Boolean 16 to integer conversion with logic node representation function B16IFCVI is used to transform a set of 16 binary (logical) signals into an integer. B16IFCVI can receive an integer from a station computer – for example, over IEC 61850. These functions are very useful when you want to generate logical commands (for selector switches or voltage controllers) by inputting an integer number. B16IFCVI has a logical node mapping in IEC 61850.

13.7.3 Setting guidelines

The function does not have any parameters available in the local HMI or Protection and Control IED Manager (PCM600).

13.8 Integer to boolean 16 conversion IB16A

13.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Integer to boolean 16 conversion	IB16A	-	-

13.8.2 Application

Integer to boolean 16 conversion function (IB16A) 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 a function (like distance protection) to binary (logical) inputs in another function (like line differential protection). IB16A function does not have a logical node mapping.

13.8.3 Setting guidelines

The function does not have any parameters available in the local HMI or Protection and Control IED Manager (PCM600).

13.9 Integer to boolean 16 conversion with logic node representation IB16FCVB

13.9.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Integer to boolean 16 conversion with logic node representation	IB16FCVB	-	-

13.9.2 Application

Integer to boolean 16 conversion with logic node representation function (IB16FCVB) is used to transform an integer into a set of 16 binary (logical) signals. IB16FCVB function can receive an integer from a station computer – for example, over IEC 61850. These functions are very useful when the user wants to generate logical commands (for selector switches or voltage controllers) by inputting an integer number. IB16FCVB function has a logical node mapping in IEC 61850.

13.9.3 Settings

The function does not have any parameters available in the local HMI or Protection and Control IED Manager (PCM600)

Section 14 Monitoring

14.1 IEC61850 generic communication I/O functions SPGGIO

14.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IEC 61850 generic communication I/O functions	SPGGIO	-	-

14.1.2 Application

IEC 61850 generic communication I/O functions (SPGGIO) function is used to send one single logical output to other systems or equipment in the substation. It has one visible input, that should be connected in ACT tool.

14.1.3 Setting guidelines

The function does not have any parameters available in Local HMI or Protection and Control IED Manager (PCM600).

14.2 IEC61850 generic communication I/O functions 16 inputs SP16GGIO

14.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IEC 61850 generic communication I/O functions 16 inputs	SP16GGIO	-	-

14.2.2 Application

SP16GGIO function block is used to send up to 16 logical signals to other systems or equipment in the substation. Inputs should be connected in ACT tool.

14.2.3 Setting guidelines

The function does not have any parameters available in Local HMI or Protection and Control IED Manager (PCM600).

14.3 IEC61850 generic communication I/O functions MVGGIO

14.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IEC61850 generic communication I/O functions	MVGGIO	-	-

14.3.2 Application

IEC61850 generic communication I/O functions (MVGGIO) function is used to send the instantaneous value of an analog output 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.

14.3.3 Setting guidelines

The settings available for IEC61850 generic communication I/O functions (MVGGIO) 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 MVGGIO function block. When a Measured value expander block (MVEXP) is connected to the range output, the logical outputs of the MVEXP are changed accordingly.

14.4 Measurements

14.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Measurements	CVMMXN	*P, Q, S, I, U, f*	-
Phase current measurement	CMMXU	*I*	-
Phase-phase voltage measurement	VMMXU	*U*	-
Table continues on next page			

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Current sequence component measurement	CMSQI	I1, I2, I0	-
Voltage sequence measurement	VMSQI	U1, U2, U0	-
Phase-neutral voltage measurement	VNMMXU	U	-

14.4.2 Application

Measurement functions is 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 of 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. There are no interconnections regarding any settings or parameters, neither between functions nor between signals within each function.

Zero clampings are handled by *ZeroDb* for each signal separately for each of the functions. For example, the zero clamping of U12 is handled by *VLZeroDB* in VMMXU, zero clamping of I1 is handled by *ILZeroDb* in CMMXU.

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.

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 output values are displayed in the local HMI under **Main menu/Tests/Function status/ Monitoring/CVMMXN/Outputs**

The measuring functions CMMXU, VNMMXU and VMMXU 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)

It is possible to calibrate the measuring function above to get better then 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 sequential quantities:

- I: sequence currents (positive, zero, negative sequence, magnitude and angle)
- V: sequence voltages (positive, zero and negative sequence, magnitude and angle).

The CVMMXN function calculates three-phase power quantities by using fundamental frequency phasors (DFT values) of the measured current respectively 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.

14.4.3 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.

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

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.

VMagCompY: Magnitude compensation to calibrate voltage measurements at Y% of Vn, where Y is equal to 5, 30 or 100.

IMagCompY: Magnitude compensation to calibrate current measurements at Y% of In, where Y is equal to 5, 30 or 100.

IAngCompY: Angle compensation to calibrate angle measurements at Y% of In, where Y is equal to 5, 30 or 100.

The following general settings can be set for the **Phase-phase current measurement** (CMMXU).

IMagCompY: Magnitude compensation to calibrate current measurements at Y% of In, where Y is equal to 5, 30 or 100.

IAngCompY: Angle compensation to calibrate angle measurements at Y% of In, 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 Vn, where Y is equal to 5, 30 or 100.

VAngCompY: Angle compensation to calibrate angle measurements at Y% of Vn, 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.

Xmax: Maximum value for analog signal X.

Xmin and *Xmax* values are directly set in applicable measuring unit, V, A, and so on, for all measurement functions, except CVMMXN where *Xmin* and *Xmax* values are set in % of *SBase*.

XZeroDb: Zero point clamping. A signal value less than *XZeroDb* is forced to zero.

XRepTyp: Reporting type. Cyclic (*Cyclic*), magnitude deadband (*Dead band*) or integral deadband (*Int deadband*). The reporting interval is controlled by the parameter *XDbRepInt*.

XDbRepInt: Reporting deadband setting. Cyclic reporting is the setting value and is reporting interval in seconds. Magnitude deadband is the setting value in % of measuring range. Integral deadband setting is the integral area, that is, measured value in % of measuring range multiplied by the time between two measured values.

Limits are directly set in applicable measuring unit, V, A , and so on, for all measurement functions, except CVMMXN where limits are set in % of *SBase*.

XHiHiLim: High-high limit.

XHiLim: High limit.

XLowLim: Low limit.

XLowLowLim: Low-low limit.

XLimHyst: Hysteresis value in % of range and is common for all limits.

All phase angles are presented in relation to defined reference channel. The parameter *PhaseAngleRef* defines the reference, see settings for analog input modules in PCM600.

Calibration curves

It is possible to calibrate the functions (CVMMXN, CMMXU, VNMMXU and VMMXU) 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 175 (example). The first phase will be used as reference channel and compared with the curve for calculation of factors. The factors will then be used for all related channels.

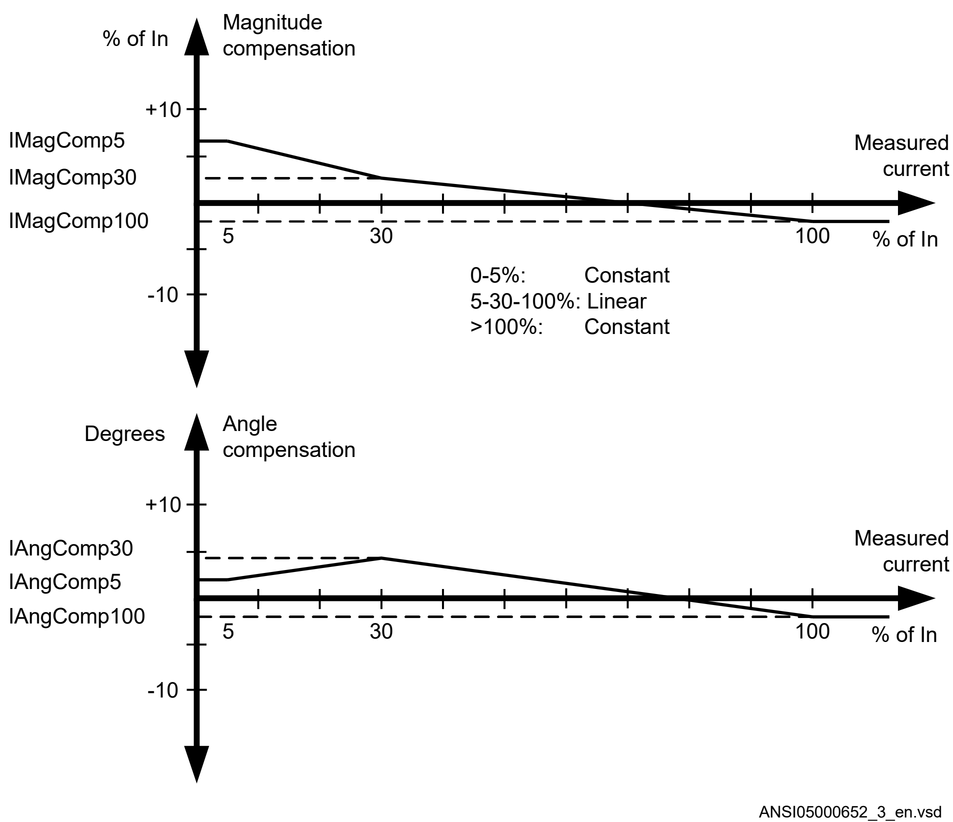


Figure 175: Calibration curves

14.4.4 Setting examples

Three setting examples, in connection to Measurement function (CVMMXN), are provided:

- Measurement function (CVMMXN) application for a 400 kV 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.

14.4.4.1 Measurement function application for a 380 kV OHL

Single line diagram for this application is given in figure 176:

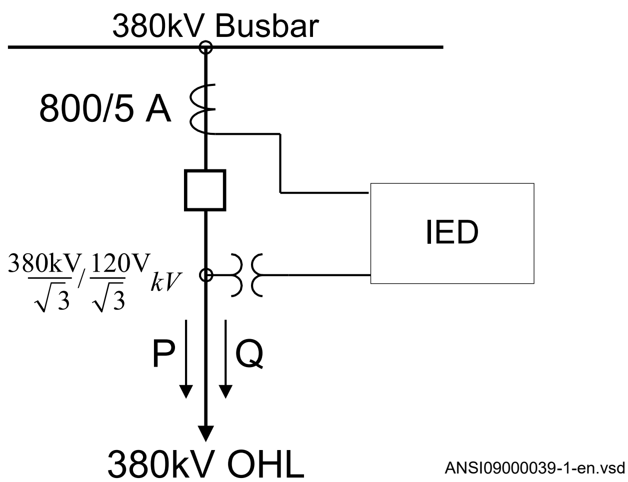


Figure 176: Single line diagram for 380 kV OHL application

In order to monitor, supervise and calibrate the active and reactive power as indicated in figure 176 it is necessary to do the following:

1. Set correctly CT and VT data and phase angle reference channel *PhaseAngleRef* (see settings for analog input modules in PCM600) 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 27.
    - level supervision of active power as shown in table 28.
    - calibration parameters as shown in table 29.

Table 27: General settings parameters for the Measurement function

Setting	Short Description	Selected value	Comments
Operation	Operation *Disabled/ Enabled*	*Enabled*	Function must be *Enabled*
PowMagFact	Magnitude 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 & V	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	*A, B, C*	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

Table 28: Settings parameters for level supervision

Setting	Short Description	Selected value	Comments
PMin	Minimum value	-750	Minimum expected load
PMax	Minimum value	750	Maximum expected load
PZeroDb	Zero point clamping in 0.001% of range	3000	Set zero point clamping to 45 MW that is, 3% of 1500 MW
PRepTyp	Reporting type	db	Select magnitude deadband supervision
PDbRepInt	Cycl: Report interval (s), Db: In % of range, Int Db: In %s	2	Set ±Δdb=30 MW that is, 2% (larger changes than 30 MW will be reported)
PHiHiLim	High High limit (physical value)	600	High alarm limit that is, extreme overload alarm
PHiLim	High limit (physical value)	500	High warning limit that is, overload warning
PLowLim	Low limit (physical value)	-800	Low warning limit. Not active
PLowLowlLim	Low Low limit (physical value)	-800	Low alarm limit. Not active
PLimHyst	Hysteresis value in % of range (common for all limits)	2	Set ±Δ Hysteresis MW that is, 2%

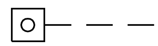
Table 29: Settings for calibration parameters

Setting	Short Description	Selected value	Comments
IMagComp5	Magnitude factor to calibrate current at 5% of In	0.00	
IMagComp30	Magnitude factor to calibrate current at 30% of In	0.00	
IMagComp100	Magnitude factor to calibrate current at 100% of In	0.00	
VAmpComp5	Magnitude factor to calibrate voltage at 5% of Vn	0.00	
Table continues on next page			

Setting	Short Description	Selected value	Comments
VMagComp30	Magnitude factor to calibrate voltage at 30% of Vn	0.00	
VMagComp100	Magnitude factor to calibrate voltage at 100% of Vn	0.00	
IAngComp5	Angle calibration for current at 5% of In	0.00	
IAngComp30	Angle pre-calibration for current at 30% of In	0.00	
IAngComp100	Angle pre-calibration for current at 100% of In	0.00	

14.5 Event counter CNTGGIO

14.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Event counter	CNTGGIO		-

14.5.2 Application

Event counter (CNTGGIO) has six counters which are used for storing the number of times each counter has been activated. CNTGGIO can be used to count how many times a specific function, for example the tripping logic, has issued a trip signal. All six counters have a common blocking and resetting feature.

14.5.3 Setting guidelines

Operation: Sets the operation of Event counter (CNTGGIO) *Enabled* or *Disabled*.

14.6 Disturbance report

14.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Disturbance report	DRPRDRE	-	-
Analog input signals	A1RADR	-	-
Analog input signals	A2RADR	-	-
Analog input signals	A3RADR	-	-
Table continues on next page			

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Analog input signals	A4RADR	-	-
Binary input signals	B1RBDR	-	-
Binary input signals	B2RBDR	-	-
Binary input signals	B3RBDR	-	-
Binary input signals	B4RBDR	-	-
Binary input signals	B5RBDR	-	-
Binary input signals	B6RBDR	-	-

14.6.2 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
- 96 binary signals.

Disturbance report function is a common name for several functions that is, Indications, Event recorder, Sequential of events, Trip value recorder, Disturbance recorder and Fault locator (FL).

Disturbance report function is characterized by great flexibility as far as configuration, starting conditions, recording times, and large 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) 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 as GOOSE or Report Control data.

14.6.3 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 96 binary signals, either internal signals or signals coming from external inputs. The binary signals are identical in all functions that is, Disturbance recorder, Event recorder, Indication, Trip value recorder and Sequential of events function.

User-defined names of binary and analog input signals is set using PCM600. The analog and binary signals appear with their user-defined names. The name is used in all related functions (Disturbance recorder, Event recorder, Indication, Trip value recorder and Sequential of events).

Figure 177 shows the relations between Disturbance report, included functions and function blocks. Sequential of events , Event recorder and Indication uses information from the binary input function blocks (BxRBDR). Trip value recorder uses analog information from the analog input function blocks (AxRADR), which is used by Fault locator after estimation by Trip Value Recorder. Disturbance report function acquires information from both AxRADR and BxRBDR.

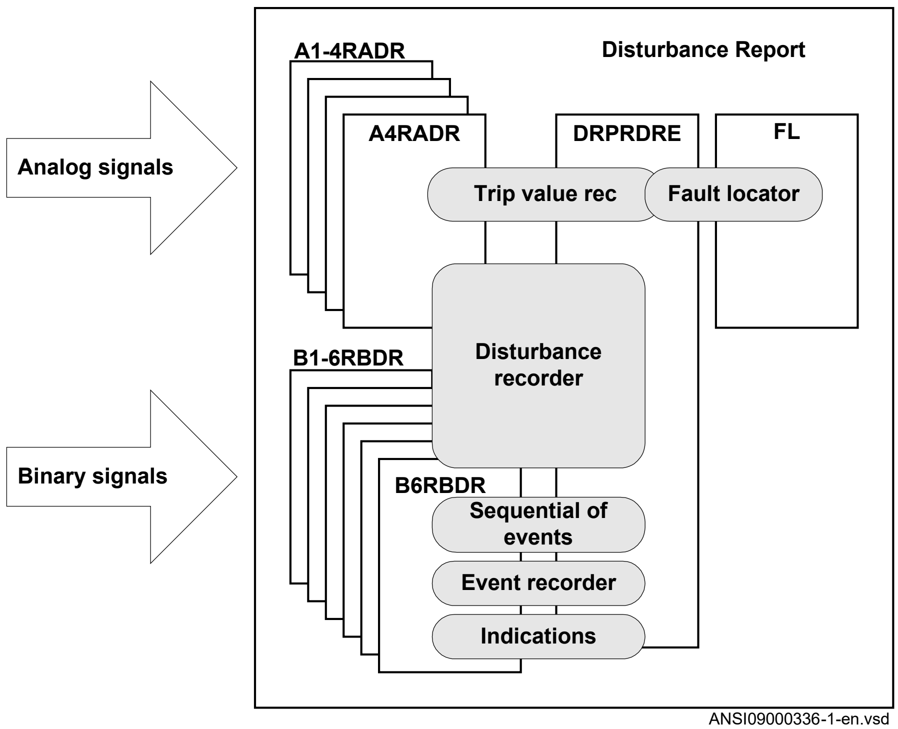


Figure 177: Disturbance report functions and related function blocks

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

Table continues on next page

Yellow LED:	Function controlled by SetLEDn setting in Disturbance report function.
Red LED:	Function controlled by SetLEDn setting in Disturbance report function.

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).

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 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.

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 function.

Postfault recording time (*PostFaultRecT*) is the maximum recording time after the disappearance of the trig-signal (does not influence the Trip value recorder function).

Recording time limit (*TimeLimit*) is the maximum recording time after trig. The parameter limits the recording time if some trigging condition (fault-time) is very long or permanently set (does not influence the Trip value recorder function).

Post retrigger (*PostRetrig*) can be set to *Enabled* or *Disabled*. Makes it possible to choose performance of Disturbance report function if a new trig signal appears in the post-fault window.

PostRetrig = *Disabled*

The function is insensitive for new trig signals during post fault time.

PostRetrig = *Enabled*

The function completes current report and starts a new complete report that is, the latter will include:

- new pre-fault- and fault-time (which will overlap previous report)
- events and indications might be saved in the previous report too, due to overlap
- new fault locator and trip value calculations if installed, in operation and started

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.

14.6.3.1 Binary input signals

Up to 96 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 96 signals, it is also possible to select if the signal is to be used as a trigger for the start of 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.

14.6.3.2 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.

14.6.3.3 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 yellow *Pick up* and red *Trip* 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.

Event recorder
Event recorder 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.

14.6.3.4 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 trigging.

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.

14.7 Measured value expander block MVEXP

14.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Measured value expander block	MVEXP	-	-

14.7.2 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 (MVGGIO) 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 (MVEXP) 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.

14.7.3 Setting guidelines

The function does not have any parameters available in Local HMI or Protection and Control IED Manager (PCM600).

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

14.8 Fault locator LMBRFLO

14.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Fault locator	LMBRFLO	-	-

14.8.2 Application

The main objective of line protection and monitoring IEDs is fast, selective and reliable operation for faults on a protected line section. Besides this, information on distance to fault is very important for those involved in operation and maintenance. Reliable information on the fault location greatly decreases the downtime of the protected lines and increases the total availability of a power system.

The fault locator is started with the input CALCDIST to which trip signals indicating in-line faults are connected, typically distance protection zone 1 and accelerating zone. The disturbance report must also be started for the same faults since the function uses pre- and post-fault information from the trip value recorder function.

Beside this information the function must be informed about faulted phases for correct loop selection . The following loops are used for different types of faults:

- for 3 phase faults: loop A-B.
- for 2 phase faults: the loop between the faulted phases.
- or 2 phase-to-ground faults: the loop between the faulted phases.
- for phase-to-ground faults: the phase-to-ground loop.

The distance to the fault, which is calculated with a high accuracy, is stored together with the recorded disturbances. This information can be read on the local HMI, uploaded to PCM600 and is available on the station bus according to IEC 61850.

The distance to fault can be recalculated on the local HMI by using the measuring algorithm for different fault loops or for changed system parameters.

14.8.3 Setting guidelines

The parameters for the Fault locator function are set via the local HMI or PCM600.

The Fault locator algorithm uses phase voltages, phase currents and residual current in observed bay (protected line) and residual current from a parallel bay (line, which is mutual coupled to protected line).

The Fault locator has close connection to the Disturbance report function. All external analog inputs (channel 1-30), connected to the Disturbance report function, are available to the Fault locator and the function uses information calculated by the Trip value recorder. After allocation of analog inputs to the Disturbance report function, the user has to point out which analog inputs to be used by the Fault locator. According to the default settings the first four analog inputs are currents and next three are voltages in the observed bay (no parallel line expected since chosen input is set to zero). Use the Parameter Setting tool within PCM600 for changing analog configuration.

The list of parameters explains the meaning of the abbreviations. Figure 178 also presents these system parameters graphically. Note, that all impedance values relate to their primary values and to the total length of the protected line.

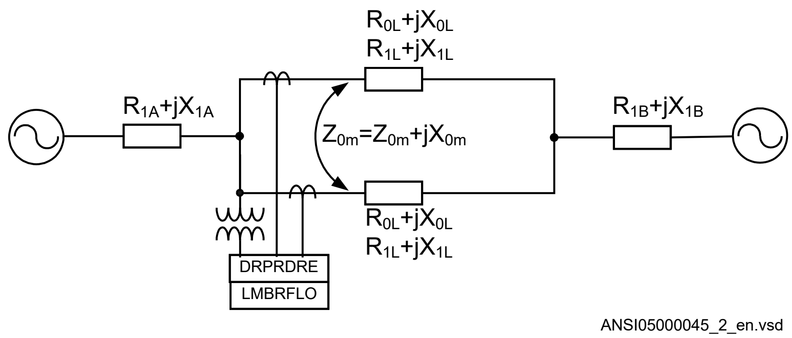


Figure 178: Simplified network configuration with network data, required for settings of the fault location-measuring function

For a single-circuit line (no parallel line), the figures for mutual zero-sequence impedance (X_{0M}, R_{0M}) and analog input are set at zero.

Power system specific parameter settings shown in table 2 are not general settings but specific setting included in the setting groups, that is, this makes it possible to change conditions for the Fault locator with short notice by changing setting group.

The source impedance is not constant in the network. However, this has a minor influence on the accuracy of the distance-to-fault calculation, because only the phase angle of the distribution factor has an influence on the accuracy. The phase angle of the distribution factor is normally very low and practically constant, because the positive sequence line impedance, which has an angle close to 90°, dominates it. Always set the source impedance resistance to values other than zero. If the actual values are not known, the values that correspond to the source impedance characteristic angle of 85° give satisfactory results.

14.8.3.1 Connection of analog currents

Connection diagram for analog currents is shown in figure 179.

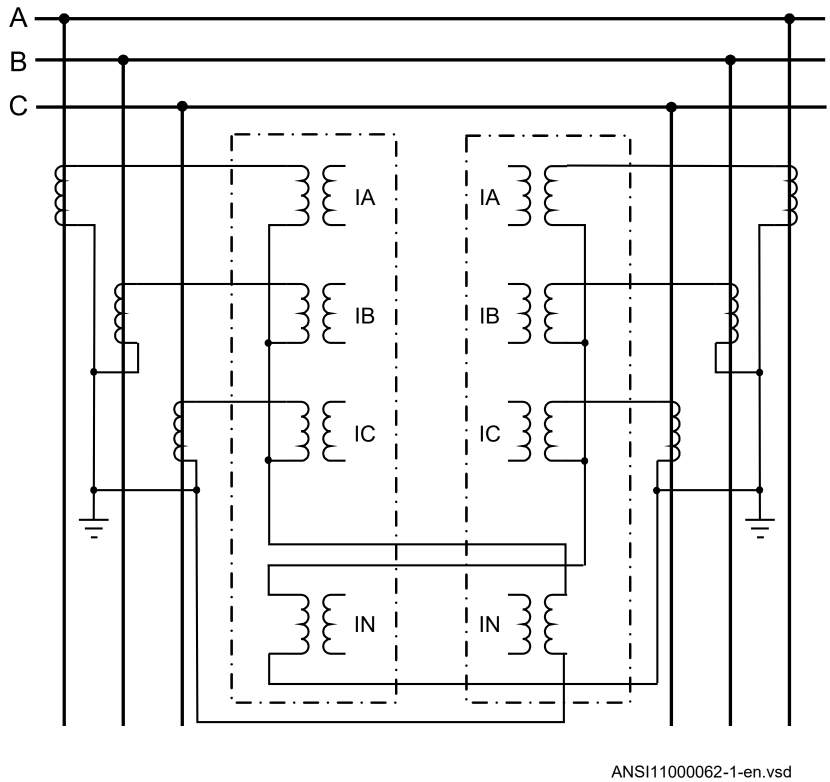


Figure 179: Example of connection of parallel line IN for Fault locator LMBRFLO

14.9 Station battery supervision SPVNZBAT

14.9.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Station battery supervision function	SPVNZBAT	U<>	-

14.9.2 Application

Usually, the load on the DC system is a constant resistance load, for example, lamps, LEDs, electronic instruments and electromagnetic contactors in a steady state condition. A transient RL load exists when breakers are tripped or closed.

The battery voltage has to be continuously monitored as the batteries can withstand moderate overvoltage and undervoltage only for a short period of time.

- If the battery is subjected to a prolonged or frequent overvoltage, it leads to the ageing of the battery, which may lead to the earlier failure of the battery. The other occurrences may be the thermal runaway, generation of heat or increased amount of hydrogen gas and the depletion of fluid in case of valve regulated batteries.

- If the value of the charging voltage drops below the minimum recommended float voltage of the battery, the battery does not receive sufficient charging current to offset internal losses, resulting in a gradual loss of capacity.
  - If a lead acid battery is subjected to a continuous undervoltage, heavy sulfation occurs on the plates, which leads to the loss of the battery capacity.

14.10 Insulation gas monitoring function SSIMG (63)

14.10.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Insulation gas monitoring function	SSIMG	-	63

14.10.2 Application

Insulation gas monitoring function (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 gets blocked to avoid disaster. Binary information based on the gas pressure in the circuit breaker is used as input signals to the function. In addition to that, the function generates alarms based on received information.

14.11 Insulation liquid monitoring function SSIML (71)

14.11.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Insulation liquid monitoring function	SSIML	-	71

14.11.2 Application

Insulation liquid monitoring function (SSIML ,71) is used for monitoring the circuit breaker condition. Proper arc extinction by the compressed oil in the circuit breaker is very important. When the level becomes too low, compared to the required value, the circuit breaker operation is blocked to avoid disaster. Binary information based on the oil level in the circuit breaker is used as input signals to the function. In addition to that, the function generates alarms based on received information.

14.12 Circuit breaker condition monitoring SSCBR

14.12.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Circuit breaker condition monitoring	SSCBR	-	-

14.12.2 Application

SSCBR includes different metering and monitoring subfunctions.

Circuit breaker status

Circuit breaker status monitors the position of the circuit breaker, that is, whether the breaker is in an open, closed or intermediate position.

Circuit breaker operation monitoring

The purpose of the circuit breaker operation monitoring is to indicate that the circuit breaker has not been operated for a long time. The function calculates the number of days the circuit breaker has remained inactive, that is, has stayed in the same open or closed state. There is also the possibility to set an initial inactive day.

Breaker contact travel time

High travelling times indicate the need for maintenance of the circuit breaker mechanism. Therefore, detecting excessive travelling time is needed. During the opening cycle operation, the main contact starts opening. The auxiliary contact A opens, the auxiliary contact B closes, and the main contact reaches its opening position. During the closing cycle, the first main contact starts closing. The auxiliary contact B opens, the auxiliary contact A closes, and the main contact reaches its close position. The travel times are calculated based on the state changes of the auxiliary contacts and the adding correction factor to consider the time difference of the main contact's and the auxiliary contact's position change.

Operation counter

Routine maintenance of the breaker, such as lubricating breaker mechanism, is generally based on a number of operations. A suitable threshold setting, to raise an alarm when the number of operation cycle exceeds the set limit, helps preventive maintenance. This can also be used to indicate the requirement for oil sampling for dielectric testing in case of an oil circuit breaker.

The change of state can be detected from the binary input of the auxiliary contact. There is a possibility to set an initial value for the counter which can be used to initialize this functionality after a period of operation or in case of refurbished primary equipment.

Accumulation of $I^y t$

Accumulation of $I^y t$ calculates the accumulated energy $\Sigma I^y t$ where the factor y is known as the current exponent. The factor y depends on the type of the circuit breaker. For oil circuit breakers the factor y is normally 2. In case of a high-voltage system, the factor y can be 1.4...1.5.

Remaining life of the breaker

Every time the breaker operates, the life of the circuit breaker reduces due to wearing. The wearing in the breaker depends on the tripping current, and the remaining life of the breaker is estimated from the circuit breaker trip curve provided by the manufacturer.

Example for estimating the remaining life of a circuit breaker

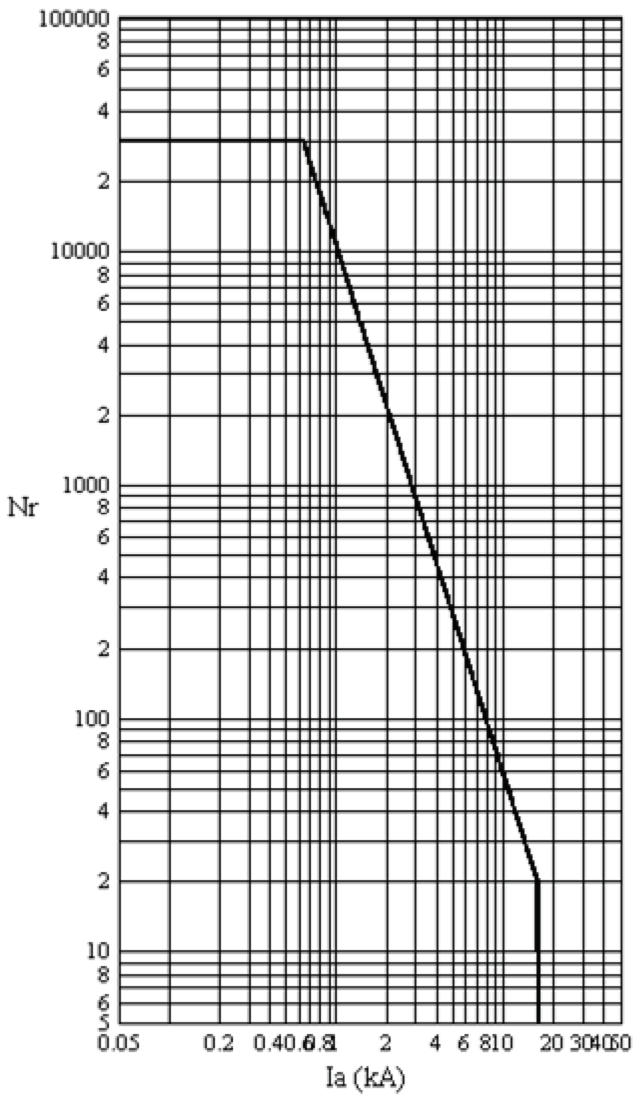


Figure 180: Trip Curves for a typical 12 kV, 630 A, 16 kA vacuum interrupter

Nr	the number of closing-opening operations allowed for the circuit breaker
Ia	the current at the time of tripping of the circuit breaker

Calculation of Directional Coefficient

The directional coefficient is calculated according to the formula:

$$Directional\,Coef = \frac{\log\left(\frac{B}{A}\right)}{\log\left(\frac{I_f}{I_r}\right)} = -2.2609$$

(Equation 195)

I_r	Rated operating current = 630 A
I_f	Rated fault current = 16 kA
A	Op number rated = 30000
B	Op number fault = 20

Calculation for estimating the remaining life

The trip curve shows that there are 30,000 possible operations at the rated operating current of 630 A and 20 operations at the rated fault current 16 kA. Therefore, if the tripping current is 10 kA, one operation at 10 kA is equivalent to 30,000/58=517 operations at the rated current. It is also assumed that prior to this tripping, the remaining life of the circuit breaker is 15,000 operations. Therefore, after one operation of 10 kA, the remaining life of the circuit breaker is 15,000-517=14,483 at the rated operating current.

Spring charged indication

For normal operation of the circuit breaker, the circuit breaker spring should be charged within a specified time. Therefore, detecting long spring charging time indicates that it is time for the circuit breaker maintenance. The last value of the spring charging time can be used as a service value.

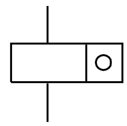
Gas pressure supervision

The gas pressure supervision monitors the gas pressure inside the arc chamber. When the pressure becomes too low compared to the required value, the circuit breaker operations are locked. A binary input is available based on the pressure levels in the function, and alarms are generated based on these inputs.

Section 15 Metering

15.1 Pulse counter PCGGIO

15.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Pulse counter	PCGGIO		-

15.1.2 Application

Pulse counter (PCGGIO) 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 (BIO), and read by the PCGGIO 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, 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 the binary input module in IED can be used for this purpose with a frequency of up to 10 Hz. PCGGIO can also be used as a general purpose counter.

15.1.3 Setting guidelines

From PCM600, these parameters can be set individually for each pulse counter:

- *Operation*: *Disabled*/ *Enabled*
- *tReporting*: *0-3600s*
- *EventMask*: *NoEvents*/ *ReportEvents*

The configuration of the inputs and outputs of PCGGIO function block is made with PCM600.

On the binary input output module (BIO), the debounce filter default time is set to 5 ms, that is, the counter suppresses pulses with a pulse length less than 5 ms. The binary input channels on the binary input output module (BIO) have individual settings for debounce time, oscillation count and oscillation time. The values can be changed in the local HMI and PCM600 under **Main menu/ Configuration/I/O modules**

The setting isindividual for all input channels on the binary input output module (BIO), that is, if changes of the limits are made for inputs not connected to the pulse counter, it will not influence the inputs used for pulse counting.

15.2 Energy calculation and demand handling EPTMMTR

15.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Energy calculation and demand handling	ETPMMTR	Wh↔	-

15.2.2 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 181.

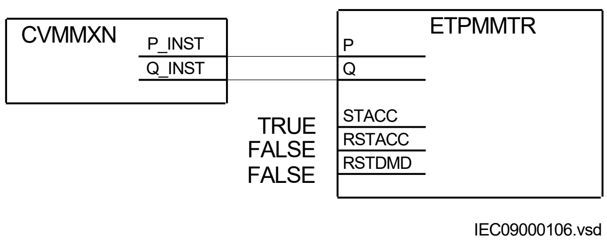


Figure 181: Connection of energy calculation and demand handling function ETPMMTR to the measurements function (CVMMXN)

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. All four values can also be presented.

Maximum demand values are presented in MWh or MVarh in the same way.

Alternatively, the values can be presented with use of the pulse counters function (PCGGIO). The output values are scaled with the pulse output setting values *EAFAccPlsQty*, *EARAccPlsQty*, *ERFAccPlsQty* and *ERRAccPlsQty* 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 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.

15.2.3 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:

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: *Disabled*/ *Enabled*

tEnergy: Time interval when energy is measured.

StartAcc: *Disabled*/ *Enabled* is used to switch the accumulation of energy on and off.

The input signal STACC is used to start accumulation. Input signal STACC cannot be used to halt accumulation. The energy content is reset every time STACC is activated. STACC can for example, be used when an external clock is used to switch two active energy measuring function blocks on and off to have indication of two tariffs.

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 *ERRAccPlsQty*: 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 16 Station communication

16.1 IEC61850-8-1 communication protocol

16.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IEC 61850-8-1 communication protocol	IEC 61850-8-1	-	-

16.1.2 Application

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 182 shows the topology of an IEC 61850–8–1 configuration. IEC 61850–8–1 specifies only the interface to the substation LAN. The LAN itself is left to the system integrator.

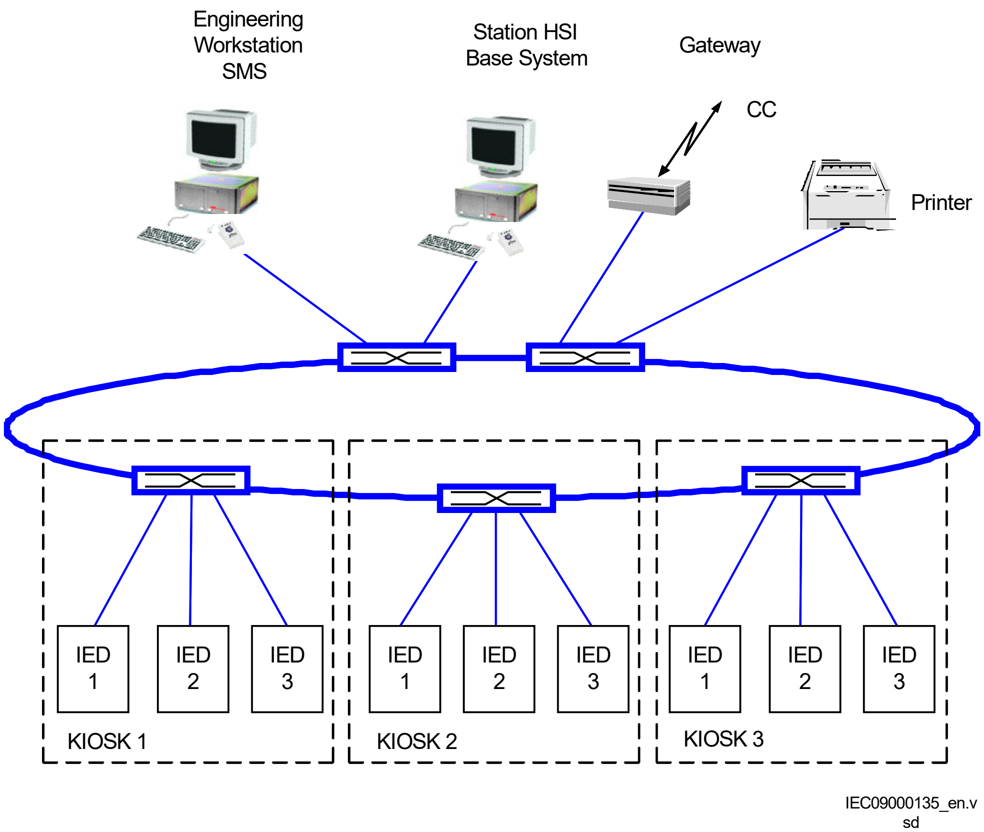


Figure 182: Example of a communication system with IEC 61850

Figure 183 shows the GOOSE peer-to-peer communication.

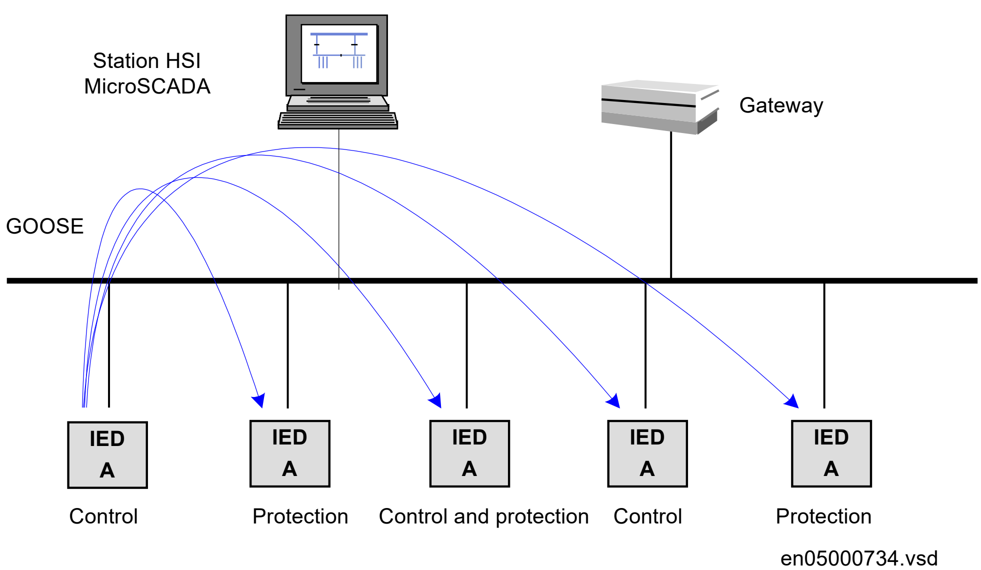


Figure 183: Example of a broadcasted GOOSE message

16.1.2.1 Horizontal communication via GOOSE

GOOSE messages are sent in horizontal communication between the IEDs. The information, which is exchanged, is used for station wide interlocking, breaker failure protection, busbar voltage selection and so on.

The simplified principle is shown in Figure 184 and can be described as follows. When IED1 has decided to transmit the data set it forces a transmission via the station bus. All other IEDs will receive the data set, but only those who have this data set in their address list will take it and keeps it in a input container. It is defined, that the receiving IED will take the content of the received data set and makes it available for the application configuration.

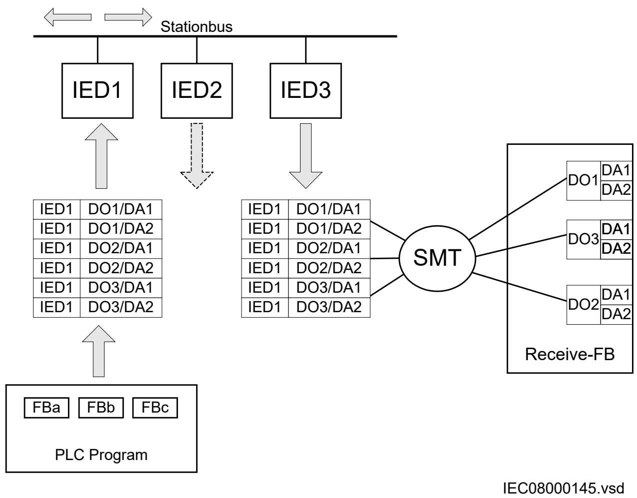


Figure 184: SMT: GOOSE principle and signal routing with SMT

Special function blocks take the data set and present it via the function block as output signals for application functions in the application configuration. Different GOOSE receive function blocks are available for the specific tasks.

SMT links the different data object attributes (for example stVal or magnitude) to the output signal to make it available for functions in the application configuration. When a matrix cell array is marked red the IEC 61850 data attribute type does not fit together, even if the GOOSE receive function block is the partner. SMT checks this on the content of the received data set. See Figure 185

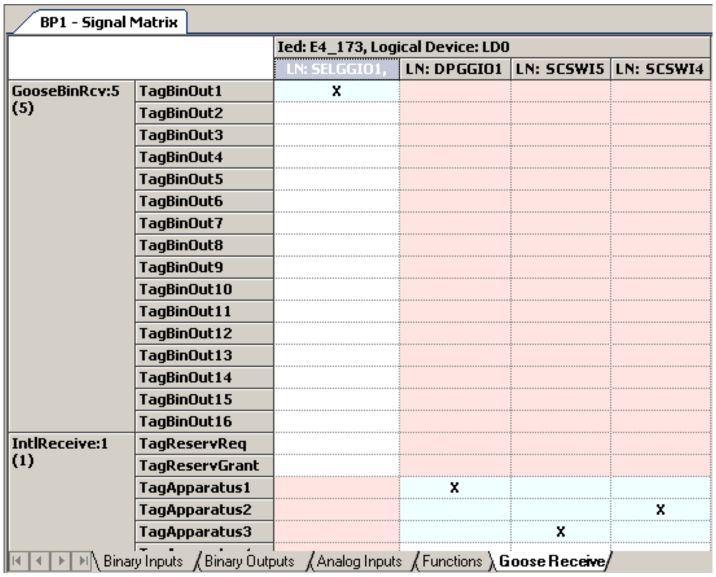


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Figure 185: SMT: GOOSE marshalling with SMT

GOOSE receive function blocks extract process information, received by the data set, into single attribute information that can be used within the application configuration. Crosses in the SMT matrix connect received values to the respective function block signal in SMT, see Figure 186

The corresponding quality attribute is automatically connected by SMT. This quality attribute is available in ACT, through the outputs of the available GOOSE function blocks.

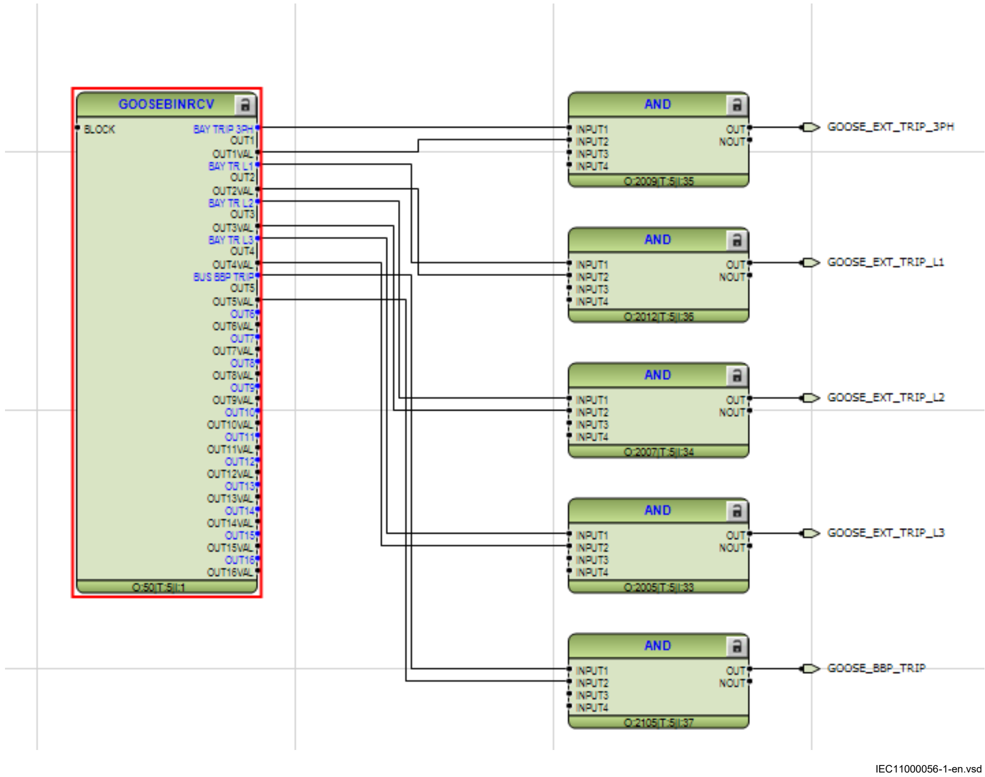

Figure 186: SMT: GOOSE receive function block with converted signals

16.1.3 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*.

GOOSE has to be set to the Ethernet link where GOOSE traffic shall be send and received.

IEC 61850–8–1 specific data (logical nodes etc.) per included function in an IED can be found in the communication protocol manual for IEC 61850.

16.2 DNP3 protocol

DNP3 (Distributed Network Protocol) is a set of communications protocols used to communicate data between components in process automation systems. For a detailed description of the DNP3 protocol, see the DNP3 Communication protocol manual.

16.3 IEC 60870-5-103 communication protocol

IEC 60870-5-103 is an unbalanced (master-slave) protocol for coded-bit serial communication exchanging information with a control system, and with a data transfer rate up to 38400 bit/s. 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 IEC 60870-5-103 communication messages.

The Communication protocol manual for IEC 60870-5-103 includes the 650 series vendor specific IEC 60870-5-103 implementation.

Section 17 Basic IED functions

17.1 Self supervision with internal event list

17.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Internal error signal	INTERRSIG	-	-
Internal event list	SELFSUPEVLST	-	-

17.1.2 Application

The protection and control IEDs have many functions included . Self supervision with internal event list (SELFSUPEVLST) and internal error signals (INTERRSIG) function provide 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 software 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).
- Change lock (on/off)

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 can be cleared via the local HMI .

The list of internal events provides valuable information, which can be used during commissioning and fault tracing.

The list of internal events can be found in the LHMI or viewed in PCM600 using the Event viewer tool.

17.2 Time synchronization

17.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time synchronization	TIMESYNCHGE N	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time system, summer time begins	DSTBEGIN	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time system, summer time ends	DSTEND	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time synchronization via IRIG-B	IRIG-B	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time synchronization via SNTP	SNTP	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time zone from UTC	TIMEZONE	-	-

17.2.2 Application

Use time synchronization to achieve a common time base for the IEDs in a protection and control system. This makes comparison of events and disturbance data between all IEDs in the system possible.

Time-tagging of internal events and disturbances are an excellent help when evaluating faults. Without time synchronization, only the events within the IED can be compared to one another. With time synchronization, events and disturbances within the entire station, and even between line ends, can be compared during evaluation.

In the IED, the internal time can be synchronized from a number of sources:

- SNTP
- IRIG-B
- DNP
- IEC60870-5-103

Micro SCADA OPC server should not be used as a time synchronization source.

17.2.3 Setting guidelines

System time
The time is set with years, month, day, hour, minute and second.

Synchronization
The setting parameters for the real-time clock with external time synchronization (TIME) are set via local HMI or PCM600.

TimeSynch
When the source of the time synchronization is selected on the local HMI, the parameter is called *TimeSynch*. The time synchronization source can also be set from PCM600. The setting alternatives are:

FineSyncSource which can have the following values:

- *Disabled*
- *SNTP*
- *IRIG-B*

CoarseSyncSrc which can have the following values:

- *Disabled*
- *SNTP*
- *DNP*
- *IEC60870-5-103*

The system time can be set manually, either via the local HMI or via any of the communication ports. The time synchronization fine tunes the clock.

IEC 60870-5-103 time synchronization
An IED with IEC 60870-5-103 protocol can be used for time synchronization, but for accuracy reasons, it is not recommended. In some cases, however, this kind of synchronization is needed, for example, when no other synchronization is available.

First, set the IED to be synchronized via IEC 60870-5-103 either from **IED Configuration/Time/Synchronization/TIMESYNCHGEN:1** in PST or from the local HMI.

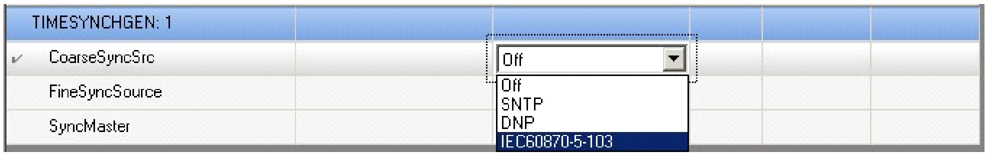

Figure 187: Settings under TIMESYNCHGEN:1 in PST

Only *CoarseSyncSrc* can be set to IEC 60870-5-103, not *FineSyncSource*.

After setting up the time synchronization source, the user must check and modify the IEC 60870-5-103 time synchronization specific settings, under: **IED Configuration/Communication/Station communication/IEC60870-5-103:1**.

- *MasterTimeDomain* specifies the format of the time sent by the master. Format can be:
    - Coordinated Universal Time (*UTC*)
    - Local time set in the master (*Local*)
    - Local time set in the master adjusted according to daylight saving time (*Local with DST*)
- *TimeSyncMode* specifies the time sent by the IED. The time synchronisation is done using the following ways:
    - *IEDTime*: The IED sends the messages with its own time.
    - *LinMasTime*: The IED measures the offset between its own time and the master time, and applies the same offset for the messages sent as in the *IEDTimeSkew*. But in *LinMasTime* it applies the time changes occurred between two synchronised messages.
    - *IEDTimeSkew*: The IED measures the offset in between its own time and the master time and applies the same offset for the messages sent.
- *EvalTimeAccuracy* evaluates time accuracy for invalid time. Specifies the accuracy of the synchronization (5, 10, 20 or 40 ms). If the accuracy is worse than the specified value, the “Bad Time” flag is raised. To accommodate those masters that are really bad in time sync, the *EvalTimeAccuracy* can be set to *Disabled*.

According to the standard, the “Bad Time” flag is reported when synchronization has been omitted in the protection for >23 h.

17.3 Parameter setting group handling

17.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Setting group handling	SETGRPS	-	-
Parameter setting groups	ACTVGRP	-	-

17.3.2 Application

Four sets of settings are available to optimize IED operation for different 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 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. Four 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.

17.3.3 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 ACTVGRP.

The parameter *MaxNoSetGrp* 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 ACTVGRP function block.

17.4 Test mode functionality TESTMODE

17.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Test mode functionality	TESTMODE	-	-

17.4.2 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 so on.

17.4.3 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 INPUT on the TESTMODE function block might be activated in the configuration.

Forcing of binary output signals is only possible when the IED is in test mode.

17.5 Change lock CHNGLCK

17.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Change lock function	CHNGLCK	-	-

17.5.2 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.
ACTIVE	Output status signal
OVERRIDE	Set if function is overridden

When CHNGLCK has a logical one on its input, then all attempts to modify the IED configuration and setting will be denied and the message "Error: Changes blocked" will be displayed on the local HMI; in PCM600 the message will be "Operation denied by active ChangeLock". The CHNGLCK function should be configured so that it is controlled by a signal from a binary input card. This guarantees that by setting that signal to a logical zero, CHNGLCK is deactivated. If any logic is included in the signal path to the CHNGLCK input, that logic must be designed so that it cannot permanently issue a logical one on the CHNGLCK input. If such a situation would occur in spite of these precautions, then please contact the local ABB representative for remedial action.

17.5.3 Setting guidelines

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

17.6 IED identifiers TERMINALID

17.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IED identifiers	TERMINALID	-	-

17.6.2 Application

17.6.2.1 Customer specific settings

The customer specific settings are used to give the IED a unique name and address. The settings are used by a central control system to communicate with the IED. The customer specific identifiers are found in the local HMI under **Configuration/Power system/Identifiers/ TERMINALID**

The settings can also be made from PCM600. For more information about the available identifiers, see the technical manual.

Use only characters A - Z, a - z and 0 - 9 in station, unit and object names.

17.7 Product information PRODINF

17.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Product information	PRODINF	-	-

17.7.2 Application

17.7.2.1 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 (like REL, REC or RET. Example: *REL650*
- ProductDef
  - Describes the release number, from the production. Example: *1.1.0.A1*
- ProductVer
  - Describes the product version. Example: *1.1.0*
- SerialNo
- OrderingNo
- ProductionDate

17.8 Primary system values PRIMVAL

17.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Primary system values	PRIMVAL	-	-

17.8.2 Application

The rated system frequency and phasor rotation are set under **Main menu/Configuration/ Power system/ Primary values/PRIMVAL** in the local HMI and PCM600 parameter setting tree.

17.9 Signal matrix for analog inputs SMAI

17.9.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Signal matrix for analog inputs	SMAI_20_1	-	-

17.9.2 Application

Signal matrix for analog inputs function SMAI (or the pre-processing function) is used within PCM600 in direct relation with the Signal Matrix tool or the Application Configuration tool. Signal Matrix tool represents the way analog inputs are brought in for one IED configuration.

17.9.3 Setting guidelines

The parameters for the signal matrix for analog inputs (SMAI) functions are set via the local HMI, 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 derivates, 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.

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

DFTRefExtOut: Parameter valid for function block SMAI_20_1:1, SMAI_20_1:2 and SMAI_80_1 only. Reference block for external output (SPFCOUT function output).

DFTReference: Reference DFT for the block.

These DFT reference block settings decide DFT reference for DFT calculations (*InternalDFTRef* will use fixed DFT reference based on set system frequency. *DFTRefGrpn* will use DFT reference from the selected group block, when own group selected adaptive DFT reference will be used based on calculated signal frequency from own group. *ExternalDFTRef* will use reference based on input DFTSPFC.

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.

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.

MinValFreqMeas: The minimum value of the voltage for which the frequency is calculated, expressed as percent of GlobeBasVaGrp(n) (for each instance n).

Settings *DFTRefExtOut* and *DFTReference* shall be set to default value *InternalDFTRef* if no VT inputs are available.

Example of adaptive frequency tracking

Task time group 1	
SMAI instance	3 phase group
SMAI_20_1:1	1
SMAI_20_2:1	2
SMAI_20_3:1	3
SMAI_20_4:1	4
SMAI_20_5:1	5
SMAI_20_6:1	6
SMAI_20_7:1	7
SMAI_20_8:1	8
SMAI_20_9:1	9
SMAI_20_10:1	10
SMAI_20_11:1	11
SMAI_20_12:1	12

DFTRefGrp7

Task time group 2	
SMAI instance	3 phase group
SMAI_20_1:2	1
SMAI_20_2:2	2
SMAI_20_3:2	3
SMAI_20_4:2	4
SMAI_20_5:2	5
SMAI_20_6:2	6
SMAI_20_7:2	7
SMAI_20_8:2	8
SMAI_20_9:2	9
SMAI_20_10:2	10
SMAI_20_11:2	11
SMAI_20_12:2	12

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Figure 188: SMAI instances as organized in different task time groups and the corresponding parameter numbers

The example 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.

Example 1

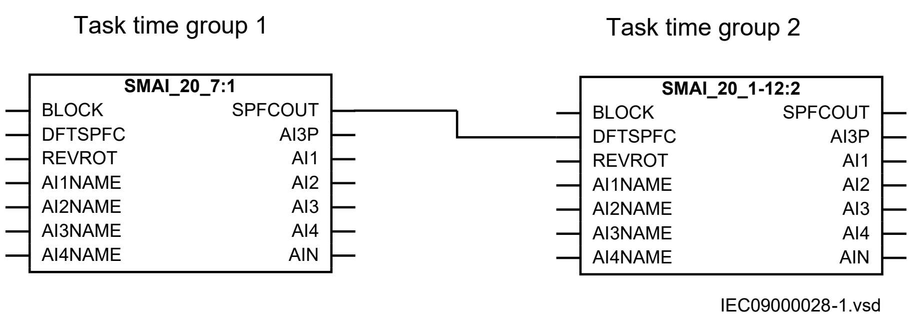

Figure 189: Configuration for using an instance in task time group 1 as DFT reference

Assume instance SMAI_20_7:1 in task time group 1 has been selected in the configuration to control the frequency tracking (For the SMAI_20_x task time groups). 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 188 for numbering):

SMAI_20_7:1: *DFTRefExtOut* = *DFTRefGrp7* to route SMAI_20_7:1 reference to the SPFCOUT output, *DFTReference* = *DFTRefGrp7* for SMAI_20_7:1 to use SMAI_20_7:1 as reference (see Figure 189). .

SMAI_20_2:1 - SMAI_20_12:1 *DFTReference* = *DFTRefGrp7* for SMAI_20_2:1 - SMAI_20_12:1 to use SMAI_20_7:1 as reference.

For task time group 2 this gives the following settings:

SMAI_20_1:2 - SMAI_20_12:2 *DFTReference* = *ExternalDFTRef* to use DFTSPFC input as reference (SMAI_20_7:1)

17.10 Summation block 3 phase 3PHSUM

17.10.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Summation block 3 phase	3PHSUM	-	-

17.10.2 Application

Summation block 3 phase function 3PHSUM is used to get the sum of two sets of three-phase analog signals (of the same type) for those IED functions that might need it.

17.10.3 Setting guidelines

The summation block receives the three-phase signals from SMAI blocks. The summation block has several settings.

Common base IED values for primary current (*IBase*), primary voltage (*VBase*) and primary power (*SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

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*) .

FreqMeasMinVal: The minimum value of the voltage for which the frequency is calculated, expressed as percent of *VBase* (for each instance x).

17.11 Global base values GBASVAL

17.11.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Global base values	GBASVAL	-	-

17.11.2 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 six 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 six sets of GBASVAL functions.

17.11.3 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 $SBase=\sqrt{3}\cdot VBase\cdot IBase$.

17.12 Authority check ATHCHCK

17.12.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Authority check	ATHCHCK	-	-

17.12.2 Application

To safeguard the interests of our customers, both the IED and the tools that are accessing the IED are protected, by means of authorization handling. The authorization handling of the IED and the PCM600 is implemented at both access points to the IED:

- local, through the local HMI
- remote, through the communication ports

17.12.2.1 Authorization handling in the IED

At delivery the default user is the SuperUser. No Log on is required to operate the IED until a user has been created with the User Management Tool.

Once a user is created and written to the IED, that user can perform a Log on, using the password assigned in the tool. Then the default user will be Guest.

If there is no user created, an attempt to log on will display a message box: “No user defined!”

If one user leaves the IED without logging off, then after the timeout (set in **Main menu/ Configuration/HMI/Screen/1:SCREEN**) elapses, the IED returns to Guest state, when only reading is possible. By factory default, the display timeout is set to 60 minutes.

If one or more users are created with the User Management Tool and written to the IED, then, when a user attempts a Log on by pressing the  key or when the user attempts to perform an operation that is password protected, the Log on window opens.

The cursor is focused on the User identity field, so upon pressing the  key, one can change the user name, by browsing the list of users, with the “up” and “down” arrows. After choosing the right user name, the user must press the  key again. When it comes to password, upon pressing the  key, the following characters will show up: “********”. The user must scroll for every letter in the password. After all the letters are introduced (passwords are case sensitive) choose OK and press the key again.

At successful Log on, the local HMI shows the new user name in the status bar at the bottom of the LCD. If the Log on is OK, when required to change for example a password protected setting, the local HMI returns to the actual setting folder. If the Log on has failed, an "Error Access Denied" message opens. If a user enters an incorrect password three times, that user will be blocked for ten minutes before a new attempt to log in can be performed. The user will be blocked from logging in, both from the local HMI and PCM600. However, other users are to log in during this period.

17.13 Authority status ATHSTAT

17.13.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Authority status	ATHSTAT	-	-

17.13.2 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.

17.14 Denial of service

17.14.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Denial of service, frame rate control for front port	DOSFRNT	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Denial of service, frame rate control for LAN1 port	DOSLAN1	-	-

17.14.2 Application

The denial of service functions (DOSFRNT,DOSLAN1 and DOSSCKT) are 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.

DOSFRNT, DOSLAN1 and DOSSCKT measures 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 outputs:

- LINKUP indicates the Ethernet link status
- WARNING indicates that communication (frame rate) is higher than normal
- ALARM indicates that the IED limits communication

17.14.3 Setting guidelines

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

Section 18 Requirements

18.1 Current transformer requirements

The performance of a protection function will depend on the quality of the measured current signal. Saturation of the current transformer (CT) will cause distortion of the current signal 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.

18.1.1 Current transformer classification

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.

There are several different ways to specify CTs. Conventional magnetic core CTs are usually specified and manufactured according to some international or national standards, which specify different protection classes as well. There are many different standards and a lot of classes but fundamentally there are three different types of CTs:

- High remanence type CT
- Low remanence type CT
- Non remanence type CT

The high remanence type has no limit for the remanent flux. This CT has a magnetic core without any airgap and a remanent flux might remain almost infinite time. In this type of transformers the remanence can be up to around 80% of the saturation flux. Typical examples of high remanence type CT are class P, PX, TPS, TPX according to IEC, class P, X according to BS (old British Standard) and non gapped class C, K according to ANSI/IEEE.

The low remanence type has a specified limit for the remanent flux. This CT is made with a small air gap to reduce the remanence to a level that does not exceed 10% of the saturation flux. The small air gap has only very limited influences on the other properties of the CT. Class PR, TPY according to IEC are low remanence type CTs.

The non remanence type CT has practically negligible level of remanent flux. This type of CT has relatively big air gaps in order to reduce the remanence to practically zero level. In the same time, these air gaps reduce the influence of the DC-component from the primary fault current. The air gaps will also decrease the measuring accuracy in the non-saturated region of operation. Class TPZ according to IEC is a non remanence type CT.

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 60044 – 6 standard is used to specify the CT requirements for the IED. The requirements are also specified according to other standards.

18.1.2 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, TPS, 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.

18.1.3 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.

18.1.4 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 and therefore the resistance of the single secondary wire always can be used in the calculation, for this case.

18.1.5 General current transformer requirements

The current transformer ratio is mainly selected based on power system data for example, maximum load. However, 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. The minimum operating current is different for different functions and normally settable so each function should be checked.

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 ±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.

18.1.6 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 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 60044-6 standard. Requirements for CTs specified in different ways are given at the end of this section.

18.1.6.1 Distance protection

The current transformers must have a rated equivalent secondary e.m.f. E_{al} that is larger than the maximum of the required secondary e.m.f. E_{alreq} below:

$$E_{al} \geq E_{alreq} = \frac{I_{k\max} \cdot I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_n^2} \right)$$

(Equation 196)

$$E_{al} \geq E_{alreq} = \frac{I_{kzone1} \cdot I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_n^2} \right)$$

(Equation 197)

where:

I_{kmax}	Maximum primary fundamental frequency current for close-in forward and reverse faults (A)
I_{kzone1}	Maximum primary fundamental frequency current for faults at the end of zone 1 reach (A)
I_{pn}	The rated primary CT current (A)
I_{sn}	The rated secondary CT current (A)
I_n	The nominal current of the protection IED (A)
R_{CT}	The secondary resistance of the CT (Ω)
R_L	The resistance of the secondary wire and additional load (Ω). In solidly grounded systems the loop resistance containing the phase and neutral wires should be used for phase-to-ground faults and the resistance of the phase wire should be used for three-phase faults. In isolated or high impedance grounded systems the resistance of the single secondary wire always can be used.
S_R	The burden of an IED current input channel (VA). S_R=0.010 VA/channel for I_r=1 A and S_r=0.250 VA/channel for I_r=5 A
a	This factor is a function of the primary time constant for the dc component in the fault current. a= 2 for the primary time constant $T_p \leq$ 50 ms a = 3 for the primary time constant $T_p >$ 50 ms
k	A factor of the primary time constant for the dc component in the fault current for a three-phase fault at the set reach of zone 1. k = 4 for the primary time constant $T_p \leq$ 30 ms k = 6 for the primary time constant $T_p >$ 30 ms

18.1.6.2 Breaker failure protection

The CTs must have a rated equivalent secondary e.m.f. E_{al} that is larger than or equal to the required secondary e.m.f. E_{alreq} below:

$$E_{al} \geq E_{alreq} = 5 \cdot I_{op} \cdot \frac{I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_n^2} \right)$$

(Equation 198)

where:

I_{op}	The primary operate value (A)
I_{pn}	The rated primary CT current (A)
I_{sn}	The rated secondary CT current (A)
I_n	The nominal current of the protection IED (A)
R_{CT}	The secondary resistance of the CT (Ω)
R_L	The resistance of the secondary cable and additional load (Ω). The loop resistance containing the phase and neutral wires, must be used for faults in solidly grounded systems. The resistance of a single secondary wire should be used for faults in high impedance grounded systems.
S_R	The burden of an IED current input channel (VA). S_R=0.010 VA/channel for I_r=1 A and S_R=0.250 VA/channel for I_r=5 A

18.1.6.3 Non-directional instantaneous and definitive time, phase and residual overcurrent protection

The CTs must have a rated equivalent secondary e.m.f. E_{al} that is larger than or equal to the required secondary e.m.f. E_{alreq} below:

$$E_{al} \geq E_{alreq} = 1.5 \cdot I_{op} \cdot \frac{I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_n^2} \right)$$

(Equation 199)

where:

I_{op}	The primary operate value (A)
I_{pn}	The rated primary CT current (A)
I_{sn}	The rated secondary CT current (A)
I_n	The nominal current of the protection IED (A)
R_{CT}	The secondary resistance of the CT (Ω)
R_L	The resistance of the secondary cable and additional load (Ω). The loop resistance containing the phase and neutral wires, must be used for faults in solidly grounded systems. The resistance of a single secondary wire should be used for faults in high impedance grounded systems.
S_R	The burden of an IED current input channel (VA). S_R=0.010 VA/channel for I_r=1 A and S_R=0.250 VA/channel for I_r=5 A

18.1.6.4 Non-directional inverse time delayed phase and residual overcurrent protection

The requirement according to Equation 200 and Equation 201 does not need to be fulfilled if the high set instantaneous or definitive time stage is used. In this case Equation is the only necessary requirement.

If the inverse time delayed function is the only used overcurrent protection function the CTs must have a rated equivalent secondary e.m.f. E_{al} that is larger than or equal to the required secondary e.m.f. E_{alreq} below:

$$E_{al} \geq E_{alreq} = 20 \cdot I_{op} \cdot \frac{I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_n^2} \right)$$

(Equation 200)

where

I_{op}	The primary current set value of the inverse time function (A)
I_{pn}	The rated primary CT current (A)
I_{sn}	The rated secondary CT current (A)
I_n	The nominal current of the protection IED (A)
R_{CT}	The secondary resistance of the CT (Ω)
R_L	The resistance of the secondary cable and additional load (Ω). The loop resistance containing the phase and neutral wires, must be used for faults in solidly grounded systems. The resistance of a single secondary wire should be used for faults in high impedance grounded systems.
S_R	The burden of an IED current input channel (VA). S_R=0.010 VA/channel for I_r=1 A and S_R=0.250 VA/channel for I_r=5 A

Independent of the value of I_{op} the maximum required E_{al} is specified according to the following:

$$E_{al} \geq E_{alreqmax} = I_{kmax} \cdot \frac{I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_n^2} \right)$$

(Equation 201)

where

I_{kmax}	Maximum primary fundamental frequency current for close-in faults (A)

18.1.6.5 Directional phase and residual overcurrent protection

If the directional overcurrent function is used the CTs must have a rated equivalent secondary e.m.f. E_{al} that is larger than or equal to the required equivalent secondary e.m.f. E_{alreq} below:

$$E_{al} \geq E_{alreq} = I_{k\max} \cdot \frac{I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_n^2} \right)$$

(Equation 202)

where:

I_{kmax}	Maximum primary fundamental frequency current for close-in forward and reverse faults (A)
I_{pn}	The rated primary CT current (A)
I_{sn}	The rated secondary CT current (A)
I_n	The rated current of the protection IED (A)
R_{CT}	The secondary resistance of the CT (Ω)
R_L	The resistance of the secondary cable and additional load (Ω). The loop resistance containing the phase and neutral wires, must be used for faults in solidly grounded systems. The resistance of a single secondary wire should be used for faults in high impedance grounded systems.
S_R	The burden of an IED current input channel (VA). S_r=0.010 VA/channel for I_r=1 A and S_r=0.250 VA/channel for I_r=5 A

18.1.7 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 secondary e.m.f. E_{al} according to the IEC 60044-6 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 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.

18.1.7.1 Current transformers according to IEC 60044-1, class P, PR

A CT according to IEC 60044-1 is specified by the secondary limiting e.m.f. E_{2max}. The value of the E_{2max} is approximately equal to the corresponding E_{al} according to IEC 60044-6. Therefore, the CTs according to class P and PR must have a secondary limiting e.m.f. E_{2max} that fulfills the following:

$$E_{2\max} > \max\text{imum of } E_{alreq}$$

(Equation 203)

18.1.7.2 Current transformers according to IEC 60044-1, class PX, 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, 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 60044-6. 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, 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 204)

18.1.7.3 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 U_{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:

$$E_{alANSI} = \left|20 \cdot I_{SN} \cdot R_{CT} + V_{ANSI}\right| = \left|20 \cdot I_{SN} \cdot R_{CT} + 20 \cdot I_{SN} \cdot Z_{bANSI}\right|$$

(Equation 205)

where:

Z_{bANSI}	The impedance (that is, 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 fulfills the following:

$$E_{alANSI} > \max imum\ of\ E_{alreq}$$

(Equation 206)

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 60044 6. Therefore, the CTs according to ANSI/IEEE must have a knee-point voltage $V_{kneeANSI}$ that fulfills the following:

18.2 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 60044–5 standard regarding ferro-resonance and transients. The ferro-resonance requirements of the CCVTs are specified in chapter 7.4 of the standard.

The transient responses for three different standard transient response classes, T1, T2 and T3 are specified in chapter 15.5 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.

18.3 SNTP server requirements

18.3.1 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.

Section 19 Glossary

AC	Alternating current
ACT	Application configuration tool within PCM600
A/D converter	Analog-to-digital converter
ADBS	Amplitude deadband supervision
AI	Analog input
ANSI	American National Standards Institute
AR	Autoreclosing
ASCT	Auxiliary summation current transformer
ASD	Adaptive signal detection
AWG	American Wire Gauge standard
BI	Binary input
BOS	Binary outputs status
BR	External bistable relay
BS	British Standards
CAN	Controller Area Network. ISO standard (ISO 11898) for serial communication
CB	Circuit breaker
CCITT	Consultative Committee for International Telegraph and Telephony. A United Nations-sponsored standards body within the International Telecommunications Union.
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
COMTRADE	Standard Common Format for Transient Data Exchange format for Disturbance recorder according to IEEE/ANSI C37.111, 1999 / IEC60255-24
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
CPU	Central processor unit
CR	Carrier receive
CRC	Cyclic redundancy check
CROB	Control relay output block
CS	Carrier send

CT	Current transformer
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/ANSI Std. 1379-2000
DR	Disturbance recorder
DRAM	Dynamic random access memory
DRH	Disturbance report handler
DSP	Digital signal processor
DTT	Direct transfer trip scheme
EHV network	Extra high voltage network
EIA	Electronic Industries Association
EMC	Electromagnetic compatibility
EMF	(Electric Motive Force)
EMI	Electromagnetic interference
EnFP	End fault protection
EPA	Enhanced performance architecture
ESD	Electrostatic discharge
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
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
HDLC protocol	High-level data link control, protocol based on the HDLC standard
HFBR connector type	Plastic fiber connector
HMI	Human-machine interface
HSAR	High speed autoreclosing
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 61850	Substation automation communication 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).
IED	Intelligent electronic device
I-GIS	Intelligent gas-insulated switchgear
Instance	When several occurrences of the same function are available in the IED, they are referred to as instances of that function. One instance of a function is identical to another of the same kind but has a different number in the IED user interfaces. The word "instance" is sometimes defined as an item of information that is representative of a type. In the same way an instance of a function in the IED is representative of a type of function.
IP	1. Internet protocol. The network layer for the TCP/IP protocol suite widely used on Ethernet networks. IP is a connectionless, best-effort packet-switching protocol. It provides packet routing, fragmentation and reassembly through the data link layer. 2. Ingression protection, according to IEC standard
IP 20	Ingression protection, according to IEC standard, level IP20- Protected against solidforeign objects of12.5mm diameter andgreater.
IP 40	Ingression protection, according to IEC standard, level IP40-Protected against solid foreign objects of 1mm diameter and greater.
IP 54	Ingression protection, according to IEC standard, level IP54-Dust-protected,protected againstsplashing 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
LDD	Local detection device
LED	Light-emitting diode
MCB	Miniature circuit breaker
MCM	Mezzanine carrier module
MVB	Multifunction vehicle bus. Standardized serial bus originally developed for use in trains.
NCC	National Control Centre
OCO cycle	Open-close-open cycle
OCP	Overcurrent protection
OLTC	On-load tap changer
OV	Over-voltage
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
PISA	Process interface for sensors & actuators
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
PSM	Power supply module
PST	Parameter setting tool within PCM600
PT ratio	Potential transformer or voltage transformer ratio
PUTT	Permissive underreach transfer trip
RASC	Synchrocheck relay, COMBIFLEX
RCA	Relay characteristic angle
RFPP	Resistance for phase-to-phase faults

	Resistance for phase-to-ground faults
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
SCS	Station control system
SCADA	Supervision, control and data acquisition
SCT	System configuration tool according to standard IEC 61850
SDU	Service data unit
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.
SRY	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.
TNC connector	Threaded Neill-Concelman, a threaded constant impedance version of a BNC connector
TPZ, TPY, TPX, TPS	Current transformer class according to IEC
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.
U/I-PISA	Process interface components that deliver measured voltage and current values
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
$3I_O$	Three times zero-sequence current. Often referred to as the residual or the -fault current
	Three times the zero sequence voltage. Often referred to as the residual voltage or the neutral point voltage

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