

# Easergy P3G30 and P3G32

## Generator protection with machine differential protection

### User Manual

P3G/en M/F006

02/2020





# Table of Contents

1 About this manual.....	13
1.1 Purpose.....	13
1.2 Related documents.....	13
1.3 Abbreviations and terms.....	14
2 Product introduction.....	19
2.1 Warranty.....	19
2.2 Product overview.....	19
2.3 Product selection guide.....	20
2.4 Access to device configuration.....	28
2.4.1 User accounts.....	28
2.4.2 Logging on via the front panel.....	29
2.4.3 HTTP and FTP logon details.....	30
2.4.4 Password management.....	30
2.4.5 Changing passwords for administrator and configurator accounts via PuTTY.....	30
2.4.6 Password restoring.....	32
2.5 Front panel.....	32
2.5.1 Push-buttons.....	33
2.5.2 LED indicators.....	34
2.5.3 Configuring the LED names via Easergy Pro.....	35
2.5.4 Controlling the alarm screen.....	36
2.5.5 Accessing operating levels.....	36
2.5.6 Adjusting the LCD contrast.....	36
2.5.7 Testing the LEDs and LCD screen.....	36
2.5.8 Controlling an object with selective control.....	36
2.5.9 Controlling an object with direct control.....	37
2.5.10 Menus.....	37
2.5.10.1 Moving in the menus .....	39
2.5.10.2 Local panel messages.....	39
2.6 Easergy Pro setting and configuration tool.....	40
3 Mechanical structure.....	41
3.1 Modularity.....	41
3.2 Slot info and order code.....	42
4 Measurement functions.....	44
4.1 Primary, secondary and per unit scaling.....	46
4.1.1 Frequency adaptation mode.....	49
4.1.2 Current transformer ratio.....	50
4.1.3 Voltage transformer ratio.....	52
4.2 Measurements for protection functions.....	55
4.3 Measurements for arc flash detection function.....	55
4.4 RMS values.....	56

4.5 Harmonics and total harmonic distortion (THD).....	57
4.6 Demand values.....	57
4.7 Minimum and maximum values.....	59
4.8 Maximum values of the last 31 days and 12 months.....	60
4.9 Power and current direction.....	61
4.10 Symmetrical components.....	63
<b>5 Control functions.....</b>	<b>64</b>
5.1 Digital outputs.....	64
5.2 Digital inputs.....	67
5.3 Virtual inputs and outputs.....	71
5.4 Matrix.....	74
5.4.1 Output matrix.....	75
5.4.2 Blocking matrix.....	76
5.4.3 LED matrix.....	77
5.4.4 Object block matrix.....	79
5.5 Releasing latches.....	80
5.5.1 Releasing latches using Easergy Pro.....	80
5.5.2 Releasing latches using buttons and local panel display.....	80
5.5.3 Releasing latches using F1 or F2 buttons.....	81
5.6 Controllable objects.....	82
5.6.1 Object control with digital inputs.....	83
5.6.2 Local or remote selection.....	83
5.6.3 Object control with Close and Trip buttons.....	84
5.6.4 Object control with F1 and F2.....	84
5.7 Logic functions.....	85
5.8 Local panel.....	93
5.8.1 Mimic view.....	93
5.8.2 Local panel configuration.....	96
<b>6 Protection functions.....</b>	<b>100</b>
6.1 Maximum number of protection stages in one application.....	100
6.2 General features of protection stages.....	100
6.3 Dependent operate time.....	108
6.3.1 Standard dependent delays using IEC, IEEE, IEEE2 and RI curves..	110
6.3.2 Custom curves.....	124
6.3.3 Programmable dependent time curves.....	125
6.4 Underimpedance (ANSI 21G).....	126
6.5 Volts/hertz overexcitation protection (ANSI 24).....	129
6.6 Synchronism check (ANSI 25).....	131
6.7 Undervoltage (ANSI 27).....	134
6.8 Positive sequence undervoltage (ANSI 27P).....	137
6.9 Directional power (ANSI 32) .....	140
6.10 Loss of field (ANSI 40).....	141
6.11 Under-reactance (ANSI 21/40) .....	143
6.12 Negative sequence overcurrent (ANSI 46) .....	147
6.13 Negative sequence overvoltage protection (ANSI 47).....	149



6.14 Thermal overload (ANSI 49 RMS).....	150
6.15 Breaker failure 1 (ANSI 50BF).....	154
6.16 Breaker failure 2 (ANSI 50BF).....	155
6.17 Switch-on-to-fault (ANSI 50HS) .....	161
6.18 Phase overcurrent (ANSI 50/51).....	163
6.19 Ground fault overcurrent (ANSI 50N/51N) .....	166
6.19.1 Ground fault phase detection.....	169
6.20 Capacitor bank unbalance (ANSI 51C) .....	170
6.21 Voltage-dependent overcurrent (ANSI 51V) .....	176
6.22 Overvoltage (ANSI 59).....	178
6.23 Neutral overvoltage (ANSI 59N).....	181
6.24 Stator ground fault (ANSI 64S).....	183
6.25 Restricted ground fault (ANSI 64REF) .....	186
6.26 Directional phase overcurrent (ANSI 67) .....	192
6.27 Directional ground fault overcurrent (ANSI 67N).....	197
6.27.1 Ground fault phase detection.....	203
6.28 Second harmonic inrush detection (ANSI 68F2).....	203
6.29 Fifth harmonic detection (ANSI 68H5).....	204
6.30 Pole slip protection (ANSI 78).....	205
6.31 Overfrequency and underfrequency (ANSI 81) .....	211
6.32 Rate of change of frequency (ANSI 81R).....	213
6.33 Lockout (ANSI 86).....	218
6.34 Differential overcurrent protection (ANSI 87M) .....	219
6.35 Arc flash detection (AFD).....	226
6.35.1 Arc flash detection, general principle.....	226
6.35.2 Arc flash detection menus.....	226
6.35.3 Configuration example of arc flash detection.....	227
6.35.4 Arc flash detection characteristics.....	231
6.36 Programmable stages (ANSI 99).....	232
<b>7 Supporting functions.....</b>	<b>235</b>
7.1 Event log.....	235
7.2 Disturbance recording.....	236
7.3 Cold load start and magnetizing inrush.....	242
7.4 System clock and synchronization.....	244
7.5 Voltage sags and swells.....	249
7.6 Voltage interruptions.....	252
7.7 Current transformer supervision (ANSI 60).....	254
7.8 Voltage transformer supervision (ANSI 60FL).....	255
7.9 Circuit breaker wear.....	256
7.10 Circuit breaker condition monitoring.....	262
7.11 Energy pulse outputs.....	265
7.12 Running hour counter.....	268
7.13 Timers.....	269
7.14 Combined overcurrent status.....	271

7.15 Trip circuit supervision (ANSI 74) .....	274
7.15.1 Trip circuit supervision with one digital input.....	274
7.15.2 Trip circuit supervision with two digital inputs.....	280
<b>8 Communication and protocols.....</b>	<b>284</b>
8.1 Cybersecurity.....	284
8.2 Communication ports.....	284
8.2.1 Ethernet port.....	286
8.2.2 Disabling the Ethernet communication.....	287
8.3 Communication protocols.....	288
8.3.1 Modbus RTU and Modbus TCP.....	288
8.3.2 Profibus DP.....	289
8.3.3 SPA-bus.....	289
8.3.4 IEC 60870-5-103 (IEC-103).....	290
8.3.5 DNP 3.0.....	291
8.3.6 IEC 60870-5-101 (IEC-101).....	291
8.3.7 IEC 61850.....	291
8.3.8 HTTP server – Webset.....	292
8.4 IP filter.....	292
8.4.1 Configuring the IP filter.....	293
8.4.2 Unexpected packets.....	294
8.4.3 Alarms.....	295
<b>9 Applications and configuration examples.....</b>	<b>296</b>
9.1 Rotor ground fault protection (ANSI 64R).....	296
9.2 Arc flash detection.....	297
9.3 Using CSH120 and CSH200 with core balance CTs.....	300
<b>10 Installation.....</b>	<b>302</b>
10.1 Safety in installation.....	302
10.2 Checking the consignment.....	303
10.3 Product identification.....	304
10.4 Storage.....	305
10.5 Mounting.....	306
10.6 Connections.....	310
10.6.1 Supply voltage cards.....	311
10.6.2 Analog measurement cards.....	312
10.6.2.1 Analog measurement card 1 (slot 8).....	313
10.6.2.2 Analog measurement card 2 (slot 8).....	314
10.6.2.3 Analog measurement card 1 (slot 4).....	316
10.6.3 I/O cards.....	317
10.6.3.1 I/O card “B = 3BIO+2Arc”.....	317
10.6.3.2 I/O card “C = F2BIO+1Arc”.....	318
10.6.3.3 I/O card “D = 2IGBT”.....	320
10.6.3.4 I/O option card “D=4Arc”.....	321
10.6.3.5 I/O card “G = 6DI+4DO”.....	321
10.6.3.6 I/O card “H = 6DI + 4DO (NC)”.....	323
10.6.3.7 I/O card “I = 10DI”.....	324

10.6.4 Arc flash sensor.....	326
10.6.4.1 Mounting the sensors to the switchgear.....	327
10.6.4.2 Connecting the sensors to the device.....	329
10.6.5 Communication cards.....	331
10.6.5.1 COM 3 – COM 4 ports.....	337
10.6.6 Local port.....	341
10.6.7 Connection data.....	342
10.6.8 External option modules.....	350
10.6.8.1 VSE-001 fiber optic interface module.....	350
10.6.8.2 VSE-002 RS-485 interface module.....	351
10.6.8.3 VSE-009 DeviceNet interface module.....	353
10.6.8.4 VPA-3CG Profibus interface module.....	354
10.6.8.5 VIO 12A RTD and analog input / output modules.....	355
10.6.9 Block diagrams.....	355
10.6.10 Connection examples.....	358
10.7 Arc flash detection system setup and testing.....	359
10.7.1 Setting up the arc flash system.....	359
10.7.2 Commissioning and testing.....	360
10.7.2.1 Checking zones.....	361
10.7.2.2 Disconnecting trip circuits.....	362
10.7.2.3 Sensor testing.....	363
10.7.2.3.1 Testing the sensors.....	364
10.7.2.3.2 Testing the sensor supervision.....	364
10.7.2.3.3 Testing the binary I/O connectivity.....	365
10.7.3 Test report .....	365
10.7.3.1 Filling in the test report.....	365
10.7.3.2 Test report example.....	367
10.7.4 Troubleshooting.....	368
10.8 Voltage system configuration.....	368
10.8.1 Multiple channel voltage measurement.....	369
10.9 CSH120 and CSH200 Core balance CTs.....	378
<b>11 Test and environmental conditions.....</b>	<b>382</b>
11.1 Disturbance tests.....	382
11.2 Electrical safety tests.....	383
11.3 Mechanical tests.....	384
11.4 Environmental tests.....	384
11.5 Environmental conditions.....	385
11.6 Casing.....	385
<b>12 Maintenance.....</b>	<b>386</b>
12.1 Preventive maintenance.....	386
12.2 Periodic testing.....	387
12.3 Hardware cleaning.....	387
12.4 System status messages.....	387
12.5 Spare parts.....	387

12.6 Self-supervision.....	387
12.6.1 Diagnostics.....	390
12.7 Arc flash detection system maintenance.....	392
12.7.1 Visual inspection.....	393
12.7.2 Hardware cleaning.....	393
12.7.3 Sensor condition and positioning check.....	393
13 Order codes and accessories.....	394
13.1 Order codes.....	394
13.2 Accessories.....	395
14 Firmware revision.....	397

## Legal information

The Schneider Electric brand and any registered trademarks of Schneider Electric Industries SAS referred to in this guide are the sole property of Schneider Electric SA and its subsidiaries. They may not be used for any purpose without the owner's permission, given in writing. This guide and its content are protected, within the meaning of the French intellectual property code (Code de la propriété intellectuelle français, referred to hereafter as "the Code"), under the laws of copyright covering texts, drawings and models, as well as by trademark law. You agree not to reproduce, other than for your own personal, noncommercial use as defined in the Code, all or part of this guide on any medium whatsoever without Schneider Electric's permission, given in writing. You also agree not to establish any hypertext links to this guide or its content. Schneider Electric does not grant any right or license for the personal and noncommercial use of the guide or its content, except for a non-exclusive license to consult it on an "as is" basis, at your own risk. All other rights are reserved.

Electrical equipment should be installed, operated, serviced and maintained only by qualified personnel. No responsibility is assumed by Schneider Electric for any consequences arising out of the use of this material.

As standards, specifications and designs change from time to time, please ask for confirmation of the information given in this publication.

# Safety information

## Important information

Read these instructions carefully and look at the equipment to become familiar with the device before trying to install, operate, service or maintain it.

The following special messages may appear throughout this publication or on the equipment to warn of potential hazards or to call attention to information that clarifies or simplifies a procedure.



This is the safety alert symbol. It is used to alert you to potential personal injury hazards. Obey all safety messages that follow this symbol to avoid possible injury or death.



The addition of either symbol to a “Danger” or “Warning” safety label indicates that an electrical hazard exists which will result in personal injury if the instructions are not followed.

<b>⚠ DANGER</b>
<b>DANGER</b> indicates a hazardous situation which, if not avoided, <b>will result in</b> death or serious injury.

<b>⚠ WARNING</b>
<b>WARNING</b> indicates a hazardous situation which, if not avoided, <b>could result in</b> death or serious injury.

<b>⚠ CAUTION</b>
<b>CAUTION</b> indicates a hazardous situation which, if not avoided, <b>could result in</b> minor or moderate injury.

<b>NOTICE</b>
<b>NOTICE</b> is used to address practices not related to physical injury.

### Please note

Electrical equipment must only be installed, operated, serviced, and maintained by qualified personnel. A qualified person is one who has skills and knowledge related to the construction, installation, and operation of electrical equipment and has received safety training to recognize and avoid the hazards involved.

No responsibility is assumed by Schneider Electric for any consequences arising out of the use of this material.

### Protective grounding

The user is responsible for compliance with all the existing international and national electrical codes concerning protective grounding of any device.

## North America regulatory compliance



Certificate number: 20190829-E215590

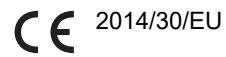
Issue date: 2019-August-29

UL certifies that the Easergy P3 products comply with the following standards:

- UL 508 Industrial Control Equipment
- CSA C22.2 No. 14-13 Industrial Control Equipment
- IEEE C37.90-2005 Guide for Power System Protection Testing
- IEEE C37.90.1-2012 Standard for Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electrical Power Apparatus
- IEEE C37.90.2-2004 Standard for Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

# EU directive compliance

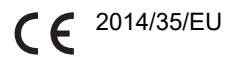
## EMC compliance



Compliance with the European Commission's EMC Directive. Product Specific Standard was used to establish conformity:

- EN 60255-26 2013

## Product safety



Compliance with the European Commission's Low Voltage Directive. Product Specific Safety Standard was used to establish conformity:

- EN 60255-27 2014



# 1 About this manual

## 1.1 Purpose

This document contains instructions on the installation, commissioning and operation of Easergy P3G30 and P3G32.

This document is intended for persons who are experts on electrical power engineering, and it covers the relay models as described by the order code.

### Related topics

[Order codes](#) on page 394

## 1.2 Related documents

Table 1 - Related documents

Document	Identification <sup>1</sup>
P3 Advanced Quick Start	P3x3x/EN QS/xxxx
Easergy Pro Setting and Configuration Tool User Manual	P3eSetup/EN M/xxxx
RTD and mA Output/Input Modules User Manual	P3VIO12A/EN M/A001
Profibus Interface Module User Manual	P3VPA3CG/EN M/A001
IEC 61850 configuration instructions	P3APS17001EN
Rapid Spanning Tree Protocol (RSTP)	P3APS17002EN
Parallel Redundancy Protocol for Easergy P3 relays with dual-port 100 Mbps Ethernet interface	P3APS17004EN
Communication parameter protocol mappings	P3TDS17005EN
Easergy P3 protection functions' parameters and recorded values	P3TDS17006EN
DeviceNet data model	P3APS17008EN
IEC103 Interoperability List	P3TDS17009EN
DNP 3.0 Device Profile Document	P3TDS17010EN
P3 Advanced Series facia label instruction	P3TDS17012EN
Principles of numerical protection techniques	P3INS17019EN

<sup>1</sup> xxxx = revision number

## 1.3 Abbreviations and terms

AFD	Arc flash detection
ANSI	American National Standards Institute A standardization organisation
bps	Bits per second
CB	Circuit breaker
CBFP	Circuit breaker failure protection
CLPU	Cold load pickup
CM	Common mode
Controlling output	Heavy duty output rated for the circuit breaker controlling
CPU	Central processing unit
$\cos\phi$	Active power divided by apparent power = P/S (See power factor PF.) Negative sign indicates reverse power.
CT	Current transformer
$CT_{PRI}$	Nominal primary value of current transformer
$CT_{SEC}$	Nominal secondary value of current transformer
Dead band	See hysteresis.
DI	Digital input
Digital output	Relay's output contact
DM	Differential mode
DMS	Distribution management system
DO	Digital output
Document file	Stores information about the relay settings, events and fault logs
DSR	Data set ready An RS232 signal. Input in front panel port of Easergy P3 devices to disable rear panel local port.
DST	Daylight saving time Adjusting the official local time forward by one hour for summer time.
DT	Definite time

DTR	Data terminal ready An RS232 signal. Output and always true (+8 Vdc) in front panel port of Easergy P3 relays.
Easergy P3 Standard	P3U10, P3U20 and P3U30 relays
Easergy P3 Advanced	P3F30, P3L30, P3M30/32, P3G30/32 and P3T32 relays
eSetup Easergy Pro	Setting and configuration tool for Easergy P3 protection relays, later called Easergy Pro
F2BIO	2 x optical BIO interfaces, fibre
GOOSE	Generic object-oriented substation event A specific definition of a type of generic substation event, for peer-peer communication.
Hysteresis	I.e. dead band Used to avoid oscillation when comparing two nearby values.
IDMT	Inverse definite minimum time
$I_{MODE}$	Nominal current of the selected mode In feeder mode, $I_{MODE} = V_{T_{PRIMARY}}$ . In motor mode, $I_{MODE} = I_{MOT}$ .
$I_{MOT}$	Nominal current of the protected motor
$I_{GN}$	Nominal current of the protected generator
$I_{NOM}$	Nominal current Rating of CT primary or secondary
$I_{SET}$	Start setting value $I > (50/51)$
$I_{N(nom)}$	Nominal current of $I_N$ input in general
IEC	International Electrotechnical Commission An international standardization organisation
IEC-101	Communication protocol defined in standard IEC 60870-5-101
IEC-103	Communication protocol defined in standard IEC 60870-5-103
IEEE	Institute of Electrical and Electronics Engineers
IRIG-B	Inter-Range Instrumentation Group time code B Standard for time transfer
IT	Instrument transformer (current or voltage transformer): electrical device used to isolate or transform voltage or current levels

LAN	Local area network Ethernet-based network for computers and devices
Latching	Digital outputs and indication LEDs can be latched, which means that they are not released when the control signal is releasing. Releasing of latched devices is done with a separate action.
LCD	Liquid crystal display
LED	Light-emitting diode
NTP	Network Time Protocol for LAN and WWW
OVF	Indication of the event overflow
P	Active power Unit = [W]
PF	Power factor The absolute value is equal to $\cos\phi$ , but the sign is 'IND' for inductive i.e. lagging current and 'CAP' for capacitive i.e. leading current.
PLC	Programmable logic controller
$P_M$	Nominal power of the prime mover (Used by reverse/under power protection.)
POC signals	Binary signals that are transferred in the communication channel of two P3L30 line differential relays in both directions. POC signals are used to transfer statuses of the DI, VI, VO and logic outputs.
pu PU	Per unit Depending of the context, the per unit refers to any nominal value. For example, for overcurrent setting $1 \text{ pu} = 1 \times I_{GN}$ .
P3G30	P3G30 generator protection relay
Q	Reactive power Unit = [var]
RELxxxx	Short order code
RH	Relative humidity
RMS	Root mean square
RS232 or RS485 (EIA-232 or EIA-485)	Standard defining the electrical characteristics of a serial communication interface
RTU	Remote terminal unit

S	Apparent power Unit = [VA]
SCADA	Supervisory control and data acquisition
SF	Alarm duty watchdog output is energized when the auxiliary power supply is on and the product status is operative. This output is referenced as "service status output" in the setting tool.
Signaling output	Alarm duty output rated, not suitable for direct circuit breaker controlling
SNTP	Simple Network Time Protocol for LAN and WWW
SOTF	Switch on to fault
SPST	Single pole single throw
SPDT	Single pole double throw
TCS	Trip circuit supervision
THD	Total harmonic distortion
V	Voltage V
$V_{NSEC}$	Voltage at input $V_C$ at zero ohm ground fault. (Used in voltage measurement mode "2LL+ $V_N$ ")
$V_A$	Voltage input for $V_{AB}$ or $V_A$ depending on the voltage measurement mode
$V_B$	Voltage input for $V_{BC}$ or $V_B$ depending on the voltage measurement mode
$V_C$	Voltage input for $V_{CA}$ or $V_N$ depending on the voltage measurement mode
$V_N$	Neutral voltage Rating of VT primary or secondary
$V_{NOM}$	Nominal voltage Rating of VT primary or secondary
UMI	User-machine interface
USB	Universal serial bus
UTC	Coordinated Universal Time Used to be called GMT = Greenwich Mean Time
Webset	http configuration interface
VI	Virtual input

VO	Virtual output
VT	Voltage transformer
VT <sub>PRI</sub>	Nominal primary value of voltage transformer
VT <sub>SEC</sub>	Nominal secondary value of voltage transformer

## 2 Product introduction

### 2.1 Warranty

This product has a standard warranty of 10 years.

### 2.2 Product overview

The relay has a modular design, and it can be optimized to medium and big sized generators.

#### Main characteristic and options

- The relay is a generator-block transformer protection relay for medium sized generators in power generation. Synchronism check and auto-reclosing extend automatic network control.
- The relay has optional arc flash communications and high speed outputs to allow for simple arc flash system configuration.
- Two alternative display options
  - 128 x 128 LCD matrix
  - 128 x 128 LCD matrix detachable
- Power quality measurements and disturbance recorder enable capture of transients
- Wide range of communication protocols, for example:
  - Modbus TCP/IP
  - Profibus
  - IEC61850

#### The following options depend on the order code:

- power supply options
- ground fault overcurrent input sensitivity
- number of digital inputs
- number of trip contacts
- integrated arc-options (point sensors)
- various possibilities with communication interfaces:
  - high-speed outputs
  - simple arc flash system communications (BIO)
  - fiber loop
- front panel protection of IP54

#### Protection functions

- Universal, adaptive protection functions for user-configurable generator and block transformer protection applications
- Neutral overvoltage, overvoltage and frequency protection including synchronism check for two breakers
- Single-line diagram, measurements and alarms in the user-machine interface (UMI)

- User-configurable interlocking for primary object control
- Optional arc flash detection utilizing point sensors and a fiber loop that can provide system wide arc flash detection.

#### **Virtual injection**

- Current and voltage injection by manipulating the database of the product by setting tool disturbance recorder file playback through the product's database

#### **Robust hardware**

- User-selectable Ethernet, RS485 or RS232 -based communication interfaces
- Designed for demanding industrial conditions with conformal-coated printed circuit boards
- Standard USB connection (type B) for Easergy P3 setting software

#### **Common technology for cost efficiency**

- Powerful CPU supporting IEC 61850
- Thanks to four setting groups, adaptation to various protection schemes is convenient

#### **User-machine interface (UMI)**

- Clear LCD display for alarms and events
- Single-line diagram mimic with control, indication and live measurements
- Programmable function keys and LEDs
- Circuit breaker ON/OFF control
- Common firmware platform with other Easergy P3 range protection relays


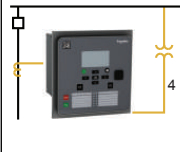

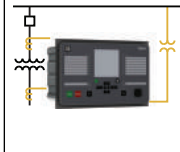
**NOTE:** If the device has been powered off for more than about one week, the UMI language after starting is IEC but after about two minutes, it is automatically updated to ANSI.

## **2.3 Product selection guide**

The selection guide provides information on the Easergy P3 platform to aid in the relay selection. It suggests Easergy P3 types suitable for your protection requirements, based on your application characteristics. The most typical applications are presented along with the associated Easergy P3 type.



Table 2 - Applications


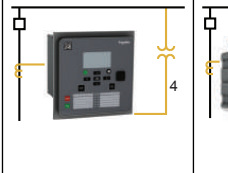
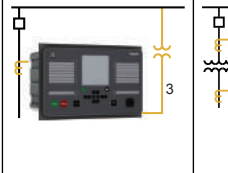
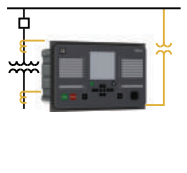
		Easergy P3 Standard			Easergy P3 Advanced	
						
Voltage		-	-	P3U30 with directional o/c with voltage protection	-	-
Feeder					P3F30 w. directional P3L30 w. line diff. & distance	-
Transformer		P3U10	P3U20		-	P3T32 with differential
Motor					P3M30	P3M32 with differential
Generator					P3G30	P3G32 with differential
Measuring inputs	Phase current	1/5A CT (x3)			1/5A CT (x3)	1/5A CT (x3 slot 4) 1A or 5A (x3 slot 8)
	Residual current	1/5A CT or 0.2/1A CT			5/1A+1/0.2A CT	5/1A+1/0.2A CT (slot 8) 5/1A CT (slot 4)
	Voltage	VT (x1)		VT (x4)	VT (x4)	VT (x4)
Arc-flash sensor input		-			0 to 4 point sensor	0 to 4 point sensor
Digital I/O	Input	2	8/10	16	6 to 36	6 to 16
	Output	5 + WD	5/8 + WD	8 + WD	10 to 21 + WD	10 to 13 + WD
Analog I/O	Input	-	0 or 4 <sup>2</sup>		0 or 4 <sup>2</sup>	
	Output	-	0 or 4 <sup>2</sup>		0 or 4 <sup>2</sup>	
Temperature sensor input		-	0 or 8 or 12 <sup>2</sup>		0 or 8 or 12 <sup>2</sup>	
Front port		USB			USB	

	<b>Easergy P3 Standard</b>	<b>Easergy P3 Advanced</b>
Nominal power supply	24 V dc or 24...48 V dc or 48...230 V ac/dc <sup>3</sup>	24...48 V dc or 110...240 V ac/dc
Ambient temperature, in service	-40...60°C (-40...140°F)	-40...60°C (-40...140°F)

<sup>2</sup> Using external RTD module

<sup>3</sup> Check the available power supply range from the device's serial number label.

Table 3 - Communication & others

		<b>Easergy P3 Standard</b>		<b>Easergy P3 Advanced</b>	
					
<b>Communication</b>					
Rear ports	RS-232	–	■	■	■
	IRIG/B		■	■	■
	RS-485	–	■	Using external I/O module	Using external I/O module
	ETHERNET	–	■	■	■
Protocols	IEC 61850 Ed1 & Ed2	–	■	■	■
	IEC 60870-5-101	–	■	■	■
	IEC 60870-5-103	–	■	■	■
	DNP3 Over Ethernet	–	■	■	■
	Modbus serial	–	■	■	■
	Modbus TCP/IP	–	■	■	■
	DeviceNet	–	■	■	■
	Profibus DP	–	■	■	■
	SPAbus	–	■	■	■
Redundancy protocols	RSTP	–	■	■	■
	PRP	–	■	■	■
<b>Others</b>					
Control		1 object Mimic	8 objects Mimic		8 objects Mimic
Logic	Matrix		■		■
	Logic equations		■		■
Cyber security			Password		Password
Withdrawability (Pluggable connector)			■		–
Remote UMI			–		■

**NOTE:** The numbers in the following tables represent the amount of stages available for each Easergy P3 type.

Table 4 - Protection functions for P3U

Protection functions	ANSI code	Feeder P3U10/20	Feeder P3U30	Motor P3U10/20	Motor P3U30
Fault locator	21FL	–	1	–	1
Synchronism check <sup>4</sup>	25	–	2	–	2
Undervoltage	27	–	3	–	3
Directional power	32	–	2	–	2
Phase undercurrent	37	1	1	1	1
RTD temperature monitoring <sup>5</sup>	38/49T	12	12	12	12
Negative sequence overcurrent (motor, generator)	46	–	–	2	2
Incorrect phase sequence	46	–	–	1	1
Cur. unbalance, broken conductor	46BC	1	1	–	–
Negative sequence overvoltage protection	47	–	3	–	3
Excessive start time, locked rotor	48/51LR	–	–	1	1
Thermal overload	49	1	1	1	1
Phase overcurrent	50/51	3	3	3	3
Ground fault overcurrent	50N/51N	5	5	5	5
Breaker failure	50BF	1	1	1	1
SOTF	50HS	1	1	1	1
Capacitor bank unbalance <sup>6</sup>	51C	2	2	2	2
Voltage-dependent overcurrent	51V	–	1	–	1
Overvoltage	59	–	3	–	3
Capacitor overvoltage	59C	1	1	–	–
Neutral overvoltage	59N	3	3	3	3
CT supervision	60	1	1	1	1
VT supervision	60FL	–	1	–	1
Starts per hour	66	–	–	1	1
Directional phase overcurrent	67	–	4	–	4

Protection functions	ANSI code	Feeder P3U10/20	Feeder P3U30	Motor P3U10/20	Motor P3U30
Directional ground fault o/c	67N	3	3	3	3
Transient intermittent	67NI	1	1	–	–
Second harmonic inrush detection	68F2	1	1	1	1
Fifth harmonic detection	68H5	1	1	1	1
Auto-Recloser	79	5	5	–	–
Over or under frequency	81	–	2/2	–	2/2
Rate of change of frequency	81R	–	1	–	1
Under frequency	81U	–	2	–	2
Lockout	86	1	1	1	1
Programmable stages	99	8	8	8	8
Cold load pickup (CLPU)	–	1	1	1	1
Programmable curves	–	3	3	3	3
Setting groups <sup>7</sup>	–	4	4	4	4

<sup>4</sup> The availability depends on the selected voltage measurement mode (in the **Scaling** setting view in Easergy Pro)

<sup>5</sup> Using external RTD module

<sup>6</sup> Capacitor bank unbalance protection is connected to the ground fault overcurrent input and shares two stages with the ground fault overcurrent protection.

<sup>7</sup> Not all protection functions have 4 setting groups. See details in the manual.

Table 5 - Protection functions for Px3x

Protection functions	ANSI code	P3F30	P3L30	P3M30	P3M32	P3G30	P3G32	P3T32
Distance	21	–	1	–	–	–	–	–
Under-impedance	21G	–	–	–	–	2	2	–
Fault locator	21FL	1	1	–	–	–	–	–
Overfluxing	24	–	–	–	–	1	1	1
Synchronism check <sup>8</sup>	25	2	2	2	2	2	2	2
Undervoltage	27	3	3	3	3	3	3	3
Positive sequence under-voltage	27P	–	–	–	–	2	2	–
Directional power	32	2	2	2	2	2	2	2
Phase undercurrent	37	–	–	1	1	–	–	–
RTD temperature monitoring <sup>9</sup>	38/49T	12	12	12	12	12	12	12
Loss of field	40	–	–	–	–	1	1	–
Under-reactance	21/40	–	–	–	–	2	2	–

Protection functions	ANSI code	P3F30	P3L30	P3M30	P3M32	P3G30	P3G32	P3T32
Negative sequence overcurrent (motor, generator)	46	–	–	2	2	2	2	2
Cur. unbalance, broken conductor	46BC	1	1	–	–	–	–	–
Incorrect phase sequence	47	–	–	1	1	–	–	–
Negative sequence overvoltage protection	47	3	3	3	3	3	3	3
Excessive start time, locked rotor	48/51LR	–	–	1	1	–	–	–
Thermal overload	49	1	1	1	1	1	1	1
Phase overcurrent	50/51	3	3	3	3	3	3	3
Ground fault overcurrent	50N/51N	5	5	5	5	5	5	5
Breaker failure	50BF	1	1	1	1	1	1	1
SOTF	50HS	1	1	1	1	1	1	1
Capacitor bank unbalance <sup>10</sup>	51C	2	2	2	2	2	2	2
Voltage-dependent overcurrent	51V	1	1	–	–	1	1	–
Overvoltage	59	3	3	3	3	3	3	3
Capacitor overvoltage	59C	1	1	–	–	–	–	–
Neutral overvoltage	59N	2	2	2	2	2	2	2
CT supervision	60	1	1	1	1	1	2	2
VT supervision	60FL	1	1	1	1	1	1	1
Restricted ground fault (low impedance)	64REF	–	–	–	–	–	1	1
Stator ground fault	64S	–	–	–	–	1	1	–
Starts per hour	66	–	–	1	1	–	–	–
Directional phase overcurrent	67	4	4	4	4	4	4	4
Directional ground fault o/c	67N	3	3	3	3	3	3	3
Transient intermittent	67NI	1	1	–	–	–	–	–
Second harmonic inrush detection	68F2	1	1	1	1	1	1	1
Fifth harmonic detection	68H5	1	1	1	1	1	1	1
Pole slip	78PS	–	–	–	–	1	1	–
Auto-Recloser	79	5	5	–	–	–	–	–

Protection functions	ANSI code	P3F30	P3L30	P3M30	P3M32	P3G30	P3G32	P3T32
Over or under frequency	81	2/2	2/2	2/2	2/2	2/2	2/2	2/2
Rate of change of frequency	81R	1	1	1	1	1	1	1
Under frequency	81U	2	2	2	2	2	2	2
Lockout	86	1	1	1	1	1	1	1
Line differential	87L	–	2	–	–	–	–	–
Machine differential	87M	–	–	–	2	–	2	–
Transformer differential	87T	–	–	–	–	–	–	2
Programmable stages	99	8	8	8	8	8	8	8
Arc flash detection (AFD)	–	8	8	8	8	8	8	8
Cold load pickup (CLPU)	–	1	1	1	1	1	1	1
Programmable curves	–	3	3	3	3	3	3	3
Setting groups <sup>11</sup>	–	4	4	4	4	4	4	4

<sup>8</sup> The availability depends on the selected voltage measurement mode (in the **Scaling** setting view in Easergy Pro)

<sup>9</sup> Using external RTD module

<sup>10</sup> Capacitor bank unbalance protection is connected to the ground fault overcurrent input and shares two stages with the ground fault overcurrent protection.

<sup>11</sup> Not all protection functions have 4 setting groups. See details in the manual.

Table 6 - Control functions

Control functions	P3U10/ 20	P3U30	P3F30	P3L30	P3M30	P3M32	P3G30	P3G32	P3T32
Switchgear control and monitoring	1/2	4	6	6	6	6	6	6	6
Switchgear monitoring only	–	–	2	2	2	2	2	2	2
Programmable switchgear interlocking	■	■	■	■	■	■	■	■	■
Local control on single-line diagram	■	■	■	■	■	■	■	■	■
Local control with O/I keys	■	■	■	■	■	■	■	■	■
Local/remote function	■	■	■	■	■	■	■	■	■
Function keys	2	2	2	2	2	2	2	2	2
Custom logic (logic equations)	■	■	■	■	■	■	■	■	■
Control with Smart App	■	■	■	■	■	■	■	■	■

Table 7 - Measurements

Measurement	P3U10/ 20	P3U30	P3F30	P3L30	P3M30	P3M32	P3G30	P3G32	P3T32
RMS current values	■	■	■	■	■	■ <sup>12</sup>	■	■ <sup>12</sup>	■ <sup>12</sup>
RMS voltage values	■	■	■	■	■	■	■	■	■
RMS active, reactive and apparent power	–	■	■	■	■	■	■	■	■
Frequency	■	■	■	■	■	■	■	■	■
Fundamental frequency current values	■	■	■	■	■	■ <sup>12</sup>	■	■ <sup>12</sup>	■ <sup>12</sup>
Fundamental frequency voltage values	–	■	■	■	■	■	■	■	■
Fundamental frequency active, reactive and apparent power values	–	■	■	■	■	■	■	■	■
Power factor	–	■	■	■	■	■	■	■	■
Energy values active and reactive	–	■	■	■	■	■	■	■	■
Energy transmitted with pulse outputs	–	■	■	■	■	■	■	■	■
Demand values: phase currents	■	■	■	■	■	■	■	■	■
Demand values: active, reactive, apparent power and power factor	–	■	■	■	■	■	■	■	■
Min and max demand values: phase currents	■	■	■	■	■	■	■	■	■
Min and max demand values: RMS phase currents	■	■	■	■	■	■	■	■	■
Min and max demand values: active, reactive, apparent power and power factor	–	■	■	■	■	■	■	■	■
Maximum demand values over the last 31 days and 12 months: active, reactive, apparent power	–	■	■	■	■	■	■	■	■
Minimum demand values over the last 31 days and 12 months: active, reactive power	–	■	■	■	■	■	■	■	■
Max and min values: currents	■	■	■	■	■	■	■	■	■

Measurement	P3U10/ 20	P3U30	P3F30	P3L30	P3M30	P3M32	P3G30	P3G32	P3T32
Max and min values: voltages	–	■	■	■	■	■	■	■	■
Max and min values: frequency	■	■	■	■	■	■	■	■	■
Max and min values: active, reactive, apparent power and power factor	–	■	■	■	■	■	■	■	■
Harmonic values of phase current and THD	■	■	■	■	■	■ <sup>12</sup>	■	■ <sup>12</sup>	■ <sup>12</sup>
Harmonic values of voltage and THD	–	■	■	■	■	■	■	■	■
Voltage sags and swells	–	■	■	■	■	■	■	■	■

<sup>12</sup> Function available on both sets of CT inputs

Table 8 - Logs and records

Logs and Records	P3U10/ 20	P3U30	P3F30	P3L30	P3M30	P3M32	P3G30	P3G32	P3T32
Sequence of event record	■	■	■	■	■	■	■	■	■
Disturbance record	■	■	■	■	■	■	■	■	■
Tripping context record	■	■	■	■	■	■	■	■	■

Table 9 - Monitoring functions

Monitoring functions	P3U10/ 20	P3U30	P3F30	P3L30	P3M30	P3M32	P3G30	P3G32	P3T32
Trip circuit supervision (ANSI 74)	1	1	1	1	1	1	1	1	1
Circuit breaker monitoring	1	1	1	1	1	1	1	1	1
Relay monitoring	■	■	■	■	■	■	■	■	■

## 2.4 Access to device configuration

You can access the device configuration via:

- the Easergy Pro setting tool
- the device’s front panel

### 2.4.1 User accounts

By default, the Easergy P3 device has five user accounts.



Table 10 - User accounts

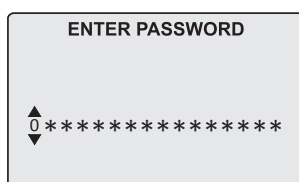
User account	User name	Default password	Use
User	user	0	Used for reading parameter values, measurements, and events, for example
Operator	operator	1	Used for controlling objects and for changing the protection stages' settings, for example
Configurator	conf	2	Needed during the device commissioning. For example, the scaling of the voltage and current transformers can be set only with this user account. Also used for logging on to the HTTP server
Administrator	admin	3	Needed for changing the passwords for other user accounts and for creating new user accounts
Easergy	easergy	2	Used for logging on to the FTP server

### 2.4.2 Logging on via the front panel

**NOTE:** To log on via the front panel, you need a password that consists of digits only.

1. Press **i** and **OK** on the front panel. The **Enter password** view opens.

Figure 1 - Enter password view



2. Enter the password for the desired access level.

Select a digit value using **▲**, and if the password is longer than one digit, move to the next digit position using **➤**.

**NOTE:** There are 16 digit positions in the **Enter password** view. Enter the password starting from the first digit position.

For example, if the password is 2, you can enter 2\*\*\*, \*\*2\*, \*\*\*2, or 0002 to log on.

3. Press **OK** to confirm the password.

**Related topics**[Password management](#) on page 30

## 2.4.3 HTTP and FTP logon details

You can log on to the HTTP server and FTP using these user names and passwords.

Table 11 - HTTP and FTP logon details

Protocol	User name	Password
HTTP	conf	2
FTP	easergy	2

## 2.4.4 Password management

### **NOTICE**

**CYBERSECURITY HAZARD**

To improve cybersecurity:

- Change all passwords from their default values when taking the protection device into use.
- Change all passwords regularly.

**Failure to follow these instructions can increase the risk of unauthorized access.**

You can change the password for the operator or configurator user accounts in the **General > Device info** setting view in Easergy Pro.

The password can contain letters, digits or any other UTF-8 characters (total 1–32 characters). However, the new password cannot be any of the default passwords (digits 0–4 or 9999).

**NOTE:** To log on via the front panel, you need a password that consists of digits only.

**Related topics**[Logging on via the front panel](#) on page 29

## 2.4.5 Changing passwords for administrator and configurator accounts via PuTTY

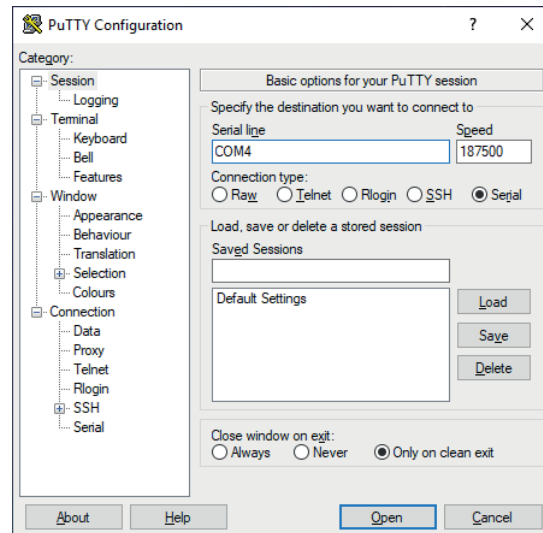
Change the password for the administrator and configurator user accounts to reach an optimal cybersecurity level. To log on as the administrator user, you need to use either a serial terminal software or a Telnet client software. This instruction describes how to change the passwords using PuTTY which is freely available at <https://www.putty.org/>.

1. Download and install PuTTY.

2. Connect the Easergy P3 device to your PC via the USB port in the device's front panel.
3. Find the COM port number for the device (for example, with Easergy Pro).
4. Connect to the device's COM port via PuTTY.
  - a. Open PuTTY.

The PuTTY Configuration dialog box opens.

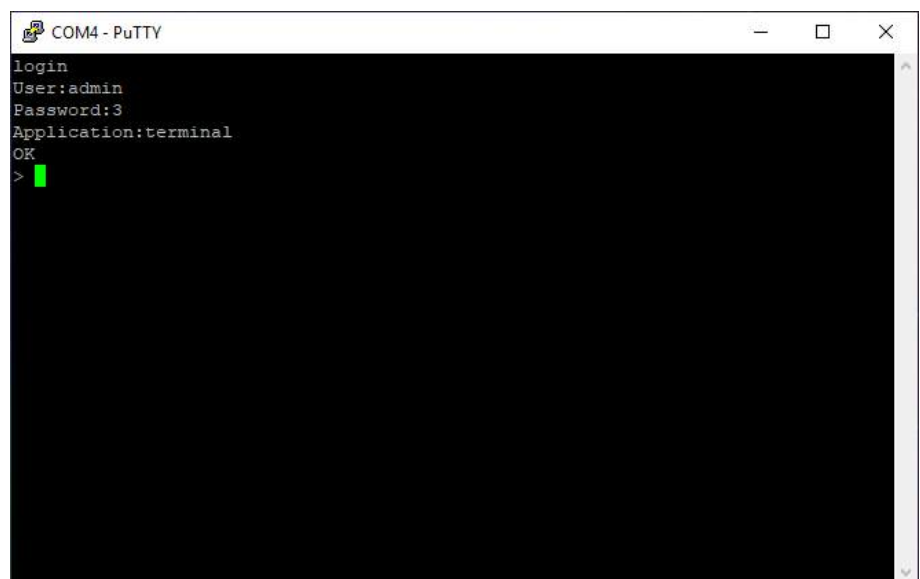
Figure 2 - PuTTY Configuration dialog box



- b. In the **Serial line** field, type the COM port name.
  - c. In the **Speed** field, set the communication speed to 187500 bps.
  - d. Click **Open**.

The PuTTY command window opens.
5. Log on as the administrator by giving command **login**.

Figure 3 - PuTTY login



6. Change the password for the administrator account by giving the command **passwd**.

Figure 4 - Changing the administrator password in PuTTY

```
>  
> passwd  
Enter new password:test  
Retype new password:test  
Password changed  
> █
```

7. Change the password for the configurator account by giving the command **passwd conf**.

Figure 5 - Changing the configurator password in PuTTY

```
>  
> passwd conf  
Changing password for conf  
Enter new password:5  
Retype new password:5  
Password changed  
> █
```

8. Log out by giving the command **logout**.

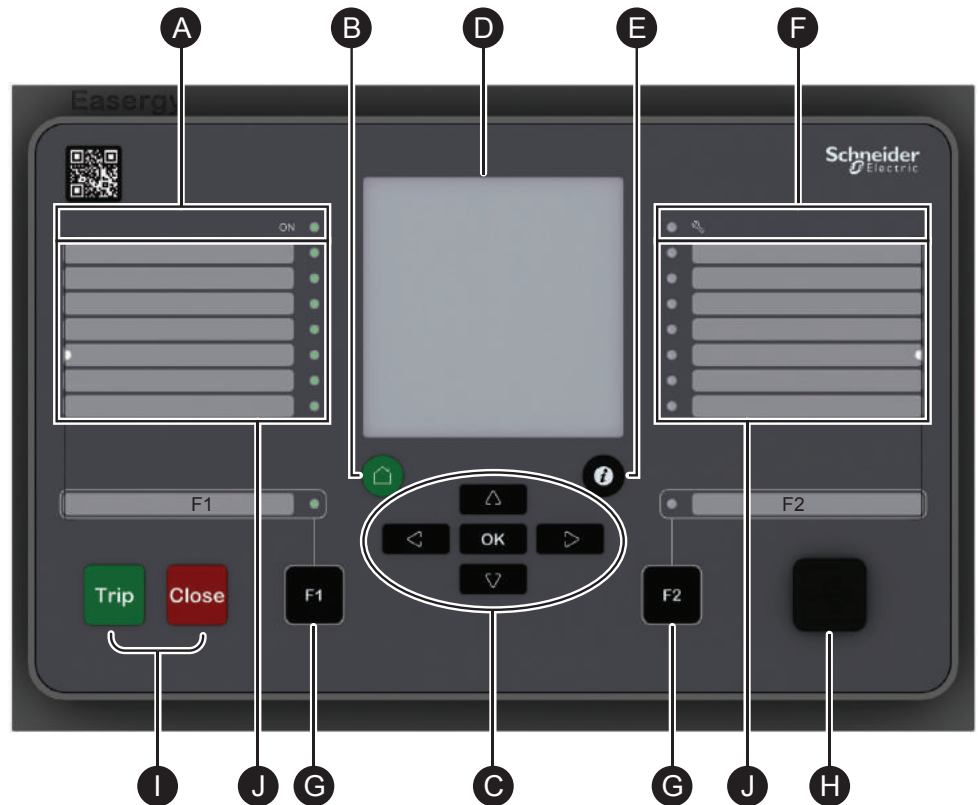
## 2.4.6 Password restoring

If you have lost or forgotten all passwords, contact Schneider Electric to restore the default passwords.

## 2.5 Front panel

Easergy P3G30 and P3G32 has a 128 x 128 LCD matrix display.








Figure 6 - Easergy P3G30 and P3G32 front panel



- A. Power LED
- B. CANCEL push-button
- C. Navigation push-buttons
- D. LCD
- E. INFO push-button
- F. Service LED
- G. Function push-buttons and LEDs showing their status
- H. Local port
- I. Object control buttons
- J. User-configurable LEDs

### 2.5.1 Push-buttons

Symbol	Function
	HOME/CANCEL push-button for returning to the previous menu. To return to the first menu item in the main menu, press the button for at least 3 seconds.
	INFO push-button for viewing additional information, for entering the password view and for adjusting the LCD contrast.
	Programmable function push-button. <sup>13</sup>
	Programmable function push-button. <sup>13</sup>

	ENTER push-button for activating or confirming a function.
	UP navigation push-button for moving up in the menu or increasing a numerical value.
	DOWN navigation push-button for moving down in the menu or decreasing a numerical value.
	LEFT navigation push-button for moving backwards in a parallel menu or selecting a digit in a numerical value.
	RIGHT navigation push-button for moving forwards in a parallel menu or selecting a digit in a numerical value.
	Circuit breaker close push-button
	Circuit breaker trip push-button

<sup>13</sup> The default names of the function buttons are Function button 1 and 2. You can change the names of the buttons in the **Control > Names for function buttons** setting view.

## 2.5.2 LED indicators

The relay has 18 LEDs on the front panel:

- two LEDs for function buttons (F1 and F2)
- two LEDs represent the unit's general status (power and service)
- 14 user-configurable LEDs (A-N)

When the relay is powered, the power LED is green. During normal use, the service LED is not active, it activates only when an error occurs or the relay is not operating correctly. Should this happen, contact your local representative for further guidance. The service LED and watchdog contact are assigned to work together. Hardwire the status output into the substation's automation system for alarm purposes.

The user-configurable LEDs may be red or green. You can configure them via Easergy Pro.

To customize the LED texts on the front panel for the user-configurable LEDs, the text may be created using a template and then printed. The printed text may be placed in the pockets beside the LEDs.

You can also customize the LED texts that are shown on the screen for active LEDs via Easergy Pro.

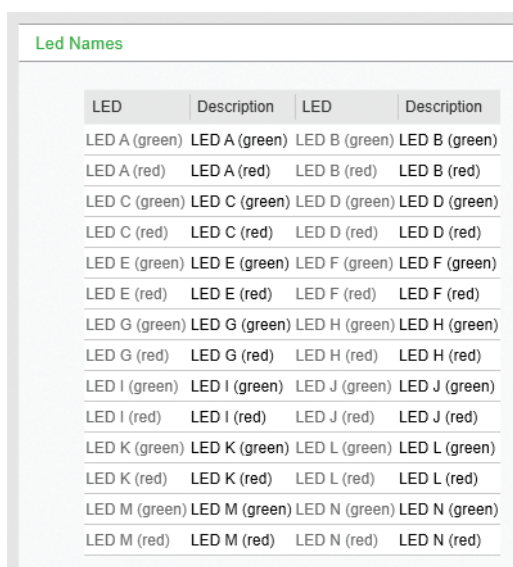
Table 12 - LED indicators and their information

LED indicator	LED color	Meaning	Measure / Remarks
Power LED lit	Green	The auxiliary power has been switched on	Normal operation state
Service LED lit	Red	Internal fault. Operates in parallel with the self-supervision output	The relay attempts to reboot. If the service LED remains lit, call for maintenance.
A–H LED lit	Green or red	Application-related status indicators.	Configurable in the <b>Matrix</b> setting view
F1 or F2 LED lit	Green	Corresponding function key pressed / activated	Depending on the function programmed to F1 / F2

### 2.5.3 Configuring the LED names via Easergy Pro

1. Go to **General > LED names**.
2. To change a LED name, click the LED **Description** text and type a new name. To save the new name, press **Enter**.

Figure 7 - LED NAMES menu in Easergy Pro for LED configuration






## 2.5.4 Controlling the alarm screen

You can enable or disable the alarm screen either via the relay's local display or using Easergy Pro:





- On the local display, go to **Events > Alarms**.
- In Easergy Pro, go to **General > Local panel conf**.

## 2.5.5 Accessing operating levels

1. On the front panel, press  and .
2. Enter the password, and press .

## 2.5.6 Adjusting the LCD contrast

Prerequisite: You have entered the correct password.

1. Press , and adjust the contrast.
  - To increase the contrast, press .
  - To decrease the contrast, press .
2. To return to the main menu, press .

**NOTE:** By nature, the LCD display changes its contrast depending on the ambient temperature. The display may become dark or unreadable at low temperatures. However, this condition does not affect the proper operation of the protection or other functions.

## 2.5.7 Testing the LEDs and LCD screen

You can start the test sequence in any main menu window.

To start the LED and LCD test:



1. Press .
2. Press .

The relay tests the LCD screen and the functionality of all LEDs.





## 2.5.8 Controlling an object with selective control

Prerequisite: You have logged in with the correct password and enabled selective control in the **Objects** setting view.

When selective control is enabled, the control operation needs confirmation (select before operate).

- Press  to close an object.
  - Press  again to confirm.





- Press  to cancel.
- Press  to trip an object.
  - Press  again to confirm.
  - Press  to cancel.

## 2.5.9 Controlling an object with direct control

Prerequisite: You have logged in with the correct password and enabled direct control in the **Objects** setting view.

When direct control is enabled, the control operation is done without confirmation.

- Press  to close an object.
- Press  to trip an object.

## 2.5.10 Menus

This section gives an overview of the menus that you can access via the device's front panel.

### The main menu

Press the right arrow to access more measurements in the main menu.

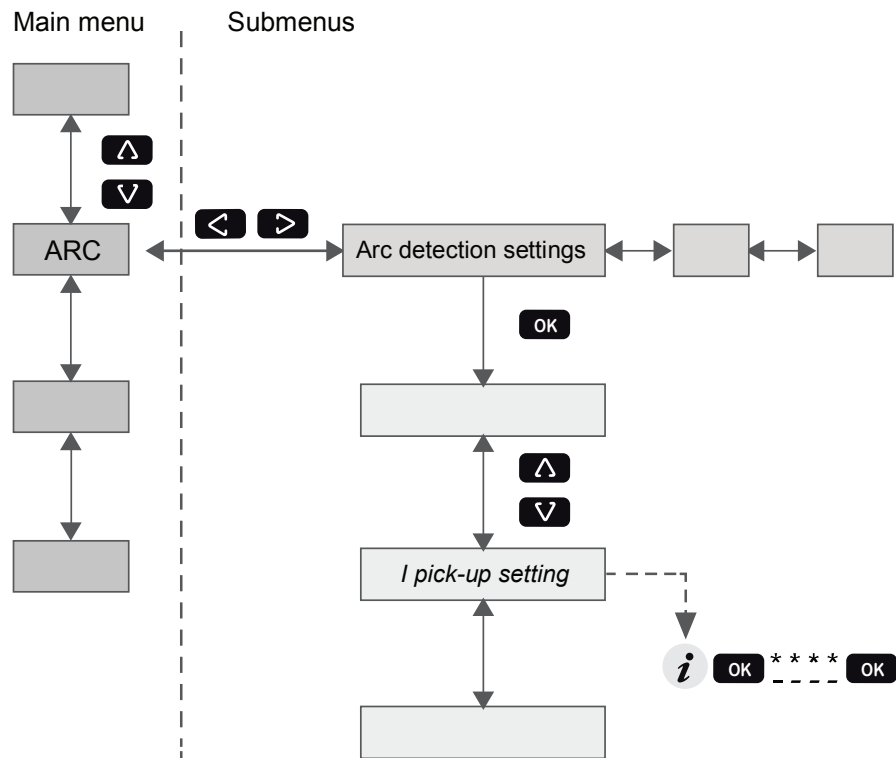
Table 13 - Main menu

Menu name	Description
Active LEDs	User-configurable texts for active LEDs
Measurements	User-configurable measurements
Single line	Single line or Single line mimic, measurements and control view. This is a default start view. To return to this view from any location, press the HOME/CANCEL button for at least 3 seconds.
Info	Information about the relay: relay's name, order code, date, time and firmware version
P	Power: power factor and frequency values calculated by the relay. Press the right arrow to view more measurements.
E	Energy: the amount of energy that has passed through the protected line, calculated by the relay from the currents and voltages. Press the right arrow to view more energy measurements.
I	Current: phase currents and demand values of phase currents. Press the right arrow to view more current measurements.
V	Line-to-line voltages. Press the right arrow to view other voltage measurements.

<b>Menu name</b>	<b>Description</b>
Dema	Minimum and maximum phase current and power demand values
Vmax	Minimum and maximum values of voltage and frequency
Imax	Minimum and maximum current values
Pmax	Minimum and maximum power values
Month	Monthly maximum current and power values
FL	Short-circuit locator applied to incomer or feeder
Evt	Event log: event codes and time stamps
DR	Disturbance recorder configuration settings
Runh	Running hour counter
TIMR	Timers: programmable timers that you can use to preset functions
DI	Digital input statuses and settings
DO	Digital output statuses and settings
Arc	Arc flash detection settings
Prot	Protection: settings and statuses for various protection functions
50/51-1–50/51-4	Protection stage settings and statuses. The availability of the menus are depends on the activated protection stages.
AR	Auto-reclosure settings, statuses and registers
OBJ	Objects: settings related to object status data and object control (open/closed)
Lgic	Logic events and counters
CONF	General device setup: CT and VT scalings, frequency adaptation, units, device info, date, time, clock, etc.
Bus	Communication port settings
Slot	Slot info: card ID (CID) that is the name of the card used by the relay firmware
Diag	Diagnosis: various diagnostic information

### 2.5.10.1 Moving in the menus

Figure 8 - Moving in menus using the front panel



- To move in the main menu, press **▲** or **▼**.
- To move in the submenus, press **>** or **<**.
- While in the submenu, press **▲** or **▼** to jump to the root.
- To enter a submenu, press **OK** and use **▼** or **▲** for moving down or up in the menu.
- To edit a parameter value, press **i** and **OK**.
- Enter the password, and press **OK**.
- To go back to the previous menu, press **🏠**.
- To go back to the first menu item in the main menu, press **🏠** for at least three seconds.


**NOTE:** To enter the parameter edit mode, enter the password. When the value is in edit mode, its background is dark.

### 2.5.10.2 Local panel messages

Table 14 - Local panel messages

Value is not editable:	The value can not be edited or password is not given
Control disabled:	Object control disabled due to wrong operating level
Change causes autoboot:	Notification that if the parameter is changed the relay boots itself

## 2.6 Easergy Pro setting and configuration tool

<b>⚡⚠ DANGER</b>	
	<p><b>HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH</b></p> <p>Only qualified personnel should operate this equipment. Such work should be performed only after reading this entire set of instructions and checking the technical characteristics of the device.</p> <p><b>Failure to follow this instruction will result in death or serious injury.</b></p>

Easergy Pro is a software tool for configuring Easergy P3 relays. It has a graphical interface where the relay settings and parameters are grouped under seven tabs:

- General
- Measurements
- Inputs/outputs
- Protection
- Matrix
- Logs
- Communication

The contents of the tabs depend on the relay type and the selected application mode.

Easergy Pro stores the relay configuration in a setting file. The configuration of one physical relay is saved in one setting file. The configurations can be printed out and saved for later use.

For more information, see the Easergy Pro user manual.

**NOTE:** Download the latest version of the software from [www.schneider-electric.com/en/product-range/64884-easergy-p3](http://www.schneider-electric.com/en/product-range/64884-easergy-p3).

<b>NOTICE</b>
<p><b>RISK OF SYSTEM SHUTDOWN</b></p> <p>After writing new settings or configurations to a relay, perform a test to verify that the relay operates correctly with the new settings.</p> <p><b>Failure to follow these instructions can result in unwanted shutdown of the electrical installation.</b></p>

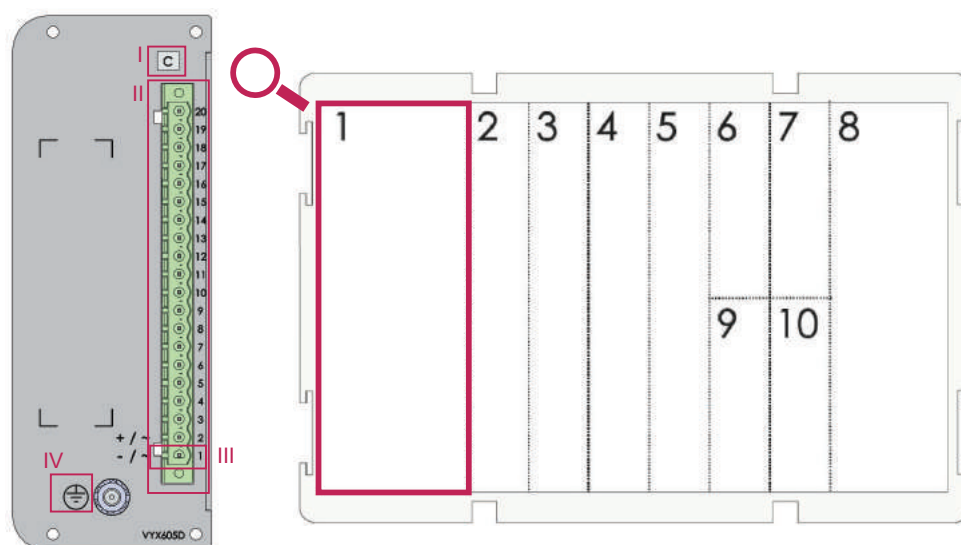
## 3 Mechanical structure

### 3.1 Modularity

The relay has a modular structure. The relay is built from hardware modules that are installed into 10 different slots at the back of the relay. The location of the slots is shown in [Figure 9 - Slot numbering and card options in the Easergy P3G30 and P3G32 rear panel and an example of defining the pin address 1/C/1:1 on page 41](#).

The type of the hardware modules is defined by the order code.

Figure 9 - Slot numbering and card options in the Easergy P3G30 and P3G32 rear panel and an example of defining the pin address 1/C/1:1



I	Card C	1	Supply voltage [V]
II	Connector 2	2, 3	I/O card
III	Pin 1	4, 5	I/O or analog measurement card
IV	Protective grounding	6, 9	Communication or I/O option card
		7, 8, 10	Analog measurement card (I, V)

For complete availability information on the different option cards, see [13.2 Accessories](#) on page 395.

[10.6 Connections](#) on page 310 contains detailed information on each card.

**Example**

Table 15 - Example of typical model P3G30-CGIII-DAENA-BB

SLOT	NAME	TYPE
	Application	G30 = Generator protection relay
1	Supply voltage	C = 110–240 V ac/dc (6 x DO: 1 change over signal duty and 5 tripping duty)
2	I/O card I	G = 6DI+4DO (6 x DI, 4 x DO)
3	I/O card II	I = 10DI (10 x DI)
4	I/O card III	I = 10DI (10 x DI)
5	I/O card IV	I = 10DI (10 x DI)
6	Option card I	D = 4Arc (4 x Arc sensor)
7	Future option	A = None
8	Analog measurement card (See application)	E = 3L(5A)+4V+2IO (5/1A+1/0.2A)
9	Communication interface I	N = 2 x RJ (Ethernet RJ 100Mbs, RSTP, PRP)
10	Future option	A = None
	Display type	B = 128x128 (128 x 128 LCD matrix)
	DI nominal voltage	B = 110 V dc/ac, with conformal coating
	Digital inputs	36 pcs
	Trip contacts	9 pcs
	Alarm contacts	1 pc
	Self-supervision contact	1 pc
	Phase currents (5A)	3 pcs
	Voltage channels	4 pcs
	Ground fault overcurrents (5/1A + 1/0.2A)	2 pcs
	Display	fixed in the relay

## 3.2 Slot info and order code

The relay's configuration can be checked via the front panel or Easergy Pro menu called **Slot** or **Slot info**. "Card ID" is the name of the card used by the relay firmware.

Figure 10 - Hardware configuration example view from Easergy Pro configuration tool

Slot Info				
Slot	Card ID	Trace ID	FPGA program	Status
1	Power C	C577631644201450VB526F -		OK
2	6DI+4DO	F837661650209172VB464F -		OK
3	None	-	-	-
4	3L+1o	F862831641000075VB574C -		OK
5	None	-	-	-
6	None	-	-	-
7	None	-	-	-
8	3L+4U+2lo	C577651650202217VB529F -		OK
9	2EthRJ	C577731651201081VB577B -		OK
10	None	-	-	-
Display	128x128	C581401647201973VB519F -		OK
MB	3xx MB	F598471651005854VB356N V1.09		OK

**NOTE:** See [13.1 Order codes](#) on page 394 for the relay ordering options.

## 4 Measurement functions

Easergy P3 has various amounts of analog inputs depending on the model in use. [Table 16 - Measurement functions in Easergy P3 on page 44](#) introduces directly measured and calculated quantities for the power system monitoring. Also see [2.3 Product selection guide on page 20](#).

The current scaling impacts the following functions:

- Protection stages
- Measurements
- Disturbance recorder
- Fault location calculation

Table 16 - Measurement functions in Easergy P3

Measurements Specification	P3U10/20	P3U30	P3x3x	Measurement range	Inaccuracy
RMS phase current	■	■	■	$0.025-50 \times I_N$	$I \leq 1.5 \times I_N$ : $\pm 0.5$ % of value or $\pm 15$ mA $I > 1.5 \times I_N$ : $\pm 3$ % of value
RMS ground fault overcurrent	■	■	■	$0.003-2 \times I_N$	$I \leq 1.5 \times I_N$ : $\pm 0.3$ % of value or $\pm 0.2$ % of $I_{0N}$ $I > 1.5 \times I_N$ : $\pm 3$ % of value
RMS line-to-line voltage	—	■	■	$0.005-1.7 \times V_N$	$\pm 0.5$ % or $\pm 0.3$ V
RMS phase-to-neutral voltage	—	■	■	$0.005-1.7 \times V_N$	$\pm 0.5$ % or $\pm 0.3$ V
RMS active power (PF >0.5)	—	■	■	$\pm 0.1-1.5 \times P_N$	$\pm 1$ % for range $0.3-1.5 \times P_N$ $\pm 3$ % for range $0.1-0.3 \times P_N$
RMS reactive power (PF >0.5)	—	■	■	$\pm 0.1-1.5 \times Q_N$	$\pm 1$ % for range $0.3-1.5 \times Q_N$ $\pm 3$ % for range $0.1-0.3 \times Q_N$
RMS apparent power (PF >0.5)	—	■	■	$\pm 0.1-1.5 \times S_N$	$\pm 1$ % for range $0.3-1.5 \times S_N$ $\pm 3$ % for range $0.1-0.3 \times S_N$
Frequency	■	■	■	16 Hz – 75 Hz	$\pm 10$ mHz
Fundamental frequency current values	■	■	■	$0.025-50 \times I_N$	$I \leq 1.5 \times I_N$ : $\pm 0.5$ % of value or $\pm 15$ mA $I > 1.5 \times I_N$ : $\pm 3$ % of value
Fundamental frequency voltage values	—	■	■	$0.005-1.7 \times V_N$	$\pm 0.5$ % or $\pm 0.3$ V
Fundamental frequency active, reactive and apparent power values	—	■	■	$\pm 0.1-1.5 \times P_N$	$\pm 1$ % for range $0.3-1.5 \times P_N$ $\pm 3$ % for range $0.1-0.3 \times P_N$



Measurements Specification	P3U10/20	P3U30	P3x3x	Measurement range	Inaccuracy
Fundamental frequency active power values	—	■	■	$\pm 0.1-1.5 \times Q_N$	$\pm 1\%$ for range $0.3-1.5 \times Q_N$ $\pm 3\%$ for range $0.1-0.3 \times Q_N$
Fundamental frequency reactive power values	—	■	■	$\pm 0.1-1.5 \times S_N$	$\pm 1\%$ for range $0.3-1.5 \times S_N$ $\pm 3\%$ for range $0.1-0.3 \times S_N$
Power factor	—	■	■	0.02-1	$\pm 2^\circ$ or $\pm 0.02$ for $PF > 0.5$
Active energy	—	■	■		$\pm 1\%$ for range $0.3-1.5 \times EP_N$
Reactive energy	—	■	■		$\pm 1\%/1h$ for range $0.3-1.5 \times EQ_N$ $\pm 3\%/1h$ for range $0.1-0.3 \times EQ_N$
Energy transmitted with pulse outputs	—	■	■		$\pm 1\%/1h$ for range $0.3-1.5 \times EP_N$ $\pm 3\%/1h$ for range $0.1-0.3 \times EP_N$
Demand values: phase currents	■	■	■	$0.025-50 \times I_N$	$I \leq 1.5 \times I_N$ : $\pm 0.5\%$ of value or $\pm 15$ mA $I > 1.5 \times I_N$ $\pm 3\%$ of value
Active power demand	—	■	■	$\pm 0.1-1.5 \times P_N$	$\pm 1\%$ for range $0.3-1.5 \times P_N$ $\pm 3\%$ for range $0.1-0.3 \times P_N$
Reactive power demand	—	■	■	$\pm 0.1-1.5 \times Q_N$	$\pm 1\%$ for range $0.3-1.5 \times Q_N$ $\pm 3\%$ for range $0.1-0.3 \times Q_N$
Apparent power demand	—	■	■	$\pm 0.1-1.5 \times S_N$	$\pm 1\%$ for range $0.3-1.5 \times S_N$ $\pm 3\%$ for range $0.1-0.3 \times S_N$
Power factor demand	—	■	■		$\pm 2^\circ$ or $\pm 0.02$ for $PF > 0.5$
Min and max demand values: phase currents	■	■	■	$0.025-50 \times I_N$	$I \leq 1.5 \times I_N$ : $\pm 0.5\%$ of value or $\pm 15$ mA $I > 1.5 \times I_N$ $\pm 3\%$ of value
Min and max demand values: RMS phase currents	■	■	■	$0.025-50 \times I_N$	$I \leq 1.5 \times I_N$ : $\pm 0.5\%$ of value or $\pm 15$ mA $I > 1.5 \times I_N$ $\pm 3\%$ of value
Min and max demand values: active, reactive, apparent power and power factor	—	■	■		$\pm 1\%$ for range $0.3-1.5 \times P_N, Q_N, S_N$ $\pm 3\%$ for range $0.1-0.3 \times P_N, Q_N, S_N$
Maximum demand values over the last 31 days and 12 months: active, reactive, apparent power	—	■	■		$\pm 1\%$ for range $0.3-1.5 \times P_N, Q_N, S_N$ $\pm 3\%$ for range $0.1-0.3 \times P_N, Q_N, S_N$

Measurements Specification	P3U10/20	P3U30	P3x3x	Measurement range	Inaccuracy
Minimum demand values over the last 31 days and 12 months: active, reactive power	—	■	■		±1 % for range 0.3-1.5xP <sub>N</sub> , Q <sub>N</sub> , S <sub>N</sub> ±3 % for range 0.1-0.3xP <sub>N</sub> , Q <sub>N</sub> , S <sub>N</sub>
Max and min values: currents	■	■	■	0.025-50 x I <sub>N</sub>	I ≤ 1.5 x I <sub>N</sub> : ±0.5 % of value or ±15 mA I > 1.5 x I <sub>N</sub> ±3 % of value
Max and min values: voltages	—	■	■	0.005-1.7 x V <sub>N</sub>	±0.5 % or ±0.3 V
Max and min values: frequency	■	■	■	16 Hz-75 Hz	±10 mHz
Max and min values: active, reactive, apparent power and power factor	—	■	■	±0.1-1.5 x P <sub>N</sub> , Q <sub>N</sub> , S <sub>N</sub>	±1 % for range 0.3-1.5xP <sub>N</sub> , Q <sub>N</sub> , S <sub>N</sub> ±3 % for range 0.1-0.3xP <sub>N</sub> , Q <sub>N</sub> , S <sub>N</sub> ±2° or ±0.02 for PF > 0.5
Harmonic values of phase current and THD	■	■	■	2nd-15th	
Harmonic values of voltage and THD	—	■	■	2nd-15th	
Voltage sags and swells	—	■	■	0.005-1.7 x V <sub>N</sub>	±2° or ±0.02 for PF > 0.5

**NOTE:** Measurement display's refresh rate is 0.2 s.

## 4.1 Primary, secondary and per unit scaling

Many measurement values are shown as primary values although the relay is connected to secondary signals. Some measurement values are shown as relative values - per unit or percent. Almost all start setting values use relative scaling.

Table 17 - Phase current and ground fault overcurrent scaling parameters

Parameter	Description
CT' primary	Primary current value of the CT at I'L side (only P3x32 relays)
CT' secondary	Secondary current value of the CT at I'L side (only P3x32 relays)
Nominal input (IL side)	Rated value of the phase current input. The given thermal withstand, burden and impedance are based on this value.  See <a href="#">Table 154 - Measuring circuits</a> on page 348 for details.

Parameter	Description
Nominal input (I'L side)	Rated value of the phase current input at I' side. The given thermal withstand, burden and impedance are based on this value (only P3x32 relays). See <a href="#">Table 154 - Measuring circuits</a> on page 348 for details.
CT primary	Primary current value of the IL current transformer
CT secondary	Secondary current value of the IL current transformer
$I_{N1}$ CT primary	Primary current value of the ground fault $I_{N1}$ overcurrent transformer
$I_{N1}$ CT secondary	Secondary current value of the ground fault $I_{N1}$ overcurrent transformer
Nominal $I_{N1}$ input	Selectable nominal input rating for the ground fault overcurrent input. Select either 5A or 1A depending on which I <sub>o</sub> input is used. The given thermal withstand, burden and impedance are based on this value. See <a href="#">Table 154 - Measuring circuits</a> on page 348 for details.
$I_{N2}$ CT primary	Primary current value of the ground fault $I_{N2}$ overcurrent transformer
$I_{N2}$ CT secondary	Secondary current value of the $I_{N2}$ overcurrent transformer
Nominal $I_{N2}$ input	Selectable nominal input rating for the ground fault overcurrent input. Select either 1A or 0.2A depending on which I <sub>o</sub> input is used. The given thermal withstand, burden and impedance are based on this value. See <a href="#">Table 154 - Measuring circuits</a> on page 348 for details.
$I_{N3}$ CT primary	Primary current value of the ground fault $I_{N3}$ overcurrent transformer
$I_{N3}$ CT secondary	Secondary current value of the ground fault $I_{N3}$ overcurrent transformer
VT primary	Primary voltage value of the voltage transformer
Nominal $I_{N3}$ input	Selectable nominal input rating for the ground fault overcurrent input. Select either 1A or 0.2A depending on which I <sub>o</sub> input is used. The given thermal withstand, burden and impedance are based on this value. See <a href="#">Table 154 - Measuring circuits</a> on page 348 for details.
VT secondary	Secondary voltage value of the voltage transformer

Parameter	Description
VTo secondary	Secondary voltage value of the neutral voltage displacement voltage transformer
Voltage measurement mode	The relay can be connected either to zero-sequence voltage, line-to-line voltage or line-to-neutral voltage. Set the voltage measurement mode according to the type of connection used.
Frequency adaptation mode	Parameter used to set the system frequency. There are three modes available: manual, auto and fixed. For more information, see section Frequency adaptation mode.
Adapted frequency	When the frequency adaption mode is set to manual, you can set the frequency in the <b>Adapted frequency</b> field, and it is not be updated even if the measured frequency is different.
Angle memory duration	Time setting for the directional overcurrent stage to keep the phase angle fixed if the system voltage collapses
I' 180 deg. angle turn	A setting to turn I' currents 180 degrees (only P3x32 relays)
Generator nominal power	Electrical power of the generator
Generator nominal voltage	Nominal voltage of the generator
Nominal shaft power Pm	Nominal mechanical power of the generator

Figure 11 - Scaling setting view in Easergy Pro

Scaling			
CT settings			
CT primary	<input type="text" value="500"/>	A	
CT secondary	<input type="text" value="5"/>	A	
Nominal input (I'L side)	<input type="text" value="5"/>	A	
CT primary	<input type="text" value="500"/>	A	
CT secondary	<input type="text" value="1"/>	A	
Io1 CT primary	<input type="text" value="50"/>	A	
Io1 CT secondary	<input type="text" value="5.0"/>	A	
Nominal Io1 input	<input type="text" value="1.0"/>	A	
Io2 CT primary	<input type="text" value="50"/>	A	
Io2 CT secondary	<input type="text" value="5.0"/>	A	
Nominal Io2 input	<input type="text" value=""/>	A	
Io3 CT primary	<input type="text" value="50"/>	A	
Io3 CT secondary	<input type="text" value="5.0"/>	A	
Nominal Io3 input	<input type="text" value="5.0"/>	A	
VT settings			
VT primary	<input type="text" value="11000"/>	V	
VT secondary	<input type="text" value="100"/>	V	
VTo secondary	<input type="text" value="100.000"/>	V	
Voltage meas. mode	<input type="text" value="3LN+Uo"/>		<input type="checkbox"/>
Frequency adaptation mode	<input type="text" value="Auto"/>		
Adapted frequency	<input type="text" value="50.0"/>	Hz	
Angle memory duration	<input type="text" value="0.50"/>	s	
I' 180 deg. angle turn	<input type="checkbox"/>		
Generator settings			
Generator nominal power	<input type="text" value="8000"/>	kVA	
Generator nominal voltage	<input type="text" value="11400"/>	V	
Nominal shaft power Pm	<input type="text" value="6400"/>	kW	

The scaling equations presented in [4.1.2 Current transformer ratio](#) on page 50 and [4.1.3 Voltage transformer ratio](#) on page 52 are useful when doing secondary testing.

### 4.1.1 Frequency adaptation mode

You can set the system frequency in **General > Scaling** in Easergy Pro.

There are three frequency adaptation modes available:

- **Manual:** When the adaption mode is set to manual, you can set the frequency in the **Adapted frequency** field, and it will not be updated even if the measured frequency is different. However, the relay monitors the system frequency internally and adapts to the new frequency even if the frequency has been set manually.
- **Auto:** The network frequency is automatically updated when the relay has measured the voltage for approximately 45 seconds. The **Adapted frequency**

field is updated even if it has been set previously. The frequency is measured from the voltage signals.

Table 18 - Voltage signals

Voltage measurement mode	Voltage	Voltage channel
2LL+V <sub>N</sub> , 2LL+V <sub>N</sub> /LNy, 2LL+V <sub>N</sub> /LLy	V <sub>AB</sub> , V <sub>BC</sub>	V <sub>1</sub> , V <sub>2</sub>
3LN, 3LN+V <sub>N</sub> , 3LN/LNy, 3LN/LLy	V <sub>A</sub> , V <sub>B</sub>	V <sub>1</sub> , V <sub>2</sub>
LN+V <sub>N/y/z</sub>	V <sub>A</sub>	V <sub>1</sub>
LL+V <sub>N/y/z</sub>	V <sub>AB</sub>	V <sub>1</sub>

- **Fixed:** The frequency is not updated based on the measured voltage and only the set value is used. This mode is recommended to be used for the line-differential function.

### 4.1.2 Current transformer ratio

**NOTE:** The rated value of the relay's current input, for example 5 A or 1 A, does not have any effect on the scaling equations, but it defines the measurement range and the maximum allowed continuous current. See [Table 154 - Measuring circuits](#) on page 348 for details.

Table 19 - Primary and secondary scaling

	Current (CT) Residual current calculated
secondary → primary	$I_{PRI} = I_{SEC} \cdot \frac{CT_{PRI}}{CT_{SEC}}$
primary → secondary	$I_{SEC} = I_{PRI} \cdot \frac{CT_{SEC}}{CT_{PRI}}$

For ground fault overcurrent to input I<sub>N</sub>, use the corresponding CT<sub>PRI</sub> and CT<sub>SEC</sub> values. For ground fault stages using I<sub>N Calc</sub> signals, use the phase current CT values for CT<sub>PRI</sub> and CT<sub>SEC</sub>.

#### Examples

1. **Secondary to primary**

CT = 500 / 5

Current to the relay's input is 4 A.

=> Primary current is I<sub>PRI</sub> = 4 x 500 / 5 = 400 A

2. **Primary to secondary**

CT = 500 / 5

The relay displays I<sub>PRI</sub> = 400 A

=> Injected current is I<sub>SEC</sub> = 400 x 5 / 500 = 4 A

### Per unit [pu] scaling

For phase currents excluding Arcl>stage:

1 pu = 1 x I<sub>GN</sub> = 100%, where I<sub>GN</sub> is the rated current of the generator.

The rated current for high-voltage side (HV) and low-voltages side (LV) are calculated by the relay itself using [Equation 1 on page 51](#).

Equation 1

$$I_{GN} = \frac{S_{GN}}{\sqrt{3} \cdot V_{GN}}$$

I<sub>GN</sub> = The rated current 1 pu.

S<sub>GN</sub> = Rated apparent power of the protected object

V<sub>GN</sub> = Rated line-to-line voltage of the protected object

For ground fault overcurrents and Arcl> stage:

1 pu = 1 x CT<sub>SEC</sub> for secondary side and 1 pu = 1 x CT<sub>PRI</sub> for primary side.

	Phase current scaling excluding Arcl> stage	Ground fault overcurrent (3I <sub>N</sub> ) scaling
secondary → per unit	$I_{PU} = \frac{I_{SEC} \cdot CT_{PRI}}{CT_{SEC} \cdot I_{GN}}$	$I_{PU} = \frac{I_{SEC}}{CT_{SEC}}$
per unit → secondary	$I_{SEC} = I_{PU} \cdot CT_{SEC} \cdot \frac{I_{GN}}{CT_{PRI}}$	$I_{SEC} = I_{PU} \cdot CT_{SEC}$

### Examples

#### 1. Secondary to per unit for Arcl>

$$CT = 750 / 5$$

Current injected to the relay's inputs is 7 A.

Per unit current is I<sub>PU</sub> = 7 / 5 = 1.4 pu = 140%

#### 2. Secondary to per unit for phase currents excluding Arcl>

$$CT = 750/5$$

$$I_{GN} = 525 \text{ A}$$

Current injected to the relay's inputs is 7 A.

Per unit current is I<sub>PU</sub> = 7 x 750 / (5 x 525) = 2.00 pu = 2.00 x I<sub>GN</sub> = 200%

#### 3. Per unit to secondary for Arcl>

$$CT = 750 / 5$$

The relay setting is 2 pu = 200%.

Secondary current is I<sub>SEC</sub> = 2 x 5 = 10 A

#### 4. Per unit to secondary for phase currents

$$CT = 750 / 5$$

$$I_{GN} = 525 \text{ A}$$

The relay setting is  $2 \times I_{GN} = 2 \text{ pu} = 200\%$ .

$$\text{Secondary current is } I_{SEC} = 2 \times 5 \times 525 / 750 = 7 \text{ A}$$

**5. Secondary to per unit for earth fault overcurrent**

Input is  $I_{N1}$ .

$$CT_0 = 50 / 1$$

Current injected to the relay's input is 30 mA.

$$\text{Per unit current is } I_{PU} = 0.03 / 1 = 0.03 \text{ pu} = 3\%$$

**6. Secondary to per unit for ground fault overcurrent**

Input is  $I_{N1}$ .

$$CT_0 = 50 / 1$$

The relay setting is  $0.03 \text{ pu} = 3\%$ .

$$\text{Secondary current is } I_{SEC} = 0.03 \times 1 = 30 \text{ mA}$$

**7. Secondary to per unit for earth fault overcurrent**

Input is  $I_{N \text{ Calc.}}$

$$CT = 750 / 5$$

Currents injected to the relay's  $I_A$  input is 0.5 A.

$$I_B = I_C = 0.$$

$$\text{Per unit current is } I_{PU} = 0.5 / 5 = 0.1 \text{ pu} = 10\%$$

**8. Secondary to per unit for earth fault overcurrent**

Input is  $I_{N \text{ Calc.}}$

$$CT = 750 / 5$$

The relay setting is  $0.1 \text{ pu} = 10\%$ .

$$\text{If } I_B = I_C = 0, \text{ then secondary current to } I_A \text{ is } I_{SEC} = 0.1 \times 5 = 0.5 \text{ A}$$

### 4.1.3 Voltage transformer ratio

**NOTE:** Voltage transformer scaling is based on the line-to-line voltages in all voltage measurements modes.

Table 20 - Primary/secondary scaling of line-to-line voltages

	Line-to-line voltage scaling	
	Voltage measurement mode = "2LL+V <sub>N</sub> "	Voltage measurement mode = "3LN"
secondary → primary	$V_{PRI} = V_{SEC} \cdot \frac{VT_{PRI}}{VT_{SEC}}$	$V_{PRI} = \sqrt{3} \cdot V_{SEC} \cdot \frac{VT_{PRI}}{VT_{SEC}}$
primary → secondary	$V_{SEC} = V_{PRI} \cdot \frac{VT_{SEC}}{VT_{PRI}}$	$V_{SEC} = \frac{V_{PRI}}{\sqrt{3}} \cdot \frac{VT_{SEC}}{VT_{PRI}}$



**Examples****1. Secondary to primary. Voltage measurement mode is "2LL+V<sub>N</sub>".**

$$VT = 12000/110$$

Voltage connected to the relay's input V<sub>A</sub> or V<sub>B</sub> is 100 V.

$$\Rightarrow \text{Primary voltage is } V_{PRI} = 100 \times 12000/110 = 10909 \text{ V.}$$

**2. Secondary to primary. Voltage measurement mode is "3LN".**

$$VT = 12000/110$$

Three phase symmetric voltages connected to the relay's inputs V<sub>A</sub>, V<sub>B</sub> and V<sub>C</sub> are 57.7 V.

$$\Rightarrow \text{Primary voltage is } V_{PRI} = \sqrt{3} \times 57.7 \times 12000/110 = 10902 \text{ V}$$

**3. Primary to secondary. Voltage measurement mode is "2LL+V<sub>N</sub>".**

$$VT = 12000/110$$

The relay displays V<sub>PRI</sub> = 10910 V.

$$\Rightarrow \text{Secondary voltage is } V_{SEC} = 10910 \times 110/12000 = 100 \text{ V}$$

**4. Primary to secondary. Voltage measurement mode is "3LN".**

$$VT = 12000/110$$

The relay displays V<sub>AB</sub> = V<sub>BC</sub> = V<sub>CA</sub> = 10910 V.

$$\Rightarrow \text{Symmetric secondary voltages at } V_A, V_B \text{ and } V_C \text{ are } V_{SEC} = 10910/\sqrt{3} \times 110/12000 = 57.7 \text{ V.}$$

**Per unit [pu] scaling of line-to-line voltages**

One per unit = 1 pu = 1 x V<sub>N</sub> = 100%, where V<sub>N</sub> = rated voltage of the VT.

	Line-to-line voltage scaling	
	Voltage measurement mode = "2LL+V <sub>N</sub> ", "1LL+V <sub>N</sub> /LLy", "2LL/LLy", "LL/LLy/LLz"	Voltage measurement mode = "3LN"
secondary → per unit	$V_{PU} = \frac{V_{SEC}}{VT_{SEC}} \cdot \frac{VT_{PRI}}{V_N}$	$V_{PU} = \sqrt{3} \cdot \frac{V_{SEC}}{VT_{SEC}} \cdot \frac{VT_{PRI}}{V_N}$
per unit → secondary	$V_{SEC} = V_{PU} \cdot VT_{SEC} \cdot \frac{V_N}{VT_{PRI}}$	$V_{SEC} = V_{PU} \cdot \frac{VT_{SEC}}{\sqrt{3}} \cdot \frac{V_N}{VT_{PRI}}$

**Examples****1. Secondary to per unit. Voltage measurement mode is "2LL+V<sub>N</sub>".**

$$VT = 12000/110$$

Voltage connected to the relay's input V<sub>A</sub> or V<sub>B</sub> is 110 V.

$$\Rightarrow \text{Per unit voltage is } V_{PU} = 110/110 = 1.00 \text{ pu} = 1.00 \times V_N = 100\%$$

**2. Secondary to per unit. Voltage measurement mode is "3LN".**

$$VT = 12000/110$$

Three symmetric phase-to-neutral voltages connected to the relay's inputs  $V_A$ ,  $V_B$  and  $V_C$  are 63.5 V

=> Per unit voltage is  $V_{PU} = \sqrt{3} \times 63.5/110 \times 12000/11000 = 1.00 \text{ pu} = 1.00 \times V_N = 100\%$

**3. Per unit to secondary. Voltage measurement mode is "2LL+V<sub>N</sub>".**

$V_T = 12000/110$

The relay displays 1.00 pu = 100%.

=> Secondary voltage is  $V_{SEC} = 1.00 \times 110 \times 11000/12000 = 100.8 \text{ V}$

**4. Per unit to secondary. Voltage measurement mode is "3LN".**

$V_T = 12000/110$

$V_N = 11000 \text{ V}$

The relay displays 1.00 pu = 100%.

=> Three symmetric phase-to-neutral voltages connected to the relay's inputs  $V_A$ ,  $V_B$  and  $V_C$  are  $V_{SEC} = 1.00 \times 110/\sqrt{3} \times 11000/12000 = 58.2 \text{ V}$

**Per unit [pu] scaling of neutral overvoltage**

	Neutral overvoltage ( $V_N$ ) scaling	
	Voltage measurement mode = "2LL+V <sub>N</sub> ", "1LL+V <sub>N</sub> /LLy"	Voltage measurement mode = "3LN"
secondary → per unit	$V_{PU} = \frac{V_{SEC}}{V_{0SEC}}$	$V_{PU} = \frac{1}{V_{T_{SEC}}} \cdot \frac{ \bar{V}_a + \bar{V}_b + \bar{V}_c _{SEC}}{\sqrt{3}}$
per unit → secondary	$V_{SEC} = V_{PU} \cdot V_{0SEC}$	$ \bar{V}_a + \bar{V}_b + \bar{V}_c _{SEC} = \sqrt{3} \cdot V_{PU} \cdot V_{T_{SEC}}$

**Examples**

**1. Secondary to per unit. Voltage measurement mode is "2LL+V<sub>N</sub>".**

$V_{0SEC} = 110 \text{ V}$  (This is a configuration value corresponding to  $V_N$  at full ground fault.)

Voltage connected to the relay's input  $V_C$  is 22 V.

=> Per unit voltage is  $V_{PU} = 22/110 = 0.20 \text{ pu} = 20\%$

**2. Secondary to per unit. Voltage measurement mode is "3LN".**

$V_T = 12000/110$

Voltage connected to the relay's input  $V_A$  is 38.1 V, while  $V_B = 0$ .

=> Per unit voltage is  $V_{PU} = (38.1+0+0)/(\sqrt{3} \times 110) = 0.20 \text{ pu} = 20\%$

**3. Per unit to secondary. Voltage measurement mode is "2LL+V<sub>N</sub>".**

$V_{0SEC} = 110 \text{ V}$  (This is a configuration value corresponding to  $V_N$  at full ground fault.)

The relay displays  $V_N = 20\%$ .

=> Secondary voltage at input  $V_C$  is  $V_{SEC} = 0.20 \times 110 = 22 \text{ V}$

**4. Per unit to secondary. Voltage measurement mode is "3LN".**

$$VT = 12000/110$$

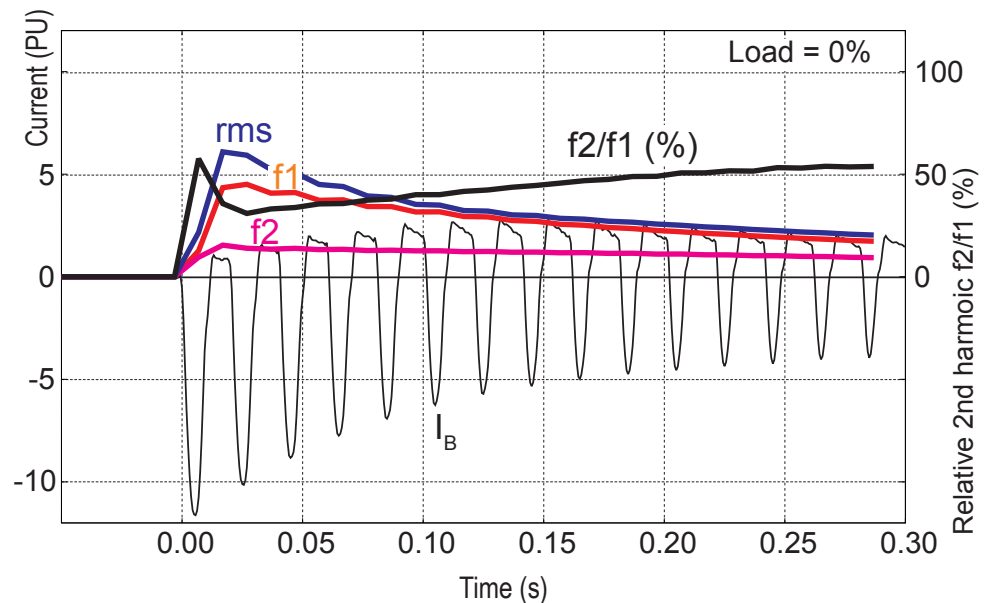
The relay displays  $V_N = 20\%$ .

=> If  $V_B = V_C = 0$ , then secondary voltages at  $V_A$  is  $V_{SEC} = \sqrt{3} \times 0.2 \times 110 = 38.1 \text{ V}$

## 4.2 Measurements for protection functions

The relay uses root mean square (RMS) measurement for the protection stages if not stated otherwise in the protection stage description.

Figure 12 - Example of various current values of a transformer inrush current



All the direct measurements are based on fundamental frequency values. The exceptions are frequency and instantaneous current for arc flash detection. Most protection functions are also based on the fundamental frequency values.

[Figure 12 - Example of various current values of a transformer inrush current](#) on page 55 shows a current waveform and the corresponding fundamental frequency component  $f_1$ , second harmonic  $f_2$ , and RMS value in a special case where the current deviates significantly from a pure sine wave.

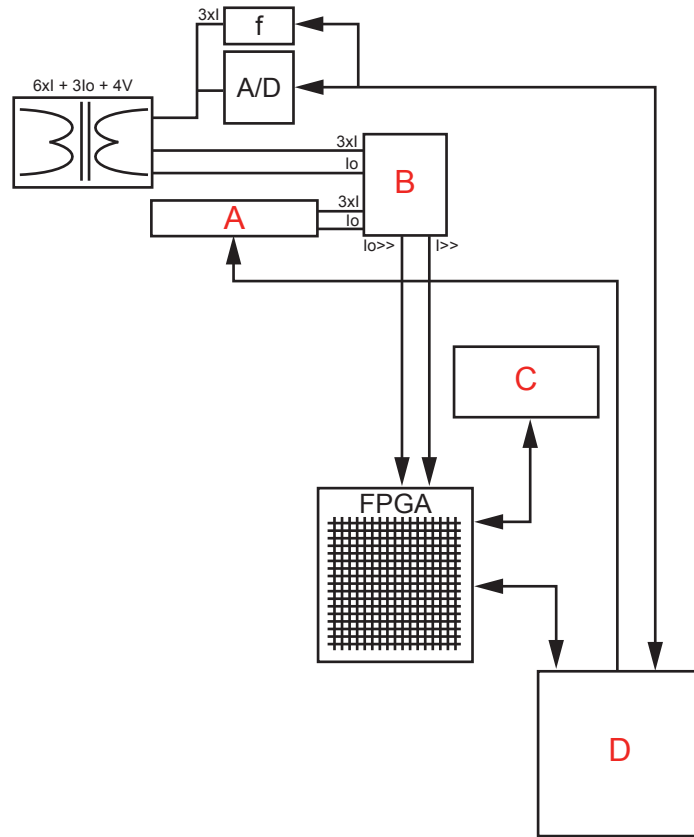
## 4.3 Measurements for arc flash detection function

The three-phase current measurement and ground fault current measurement for arc flash detection are done with electronics. The electronics compares the current levels to the start settings - THRESHOLDS - and gives a binary signals " $I >$ " or " $I_{N1} >$ " to the arc flash detection function if limit is exceeded. All the frequency components of the currents are taken into account.

Signals " $I >$ " or " $I_{N1} >$ " are connected to a FPGA chip which implements the arc flash detection function. The start settings are named " $I > \text{int}$ " and " $I_{N1} > \text{int}$ " in the local

LCD panel or Easergy Pro views, these settings are used to set the THRESHOLD levels for the electronics.

Figure 13 - Measurement logic for the arc flash detection function



- A. Threshold
- B. Comp
- C. Conf. memory
- D. CPU

## 4.4 RMS values

### RMS currents

The relay calculates the RMS value of each phase current. The minimum and maximum RMS values are recorded and stored (see [4.7 Minimum and maximum values](#) on page 59).

$$I_{RMS} = \sqrt{I_{f1}^2 + I_{f2}^2 + \dots + I_{f15}^2}$$

### RMS voltages

The relay calculates the RMS value of each voltage input. The minimum and the maximum of RMS values are recorded and stored (see [4.7 Minimum and maximum values](#) on page 59).

$$V_{RMS} = \sqrt{V_{f1}^2 + V_{f2}^2 + \dots + V_{f15}^2}$$

## 4.5 Harmonics and total harmonic distortion (THD)

The relay calculates the the total harmonic distortions (THDs) as a percentage of the currents and voltages values measured at the fundamental frequency. The relay calculates the harmonics from the 2nd to the 15th of phase currents and voltages. (The 17th harmonic component is also shown partly in the value of the 15th harmonic component. This is due to the nature of digital sampling.)

The harmonic distortion is calculated:

Equation 2

$$THD = \frac{\sqrt{\sum_{i=2}^{15} f_i^2}}{h_1}$$

$f_1$  = Fundamental value

$f_{2-15}$  = Harmonics

### Example

$f_1 = 100 \text{ A}$ ,                       $f_3 = 10 \text{ A}$ ,                       $f_7 = 3 \text{ A}$ ,                       $f_{11} = 8 \text{ A}$

$$THD = \frac{\sqrt{10^2 + 3^2 + 8^2}}{100} = 13.2\%$$

For reference, the RMS value is:

$$RMS = \sqrt{100^2 + 10^2 + 3^2 + 8^2} = 100.9 \text{ A}$$

Another way to calculate the THD is to use the RMS value as reference instead of the fundamental frequency value. In the example above, the result would then be 13.0 %.

## 4.6 Demand values

The device calculates average values (demand values) of phase currents  $I_A$ ,  $I_B$ ,  $I_C$  and power values S, P and Q.

The demand time is configurable from 10 to 60 minutes with the parameter "Demand time".

Figure 14 - Demand values

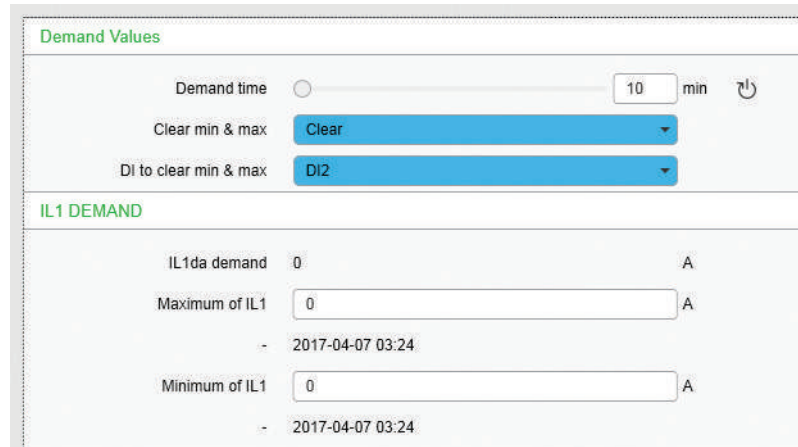


Table 21 - Demand value parameters

Parameter	Value	Unit	Description	Set <sup>14</sup>
Time	10 – 30	min	Demand time (averaging time)	Set
<b>Fundamental frequency values</b>				
I <sub>A</sub> da		A	Demand of phase current I <sub>A</sub>	
I <sub>B</sub> da		A	Demand of phase current I <sub>B</sub>	
I <sub>C</sub> da		A	Demand of phase current I <sub>C</sub>	
Pda		kW	Demand of active power P	
PFda			Demand of power factor PF	
Qda		kvar	Demand of reactive power Q	
Sda		kVA	Demand of apparent power S	
<b>RMS values</b>				
I <sub>A</sub> RMSda		A	Demand of RMS phase current I <sub>A</sub>	
I <sub>B</sub> RMSda		A	Demand of RMS phase current I <sub>B</sub>	
I <sub>C</sub> RMSda		A	Demand of RMS phase current I <sub>C</sub>	
Prmsda		kW	Demand of RMS active power P	
Qrmsda		kvar	Demand of RMS reactive power Q	
Srmsda		kVA	Demand of RMS apparent power S	

<sup>14</sup> Set = An editable parameter (password needed)

## 4.7 Minimum and maximum values

Minimum and maximum values are registered with time stamps since the latest manual clearing or since the relay has been restarted. The available registered values are listed in [Table 22 - Minimum and maximum measurement values](#) on page 59.

Figure 15 - Minimum and maximum values

The screenshot shows a web interface for configuring measurement values. At the top, there's a section titled 'Current Minimums and Maximums'. It contains two dropdown menus: 'Clear min & max' set to '-' and 'DI to clear min & max' set to 'DI2'. Below this is a section titled 'IL1 MIN/MAX'. It has two rows: 'Minimum of IL1' and 'Maximum of IL1'. Each row has a text input field containing '0' and a unit 'A'. To the right of each input field are two lines of text representing a date and time: '2017-04-07' and '03:24:59'.

Table 22 - Minimum and maximum measurement values

Min & Max measurement	Description
$I_A, I_B, I_C$	Phase current, fundamental frequency value
$I_{A\text{ RMS}}, I_{B\text{ RMS}}, I_{C\text{ RMS}}$	Phase current, RMS value
$I_{N1}, I_{N2}$	Ground fault overcurrent, fundamental value
$V_A, V_B, V_C, V_D$	Voltages, fundamental frequency values
$V_{A\text{ RMS}}, V_{B\text{ RMS}}, V_{C\text{ RMS}}, V_{D\text{ RMS}}$	Line-to-neutral voltages, RMS value
$V_N$	Neutral voltage displacement, fundamental value
f	Frequency
P, Q, S	Active, reactive, apparent power
$I_{A\text{ da}}, I_{B\text{ da}}, I_{C\text{ da}}$	Demand values of phase currents
$I_{A\text{ da}}, I_{B\text{ da}}, I_{C\text{ da}}$ (rms value)	Demand values of phase currents, rms values
P.F.	Power factor

The clearing parameter "ClrMax" is common for all these values.

Table 23 - Parameters

Parameter	Value	Description	Set <sup>15</sup>
ClrMax	-; Clear	Reset all minimum and maximum values	Set

<sup>15</sup> Set = An editable parameter (password needed).

## 4.8 Maximum values of the last 31 days and 12 months

The maximum and minimum values of the last 31 days and the last 12 months are stored in the relay's non-volatile memory. You can view them in the **Month max** setting view in Easergy Pro.

**NOTE:** The saving process starts every 30 minutes and it takes a while. If the relay's auxiliary supply power is switched off before all values have been saved, the old values remain for the unsaved ones.

Corresponding time stamps are stored for the last 31 days. The registered values are listed in [Table 24 - Maximum registered values of the last 31 days and 12 months](#) on page 61.

Figure 16 - Maximum and minimum values of the past 31 days

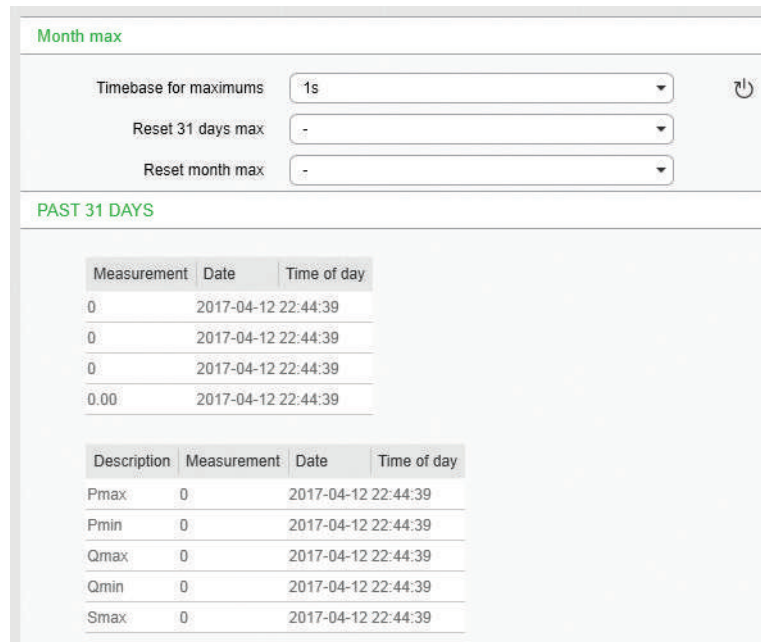


Figure 17 - Maximum and minimum values of the past 12 months

PAST 12 MONTHS

Month	Year	IAmax	IBmax	ICmax	IN-1max	Pmax	Pmin	Qmax	Qmin	Smax
JANUARY	2019	0 A	0 A	0 A	0.00 A	0 kW	0 kW	0 kvar	0 kvar	0 kVA
FEBRUARY	2019	0 A	0 A	0 A	0.00 A	0 kW	0 kW	0 kvar	0 kvar	0 kVA
MARCH	2019	43 A	39 A	41 A	772.50 A	20 kW	0 kW	1 kvar	0 kvar	20 kVA
APRIL	2019	0 A	0 A	0 A	0.00 A	0 kW	0 kW	0 kvar	0 kvar	0 kVA
MAY	2019	0 A	0 A	0 A	0.00 A	0 kW	0 kW	0 kvar	0 kvar	0 kVA
JUNE	2019	62 A	62 A	64 A	13.30 A	38 kW	0 kW	1 kvar	0 kvar	38 kVA
JULY	2019	0 A	0 A	0 A	0.00 A	0 kW	0 kW	0 kvar	0 kvar	0 kVA
AUGUST	2018	0 A	0 A	0 A	0.00 A	0 kW	0 kW	0 kvar	0 kvar	0 kVA
SEPTEMBER	2018	0 A	0 A	0 A	0.00 A	0 kW	0 kW	0 kvar	0 kvar	0 kVA
OCTOBER	2018	0 A	0 A	0 A	0.00 A	0 kW	0 kW	0 kvar	0 kvar	0 kVA
NOVEMBER	2018	0 A	0 A	0 A	0.00 A	0 kW	0 kW	0 kvar	0 kvar	0 kVA



Table 24 - Maximum registered values of the last 31 days and 12 months

12 months Measurement	Max	Min	Description	31 days	12 months
$I_A, I_B, I_C$	X		Phase current (fundamental frequency value)		
$I_{N1}, I_{N2}$	X		Ground fault overcurrent		
S	X		Apparent power	X	X
P	X	X	Active power	X	X
Q	X	X	Reactive power	X	X

The timebase can be a value from one cycle to one minute. Also a demand value can be used as the timebase and its value can be set between 10 and 60 minutes. The demand value menu is located under the **Measurements** view.

Table 25 - Parameters of the day and month registers

Parameter	Value	Description	Set <sup>16</sup>
Timebase		Parameter to select the type of the registered values	Set
	20 ms	Collect min & max of one cycle values <sup>17</sup>	
	200 ms	Collect min & max of 200 ms average values	
	1 s	Collect min & max of 1 s average values	
	1 min	Collect min & max of 1 minute average values	
	demand	Collect min & max of demand values ( <a href="#">4.6 Demand values on page 57</a> )	
ResetDays		Reset the 31 day registers	Set
ResetMon		Reset the 12 month registers	Set

<sup>16</sup> Set = An editable parameter (password needed)

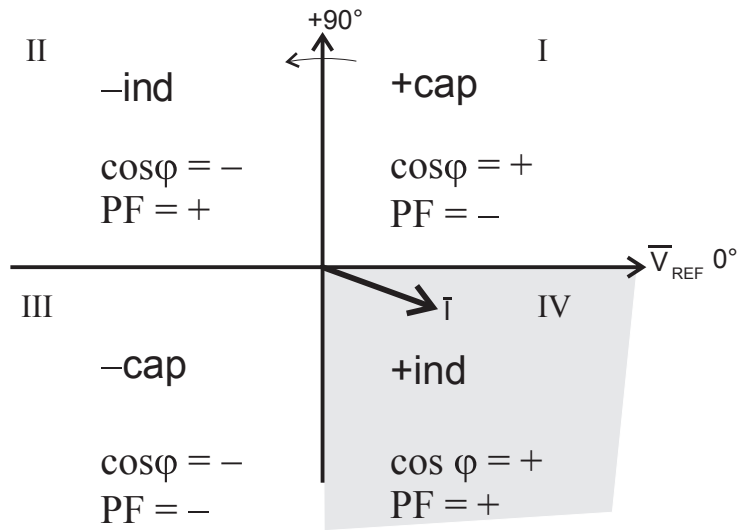
<sup>17</sup> This is the fundamental frequency RMS value of one cycle updated every 20 ms.

## 4.9 Power and current direction

[Figure 18 - Quadrants of voltage/current phasor plane](#) on page 62 shows the concept of three-phase current direction and sign of  $\cos\phi$  and power factor PF (the absolute value is equal to  $\cos\phi$ , but the sign is 'IND' for inductive i.e. lagging

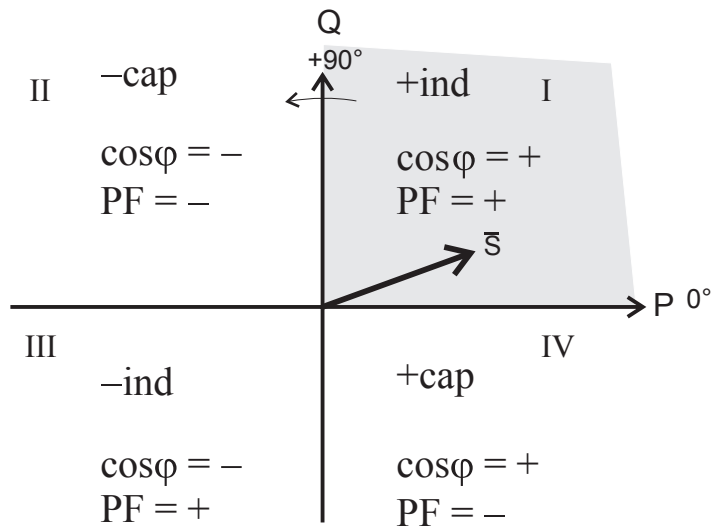
current and 'CAP' for capacitive i.e. leading current). [Figure 19 - Quadrants of power plane](#) on page 62 shows the same concepts on a PQ power plane.

Figure 18 - Quadrants of voltage/current phasor plane



I:	Forward capacitive power, current is leading
II:	Reverse inductive power, current is leading
III:	Reverse capacitive power, current is lagging
IV:	Forward inductive power, current is lagging

Figure 19 - Quadrants of power plane



I:	Forward inductive power, current is lagging
II:	Reverse capacitive power, current is lagging
III:	Reverse inductive power, current is leading

IV:	Forward capacitive power, current is leading
-----	--

Table 26 - Power quadrants

Power quadrant	Current related to voltage	Power direction	cosφ	Power factor PF
+ inductive	Lagging	Forward	+	+
+ capacitive	Leading	Forward	+	-
- inductive	Leading	Reverse	-	+
- capacitive	Lagging	Reverse	-	-

## 4.10 Symmetrical components

In a three-phase system, the voltage or current phasors may be divided into symmetrical components.

- Positive sequence 1
- Negative sequence 2
- Zero sequence 0

Symmetrical components are calculated according to the following equations:

$$\begin{bmatrix} \underline{S}_0 \\ \underline{S}_1 \\ \underline{S}_2 \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & \underline{a} & \underline{a}^2 \\ 1 & \underline{a}^2 & \underline{a} \end{bmatrix} \begin{bmatrix} \underline{S}_A \\ \underline{S}_B \\ \underline{S}_C \end{bmatrix}$$

$\underline{S}_0$  = zero sequence component

$\underline{S}_1$  = positive sequence component

$\underline{S}_2$  = negative sequence component

$$\underline{a} = 1 \angle 120^\circ = -\frac{1}{2} + j \frac{\sqrt{3}}{2}$$

, a phase rotating constant

$\underline{S}_A$  = phasor of phase A (phase current or voltage)

$\underline{S}_B$  = phasor of phase B

$\underline{S}_C$  = phasor of phase C

## 5 Control functions

### 5.1 Digital outputs

The digital outputs are also called controlling outputs, signaling outputs and self-supervision outputs. Trip contacts can be controlled by using the relay output matrix or logic functions. Also forced control is possible. To use forced control, you must enable it in the **Relays** setting view.

Any internal signal can be connected to the digital outputs in the **Matrix > Arc matrix - output** setting views.

The **Output matrix** and **Relays** setting views represent the state (de-energized / energized) of the digital output's coil. For example, a bright green vertical line in the **Output matrix** and a logical "1" in the **Relays** view represent the energized state of the coil. The same principle applies for both NO and NC type digital outputs. The actual position (open / closed) of the digital outputs' contacts in coil's de-energized and energized state depends on the type (NO / NC) of the digital outputs. De-energized state of the coil corresponds to the normal state of the contacts. A digital output can be configured as latched or non-latched. [5.5 Releasing latches on page 80](#) describes releasing latches procedure.

The difference between trip contacts and signal contacts is the DC breaking capacity. The contacts are **single pole single throw (SPST)** normal open (NO) type, except signal relay A1 which has a changeover contact **single pole double throw (SPDT)**.

In addition to this, the relay has so called heavy duty outputs available in the power supply modules C and D. For more details, see [Table 154 - Measuring circuits on page 348](#).

#### Programming matrix

1. Connected (single bullet)
2. Connected and latched (single bullet rounded with another circle)
3. Not connected (line crossing is empty)

Figure 20 - Trip contacts can be connected to protection stages or other similar purpose in the Output matrix setting view

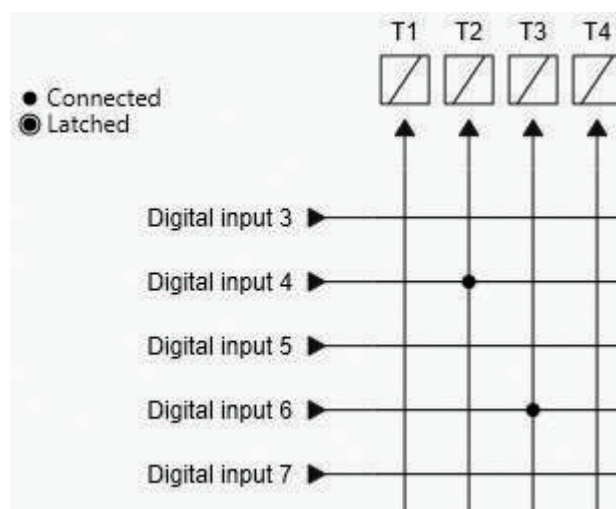
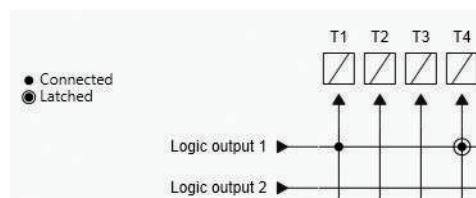


Figure 21 - Trip contacts can be assigned directly to outputs of logical operators



**NOTE:** Logic outputs are assigned automatically in the output matrix as well when logic is built.

Trip contact status can be viewed and forced to operate in the **Relays** setting view. Logical "0" means that the output is not energized and logical "1" states that the output is set active.

Figure 22 - **Relays** setting view

**RELAYS**

---

Trip relay 1

Trip relay 2

---

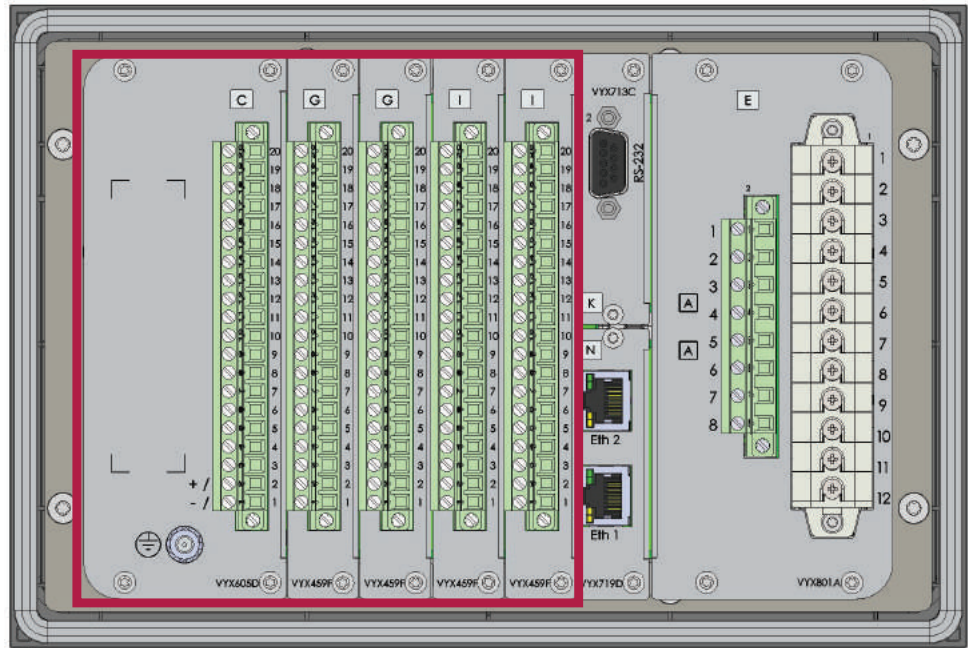
Force flag

**Default numbering of DI / DO**

Every option card and slot has default numbering. Below is an example of model P3x30 CGGII-AAEAA-BA showing the default numbering of digital outputs.

You can see the default digital output numbering and change the numbering of the following option cards in the **Inputs/Outputs > Relay config** setting view: slot 2, 3, 4, 5: G, I.

Figure 23 - Default numbering of digital outputs for model P3x30-CGGII-AAEAA-BA



- C: T1, T9–12, A1, SF
- G: T13-16
- G: T17-20
- I: –
- I: –

Power supply card outputs are not visible in the **Relay config** setting view.

Figure 24 - **Relay config** setting view

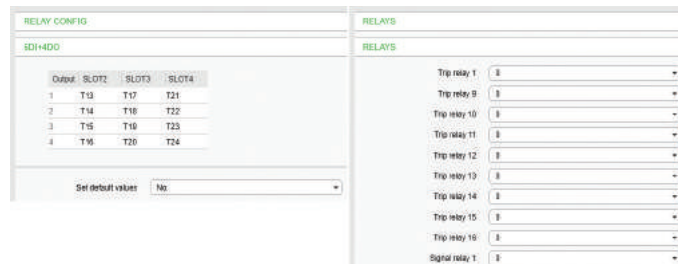


Table 27 - Parameters of digital outputs

Parameter	Value	Unit	Description	Note
T1 – Tx the available parameter list depends on the number and type of the I/O cards.	0 1		Status of trip controlling output	F <sup>18</sup>
A1	0 1		Status of alarm signalling output	F

Parameter	Value	Unit	Description	Note
WD	0		Status of the WD relay	F
	1		In Easergy Pro, it is called "Service status output"	
Force	On		Force flag for digital output forcing for test purposes	Set <sup>19</sup>
	Off			
Names for output relays (editable with Easergy Pro only)				
Description	String of max. 32 characters		Names for DO on Easergy Pro screens. Default is "Trip relay n", n=1 – x or "Signal relay n", n=1	Set

<sup>18</sup> F = Editable when force flag is on

<sup>19</sup> Set = An editable parameter (password needed).

## 5.2 Digital inputs

Digital inputs are available for control purposes. The number of available inputs depends on the number and type of option cards.

The polarity normal open (NO) / normal closed (NC) and a delay can be configured according to the application by using the front panel or Easergy Pro.

Digital inputs can be used in many operations. The status of the input can be checked in the **Output matrix** and **Digital inputs** setting views. The digital inputs make it possible to change group, block/enable/disable functions, to program logics, indicate object status, etc.

The digital inputs require an external control voltage (ac or dc). The digital inputs are activated after the activation voltage is exceeded. Deactivation follows when the voltage drops below threshold limit. The activation voltage level of digital inputs can be selected in the order code when such option cards are equipped.

Figure 25 - Digital inputs can be connected, latched or unlatched to trip contacts or other similar purpose in **Output matrix** setting view

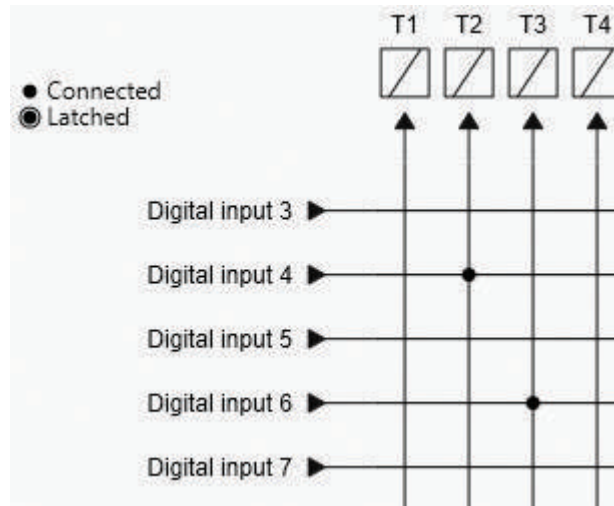
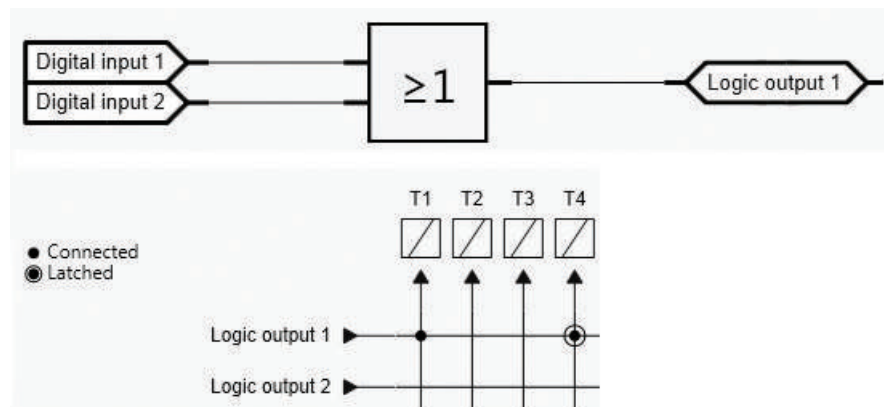


Figure 26 - Digital inputs can be assigned, latched or unlatched directly to inputs/ outputs of logical operators



If inputs are energized by using ac voltage, “mode” has to be selected as ac.

All essential information on digital inputs can be found in the same location in the **Digital inputs** setting view. DI on/off events and alarm display (pop-up) can be enabled and disabled in **Digital inputs** setting view. Individual operation counters are located in the same view as well.

Label and description texts can be edited with Easergy Pro according to the demand. Labels are the short parameter names used on the local panel and descriptions are the longer names used by Easergy Pro.

The digital input activation thresholds are hardware-selectable.

Digital input delay determines the activation and de-activation delay for the input.

[Figure 27 - Digital input's behavior when delay is set to 1 second](#) on page 69 shows how the digital input behaves when the delay is set to 1 second.



Figure 27 - Digital input's behavior when delay is set to 1 second

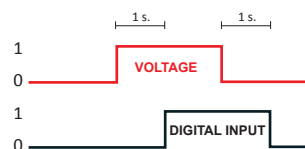


Table 28 - Parameters of digital inputs

Parameter	Value	Unit	Description	Note
Mode	dc, ac		Used voltage of digital inputs	Set <sup>20</sup>
Input	DI1 – DIx		Number of digital input. The available parameter list depends on the number and type of the I/O cards.	
Slot	2 – 6		Card slot number where option card is installed.	
State	0, 1		Status of digital input 1 – digital input x.	
Polarity	NO NC		For normal open contacts (NO). Active edge is 0 > 1  For normal closed contacts (NC)  Active edge is 1 > 0	Set
Delay	0.00 – 60.00	s	Definite delay for both on and off transitions	Set
On event	On		Active edge event enabled	Set
	Off		Active edge event disabled	
Off event	On		Inactive edge event enabled	Set
	Off		Inactive edge event disabled	
Alarm display	no		No pop-up display	Set
	yes		Alarm pop-up display is activated at active DI edge	
Counters	0 – 65535		Cumulative active edge counter	(Set)
<b>NAMES for DIGITAL INPUTS (editable with Easergy Pro only)</b>				

Parameter	Value	Unit	Description	Note
Label	String of max. 10 characters		Short name for DIs on the local display Default is "DI1 – DIx". x is the maximum number of the digital input.	Set
Description	String of max. 32 characters		Long name for DIs. Default is "Digital input 1 – Digital input x". x is the maximum number of the digital input.	Set

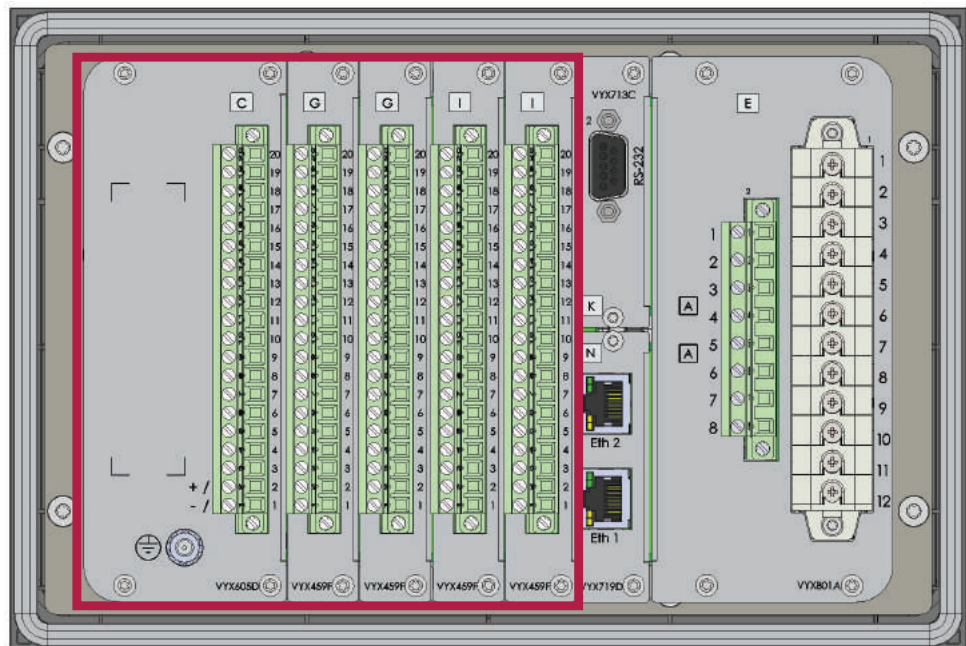
<sup>20</sup> Set = An editable parameter (password needed).

Every option card and slot has default numbering. After making any changes to the numbering, read the settings from the relay after the relay has rebooted.

Below is an example of model P3x30-CGGII-AAEAA-BAAAA showing default numbering of DI.

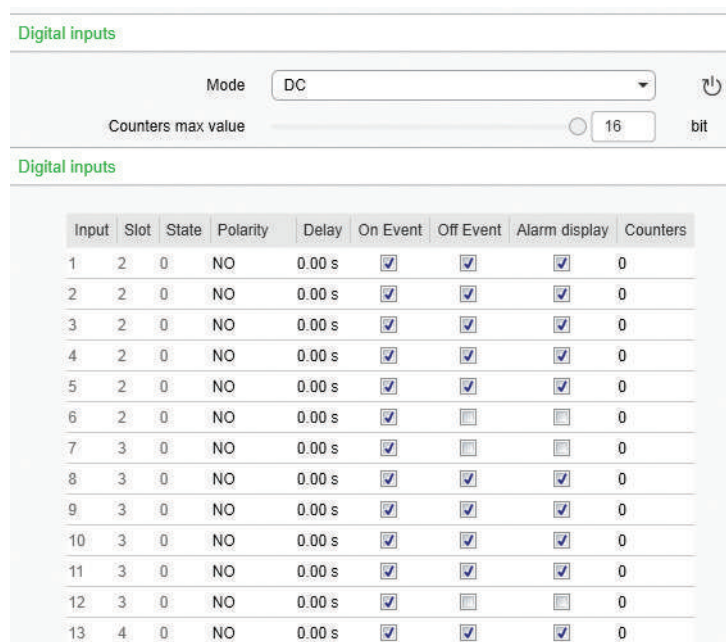
You can see the default digital input numbering and change the numbering of the following option cards in the **Inputs/Outputs > Digital inputs** setting view: slot 2, 3, 4, 5: G, I.

Figure 28 - Default numbering of digital inputs for model P3x30-CGGII-AAEAA-BA



- C: -
- G: DI1–6
- G: DI7–12
- I: DI13–22
- I: DI23–32

Figure 29 - Digital inputs setting view



### 5.3 Virtual inputs and outputs

There are virtual inputs and virtual outputs that can in many places be used like their hardware equivalents except that they are located in the memory of the relay. The virtual inputs act like normal digital inputs. The status of the virtual input can be changed via the local display, communication bus and Easergy Pro. For example setting groups can be changed using virtual inputs.

Virtual inputs can be used in many operations. The status of the input can be checked in the **Output matrix** and **Virtual inputs** setting views. The status is also visible on local mimic display, if so selected. Virtual inputs can be selected to be operated with the function buttons F1 and F2, the local mimic or simply by using the virtual input menu. Virtual inputs have similar functions as digital inputs: they enable changing groups, block/enable/disable functions, to program logics and other similar to digital inputs.

The activation and reset delay of the input is approximately 5 ms.

Table 29 - Virtual input and output

Number of inputs	20
Number of outputs	20
Activation time / Reset time	< 5 ms

Figure 30 - Virtual inputs and outputs can be used for many purpose in the **Output matrix** setting view.

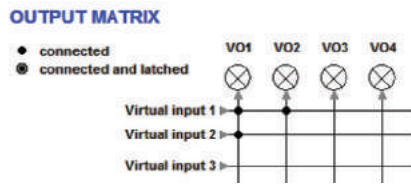
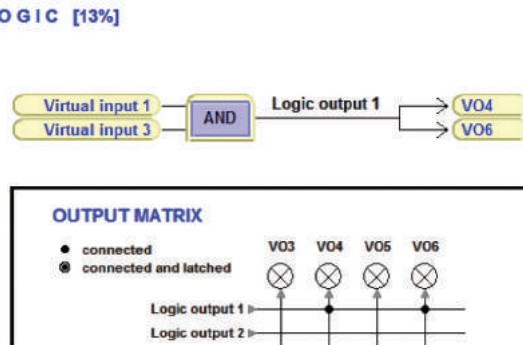


Figure 31 - Virtual inputs and outputs can be assigned directly to inputs/outputs of logical operators.



Notice the difference between latched and non-latched connection.

### Virtual input

The virtual inputs can be viewed, named and controlled in the **Virtual inputs** setting view.

Figure 32 - **Virtual inputs** setting view

**Virtual Inputs**

Virtual input 1: 0

Virtual input 2: 0

Virtual input 3: 0

Virtual input 4: 0

Virtual input 5: 0

Virtual input 6: 0

Virtual input 7: 0

Virtual input 8: 0

Virtual input 9: 0

Virtual input 10: 0

Virtual input 11: 0

Virtual input 12: 0

Virtual input 13: 0

Virtual input 14: 0

Virtual input 15: 0

Virtual input 16: 0

Virtual input 17: 0

Virtual input 18: 0

Virtual input 19: 0

Virtual input 20: 0

Event enabling:

Check L/R selection:

**VIRTUAL INPUTS**

Input	Label	Description
1	V11	Virtual input 1
2	V12	Virtual input 2
3	V13	Virtual input 3
4	V14	Virtual input 4
5	V15	Virtual input 5
6	V16	Virtual input 6
7	V17	Virtual input 7
8	V18	Virtual input 8
9	V19	Virtual input 9
10	V110	Virtual input 10
11	V111	Virtual input 11
12	V112	Virtual input 12
13	V113	Virtual input 13
14	V114	Virtual input 14
15	V115	Virtual input 15
16	V116	Virtual input 16
17	V117	Virtual input 17
18	V118	Virtual input 18
19	V119	Virtual input 19
20	V120	Virtual input 20

Table 30 - Parameters of virtual inputs

Parameter	Value	Unit	Description	Set <sup>21</sup>
VI1-VI20	0 1		Status of virtual input	
Events	On Off		Event enabling	Set
<b>NAMES for VIRTUAL INPUTS (editable with Easergy Pro only)</b>				
Label	String of max. 10 characters		Short name for VIs on the local display Default is "VIn", n = 1–20	Set
Description	String of max. 32 characters		Long name for VIs. Default is "Virtual input n", n = 1–20	Set

<sup>21</sup> Set = An editable parameter (password needed).

### Virtual output

In Easergy Pro, the **Virtual outputs** setting view is located **Inputs/Outputs** view.

Figure 33 - **Virtual outputs** setting view

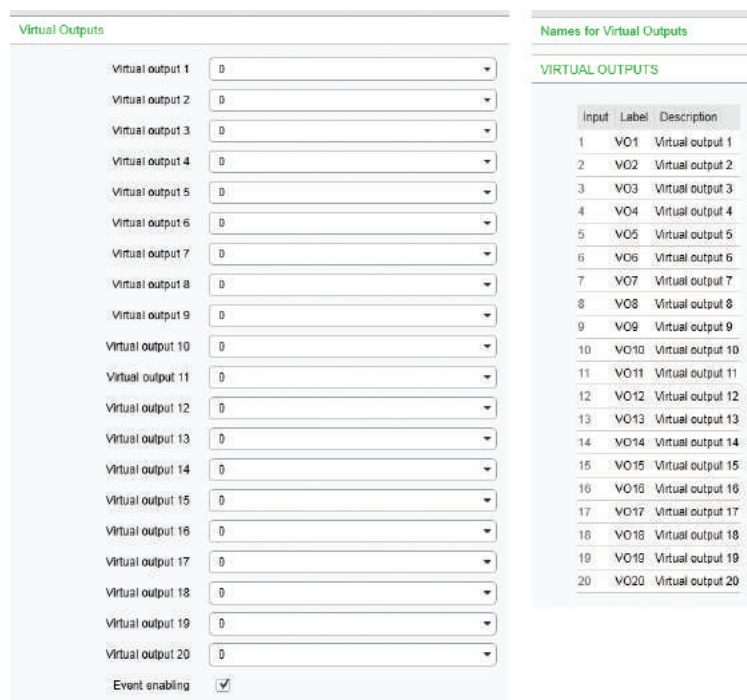


Table 31 - Parameters of virtual outputs

Parameter	Value	Unit	Description	Set <sup>22</sup>
VO1-VO20	0 1		Status of virtual output	F
Events	On Off		Event enabling	Set
NAMES for VIRTUAL OUTPUTS (editable with Easergy Pro only)				
Label	String of max. 10 characters		Short name for VOs on the local display Default is "VO $n$ ", $n=1-20$	Set
Description	String of max. 32 characters		Long name for VOs. Default is "Virtual output $n$ ", $n=1-20$	Set

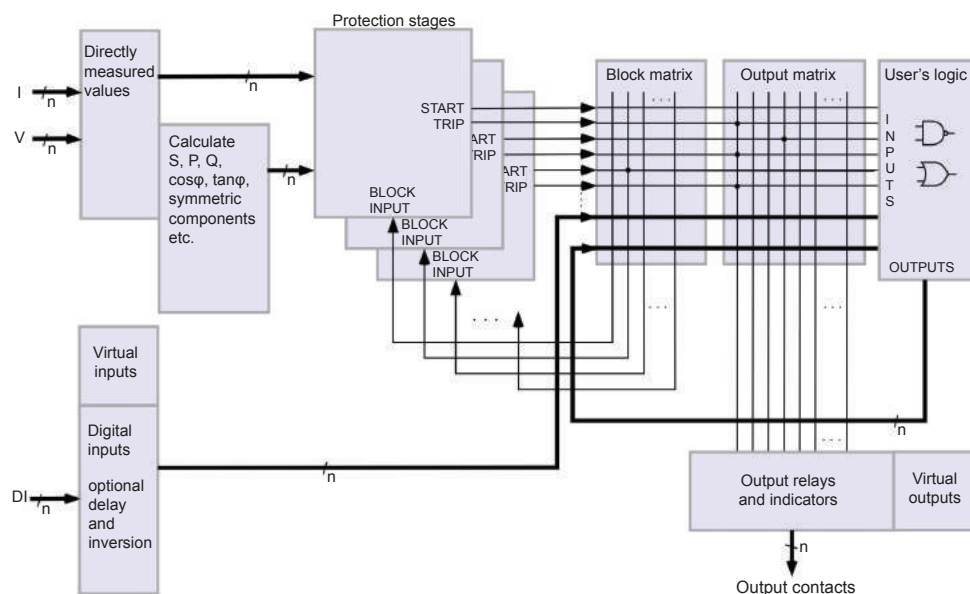
<sup>22</sup> Set = An editable parameter (password needed). F = Editable when force flag is on.

## 5.4 Matrix

The relay has several matrices that are used for configuring the relay:

- **Output matrix** used to link protection stage signals, digital inputs, virtual inputs, function buttons, object control, logic output, relay's internal alarms, GOOSE signals and release latch signals to outputs, disturbance recorder trig input and virtual outputs
- **Block matrix** used to block protection stages
- **LED matrix** used to control LEDs on the front panel
- **Object block matrix** used to inhibit object control
- **Auto-recloser matrix** used to control auto-recloser
- **Arc matrix** used to control current and light signals to arc stages and arc stages to the high-speed outputs

Figure 34 - Blocking matrix and output matrix



**NOTE:** Blocking matrix can not be used to block the arc flash detection stages.

### 5.4.1 Output matrix

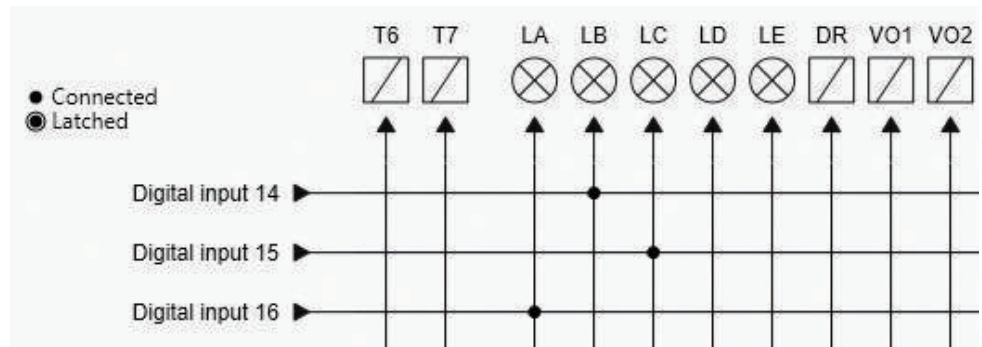
There are general-purpose LED indicators – "A", "B", "C" to "N" – available for customer-specific indications on the front panel. Their usage is define in a separate LED matrix.

There are two LED indicators specified for keys F1 and F2. The triggering of the disturbance recorder (DR) and virtual outputs are configurable in the output matrix.

A digital output or indicator LED can be configured as latched or non-latched. A non-latched relay follows the controlling signal. A latched relay remains activated although the controlling signal releases.

There is a common "release all latches" signal to release all the latched relays. This release signal resets all the latched digital outputs and indicators. The reset signal can be given via a digital input, via front panel or remotely through communication. For instructions on how to release latches, see [5.5 Releasing latches on page 80](#).

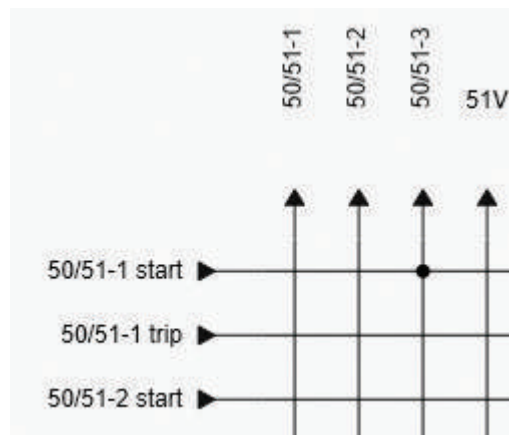
Figure 35 - Trip and alarm relays together with virtual outputs can be assigned in output matrix. Also automatic triggering of disturbance recorder is done in output matrix.



### 5.4.2 Blocking matrix

By means of a blocking matrix, the operation of any protection stage (except the arc flash detection stages) can be blocked. The blocking signal can originate from the digital inputs or it can be a start or trip signal from a protection stage or an output signal from the user's programmable logic. In [Figure 36 - All protection stages \(except Arc stages\) can be blocked in the block matrix](#) on page 76, an active blocking is indicated with a black dot (●) in the crossing point of a blocking signal and the signal to be blocked.

Figure 36 - All protection stages (except Arc stages) can be blocked in the block matrix



The Blocked status becomes visible only when the stage is about to activate.



Figure 37 - A view from the setting tool showing a DI input blocking connection

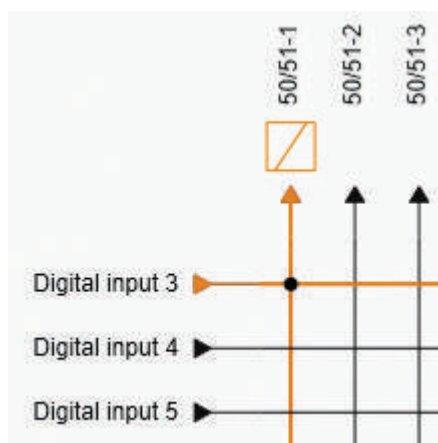


Figure 38 - Result for the I&gt; stage when the DI is active and the stage exceeds its current start value

Phase overcurrent 50/51-1

Enable for 50/51-1

Max. of IA IB IC 772.2 Arms

Status Blocked

Estimated time to trip 0.0 s

Start counter

Trip counter

## NOTICE

### RISK OF NUISANCE TRIPPING

- The blocking matrix is dynamically controlled by selecting and deselecting protection stages.
- Activate the protection stages first, then store the settings in a relay. After that, refresh the blocking matrix before configuring it.

**Failure to follow these instructions can result in unwanted shutdown of the electrical installation.**

### 5.4.3 LED matrix

The LED matrix is used to link digital inputs, virtual inputs, function buttons, protection stage outputs, object statuses, logic outputs, alarm signals and GOOSE signals to various LEDs located on the front panel.

In the **LED configuration** setting view, each LED has three checkboxes with which the behavior of the LED is configured.

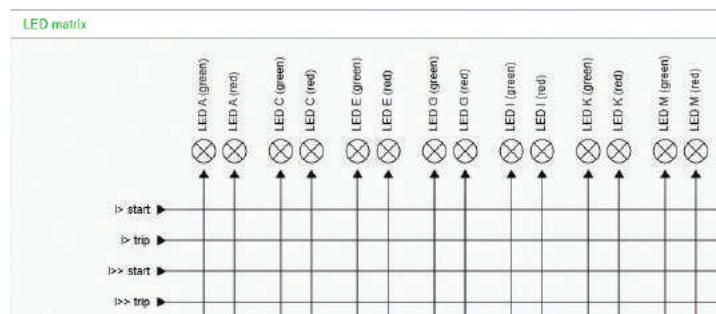
Figure 39 - LED configuration

LED configuration

LED	Description	Latch	Blink	Store
LED A (green)	LED A (green)	<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input checked="" type="checkbox"/>
LED A (red)	LED A (red)	<input type="checkbox"/>	<input checked="" type="checkbox"/>	<input type="checkbox"/>
LED B (green)	LED B (green)	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input type="checkbox"/>
LED B (red)	LED B (red)	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
LED C (green)	LED C (green)	<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
LED C (red)	LED C (red)	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
LED D (green)	LED D (green)	<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>

LEDs are assigned to control signals in the **LED matrix** setting view. It is not possible to control LEDs directly with logics.

Figure 40 - LED matrix



**Normal setting**

With no checkboxes selected, the assigned LED is active when the control signal is active. After deactivation, the LED turns off. LED activation and deactivation delay when controlled is approximately 10 ms.

**Latch setting**

A latched LED activates when the control signal activates but remains active when the control signal deactivates. Latched LEDs are released using the procedure described in [5.5 Releasing latches on page 80](#).

**Blink setting**

When the **Blink** setting is selected, the LED blinks when it is active.

**Store setting**

In the **LED configuration** setting view, you can configure the latched states of LEDs to be stored after a restart. In [Figure 39 - LED configuration on page 78](#), storing has been configured for LED A (green).

**NOTE:** To use the **Store** setting, **Latch** must also be selected.

### Inputs for LEDs

Inputs for LEDs can be assigned in the LED matrix. All 14 LEDs can be assigned as green or red. The connection can be normal, latched or blink-latched. In addition to protection stages, there are lots of functions that can be assigned to output LEDs. See [Table 32 - Inputs for LEDs A-N](#) on page 79.

Table 32 - Inputs for LEDs A-N

Input	LED mapping	Latch	Description	Note
Detection, Arc and programmable stages	LED A–N green or red	Normal/ Latched/ BlinkLatch	Different type of detection stages can be assigned to LEDs	Set
Digital/Virtual inputs and function buttons	LED A–N green or red	Normal/ Latched/ BlinkLatch	All different type of inputs can be assigned to LEDs	Set
Object open/close, object final trip and object failure information	LED A–N green or red	Normal/ Latched/ BlinkLatch	Information related to objects and object control	Set
Local control enabled	LED A–N green or red	Normal/ Latched/ BlinkLatch	While remote/local state is selected as local the “local control enabled” is active	Set
Logic output 1–20	LED A–N green or red	Normal/ Latched/ BlinkLatch	All logic outputs can be assigned to LEDs at the LED matrix	Set
Manual control indication	LED A–N green or red	Normal/ Latched/ BlinkLatch	When the user has controlled the objectives	Set
COM 1–5 comm.	LED A–N green or red	Normal/ Latched/ BlinkLatch	When the communication port 1 - 5 is active	Set
Setting error, seldiag alarm, pwd open and setting change	LED A–N green or red	Normal/ Latched/ BlinkLatch	Self diagnostic signal	Set
GOOSE NI1–64	LED A–N green or red	Normal/ Latched/ BlinkLatch	IEC 61850 goose communication signal	Set
GOOSEERR1–16	LED A–N green or red	Normal/ Latched/ BlinkLatch	IEC 61850 goose communication signal	Set

### 5.4.4 Object block matrix

The object block matrix is used to link digital inputs, virtual inputs, function buttons, protection stage outputs, logic outputs, alarm signals and GOOSE signals to inhibit the control of objects, that is, circuit breakers, isolators and grounding switches.

Typical signals to inhibit controlling of the objects like circuit breaker are:

- protection stage activation
- statuses of other objects

- interlocking made with logic
- GOOSE signals

These and other signals are linked to objects in the object block matrix.

There are also event-type signals that do not block objects as they are on only for a short time, for example "Object1" open and "Object1 close" signals.

## 5.5 Releasing latches

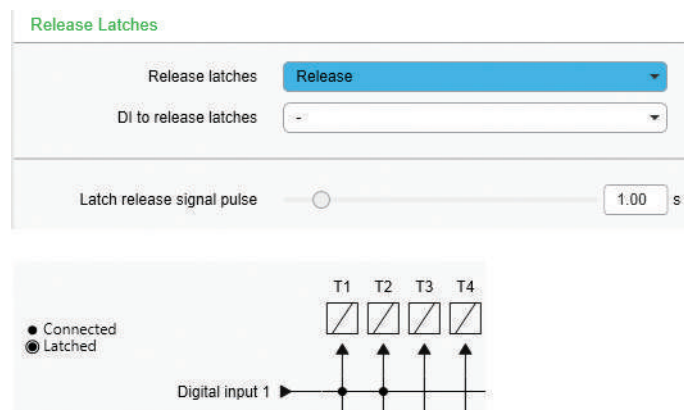
You can release latches using:

- Easergy Pro
- buttons and local panel display
- F1 or F2 buttons

### 5.5.1 Releasing latches using Easergy Pro




1. Go to **General>Release latches**.
2. Select **Release** from the release latches drop-down menu.

Figure 41 - Latched output matrix signals released by using Easergy Pro setting tool



### 5.5.2 Releasing latches using buttons and local panel display

Prerequisite: You have entered the correct password

1. Press .
  2. Press .
  3. Select **Release**, and press .
- All latches are released.

### 5.5.3 Releasing latches using F1 or F2 buttons

You can use the function buttons F1 or F2 to release all latches after configuring this function in Easergy Pro. You can make the configuration either under **GENERAL > RELEASE LATCHES** or under **INPUTS/OUTPUTS > FUNCTION BUTTONS**

- To configure F1 to release latches under **GENERAL > RELEASE LATCHES**:
  - a. In Easergy Pro, go to **GENERAL > RELEASE LATCHES**.
  - b. Under **RELEASE LATCHES** select F1 from the **DI to release latches** drop-down menu.
  - c. Set 1 s delay for **Latch release signal pulse**.

Figure 42 - Release latches

The screenshot shows the 'RELEASE LATCHES' configuration interface. It includes a dropdown menu for 'Release latches' currently set to '-'. Below it is another dropdown for 'DI to release latches' set to 'F1'. At the bottom, there is a slider control for 'Latch release signal pulse' with a numerical input field showing '1.00' and a unit 's'.

After this, pressing the F1 button on the relay's front panel releases all latches.

- To configure F1 to release latches under **Inputs/Outputs>Function buttons**:
  - a. Under **Function buttons**, for F1, select PrgFncls from the **Selected control** drop down menu.
  - b. Set 1 s delay for **F1 pulse length**.
  - c. Under **Programmable functions for F1**, select "On" from the **Release all latches** drop-down menu.

Figure 43 - Function buttons

The screenshot shows the 'FUNCTION BUTTONS' configuration interface. It features a table with columns: Button, State, Selected control, and Selected Object. Below the table are two slider controls for 'F1 pulse length (0=infinite)' and 'F2 pulse length (0=infinite)', with values 1.00 s and 0.00 s respectively. A section titled 'Programmable functions for F1' contains three dropdown menus: 'Release all latches' (set to 'On'), 'Clear I/O units' registers' (set to 'Off'), and 'Install arc sensors & I/O units' (set to 'Off').

Button	State	Selected control	Selected Object
F1	0	PrgFncls	-
F2	0	F2	-

After this, pressing the F1 button on the relay's front panel releases all latches.

**NOTE:** The latch release signal can be activated only if the latched output is active.

## 5.6 Controllable objects

The relay allows controlling eight objects, that is, circuit breakers, disconnectors and grounding switches by the "select before operate" or "direct control" principle.

Controlling is possible in the following ways:

- through the object control buttons
- through front panel and display using single-line diagram
- through the function keys
- through digital input
- through remote communication
- through Easergy Pro setting tool
- through Web server
- through Smart APP

The connection of an object to specific controlling outputs is done via an output matrix (object 1–8 open output, object 1–8 close output). There is also an output signal "Object failed" that is activated if the control of an object is not completed.

### Object states

Each object has the following states:

Setting	Value	Description
Object state	Undefined (00)	Actual state of the object
	Open	
	Close	
	Undefined (11)	

### Basic settings for objects

Each object has the following settings:

Setting	Value	Description
DI for 'obj open'	None, any digital input, virtual input or virtual output	Open information
DI for 'obj close'		Close information
DI for 'obj ready'		Ready information
Max ctrl pulse length	0.02–600 s	Pulse length for open and close commands. Control pulse stops once object changes its state
Completion timeout	0.02–600 s	Timeout of ready indication
Object control	Open/Close	Direct object control

If changing the states takes longer than the time defined by the "Max ctrl pulse length" setting, the object is inoperative and the "Object failure" matrix signal is

set. Also, an undefined event is generated. “Completion timeout” is only used for the ready indication. If “DI for ‘obj ready’” is not set, the completion timeout has no meaning.

### Output signals of objects

Each object has two control signals in matrix:

Output signal	Description
Object x Open	Open control signal for the object
Object x Close	Close control signal for the object

These signals send control pulse when an object is controlled by digital input, remote bus, auto-reclose etc.

## 5.6.1 Object control with digital inputs

Objects can be controlled with digital inputs, virtual inputs or virtual outputs. There are four settings for each object:

Setting	Active
DI for remote open / close control	In remote state
DI for local open / close control	In local state

If the relay is in local control state, the remote control inputs are ignored and vice versa. An object is controlled when a rising edge is detected from the selected input. The length of digital input pulse should be at least 60 ms.

## 5.6.2 Local or remote selection

In local mode, digital outputs can be controlled via the front panel but they cannot be controlled via a remote serial communication interface.

In remote mode, digital outputs cannot be controlled via a front panel but they can be controlled via a remote serial communication interface.

The local or remote mode can be selected by using the front panel or via one selectable digital input. The digital input is normally used to change a whole station to local or remote mode. You can select the L/R digital input in the **Objects** setting view in Easergy Pro.

Table 33 - Local or remote selection

Action	Control through Easergy Pro or SmartApp		Control through communication protocol	
	Local	Remote	Local	Remote
Local/Remote switch status	Local	Remote	Local	Remote
CB control	Yes	No	No	Yes
Setting or configuration changes	Yes	Yes	Yes	Yes



Action	Control through Easergy Pro or SmartApp		Control through communication protocol	
	Yes	No	Yes	No
Communication configuration	Yes	Yes	Yes	Yes
Virtual inputs <sup>23</sup>	Yes	No	No	Yes

<sup>23</sup> Virtual inputs have a general parameter “Check L/R selection” for disabling the L/R check.

### 5.6.3 Object control with Close and Trip buttons

The relay also has dedicated control buttons for objects. **Close** stands for object closing and **Trip** controls object open command internally. Control buttons are configured in the **Objects** setting view.

Table 34 - Parameters of function keys



Parameter	Value	Unit	Description	Set
Object for control buttons	Obj1–Obj8		Button  closes selected object if password is enabled  Button  opens selected object if password is enabled	Set
Mode for control buttons	Selective Direct		Control operation needs confirmation (select-execute)  Control operation is done without confirmation	

### 5.6.4 Object control with F1 and F2

Objects can be controlled with the function buttons F1 and F2.

By default, the F1 and F2 buttons are configured to control F1 and F2 variables that can further be assigned to control objects.

Table 35 - Parameters of F1 and F2

Parameter	Value	State	Pulse length <sup>24</sup>	Description
F1	F1, V <sub>1</sub> -V <sub>20</sub> , ObjCtrl	0.1	0600 s	 controls F1, V <sub>1</sub> -V <sub>20</sub> or ObjCtrl parameters.
F2	F2, V <sub>1</sub> -V <sub>20</sub> , ObjCtrl	0.1	0-600 s	 controls F2, V <sub>1</sub> -V <sub>20</sub> and ObjCtrl parameters.

<sup>24</sup> Pulse length applies to values F1 and F2 only

You can configure the button functions in the **Inputs/outputs > Function buttons** setting view in Easergy Pro.



Figure 44 - Function buttons setting view

Function buttons			
Button	State	Selected control	Selected Object
F1	0	ObjCtrl	2 LocOpen
F2	0	F2	-

If **ObjCtrl** has been selected under **Selected control**, the selected object is shown under **Selected object**. Otherwise, this column is empty.

When selecting **ObjCtrl**, link the function button to the appropriate object in the **General > Objects** setting view.

Figure 45 - Ctrl object 2 setting view

**CTRL OBJECT 2**

Label(Obj2):

Obj2 state:

Obj2 final trip by:

DI for 'obj open':

DI for 'obj closed':

DI for 'obj ready':

Max ctrl pulse length:  s

Completion timeout:  s

Object 2 control:

DI for remote open ctr:

DI for remote close ctr:

DI for local open ctr:

DI for local close ctr:

Inactivity days limit:

Last state change:

## 5.7 Logic functions

The relay supports customer-defined programmable logic for boolean signals. User-configurable logic can be used to create something that is not provided by the relay as a default. You can see and modify the logic in the **General > Logic** setting view in the Easergy Pro setting tool.

Table 36 - Available logic functions and their memory use

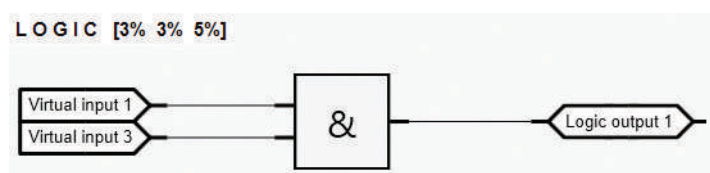
Logic functions	No. of gates reserved	Max. no. of input gates	Max. no. of logic outputs
AND	1	32	20
OR	1	(An input gate can include any number of inputs.)	

Logic functions	No. of gates reserved	Max. no. of input gates	Max. no. of logic outputs
XOR	1		
AND+OR	2		
CT (count+reset)	2		
INVAND	2		
INVOR	2		
OR+AND	2		
RS (set+reset)	2		
RS_D (set+D +load+reset)	4		

The consumed memory is dynamically shown on the configuration view in percentage. The first value indicates the memory consumption of inputs, the second value the memory consumption of gates and the third value the memory consumption of outputs.



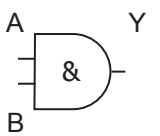
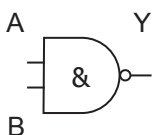
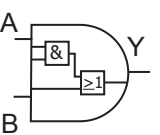
The logic is operational as long the memory consumption of the inputs, gates or outputs remains individually below or equal to 100%.

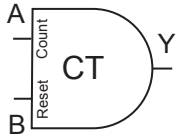
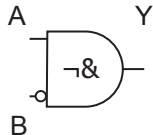
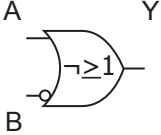
Figure 46 - Logic and memory consumption

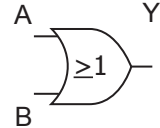
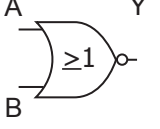
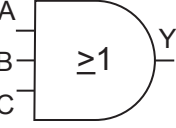
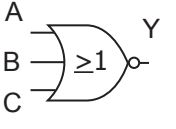


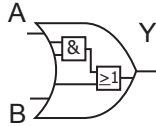
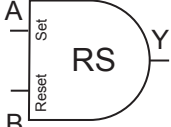
## Truth tables

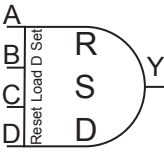
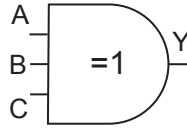
Table 37 - Truth table

Gate	Symbol	Truth table																		
AND		<table border="1"> <thead> <tr> <th>In</th> <th>Out</th> </tr> </thead> <tbody> <tr> <td>A</td> <td>Y</td> </tr> <tr> <td>0</td> <td>0</td> </tr> <tr> <td>1</td> <td>1</td> </tr> </tbody> </table>	In	Out	A	Y	0	0	1	1										
	In	Out																		
	A	Y																		
	0	0																		
1	1																			
	<table border="1"> <thead> <tr> <th>In</th> <th>Out</th> </tr> </thead> <tbody> <tr> <td>A</td> <td>Y</td> </tr> <tr> <td>0</td> <td>1</td> </tr> <tr> <td>1</td> <td>0</td> </tr> </tbody> </table>	In	Out	A	Y	0	1	1	0											
In	Out																			
A	Y																			
0	1																			
1	0																			
	<table border="1"> <thead> <tr> <th colspan="2">In</th> <th>Out</th> </tr> <tr> <th>A</th> <th>B</th> <th>Y</th> </tr> </thead> <tbody> <tr> <td>0</td> <td>1</td> <td>0</td> </tr> <tr> <td>1</td> <td>0</td> <td>0</td> </tr> <tr> <td>1</td> <td>1</td> <td>1</td> </tr> <tr> <td>0</td> <td>0</td> <td>0</td> </tr> </tbody> </table>	In		Out	A	B	Y	0	1	0	1	0	0	1	1	1	0	0	0	
In		Out																		
A	B	Y																		
0	1	0																		
1	0	0																		
1	1	1																		
0	0	0																		
	<table border="1"> <thead> <tr> <th colspan="2">In</th> <th>Out</th> </tr> <tr> <th>A</th> <th>B</th> <th>Y</th> </tr> </thead> <tbody> <tr> <td>0</td> <td>1</td> <td>1</td> </tr> <tr> <td>1</td> <td>0</td> <td>1</td> </tr> <tr> <td>1</td> <td>1</td> <td>0</td> </tr> <tr> <td>0</td> <td>0</td> <td>1</td> </tr> </tbody> </table>	In		Out	A	B	Y	0	1	1	1	0	1	1	1	0	0	0	1	
In		Out																		
A	B	Y																		
0	1	1																		
1	0	1																		
1	1	0																		
0	0	1																		
AND+OR		<table border="1"> <thead> <tr> <th colspan="2">In</th> <th>Out</th> </tr> <tr> <th>A</th> <th>B</th> <th>Y</th> </tr> </thead> <tbody> <tr> <td>0</td> <td>0</td> <td>0</td> </tr> <tr> <td>1</td> <td>1</td> <td>1</td> </tr> <tr> <td>1</td> <td>0</td> <td>1</td> </tr> <tr> <td>0</td> <td>1</td> <td>1</td> </tr> </tbody> </table>	In		Out	A	B	Y	0	0	0	1	1	1	1	0	1	0	1	1
In		Out																		
A	B	Y																		
0	0	0																		
1	1	1																		
1	0	1																		
0	1	1																		

Gate	Symbol	Truth table																												
CT (count+reset)		<table border="1"> <thead> <tr> <th colspan="2">In</th> <th colspan="2">Out</th> </tr> <tr> <th>A</th> <th>B</th> <th>Y</th> <th>Y</th> </tr> </thead> <tbody> <tr> <td>Count</td> <td>Reset</td> <td>Setting</td> <td>New</td> </tr> <tr> <td>1</td> <td></td> <td>3</td> <td>0</td> </tr> <tr> <td>1</td> <td></td> <td>3</td> <td>0</td> </tr> <tr> <td>1</td> <td></td> <td>3</td> <td>1</td> </tr> <tr> <td></td> <td>1</td> <td>3</td> <td>0</td> </tr> </tbody> </table>	In		Out		A	B	Y	Y	Count	Reset	Setting	New	1		3	0	1		3	0	1		3	1		1	3	0
In		Out																												
A	B	Y	Y																											
Count	Reset	Setting	New																											
1		3	0																											
1		3	0																											
1		3	1																											
	1	3	0																											
INVAND		<table border="1"> <thead> <tr> <th colspan="2">In</th> <th>Out</th> </tr> <tr> <th>A</th> <th>B</th> <th>Y</th> </tr> </thead> <tbody> <tr> <td>0</td> <td>0</td> <td>0</td> </tr> <tr> <td>1</td> <td>0</td> <td>1</td> </tr> <tr> <td>1</td> <td>1</td> <td>0</td> </tr> <tr> <td>0</td> <td>1</td> <td>0</td> </tr> </tbody> </table>	In		Out	A	B	Y	0	0	0	1	0	1	1	1	0	0	1	0										
In		Out																												
A	B	Y																												
0	0	0																												
1	0	1																												
1	1	0																												
0	1	0																												
INVOR		<table border="1"> <thead> <tr> <th colspan="2">In</th> <th>Out</th> </tr> <tr> <th>A</th> <th>B</th> <th>Y</th> </tr> </thead> <tbody> <tr> <td>0</td> <td>0</td> <td>1</td> </tr> <tr> <td>1</td> <td>1</td> <td>1</td> </tr> <tr> <td>1</td> <td>0</td> <td>1</td> </tr> <tr> <td>0</td> <td>1</td> <td>0</td> </tr> </tbody> </table>	In		Out	A	B	Y	0	0	1	1	1	1	1	0	1	0	1	0										
In		Out																												
A	B	Y																												
0	0	1																												
1	1	1																												
1	0	1																												
0	1	0																												

Gate	Symbol	Truth table																												
OR		<table border="1"> <thead> <tr> <th colspan="3">In</th> <th>Out</th> </tr> <tr> <th>A</th> <th>B</th> <th>Y</th> </tr> </thead> <tbody> <tr> <td>0</td> <td>0</td> <td>0</td> </tr> <tr> <td>1</td> <td>1</td> <td>1</td> </tr> <tr> <td>1</td> <td>0</td> <td>1</td> </tr> <tr> <td>0</td> <td>1</td> <td>1</td> </tr> </tbody> </table>	In			Out	A	B	Y	0	0	0	1	1	1	1	0	1	0	1	1									
	In			Out																										
	A	B	Y																											
	0	0	0																											
1	1	1																												
1	0	1																												
0	1	1																												
	<table border="1"> <thead> <tr> <th colspan="3">In</th> <th>Out</th> </tr> <tr> <th>A</th> <th>B</th> <th>Y</th> </tr> </thead> <tbody> <tr> <td>0</td> <td>0</td> <td>1</td> </tr> <tr> <td>1</td> <td>1</td> <td>0</td> </tr> <tr> <td>1</td> <td>0</td> <td>0</td> </tr> <tr> <td>0</td> <td>1</td> <td>0</td> </tr> </tbody> </table>	In			Out	A	B	Y	0	0	1	1	1	0	1	0	0	0	1	0										
In			Out																											
A	B	Y																												
0	0	1																												
1	1	0																												
1	0	0																												
0	1	0																												
	<table border="1"> <thead> <tr> <th colspan="4">In</th> <th>Out</th> </tr> <tr> <th>A</th> <th>B</th> <th>C</th> <th>Y</th> </tr> </thead> <tbody> <tr> <td>0</td> <td>0</td> <td>0</td> <td>1</td> </tr> <tr> <td>1</td> <td>1</td> <td>0</td> <td>1</td> </tr> <tr> <td>1</td> <td>0</td> <td>0</td> <td>1</td> </tr> <tr> <td>0</td> <td>1</td> <td>0</td> <td>1</td> </tr> <tr> <td>1</td> <td>1</td> <td>1</td> <td>1</td> </tr> </tbody> </table>	In				Out	A	B	C	Y	0	0	0	1	1	1	0	1	1	0	0	1	0	1	0	1	1	1	1	1
In				Out																										
A	B	C	Y																											
0	0	0	1																											
1	1	0	1																											
1	0	0	1																											
0	1	0	1																											
1	1	1	1																											
	<table border="1"> <thead> <tr> <th colspan="4">In</th> <th>Out</th> </tr> <tr> <th>A</th> <th>B</th> <th>C</th> <th>Y</th> </tr> </thead> <tbody> <tr> <td>0</td> <td>0</td> <td>0</td> <td>1</td> </tr> <tr> <td>1</td> <td>0</td> <td>0</td> <td>0</td> </tr> <tr> <td>1</td> <td>1</td> <td>0</td> <td>0</td> </tr> <tr> <td>0</td> <td>1</td> <td>0</td> <td>0</td> </tr> <tr> <td>1</td> <td>1</td> <td>1</td> <td>0</td> </tr> </tbody> </table>	In				Out	A	B	C	Y	0	0	0	1	1	0	0	0	1	1	0	0	0	1	0	0	1	1	1	0
In				Out																										
A	B	C	Y																											
0	0	0	1																											
1	0	0	0																											
1	1	0	0																											
0	1	0	0																											
1	1	1	0																											

Gate	Symbol	Truth table																					
OR+AND		<table border="1"> <thead> <tr> <th colspan="2">In</th> <th>Out</th> </tr> <tr> <th>A</th> <th>B</th> <th>Y</th> </tr> </thead> <tbody> <tr> <td>0</td> <td>0</td> <td>0</td> </tr> <tr> <td>1</td> <td>1</td> <td>1</td> </tr> <tr> <td>1</td> <td>0</td> <td>0</td> </tr> <tr> <td>0</td> <td>1</td> <td>0</td> </tr> </tbody> </table>	In		Out	A	B	Y	0	0	0	1	1	1	1	0	0	0	1	0			
In		Out																					
A	B	Y																					
0	0	0																					
1	1	1																					
1	0	0																					
0	1	0																					
RS (set+reset)		<table border="1"> <thead> <tr> <th colspan="2">In</th> <th>Out</th> </tr> <tr> <th>A</th> <th>B</th> <th>Y</th> </tr> <tr> <th>Set</th> <th>Reset</th> <th>Y</th> </tr> </thead> <tbody> <tr> <td>1</td> <td>0</td> <td>1</td> </tr> <tr> <td>1</td> <td>1</td> <td>0</td> </tr> <tr> <td>0</td> <td>0</td> <td>0</td> </tr> <tr> <td>0</td> <td>1</td> <td>0</td> </tr> </tbody> </table>	In		Out	A	B	Y	Set	Reset	Y	1	0	1	1	1	0	0	0	0	0	1	0
In		Out																					
A	B	Y																					
Set	Reset	Y																					
1	0	1																					
1	1	0																					
0	0	0																					
0	1	0																					

Gate	Symbol	Truth table																																								
RS_D (set+D+load+reset)		<table border="1" data-bbox="1166 188 1471 667"> <thead> <tr> <th>A</th> <th>B</th> <th>C</th> <th>D</th> <th>Y</th> </tr> <tr> <th>Set</th> <th>D</th> <th>Load</th> <th>Reset</th> <th>State</th> </tr> </thead> <tbody> <tr> <td>0</td> <td>0</td> <td>0</td> <td>0</td> <td>0<sup>25</sup></td> </tr> <tr> <td>1</td> <td>X</td> <td>X</td> <td>0</td> <td>1</td> </tr> <tr> <td>1</td> <td>X</td> <td>X</td> <td>1</td> <td>0</td> </tr> <tr> <td>0</td> <td>1</td> <td>0</td> <td>0</td> <td>0</td> </tr> <tr> <td>0</td> <td>1</td> <td>1</td> <td>0</td> <td>1</td> </tr> <tr> <td>0</td> <td>1</td> <td>1</td> <td>1</td> <td>0<sup>26</sup></td> </tr> </tbody> </table> <p data-bbox="1166 667 1471 748"> <sup>25</sup> Initial state  <sup>26</sup> The state remains 1 until Reset is set active                 </p> <p data-bbox="1166 786 1471 936">                     X = Any state                      If Set or D + Load are high, the state returns to high if Reset returns to low.                 </p>	A	B	C	D	Y	Set	D	Load	Reset	State	0	0	0	0	0 <sup>25</sup>	1	X	X	0	1	1	X	X	1	0	0	1	0	0	0	0	1	1	0	1	0	1	1	1	0 <sup>26</sup>
A	B	C	D	Y																																						
Set	D	Load	Reset	State																																						
0	0	0	0	0 <sup>25</sup>																																						
1	X	X	0	1																																						
1	X	X	1	0																																						
0	1	0	0	0																																						
0	1	1	0	1																																						
0	1	1	1	0 <sup>26</sup>																																						
XOR		<table border="1" data-bbox="1166 981 1471 1525"> <thead> <tr> <th colspan="3">In</th> <th>Out</th> </tr> <tr> <th>A</th> <th>B</th> <th>C</th> <th>Y</th> </tr> </thead> <tbody> <tr> <td>0</td> <td>0</td> <td>0</td> <td>0</td> </tr> <tr> <td>0</td> <td>0</td> <td>1</td> <td>1</td> </tr> <tr> <td>0</td> <td>1</td> <td>0</td> <td>1</td> </tr> <tr> <td>0</td> <td>1</td> <td>1</td> <td>0</td> </tr> <tr> <td>1</td> <td>0</td> <td>0</td> <td>1</td> </tr> <tr> <td>1</td> <td>0</td> <td>1</td> <td>0</td> </tr> <tr> <td>1</td> <td>1</td> <td>0</td> <td>0</td> </tr> <tr> <td>1</td> <td>1</td> <td>1</td> <td>1</td> </tr> </tbody> </table>	In			Out	A	B	C	Y	0	0	0	0	0	0	1	1	0	1	0	1	0	1	1	0	1	0	0	1	1	0	1	0	1	1	0	0	1	1	1	1
In			Out																																							
A	B	C	Y																																							
0	0	0	0																																							
0	0	1	1																																							
0	1	0	1																																							
0	1	1	0																																							
1	0	0	1																																							
1	0	1	0																																							
1	1	0	0																																							
1	1	1	1																																							

<sup>25</sup> Initial state

<sup>26</sup> The state remains 1 until Reset is set active

**Logic element properties**

After you have selected the required logic gate in Easergy Pro, you can change the function of the gate in the **Element properties** window by clicking the gate.

Figure 47 - Logic element properties

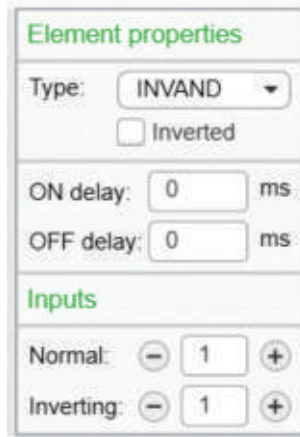


Table 38 - Settings available for the logical gates depending on the selected element

Property	Description
Element properties	
Type	Change the logical function of the gate
Inverted	Inverts the output state of the logical gate
ON delay	Time delay to activate the output after logical conditions are met
OFF delay	Time delay for how long the gate remain active even the logical condition is reset
Count	Setting for counter (CT gate only)
Reverse	Use to reverse AND and OR gates (AND+OR gate only)
Inputs	
Normal - / +	Use to increase or decrease number of inputs
Inverting - / +	Use to increase or decrease number of inverted inputs. This setting is visible for INVAND and INVOR gates only
Count	Use to increase or decrease number of count inputs (CT gate only)
Reset	Use to increase or decrease number of count inputs (CT gate only)
AND	Use to increase or decrease number of inputs for AND gates (AND+OR gate only)
OR	Use to increase or decrease number of inputs for OR gates (AND+OR gate only)
Set	Use to increase or decrease number of Set inputs (RS_D gate only)
D	Use to increase or decrease number of Data inputs (RS_D gate only)



Property	Description
Load	Use to increase or decrease number of Load inputs (RS_D gate only)
Reset	Use to increase or decrease number of Reset inputs (RS_D gate only)

## 5.8 Local panel

Easergy P3G30 and P3G32 have one LCD matrix display.

All the main menus are located on the left side of the display. To get to a submenu, move up and down the main menus.

Figure 48 - Local panel's main menu

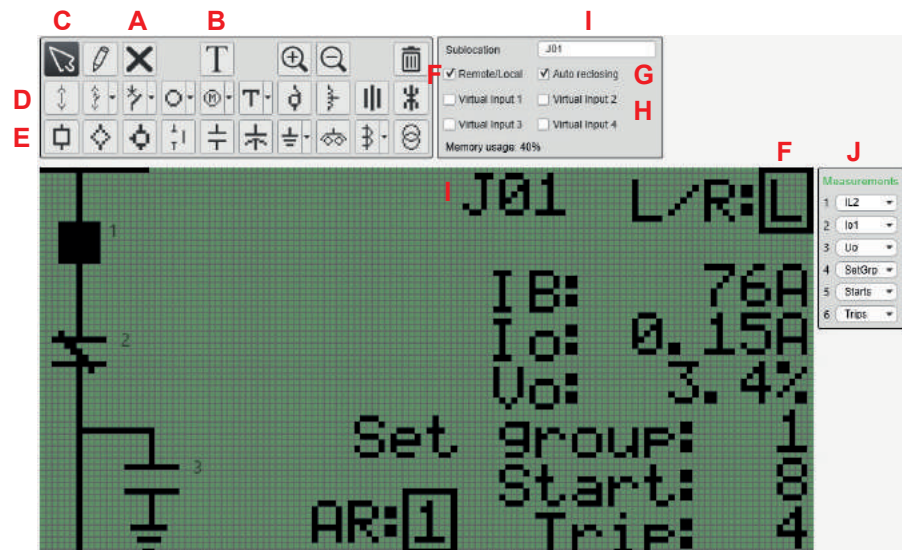
50/51-1 STATUS	
Month	Status -
FL	TripTime 0.0s
Evnt	SCntr 4
DR	TCntr 0
Runh	SetGrp 1
TIMR	SGrp1DI -
DI	SGrp2DI -
DO	SGrp3DI -
Arc	SGrp4DI -
Prot.	Force Off
50/51-1	
50/51-2	
50/51-3	
50N/51N-1	
50N/51N-2	

### 5.8.1 Mimic view

The mimic view is set as the local panel's main view as default. You can modify the mimic according to the application or disable it, if it is not needed, via the Easergy Pro setting tool.

You can modify the mimic in the **General > Mimic** setting view in Easergy Pro and disable the mimic view in the **General > Local panel conf** setting view.

**NOTE:** The mimic itself or the local mimic settings cannot be modified via the local panel.



- A) To clear an object or drawing, first point an empty square (A) with the mouse. Then point the object item with the mouse. The color of the object item turns red. To clear the whole mimic, click on the empty area.
- 
- B) Text tool
- 
- C) To move an existing drawing or object, point it with the mouse. The color turns green. Hold down the left mouse button and move the object.
- 
- D) Different type of configurable objects. The object's number corresponds to the number in **General > Objects**.
- 
- E) Some predefined drawings.
- 
- F) The remote/local selection defines whether certain actions are granted or not. In remote state, it is not possible to locally enable or disable auto-reclosing or to control objects. The remote/local state can be changed in **General > Objects**.
- 
- G) Creates auto-reclosing on/off selection to mimic.
- 
- H) Creates virtual input activation on the local mimic view.
- 
- I) Describes the relay's location. Text comes from the relay info menu.
- 
- J) Up to six configurable measurements.

Table 39 - Mimic functionality

Parameter	Value	Unit	Description	Set
Sublocation	Text field		Up to 9 characters. Fixed location.	Set
Object 1–8	1–8		Double-click on top of the object to change the control number between 1 and 8. Number 1 corresponds to object 1 in <b>General &gt; Objects</b> .	Set
Remote/Local mode	L R		Local / Remote control. R stands for remote. Remote local state can be changed in <b>General &gt; Objects</b> as well. Position can be changed.	Set
Auto reclosing	0 1		Possible to enable/disable auto-reclosure locally in local mode (L) or remotely in remote mode (R). Position can be changed.	Set
Measurement display 1–6	$I_A$ – $I_C$ $I_N$ $V_{AB}$ , $V_{BC}$ , $V_{CA}$ , $V_A$ , $V_B$ , $V_C$ , $V_N$ $f$ , $P$ , $Q$ , $S$ , $P.F.$ $\text{CosPhi}$ $E+$ , $E_q+$ , $E-$ , $E_q-$ $ARStart$ , $ARFail$ , $ARShot1$ – $5$ $IFLT$ Starts, Trips $I_{N\text{ Calc}}$ $I_A$ – $I_{Cda}$ , $IL$ $Pda$ , $Qda$ , $Sda$ $T$ $fSYNC$ , $VSYNC$ $I_{A-2}$ – $I_{C-2}$ $d_{IL1}$ – $d_{IL3}$ $dI_A$ – $I_C$ $VAI1$ – $VAI5$ $ExtAI1$ – $6^{27}$		Up to 6 freely selectable measurements.	Set
Virtual input 1–4	0 1		Change the status of virtual inputs while the password is enabled. Position can be changed.	Set

<sup>27</sup> Requires serial communication interface and External IO protocol activated.

Set = Settable.

**NOTE:** The measurement view's data selection depends on the voltage measurement mode selected in the **General > Scaling** setting view.

### 5.8.2 Local panel configuration

You can modify the local panel configuration in the **General > Local panel conf** setting view in Easergy Pro.

Figure 49 - Local panel configuration setting view

**Local panel conf**

---

**MEASUREMENT DISPLAYS**

DISPLAY 1	DISPLAY 2	DISPLAY 3	DISPLAY 4	DISPLAY 5
IA	VAB	VA	f	P.F.
IB	VBC	VB	P	CosPhi
IC	VCA	VC	Q	-
IN-1	VN	VN	S	-

---

Display contrast 108

Display backlight ctrl -

Backlight off timeout 60.0 min

Panel reset timeout 15.0 min

Default screen Mimic

Enable alarm screen

Display event time not in sync

AR info for mimic display

Auto LED release

Auto LED release enable time 1.5 s

Object for control buttons Obj1

Mode for control buttons Selective

Fault value scaling PU

Date style d.m.y

Local MIMIC

Event buffer size 504

Scroll order Old-New

Clear Events Clear

Table 40 - Local panel configuration parameters

Parameter	Value	Unit	Description	Set <sup>28</sup>
Display 1–5	$I_{LA-C}$ $I_N$ $V_{AB}, V_{BC}, V_{CA}, V_A,$ $V_B, V_C, V_N$ $f, P, Q, S, P.F.$ $\text{CosPhi}$ $E+, Eq+, E-, Eq-$ $ARStart, ARFail,$ $ARShot1-5$ $IFLT$ $Starts, Trips$ $I_{N\text{ Calc}}$ Phase currents $IA-Cda$ $IA-C\text{ max}$ $IA-C\text{ min}$ $IA-CdaMax$ $Pda, Qda, Sda$ $T$ $fSYNC, VSYNC$ $I_{A-2}-I_{C-2}$ $dIA-C$ $VAI1-5$ $ExtAI1-6^{29}$ $SetGrp$		20 (5 x 4) freely configurable measurement values can be selected	Set <sup>30</sup>
Display contrast	50–210		Contrast can be changed in the relay menu as well.	Set
Display backlight control	DI1–44, Arc1–3, ArcF, BI, VI1–4, LED1–14, VO1–6		Activates the backlight of the display.	Set <sup>30</sup>
Panel reset timeout	Value range: 0.0–2000.0 Default value: 15.0	min	Configurable delay for the front panel to return to the default screen when the front panel is not used. When this value is zero (0.0), this timeout never occurs.	Set

Parameter	Value	Unit	Description	Set <sup>28</sup>
Default screen	Value range: Mimic, Meas disp1, Meas disp2, Meas disp3, Meas disp4, Meas disp5 Default value: Mimic		Default screen for the front panel.  If the selected screen would result in a blank screen, the title screen is used as the default screen.	Set
Backlight off timeout	0.0–2000.0	min	Configurable delay for backlight to turn off when the relay is not used. Default value is 60 minutes. When value is zero (0.0) backlight stays on all the time.	Set
Enable alarm screen	Selected Unselected		Pop-up text box for events. pop-up events can be checked individually by pressing enter, but holding the button for 2 seconds checks all the events at once.	Set
AR info for mimic display	Selected Unselected		Auto reclosure status visible on top of the local mimic view.	Set
Sync I info for mimic display	Selected Unselected		Synchro-check status visible on top of the local mimic view. Operates together with auto-reclosure.	Set
Auto LED release	Selected Unselected		Enables automatic LED release functionality.	Set
Auto LED release enable time	0.1–600	s	Default 1.5 s. When new LEDs are latched, the previous active latches are released automatically if the set time has passed.	Set
Fault value scaling	PU, Pri		Fault values per unit or primary scaled.	Set

Parameter	Value	Unit	Description	Set <sup>28</sup>
Local MIMIC	Selected Unselected		Enable or disable the local mimic (enabled as default).  When selected, the mimic is the local panel's default main view. When unselected, the measurement view is the default main view.	Set
Event buffer size	50–2000		Event buffer size. Default setting is 200 events.	Set <sup>31</sup>

<sup>28</sup> Set = Settable

<sup>29</sup> Requires serial communication interface and External IO protocol activated.

<sup>30</sup> Inputs vary according to the relay type.

<sup>31</sup> The existing events are lost if the event buffer size is changed.

## 6 Protection functions

Each protection stage can independently be enabled or disabled according to the requirements of the intended application.

**NOTE:** When protection stages are enabled or disabled, the disturbance recordings are deleted from the relay's memory. Therefore, before activating or deactivating stages, store the recordings in your PC.

### 6.1 Maximum number of protection stages in one application

The relay limits the maximum number of enabled protection stages to about 30. The exact number depends on the central processing unit's load consumption and available memory as well as the type of the stages.

The individual protection stage and total load status can be found in the **Protection > Protection stage status** setting view in the Easergy Pro setting tool.

### 6.2 General features of protection stages

#### Setting groups

Setting groups are controlled by using digital inputs, function keys or virtual inputs, via the front panel or custom logic. When none of the assigned inputs are active, the setting group is defined by the parameter 'SetGrp no control state'. When controlled input activates, the corresponding setting group is activated as well. If the control signal of the setting group is lost, the setting "Keep last" forces the last active group into use. If multiple inputs are active at the same time, the active setting group is defined by 'SetGrp priority'. By using virtual I/O, the active setting group can be controlled using the local panel display, any communication protocol or the built-in programmable logic functions. All protection stages have four setting groups.

The screenshot shows the configuration interface for protection setting groups. At the top, four digital inputs (DI1-DI4) are assigned to control Set groups 1 through 4. Below, a table displays parameters for Group 1 (selected), Group 2, Group 3, and Group 4. The parameters include Pick-up setting [A], Pick-up setting [Inmot], Delay curve family, Delay type, Operation delay [s], and Inv. time coefficient k.

	Group 1	Group 2	Group 3	Group 4
Pick-up setting [A]	200	2000	480	480
Pick-up setting [Inmot]	0.50	5.00	1.20	1.20
Delay curve family	DT	DT	IEC	IEC
Delay type	DT	DT	NI	NI
Operation delay [s]	300.00	0.30	0.30	0.30
Inv. time coefficient k	1.00	1.00	1.00	1.00



### Example

Any digital input can be used to control setting groups but in this example, DI1, DI2, DI3 and DI4 are chosen to control setting groups 1 to 4. This setting is done with the parameter “Set group x DI control” where x refers to the desired setting group.

Figure 50 - DI1, DI2, DI3, DI4 configured to control Groups 1 to 4 respectively

The screenshot shows a configuration interface for protection settings. At the top, four digital inputs (DI1, DI2, DI3, DI4) are mapped to control setting groups 1 through 4. Below this, a table displays the parameters for each group, with Group 2 selected. The parameters for Group 2 are highlighted in green.

	Group 1	Group 2	Group 3	Group 4
Pick-up setting [A]	50	500	120	120
Pick-up setting [xIn]	0.50	5.00	1.20	1.20
Delay curve family	DT	DT	IEC	IEC
Delay type	DT	DT	NI	NI
Operation delay [s]	300.00	0.30	0.30	0.30
Inv. time coefficient k	1.00	1.00	1.00	1.00

Use the 'SetGrp common change' parameter to force all protection stages to group 1, 2, 3 or 4. The control becomes active if there is no local control in the protection stage. You can activate this parameter using Easergy Pro.

“SetGrp priority” is used to give a condition to a situation where two or more digital inputs, controlling setting groups, are active at the same time. SetGrp priority could have values “1 to 4” or “4 to 1”.

Figure 51 - SetGrp priority setting in the Valid Protection stages view

The screenshot shows the 'Valid Protection Stages' view. It displays the number of enabled stages (22) and four configuration parameters for SetGrp:

- SetGrp common change: 1
- SetGrp no control state: 1
- SetGrp priority: 1 to 4

Assuming that DI2 and DI3 are active at the same time and SetGrp priority is set to “1 to 4”, setting group 2 becomes active. If SetGrp priority is reversed, that is, set to “4 to 1”, the setting group 3 becomes active.

### Protection stage statuses

The status of a protection stage can be one of the followings:

- **Ok** = ‘-’

The stage is idle and is measuring the analog quantity for the protection. No power system fault detected.

- **Blocked**

The stage is detecting a fault but blocked for some reason.

- **Start**

The stage is counting the operation delay.

- **Trip**

The stage has tripped and the fault is still on.

The blocking reason may be an active signal via the block matrix from other stages, the programmable logic or any digital input. Some stages also have built-in blocking logic. For more details about the block matrix, see [5.4.2 Blocking matrix](#) on page 76.

**Protection stage counters**

Each protection stage has start and trip counters that are incremented when the stage starts or trips. The start and trip counters are reset on relay reboot.

**Forcing start or trip condition for testing purposes**

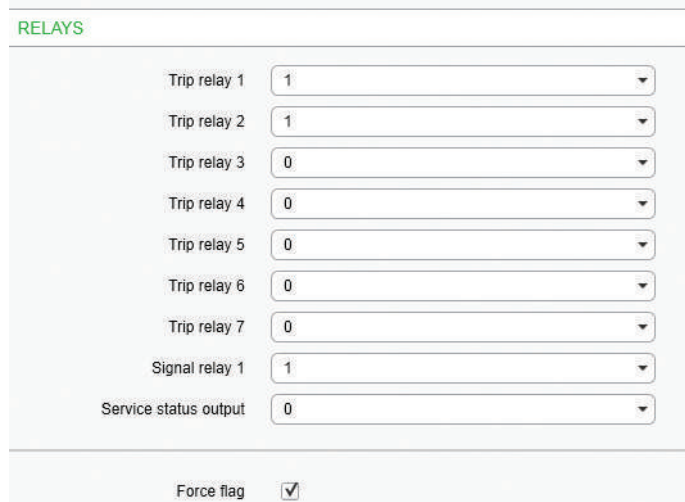
There is a "Forcing flag" parameter which, when activated, allows forcing the status of any protection stage to be "start" or "trip" for half a second. By using this forcing feature, current or voltage injection is not necessary to check the output matrix configuration, to check the wiring from the digital outputs to the circuit breaker and also to check that communication protocols are correctly transferring event information to a SCADA system.

After testing, the forcing flag is automatically reset five minutes after the last local panel push button activity.

The force flag also enables forcing the digital outputs and the optional mA outputs.

The force flag can be found in the **Relays** setting view.

Figure 52 - Force flag



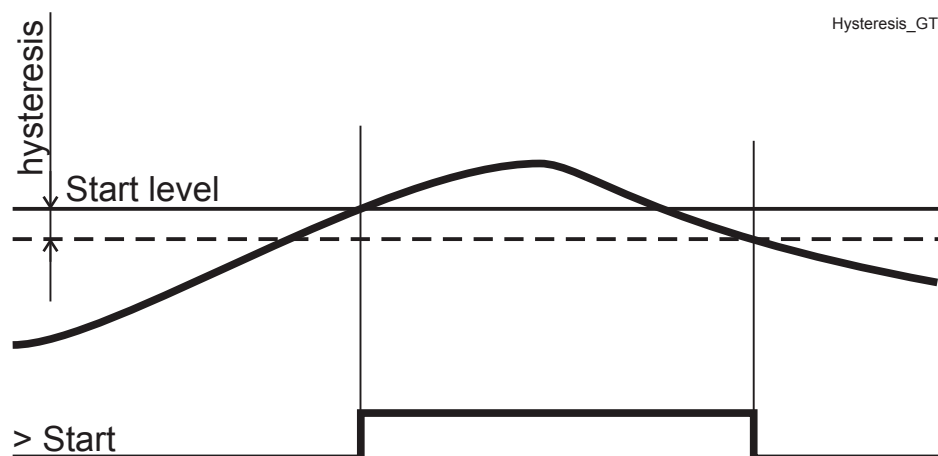
**Start and trip signals**

Every protection stage has two internal binary output signals: start and trip. The start signal is issued when a fault has been detected. The trip signal is issued

after the configured operation delay unless the fault disappears before the end of the delay time.

The hysteresis, as indicated in the protection stage's characteristics data, means that the signal is regarded as a fault until the signal drops below the start setting determined by the hysteresis value.

Figure 53 - Behavior of a greater than comparator (for example, the hysteresis (dead band) in overvoltage stages)



### Output matrix

Using the output matrix, you can connect the internal start and trip signals to the digital outputs and indicators. For more details, see [5.4.1 Output matrix](#) on page 75.

### Blocking

Any protection function, except for arc flash detection, can be blocked with internal and external signals using the block matrix ([5.4.2 Blocking matrix](#) on page 76). Internal signals are for example logic outputs and start and trip signals from other stages and external signals are for example digital and virtual inputs.

Some protection stages have also built-in blocking functions. For example under-frequency protection has built-in under-voltage blocking to avoid tripping when the voltage is off.

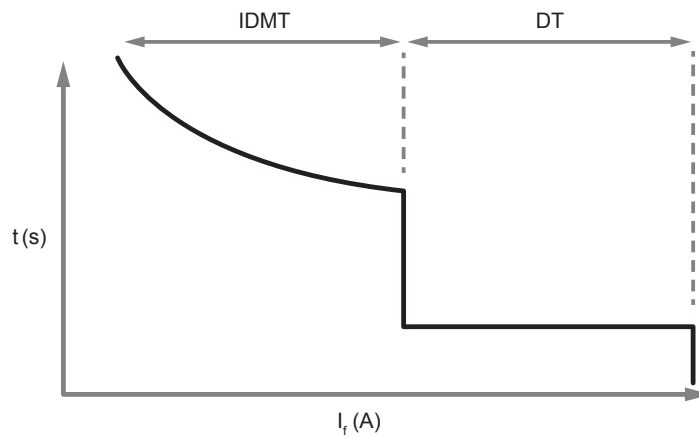
When a protection stage is blocked, it does not start if a fault condition is detected. If blocking is activated during the operation delay, the delay counting is frozen until the blocking goes off or the start reason, that is the fault condition, disappears. If the stage is already tripping, the blocking has no effect.

### Dependent time operation

The operate time in the dependent time mode is dependent on the magnitude of the injected signal. The bigger the signal, the faster the stage issues a trip signal and vice versa. The tripping time calculation resets if the injected quantity drops below the start level.

### Definite time operation

Figure 54 - Dependent time and definite time operation curves



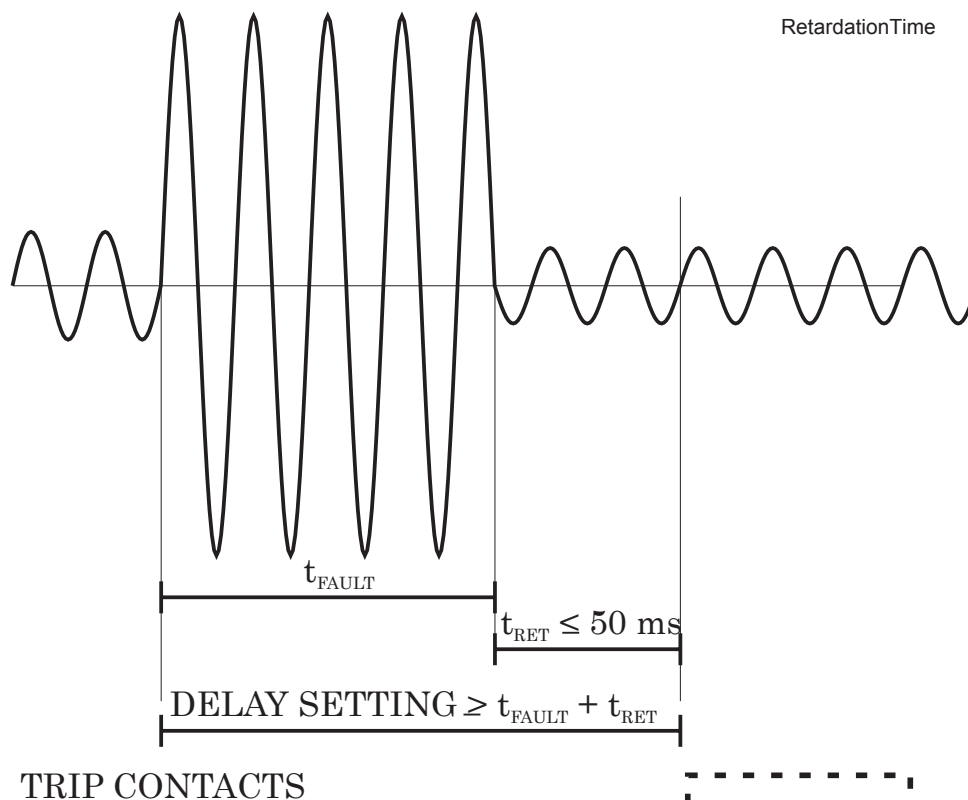
The operate time in the definite time mode is fixed by the **Operation delay** setting. The timer starts when the protection stage activates and counts until the set time has elapsed. After that, the stage issues a trip command. Should the protection stage reset before the definite time operation has elapsed, then the stage resets.

By default, the definite time delay cannot be set to zero because the value contains processing time of the function and operate time of the output contact. This means that the time indicated in the **Definite time** setting view is the actual operate time of the function. Use the **Accept zero delay** setting in the protection stage setting view to accept the zero setting for definite time function. In this case, the minimum operate time of the function must be tested separately.

### Overshoot time

Overshoot time is the time the protection relay needs to notice that a fault has been cleared during the operate time delay. This parameter is important when grading the operate time delay settings between relays.

Figure 55 - Overshoot time



If the delay setting would be slightly shorter, an unselective trip might occur (the dash line pulse).

For example, when there is a big fault in an outgoing feeder, it might start both the incoming and outgoing feeder relay. However, the fault must be cleared by the outgoing feeder relay and the incoming feeder relay must not trip. Although the operating delay setting of the incoming feeder is more than at the outgoing feeder, the incoming feeder might still trip if the operate time difference is not big enough. The difference must be more than the overshoot time of the incoming feeder relay plus the operate time of the outgoing feeder circuit breaker.

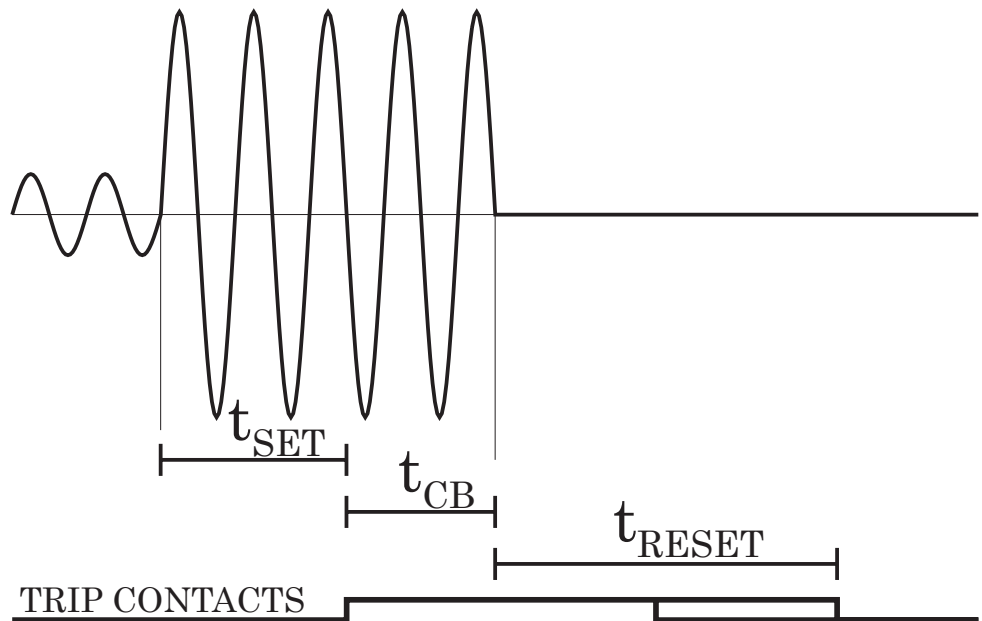
[Figure 55 - Overshoot time](#) on page 105 shows an overvoltage fault seen by the incoming feeder when the outgoing feeder clears the fault. If the operation delay setting would be slightly shorter or if the fault duration would be slightly longer than in the figure, an unselective trip might happen (the dashed 40 ms pulse in the figure). In Easergy P3 relays, the overshoot time is less than 50 ms.

### Reset time

[Figure 56 - Reset time](#) on page 106 shows an example of reset time, that is, release delay when the relay is clearing an overcurrent fault. When the relay's trip contacts are closed, the circuit breaker (CB) starts to open. After the CB contacts are open, the fault current still flows through an arc between the opened contacts. The current is finally cut off when the arc extinguishes at the next zero crossing of the current. This is the start moment of the reset delay. After the reset delay the trip contacts and start contact are opened unless latching is configured. The precise reset time depends on the fault size; after a big fault, the reset time is longer. The reset time also depends on the specific protection stage.

The maximum reset time for each stage is specified under the characteristics of every protection function. For most stages, it is less than 95 ms.

Figure 56 - Reset time



Reset time is the time it takes the trip or start relay contacts to open after the fault has been cleared.

**Hysteresis or dead band**

When comparing a measured value against a start value, some amount of hysteresis is needed to avoid oscillation near equilibrium situation. With zero hysteresis, any noise in the measured signal or any noise in the measurement itself would cause unwanted oscillation between fault-on and fault-off situations.

Figure 57 - Example behavior of an over-protection with hysteresis

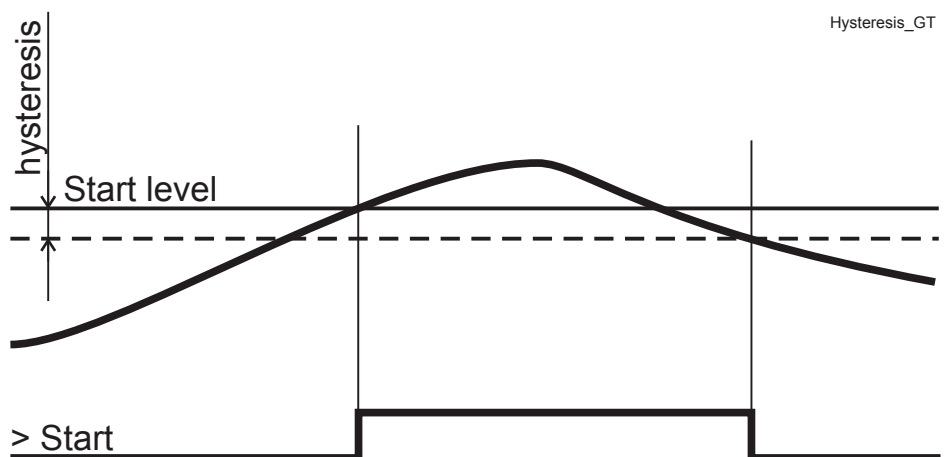
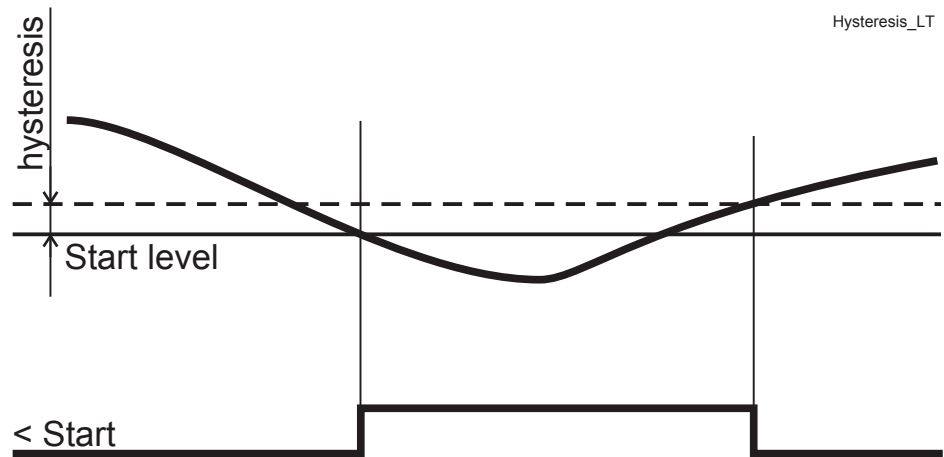


Figure 58 - Example behavior of an under-protection with hysteresis



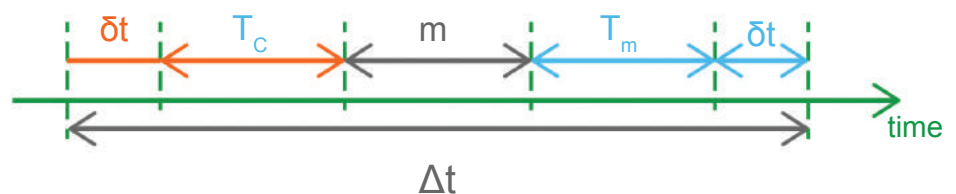
**Time grading**

When a fault occurs, the protection scheme only needs to trip circuit breakers whose operation is required to isolate the fault. This selective tripping is also called discrimination or protection coordination and is typically achieved by time grading. Protection systems in successive zones are arranged to operate in times that are graded through the sequence of equipment so that upon the occurrence of a fault, although a number of protections devices respond, only those relevant to the faulty zone complete the tripping function.

The recommended discrimination time between two Easergy P3 relays in an MV network is 170–200 ms. This is based on the following facts:

- $T_c$ : circuit breaker operating time, 60 ms
- $T_m$ : upstream protection overshoot time (retardation time), 50 ms
- $\delta t$ : time delay tolerance, 25 ms
- $m$ : safety margin, 10 ms
- $\Delta t$ : discrimination time, 170–200 ms

Figure 59 - Time grading



**Recorded values of the last eight faults**

There is detailed information available on the last eight faults for each protection stage. The recorded values are specific for the protection stages and can contain information like time stamp, fault value, elapsed delay, fault current, fault voltage, phase angle and setting group.

**NOTE:** The recorded values are lost if the relay power is switched off.

## 6.3 Dependent operate time

The dependent operate time – that is, the inverse definite minimum time (IDMT) type of operation – is available for several protection functions. The common principle, formula and graphic representations of the available dependent delay types are described in this chapter.

Dependent delay means that the operate time depends on the measured real time process values during a fault. For example, with an overcurrent stage using dependent delay, a bigger a fault current gives faster operation. The alternative to dependent delay is definite delay. With definite delay, a preset time is used and the operate time does not depend on the size of a fault.

### Stage-specific dependent delay

Some protection functions have their own specific type of dependent delay. Details of these dedicated dependent delays are described with the appropriate protection function.

### Operation modes

There are three operation modes to use the dependent time characteristics:

- Standard delays

Using standard delay characteristics by selecting a curve family (IEC, IEEE, IEEE2, RI) and a delay type (Normal inverse, Very inverse etc). See [6.3.1 Standard dependent delays using IEC, IEEE, IEEE2 and RI curves on page 110](#).

- Standard delay formulae with free parameters

selecting a curve family (IEC, IEEE, IEEE2) and defining one's own parameters for the selected delay formula. This mode is activated by setting delay type to 'Parameters', and then editing the delay function parameters A – E. See [6.3.2 Custom curves on page 124](#).

- Fully programmable dependent delay characteristics

Building the characteristics by setting 16 [current, time] points. The relay interpolates the values between given points with second degree polynomials. This mode is activated by the setting curve family to 'PrgN'. There is a maximum of three different programmable curves available at the same time. Each programmed curve can be used by any number of protection stages. See [6.3.3 Programmable dependent time curves on page 125](#).

### Dependent time limitation

The maximum dependent time is limited to 600 seconds.

### Local panel graph

The relay shows a graph of the currently used dependent delay on the local panel display. The up and down keys can be used for zooming. Also the delays at  $20 \times I_{SET}$ ,  $4 \times I_{SET}$  and  $2 \times I_{SET}$  are shown.

### Dependent time setting error signal

If there are any errors in the dependent delay configuration, the appropriate protection stage uses the definite time delay.



There is a signal 'Setting Error' available in the output matrix that indicates different situations:

1. Settings are currently changed with Easergy Pro or local panel.
2. There is temporarily an illegal combination of curve points. For example, if previous setting was IEC/NI and then curve family is changed to IEEE, this causes a setting error because there is no NI type available for IEEE curves. After changing valid delay type for IEEE mode (for example MI), the 'Setting Error' signal releases.
3. There are errors in formula parameters A – E, and the relay is not able to build the delay curve.
4. There are errors in the programmable curve configuration, and the relay is not able to interpolate values between the given points.

### Limitations

The maximum measured secondary phase current is  $50 \times I_N$  and the maximum directly measured ground fault current is  $10 \times I_{0N}$  for ground fault overcurrent input. The full scope of dependent delay curves goes up to 20 times the setting. At a high setting, the maximum measurement capability limits the scope of dependent curves according to [Table 41 - Maximum measured secondary currents and settings for phase and ground fault overcurrent inputs](#) on page 109.

Table 41 - Maximum measured secondary currents and settings for phase and ground fault overcurrent inputs

Current input	Maximum measured secondary current	Maximum secondary scaled setting enabling dependent delay times up to full 20x setting
$I_A, I_B, I_C$ and $I_{N\text{ Calc}}$	250 A	12.5 A
$I_{N1} = 5$ A	50 A	2.5 A
$I_{N1} = 1$ A	10 A	0.5 A
$I_{N1} = 0.2$ A	2 A	0.1 A

#### 1. Example of limitation

$$CT = 750 / 5$$

$$CT_0 = 100 / 1 \text{ (cable CT is used for ground fault overcurrent)}$$

The  $CT_0$  is connected to a 1 A terminals of input  $I_{N1}$ .

For overcurrent stage 50/51 - 1, [Table 41 - Maximum measured secondary currents and settings for phase and ground fault overcurrent inputs](#) on page 109 gives 12.5 A. Thus, the maximum setting the for 50/51 - 1 stage giving full dependent delay range is  $12.5 \text{ A} / 5 \text{ A} = 2.5 \times I_N = 1875 \text{ A}_{\text{Primary}}$ .

For ground fault stage 50N/51N-1, [Table 41 - Maximum measured secondary currents and settings for phase and ground fault overcurrent inputs](#) on page 109 gives 0.5 A. Thus, the maximum setting for the 50N/51N-1 stage giving full dependent delay range is  $0.5 \text{ A} / 1 \text{ A} = 0.5 \times I_{0N} = 50 \text{ A}_{\text{Primary}}$ .

#### 2. Example of limitation

$$CT = 750 / 5$$

Application mode is Motor

Rated current of the motor = 600 A

$I_{N\text{ Calc}} = (I_A + I_B + I_C)$  is used for ground fault overcurrent.

At secondary level, the rated motor current is  $600 / 750 \times 5 = 4$  A

For overcurrent stage 50/51 - 1, [Table 41 - Maximum measured secondary currents and settings for phase and ground fault overcurrent inputs](#) on page 109 gives 12.5 A. Thus, the maximum setting giving full dependent delay range is  $12.5 \text{ A} / 4 \text{ A} = 3.13 \times I_{MOT} = 1875 \text{ A}_{\text{Primary}}$ .

For ground fault 50N/51N-1, [Table 41 - Maximum measured secondary currents and settings for phase and ground fault overcurrent inputs](#) on page 109 gives 12.5 A. Thus, the maximum setting for the 50N/51N-1 stage giving full dependent delay range is  $12.5 \text{ A} / 5 \text{ A} = 2.5 \times I_{0N} = 1875 \text{ A}_{\text{Primary}}$ .

### 6.3.1 Standard dependent delays using IEC, IEEE, IEEE2 and RI curves

The available standard dependent delays are divided in four categories called dependent curve families: IEC, IEEE, IEEE2 and RI. Each category contains a set of different delay types according to [Table 42 - Available standard delay families and the available delay types within each family](#) on page 110.

#### Dependent time setting error signal

The dependent time setting error signal activates if the delay category is changed and the old delay type does not exist in the new category. See [6.3 Dependent operate time](#) on page 108 for more details.

#### Limitations

The minimum definite time delay starts when the measured value is twenty times the setting, at the latest. However, there are limitations at high setting values due to the measurement range. See [6.3 Dependent operate time](#) on page 108 for more details.

Table 42 - Available standard delay families and the available delay types within each family

Delay type		Curve family				
		DT	IEC	IEEE	IEEE2	RI
DT	Definite time	X				
NI	Normal inverse		X		X	
VI	Very inverse		X	X	X	
EI	Extremely inverse		X	X	X	
LTI	Long time inverse		X	X		
LTEI	Long time extremely inverse			X		

Delay type		Curve family				
		DT	IEC	IEEE	IEEE2	RI
<b>LTVI</b>	Long time very inverse			X		
<b>MI</b>	Moderately inverse			X	X	
<b>STI</b>	Short time inverse			X		
<b>STEI</b>	Short time extremely inverse			X		
<b>RI</b>	Old ASEA type					X
<b>RXIDG</b>	Old ASEA type					X

### IEC dependent operate time

The operate time depends on the measured value and other parameters according to [Equation 3 on page 111](#). Actually this equation can only be used to draw graphs or when the measured value  $I$  is constant during the fault. A modified version is implemented in the relay for real time usage.

#### Equation 3

$$t = \frac{k A}{\left(\frac{I}{I_{START}}\right)^B - 1}$$

$t$  = Operation delay in seconds

$k$  = User's multiplier Inv. time coefficient  $k$

$I$  = Measured value

$I_{START}$  = Start setting

$A, B$  = Constants parameters according to [Table 43 - Constants for IEC dependent delay equation on page 111](#).

There are three different dependent delay types according to IEC 60255-3, Normal inverse (NI), Extremely inverse (EI), Very inverse (VI) and a VI extension. In addition, there is a de facto standard Long time inverse (LTI).

Table 43 - Constants for IEC dependent delay equation

Delay type		Parameter	
		A	B
NI	Normal inverse	0.14	0.02
EI	Extremely inverse	80	2

Delay type		Parameter	
		A	B
VI	Very inverse	13.5	1
LTI	Long time inverse	120	1

**Example of the delay type "Normal inverse (NI)":**

k = 0.50

I = 4 pu (constant current)

I<sub>PICKUP</sub> = 2 pu

A = 0.14

B = 0.02

Equation 4

$$t = \frac{0.50 \cdot 0.14}{\left(\frac{4}{2}\right)^{0.02} - 1} = 5.0$$

The operate time in this example is five seconds. The same result can be read from [Figure 60 - IEC normal inverse delay](#) on page 112.

Figure 60 - IEC normal inverse delay

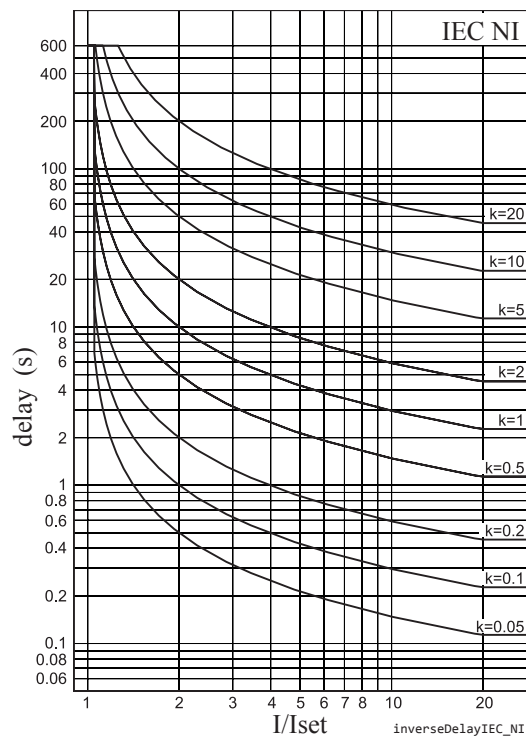


Figure 61 - IEC extremely inverse delay

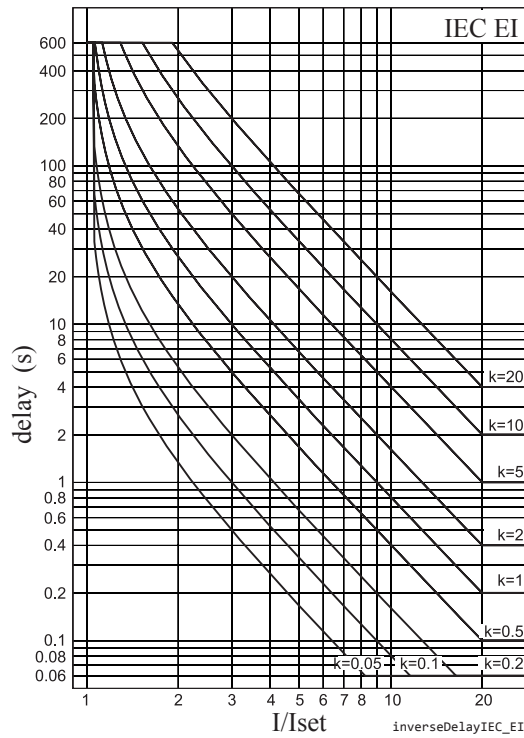


Figure 62 - IEC very inverse delay

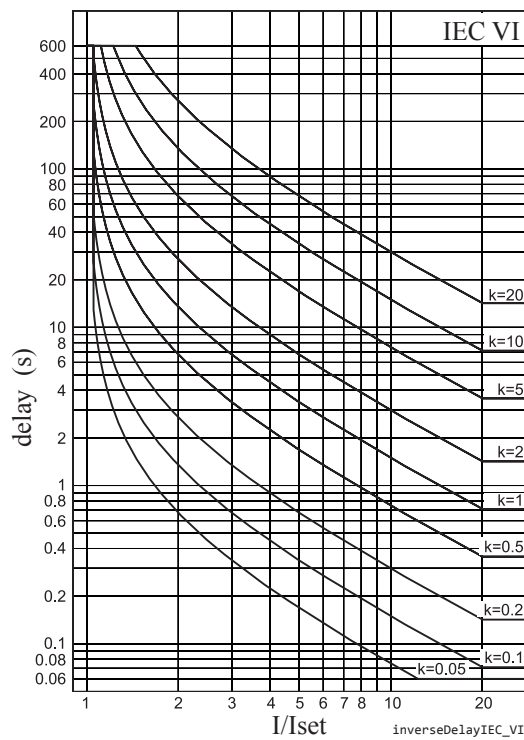
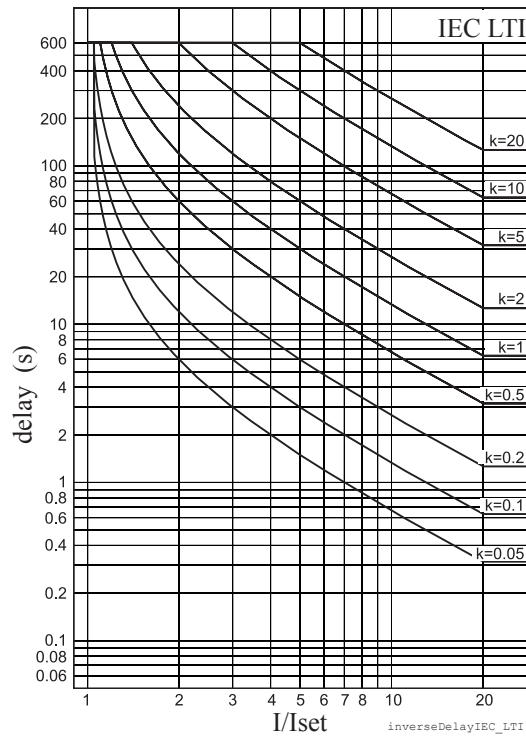


Figure 63 - IEC long time inverse delay



**IEEE/ANSI dependent operate time**

There are three different delay types according to IEEE Std C37.112-1996 (MI, VI, EI) and many de facto versions according to [Table 44 - Constants for IEEE/ANSI inverse delay equation on page 115](#). The IEEE standard defines dependent delay for both trip and release operations. However, in the Easergy P3 relay only the trip time is dependent according to the standard but the reset time is constant.

The operate delay depends on the measured value and other parameters according to [Equation 5 on page 114](#). Actually, this equation can only be used to draw graphs or when the measured value I is constant during the fault. A modified version is implemented in the relay for real-time usage.

Equation 5

$$t = k \left[ \frac{A}{\left( \frac{I}{I_{START}} \right)^C - 1} + B \right]$$

t = Operation delay in seconds

k = User's multiplier

I = Measured value

I<sub>START</sub> = Start setting

A,B,C = Constant parameter according to [Table 44 - Constants for IEEE/ANSI inverse delay equation](#) on page 115

Table 44 - Constants for IEEE/ANSI inverse delay equation

Delay type		Parameter		
		A	B	C
LTI	Long time inverse	0.086	0.185	0.02
LTVI	Long time very inverse	28.55	0.712	2
LTEI	Long time extremely inverse	64.07	0.250	2
MI	Moderately inverse	0.0515	0.1140	0.02
VI	Very inverse	19.61	0.491	2
EI	Extremely inverse	28.2	0.1217	2
STI	Short time inverse	0.16758	0.11858	0.02
STEI	Short time extremely inverse	1.281	0.005	2

**Example of the delay type "Moderately inverse (MI)":**

$$k = 0.50$$

$$I = 4 \text{ pu}$$

$$I_{\text{PICKUP}} = 2 \text{ pu}$$

$$A = 0.0515$$

$$B = 0.114$$

$$C = 0.02$$

Equation 6

$$t = 0.50 \cdot \left[ \frac{0.0515}{\left(\frac{4}{2}\right)^{0.02} - 1} + 0.1140 \right] = 1.9$$

The operate time in this example is 1.9 seconds. The same result can be read from [Figure 67 - ANSI/IEEE moderately inverse delay](#) on page 117.

Figure 64 - ANSI/IEEE long time inverse delay

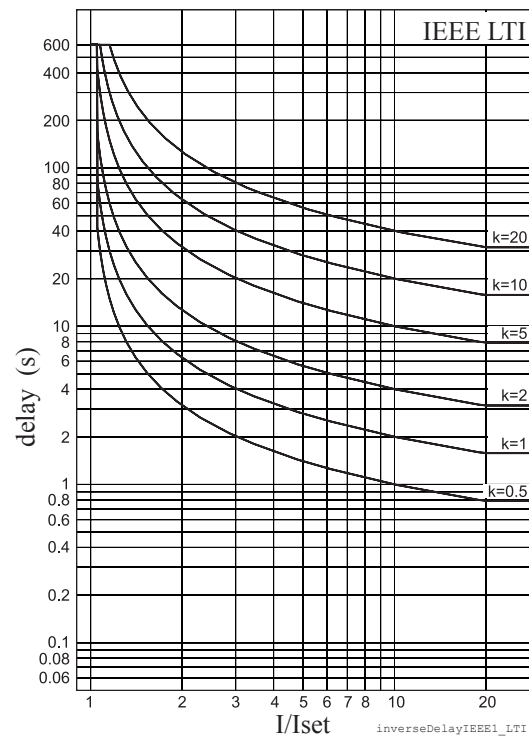


Figure 65 - ANSI/IEEE long time very inverse delay

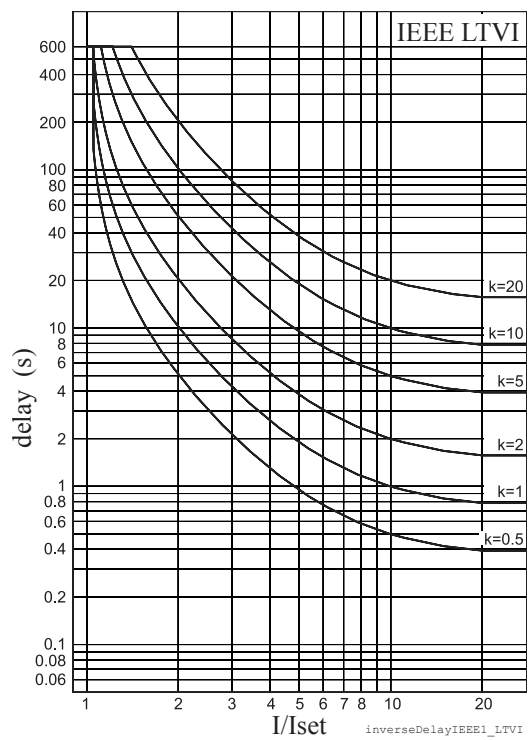




Figure 66 - ANSI/IEEE long time extremely inverse delay

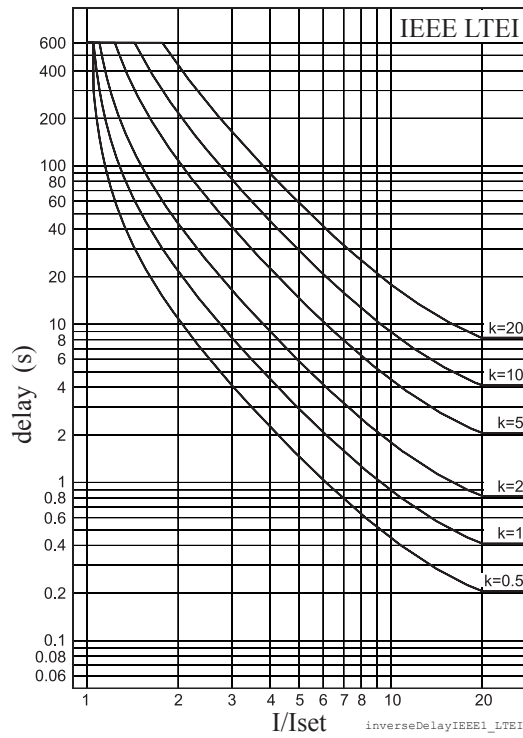


Figure 67 - ANSI/IEEE moderately inverse delay

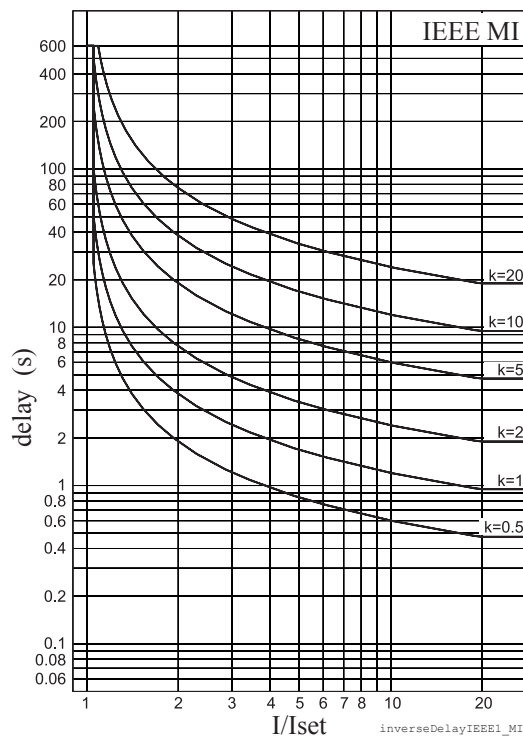


Figure 68 - ANSI/IEEE short time inverse delay

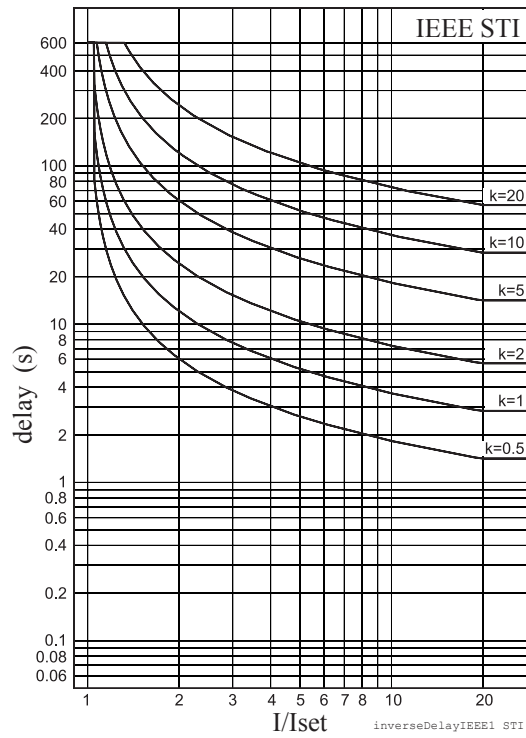
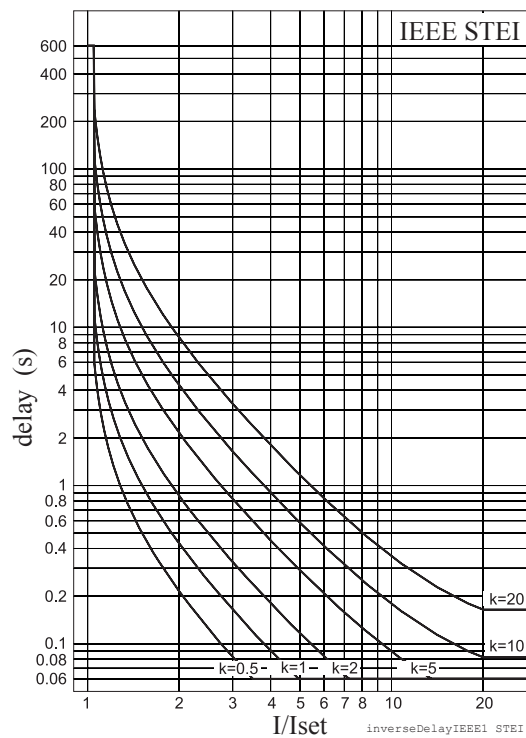


Figure 69 - ANSI/IEEE short time extremely inverse delay



**IEEE2 dependent operate time**

Before the year 1996 and ANSI standard C37.112 microprocessor relays were using equations approximating the behavior of various induction disc type relays. A quite popular approximation is [Equation 7](#) on page 119 which in Easergy P3

relays is called IEEE2. Another name could be IAC because the old General Electric IAC relays have been modeled using the same equation.

There are four different delay types according to [Table 45 - Constants for IEEE2 inverse delay equation](#) on page 119. The old electromechanical induction disc relays have dependent delay for both trip and release operations. However, in Easergy P3 relays, only the trip time is dependent and the reset time is constant.

The operate delay depends on the measured value and other parameters according to [Equation 7](#) on page 119. Actually, this equation can only be used to draw graphs or when the measured value  $I$  is constant during the fault. A modified version is implemented in the relay for real-time usage.

Equation 7

$$t = k \left[ A + \frac{B}{\left( \frac{I}{I_{START}} - C \right)} + \frac{D}{\left( \frac{I}{I_{START}} - C \right)^2} + \frac{E}{\left( \frac{I}{I_{START}} - C \right)^3} \right]$$

$t$  = Operation delay in seconds

$k$  = User's multiplier

$I$  = Measured value

$I_{START}$  = User's start setting

$A, B, C, D$  = Constant parameter according to [Table 45 - Constants for IEEE2 inverse delay equation](#) on page 119.

Table 45 - Constants for IEEE2 inverse delay equation

Delay type		Parameter				
		A	B	C	D	E
MI	Moderately inverse	0.1735	0.6791	0.8	-0.08	0.1271
NI	Normally inverse	0.0274	2.2614	0.3	-0.1899	9.1272
VI	Very inverse	0.0615	0.7989	0.34	-0.284	4.0505
EI	Extremely inverse	0.0399	0.2294	0.5	3.0094	0.7222

**Example of the delay type "Moderately inverse (MI)":**

$k = 0.50$

$I = 4$  pu

$I_{START} = 2$  pu

$A = 0.1735$

$B = 0.6791$

$C = 0.8$

$D = -0.08$

$E = 0.127$

Equation 8

$$t = 0.5 \cdot \left[ 0.1735 + \frac{0.6791}{\left(\frac{4}{2} - 0.8\right)} + \frac{-0.08}{\left(\frac{4}{2} - 0.8\right)^2} + \frac{0.127}{\left(\frac{4}{2} - 0.8\right)^3} \right] = 0.38$$

The operate time in this example is 0.38 seconds. The same result can be read from [Figure 70 - IEEE2 moderately inverse delay](#) on page 120.

Figure 70 - IEEE2 moderately inverse delay

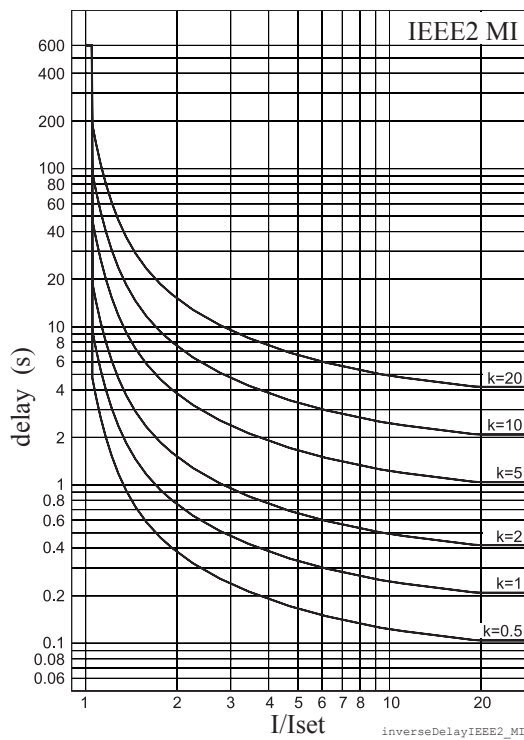


Figure 71 - IEEE2 normal inverse delay

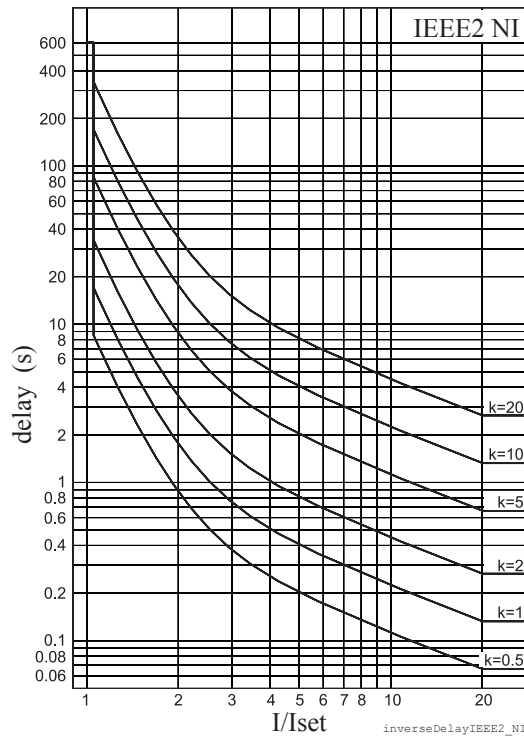


Figure 72 - IEEE2 very inverse delay

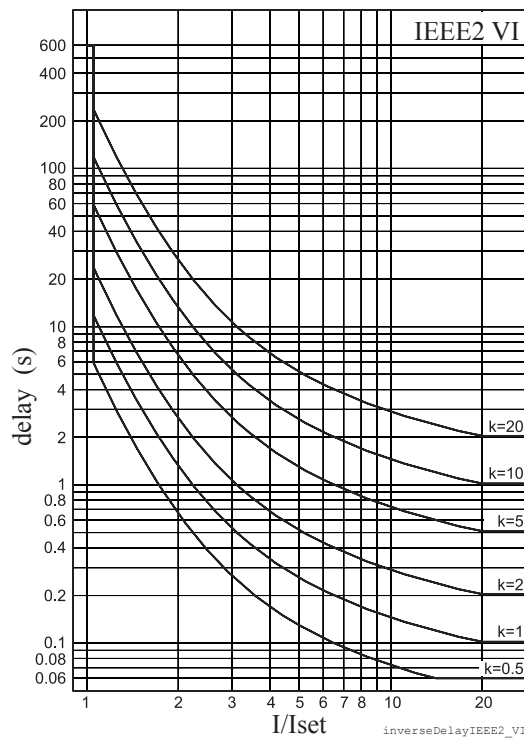
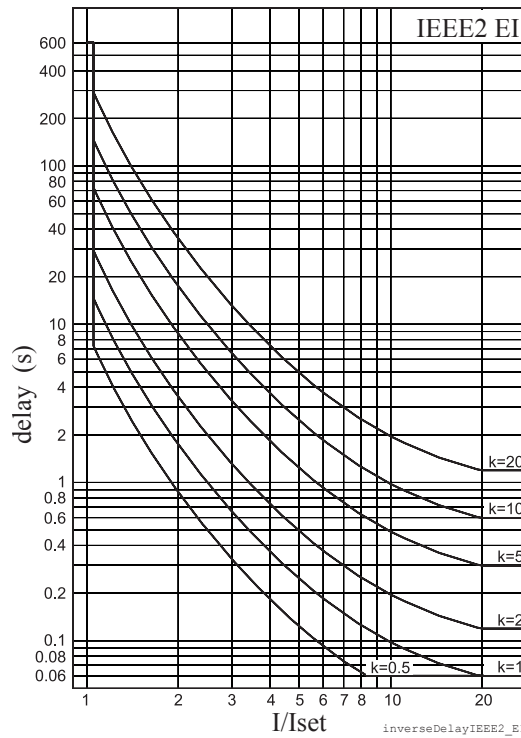


Figure 73 - IEEE2 extremely inverse delay



**RI and RXIDG type dependent operate time**

These two dependent delay types have their origin in old ASEA (nowadays ABB) ground fault relays.

The operate delay of types RI and RXIDG depends on the measured value and other parameters according to [Equation 9 on page 122](#) and [Equation 10 on page 122](#). Actually, these equations can only be used to draw graphs or when the measured value I is constant during the fault. Modified versions are implemented in the relay for real-time usage.

Equation 9

$$t_{RI} = \frac{k}{0.339 - \frac{0.236}{\left(\frac{I}{I_{START}}\right)}}$$

Equation 10

$$t_{RXIDG} = 5.8 - 1.35 \ln \frac{I}{k I_{START}}$$

t = Operate delay in seconds

k = User's multiplier

I = Measured value

I<sub>START</sub> = Start setting

**Example of the delay type RI**

k = 0.50

I = 4 pu

$$I_{START} = 2 \text{ pu}$$

Equation 11

$$t_{RI} = \frac{0.5}{0.339 - \frac{0.236}{\left(\frac{4}{2}\right)}} = 2.3$$

The operate time in this example is 2.3 seconds. The same result can be read from [Figure 74 - RI dependent delay](#) on page 123.

**Example of the delay type RXIDG**

$$k = 0.50$$

$$I = 4 \text{ pu}$$

$$I_{START} = 2 \text{ pu}$$

Equation 12

$$t_{RXIDG} = 5.8 - 1.35 \ln \frac{4}{0.5 \cdot 2} = 3.9$$

The operate time in this example is 3.9 seconds. The same result can be read from [Figure 75 - RXIDG dependent delay](#) on page 124.

Figure 74 - RI dependent delay

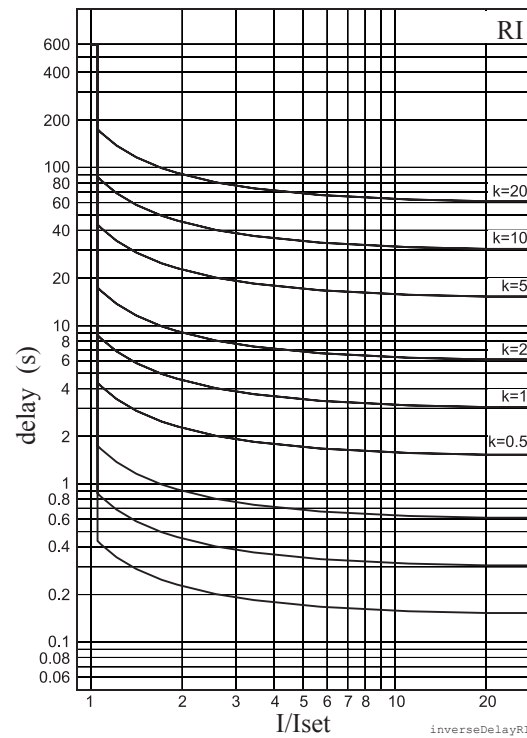
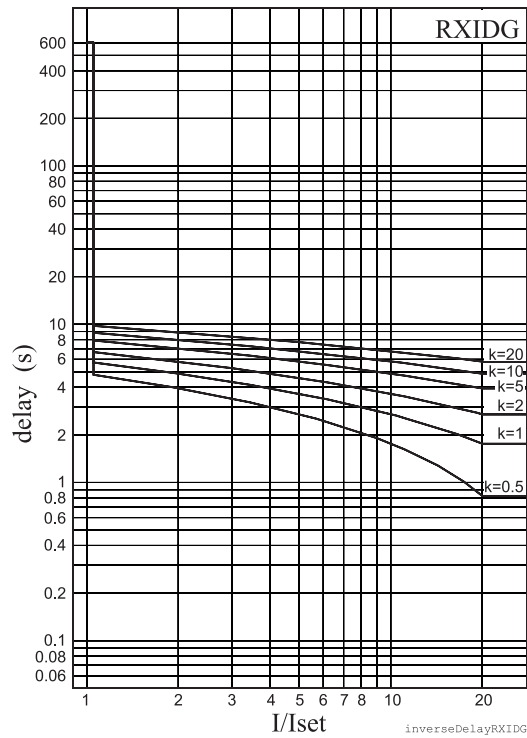


Figure 75 - RXIDG dependent delay



### 6.3.2 Custom curves

This mode is activated by the setting delay type to 'Parameters', and then editing the delay function constants, that is, the parameters A – E. The idea is to use the standard equations with one's own constants instead of the standardized constants as in the previous chapter.

#### Example of the GE-IAC51 delay type:

$$k = 0.50$$

$$I = 4 \text{ pu}$$

$$I_{START} = 2 \text{ pu}$$

$$A = 0.2078$$

$$B = 0.8630$$

$$C = 0.8000$$

$$D = -0.4180$$

$$E = 0.1947$$



Equation 13

$$t = 0.5 \cdot \left[ 0.2078 + \frac{0.8630}{\left(\frac{4}{2} - 0.8\right)} + \frac{-0.4180}{\left(\frac{4}{2} - 0.8\right)^2} + \frac{0.1947}{\left(\frac{4}{2} - 0.8\right)^3} \right] = 0.37$$

The operate time in this example is 0.37 seconds.

The resulting time/current characteristic of this example matches quite well the characteristic of the old electromechanical IAC51 induction disc relay.

### Dependent time setting error signal

The dependent time setting error signal activates if interpolation with the given parameters is not possible. See [6.3 Dependent operate time on page 108](#) for more details.

### Limitations

The minimum definite time delay starts at the latest when the measured value is twenty times the setting. However, there are limitations at high setting values due to the measurement range. See [6.3 Dependent operate time on page 108](#) for more details.

## 6.3.3 Programmable dependent time curves

Programming dependent time curves requires Easergy Pro setting tool and rebooting the unit.

The [current, time] curve points are programmed using Easergy Pro PC program. There are some rules for defining the curve points:

- the configuration must begin from the topmost line
- the line order must be as follows: the smallest current (longest operate time) on the top and the largest current (shortest operate time) on the bottom
- all unused lines (on the bottom) should be filled with [1.00 0.00s]

Here is an example configuration of curve points:

Point	Current $I/I_{START}$	Operate delay
1	1.00	10.00 s
2	2.00	6.50 s
3	5.00	4.00 s
4	10.00	3.00 s
5	20.00	2.00 s
6	40.00	1.00 s

Point	Current $I/I_{START}$	Operate delay
7	1.00	0.00 s
8	1.00	0.00 s
9	1.00	0.00 s
10	1.00	0.00 s
11	1.00	0.00 s
12	1.00	0.00 s
13	1.00	0.00 s
14	1.00	0.00 s
15	1.00	0.00 s
16	1.00	0.00 s

### Dependent time setting error signal

The dependent time setting error signal activates if interpolation with the given points fails. See [6.3 Dependent operate time on page 108](#) for more details.

### Limitations

The minimum definite time delay starts at the latest when the measured value is twenty times the setting. However, there are limitations at high setting values due to the measurement range. See [6.3 Dependent operate time on page 108](#) for more details.

## 6.4 Underimpedance (ANSI 21G)

Underimpedance protection can be used to detect near short-circuit faults, even when the excitation of the generator collapses, thus limiting the available short-circuit current. It is an alternative to the voltage-dependent overcurrent protection ([6.21 Voltage-dependent overcurrent \(ANSI 51V\) on page 176](#)). When the generator's short-circuit current capacity is limited, an instantaneous overcurrent stage might not activate, but an underimpedance stage detects the fault.

The stage is sensitive to the positive sequence impedance  $Z_1$  that is calculated using the equation

Equation 14

$$Z_1 = \frac{V_1}{I_1}$$

$Z_1$  = absolute value of positive sequence impedance

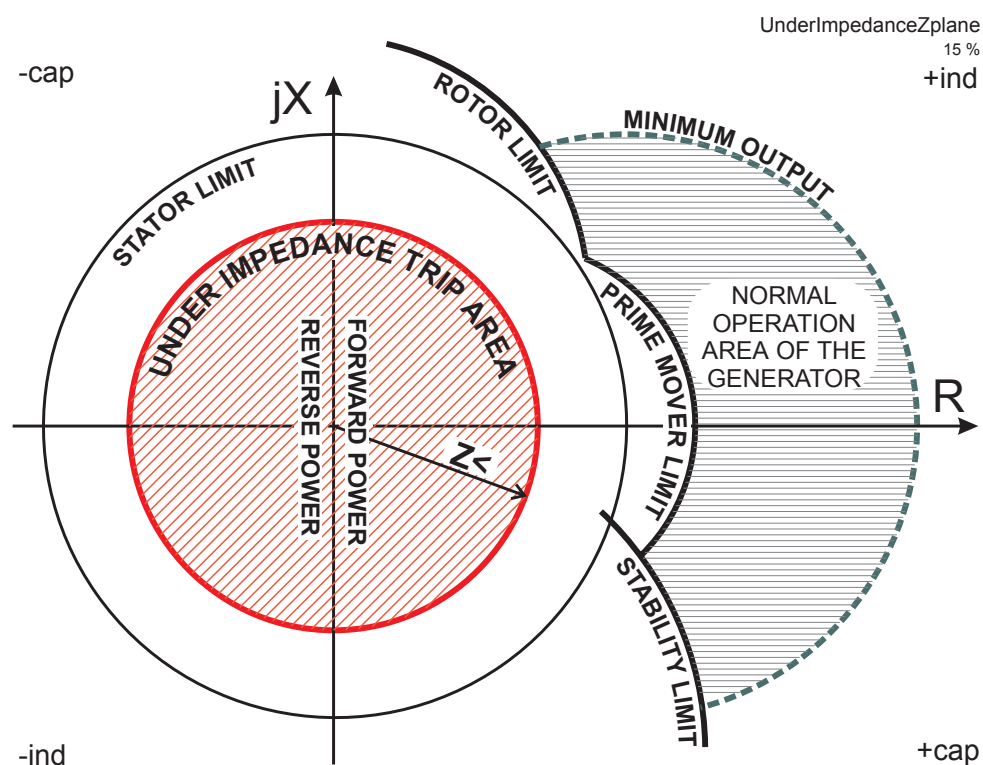
$V_1$  = positive sequence voltage

$I_1$  = positive sequence current

The trip region of underimpedance stage is a circle in origin. The radius  $Z<$  is the setting value. The bigger circle "stator limit" represents the rated power of the generator.

The impedance relay is insensitive to the phase angle between current and voltage. Its characteristic in an impedance plane is a circle in origin where the horizontal axis represents resistance  $R$  and the vertical axis represents reactance  $jX$ .

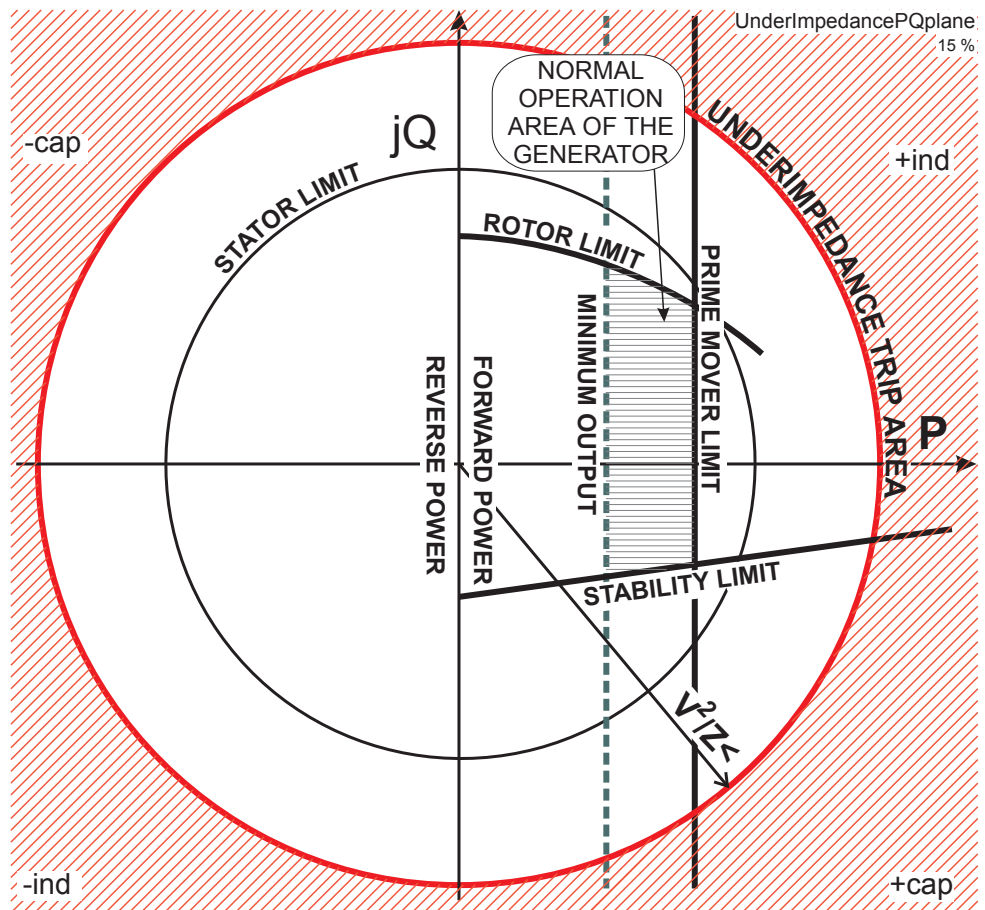
Figure 76 - Underimpedance Z plane characteristic



Whenever the positive sequence impedance goes inside the circle, the stage starts. The radius  $Z<$  of the circle and the definite delay time are the setting parameters.

[Figure 77 - Underimpedance plane with a constant voltage](#) on page 128 shows the underimpedance characteristics drawn in power plane assuming that the voltage is constant. The trip area is now outside the circle having radius  $V_2/Z<$  where  $Z<$  is the start setting.

Figure 77 - Underimpedance plane with a constant voltage



**Undercurrent blocking**

When for some reason, the voltage collapses but the currents remain at normal load levels, the calculated impedance may fall into the trip area. An inverted start signal from the most sensitive overcurrent stage can be used to block the underimpedance stages during abnormal voltages not caused by short-circuit faults.

**Self-blocking at very low voltages**

The underimpedance stages are self-blocked at very low voltages. The purpose of self-blocking is to avoid incorrect operation when the voltage is too low to be measured correctly.

The self-blocking limit has been fixed to 5% of the nominal voltage. When the maximum line-to-line voltage is below 5%, the stage is blocked.

**Characteristic on a PQ power plane**

In [Figure 77 - Underimpedance plane with a constant voltage](#) on page 128, the same characteristic as in the previous figure is drawn on a PQ power plane assuming a constant voltage of 1 PU. The transformation is  $\underline{S} = V \underline{I}^*$ , where V is the voltage and  $Z^*$  is the complex conjugate of impedance Z.

The borderline of the underimpedance trip area in the power plane is still a circle in origin, but now the trip area is outside the circle. The shape of the normal

operation area is totally different. For example the maximum active power (prime mover limit) is just a vertical line while in impedance plane ([Figure 76 - Underimpedance Z plane characteristic on page 127](#)), it is a circle touching the  $jX$  axis.

When the current is zero, the impedance calculation gives infinite as the result. Thus, the stage does not start in a machine standstill situation.

### Two independent underimpedance stages

There are two separately adjustable stages available:  $Z<$  and  $Z<<$ .

### Setting groups

This stage has one setting group.

### Characteristics

Table 46 - Underimpedance stages  $Z<$ ,  $Z<<$  (21G)

Start value	$0.05 - 2.00 \times Z_N$
Definite time function: - Operate time	$0.08^{32} - 300.00 \text{ s}$ (step 0.02 s)
Start time	Typically 60 ms
Reset time	<95 ms
Overshoot time	< 50 ms
Reset ratio	1.05
Inaccuracy: - Starting - Operate time at definite time function	$\pm 4\%$ of set value or $\pm 0.01 \times Z_N$ $\pm 1\%$ or $\pm 30 \text{ ms}$

<sup>32</sup> This is the instantaneous time i.e. the minimum total operational time including the fault detection time and operate time of the trip contacts.

## 6.5 Volts/hertz overexcitation protection (ANSI 24)

The saturation of any inductive network components like transformers, inductors, motors and generators depends on the voltage and frequency. The lower the frequency, the lower is the voltage at which the saturation begins.

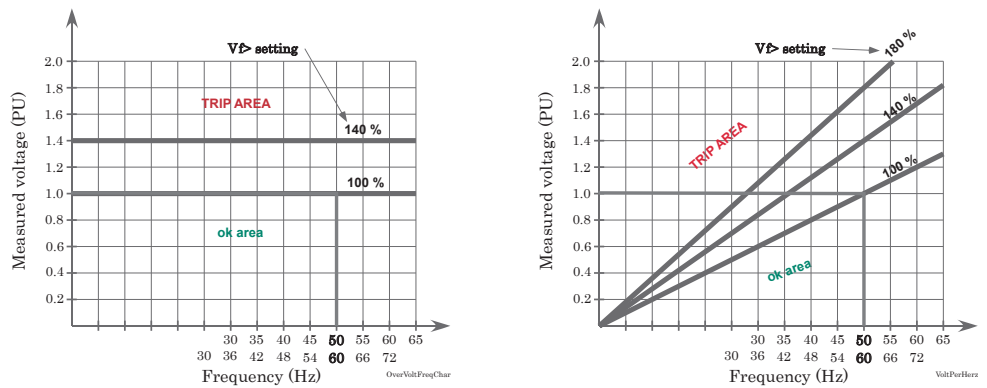
The volts/hertz overexcitation protection stage is sensitive to the voltage/frequency ratio instead of voltage only. [Figure 78 - Difference between volts/hertz and normal overvoltage protection on page 130](#) shows the difference between volts/hertz and a standard overvoltage function. The highest of the three line-to-line voltages is used regardless of the voltage measurement mode ([10.8 Voltage system configuration on page 368](#)). By using line-to-line voltages, any line-to-neutral overvoltages during ground faults have no effect. (The ground fault protection functions take care of ground faults.)

The used net frequency is automatically adopted according to the local network frequency.

Overexcitation protection is needed for generators that are excited even during startup and shutdown. If such a generator is connected to a unit transformer, also the unit transformer needs volts/hertz overexcitation protection. Another application is sensitive overvoltage protection of modern transformers with no flux density margin in networks with unstable frequency.

This figure shows the difference between volts/hertz and normal overvoltage protection. The volts/hertz characteristics on the left depend on the frequency, while the standard overvoltage function on the right is insensitive to frequency. The network frequency, 50 Hz or 60 Hz, is automatically adopted by the relay.

Figure 78 - Difference between volts/hertz and normal overvoltage protection



**Setting groups**

There are four setting groups available for each stage.

**Characteristics**

Table 47 - Volts/hertz over-excitation protection 24–1

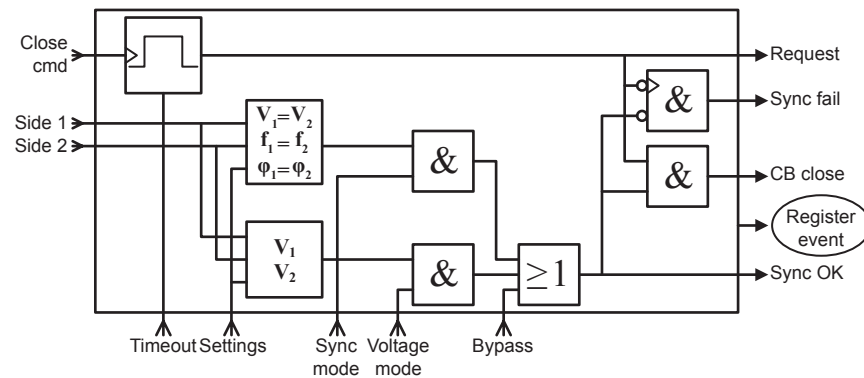
Start setting range	100–200%
Operating time	0.3–300.0 s
Start time	Typically 200 ms
Reset time	< 450 ms
Reset ratio	0.995
Inaccuracy:	
- Starting	V < 0.5% unit f < 0.05 Hz
- Operating time at definite time function	±1% or ±150 ms

## 6.6 Synchronism check (ANSI 25)

### Description

The relay includes a function that checks the synchronism before giving or enabling the circuit breaker close command. The function monitors the voltage amplitude, frequency and phase angle difference between two voltages. Since there are two stages available, it is possible to monitor three voltages. The voltages can be busbar and line or busbar and busbar (bus coupler).

Figure 79 - Synchronism check function



The synchronism check stage includes two separate synchronism criteria that can be used separately or combined:

- voltage only
- voltage, frequency, and phase

The voltage check simply compares voltage conditions of the supervised objects. The supervised object is considered dead (not energized) when the measured voltage is below the  $V_{dead}$  setting limit. Similarly, the supervised object is considered live (energized) when the measured voltage is above the  $V_{live}$  setting limit. Based on the measured voltage conditions and the selected voltage check criteria, synchronism is declared.

When the network sections to be connected are part of the same network, the frequency and phase are the same. Therefore, the voltage check criteria is safe to use without frequency and phase check.

The frequency and phase check compares the voltages, frequency and phase of the supervised objects. Synchronism is declared if the voltages are above the  $V_{live}$  limit and all three difference criteria are within the given limits. This synchronism check is dynamic by nature, and the object close command is given at a certain moment of time, depending on the selected mode of operation.

When two networks are running at slightly different frequencies, there is also a phase difference between these two networks. Because of the different frequency, the phase angle tends to rotate. The time for one cycle depends on the frequency difference. The stress for electrical components is lowest when two networks are connected at zero phase difference.

In the "Sync" mode, the circuit breaker closing is aimed at the moment of zero phase difference. Therefore, the close command is advanced by the time defined by the CB close time setting. In the "Async" mode, the circuit breaker closing is

aimed at the moment when the synchronism conditions are met, that is, when the phase difference is within the given phase difference limit.

When two network sections to be connected are from different sources or generators, the voltage criteria alone is not safe, so also frequency and phase check must be used.

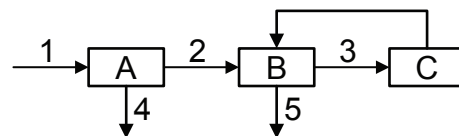
When two networks with different frequencies are to be connected, the request timeout setting must be long enough to allow the synchronism criteria to be met. For example, if the frequency difference is 0.1 Hz, the synchronism criteria is met only once in ten seconds.

The synchronism check stage starts from an object close command that generates a request to close the selected circuit breaker when the synchronism conditions are met. The synchronism check stage provides a "request" signal that is active from the stage start until the synchronism conditions are met or the request timeout has elapsed. When the synchronism conditions are not met within the request timeout, a "fail" pulse is generated. The fail pulse has a fixed length of 200 ms. When the synchronism conditions are met in a timely manner, the object close command is initiated for the selected object. This signal is purely internal and not available outside the synchronism check stage. When the synchronism conditions are met, the "OK" signal is always active. The activation of the bypass input bypasses the synchronism check and declares synchronism at all times.

The request, OK, and fail signals are available in the output matrix.

The synchronized circuit breaker close execution order is shown in [Figure 80 - Synchronism check execution order](#) on page 132.

Figure 80 - Synchronism check execution order

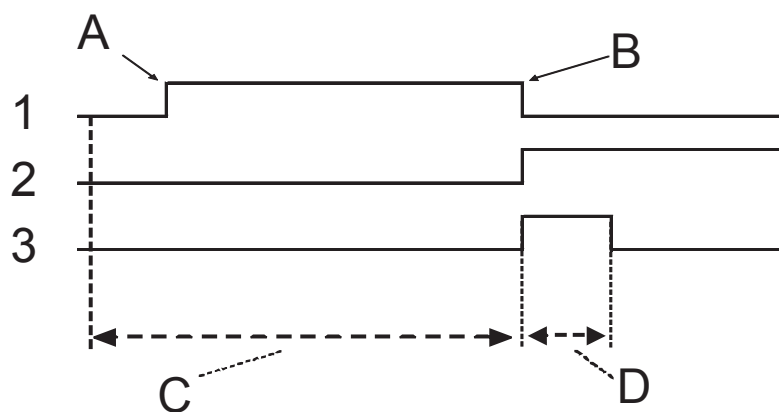


- A. Synchronism check stage
- B. Object
- C. Circuit breaker (physical)

1. Object close command from mimic, digital inputs or communication protocol
2. Synchronism declared
3. Circuit breaker close command
4. Sync fail signal if request timeout elapsed before synchronism conditions met
5. Object fail signal if CB failed to operate



Figure 81 - Synchronism check function principle



1. Sync request
2. Sync OK
3. Object close command

- A. The object close command given (minic or bus) actually only makes a sync request.
- B. The sync request ends when the synchronism conditions are met and CB command is given or if the request timeout elapsed.
- C. If the request timeout elapsed before synchronism conditions are met, sync fail pulse is generated.
- D. Normal object close operation

The synchronism check function is available when one of the following analog measurement modules and a suitable measuring mode are in use:

**Connections for synchronism check**

The voltage used for checking the synchronism is always line-to-line voltage  $V_{AB}$  even when  $V_A$  is measured. The synchronism check stage 1 always compares  $V_{AB}$  with  $V_{ABy}$ . The compared voltages for the stage 2 can be selected ( $V_{AB}/V_{ABy}$ ,  $V_{AB}/V_{ABz}$ ,  $V_{ABy}/V_{ABz}$ ). See [10.8 Voltage system configuration](#) on page 368.

**NOTE:** To perform its operation, the synchronism check stage 2 converts the voltages  $LN_y$  and  $LN_z$  to line-to-line voltage  $V_{AB}$ . As such, the measured voltage for  $LN_y$  and  $LN_z$  must be  $V_{A-N}$ .

**NOTE:** The wiring of the secondary circuits of voltage transformers to the relay terminal depends on the selected voltage measuring mode.

See the synchronism check stage's connection diagrams in [10.8 Voltage system configuration](#) on page 368.

**Characteristics**

Table 48 - Synchronism check function (25)

Input signal	$V_1 - V_4$
Synchronism check mode ( $S_{MODE}$ )	Off; Async; Sync <sup>33 34 35</sup>

Voltage check mode ( $V_{MODE}$ )	DD; DL; LD; DD/DL; DD/LD; DL/LD; DD/DL/ LD <sup>36 37 38 39</sup>
CB closing time	0.04–0.6 s
$V_{DEAD}$ limit setting	10–120% $V_N$
$V_{LIVE}$ limit setting	10–120% $V_N$
Frequency difference	0.01–1.00 Hz
Voltage difference	1–60% $V_N$
Phase angle difference	2°–90°
Request timeout	0.1–600.0 s
Stage operation range	46.0–64.0 Hz
Reset ratio (V)	0.97
Inaccuracy: - voltage - frequency - phase angle - operate time	$\pm 3\% V_N$ $\pm 20$ mHz $\pm 2^\circ$ (when $\Delta f < 0.2$ Hz, else $\pm 5^\circ$ ) $\pm 1\%$ or $\pm 30$ ms

<sup>33</sup> Off – Frequency and phase criteria not in use

<sup>34</sup> Async –  $d_F$ ,  $d_U$  and  $d$  angle criteria are used. Circuit breaker close is aimed at the moment when the phase angle is within phase angle difference limit. Slip frequency  $d_F$  determines how much the close command needs to be advanced to make the actual connection at the moment when the phase angle is within the phase angle limit

<sup>35</sup> Sync mode –  $d_F$ ,  $d_U$  and  $d$  angle criteria are used. Circuit breaker close is aimed at the moment when the phase angle becomes zero. Slip frequency  $d_F$  determines how much the close command needs to be advanced to make the actual connection at zero phase angle.

<sup>36</sup> The first letter refers to the reference voltage and the second letter to the comparison voltage.

<sup>37</sup> D means that the side must be “dead” when closing (dead = The voltage is below the dead voltage limit setting).

<sup>38</sup> L means that the side must be “live” when closing (live = The voltage is higher than the live voltage limit setting).

<sup>39</sup> Example: DL mode for stage 1: The U12 side must be “dead” and the U12y side must be “live”.

## 6.7 Undervoltage (ANSI 27)

### Description

Undervoltage protection is used to detect voltage dips or sense abnormally low voltages to trip or trigger load shedding or load transfer. The function measures the three line-to-line voltages, and whenever the smallest of them drops below the start setting of a particular stage, this stage starts and a start signal is issued. If the fault situation remains on longer than the operate time delay setting, a trip signal is issued.

### Blocking during voltage transformer fuse failure

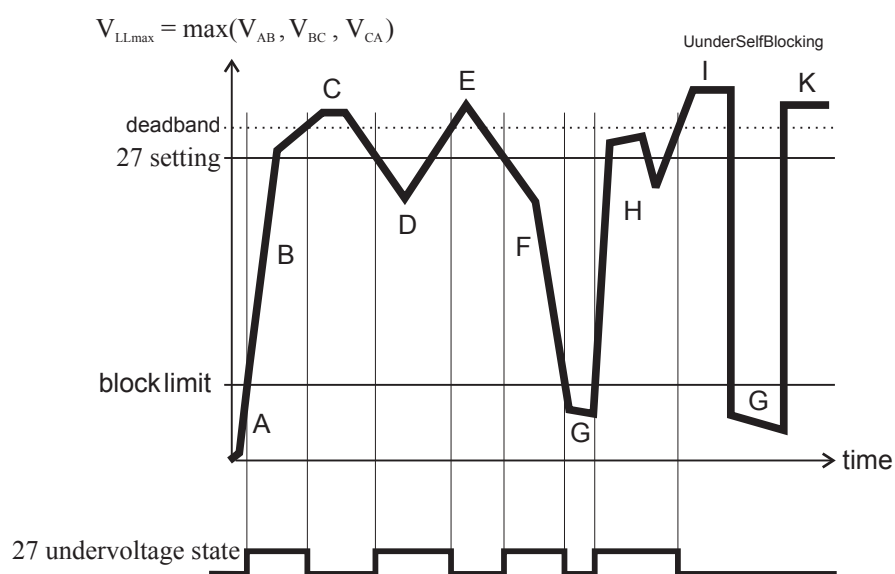
As all the protection stages, the undervoltage function can be blocked with any internal or external signal using the block matrix. For example if the secondary

voltage of one of the measuring transformers disappears because of a fuse failure (See the voltage transformer supervision function in [7.8 Voltage transformer supervision \(ANSI 60FL\)](#) on page 255). The blocking signal can also be a signal from the custom logic (see [5.7 Logic functions](#) on page 85).

### Low-voltage self blocking

The stages can be blocked with a separate low-limit setting. With this setting, the particular stage is blocked when the biggest of the three line-to-line voltages drops below the given limit. The idea is to avoid unwanted tripping when the voltage is switched off. If the operate time is less than 0.08 s, the blocking level setting should not be less than 15% for the blocking action to be fast enough. The self blocking can be disabled by setting the low-voltage block limit equal to zero.

Figure 82 - Example of low-voltage self blocking



- A.** The maximum of the three line-to-line voltages  $V_{LLmax}$  is below the block limit. This is not regarded as an undervoltage situation.
- B.** The voltage  $V_{LLmin}$  is above the block limit but below the start level. This is an undervoltage situation.
- C.** The voltage is OK because it is above the start limit.
- D.** This is an undervoltage situation.
- E.** Voltage is OK.
- F.** This is an undervoltage situation.
- G.** The voltage  $U_{LLmin}$  is under block limit and this is not regarded as an undervoltage situation.
- H.** This is an undervoltage situation.
- I.** Voltage is OK.
- J.** Same as G
- K.** Voltage is OK.

### Three independent stages

There are three separately adjustable stages: 27-1, 27-2 and 27-3. All these stages can be configured for the definite time (DT) operation characteristic.

## Setting groups

There are four setting groups available for all stages.

## Characteristics

Table 49 - Undervoltage (27-1)

Input signal	$V_A - V_C$
Start value	20–120% $V_N$ (step 1%)
Definite time characteristic:	
- Operate time	0.08 <sup>40</sup> – 300.00 s (step 0.02)
Hysteresis (reset ratio)	1.001–1.200 (0.1–20.0%, step 0.1%)
Self-blocking value of the undervoltage	0–80% $V_N$
Start time	Typically 60 ms
Release delay	0.06–300.00 s (step 0.02 s)
Reset time	< 95 ms
Overshoot time	< 50 ms
Reset ratio (Block limit)	0.5 V or 1.03 (3%)
Reset ratio	1.03 (depends on the hysteresis setting)
Inaccuracy:	
- Starting	±3% of the set value
- Blocking	±3% of set value or ±0.5 V
- Operate time	±1% or ±30 ms

<sup>40</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.

Table 50 - Undervoltage (27-2)

Input signal	$V_A - V_C$
Start value	20–120% $V_N$ (step 1%)
Definite time characteristic:	
- Operate time	0.06 <sup>41</sup> – 300.00 s (step 0.02)
Hysteresis (reset ratio)	1.001–1.200 (0.1–20.0%, step 0.1%)
Self-blocking value of the undervoltage	0–80% $V_N$
Start time	Typically 60 ms
Reset time	< 95 ms

Overshoot time	< 50 ms
Reset ratio (Block limit)	0.5 V or 1.03 (3%)
Reset ratio	1.03 (depends on the hysteresis setting)
Inaccuracy:	
- Starting	±3% of the set value
- Blocking	±3% of set value or ±0.5 V
- Operate time	±1% or ±30 ms

<sup>41</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.

Table 51 - Undervoltage (27–3)

Input signal	$V_A - V_C$
Start value	20–120% $V_N$ (step 1%)
Definite time characteristic:	
- Operate time	0.04 <sup>42</sup> – 300.00 s (step 0.01)
Hysteresis (reset ratio)	1.001–1.200 (0.1–20.0%, step 0.1%)
Self-blocking value of the undervoltage	0–80% $V_N$
Start time	Typically 30 ms
Reset time	< 95 ms
Overshoot time	< 50 ms
Reset ratio (Block limit)	0.5 V or 1.03 (3%)
Reset ratio	1.03 (depends on the hysteresis setting)
Inaccuracy:	
- Starting	±3% of the set value
- Blocking	±3% of set value or ±0.5 V
- Operate time	±1% or ±25 ms

<sup>42</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.

## 6.8 Positive sequence undervoltage (ANSI 27P)

This is a special undervoltage protection function for generator applications where the voltage is measured at the generator side of the generator circuit breaker. There are special self-blocking features for starting up and shutting down a generator.

This undervoltage function measures the positive sequence of the fundamental frequency component  $V_1$  of the measured voltages (for calculation of  $V_1$ , see [4.10 Symmetrical components](#) on page 63). By using the positive sequence, all three phases are supervised with one value and if the generator loses the connection

to the network (loss of mains), the undervoltage situation is detected faster than by using just the lowest of the three line-to-line voltages.

Whenever the positive sequence voltage  $V_1$  drops below the start setting of a particular stage, this stage activates and a start signal is issued. If the fault situation remains on longer than the time defined in the operate time delay setting, a trip signal is issued.

### **Blocking during VT fuse failure**

Like all the protection stages, the undervoltage function can be blocked with any internal or external signal using the block matrix, for example, if the secondary voltage of one of the measuring transformers disappears because of a fuse failure (See VT supervision function in [7.8 Voltage transformer supervision \(ANSI 60FL\) on page 255](#)). The blocking signal can also be a signal from the user's logic (see [5.7 Logic functions on page 85](#)).

### **Selfblocking at very low voltage**

The stages are blocked when the voltage is below a separate low-voltage blocking setting. With this setting, LVBlk, both stages are blocked when the voltage  $V_1$  drops below the given limit. The idea is to avoid purposeless alarms when the generator is not running. The LVBlk setting is common for both stages. The selfblocking can not be disabled.

### **Temporary selfblocking at very low currents**

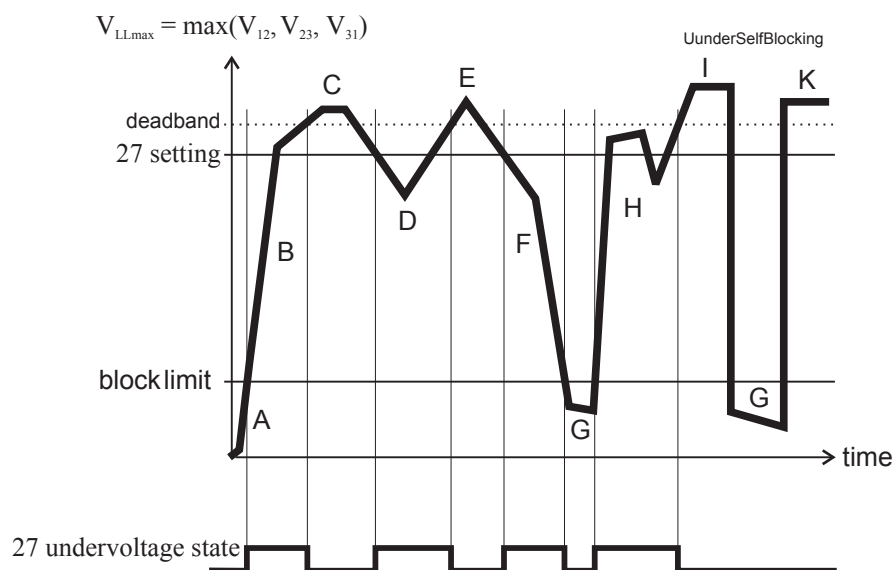
Further the start can be delayed by using the setting I<Blk. When the maximum of the three measured phase currents is less than 1% of the rated generator current, this delay is enabled. The idea is to avoid purposeless alarms, when the generator circuit breaker is open and the excitation is switched off. By setting the delay equal to zero, this feature is disabled.

### **Initial selfblocking**

When the voltage  $V_1$  has been below the block limit, the stages are blocked until the start setting has been reached.

[Figure 83 - Positive sequence undervoltage state and block limit on page 139](#) shows an example of low voltage selfblocking.

Figure 83 - Positive sequence undervoltage state and block limit



- |  |  |
|--|--|
| <p>A The positive sequence voltage <math>V_1</math> is below the block limit. This is not regarded as an undervoltage situation.</p>   | <p>F This is an undervoltage situation.</p>  |
| <p>B The positive sequence voltage <math>V_1</math> is above the block limit but below the start level. However, this is not regarded as an undervoltage situation because the voltage has never been above the start level since being below the block limit.</p> | <p>G The voltage is below the block limit and this is not regarded as an undervoltage situation.</p> |
| <p>C The voltage is OK because it is above the start limit.</p>  | <p>H Same as B.</p>  |
| <p>D This is an undervoltage situation.</p>  | <p>I The voltage is OK.</p>  |
| <p>E The voltage is OK.</p>  | <p>J Same as G.</p>  |
|  | <p>K The voltage is OK.</p>  |

**Two independent stages**

There are two separately adjustable stages: 27P-1 and 27P-2. Both stages can be configured for definite time (DT) operate characteristic.

**Setting groups**

There are four setting groups available for each stage.

**Characteristic**

Table 52 - Positive sequence undervoltage stages 27P-1, 27P-2

Start value	20 – 120% x $V_N$
Definite time function: - Operate time	0.08 <sup>43</sup> – 300.00 s
Undervoltage blocking - Blocking time, when $I < 1\% \times I_{GN}$	2–100% x $V_N$ (common for both stages) 2–100% x $V_{GN}$ (common for both stages) 0–30 s (common for both stages)
Start time	Typically 60 ms
Reset time	<95 ms
Overshoot time	< 50 ms
Reset ratio	1.05
Inaccuracy: - Starting - Operate time	1% unit $\pm 1\%$ or $\pm 30$ ms

<sup>43</sup> This is the instantaneous time i.e. the minimum total operational time including the fault detection time and operate time of the trip contacts.

## 6.9 Directional power (ANSI 32)

**Description**

The directional power function can be used, for example, to disconnect a motor if the supply voltage is lost and thus prevent power generation by the motor. It can also be used to detect loss of load of a motor.

The directional power function is sensitive to active power. For the directional power function, the start value is negative. For the underpower function, a positive start value is used. Whenever the active power goes under the start value, the stage starts and issues a start signal. If the fault situation stays on longer than the delay setting, a trip signal is issued.

The start setting range is from -200% to +200% of the nominal apparent power  $S_N$ . The nominal apparent power is determined by the configured voltage and current transformer values.

Equation 15

$$S_n = VT_{Rated\ Primary} \cdot CT_{Rated\ Primary} \cdot \sqrt{3}$$

There are two identical stages available with independent setting parameters.



### Setting groups

There are four setting groups available for all stages.

### Characteristics

Table 53 - Directional power stages 32-1, 32-2

Input signal	$I_A - I_C$ $V_A - V_C$
Start value	-200.0 to +200.0% $S_N$ (step 0.5)
Definite time function: - Operate time	0.3–300.0 s (step 0.1)
Start time	Typically 200 ms
Reset time	< 500 ms
Reset ratio	1.05
Inaccuracy: - Starting - Operate time at definite time function	- $\pm 3\%$ of set value or $\pm 0.5\%$ of rated value $\pm 1\%$ or $\pm 150$ ms

**NOTE:** When the start setting is +1 to +200% , an internal block is activated if the maximum voltage of all phases drops below 5% of rated.

## 6.10 Loss of field (ANSI 40)

Synchronous machines need some minimum level of excitation to remain stable throughout their load range. If the excitation is too low, the machine may drop out of synchronism. The under-excitation protection protects the generator against the risk of lost of synchronism.

When the generator produces capacitive power, that is when the reactive component of the power phasor is negative, the excitation current can be so low that the synchronism is lost.

This stage supervises the amount of capacitive power. If it exceeds the setting value, a start signal is issued. If the fault continues longer than user's operate delay time setting, a trip signal is issued.

The measurement of the degree of excitation is based on a complex three-phase power vector that is calculated from the fundamental components of the phase currents and line-to-line voltages.

### Trip area on a PQ plane

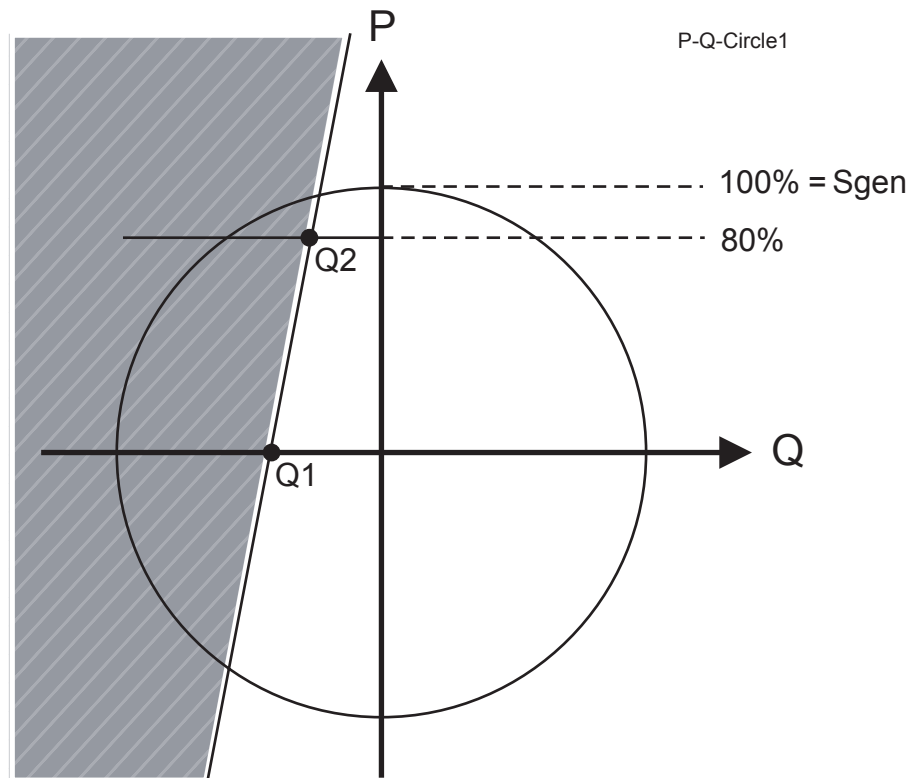
The tripping area of the stage on a PQ plane is defined with two parameters: Q1 and Q2, see [Figure 84 - Trip area on a PQ plane, setting 1 on page 142](#) and [Figure 85 - Trip area on a PQ plane, setting 2 on page 143](#). When the tip of the power phasor lies on the left side of the left side of a straight line drawn through Q1 and Q2 and on the negative side of the P axis, the stage activates.

The P coordinate of the setting point Q1 has a fixed value equal to zero and the Q coordinate is adjustable.

The P coordinate of the setting point Q2 has a fixed value of 80 % of the rated power of the generator and the Q coordinate is adjustable.

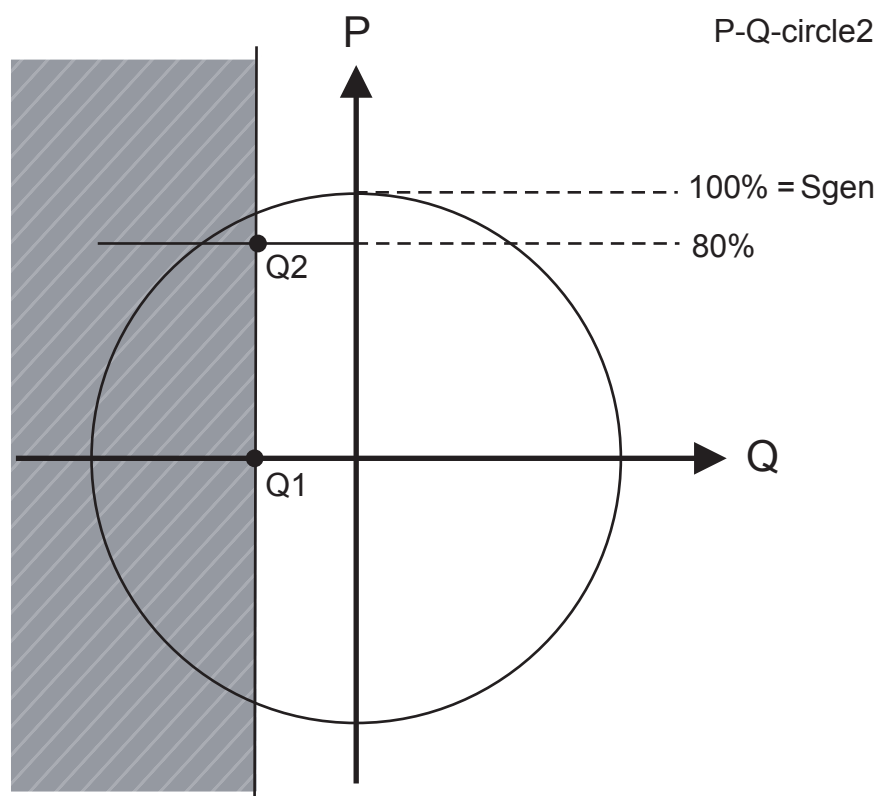
In [Figure 84 - Trip area on a PQ plane, setting 1](#) on page 142, the operation depends on both P and Q because the operating line has an 8° slope (Q1-Q2 = 14 %). The shaded area is the area of operation.

Figure 84 - Trip area on a PQ plane, setting 1



In [Figure 85 - Trip area on a PQ plane, setting 2](#) on page 143, the operation solely depends on the reactive power because the operating line is vertical (Q1-Q2 = 0 %). The shaded area is the area of operation.

Figure 85 - Trip area on a PQ plane, setting 2



### Power swing

A release time setting is available against prolonged power swings. In a power swing situation, the power phasor is swinging back and forth between capacitive and inductive power. With a long enough release time setting, the stage accumulates the total fault time and eventually trips.

### Setting groups

There are two settings groups available. Switching between the setting groups can be controlled by digital inputs, virtual inputs (mimic display, communication, logic) and manually.

## 6.11 Under-reactance (ANSI 21/40)

Synchronous machines need some minimum level of excitation to remain stable throughout their load range. If excitation is lost or is too low, the machine may drop out of synchronism. The under-reactance stages  $X<$  and  $X<<$  are used to make sure that the synchronous machine is working in the stable area.

The protection is based on positive sequence impedance as viewed from the machine terminals. This impedance is calculated using the measured three-line-to-line voltages and phase currents according to the following equation:

Equation 16

$$\bar{Z}_1 = \frac{\bar{V}_1}{\bar{I}_1}$$

 $Z_1$  = positive sequence impedance $V_1$  = positive sequence voltage phasor $I_1$  = positive sequence current phasor

If this impedance goes under the steady state stability limit, the synchronous machine may lose its stability and drop out of synchronism.

### Detecting power swinging

A release time setting is available against prolonged power swings. In a power swing situation, the power phasor is swinging back and forth between capacitive and inductive power. With a long enough release time, the stage accumulates the total fault time and eventually trips.

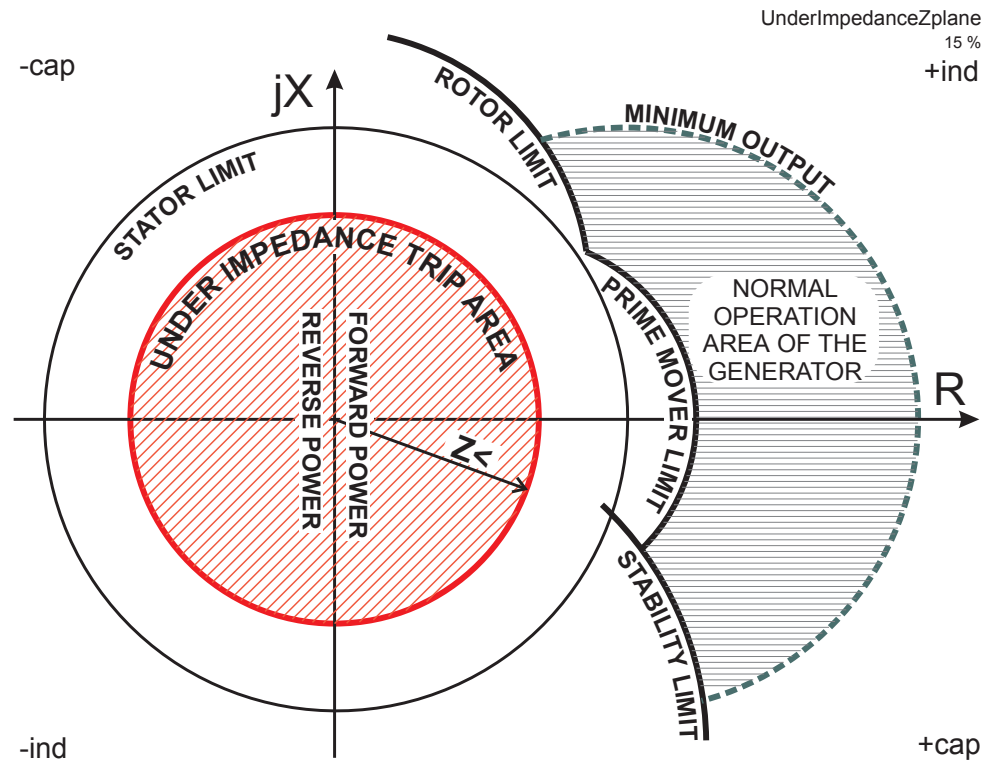
### Undercurrent blocking

When for some reason, the voltage collapses but the currents remain at normal load levels, the calculated impedance may fall into the trip area. Inverted start signal from the most sensitive overcurrent stage can be used to block the under-reactance stages during abnormal voltages not caused by short-circuit faults.

### Characteristic on an impedance plane

The characteristic on an impedance plane is a circle covering the unstable area of the synchronous machine ([Figure 86 - The trip region of loss of excitation stage is a circle covering the unstable area of the generator on page 145](#)). The radius  $X_c$  and centre point [Roffset, Xoffset] of the circle are editable. Whenever the positive sequence impedance goes inside this circle, the stage activates. If the fault stays on longer than the definite time delay setting, the stage issues a trip signal.

Figure 86 - The trip region of loss of excitation stage is a circle covering the unstable area of the generator



The radius  $X_{<}$ ,  $R_{offset}$  and  $X_{offset}$  are the setting parameters. Whenever the positive sequence impedance falls inside the  $X_{<}$  circle, the stage activates.

### Calculating setting values

The machine manufacturer specifies:

$X_d$  = synchronous unsaturated reactance

$X'_d$  = transient reactance for the synchronous machine

The settings for loss of excitation stages can be derived from these machine parameters, but there are many practices to do it. Here is one:

Radius of the circle  $X_{<} = X_d/2$

Resistive offset  $R_{os} = 0.14 (X'_d + X_d/2)$

Reactive offset  $X_{os} = -(X'_d + X_d/2)$

All the settings are per unit.

Equation 17

$$X_{PU} = \frac{X}{Z_N}$$

$X_{PU}$  = Reactance (or resistance) per unit

$X$  = Reactance (or resistance) in ohms

$Z_N$  = Nominal impedance of the machine

Equation 18

$$Z_N = \frac{V_N^2}{S_N}$$

$Z_N$  = Nominal impedance of the machine

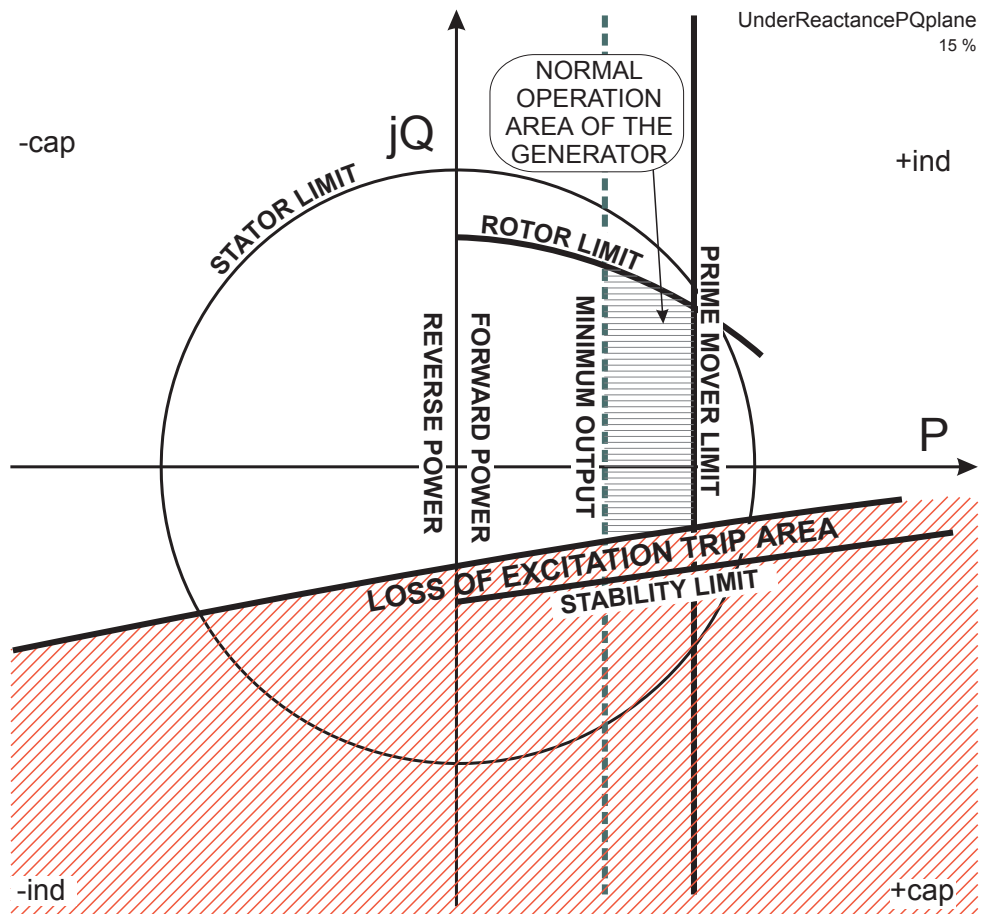
$V_N$  = Nominal voltage of the machine

$S_N$  = Nominal power of the machine

**Characteristic on power plane**

In [Figure 86 - The trip region of loss of excitation stage is a circle covering the unstable area of the generator](#) on page 145, the same characteristics as in the previous figure are drawn on a PQ-power plane assuming a constant voltage of 1 PU. The transformation is  $\underline{S} = V^2/Z^*$ , where V is the voltage and  $Z^*$  is the complex conjugate of impedance Z.

Figure 87 - Loss of excitation characteristic drawn on a power plane



**Two independent under-reactance stages**

There are two separately adjustable stages available:  $X <$  and  $X <<$ .

**Setting groups**

There are four setting groups available for each stage.

## Characteristics

Table 54 - Under-reactance (21/40)

Trip area radius setting range	0.05 – 2.00 x Z <sub>N</sub>
Resistive offset Ros	-2.00 – 2.00 x Z <sub>N</sub>
Reactive offset Xos	-2.00 – 2.00 x Z <sub>N</sub>
Definite time function: - Operating time	0.08 <sup>44</sup> – 300.00 s (step 0.02 s)
Start time	<80 ms
Reset time	0.08 – 300.00 s (step 0.02 s)
Reset ratio	1.05
Inaccuracy: - Starting - Operating time at definite time function	±4 % of set value or ±0.01 x Z <sub>N</sub> ±1 % or ±30 ms

<sup>44</sup> This is the instantaneous time i.e. the minimum total operational time including the fault detection time and operate time of the trip contacts.

## 6.12 Negative sequence overcurrent (ANSI 46)

### Description

Negative sequence overcurrent protects against unbalanced phase currents and single phasing. The protection is based on the negative sequence current. Both definite time and dependent time characteristics are available. The dependent delay is based on [Equation 19 on page 147](#). Only the base frequency components of the phase currents are used to calculate the negative sequence value I<sub>2</sub>.

The negative sequence overcurrent protection is based on the negative sequence of the base frequency phase currents. Both definite time and dependent time characteristics are available.

### Dependent time delay

The dependent time delay is based on the following equation:

Equation 19

$$T = \frac{K_1}{\left(\frac{I_2}{I_{GN}}\right)^2 - K_2^2}$$

T = Operate time

K<sub>1</sub> = Delay multiplier

$I_2$  = Measured and calculated negative sequence phase current of fundamental frequency

$I_{GN}$  = Nominal current of the generator

$K_2$  = Start setting  $I_2 >$  in pu. The maximum allowed degree of unbalance.

**Example**

$K_1 = 15$  s

$I_2 = 22.9\% = 0.229 \times I_{GN}$

$K_2 = 5\% = 0.05 \times I_{GN}$

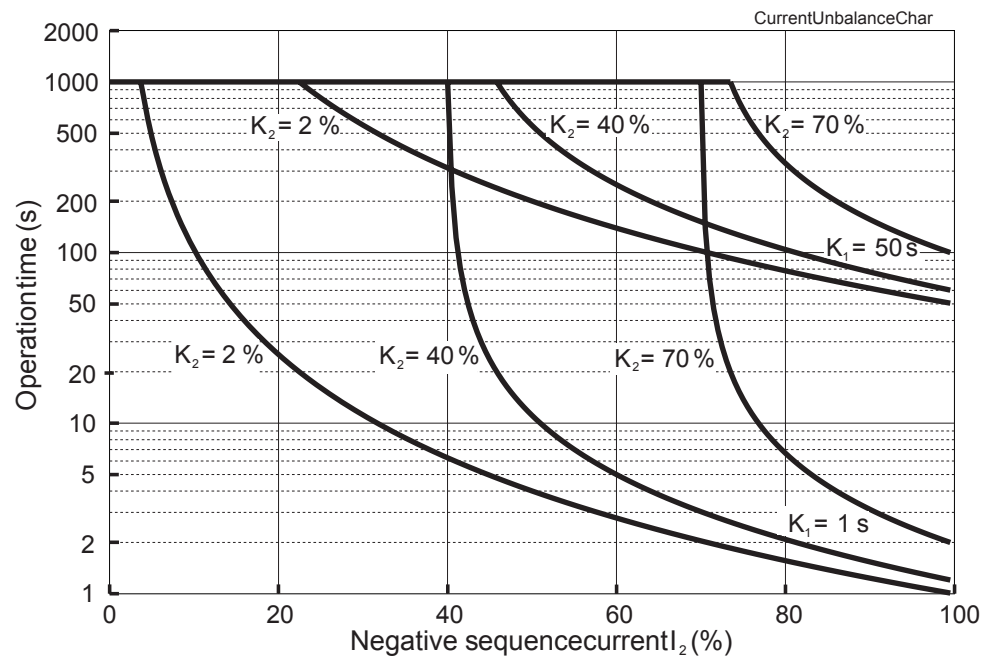
$$t = \frac{15}{\left(\frac{0.229}{1}\right)^2 - 0.05^2} = 300.4$$

The operate time in this example is five minutes.

**More stages (definite time delay only)**

If more than one definite time delay stages are needed for negative sequence overcurrent protection, the freely programmable stages can be used ([6.36 Programmable stages \(ANSI 99\)](#) on page 232).

Figure 88 - Dependent operation delay of negative sequence overcurrent  $I_2 >$  (ANSI 46). The longest delay is limited to 1000 seconds (=16min 40s).



**Setting groups**

There are four setting groups available.



## Characteristics

Table 55 - Negative sequence overcurrent  $I_2 > 46-1$

Input signal	$I_A - I_C$
Start value	2–70% (step 1%)
Definite time characteristic: - Operate time	1.0–600.0 s (step 0.1 s)
Dependent time characteristic: - 1 characteristic curve - Time multiplier - Upper limit for dependent time	Inv 1–50 s (step 1) 1000 s
Start time	Typically 300 ms
Reset time	< 450 ms
Reset ratio	0.95
Inaccuracy: - Starting - Operate time	$\pm 1\%$ - unit $\pm 5\%$ or $\pm 200$ ms

**NOTE:** The stage is operational when all secondary currents are above 250 mA.

## 6.13 Negative sequence overvoltage protection (ANSI 47)

### Description

This protection stage can be used to detect voltage unbalance and phase reversal situations. It calculates the fundamental frequency value of the negative sequence component  $V_2$  based on the measured voltages (for calculation of  $V_2$ , see [4.10 Symmetrical components](#) on page 63).

Whenever the negative sequence voltage  $V_2$  raises above the user's start setting of a particular stage, this stage starts, and a start signal is issued. If the fault situation remains on longer than the user's operate time delay setting, a trip signal is issued.

### Blocking during VT fuse failure

Like all the protection stages, the negative sequence overvoltage can be blocked with any internal or external signal using the block matrix, for example, if the secondary voltage of one of the measuring transformers disappears because of a fuse failure (See VT supervision function in [7.8 Voltage transformer supervision \(ANSI 60FL\)](#) on page 255).

The blocking signal can also be a signal from the user's logic (see [5.7 Logic functions](#) on page 85).

### Three independent stages

There are three separately adjustable stages: 47-1, 47-2, and 47-3. Both stages can be configured for the definite time (DT) operation characteristic.

### Setting groups

There are four settings groups available for all stages. Switching between setting groups can be controlled by digital inputs, virtual inputs (mimic display, communication, logic) and manually.

### Characteristics

Table 56 - Negative sequence overvoltage protection (47)

Start value: 47-1, 47-2, 47-3	2–120%
Operate time	0.08–300 s
Reset ratio	0.95
Inaccuracy:	
- Starting	±1% - unit
- Operate time	±5% or ±200 ms

## 6.14 Thermal overload (ANSI 49 RMS)

### Description

The thermal overload function protects the generator stator windings against excessive temperatures.

### Thermal model

The temperature is calculated using RMS values of phase currents and a thermal model according IEC60255-149. The RMS values are calculated using harmonic components up to the 15th.

Trip time:

$$t = \tau \cdot \ln \frac{I^2 - I_P^2}{I^2 - a^2}$$

Alarm (alarm 60% = 0.6):

$$a = k \cdot k_{\Theta} \cdot I_N \cdot \sqrt{alarm}$$

Trip:

$$a = k \cdot k_{\Theta} \cdot I_N$$

Reset time:

$$t = \tau \cdot C_{\tau} \cdot \ln \frac{I_P^2}{a^2 - I^2}$$

Trip release:

$$a = \sqrt{0.95} \times k \times I_N$$

Start release (alarm 60% = 0.6):

$$a = \sqrt{0.95} \times k \times I_N \times \sqrt{alarm}$$

T = Operate time

$\tau$  = Thermal time constant tau (setting value). Unit: minute

ln = Natural logarithm function

I = Measured RMS phase current (the max. value of three phase currents)

k = Overload factor (Maximum continuous current), i.e. service factor (setting value).

k $\Theta$  = Ambient temperature factor (permitted current due to tamb).

I<sub>p</sub> = Preload current,  $I_p = \sqrt{\theta} \times k \times I_{GN}$  (If temperature rise is 120% ->  $\theta = 1.2$ ). This parameter is the memory of the algorithm and corresponds to the actual temperature rise.

I<sub>GN</sub> = The rated current of the generator

C<sub>τ</sub> = Relay cooling time constant (setting value)

### Time constant for cooling situation

Cooling time constant C<sub>τ</sub> parameter is used to indicate how quickly the protected object can cool down in the application. This parameter become active when current is less than 0.3 x I<sub>GN</sub>.

### Heat capacitance, service factor and ambient temperature

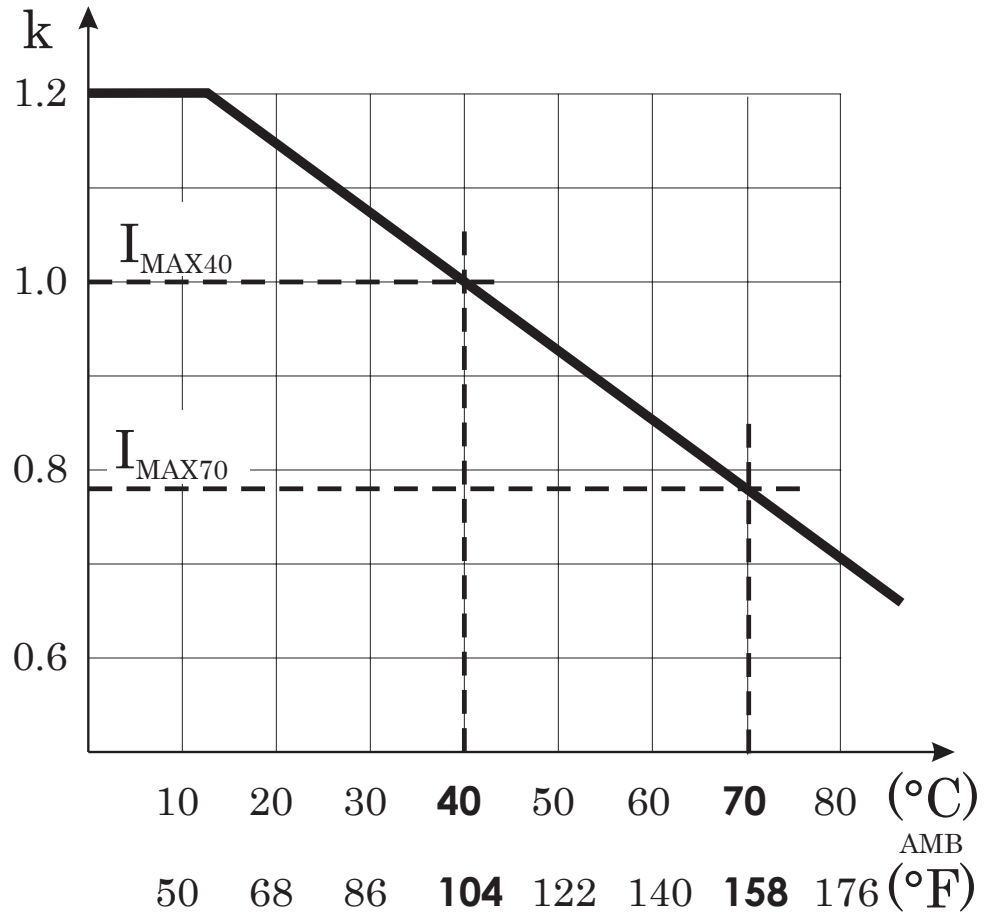
The trip level is determined by the maximum allowed continuous current I<sub>MAX</sub> corresponding to the 100% temperature rise  $\Theta_{TRIP}$  for example the heat capacitance of the generator. I<sub>MAX</sub> depends of the given service factor k and ambient temperature  $\Theta_{AMB}$  and settings I<sub>MAX40</sub> and I<sub>MAX70</sub> according the following equation.

$$I_{MAX} = k \cdot k_{\Theta} \cdot I_N$$

The value of ambient temperature compensation factor k $\Theta$  depends on the ambient temperature  $\Theta_{AMB}$  and settings I<sub>MAX40</sub> and I<sub>MAX70</sub>. See [Figure 89 - Ambient temperature correction of the overload stage T>](#) on page 152. Ambient temperature is not in use when k $\Theta$  = 1. This is true when

- I<sub>MAX40</sub> is 1.0
- Samb is "n/a" (no ambient temperature sensor)
- $\Theta_{AMB}$  is +40 °C.

Figure 89 - Ambient temperature correction of the overload stage T>



**Example of the thermal model behavior**

[Figure 89 - Ambient temperature correction of the overload stage T>](#) on page 152

shows an example of the thermal model behavior. In this example,  $\tau = 30$  minutes,  $k = 1.06$  and  $k\Theta = 1$  and the current has been zero for a long time and thus the initial temperature rise is 0%. At time = 50 minutes, the current changes to  $0.85 \times I_{GN}$  and the temperature rise starts to approach value  $(0.85/1.06)^2 = 64\%$  according to the time constant. At time = 300 min, the temperature is nearly stable, and the current increases to 5% over the maximum defined by the rated current and the service factor  $k$ . The temperature rise starts to approach value 110%. At about 340 minutes, the temperature rise is 100% and a trip follows.

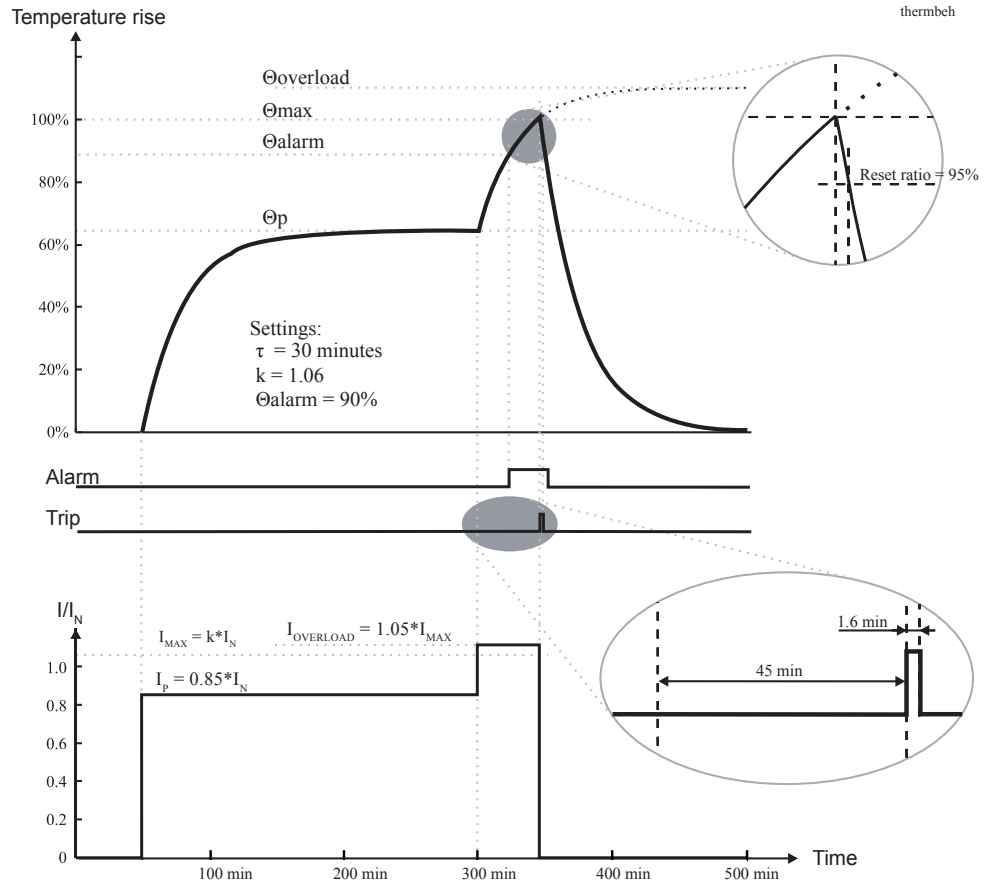
**Initial temperature rise after restart**

When the relay is switched on, an initial temperature rise of 70% is used. Depending on the actual current, the calculated temperature rise then starts to approach the final value.

**Alarm function**

The thermal overload stage is provided with a separately settable alarm function. When the alarm limit is reached, the stage activates its start signal.

Figure 90 - Example of the thermal model behavior



**Setting groups**

This stage has one setting group.

**Characteristics**

Table 57 - Thermal overload (49G)

Input signal	$I_A - I_C$
Maximum continuous current	$0.1-2.40 \times I_{GN}$
Alarm setting range	60–99% (step 1%)
Time constant $\tau$	2–180 min (step 1)
Cooling time coefficient	$1.0-10.0 \times \tau$ (step 0.1)
Max. overload at +40°C	70–120 % $I_{GN}$ (step 1)
Max. overload at +70°C	50–100 % $I_{GN}$ (step 1)
Ambient temperature	-55 – 125°C (step 1°)

Reset ratio (Start & trip)	0.95
Operate time inaccuracy	Relative inaccuracy $\pm 5\%$ or absolute inaccuracy 1 s of the theoretical value

## 6.15 Breaker failure 1 (ANSI 50BF)

### Description

The circuit breaker failure protection stage (CBFP) can be used to operate any upstream circuit breaker (CB) if the programmed output matrix signals, selected to control the main breaker, have not disappeared within a given time after the initial command. The supervised output contact is defined by the “Monitored Trip Relay” setting. An alternative output contact of the relay must be used for this backup control selected in the **Output matrix** setting view.

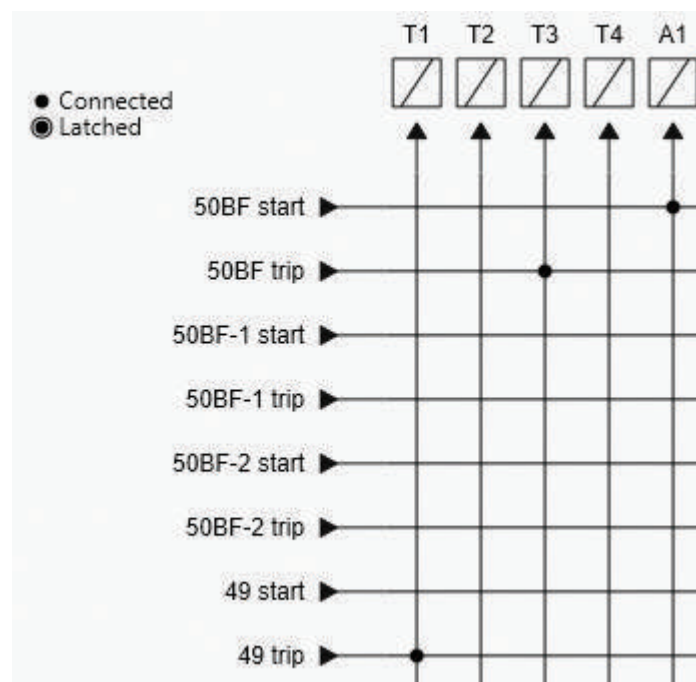
The CBFP operation is based on the supervision of the signal to the selected output contact and the time. The following output matrix signals, when programmed into use, start the CBFP function:

- protection functions
- control functions
- supporting functions
- GOOSE signals (through communication)

If the signal is longer than the CBFP stage’s operate time, the stage activates another output contact defined in the **Output matrix** setting view. The output contact remains activated until the signal resets. The CBFP stage supervises all the signals assigned to the same selected output contact.

In [Figure 91 - Trip and CBFP start signals in the Output matrix setting view](#) on page 155, both the trip and CBFP start signals activate simultaneously (left picture). If T> trip fails to control the CB through T1, the CBFP activates T3 after the breaker failure operate time.

Figure 91 - Trip and CBFP start signals in the Output matrix setting view



**NOTE:** For the CBFP, always select the "Connected" crossing symbol in the **Output matrix** setting view.

### Characteristics

Table 58 - Breaker failure (50BF)

Relay to be supervised	T1–T4 (depending on the order code)
Definite time function:	
- Operate time	0.1–10.0 s (step 0.1 s)
Inaccuracy:	
- Operate time	±20 ms

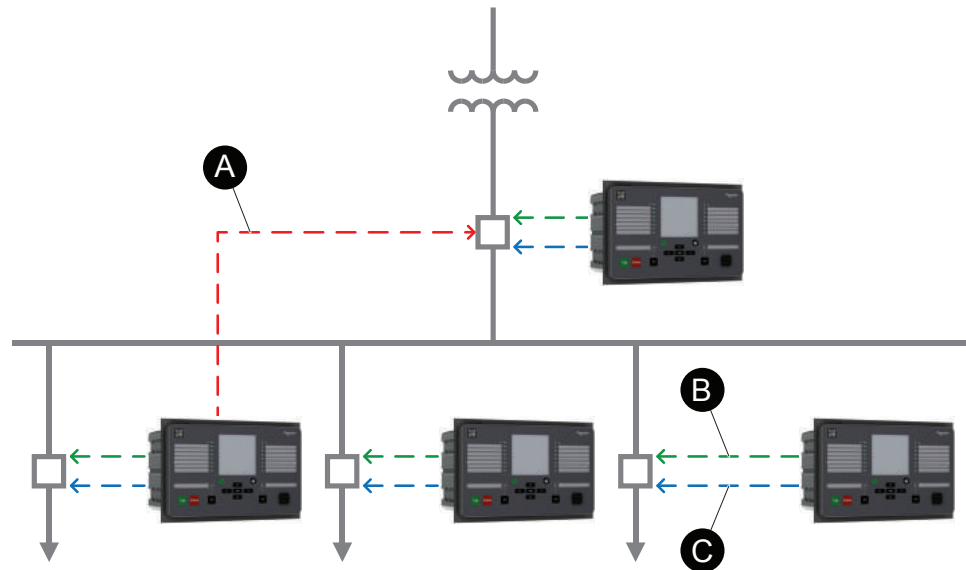
## 6.16 Breaker failure 2 (ANSI 50BF)

### Description

Power system protection should always have some sort of backup protection available. Backup protection is intended to operate when a power system fault is not cleared or an abnormal condition is not detected in the required time because of a failure or the inability of the primary protection to operate or failure of the appropriate circuit breakers to trip. Backup protection may be local or remote.

Circuit breaker failure protection (CBFP) is part of the local backup protection. CBFP provides a backup trip signal to an upstream circuit breaker (CB) when the CB nearest to fault fails to clear fault current. The CB may fail to operate for several reasons, for example burnt open coil or a flashover in the CB.

Figure 92 - CBFP implementation

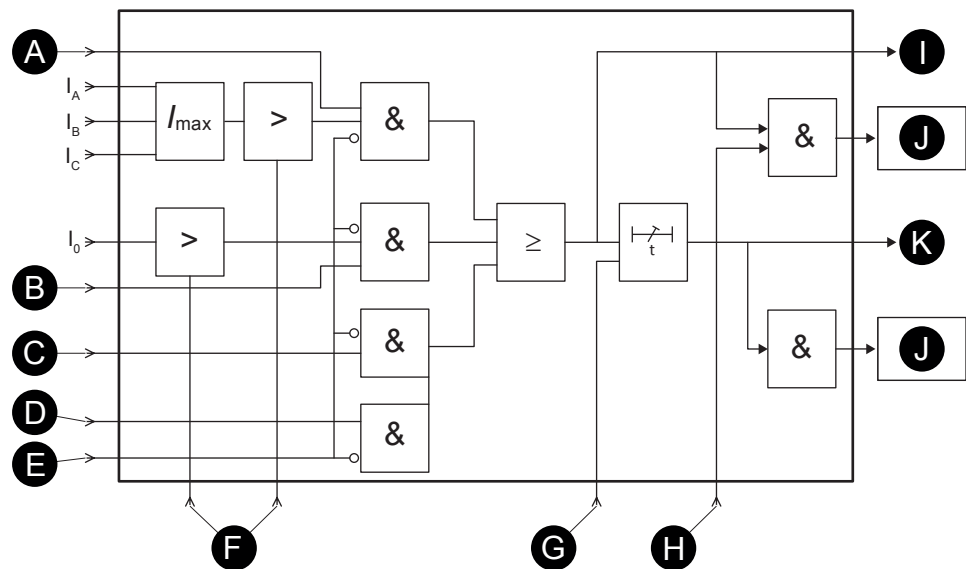


- A. CBFP trip
- B. Normal trip
- C. Re-trip

Two separate stages are provided to enable re-trip and CBFP trip commands. The first stage can be used to give re-trip command (for example to control second/backup open coil of the main CB) while the second stage can give dedicated CBFP trip command to an upstream circuit breaker. Select the required outputs for re-trip and CBFP trip through the output matrix.

**Block diagram**

Figure 93 - Breaker failure 2 operation





<b>A.</b> Condition 1	<b>G.</b> Delay setting
<b>B.</b> Condition 2	<b>H.</b> Enable events setting
<b>C.</b> Condition 3	<b>I.</b> Start
<b>D.</b> Condition 4	<b>J.</b> Event register
<b>E.</b> Block	<b>K.</b> Trip
<b>F.</b> Zero-current setting	

### CBFP operation

The CBFP function can be enabled and disabled with the **Enable for BF2** selection. The CBFP function activates when any of the selected start signals becomes and stays active.

The CBFP operation can be temporarily blocked by the stage block signal from the block matrix. When the stage is blocked by the block signal, the stage timer stops but it does not reset. The stage timer continues its operation when the block signal is disabled. When the block signal is active, the stage output signals are disabled.

The CBFP stage provides the following events:

- start on
- start off
- trip on
- trip off

Events can be activated via the **Enable events** setting view.

### Condition selectors

The CBFP function has four condition selectors that can be used separately or all together to activate and reset the CBFP function.

The four condition selectors are almost identical. The only difference is that condition selectors 1 and 2 are for all protection functions that benefit from zero-current detection for resetting the CBFP as described in section [Zero-current detector on page 159](#), and selectors 3 and 4 are for all the protection functions that do not benefit from zero-current detection for CBFP.

Condition selector 4 can be used to support selectors 1, 2 and 3. For example, if there are too many stages to be monitored in condition set 1, condition selector 4 can be used to monitor the output contacts. Monitoring digital inputs is also possible if the backup protection is based on external current relay, for example. The only CBFP reset criteria for condition set 4 are the monitored input and output signals.

Figure 94 - Start signal and reset condition setting view for Condition 1

**Condition 1**

State: inactive

Enable monitoring:

Monitored protection stage:

Monitored protection stage:

Monitored protection stage:

Monitored protection stage:

Monitored protection stage:

Monitored protection stage:

---

**Reset condition 1**

Reset by CB status:

Reset by monitored stage:

Reset by zero current:

Separate zero-current detection with dedicated start settings exists for phase overcurrent and ground fault overcurrent signals. Zero-current detection is independent of the protection stages.

The condition criteria, available signals and reset conditions are listed in [Table 59 - CBFP condition selectors](#) on page 158.

**NOTE:** The start signal can be selected for each condition in advance from the pull-down menu even if the concerned stage is not enabled. For the CBFP activation, the concerned stage must be enabled from the protection stage menu and the stage has to start to activate the CBFP start signal.

Table 59 - CBFP condition selectors

Criteria	Start signal	Reset condition
Condition 1	50/51-1, 50/51-2, 50/51-3, 37, 46, 87M-1, 87M-2, 67-1, 67-2, 67-3, 67-4, 49RMS, 68F2, 21/40-1, 21/40-2, 68F5, SOTF	<b>Reset by CB status:</b> DI1 – DIx (1, F1, F2, VI1-20, VO1–20, GOOSE_NI1–64, POC1–16, Obj1-8Op <b>Monitored stage:</b> On/Off
Condition 2	50N/51N-1, 50N/51N-2, 50N/51N-3, 50N/51N-4, 50N/51N-5, 67N-1, 67N-2, 67N-3	<b>Zero-current detection:</b> On/Off

Criteria	Start signal	Reset condition
Condition 3	64S, 59-1, 59-2, 59-3, 27-1, 27-2, 27-3, 27P-1, 27P-2, 59N-1, 59N-2, 32-1, 32-2, 40, 21G-1, 21G-2, Pgr1-8, 81U-1, 81U-2, 81-1, 81-2, 81R, 24, Pslip	<b>Reset by CB status:</b> DI1 – DIx (1, F1, F2, VI1-20, VO1–20, GOOSE_NI1–64, POC1–16, Obj1-8Op <b>Monitored stage:</b> On/Off
Condition 4	Outputs: A1, T1-Tx (1 Inputs: DI1 – DIx (1, F1, F2, VI1-20, VO1 – 20, GOOSE_NI1 – 64, POC1 – 16 Arc sensor 3- 10, ArcStg1-8, I>int, Io>int	

In addition to the selection of the start signal, the CBFP reset condition needs to be selected.

If no reset conditions are selected, the stage uses **Reset by monitored stage** as the reset condition. This prevents a situation where the stage never releases.

The reset condition **Reset by CB status** is useful if the current is already zero when the CB is opened (for example unloaded CB).

When more than one selection criteria are selected, AND condition is used, for example “zero current detection” AND “object open”. See [Figure 93 - Breaker failure 2 operation](#) on page 156 for details.

### Stage timer

The operate delay timer is started by a signal activated by the monitored stages (condition selectors). The operate time delay is a settable parameter. When the given time delay has elapsed, the stage provides a trip signal through the output matrix and the event codes.

The timer delay can be set between 40 and 200 ms.

### Zero-current detector

The zero-current detector is an undercurrent condition to reset the CBFP function when all phase currents are below the start (pick-up) setting value. This separate undercurrent condition is needed to properly detect successful CB operation. For example, in a CB failure condition where one or more CB poles are partly conducting when the CB is open, the fault current can be small enough to reset the primary protection stage (for example overcurrent stage), in which case the CBFP does not operate. When a separate undercurrent limit is used, CBFP reset can be performed only when the fault current really is zero or near zero instead of relying on the protection stage reset.

Figure 95 - Zero-current detector setting view

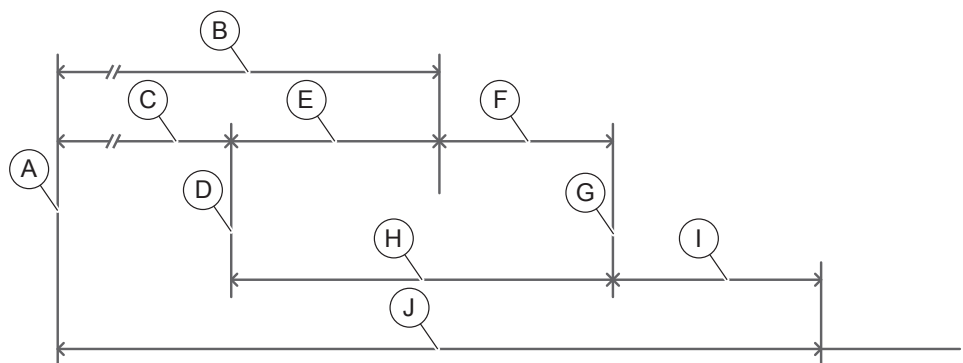
Enable for 50BF-2 <input checked="" type="checkbox"/>		
Status	-	
Start counter	0	Clear
Trip counter	0	Clear
<b>Zero current detection</b>		
Max. of IA IB IC	0	A
Pick-up setting	40	A
Pick-up setting	<input type="range" value="0.10"/>	0.10 xIn
<b>Zero E-F current detection</b>		
IN-1 residual current	0.000	pu
IN input	IN-1	
Pick-up setting	2.50	A
Pick-up setting	<input type="range" value="0.050"/>	0.050 pu

The setting range of the zero-current detector is always associated with the CT nominal value, even in case of motor and transformer protection. The setting range minimum depends on the relay accuracy. Instead of zero, a small minimum value can be accepted. See [Table 60 - Breaker failure 2 \(ANSI 50BF\)](#) on page 161.

**CBFP coordination**

The CBFP delay setting has to be coordinated according to the CB operation time and the reset time of protection stages monitored by the CBFP function as described in [Figure 96 - CBFP coordination](#) on page 160.

Figure 96 - CBFP coordination



- A. Fault occurrence

---

- B. Normal fault clearing time

---

- C. Protection delay

---

- D. CBFP stage start

---

- E. CB operate time

---

- F. Protection stage reset time + safety margin

---

- G. CBFP trip

---

- H. CBFP stage operate delay (CB operate time + protection stage reset time + safety margin)

---

- I. CB operate time

---

- J. Total fault clearing time in case of failed CB operation but successful CBFP operation

### Characteristics

Table 60 - Breaker failure 2 (ANSI 50BF)

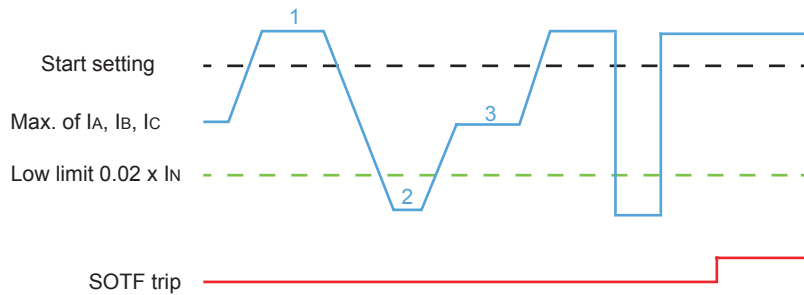
Zero-current detection:	
- Phase overcurrent	0.05–0.2 x $I_n$
- Ground fault overcurrent	0.005–20 x p.u.
Definite time function:	
- Operate time	0.04–0.2 s
Inaccuracy:	
- Operate time	±20 ms

## 6.17 Switch-on-to-fault (ANSI 50HS)

### Description

The switch-on-to-fault (SOTF) protection function offers fast protection when the circuit breaker (CB) is closed manually against a faulty line. Overcurrent-based protection does not clear the fault until the intended time delay has elapsed. SOTF gives a trip signal without additional time delay if the CB is closed and a fault is detected after closing the CB.

Figure 97 - Switch-on-to-fault function operates when the CB has detected open and the fault current reaches start setting value



1. Switch-on-to-fault does not activate if the CB has not been in open position before the fault. Open CB detection is noticed from the highest phase current value which has to be under a fixed low-limit threshold ( $0.02 \times I_N$ ). Opening of the CB can be detected also with digital inputs (Dead line detection input = DI1 – DIx, V11 – V1x). The default detection input is based on the current threshold, so the dead line detection input parameter has value “–“.
2. Dead line detection delay defines how long the CB has to be open so that the SOTF function is active. If the set time delay is not fulfilled and the highest phase current value (maximum of  $I_A$ ,  $I_B$ ,  $I_C$ ) rises over the start setting, the SOTF does not operate.
3. If the highest phase current value of  $I_A$ ,  $I_B$ ,  $I_C$  goes successfully under the low limit and rises to a value between the low limit and the start value, then if the highest phase current value rises over the start setting value before the set SOTF active after CB closure time delay has elapsed, the SOTF trips. If this time delay is exceeded, the SOTF does not trip even if the start setting value is exceeded.

**Setting groups**

This stage has one setting group.

**Characteristics**

Table 61 - Switch-on-to-fault SOTF (50HS)

Start value	1.00–3.00 x $I_N$ (step 0.01)
Dead line detection delay	0.00–60.00 s (step 0.01)
SOTF active after CB closure	0.10–60.00 s (step 0.01)
Operate time	< 30 ms (When $I_M/I_{SET}$ ratio > 1.5)
Reset time	< 95 ms
Reset ratio	0.97
Inaccuracy	±3% of the set value or 5 mA secondary

## 6.18 Phase overcurrent (ANSI 50/51)

### Description

Phase overcurrent protection is used against short-circuit faults and heavy overloads.

The overcurrent function measures the fundamental frequency component of the phase currents. The protection is sensitive to the highest of the three phase currents. Whenever this value exceeds the user's start setting of a particular stage, this stage starts and a start signal is issued. If the fault situation remains on longer than the operation delay setting, a trip signal is issued.

### Block diagram

Figure 98 - Block diagram of the three-phase overcurrent stage 50/51-1

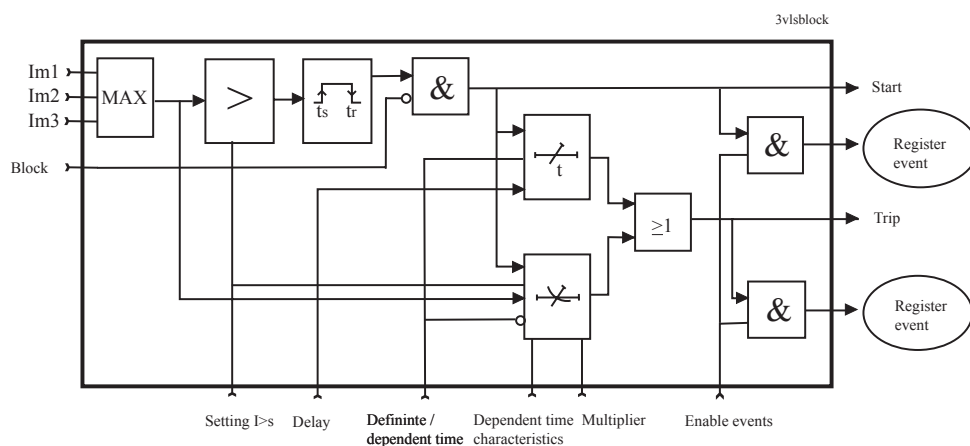
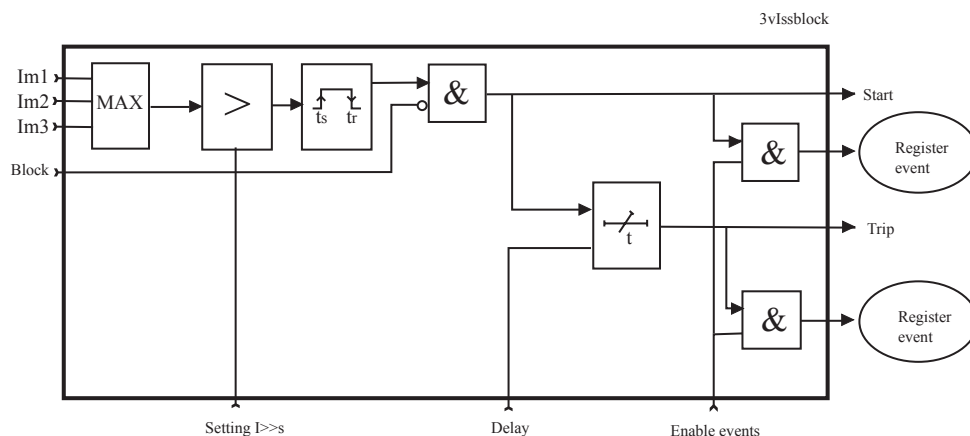


Figure 99 - Block diagram of the three-phase overcurrent stage 50/51-2 and 50/51-3



### Three independent stages

There are three separately adjustable overcurrent stages: 50/51-1, 50/51-2 and 50/51-3. The first stage 50/51-1 can be configured for definite time (DT) or dependent operate time (IDMT) characteristic. The stages 50/51-2 and 50/51-3 have definite time operation characteristic. By using the definite delay type and

setting the delay to its minimum, an instantaneous (ANSI 50) operation is obtained.

[Figure 98 - Block diagram of the three-phase overcurrent stage 50/51-1](#) on page 163 shows a functional block diagram of the 50/51-1 overcurrent stage with definite time and dependent time operate time. [Figure 99 - Block diagram of the three-phase overcurrent stage 50/51-2 and 50/51-3](#) on page 163 shows a functional block diagram of the 50/51-2 and 50/51-3 overcurrent stages with definite time operation delay.

### Dependent operate time

Dependent operate time means that the operate time depends on the amount the measured current exceeds the start setting. The bigger the fault current is, the faster is the operation. The dependent time delay types are described in [6.3 Dependent operate time](#) on page 108. The relay shows the currently used dependent operate time curve graph on the local panel display.

### Dependent time limitation

The maximum measured secondary current is  $50 \times I_N$ . This limits the scope of *dependent curves* with high start settings. See [6.3 Dependent operate time](#) on page 108 for more information.

### Include harmonics setting

The 50/51-1 and 50/51-2 (50/51) overcurrent protection stages have a setting parameter to include harmonics. When this setting is activated, the overcurrent stage calculates the sum of the base frequency and all measured harmonics. This feature is used to determine the signal's true root mean square value to detect the signal's real heating factor. The operate time is 5 ms more when harmonics are included in the measurement. Activate the "Include harmonics" setting if the overcurrent protection is used for thermal protection and the content of the harmonics is known to exist in the power system.

### Cold load and inrush current handling

See [7.3 Cold load start and magnetizing inrush](#) on page 242.

### Setting groups

There are four setting groups available for each stage.

### Characteristics

Table 62 - Phase overcurrent stage 50/51-1 (50/51)

Input signal	$I_A - I_C$
Start value	$0.05 - 5.00 \times I_{GN}$ (step 0.01)
Definite time function: - Operate time	DT <sup>45</sup> 0.04–300.00 s (step 0.01 s)



IDMT function: - Delay curve family - Curve type - Inv. time coefficient k - RI curve	(DT), IEC, IEEE, RI Prg EI, VI, NI, LTI, MI..., depends on the family <sup>46</sup> 0.025–20.0 0.025–20.0
Start time	Typically 35 ms
Reset time	< 95 ms
Overshoot time	< 50 ms
Reset ratio	0.97
Transient overreach, any $\tau$	< 10%
Inaccuracy: - Starting - Operate time at definite time function - Operate time at IDMT function	$\pm 3\%$ of the set value or 5 mA secondary $\pm 1\%$ or $\pm 25$ ms $\pm 5\%$ or at least $\pm 25$ ms**

<sup>45</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.

<sup>46</sup> EI = Extremely Inverse, NI = Normal Inverse, VI = Very Inverse, LTI = Long Time Inverse, MI = Moderately Inverse

Table 63 - Phase overcurrent stage 50/51-2 (50/51)

Input signal	$I_A - I_C$
Start value	0.10 – 20.00 x $I_{GN}$ (step 0.01)
Definite time function: - Operate time	DT <sup>47</sup> 0.04 – 1800.00 s (step 0.01 s)
Start time	Typically 35 ms
Reset time	< 95 ms
Overshoot time	< 50 ms
Reset ratio	0.97
Transient overreach, any $\tau$	< 10%
Inaccuracy: - Starting - operate time	$\pm 3\%$ of the set value or 5 mA secondary $\pm 1\%$ or $\pm 25$ ms

<sup>47</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.

Table 64 - Phase overcurrent stage 50/51-3 (50/51)

Input signal	$I_A - I_C$
Start value	$0.10 - 40.00 \times I_{GN}$ (step 0.01)
Definite time function: - Operate time	DT <sup>48</sup> 0.03–300.00 s (step 0.01 s)
Instant operate time: $I_M / I_{SET}$ ratio > 1.5 $I_M / I_{SET}$ ratio 1.03 – 1.5	<30 ms < 50 ms
Start time	Typically 20 ms
Reset time	< 95 ms
Overshoot time	< 50 ms
Reset ratio	0.97
Inaccuracy: - Starting - Operate time DT ( $I_M/I_{SET}$ ratio > 1.5) - Operate time DT ( $I_M/I_{SET}$ ratio 1.03 – 1.5)	$\pm 3\%$ of the set value or 5 mA secondary $\pm 1\%$ or $\pm 15$ ms $\pm 1\%$ or $\pm 25$ ms

<sup>48</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.

## 6.19 Ground fault overcurrent (ANSI 50N/51N)

### Description

The purpose of the nondirectional ground fault overcurrent protection is to detect ground faults in low-impedance grounded networks. In high-impedance grounded networks, compensated networks and isolated networks, nondirectional ground fault overcurrent can be used as backup protection.

The nondirectional ground fault overcurrent function is sensitive to the fundamental frequency component of the ground fault overcurrent  $3I_N$ . The attenuation of the third harmonic is more than 60 dB. Whenever this fundamental value exceeds the start setting of a particular stage, this stage starts and a start signal is issued. If the fault situation remains on longer than the operate time delay setting, a trip signal is issued.

**Block diagram**

Figure 100 - Block diagram of the ground fault stage overcurrent 50N/51N-1

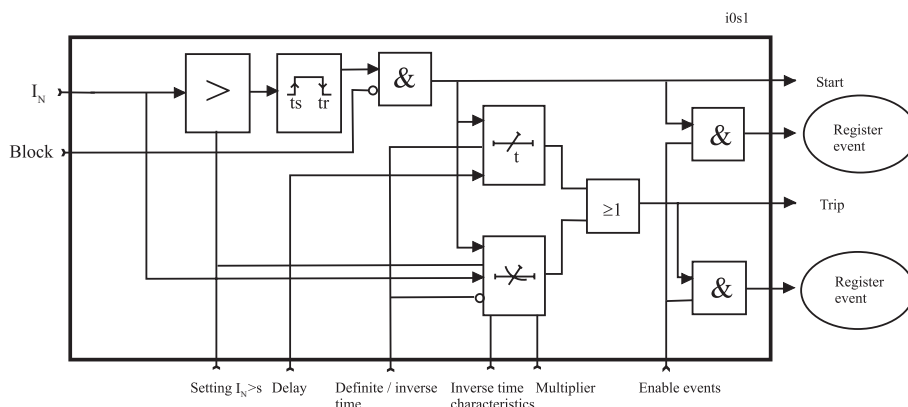
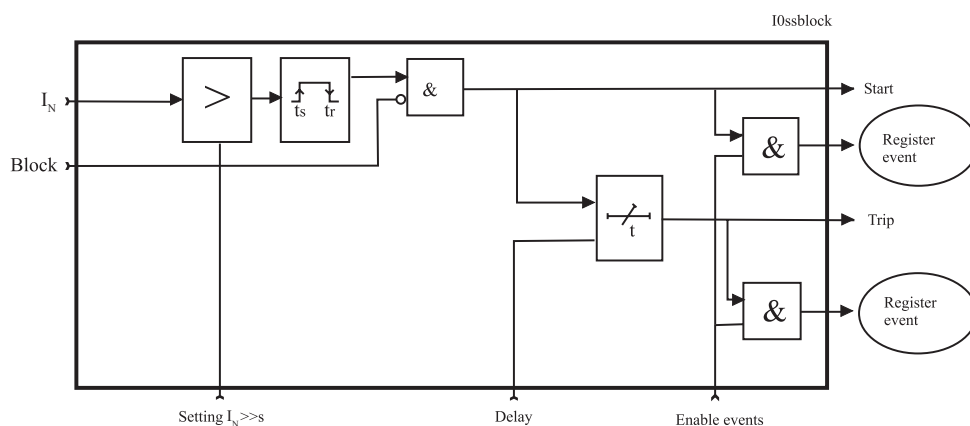


Figure 101 - Block diagram of the ground fault stages overcurrent 50N/51N-2, 50N/51N-3, 50N/51N-4



**Input signal selection**

Each stage can be connected to supervise any of the following inputs and signals:

- Input  $I_{N1}$  for all networks other than solidly grounded.
- Input  $I_{N2}$  for all networks other than solidly grounded.
- Calculated signal  $I_{N\text{Calc}}$  for solidly and low-impedance grounded networks.  $I_{N\text{Calc}} = I_A + I_B + I_C$ .

**Four or six independent nondirectional ground fault overcurrent stages**

There are four separately adjustable ground fault overcurrent stages: 50N/51N-1, 50N/51N-2, 50N/51N-3, and 50N/51N-4. The first stage 50N/51N-1 can be configured for definite time (DT) or dependent time operation characteristic (IDMT). The other stages have definite time operation characteristic. By using the definite delay type and setting the delay to its minimum, an instantaneous (ANSI 50N) operation is obtained.

**Five or eight independent nondirectional ground fault overcurrent stages**

There are five separately adjustable ground fault overcurrent stages: 50N/51N-1, 50N/51N-2, 50N/51N-3, 50N/51N-4 and 50N/51N-5. The first stage 50N/51N-1 can be configured for definite time (DT) or dependent time operation characteristic (IDMT). The other stages have definite time operation characteristic. By using the definite delay type and setting the delay to its minimum, an instantaneous (ANSI 50N) operation is obtained.

Using the directional ground fault overcurrent stages ([6.27 Directional ground fault overcurrent \(ANSI 67N\) on page 197](#)) in nondirectional mode, three more stages with dependent operate time delay are available for nondirectional ground fault overcurrent protection.

**Dependent time limitation**

The maximum measured secondary ground fault overcurrent is  $10 \times I_{0N}$  and the maximum measured phase current is  $50 \times I_N$ . This limits the scope of dependent curves with high start settings.

**Setting groups**

There are four setting groups available for each stage.

**Characteristics**

Table 65 - Ground fault overcurrent 50N/51N-1 (50N/51N)

Input signal	$I_{N1}, I_{N2}$ $I_{N\text{ Calc}} = (I_A + I_B + I_C)$
Start value	0.005–8.00 pu (when $I_{N1}$ or $I_{N2}$ ) (step 0.001) 0.005–20.0 pu (when $I_{N\text{ Calc}}$ )
Definite time function: - Operate time	DT <sup>49</sup> 0.04 <sup>49</sup> –300.00 s (step 0.01 s)
IDMT function: - Delay curve family - Curve type - Inv. time coefficient k	(DT), IEC, IEEE, RI Prg EI, VI, NI, LTI, MI..., depends on the family <sup>50</sup> 0.025–20.0, except 0.50–20.0 for RXIDG, IEEE and IEEE2
Start time	Typically 30 ms
Reset time	< 95 ms

Reset ratio	0.95
Inaccuracy:	
- Starting	±2% of the set value or ±0.3% of the rated value
- Starting (Peak mode)	±5% of the set value or ±2% of the rated value (Sine wave <65 Hz)
- Operate time at definite time function	±1% or ±25 ms
- Operate time at IDMT function	±5% or at least ±25 ms <sup>49</sup>

<sup>49</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.

<sup>50</sup> EI = Extremely Inverse, NI = Normal Inverse, VI = Very Inverse, LTI = Long Time Inverse, MI = Moderately Inverse

Table 66 - Ground fault overcurrent 50N/51N-2, 50N/51N-3, 50N/51N-4 (50N/51N)

Input signal	$I_{N1}, I_{N2}$ $I_{N \text{ Calc}} = (I_A + I_B + I_C)$
Start value	0.01–8.00 pu (When $I_{N1}$ or $I_{N2}$ ) (step 0.01) 0.005–20.0 pu (When $I_{N \text{ Calc}}$ ) (step 0.01)
Definite time function:	
- Operate time	0.04 <sup>51</sup> – 300.00 s (step 0.01 s)
Start time	Typically 30 ms
Reset time	<95 ms
Reset ratio	0.95
Inaccuracy:	
- Starting	±2% of the set value or ±0.3% of the rated value
- Starting (Peak mode)	±5% of the set value or ±2% of the rated value (Sine wave <65 Hz)
- Operate time	±1% or ±25 ms

<sup>51</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.

### 6.19.1 Ground fault phase detection

The ground fault overcurrent stage (ANSI 50N/51N) and directional ground fault overcurrent stage (ANSI 67N) have an inbuilt detection algorithm to detect a faulty phase. This algorithm is meant to be used in radial-operated distribution networks. The faulty phase detection can be used in solidly-grounded, impedance-grounded or resonant-grounded networks.

### Operation

The faulty phase detection starts from the ground fault stage trip. At the moment of stage start, the phase currents measured prior to start are registered and stored as prior-to-fault currents. At the moment of trip, phase currents are registered again. Finally, faulty phase detection algorithm is performed by comparing prior-to-fault currents to fault currents. The algorithm also uses positive sequence current and negative sequence current to detect faulty phase.

The detection algorithm can be enabled and disabled by selecting or unselecting a checkbox in the protection stage settings. Correct network grounding configuration must be selected in the stage settings, too. In the ground fault overcurrent stage settings, you can select between RES and CAP network grounding configuration. This selection has no effect on the protection itself, only on the faulty phase detection. In the directional ground fault overcurrent stage settings, the detection algorithm uses the same network grounding type as selected for protection. RES is used for solidly-grounded, impedance-grounded and resonant-grounded networks. CAP is only used for isolated networks.

The detected faulty phase is registered in the protection stage fault log (and also in the event list and alarm screen). Faulty phase is also indicated by a line alarm and line fault signals in the output matrix.

Possible detections of faulty phases are A-N, B-N, C-N, AB-N, AC-N, BC-N, ABC-N, and REV. If the relay protection coordination is incorrect, REV indication is given in case of a relay sympathetic trip to a reverse fault.

## 6.20 Capacitor bank unbalance (ANSI 51C)

**NOTE:** Configure the capacitor bank unbalance protection through the ground fault overcurrent stages 50N/51N-3 and 50N/51N-4.

### Description

The relay enables capacitor, filter and reactor bank protection with its five current measurement inputs. The fifth input is typically useful for unbalance current measurement of a double-wye connected ungrounded bank.

The unbalance protection is highly sensitive to internal faults of a bank because of the sophisticated natural unbalance compensation. The location method enables easy maintenance monitoring for a bank.

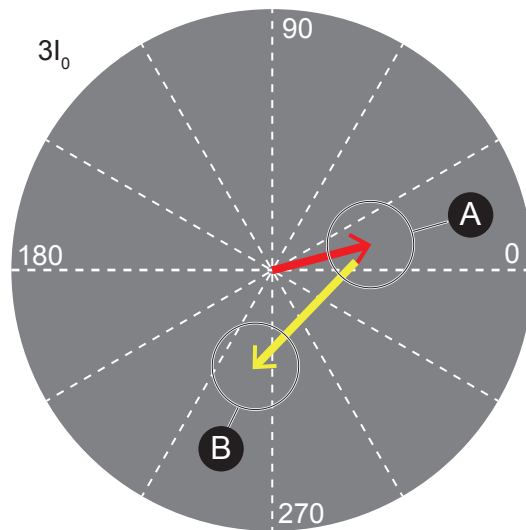
This protection scheme is specially used in double-wye-connected capacitor banks. The unbalance current is measured with a dedicated current transformer (like 5A/5A) between two starpoints of the bank.

As the capacitor elements are not identical and have acceptable tolerances, there is a natural unbalance current between the starpoints of the capacitor banks. This natural unbalance current can be compensated to tune the protection sensitive against real faults inside the capacitor banks.



However, the setting must be 10% smaller than the calculated value, since there are some tolerances in the primary equipment as well as in the relay measurement circuit. Then, the time setting of 50N/51N-4 is not used for tripping purposes. The time setting specifies, how long the relay must wait until it is certain that there is a faulty element in the bank. After this time has elapsed, the stage 50N/51N-4 makes a new compensation automatically, and the measured unbalance current for this stage is now zero. Note, the automatic compensation does not affect the measured unbalance current of stage 50N/51N-3.

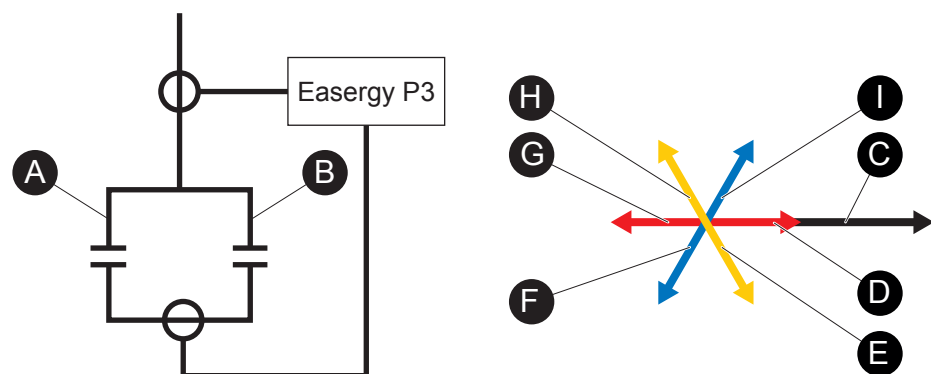
Figure 103 - Natural unbalance compensation and a single capacitor fault



- A.** The natural unbalance is compensated for.
- B.** When the  $I_N$  current increases above the set start value (normally 90% of a single capacitor unit) according to the angle ratio between  $I_N$  and  $I_A$ , it is decided in which branch and phase the fault occurred. The fault is memorised and compensation is completed automatically. After the set amount of faults, the stage trips.

If there is an element failure in the bank, the algorithm checks the phase angle of the unbalance current related to the phase angle of the phase current  $I_A$ . Based on this angle, the algorithm can increase the corresponding faulty elements counter (there are six counters).

Figure 104 - How a failure in different branches of the bank affects the  $I_N$  measurement





- |    |                           |
|----|---------------------------|
| A. | Branch 1                  |
| B. | Branch 2                  |
| C. | $I_A$ as reference        |
| D. | Phase 1 fault in branch 1 |
| E. | Phase 3 fault in branch 2 |
| F. | Phase 2 fault in branch 1 |
| G. | Phase 1 fault in branch 2 |
| H. | Phase 3 fault in branch 1 |
| I. | Phase 2 fault in branch 2 |

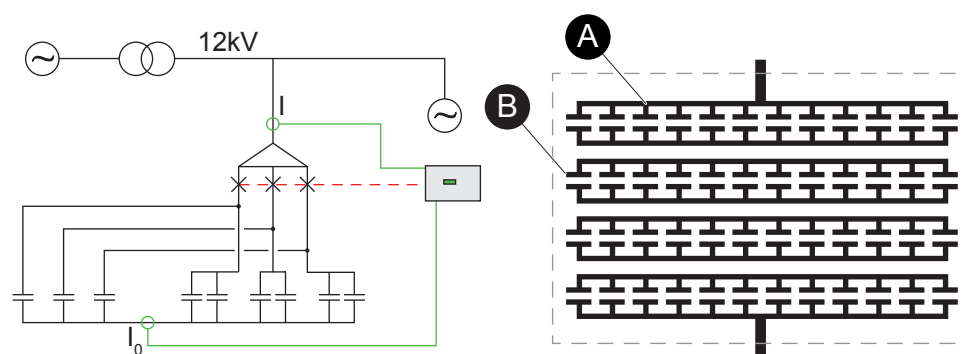
You can set for the stage 50N/51N-4 the allowed number of faulty elements. For example, if set to three elements, the fourth fault element will issue the trip signal.

The fault location is used with internal fused capacitor and filter banks. There is no need to use it with fuseless or external fused capacitor and filter banks, nor with the reactor banks.

### Application example

An application example is presented below. Each capacitor unit has 12 elements in parallel and four elements in series.

Figure 105 - 131.43  $\mu\text{F}$  Y-Y connected capacitor bank with internal fuses

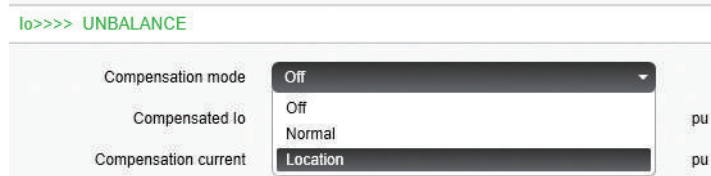


- |    |                |
|----|----------------|
| A. | 12 in parallel |
| B. | Four in series |

### Taking unbalance protection into use

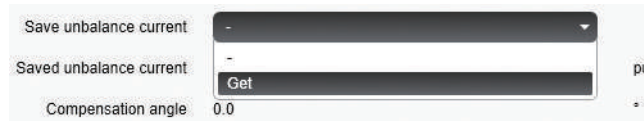
1. Enable the capacitor bank protection:
  - in Easergy Pro, in the **Protection > 50N/51N-4 Unbalance** setting view, select **Location** for **Compensation mode**.

Figure 106 - Enabling unbalance protection



- via the relay's front panel: go to the **50N/51N-4** menu, scroll right to **1 SET 50N/51N**, and select **Location** for **CMode**.
2. Save the natural unbalance:
- in Easergy Pro, in the **Protection > 50N/51N-4 Unbalance** setting view, select **Get** for **Save unbalance current**.

Figure 107 - Saving the unbalance current



- via the relay's front panel: go to the **50N/51N-4** menu, scroll right to **SET2 50N/51N**, and select **Get** for **SaveBal**.

**NOTE: CMode** has to be selected as **Location** before proceeding to this step.

3. Set the start value for both branches.

Total capacitance of the bank is 131.43 μF. In each phase, there are three capacitor units (1+2), so the capacitance of one unit is 43.81 μF. Failure of one element inside the capacitor unit makes the total capacitance decrease to 41.92 μF (Ohm's law). This value is important when calculating the start value.

Equation 21

$$3I_0 = \frac{V_{L-N}}{(2 \cdot \pi \cdot f \cdot C_1)^{-1}} - \frac{V_{L-N}}{(2 \cdot \pi \cdot f \cdot C_2)^{-1}}$$

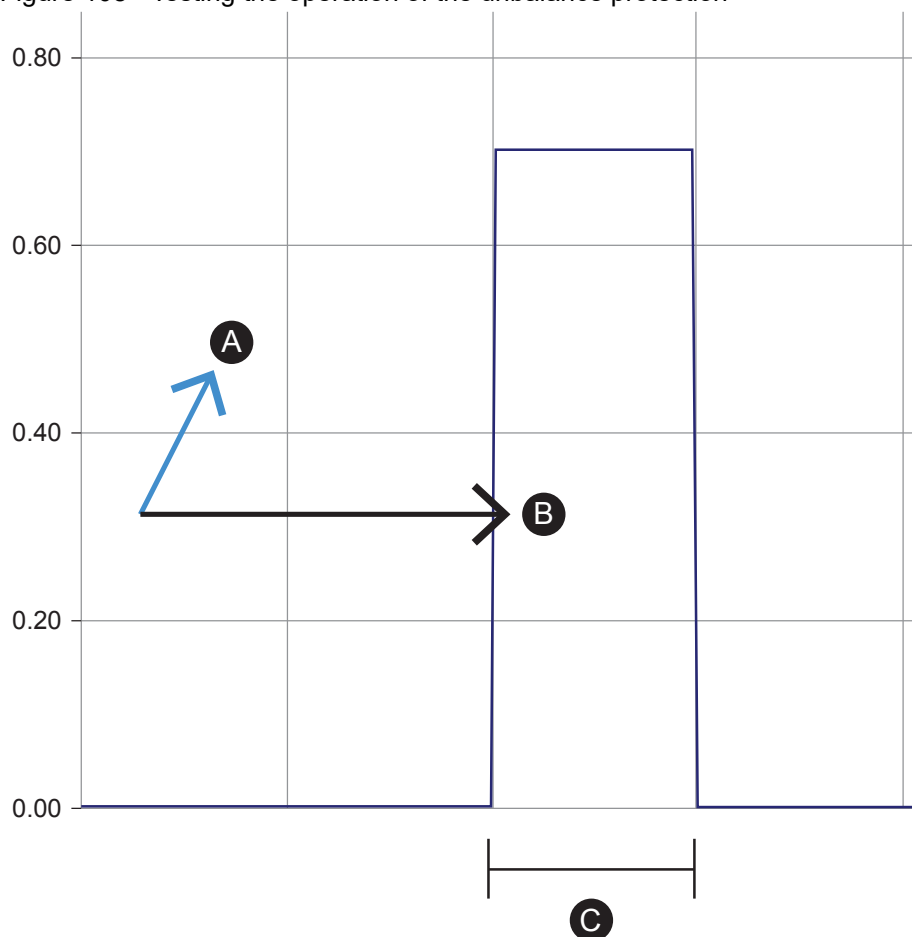
$$3I_0 = \frac{6928}{(2 \cdot \pi \cdot 50 \cdot 43.81 \cdot 10^{-6})^{-1}} - \frac{6928}{(2 \cdot \pi \cdot 50 \cdot 43.81 \cdot 10^{-6})^{-1}}$$

$$3I_0 = 1.37A$$

Failure of one element inside the bank on the left branch causes approximately 1.37 ampere unbalance current at the star point. On the right branch, there are two capacitor units in parallel, and therefore, a failure of one element causes only 0.69 ampere unbalance. A different start value for each branch is necessary. Set the start value to 80% of the calculated value.

4. Test the operation of the unbalance protection.

Figure 108 - Testing the operation of the unbalance protection

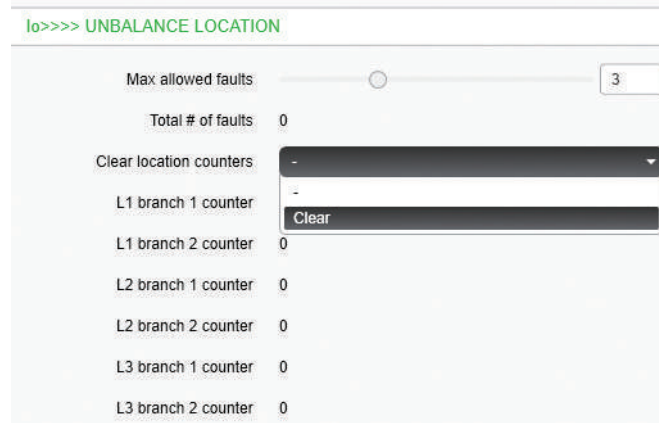


- A. Phase 2 fault in branch 2
- B.  $I_A$  as reference
- C. Set operation delay

Conduct testing by injecting current to channels  $I_A$  and  $I_{N1}$  of the relay. In the example above, 0.69 A primary current is injected to the  $I_{N1}$  channel.  $I_{N1}$  is leading the phase current  $I_A$  by 60 degrees. This means the fault has to be on the right branch and in phase 2. Compensation happens automatically after the set operate time until the allowed total amount of failed units is exceeded (Max. allowed faults). In this application, the fourth failed element would cause the stage to trip.

**NOTE:** If branch 1 faults occur in branch 2, change the polarity of the  $I_N$  input. Clear the location counters when the commissioning of the relay has been completed.

Figure 109 - Clearing location counters



**Characteristics**

Table 67 - Capacitor bank unbalance50N/51N-3 and 50N/51N-4 (51C)

Start value	0.01-20.0 pu (step 0.01)
Operate time	0.04-300 s (step 0.01)
Start time	Typically 30 ms
Reset time	<95 ms
Reset ratio	0.95
Inaccuracy:	
- Starting	±2% of the set value or ±0.3% of the rated value
- Operate time	±1% or ±25 ms

## 6.21 Voltage-dependent overcurrent (ANSI 51V)

**NOTE:** The voltage-dependent overcurrent stage can be configured to be either voltage-restrained or voltage-controlled.

**Description**

The voltage-dependent overcurrent stage 51V is typically used for generator short-circuit protection in applications where the static excitation system of the generator is fed only from the generator terminals. Other possible applications are conditions where the fault current level depends on the sources feeding the fault.

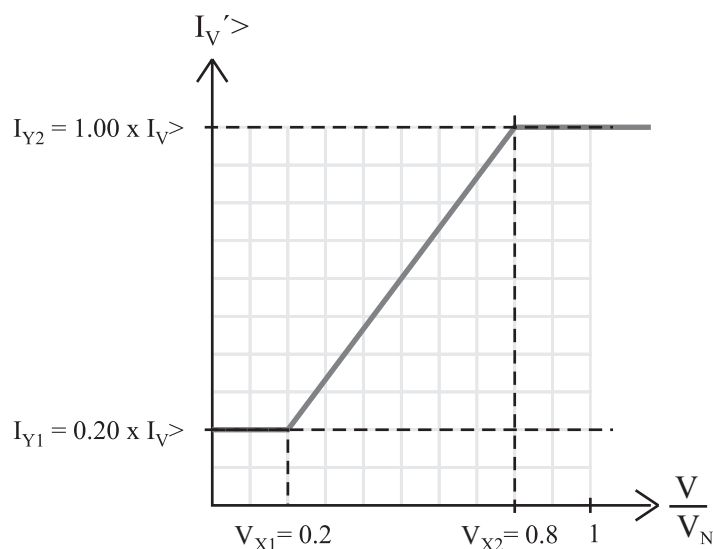
In close-by short circuits, the fault current rapidly decreases, thus jeopardizing the operation of the high-set short circuit protection. The operation can be secured using the voltage-dependent overcurrent function.

The voltage-dependent overcurrent stage operates with definite time characteristic. The start current  $I_{V>}$  and the operate time  $t_{>}$  can be set by the user.

### Voltage-restrained overcurrent principle

The current start limit of the voltage-restrained overcurrent function is conditional to the control voltage (fundamental frequency component positive sequence voltage  $V_1$ ).

Figure 110 - Characteristics of the voltage-restrained overcurrent function  $I_V >$



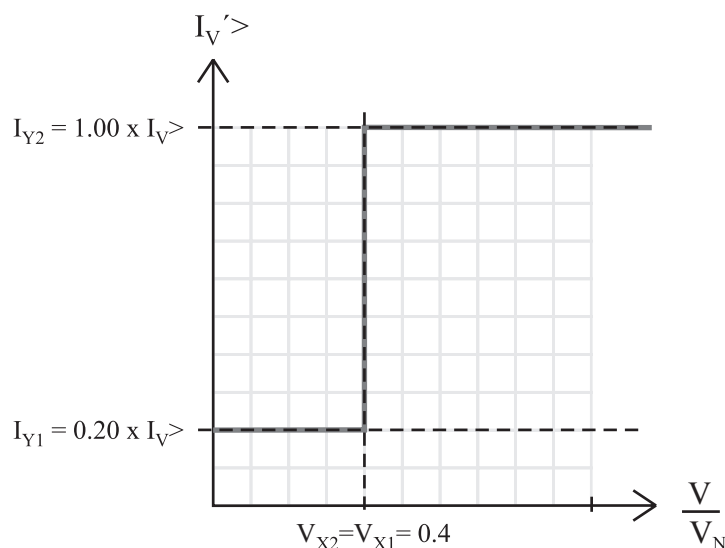
When the generator terminal or busbar voltage falls below the set voltage level, the start current level of the overcurrent stage 51V also starts falling linearly controlled by the control voltage according to the characteristic curve.

### Voltage-controlled overcurrent principle

When the setting parameters are selected according to [Figure 111 - Voltage-controlled overcurrent characteristics](#) on page 177, the function is said to be voltage-controlled.

**NOTE:** The overcurrent function can be used as a normal high-set overcurrent stage 50/51-3if  $I_{Y1}$  and  $I_{Y2}$  are set to 100%.

Figure 111 - Voltage-controlled overcurrent characteristics



The voltage setting parameters  $V_{X1}$  and  $V_{X2}$  are proportional to the rated voltage of the generator. They define the voltage limits, within which the start current of the overcurrent unit is restrained. The multipliers  $I_{Y1}$  and  $I_{Y2}$  are used for setting the area of change of the start level of the overcurrent function in proportion to the  $V_{X1}$  and  $V_{X2}$  settings.

### Cold load and inrush current handling

See [7.3 Cold load start and magnetizing inrush](#) on page 242.

### Setting groups

There are four setting groups available.

### Characteristics

Table 68 - Voltage-dependent overcurrent (51V)

Settings:	
-	0.50–4.00 x $I_{GN}$
- $V_{X1}$ , $V_{X2}$	0–150%
- $I_{Y1}$ , $I_{Y2}$	0–200% $I_V$
Definite time function:	
- Operate time	0.08 <sup>52</sup> –300.00 s (step 0.02 s)
Start time	Typically 60 ms
Reset time	< 95 ms
Overshoot time	< 50 ms
Reset ratio	0.97
Transient overreach, any $\tau$	< 10%
Inaccuracy:	
- Starting	±3% of set value
- Operate time at definite time function	±1% or ±30 ms

<sup>52</sup> This is the instantaneous time i.e. the minimum total operational time including the fault detection time and operate time of the trip contacts.

## 6.22 Overvoltage (ANSI 59)

### Description

Overvoltage protection is used to detect too high system voltages or to check that there is sufficient voltage to authorize a source transfer.

The overvoltage function measures the fundamental frequency component of the line-to-line voltages regardless of the voltage measurement mode ([10.8 Voltage system configuration](#) on page 368). By using line-to-line voltages any line-to-neutral over-voltages during ground faults have no effect. (The ground fault

protection functions take care of ground faults.) Whenever any of these three line-to-line voltages exceeds the start setting of a particular stage, this stage starts and a start signal is issued. If the fault situation remains on longer than the operate time delay setting, a trip signal is issued.

In solidly grounded, four-wire networks with loads between phase and neutral voltages, overvoltage protection may be needed for line-to-neutral voltages, too. In such applications, the programmable stages can be used. [6.36 Programmable stages \(ANSI 99\) on page 232.](#)

### Three independent stages

There are three separately adjustable stages: 59-1, 59-2, and 59-3. All the stages can be configured for the definite time (DT) operation characteristic.

### Configurable release delay

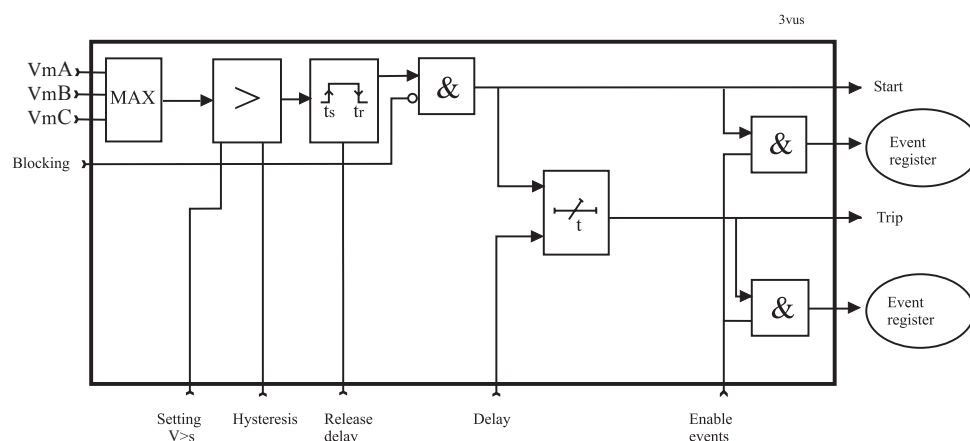
The 59–1 stage has a settable reset delay that enables detecting intermittent faults. This means that the time counter of the protection function does not reset immediately after the fault is cleared, but resets after the release delay has elapsed. If the fault appears again before the release delay time has elapsed, the delay counter continues from the previous value. This means that the function eventually trips if faults are occurring often enough.

### Configurable hysteresis

The dead band is 3% by default. This means that an overvoltage fault is regarded as a fault until the voltage drops below 97% of the start setting. In a sensitive alarm application, a smaller hysteresis is needed. For example, if the start setting is about only 2% above the normal voltage level, the hysteresis must be less than 2%. Otherwise, the stage does not release after fault.

### Block diagram

Figure 112 - Block diagram of the three-phase overvoltage stages 59-1, 59-2, and 59-3



### Setting groups

There are four setting groups available for each stage.

**Characteristics**

Table 69 - Overvoltage stage 59–1 (59)

Input signal	$V_A - V_C$
Start value	50–150% $V_N$ (step 1%)
Definite time characteristic: - operate time	0.08 <sup>53</sup> – 300.00 s (step 0.02)
Hysteresis	0.99–0.800 (0.1 – 20.0%, step 0.1%)
Start time	Typically 60 ms
Release delay	0.06–300.00 s (step 0.02)
Reset time	< 95 ms
Overshoot time	< 50 ms
Inaccuracy: - Starting - operate time	$\pm 3\%$ of the set value $\pm 1\%$ or $\pm 30$ ms

<sup>53</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.

Table 70 - Overvoltage stage 59–2 (59)

Input signal	$V_A - V_C$
Start value	50–150% $V_N$ (step 1%)  The measurement range is up to 160 V. This limit is the maximum usable setting when rated VT secondary is more than 100 V.
Definite time characteristic: - Operate time	0.06 <sup>54</sup> – 300.00 s (step 0.02)
Hysteresis	0.99–0.800 (0.1–20.0%, step 0.1%)
Start time	Typically 60 ms
Reset time	< 95 ms
Overshoot time	< 50 ms
Inaccuracy: - Starting - Operate time	$\pm 3\%$ of the set value $\pm 1\%$ or $\pm 30$ ms

<sup>54</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.



Table 71 - Overvoltage stage 59–3 (59)

Input signal	$V_A - V_C$
Start value	50–160% $V_N$ (step 1%)  The measurement range is up to 160 V. This limit is the maximum usable setting when rated VT secondary is more than 100 V.
Definite time characteristic: - Operate time	0.04 <sup>55</sup> – 300.00 s (step 0.01)
Hysteresis	0.99–0.800 (0.1–20.0%, step 0.1%)
Start time	Typically 50 ms
Reset time	< 95 ms
Overshoot time	< 50 ms
Inaccuracy: - Starting - Operate time	$\pm 3\%$ of the set value  $\pm 1\%$ or $\pm 25$ ms

<sup>55</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.

## 6.23 Neutral overvoltage (ANSI 59N)

### Description

The neutral overvoltage protection is used as unselective backup for ground faults and also for selective ground fault protections for motors having a unit transformer between the motor and the busbar.

This function is sensitive to the fundamental frequency component of the neutral overvoltage. The attenuation of the third harmonic is more than 60 dB. This is essential because third harmonics exist between the neutral point and ground also when there is no ground fault.

Whenever the measured value exceeds the start setting of a particular stage, this stage starts and a start signal is issued. If the fault situation remains on longer than the operate time delay setting, a trip signal is issued.

### Measuring the neutral overvoltage

The neutral overvoltage is either measured with three voltage transformers (for example broken delta connection), one voltage transformer between the motor's neutral point and ground or calculated from the measured phase-to-neutral voltages according to the selected voltage measurement mode (see [10.8 Voltage system configuration](#) on page 368):

- When the voltage measurement mode is 3LN: the neutral displacement voltage is calculated from the line-to-line voltages and therefore a separate

neutral displacement voltage transformer is not needed. The setting values are relative to the configured voltage transformer (VT) voltage/ $\sqrt{3}$

- When the voltage measurement mode contains "+V<sub>N</sub>": The neutral displacement voltage is measured with voltage transformer(s) for example using a broken delta connection. The setting values are relative to the VT<sub>N</sub> secondary voltage defined in configuration.
- Connect the V<sub>N</sub> signal according to the connection diagram to achieve correct polarization.

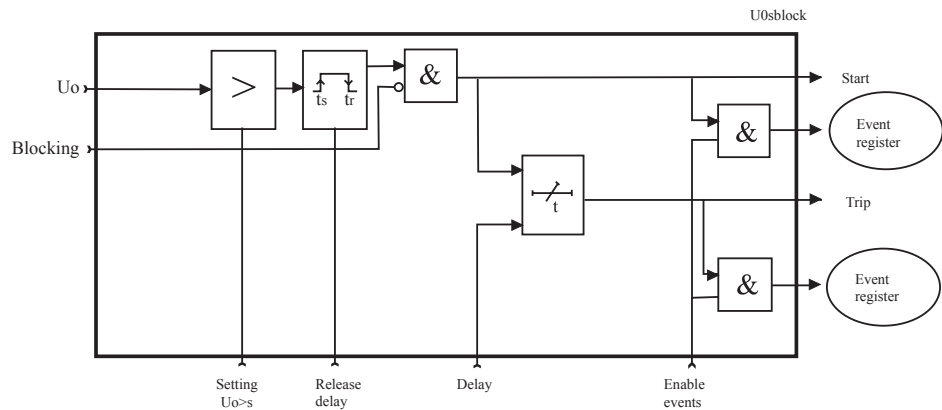
**Two independent stages**

There are two separately adjustable stages: 59N-1 and 59N-2. Both stages can be configured for the definite time (DT) operation characteristic.

The neutral overvoltage function comprises two separately adjustable neutral voltage displacement stages (stage 59N-1 and 59N-2).

**Block diagram**

Figure 113 - Block diagram of the neutral overvoltage stages 59N-1, 59N-2



**Setting groups**

There are four setting groups available for both stages.

**Characteristics**

Table 72 - Neutral overvoltage stage 59N-1 (59N)

Input signal	V <sub>N</sub> $V_{N \text{ Calc}} = (V_A + V_B + V_C)$
Start value	1–60% V <sub>0N</sub> (step 1%)
Definite time function: - Operate time	0.3–300.0 s (step 0.1 s)
Start time	Typically 200 ms
Reset time	< 450 ms

Reset ratio	0.97
Inaccuracy:	
- Starting	$\pm 2\%$ of the set value or $\pm 0.3\%$ of the rated value
- Starting $V_{N\text{ Calc}}$ (3LN mode)	$\pm 1\text{ V}$
- Operate time	$\pm 1\%$ or $\pm 150\text{ ms}$

Table 73 - Neutral overvoltage stage 59N-2 (59N)

Input signal	$V_N$ $V_{N\text{ Calc}} = (V_A + V_B + V_C)$
Start value	1–60% $V_{0N}$ (step 1%)
Definite time function:	
- Operate time	0.08–300.0 s (step 0.02 s)
Start time	Typically 60 ms
Reset time	<95 ms
Reset ratio	0.97
Inaccuracy:	
- Starting	$\pm 2\%$ of the set value or $\pm 0.3\%$ of the rated value
- Starting $V_{N\text{ Calc}}$ (3LN mode)	$\pm 1\text{ V}$
- Operate time	$\pm 1\%$ or $\pm 30\text{ ms}$

## 6.24 Stator ground fault (ANSI 64S)

### Description

**NOTE:** This protection stage is available only in the voltage measurement modes 2LL +  $V_N$  and 3LN +  $V_N$  (see [10.8 Voltage system configuration](#) on page 368).

For this function, the neutral voltage displacement voltage must be measured from the generator's neutral point and the earth.

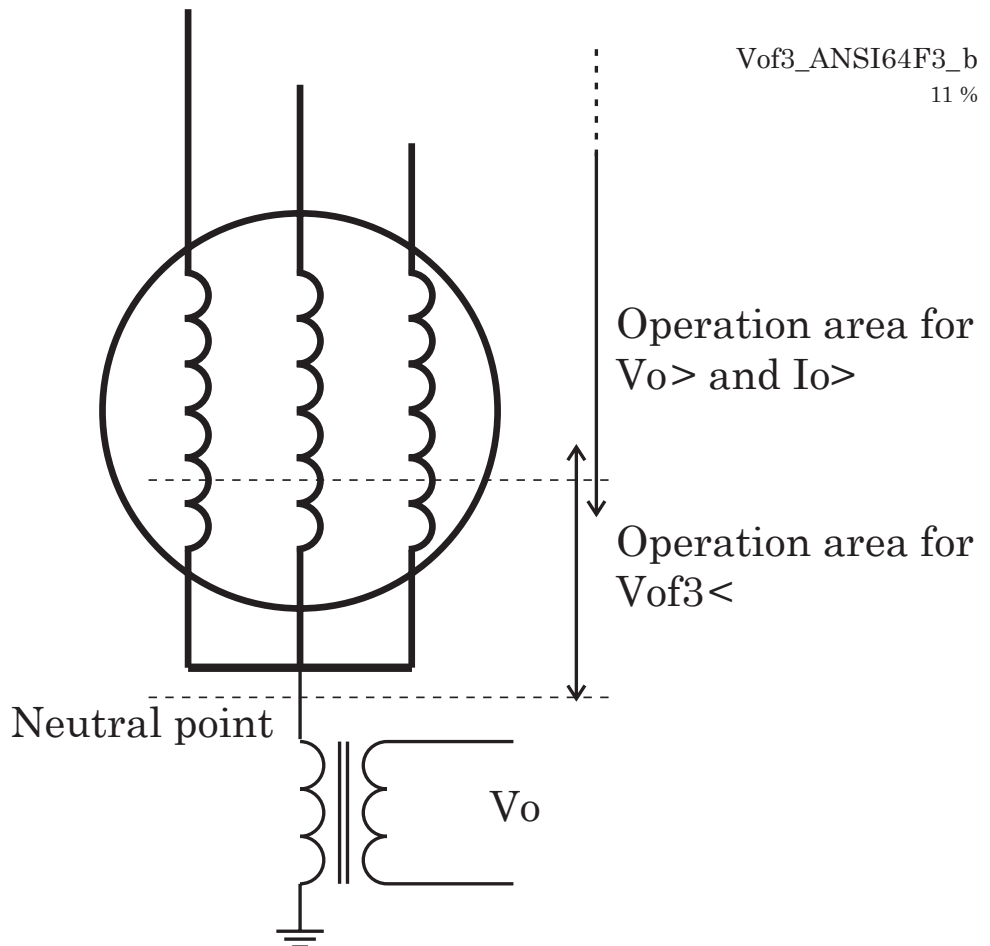
A unit transformer is usually needed between the generator and the busbar for this function's selective operation.

The third harmonic undervoltage stage can be used to detect ground faults near a high-impedance grounded generator's neutral point or even at the neutral point. These kind of faults are rare, but if a second ground fault would occur in one of the phases, the consequences would be severe because the first ground fault had made the network solidly grounded. By using the  $V_{0F3} <$  stage, such a situation can be avoided.

**Neutral point is a blind point for conventional ground fault function**

If there is an ground fault near the neutral point or even at the neutral point , the ground fault current and neutral voltage displacement voltage caused by such a fault are negligible or even zero. Thus, a conventional ground fault protection based on fundamental frequency  $I_N$  or  $V_N$  measurement is not able to detect such faults. On the other hand, faults near the neutral point are rare because the voltage stress is low.

Figure 114 - Overlapping coverage of winding ground fault protection of basic protection stages and the third harmonic undervoltage protection stage



**100% coverage of the windings**

The "one hundred per cent" in the title is slightly misleading. Actually, the 100% coverage is achieved only when this stage is used together with conventional ground fault protection.

The operation range of fundamental frequency ground fault functions 59N and 51N covers about 95% of the stator windings starting from the HV end, but never 100% of the windings. The coverage of the  $V_{of3} <$  stage is about 10%–30% of the windings but starting from the LV end, that is, the neutral point. Thus, the ranges overlap as in [Figure 114 - Overlapping coverage of winding ground fault protection of basic protection stages and the third harmonic undervoltage protection stage](#) on page 184 and 59N or 51N together with this 64F3 covers 100% of the stator windings.

### Natural third harmonic at the neutral point

The voltage of the generator is not ideal pure sine wave. There is a small amount of harmonics as well. At the neutral point, there is some amount of 3rd, 6th, 9th, 12th ..., that is, 3n harmonics. The base frequency and other than 3n harmonics in line-to-line voltages cancel each other at the neutral point ([Figure 115 - When symmetric line-to-neutral voltages containing third harmonic are summed together, the result is not zero on page 185](#) and [Figure 116 - When the line-to-neutral voltages do contain fifth harmonic, they cancel each other when summed and the resulting zero sequence voltage  \$V\_N\$  is zero on page 185](#)). The third harmonic residual undervoltage stage  $V_{of3}$  is supervising the level of the 3rd harmonic at the neutral point. If there is an ground fault near the neutral point, this 150 Hz or 180 Hz voltage drops below the setting and the stage activates.

Figure 115 - When symmetric line-to-neutral voltages containing third harmonic are summed together, the result is not zero

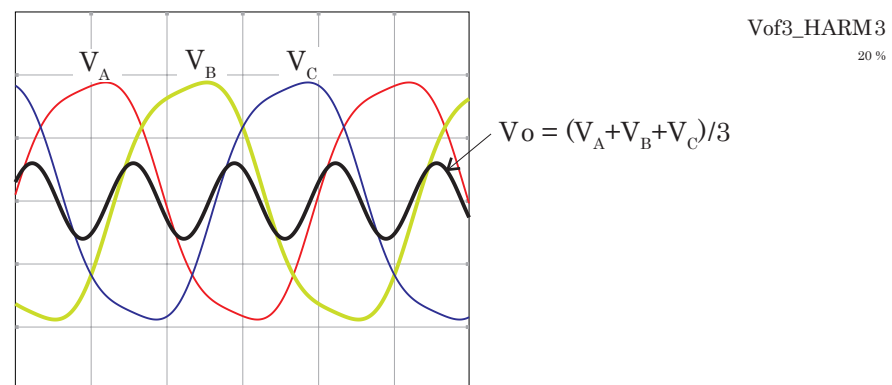
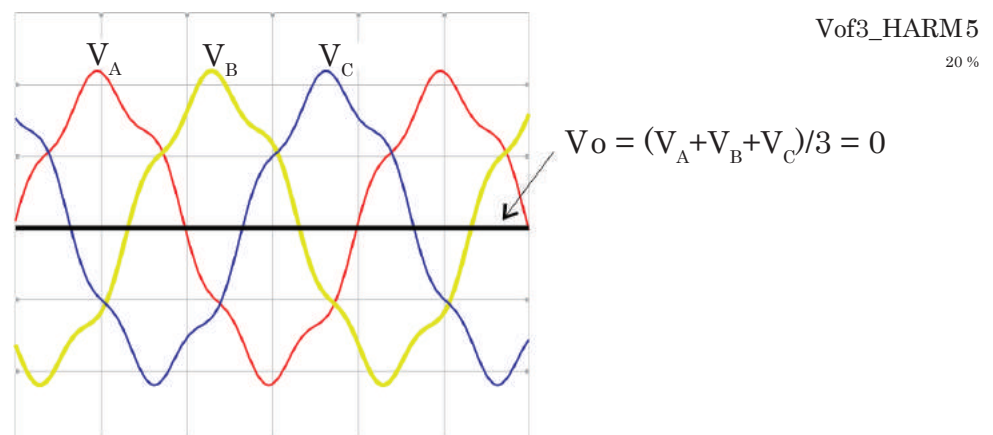


Figure 116 - When the line-to-neutral voltages do contain fifth harmonic, they cancel each other when summed and the resulting zero sequence voltage  $V_N$  is zero



### Finding out the correct start setting

A problem with this third harmonic undervoltage stage is to find a proper start setting. In practice, an empirical value is used, because the natural 3rd harmonic at the neutral point depends on:

- Construction of the generator
- Loading and the power factor

- Amount of excitation
- Grounding circuitry
- Transformers connected.

The relay itself can be used to measure the actual level of 3rd,  $V_N$  harmonic during various situations. Typically, the generator is producing its minimum amount of 3rd harmonic when the load is small and the excitation is low. The start setting must be below this minimum value. A typical operation delay is one minute.

### Blocking the protection

The squelch of voltage measurement blocks the stage when the generator is stopped. Using the block matrix, blocking by undervoltage, underpower, circuit breaker position and other blocking schemes is possible.

### Setting groups

There are four setting groups available.

### Characteristics

Table 74 - Stator ground fault (64S)

Start value	1–50%
Definite time function: - Operate time	0.5–30.0 minutes
Start time	<2 s
Reset time	<4 s
Reset ratio	1.05 (When start setting is below 5%, reset value is less than set value +0.5% unit)
Fundamental low voltage block limit ( $V_{AB}$ and $V_{BC}$ )	Blocked when $V_{AB}$ and $V_{BC}$ < 65% of nominal
Inaccuracy: - Starting - Operate time at definite time function	$\pm 1\%$ units $\pm 1\%$ or $\pm 2$ s

## 6.25 Restricted ground fault (ANSI 64REF)

### Description

The restricted ground fault (REF) protection function is used to detect ground faults in solidly-grounded or impedance-grounded power transformers, grounding transformers and shunt reactors. REF protection can also be used to protect rotating machines if the machine's neutral point is grounded.

A traditional REF protection scheme is based on a high-impedance REF protection principle. Modern REF protection operation is based on a low-

impedance principle that overcomes some drawbacks of the high-impedance REF principle. [Figure 117 - Restricted ground fault protection of a solidly-grounded transformer](#) on page 187 to [Figure 120 - Restricted ground fault protection of a rotating machine](#) on page 188 describe the basic low-impedance REF protection schemes.

Figure 117 - Restricted ground fault protection of a solidly-grounded transformer

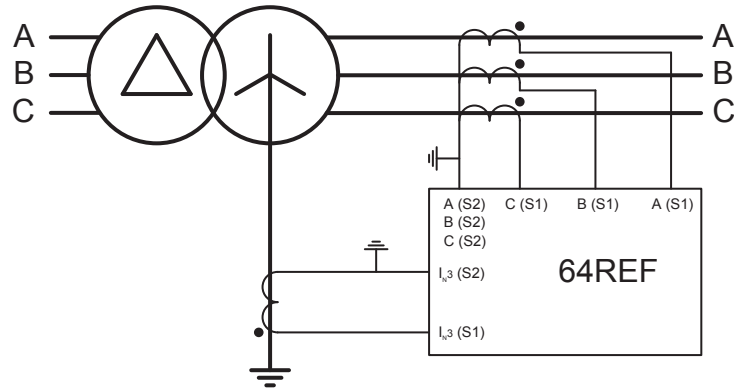


Figure 118 - Restricted ground fault protection of a transformer and neutral point reactor

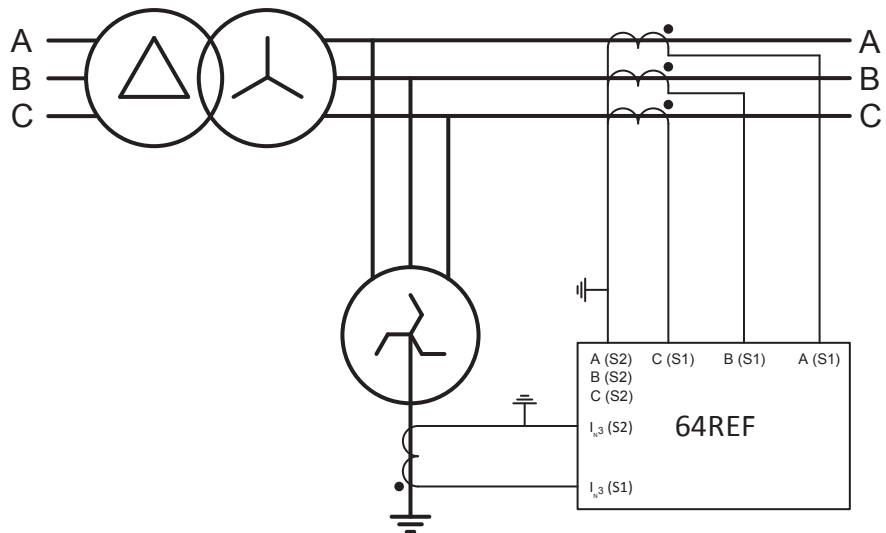


Figure 119 - Restricted ground fault protection of a shunt reactor

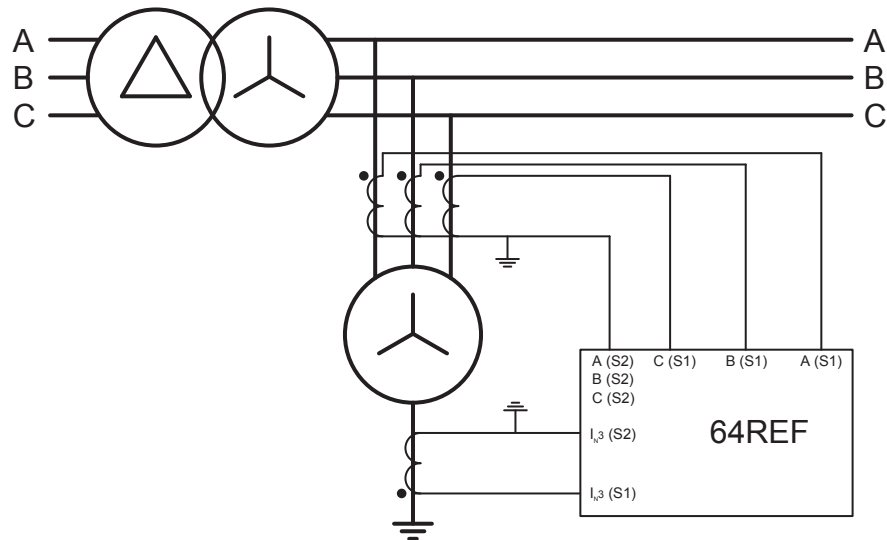
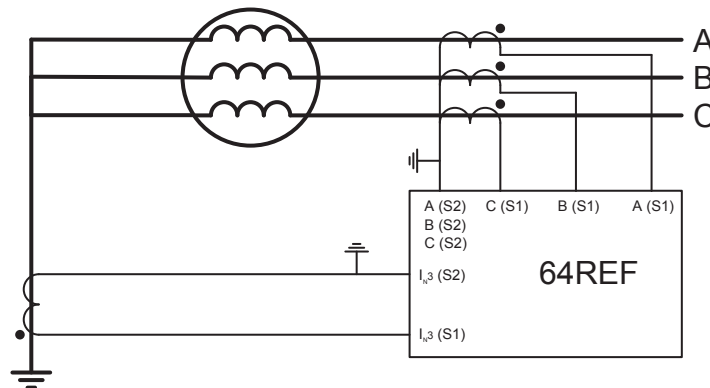


Figure 120 - Restricted ground fault protection of a rotating machine



The REF protection principle has several advantages. It is very selective because the protection zone is limited between the current transformers that are used for the REF protection. Because of its selectivity, the REF protection requires no additional time delay for protection coordination. Therefore, REF protection is especially suitable for the protection of transformers and rotating machines against internal ground faults. Because of the differential protection principle, it is also very sensitive which makes it suitable for detecting faults located near the neutral point of transformers and rotating machines.

**Restricted ground fault protection principle**

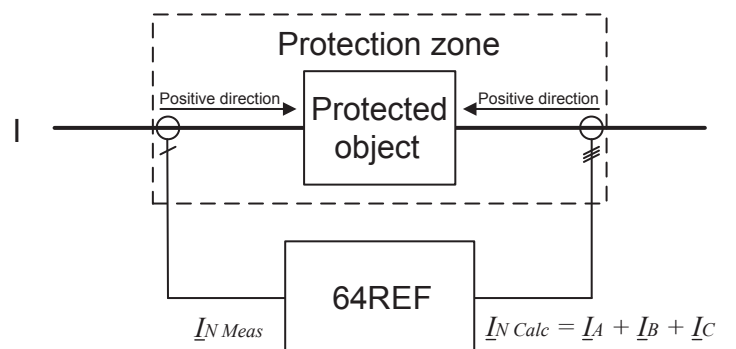
The REF protection function is based on the differential protection principle and is sensitive to the fundamental frequency component of the measured currents.

[Figure 117 - Restricted ground fault protection of a solidly-grounded transformer on page 187](#) depicts the differential protection principle applied to REF protection.

The protection zone is determined by the location of current transformers. The direction of currents in REF protection are defined so that currents entering the protection zone have positive direction and currents leaving the zone have negative direction.



Figure 121 - Differential protection principle applied to REF protection



The function is based on the difference of the current measured at the neutral point ( $I_{N Meas}$ ) and the calculated residual current ( $I_{N Calc}$ ). The function calculates the differential current  $I_D$  according to [Equation 22](#) on page 189. So the function is based on the absolute value of  $I_D$  that is a sum of the current vectors  $I_{N Meas}$  and  $I_{N Calc}$ .

**NOTE:** Nominal current of the  $I_{N Meas}$  and  $I_{N Calc}$  are current transformer ratings.

Equation 22

$$I_D = |I_{N Meas} + I_{N Calc}|$$

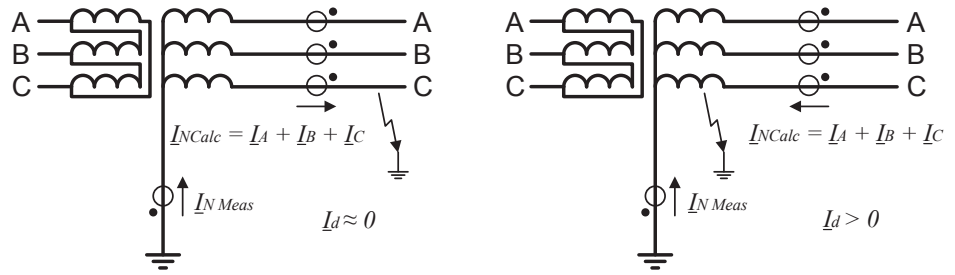
During healthy conditions, the neutral point current ( $I_{N Meas}$ ) is near or equal to zero and the same is true for the residual current or the calculated sum of the phase currents  $I_{N Calc} = 3I_0 = I_A + I_B + I_C$ . During healthy conditions, the differential current  $I_D$  is also close to zero and the REF protection stage does not start.

[Figure 117 - Restricted ground fault protection of a solidly-grounded transformer on page 187](#) depicts through-fault conditions and a fault in the protected zone.

During a through-fault condition, a ground fault current flowing from the faulty phase to earth returns to the system's neutral point. Because of the convention of current directions, the resulting neutral point current ( $I_{N Meas}$ ) and calculated residual current ( $I_{N Calc}$ ) are flowing in opposite directions resulting in zero or very small differential current  $I_D$  according to [Equation 23](#) on page 190.

When a fault occurs inside the protection zone, the neutral point current flowing into the protection zone has a positive current direction according to the current direction convention. Depending on the network conditions, an additional fault current may or may not flow into the zone along the line. This additional fault current manifests itself as a residual current. Additional fault currents flowing into the protection zone have a positive current direction, too. In other words, the neutral point current and residual current are in a phase which results in a high differential current  $I_D$  according to [Equation 23](#) on page 190.

Figure 122 - Through-fault condition (left) and ground fault in protected zone (right)



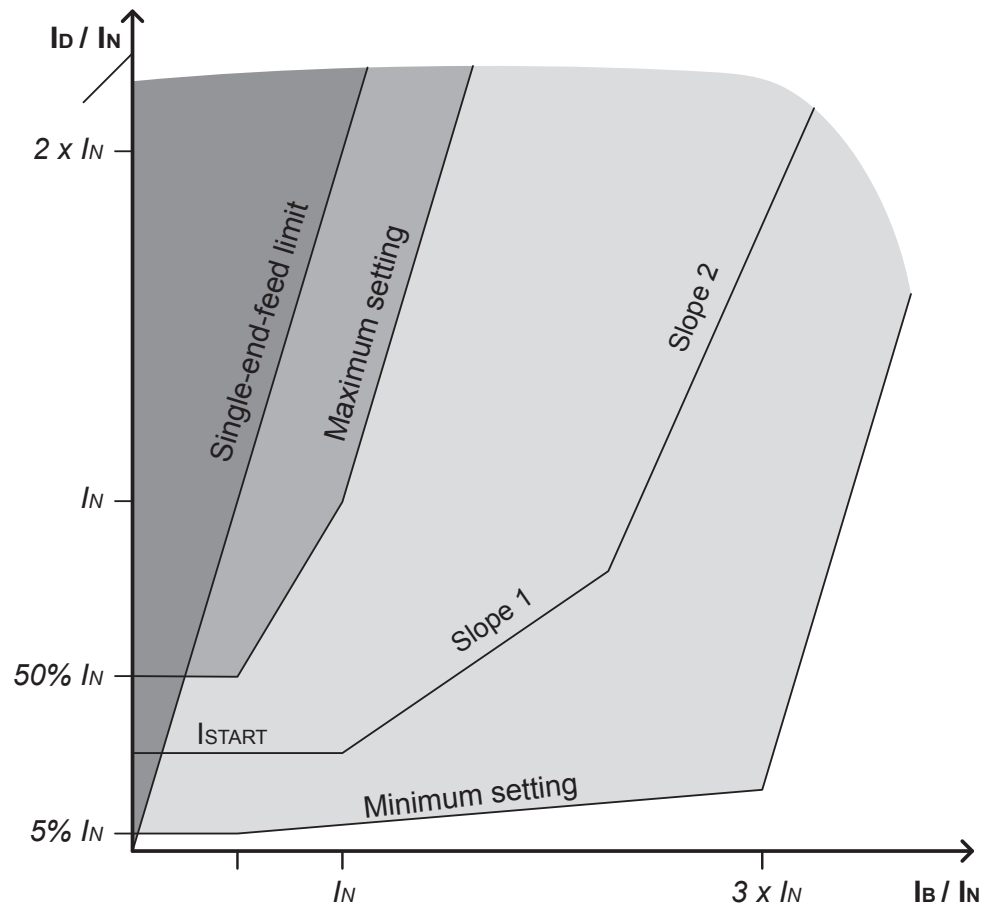
During a through-fault or short-circuit fault outside the protection zone, the current transformers may be exposed to very high currents. These high fault currents may lead to different saturation of the phase current transformers resulting in an erroneous residual current. To ensure correct operation of the protection stage, a stabilization method is provided. Protection stage stabilisation is based on the calculated bias current  $I_B$  and programmable operating characteristics. The bias current is calculated according to [Equation 23](#) on page 190.

Equation 23

$$I_B = \frac{|I_A| + |I_B| + |I_C|}{3}$$

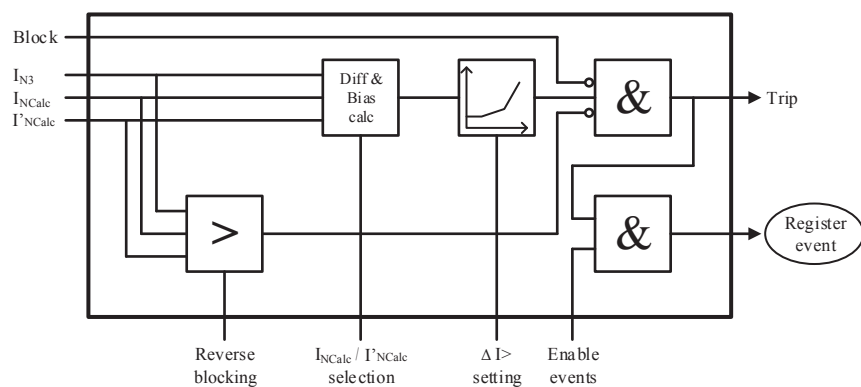
This bias current stabilization method is used in the  $dI_0 >$  stage. The  $dI_0 >>$  stage does not consider the stabilization current  $I_B$  and is purely based on the differential current  $I_D$ . Both the differential current  $I_D$  and stabilization current  $I_B$  are current transformer ratings.

Figure 123 - Restricted ground fault protection operating characteristics



Additional stabilization can be activated by selecting the directional blocking feature. When directional blocking is used, the trip command is issued only when the measured neutral current and calculated residual current are less than  $\pm 88^\circ$  apart. Normal second harmonic blocking and cold-load blocking can be used to block the stage via the blocking matrix.

Figure 124 - Block diagram of REF protection stage



## Characteristics

Table 75 - Restricted ground fault overcurrent (64REF)

	64-1	64-2
Input signals	-	-
- Measured ground fault overcurrent input	$I_{N3}$	$I_{N3}$
- Calculated ground fault overcurrent source	$I_{N \text{ Calc}}$ or $I'_{N \text{ Calc}}$	$I_{N \text{ Calc}}$ or $I'_{N \text{ Calc}}$
Start value	-	-
- $dI_0 >$	5–50 % of $I_N$	5–50 % of $I_n$
Ibias for start of slope 1	$0.5 \times I_N$	-
Slope 1	5–100 %	-
Ibias for start of slope 2	$1-3 \times I_N$	-
Slope 2	100–200 %	-
Directional blocking	On/off	-
Operate time ( $I_D > 1.2 \times I_{SET}$ )	< 60 ms	-
Operate time ( $I_D > 3.5 \times I_{SET}$ )	< 50 ms	< 50 ms
Reset time	< 95 ms	< 95 ms
Reset ratio	0.95	0.95
Inaccuracy of starting	$\pm 3\%$ of set value or $0.02 \times I_n$ when currents are < 200 mA	$\pm 3\%$ of the set value or $\pm 0.5\%$ of the rated value

## 6.26 Directional phase overcurrent (ANSI 67)

### Description

Directional overcurrent protection can be used for directional short circuit protection. Typical applications are:

- Short-circuit protection of two parallel cables or overhead lines in a radial network.
- Short-circuit protection of a looped network with single feeding point.
- Short-circuit protection of a two-way feeder, which usually supplies loads but is used in special cases as an incoming feeder.
- Directional overcurrent protection in low impedance grounded networks. In this case, the relay has to be connected to line-to-neutral voltages instead of line-to-line voltages. In other words, the voltage measurement mode has to be "3LN" (See chapter [10.8 Voltage system configuration](#) on page 368).

The stages are sensitive to the amplitude of the highest fundamental frequency current of the three measured phase currents.

In line-to-line and in three-phase faults, the fault angle is determined by using angles between positive sequence of currents and voltages. In line-to-neutral faults, the fault angle is determined by using fault-phase current and the healthy line to line voltage. For details of power direction, see [4.9 Power and current direction](#) on page 61.

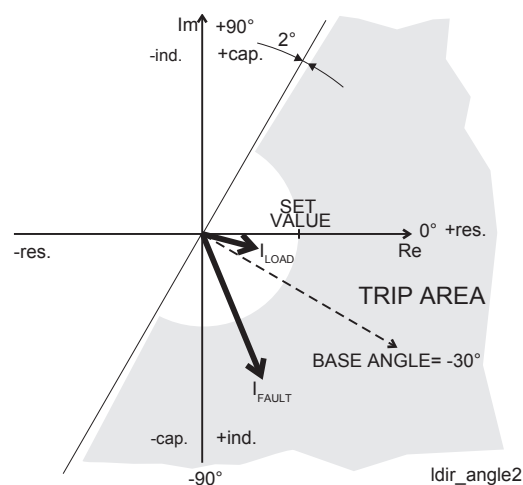
A typical characteristic is shown in [Figure 125 - Example of the directional overcurrent function's protection area](#) on page 193. The base angle setting is  $-30^\circ$ . The stage starts if the tip of the three phase current phasor gets into the grey area.

**NOTE:** If the maximum possible ground fault current is greater than the used most sensitive directional overcurrent setting, connect the relay to the line-to-neutral voltages instead of line-to-line voltages to get the right direction for ground faults, too. For networks having the maximum possible ground fault current less than the over current setting, use 67N, the directional ground fault stages.

### Voltage memory

An adjustable 0.2–3.2 second cyclic buffer storing the phase-to-ground voltages is used as the voltage memory. The stored phase angle information is used as direction reference if all the line-to-line voltages drop below 1% during a fault. To adjust the voltage memory, set the **Angle memory duration** parameter in the **Scalings** setting view in Easergy Pro.

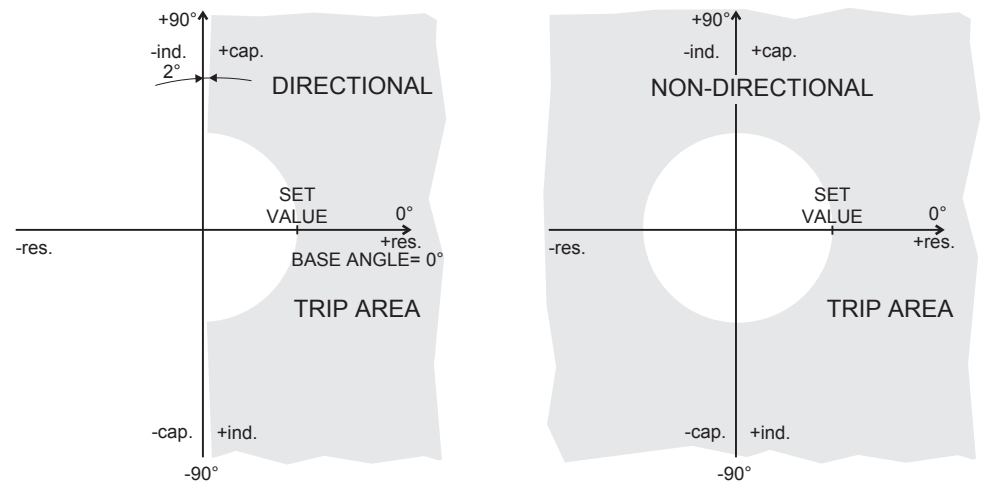
Figure 125 - Example of the directional overcurrent function's protection area



Three modes are available: directional, non-direct, and directional+back-up ([Figure 126 - Difference between directional mode and non-directional mode. The grey area is the trip region.](#) on page 194). In the non-directional mode, the stage is acting just like an ordinary overcurrent 50/51 stage.

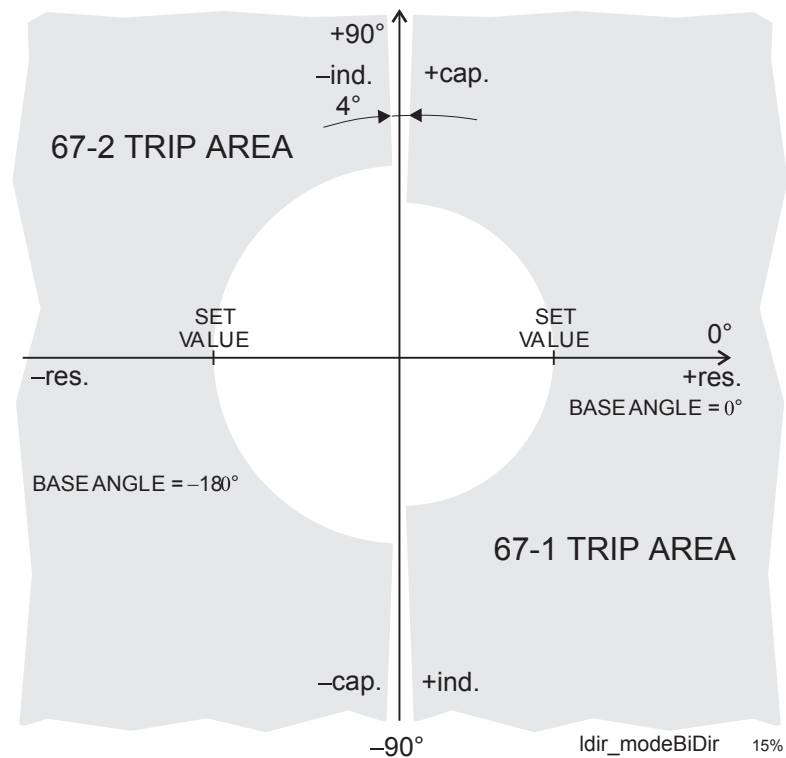
Directional+back-up mode works the same way as the directional mode, but it has unidirectional backup protection in case a close-up fault forces all voltages to about zero. After the angle memory hold time, the direction would be lost. Basically the directional+backup mode is required when operate time is set longer than voltage memory setting and no other unidirectional back-up protection is in use.

Figure 126 - Difference between directional mode and non-directional mode. The grey area is the trip region.



An example of the bi-directional operation characteristic is shown in [Figure 127 - Bi-directional application with two stages 67-1 and 67-2](#) on page 194. The right side stage in this example is the stage 67-1 and the left side is 67-2. The base angle setting of the 67-1 is 0° and the base angle of 67-2 is set to -180°.

Figure 127 - Bi-directional application with two stages 67-1 and 67-2



When any of the three phase currents exceeds the setting value and, in directional mode, the phase angle including the base angle is within the active  $\pm 88^\circ$  wide sector, the stage starts and issues a start signal. If this fault situation remains on longer than the delay setting, a trip signal is issued.

### Four independent stages

There are four separately adjustable stages available: 67-1, 67-2, 67-3, and 67-4.

### Dependent operate time

Stages 67-1 and 67-2 can be configured for definite time or dependent time characteristic. See [6.3 Dependent operate time on page 108](#) for details of the available dependent delays.

Stages 67-3 and 67-4 have definite time (DT) operation delay. The relay shows a scaleable graph of the configured delay on the local panel display.

### Dependent time limitation

The maximum measured secondary current is  $50 \times I_N$ . This limits the scope of dependent curves with high start settings. See [6.3 Dependent operate time on page 108](#) for more information.

### Cold load and inrush current handling

See [7.3 Cold load start and magnetizing inrush on page 242](#).

### Setting groups

There are four setting groups available for each stage.

### Characteristics

Table 76 - Directional phase overcurrent 67-1, 67-2 (67)

Input signal	$I_A - I_C$ $V_A - V_C$
Start value	$0.10 - 4.00 \times I_N$ (step 0.01)
Mode	Directional/Directional+BackUp
Minimum voltage for the direction solving	$2 V_{\text{SECONDARY}}$
Base angle setting range	$-180^\circ - +179^\circ$
Operate angle	$\pm 88^\circ$
Definite time function: - Operate time	DT <sup>56</sup> 0.04–300.00 s (step 0.01)
IDMT function: - Delay curve family - Curve type - Inv. time coefficient k	(DT), IEC, IEEE, RI Prg EI, VI, NI, LTI, MI...depends on the family <sup>57</sup> 0.025–20.0, except 0.50–20.0 for RXIDG, IEEE and IEEE2
Start time	Typically 30 ms

Reset time	< 95 ms
Overshoot time	< 50 ms
Reset ratio	0.95
Reset ratio (angle)	2°
Transient overreach, any τ	< 10%
Angle memory duration	0.2–3.2 s
Inaccuracy: - Starting (rated value $I_N= 1-5A$ ) - Angle  - Operate time at definite time function - Operate time at IDMT function	±3% of the set value or ±0.5% of the rated value ±2° $V>5 V$ ±30° $V= 0.1-5.0 V$ ±1% or ±25 ms ±5% or at least ±30 ms <sup>56</sup>

<sup>56</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.

<sup>57</sup> EI = Extremely Inverse, NI = Normal Inverse, VI = Very Inverse, LTI = Long Time Inverse, MI= Moderately Inverse

Table 77 - Directional phase overcurrent 67–3, 67–4 (67)

Input signal	$I_A - I_C$ $V_a - V_C$
Start value	0.10–20.00 x $I_N$ (step 0.01)
Mode	Directional/Directional+BackUp
Minimum voltage for the direction solving	2 $V_{SECONDARY}$
Base angle setting range	-180° – +179°
Operate angle	±88°
Definite time function: - Operate time	DT <sup>58</sup> 0.04–300.00 s (step 0.01)
Start time	Typically 30 ms
Reset time	< 95 ms
Overshoot time	< 50 ms
Reset ratio	0.95
Reset ratio (angle)	2°
Transient overreach, any τ	< 10%



Angle memory duration	0.2–3.2 s
Inaccuracy:	
- Starting (rated value $I_N = 1 - 5A$ )	$\pm 3\%$ of the set value or $\pm 0.5\%$ of the rated value
- Angle	$\pm 2^\circ$ $V > 5 V$
- Operate time at definite time function	$\pm 30^\circ$ $V = 0.1 - 5.0 V$
	$\pm 1\%$ or $\pm 25$ ms

<sup>58</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.

## 6.27 Directional ground fault overcurrent (ANSI 67N)

### Description

The ground fault protection is adapted for various network ground systems.

The function is sensitive to the fundamental frequency component of the ground fault overcurrent and neutral voltage displacement voltage and the phase angle between them. The attenuation of the third harmonic is more than 60 dB.

Whenever the size of  $I_N$  and  $V_N$  and the phase angle between  $I_N$  and  $V_N$  fulfils the start criteria, the stage starts and a start signal is issued. If the fault situation remains on longer than the operate time delay setting, a trip signal is issued.

### Polarization

The neutral overvoltage, used for polarization, is measured by energizing input  $V_N$ , that is, the angle reference for  $I_N$ . Connect the  $V_N$  signal according to the connection diagram. Alternatively, the  $V_N$  can be calculated from the line-to-line voltages internally depending on the selected voltage measurement mode (see [10.8 Voltage system configuration](#) on page 368):

- $3LN/LL_Y$ ,  $3LN/LN_Y$  and  $3LN/V_N$ : the zero sequence voltage is calculated from the line-to-line voltages and therefore any separate zero sequence voltage transformers are not needed. The setting values are relative to the configured voltage transformer (VT) voltage/ $\sqrt{3}$ .
- $3LN+V_N$ ,  $2LL+V_N$ ,  $2LL+V_N+LL_Y$ ,  $2LL+V_N+LN_Y$ ,  $LL+V_N+LL_Y+LL_Z$ , and  $LN+V_N+LN_Y+LN_Z$ : the neutral overvoltage is measured with voltage transformer(s) for example using a broken delta connection. The setting values are relative to the  $VT_N$  secondary voltage defined in the configuration.
- $3LN$ : the zero sequence voltage is calculated from the line-to-line voltages and therefore any separate zero sequence voltage transformers are not needed. The setting values are relative to the configured voltage transformer (VT) voltage/ $\sqrt{3}$ .
- $3LN+V_N$  and  $2LL+V_N$ : the zero sequence voltage is measured with voltage transformer(s) for example using a broken delta connection. The setting values are relative to the  $VT_N$  secondary voltage defined in configuration.

### Modes for different network types

The available modes are:

- ResCap

This mode consists of two sub modes, Res and Cap. A digital signal can be used to dynamically switch between these two submodes. When the digital input is active (DI = 1), Cap mode is in use and when the digital input is inactive (DI = 0), Res mode is in use. This feature can be used with compensated networks when the Petersen coil is temporarily switched off.

- Res

The stage is sensitive to the resistive component of the selected  $I_N$  signal. This mode is used with compensated **networks** (resonant grounding) and **networks grounded with a high resistance**. Compensation is usually done with a Petersen coil between the neutral point of the main transformer and ground. In this context, high resistance means that the fault current is limited to be less than the rated phase current. The trip area is a half plane as drawn in [Figure 129 - Operation characteristics of the directional ground fault protection in Res and Cap mode](#) on page 200. The base angle is usually set to zero degrees.

- Cap

The stage is sensitive to the capacitive component of the selected  $I_N$  signal. This mode is used with **ungrounded networks**. The trip area is a half plane as drawn in [Figure 129 - Operation characteristics of the directional ground fault protection in Res and Cap mode](#) on page 200. The base angle is usually set to zero degrees.

- Sector

This mode is used with **networks grounded with a small resistance**. In this context, "small" means that a fault current may be more than the rated phase currents. The trip area has a shape of a sector as drawn in [Figure 130 - Operation characteristics examples of the directional ground fault stages in the sector mode](#) on page 200. The base angle is usually set to zero degrees or slightly on the lagging inductive side (negative angle).

- Undir

This mode makes the stage equal to the non directional stage 50N/51N-1. The phase angle and  $V_N$  amplitude setting are discarded. Only the amplitude of the selected  $I_N$  input is supervised.

### Input signal selection

Each stage can be connected to supervise any of the following inputs and signals:

- Input  $I_{N1}$  for all networks other than solidly grounded.
- Input  $I_{N2}$  for all networks other than solidly grounded.
- Calculated signal  $I_{N\text{Calc}}$  for solidly and low-impedance grounded networks.  $I_{N\text{Calc}} = I_A + I_B + I_C = 3I_N$ .

### Intermittent ground fault detection

Short ground faults make the protection start but does not cause a trip. A short fault means one cycle or more. For shorter than 1 ms transient type of intermittent ground faults in compensated networks, there is a dedicated stage  $I_{0\text{INT}} > 67I_N$ . When starting happens often enough, such intermittent faults can be cleared using the intermittent time setting.

When a new start happens within the set intermittent time, the operation delay counter is not cleared between adjacent faults and finally the stage trips.

### Two independent stages

There are two separately adjustable stages: 67N-1 and 67N-2. Both stages can be configured for definite time delay (DT) or dependent time delay operate time.

### Dependent operate time

Accomplished dependent delays are available for all stages 67N-1 and 67N-2.

The relay shows a scalable graph of the configured delay on the local panel display.

### Dependent time limitation

The maximum measured secondary ground fault overcurrent is  $10 \times I_{0N}$  and the maximum measured phase current is  $50 \times I_N$ . This limits the scope of dependent curves with high start settings.

### Block diagram

Figure 128 - Block diagram of the directional ground fault overcurrent stages 67N-1, 67N-2

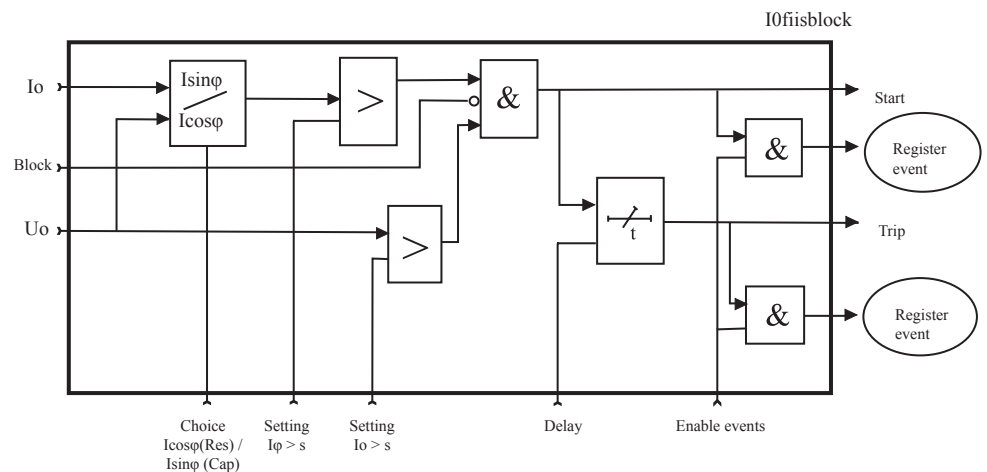
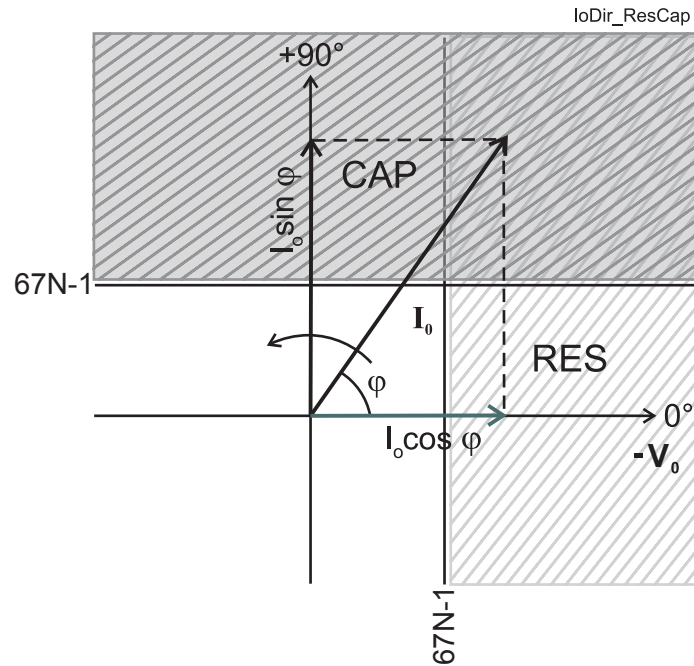
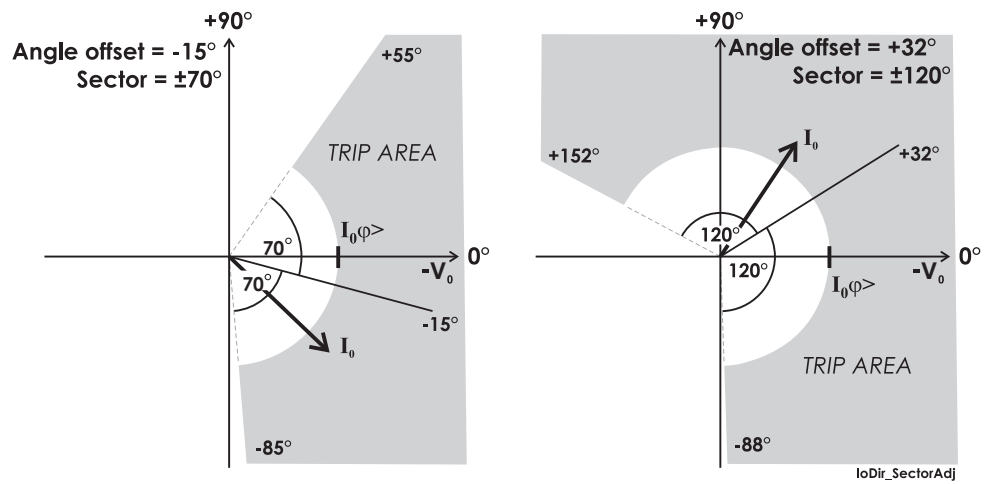


Figure 129 - Operation characteristics of the directional ground fault protection in Res and Cap mode



Res mode can be used with compensated networks.  
 Cap mode is used with ungrounded networks.

Figure 130 - Operation characteristics examples of the directional ground fault stages in the sector mode



The drawn  $I_N$  phasor is inside the trip area.  
 The angle offset and half sector size are user's parameters.

**Setting groups**

There are four setting groups available for each stage.

**Characteristics**

Table 78 - Directional ground fault overcurrent 67N-1, 67N-2 (67N)

Input signal	$I_N, V_N$ $I_{N \text{ Calc}} = (I_A + I_B + I_C)$
Start value 67N-1	0.001–20.00 x $I_{0N}$ (up to 8.00 for inputs other than $I_{N \text{ Calc}}$ )
Start value 67N-2	0.01–20.00 x $I_{0N}$ (up to 8.00 for inputs other than $I_{N \text{ Calc}}$ )
Start voltage	1–100% $V_{0N}$ (step 1%)
Mode	Non-directional/Sector/ResCap
Base angle setting range	-180°–179°
Operate angle	±88°
Definite time function: - Operate time	0.10 <sup>59</sup> – 300.00 s (step 0.02 s)
IDMT function: - Delay curve family - Curve type - Inv. time coefficient k	(DT), IEC, IEEE, RI Prg EI, VI, NI, LTI, MI..., depends on the family <sup>60</sup> 0.025–20.0, except 0.50–20.0 for RI, IEEE and IEEE2
Start time	Typically 60 ms
Reset time	< 95 ms
Reset ratio	0.95
Reset ratio (angle)	2°
Inaccuracy:	
- Starting $V_N$ & $I_N$ (rated value $I_N = 1–5A$ )	±3% of the set value or ±0.3% of the rated value
- Starting $V_N$ & $I_N$ (Peak Mode when, rated value $I_{0N} = 1–10A$ )	±5% of the set value or ±2% of the rated value (Sine wave <65 Hz)
- Starting $V_N$ & $I_N$ ( $I_{N \text{ Calc}}$ )	±3% of the set value or ±0.5% of the rated value
- Angle	±2° when $V > 1V$ and $I_N > 5\%$ of $I_{0N}$ or $> 50 \text{ mA}$ else ±20°

- Operate time at definite time function	±1% or ±30 ms
- Operate time at IDMT function	±5% or at least ±30 ms <sup>59</sup>

<sup>59</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.

<sup>60</sup> EI = Extremely Inverse, NI = Normal Inverse, VI = Very Inverse, LTI = Long Time Inverse, MI= Moderately Inverse

Table 79 - Directional ground fault overcurrent 67N-3 (67N)

Input signal	$I_N, V_N$ $I_{N\text{ Calc}} = (I_A + I_B + I_C)$
Start value	0.005–20.00 x $I_{0N}$ (up to 8.00 for inputs other than $I_{N\text{ Calc}}$ )
Start voltage	1–100% $V_{0N}$ (step 1%)
Mode	Non-directional/Sector/ResCap
Base angle setting range	-180° – 179°
Operation angle	±88°
Definite time function: - Operate time	0.10 <sup>61</sup> – 300.00 s (step 0.02 s)
IDMT function: - Delay curve family - Curve type - Inv. time coefficient k	(DT), IEC, IEEE, RI Prg EI, VI, NI, LTI, MI..., depends on the family <sup>62</sup> 0.05–20.0, except 0.50–20.0 for RI, IEEE and IEEE2
Start time	Typically 60 ms
Reset time	< 95 ms
Reset ratio	0.95
Reset ratio (angle)	2°
Inaccuracy:	
- Starting $V_N$ & $I_N$ (rated value $I_N = 1 - 5A$ )	±3% of the set value or ±0.3% of the rated value
- Starting $V_N$ & $I_N$ (Peak Mode when, rated value $I_{0N} = 1 - 10A$ )	±5% of the set value or ±2% of the rated value (Sine wave <65 Hz)
- Starting $V_N$ & $I_N$ ( $I_{N\text{ Calc}}$ )	±3% of the set value or ±0.5% of the rated value

- Angle	$\pm 2^\circ$ when $V > 1V$ and $I_N > 5\%$ of $I_{0N}$ or $> 50$ mA else $\pm 20^\circ$
- Operate time at definite time function	$\pm 1\%$ or $\pm 30$ ms
- Operate time at IDMT function	$\pm 5\%$ or at least $\pm 30$ ms <sup>61</sup>

<sup>61</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.

<sup>62</sup> EI = Extremely Inverse, NI = Normal Inverse, VI = Very Inverse, LTI = Long Time Inverse, MI = Moderately Inverse

## 6.27.1 Ground fault phase detection

The ground fault overcurrent stage (ANSI 50N/51N) and directional ground fault overcurrent stage (ANSI 67N) have an inbuilt detection algorithm to detect a faulty phase. This algorithm is meant to be used in radial-operated distribution networks. The faulty phase detection can be used in solidly-grounded, impedance-grounded or resonant-grounded networks.

### Operation

The faulty phase detection starts from the ground fault stage trip. At the moment of stage start, the phase currents measured prior to start are registered and stored as prior-to-fault currents. At the moment of trip, phase currents are registered again. Finally, faulty phase detection algorithm is performed by comparing prior-to-fault currents to fault currents. The algorithm also uses positive sequence current and negative sequence current to detect faulty phase.

The detection algorithm can be enabled and disabled by selecting or unselecting a checkbox in the protection stage settings. Correct network grounding configuration must be selected in the stage settings, too. In the ground fault overcurrent stage settings, you can select between RES and CAP network grounding configuration. This selection has no effect on the protection itself, only on the faulty phase detection. In the directional ground fault overcurrent stage settings, the detection algorithm uses the same network grounding type as selected for protection. RES is used for solidly-grounded, impedance-grounded and resonant-grounded networks. CAP is only used for isolated networks.

The detected faulty phase is registered in the protection stage fault log (and also in the event list and alarm screen). Faulty phase is also indicated by a line alarm and line fault signals in the output matrix.

Possible detections of faulty phases are A-N, B-N, C-N, AB-N, AC-N, BC-N, ABC-N, and REV. If the relay protection coordination is incorrect, REV indication is given in case of a relay sympathetic trip to a reverse fault.

## 6.28 Second harmonic inrush detection (ANSI 68F2)

### Description

This stage is mainly used to block other stages. The ratio between the second harmonic component and the fundamental frequency component is measured on

all the phase currents. When the ratio in any phase exceeds the setting value, the stage gives a start signal. After a settable delay, the stage gives a trip signal.

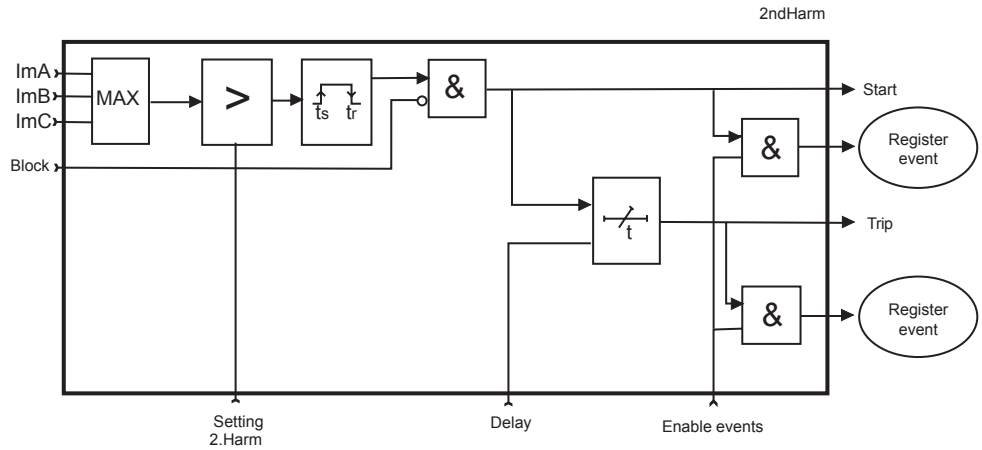
The start and trip signals can be used for blocking the other stages.

The trip delay is irrelevant if only the start signal is used for blocking.

The trip delay of the stages to be blocked must be more than 60 ms to ensure a proper blocking.

**Block diagram**

Figure 131 - Block diagram of the second harmonic inrush detection stage



**Characteristics**

Table 80 - Second harmonic inrush detection (68F2)

Input signal	$I_A - I_C$
Settings:	
- Start value	10–100 % (step 1%)
- Operate time	0.03–300.00 s (step 0.01 s)
Inaccuracy:	
- Starting	$\pm 1\%$ - unit

**NOTE:** The amplitude of second harmonic content has to be at least 2% of the nominal of CT. If the nominal current is 5 A, the 100 Hz component needs to exceed 100 mA.

## 6.29 Fifth harmonic detection (ANSI 68H5)

**Description**

Overexcitation of a transformer creates odd harmonics. The fifth harmonic detection stage can be used detect overexcitation. This stage can also be used to block some other stages.



The ratio between the fifth harmonic component and the fundamental frequency component is measured on all the phase currents. When the ratio in any phase exceeds the setting value, the stage activates a start signal. After a settable delay, the stage operates and activates a trip signal.

The trip delay of the stages to be blocked must be more than 60 ms to ensure a proper blocking.

### Characteristics

Table 81 - Fifth harmonic detection (68H5)

Input signal	$I_A - I_C$
Settings:	
- Setting range over excitation	10–100% (step 1%)
- Operate time	0.03–300.00 s (step 0.01 s)
Inaccuracy:	
- Starting	±2%- unit

## 6.30 Pole slip protection (ANSI 78)

**NOTE:** This protection stage is available only in the voltage measurement modes 3LN, 3LN+V<sub>N</sub>, 3LN+LLy, and 3LN+LNy (see [10.8 Voltage system configuration](#) on page 368).

Dynamic changes in a power system such as prolonged short circuits, load jumps or line switching operations may lead to power system oscillations known as power swings. A power swing manifests itself as regular large fluctuations in currents, voltages and power angles between power system parts.

In a stable power swing situation, power oscillations decay and diminish within few seconds. After a stable power swing, synchronism is recaptured and the system reaches new stable equilibrium conditions. Such a stable power swing should not cause a generator or power system part to be separated from the rest of the power system.

In an unstable power swing, power oscillations continue to grow eventually causing loss of synchronism or pole slipping. Pole slipping can very quickly result in generator overloading and damages. When a generator is working out of step or pole slipping occurs, the generator is alternatively producing generating and motoring action in a cycle of some seconds. This oscillation between the generating and motoring mode causes high mechanical stress to generator and prime mover and also high electrical overload. Unstable operation conditions may also cause propagation of disturbances in the power system leading to possible widespread outages. A generator under out-of-step condition must be separated from the rest of power system.

The generator may pole slip because of various reasons. A few most obvious reasons are:

- the prime mover or governor failure
- the failure in generator operating close to its stability limits
- prolonged clearance of low-impedance fault

- generator unsynchronized connection to a power system
- any disturbance in the network switching action

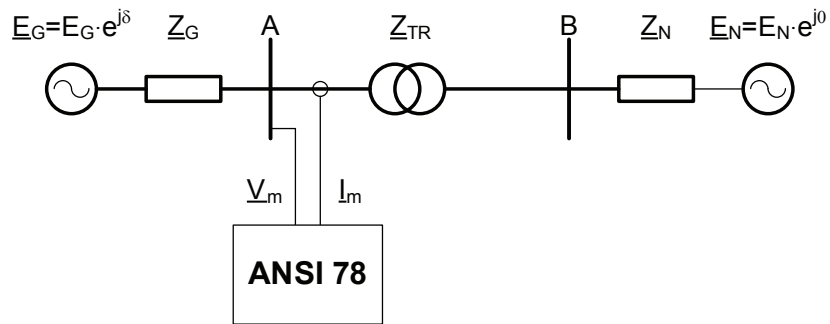
**Pole slip protection principle**

A common method to implement pole slipping protection is to measure the apparent impedance in the generator or block transformer terminals and track impedance vector trajectory in the RX plane. Apparent generator impedance measured on generator terminals (Point A) varies as a function of the power angle and ratio of the generator and power system voltages. Apparent impedance is plotted on the RX plane where a characteristic set of impedance loci is shown. The decision to separate the generator from the power system is based on an actual course of impedance vectors (loci) on the RX plane.

As pole slipping is essentially a symmetrical phenomenon, the apparent impedances are calculated from the positive sequences' fundamental frequency components of the voltages and currents.

A common practice to illustrate pole slipping is to use a simplified two-machine model. The following diagram shows the generator, power network and equivalent voltages  $\underline{V}_G$  and  $\underline{V}_N$ . The generator, power network and possible transformer impedances lie between these two sources. Total system impedance  $Z_{tot}$  is the sum of component impedances  $\underline{Z}_G$ ,  $\underline{Z}_{TR}$  and  $\underline{Z}_N$ .

Figure 132 - Two machine model of power swing



The following equations apply on location A:

Equation 24 - Total impedance

$$\underline{Z}_{tot} = \underline{Z}_G + \underline{Z}_{TR} + \underline{Z}_N$$

Equation 25 - Measured current, independent of location

$$\underline{I}_m = \underline{I} = \frac{\underline{E}_G - \underline{E}_N}{\underline{Z}_{tot}}$$

Equation 26 - Measured voltage at location A

$$\underline{V}_m = \underline{E}_G - \underline{Z}_G \cdot \underline{I}$$

Equation 27 - Measured apparent impedance

$$\underline{Z}_m = \frac{V_m}{I}$$

Substitute  $V_M$  and  $I$  with [Equation 25](#) on page 206 and [Equation 26](#) on page 206 in [Equation 27](#) on page 207.

Equation 28

$$\underline{Z}_m = \frac{\underline{E}_G}{\underline{E}_G - \underline{E}_N} \cdot \underline{Z}_{tot} - \underline{Z}_G = \frac{\underline{Z}_{tot}}{1 - \frac{\underline{E}_N}{\underline{E}_G}} - \underline{Z}_G$$

As  $\underline{E}_G = E_G \cdot e^{-j\delta}$  and  $\underline{E}_N = E_N \cdot e^{-j0} = E_N$ , [Equation 28](#) on page 207 becomes as

Equation 29

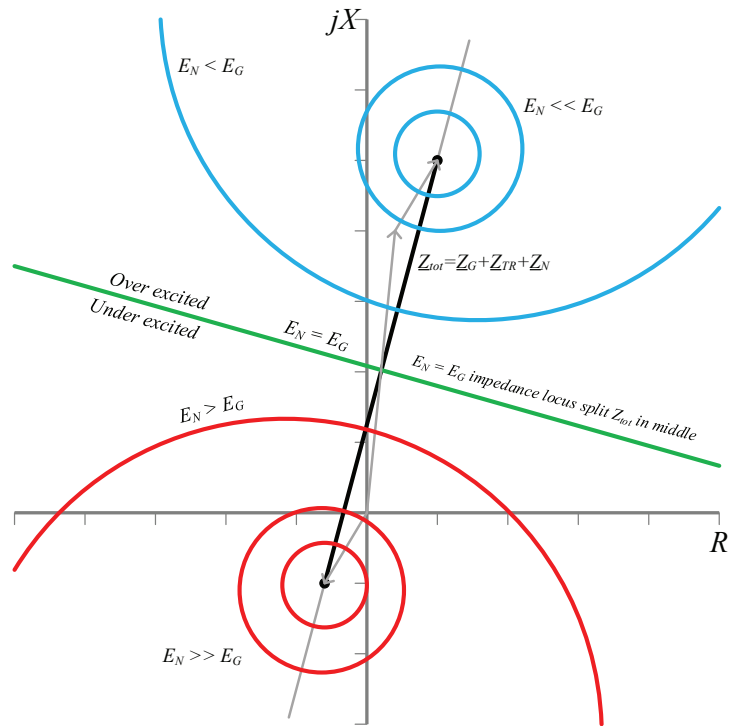
$$\underline{Z}_m = \frac{\underline{Z}_{tot}}{1 - \frac{E_N}{E_G} \cdot e^{j\delta}} - \underline{Z}_G$$

[Equation 29](#) on page 207 represents the impedance behavior of a two-machine model in the pole slipping condition. Plotting impedances on the RX plane as a function of power angle  $\delta$  and voltage ratio  $E_N/E_G$  gives a set of impedance loci representing apparent impedance behavior with the given power angle  $\delta$  and voltage ratio  $E_N/E_G$ .

In stable operation conditions, the power angle  $\delta$  depends on the generator load and it is essentially constant. In stable operation conditions, the power angle  $\delta$  varies between  $30^\circ$  and  $60^\circ$  depending on the generator load. During pole slipping, the power angle  $\delta$  can vary between  $0^\circ$  and  $360^\circ$  and therefore, impedance behavior according to [Equation 29](#) on page 207 should be plotted with a power angle ranging from  $0^\circ$  to  $360^\circ$ . While plotting impedance loci, the voltage ratio  $E_N/E_G$  is assumed to be constant during the pole slip, resulting in a circular impedance loci.

[Figure 133 - Pole slipping impedance loci](#) on page 208 represents the general concept of apparent impedance behavior during the pole slip.

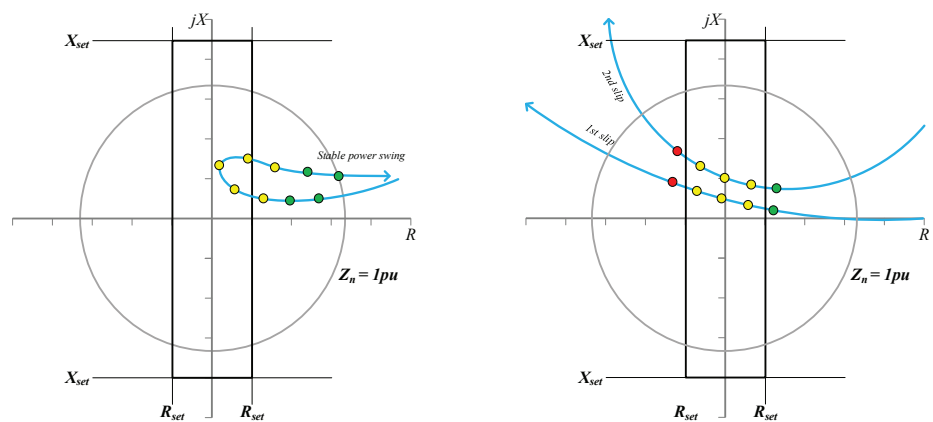
Figure 133 - Pole slipping impedance loci



**Protection settings**

The pole slip protection stage has a rectangular power swing detection characteristic that is set by forward and reverse R and X. The setting values are given as relative to the generator nominal impedance. As the measured apparent impedance locus passes the set power swing characteristic, the pole slip is detected and count. The pole slip is counted only if the positive sequence current exceeds the minimum threshold value.

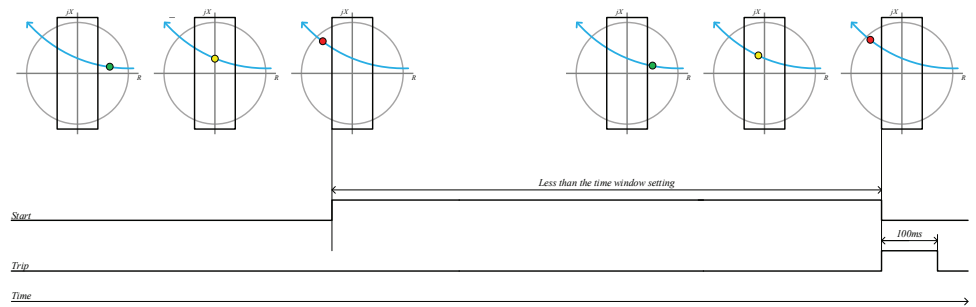
Figure 134 - Stable and unstable power swing (pole slip) in reference to the detection characteristics



The first detected pole slip starts the stage counter. If the required number of pole slips occurs within the set time window, the stage trips. The tripping pulse has a

fixed length of 100 ms. [Figure 135 - Pole slip protection stage starting and tripping on page 209](#) shows the stage starting and tripping actions.

Figure 135 - Pole slip protection stage starting and tripping

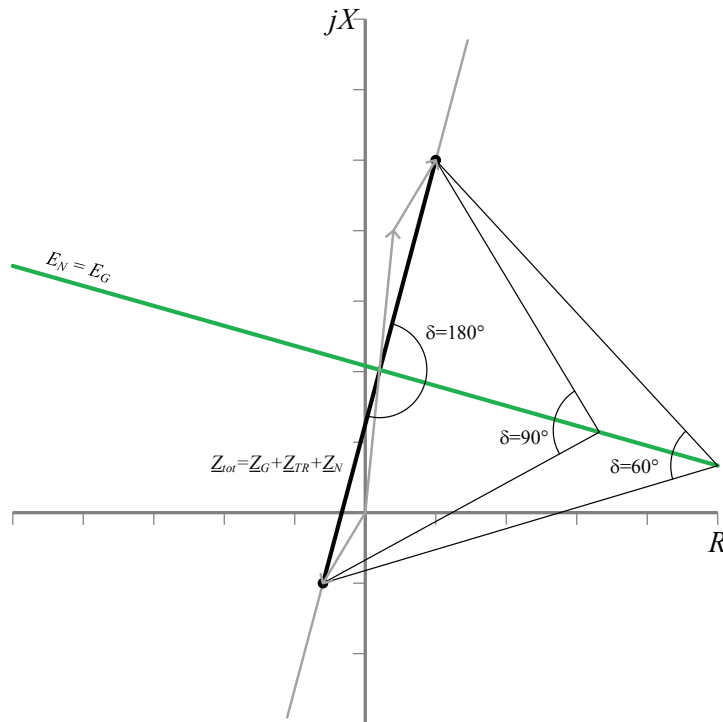


**Finding out the settings**

Plotting [Equation 29 on page 207](#) in the RX plane when  $E_N = E_G$  and adding total impedance line  $Z_{tot}$  together with two lines connecting the swing center line and both source impedances gives a graphical presentation of the  $E_N/E_G$  ratio and power angle  $\delta$ . This graphical presentation is a great aid in determining the out-of-step stage setting.

[Figure 136 - Total impedance line and swing center line in RX plane on page 209](#) shows the impedance swing locus, source impedances connected with total impedance vector  $Z_{tot}$  and three points on swing trajectory representing three different generator operating conditions.

Figure 136 - Total impedance line and swing center line in RX plane



The rightmost operating point identifies the operating point where the power angle  $\delta=60^\circ$ . This can be considered to be within an acceptable power angle range. Therefore, the stage setting should rule out this operating point.

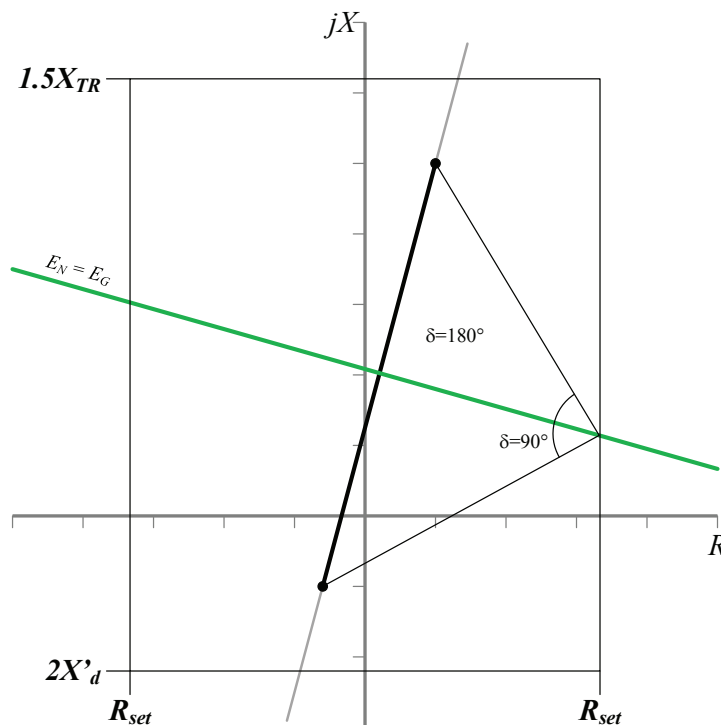
The operating point  $\delta=90^\circ$  is the stability limit of the two-machine model shown in [Figure 132 - Two machine model of power swing on page 206](#). Setting  $R_{set}$  according to  $\delta=90^\circ$  is a good candidate for the setting point. To have some safety margin, a somewhat bigger power angle  $\delta$  can be selected.

The last operating point in [Figure 136 - Total impedance line and swing center line in RX plane on page 209](#) indicates the moment of  $E_N$  and  $E_G$  phase reversal. Initiating circuit breaker trip command when  $E_N$  and  $E_G$  are in phase reversal results in CB opening in the moment of the highest load. This should be avoided.

Reactance settings of the stage are defined in accordance of source reactance and transformer and line reactance. In pole slipping conditions, the generator synchronous impedance  $X_d$  is not valid but transient impedance  $X'_d$  should be used. In source direction reactance, a setting of  $2X'_d$  can be used and in line direction, the setting value can be set in a range of  $1-1.5 \times X_{TR}$ . [Figure 137 - Pole slip stage setting principles on page 210](#) shows the setting values for the out-of-step stage.

Pole slip frequency is a characteristic property of the power system that is determined by generator torque and inertia. Slip frequency can not be determined analytically but utilizing transient stability studies. The slip frequency is not constant. From the protection point of view, the start of pole slipping it the most important moment. At the first moment of an unstable power swing, the slipping frequency may be in a range of 0.5–2.5Hz.

Figure 137 - Pole slip stage setting principles



### Setting groups

There are four setting groups available for each stage.

### Characteristics

Table 82 - Pole slipping stage (78)

R setting forward	0.10–1.00 $\times Z_N$
R setting reverse	0.10–1.00 $\times Z_N$
X setting reverse	0.10–1.00 $\times Z_N$
X setting reverse	0.10–1.00 $\times Z_N$
I1 min setting	0.10–1.00 $\times Z_N$
Number of pole slips	1–10
Time window	0.10–600.0 s

## 6.31 Overfrequency and underfrequency (ANSI 81)

### Description

Frequency protection is used for load sharing and shedding, loss of power system detection and as a backup protection for overspeeding.

The frequency function measures the frequency from the two first voltage inputs. At least one of these two inputs must have a voltage connected to be able to measure the frequency. Whenever the frequency crosses the start setting of a particular stage, this stage starts, and a start signal is issued. If the fault remains on longer than the operating delay setting, a trip signal is issued. For situations where no voltage is present, an adapted frequency is used.

### Protection mode for 81–1 and 81–2 stages

These two stages can be configured either for overfrequency or for underfrequency.

### Undervoltage self-blocking of underfrequency stages

The underfrequency stages are blocked when the biggest of the three line-to-line voltages is below the low-voltage block limit setting. With this common setting, LVBik, all stages in underfrequency mode are blocked when the voltage drops below the given limit. The idea is to avoid purposeless alarms when the voltage is off.

### Initial self-blocking of underfrequency stages

When the biggest of the three line-to-line voltages has been below the block limit, the underfrequency stages are blocked until the start setting has been reached.

### Four independent frequency stages

There are four separately adjustable frequency stages: 81–1, 81–2, 81U–1, 81U–2. The two first stages can be configured for either overfrequency or underfrequency usage. So totally four underfrequency stages can be in use simultaneously. Using the programmable stages even more can be implemented (chapter [6.36 Programmable stages \(ANSI 99\)](#) on page 232). All the stages have definite operate time delay (DT).

### Setting groups

There are four setting groups available for each stage.

### Characteristics

Table 83 - Overfrequency and underfrequency 81–1, 81–2 (81H/81L)

Input signal	$V_A - V_C$
Frequency measuring area	16.0–75.0 Hz
Current and voltage meas. range	45.0–65.0 Hz
Frequency stage setting range	40.0–70.0 Hz (step 0.01)
Low-voltage blocking	10–100% $V_n$
Definite time function: - Operate time	$0.10^{63} - 300.0$ s (step 0.02 s)
Start time	< 100 ms
Reset time	<120 ms
Reset ratio (LV block)	Instant (no hysteresis)
Inaccuracy: - Starting - Starting (LV block) - operate time	$\pm 20$ mHz 3% of the set value or $\pm 0.5$ V $\pm 1\%$ or $\pm 30$ ms

<sup>63</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.

**NOTE:** If the relay restarts for some reason, there is no trip even if the frequency is below the set limit during the start-up (Start and trip is blocked). To cancel this block, frequency has to rise above the set limit.

Table 84 - Underfrequency 81U–1, 81U–2 (81L)

Input signal	$V_A - V_C$
Frequency measuring area	16.0–75.0 Hz
Current and voltage meas. range	45.0–65.0 Hz
Frequency stage setting range	40.0–64.0 Hz



Low-voltage blocking	10–100% $V_n$
Definite time function: - operate time	$0.10^{64} - 300.0$ s (step 0.02 s)
Undervoltage blocking	2–100 %
Start time	< 100 ms
Reset time	< 120 ms
Reset ratio	1.002
Reset ratio (LV block)	Instant (no hysteresis)
Inaccuracy: - Starting - starting (LV block) - operate time	$\pm 20$ mHz 3% of the set value or $\pm 0.5$ V $\pm 1\%$ or $\pm 30$ ms

<sup>64</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.

## 6.32 Rate of change of frequency (ANSI 81R)

### Description

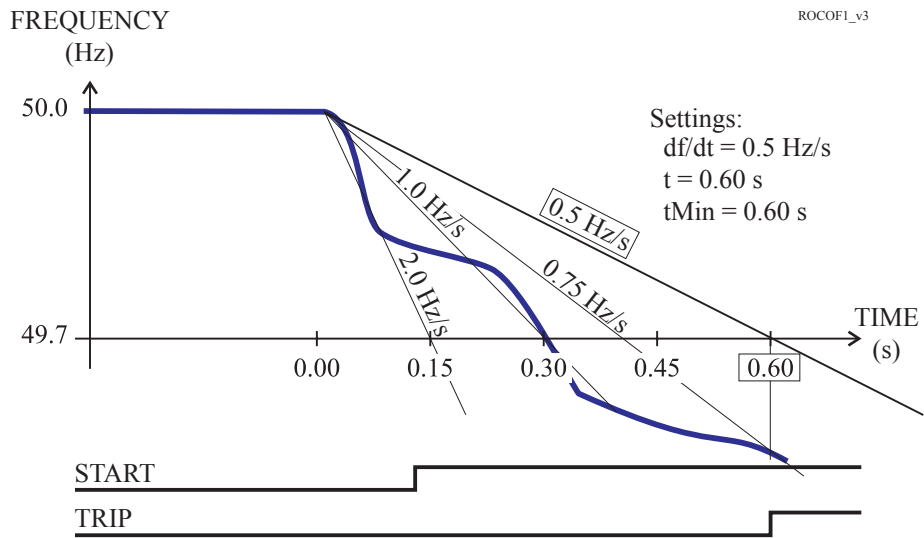
The rate of change of frequency (ROCOF or  $df/dt$ ) function is used for fast load shedding, to speed up operate time in overfrequency and underfrequency situations and to detect loss of grid. For example, a centralized dedicated load shedding relay can be omitted and replaced with distributed load shedding, if all outgoing feeders are equipped with Easergy P3 relays.

A special application for ROCOF is to detect loss of grid (loss of mains, islanding). The more the remaining load of the local generator differs from the load before the loss of grid, the better the ROCOF function detects the situation.

### Frequency behavior during load switching

Load switching and fault situations may generate change in frequency. A load drop may increase the frequency and increasing load may decrease the frequency, at least for a while. The frequency may also oscillate after the initial change. After a while, the control system of any local generator may drive the frequency back to the original value. However, in case of a heavy short-circuit fault or if the new load exceeds the generating capacity, the average frequency keeps on decreasing.

Figure 138 - An example of definite time df/dt operate time. At 0.6 s, which is the delay setting, the average slope exceeds the setting 0.5 Hz/s and a trip signal is generated.



**ROCOF implementation**

The ROCOF function is sensitive to the absolute average value of the time derivate of the measured frequency  $|df/dt|$ . Whenever the measured frequency slope  $|df/dt|$  exceeds the setting value for 80 ms time, the ROCOF stage starts and issues a start signal after an additional 60 ms delay. If the average  $|df/dt|$ , since the start moment, still exceeds the setting, when the operation delay has elapsed, a trip signal is issued. In this definite time mode the second delay parameter "minimum delay,  $t_{MIN}$ " must be equal to the operation delay parameter "t".

If the frequency is stable for about 80 ms and the time t has already elapsed without a trip, the stage resets.

**ROCOF and overfrequency and underfrequency stages**

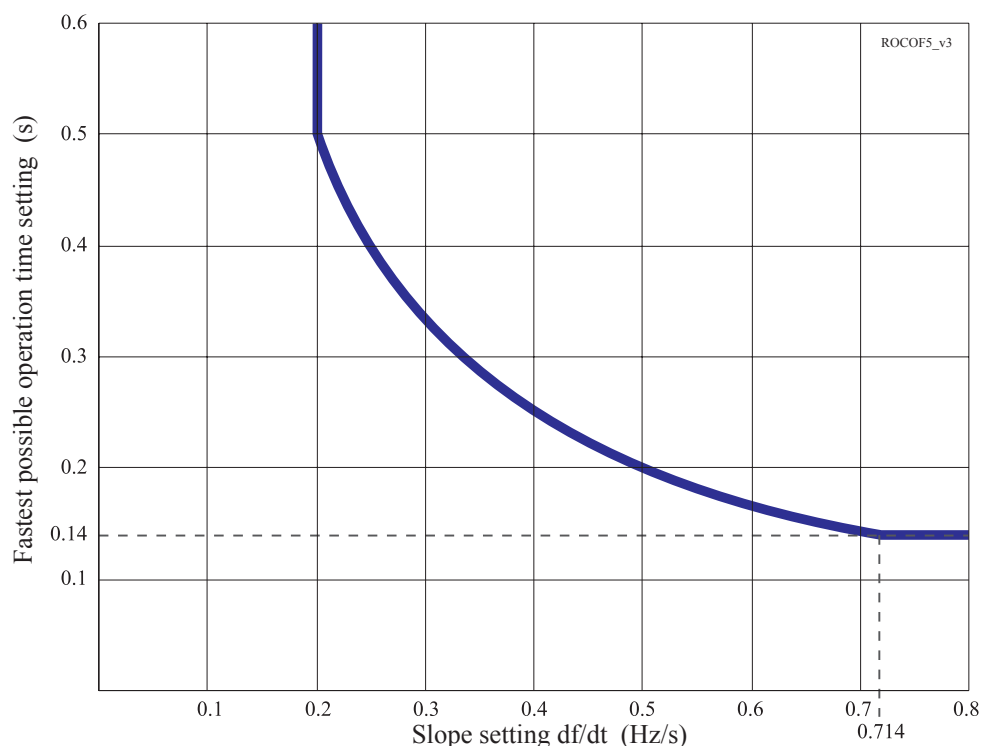
One difference between the overfrequency and underfrequency and the df/dt function is the speed. Often a df/dt function can predict an overfrequency or underfrequency situation and is thus faster than a simple overfrequency or underfrequency function. However, in most cases, standard overfrequency and underfrequency stages must be used together with ROCOF to ensure tripping also if the frequency drift is slower than the slope setting of ROCOF.

**Definite operate time characteristics**

*Figure 138 - An example of definite time df/dt operate time. At 0.6 s, which is the delay setting, the average slope exceeds the setting 0.5 Hz/s and a trip signal is generated.* on page 214 shows an example where the df/dt start value is 0.5 Hz/s and the delay settings are  $t = 0.60$  s and  $t_{MIN} = 0.60$  s. Equal times  $t = t_{MIN}$  gives a definite time delay characteristic. Although the frequency slope fluctuates, the stage does not release but continues to calculate the average slope since the initial start. At the defined operate time,  $t = 0.6$  s, the average slope is 0.75 Hz/s. This exceeds the setting, and the stage trips.

At slope settings less than 0.7 Hz/s, the fastest possible operate time is limited according to the [Figure 139 - At very sensitive slope settings the fastest possible operate time is limited.](#) on page 215.

Figure 139 - At very sensitive slope settings the fastest possible operate time is limited.



### Dependent operate time characteristics

By setting the second delay parameter  $t_{\text{MIN}}$  smaller than the operate time delay  $t$ , a dependent type of operate time characteristic is achieved.

[Figure 141 - An example of dependent df/dt operate time. The time to trip will be 0.3 s, although the setting is 0.6 s, because the average slope 1 Hz/s is steeper than the setting value 0.5 Hz/s.](#) on page 217 shows one example, where the frequency behavior is the same as in the first figure, but the  $t_{\text{MIN}}$  setting is 0.15 s instead of being equal to  $t$ . The operate time depends on the measured average slope according to the following equation:

Equation 30

$$t_{\text{TRIP}} = \frac{s_{\text{SET}} \cdot t_{\text{SET}}}{|s|}$$

$t_{\text{TRIP}}$  = Resulting operate time (seconds).

$s_{\text{SET}}$  = df/dt i.e. slope setting (hertz/seconds).

$t_{\text{SET}}$  = Operate time setting  $t$  (seconds).

$s$  = Measured average frequency slope (hertz/seconds).

The minimum operate time is always limited by the setting parameter  $t_{MIN}$ . In the example, the fastest operate time, 0.15 s, is achieved when the slope is 2 Hz/s or more. The leftmost curve in [Figure 140 - Three examples of possible dependent df/dt operate time characteristics. The slope and operation delay settings define the knee points on the left. A common setting for  \$t\_{Min}\$  has been used in these three examples. This minimum delay parameter defines the knee point positions on the right.](#) on page 216 shows the dependent characteristics with the same settings as in [Figure 141 - An example of dependent df/dt operate time. The time to trip will be 0.3 s, although the setting is 0.6 s, because the average slope 1 Hz/s is steeper than the setting value 0.5 Hz/s.](#) on page 217.

Figure 140 - Three examples of possible dependent df/dt operate time characteristics. The slope and operation delay settings define the knee points on the left. A common setting for  $t_{Min}$  has been used in these three examples. This minimum delay parameter defines the knee point positions on the right.

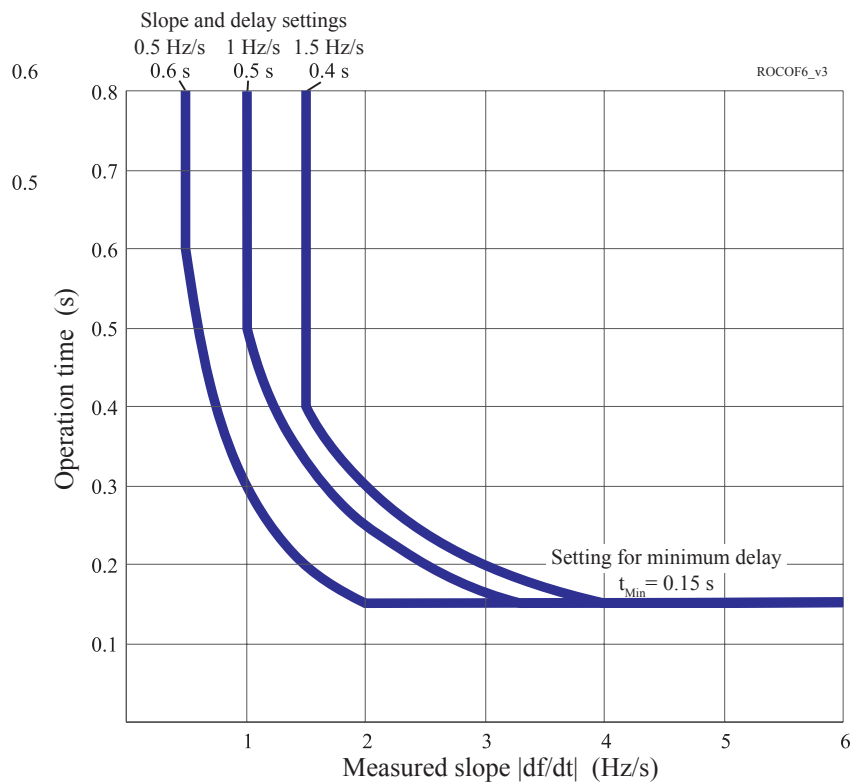
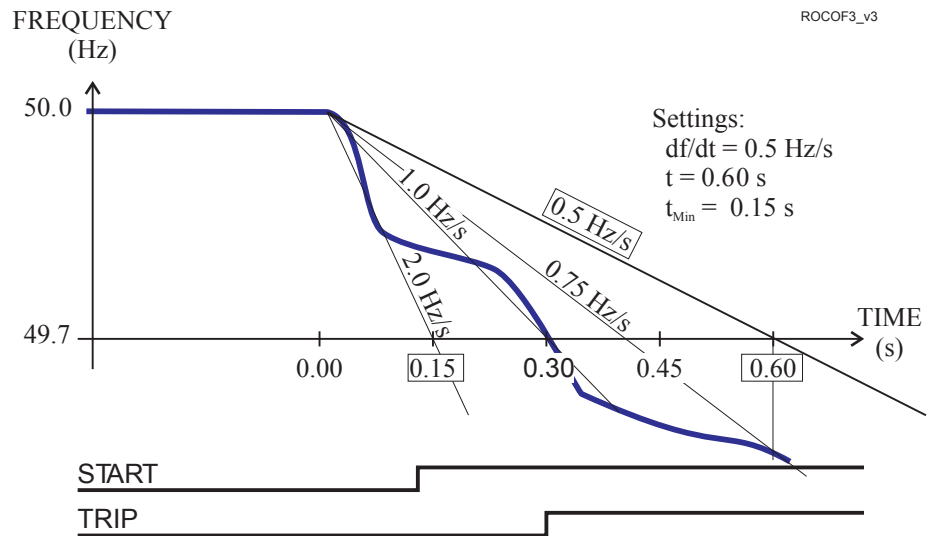


Figure 141 - An example of dependent df/dt operate time. The time to trip will be 0.3 s, although the setting is 0.6 s, because the average slope 1 Hz/s is steeper than the setting value 0.5 Hz/s.



**Settings groups**

There are four setting groups available.

**Characteristics**

Table 85 - Rate of change of frequency 81R (81R)

Start setting df/dt	0.2–10.0 Hz/s (step 0.1 Hz/s)
Definite time delay (t> and t <sub>Min</sub> > are equal):	
- Operate time t>	0.14 <sup>65</sup> – 10.00 s (step 0.02 s)
Dependent time delay (t> is more than t <sub>Min</sub> >):	
- Minimum operate time t <sub>Min</sub> >	0.14 <sup>65</sup> – 10.00 s (step 0.02 s)
Start time	Typically 140 ms
Reset time	150 ms
Overshoot time	< 90 ms
Reset ratio	1
Inaccuracy:	
- Starting	10% of set value or ±0.1 Hz/s
- Operate time(overshoot ≥ 0.2 Hz/s)	±35 ms, when area is 0.2 – 1.0 Hz/s

<sup>65</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.

**NOTE:** ROCOF stage is using the same low voltage blocking limit as the frequency stages.

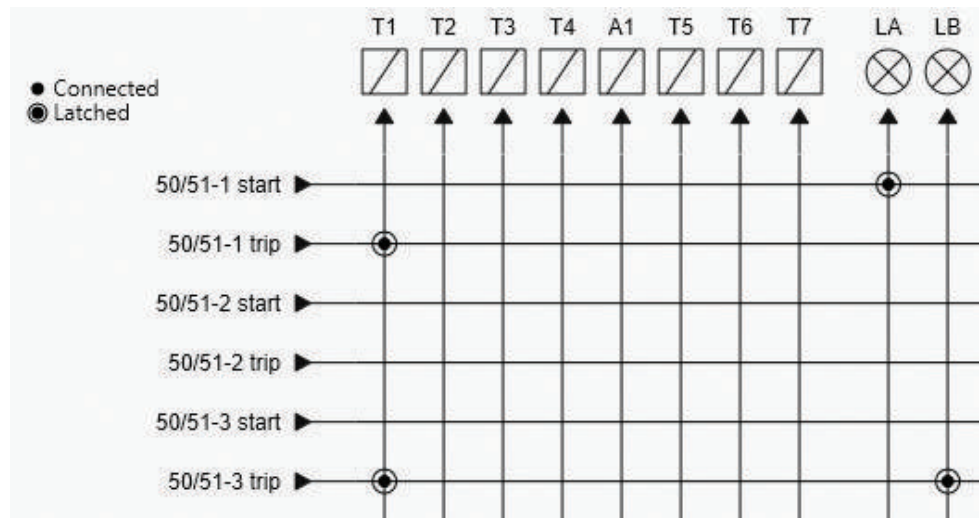
## 6.33 Lockout (ANSI 86)

### Description

The lockout feature, also called latching, can be programmed for outputs in the **Output matrix** setting view. Any protection stage start or trip, digital input, logic output, alarm and GOOSE signal connected to the following outputs can be latched when required:

- output contacts T1 – T7, A1
- LEDs on the front panel
- virtual outputs VO1- VO20

Figure 142 - The lockout programmed for LED A and 50/51-2 trip signals



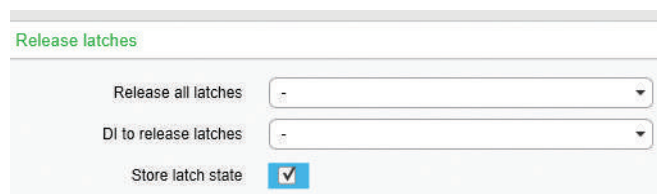
In [Figure 142 - The lockout programmed for LED A and 50/51-2 trip signals](#) on page 218, the latched signal is identified with a dot and circle in the matrix signal line crossing.

The lockout can be released through the display or via the Easergy Pro. See Chapter 4 Control functions.

### Storing latch states

In the **General > Release latches** setting view, select the **Store latch state** setting to configure latched states of relay outputs, virtual outputs, binary outputs (BO) and high-speed outputs (HSO) to be stored. If some of these outputs are latched and in “on” state, and the device is restarted, their status is set back to “on” after restart.

Figure 143 - Store latch setting view



In the **LED configuration** setting view, you can configure the latched states of LEDs to be stored after a restart. In this example, storing has been configured for LED A (green).

Figure 144 - LED configuration example

LED configuration				
LED	Description	Latch	Blink	Store
LED A (green)	LED A (green)	<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input checked="" type="checkbox"/>
LED A (red)	LED A (red)	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
LED B (green)	LED B (green)	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
LED B (red)	LED B (red)	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
LED C (green)	LED C (green)	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
LED C (red)	LED C (red)	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
LED D (green)	LED D (green)	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
LED D (red)	LED D (red)	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>

**NOTE:** To use the **Store** setting, **Latch** must also be selected.

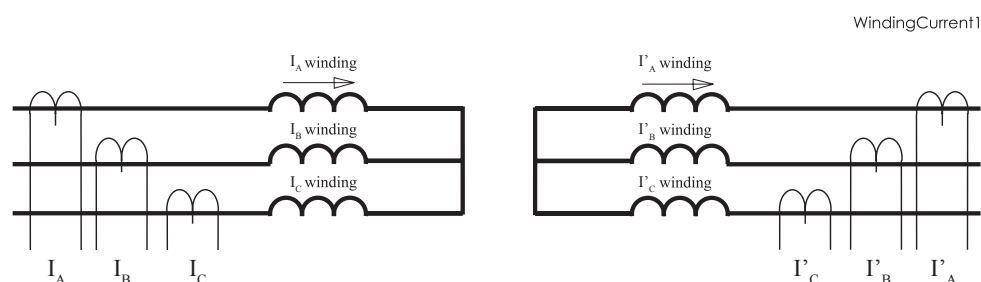
## 6.34 Differential overcurrent protection (ANSI 87M)

### Description

The differential overcurrent protection comprises of two separately adjustable stages: 87-1 and 87-2.

The differential protection is based on the winding currents' difference between I-1 and I-2 side. In a Yy0 connection, the measured currents are also winding currents, see [Figure 145 - Winding currents in connection group Yy0 on page 219](#). In pure generator applications, the connection group is always Yy0. But should the generator also have a block transformer, the connection group is dependent on both the generator and transformer groups.

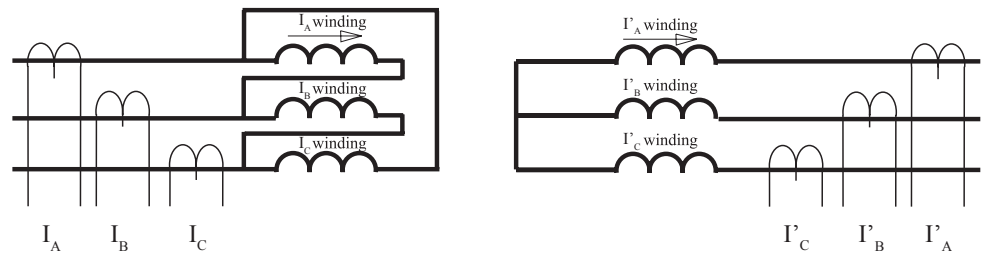
Figure 145 - Winding currents in connection group Yy0



In the second example, if the transformer IL side is connected to open delta for example Dy11, then the winding currents are calculated on the delta side (IL side), see [Figure 146 - Winding currents in connection group Dy11 on page 220](#).

Figure 146 - Winding currents in connection group Dy11

WindingCurrent2



Equation 31 - Winding current calculation in delta side, Dy11 connection

$$\frac{\overline{I_{AW}}}{\sqrt{3}} = \frac{(\overline{I_A} - \overline{I_B})}{\sqrt{3}}$$

$$\frac{\overline{I_{BW}}}{\sqrt{3}} = \frac{(\overline{I_B} - \overline{I_C})}{\sqrt{3}}$$

$$\frac{\overline{I_{CW}}}{\sqrt{3}} = \frac{(\overline{I_C} - \overline{I_A})}{\sqrt{3}}$$

Equation 32 - Winding currents in star side, Dy11 connection

$$\overline{I'_{AW}} = \overline{I'_A}$$

$$\overline{I'_{BW}} = \overline{I'_B}$$

$$\overline{I'_{CW}} = \overline{I'_C}$$

Equation 33 - Bias current

$$I_b = \frac{|\overline{I_W}| + |\overline{I'_W}|}{2}$$

Equation 34 - Differential current

$$I_d = |\overline{I_W} - \overline{I'_W}|$$

Bias current calculation is only used in protection stage 87-1>. Bias current describes the average current flow in the transformer. Bias and differential currents are calculated individually for each phase.



If the transformer is grounded, for example having the connection group Dyn11, then zero current must be compensated before differential and bias current calculation. Zero current compensation can be selected individually for the IL and I'L side.

[Table 86 - Zero-current compensation in transformer applications](#) on page 221 describes the connection group and zero current compensation for different connection groups. If the protection area is only generator, then the connection group setting is always Yy0, see [Table 86 - Zero-current compensation in transformer applications](#) on page 221. Also the settings of Vn and V'n are set to be the same, for example generator nominal voltage.

Table 86 - Zero-current compensation in transformer applications

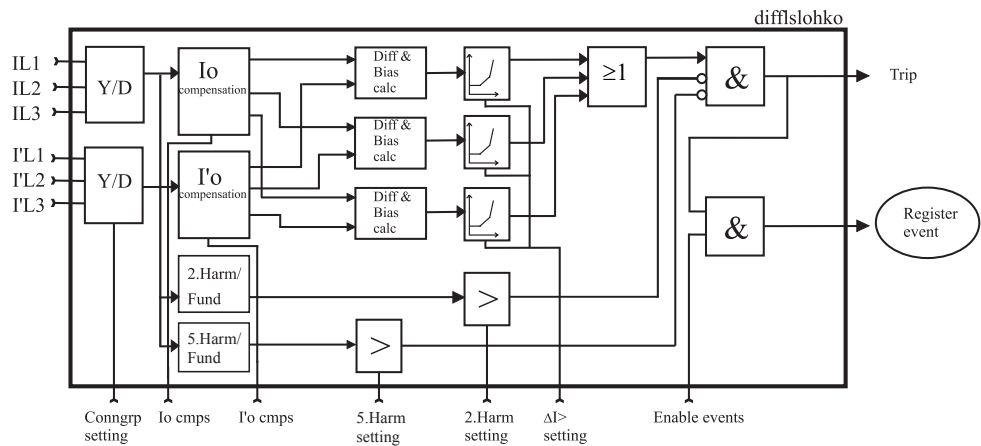
Transformer	Relay setting		
Connection group	ConnGrp	Io cmps	I'o cmps
YNy0	Yy0	ON	OFF
YNyn0	Yy0	ON	ON
Yy0	Yy0	OFF	OFF
Yyn0	Yy0	OFF	ON
YNy6	Yy6	ON	OFF
YNyn6	Yy6	ON	ON
Yy6	Yy6	OFF	OFF
Yyn6	Yy6	OFF	ON
Yd1	Yd1	OFF	OFF
YNd1	Yd1	ON	OFF
Yd5	Yd5	OFF	OFF
YNd5	Yd5	ON	OFF
Yd7	Yd7	OFF	OFF
YNd7	Yd7	ON	OFF
Yd11	Yd11	OFF	OFF
YNd11	Yd11	ON	OFF
Dy1	Dy1	OFF	OFF
Dyn1	Dy1	OFF	ON
Dy5	Dy5	OFF	OFF
Dyn5	Dy5	OFF	ON
Dy7	Dy7	OFF	OFF

Transformer	Relay setting		
Connection group	ConnGrp	Io cmps	I'o cmps
Dyn7	Dy7	OFF	ON
Dy11	Dy11	OFF	OFF
Dyn11	Dy11	OFF	ON

Table 87 - Zero-current compensation in generator applications

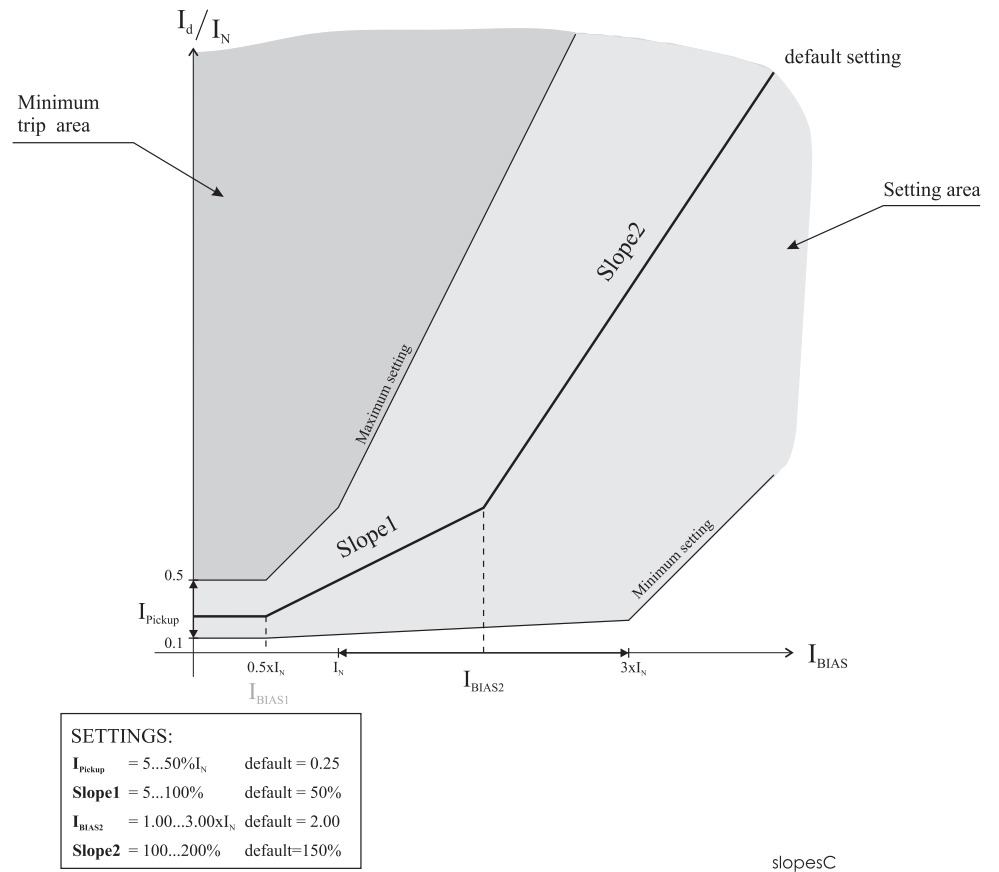
Generator only	Relay setting		
	ConnGrp	Io cmps	I'o cmps
No grounding	Yy0	OFF	OFF

Figure 147 - Block diagram of the differential overcurrent stage  $\Delta I >$



The stage 87–1 can be configured to operate as shown in [Figure 148 - Example of differential overcurrent characteristics](#) on page 223. This dual slope characteristic allows more differential current at higher currents before tripping.

Figure 148 - Example of differential overcurrent characteristics



The stage also includes second harmonic blocking. The second harmonic is calculated from winding currents. Harmonic ratio is:

$$100 \times I_{f2\_Winding} / I_{f1\_Winding} [\%].$$

The fast differential overcurrent stage 87–1 does not include slope characteristics or second harmonics blocking.

### Current transformer supervision

The current transformer supervision (CTS) feature is used to detect a failure of one or more of the phase current inputs to the relay. Failure of a phase current transformer (CT) or an open circuit of the interconnecting wiring can result in incorrect operation of any current-operated element. Additionally, interruption in the current circuit generates dangerous CT secondary voltages.

Figure 149 - Current transformer supervision settings



The differential CTS method uses the ratio between positive and negative sequence currents at both sides of the protected generator to determine a CT

failure. This algorithm is inbuilt in the dI> stage. When this ratio is small (zero), one of the following four conditions is present:

- The system is unloaded – both I2 and I1 are zero.
- The system is loaded but balanced – I2 is zero.
- The system has a three-phase fault – I2 is zero.
- There is a three-phase CT failure – unlikely to happen.

When the ratio is non-zero, one of the following two conditions is present:

- The system has an asymmetric fault – both I2 and I1 are non-zero.
- There is a 1 or 2 phase CT fault – both I2 and I1 are non-zero.

The I2 to I1 ratio is calculated at both sides of the protected generator. With this information, we can assume that:

- If the ratio is non-zero at both sides, there is a real fault in the network and the CTS should not operate.
- If the ratio is non-zero only at one side, there is a change of CT failure and the CTS should operate.

Another criterion for CTS is to check whether the differential system is loaded or not. For this purpose, the positive sequence current I1 is checked at both sides of the protected generator.

If load current is detected only at one side, it is assumed that there is an internal fault condition and CTS is prevented from operating, but if load current is detected at both line ends, CTS operation is permitted.

Another criterion for CTS is to check whether the differential system is loaded or not. For this purpose, the positive sequence current I1 is checked at both ends. If load current is detected only at one end, it is assumed that there is an internal fault condition and CTS is prevented from operating, but if load current is detected at both line ends, CTS operation is permitted.

There are three modes of operation:

- indication mode: CTS alarm is raised but there is no effect on tripping
- restrain mode: an alarm is raised and the differential current percentage setting value increased by 100 (for example 30 % + 100 % = 130 %). The new value is theoretically the maximum amount of differential current that a CT failure can produce in a normal full-load condition.
- block mode: an alarm is raised and differential protection is prevented from tripping

The differential CTS block mode is not recommended for two reasons:

- If there is a real fault during a CT failure, the differential protection would not protect the line at all.
- Blocking the protection could slow down the operate time of the differential protection because of transients in the beginning of the fault on the protected line.

### Setting groups

This stage has one setting group.

**Characteristics**

Table 88 - Differential overcurrent stage 87T-1

Start value	5–50 % $I_N$
Bias current for start of slope 1	0.50 x $I_N$
Slope 1	5–100 %
Bias current for start of slope 2	1.00–3.00 x $I_N$
Slope 2	100–200 %
Second harmonic blocking	5–30 %, or disable
Fifth harmonic blocking	20–50 %, or disable
Reset time	< 95 ms
Reset ratio	0.95
Inaccuracy:	
- Second harmonic blocking	±2% - unit
- Fifth harmonic blocking	±3% - unit
- Starting	±3% of set value or 0.02 x $I_N$ when currents are < 200 mA
- Operate time ( $I_D > 1.2 \times I_{SET}$ )	< 60 ms
- Operate time ( $I_D > 3.5 \times I_{SET}$ )	< 50 ms

Table 89 - Differential overcurrent stage 87T-2

Start value	5.0 – 40.0 x $I_N$
Reset time	< 95 ms
Reset ratio	0.95
Inaccuracy:	
- Starting	±3% of set value or ±0.5% of rated value
- Operate time ( $I_D > 3.5 \times I_{SET}$ )	< 40 ms

## 6.35 Arc flash detection (AFD)

**⚡ ⚠ DANGER**

**HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

Information on this product is offered as a tool for conducting arc flash hazard analysis. It is intended for use only by qualified persons who are knowledgeable about power system studies, power distribution equipment, and equipment installation practices. It is not intended as a substitute for the engineering judgement and adequate review necessary for such activities.

**Failure to follow this instruction will result in death or serious injury.**

### 6.35.1 Arc flash detection, general principle

The arc flash detection contains 8 arc stages that can be used to trip for example the circuit breakers. Arc stages are activated with overcurrent and light signals (or light signals alone). The allocation of different current and light signals to arc stages is defined in arc flash detection matrices: current, light and output matrix. The matrices are programmed via the arc flash detection menus. Available matrix signals depend on the order code (see [13.1 Order codes](#) on page 394).

The available signal inputs and outputs for arc flash detection depend on the relay's hardware configuration.

### 6.35.2 Arc flash detection menus

The arc flash detection menus are located in the main menu under ARC. The ARC menu can be viewed either on the front panel or by using Easergy Pro.

#### Arc protection

Table 90 - Arc protection parameter group

Item	Default	Range	Description
I>int. start setting	1.00 xIn	0.50–8.00 x In	Phase A, B, C overcurrent start level
Io>int. start setting	1.00 xIn	0.10–5.00 x In	Residual overcurrent start level
Install arc sensors	-	-, Install	Installs all connected sensors
Installation state	Ready	Installing, Ready	Installation state
Link Arc selfdiag to SF relay	On	On, Off	Links Arc protection selfsupervision signal to SF relay
Stage Enabled	On or Off	On, Off	Enables the arc protection stage

Item	Default	Range	Description
Trip delay [ms]	0	0–255	Trip delay for the arc protection stage
Min. hold time [10ms]	2	2–255	Minimum trip pulse length for the arc protection stage (Overshoot time <35ms)

## ⚠ WARNING

### HAZARD OF DELAYED OPERATION

Do not use the arc stage delay for primary trip. This delay is intended, with the separate arc stage, for the circuit breaker failure scheme only

**Failure to follow these instructions can result in death, serious injury, or equipment damage.**

## 6.35.3 Configuration example of arc flash detection

### Installing the arc flash sensors and I/O units

1. Go to **Protection > Arc protection**.
2. Under **Settings**, click the **Install arc sensors** drop-down list and select **Install**.
3. Wait until the **Installation state** shows **Ready**. The communication between the system components is created.
4. The installed sensors and units can be viewed at the bottom of the **Arc protection** group view.

Figure 150 - Installed arc sensors

Local Arc Sensors Installed	
Sensor	Arc sensor status
3	OK
4	OK
5	OK
6	OK

On the Easergy Pro group list, select **Arc protection**.

5. Click the Arc Stages 1, 2, and select Stage 1 and 2 'On'.
6. Click the Trip delay[ms] value, set it to for example '0' and press Enter.
7. Click the DI block value, set it to for example '-' and press Enter.

### Configuring the current start values

The **General > Scaling** setting view contains the primary and secondary values of the CT. However, the **Arc protection** menu calculates the primary value only after the **I start setting** value is given.

For example:

1. Go to **General > Scaling**.
2. Click the **CT primary** value, set it to for example *1200 A*, and press **Enter**.
3. Click the **CT secondary** value, set it to for example *5 A*, and press **Enter**.
4. On the Easergy Pro group list, select **Protection > Arc protection**.
5. Define the **I start setting** value for the relay.
6. Define the **Io start setting** in a similar manner.

Figure 151 - Example of setting the current transformer scaling values

**SCALING**

CT primary 1200 A

CT secondary 5 A

Nominal input 5 A

Figure 152 - Example of defining the I start setting value

**ARC PROTECTION**

**Settings**

I>int. pick-up setting 1440 A

I>int. pick-up setting 1.20 xIn

### Configuring the current matrix

Define the current signals that are received in the arc flash detection system's relay. Connect currents to Arc stages in the matrix.

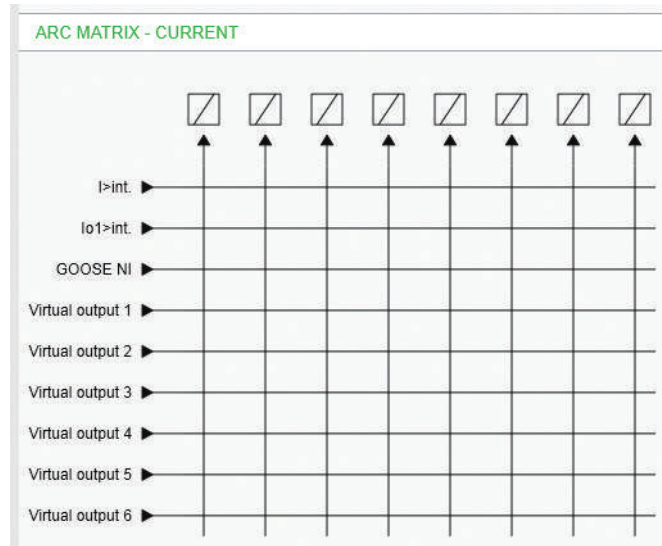
For example:

The arc flash fault current is measured from the incoming feeder, and the current signal is linked to **Arc stage 1** in the current matrix.

1. Go to **Matrix > Arc matrix - Current**
2. In the matrix, select the connection point of **Arc stage 1** and **I>int**.
3. On the **Communication** menu, select **Write Changed Settings To Device**.



Figure 153 - Configuring the current matrix – an example



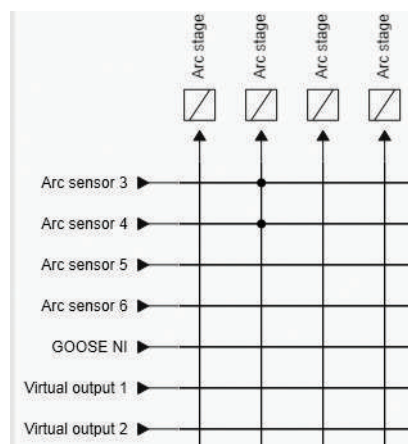
### Configuring the light matrix

Define what light sensor signals are received in the detection system. Connect the light signals to the arc stages in the matrix.

For example:

1. Go to **Matrix > Arc matrix - Light**.
2. In the matrix, select the connection point of **Arc sensor 1** and **Arc stage 2**.
3. Select the connection point of **Arc sensor 2** and **Arc stage 2**.
4. On the **Communication** menu, select **Write Changed Settings To Device**.

Figure 154 - Configuring the light arc matrix



### Configuring the output matrix

Define the trip relays that the current and light signals affect.

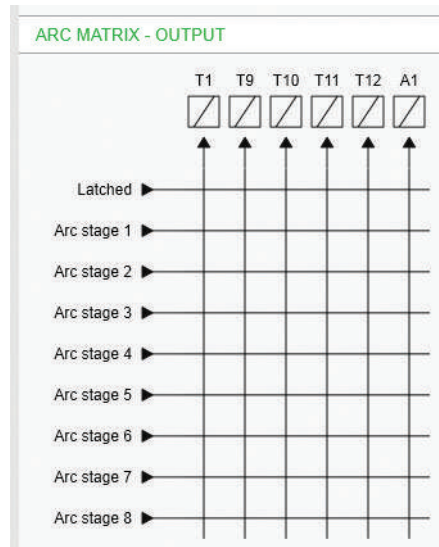
For example:

1. Go to **Matrix > Arc matrix - Output**.
2. In the matrix, select the connection point of **Arc stage 1** and **T1**.
3. Select the connection points of **Latched** and **T1** and **T9**.
4. Select the connection point of **Arc stage 2** and **T9**.
5. On the **Communication** menu, select **Write Changed Settings To Device**.

**NOTE:** It is recommended to use latched outputs for the trip outputs.

Arc output matrix includes only outputs which are directly controlled by FPGA.

Figure 155 - Configuring the output matrix - an example



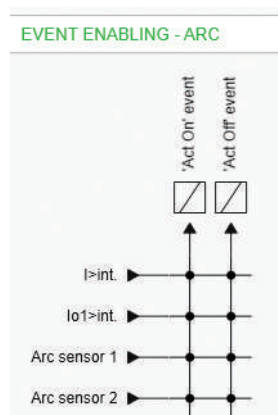
### Configuring the arc events

Define which arc events are written to the event list in this application.

For example:

1. Go to **Logs > Event enabling - Arc**.
2. In the matrix, enable both **'Act On' event** and **'Act Off' event** for **Arc sensor 1**, **Arc stage 1**, and **Arc stage 2**.
3. On the **Communication** menu, select **Write Changed Settings To Device**.

Figure 156 - Configuring the arc events – an example



### 6.35.4 Arc flash detection characteristics

The operation of the arc detection depends on the setting value of the  $I > \text{int}$  and  $I_{o1} > \text{int}$  current limits.

The arc current limits cannot be set, unless the relay is provided with the optional arc protection card.

Table 91 - Arc flash detection characteristics

Start current:	
Phase currents	0.50–8.00 x IN (step 0.01)
Residual current	0.10–5.00 x IN (step 0.01)
Operate time	
High break trip relays (T1, T9–T12)	
- Light only	≤9 ms
- 4 x Iset and light	≤9 ms
Trip relays (T2, T3 and T4)	
- Light only	≤7 ms
- 4 x Iset and light	≤7 ms
Semiconductor outputs (HSO1 – HSO2)	
- Light only	≤2 ms
- 4 x Iset and light	≤2 ms
- Arc stage delay	0 – 255 ms
Inaccuracy:	
Current	±5% of the set value
Delayed operation time	+≤10 ms of the set value

## 6.36 Programmable stages (ANSI 99)

### Description

For special applications the user can built own detection stages by selecting the supervised signal and the comparison mode.

The following parameters are available:

- **Priority**

If operate times less than 80 milliseconds are needed, select 10 ms. For operate times under one second, 20 ms is recommended. For longer operation times and THD signals, 100 ms is recommended.

- **Coupling A**

The selected supervised signal in ">" and "<" mode. The available signals are shown in the table below.

- **Coupling B**

The selected supervised signal in "Diff" and "AbsDiff" mode. This selection becomes available once "Diff" or "AbsDiff" is chosen for Coupling A.

- **Compare condition**

Compare mode. '>' for over or '<' for under comparison, "Diff" and "AbsDiff" for comparing Coupling A and Coupling B.

- **AbsDiff | d |**

Coupling A – coupling B. The stage activates if the difference is greater than the start setting.

- **Diff d**

Coupling A – coupling B. The stage activates if the sign is positive and the difference greater than the start setting.

- **Start**

Limit of the stage. The available setting range and the unit depend on the selected signal.

- **Operation delay**

Definite time operation delay

- **Hysteresis**

Dead band (hysteresis). For more information, see [6.2 General features of protection stages](#) on page 100.

- **No Compare limit for mode <**

Only used with compare mode under ('<'). This is the limit to start the comparison. Signal values under NoCmp are not regarded as fault.

Table 92 - Available signals to be supervised by the programmable stages

$I_A, I_B, I_C$	Phase currents (RMS values)
$V_{AB}, V_{BC}, V_{CA}$	Line-to-line voltages
$I_N$	Ground fault overcurrent
$V_A, V_B, V_C$	Line-to-neutral voltages

$V_N$	Neutral displacement voltage
f	Frequency
P	Active power
Q	Reactive power
S	Apparent power
Cos Phi	Cosine $\varphi$
$I_{N \text{ Calc}}$	Phasor sum $I_A + I_B + I_C$
I1	Positive sequence current
I2	Negative sequence current
I2/I1	Relative negative sequence current
I2/In	Negative sequence current in pu
$V_1$	Positive sequence overvoltage
$V_2$	Negative sequence overvoltage
$V_2/V_1$	Relative negative sequence voltage
$I_{AVG}$	Average $(I_A + I_B + I_C) / 3$
Tan Phi	Tangent $\varphi$ [= $\tan(\arccos\varphi)$ ]
PRMS	Active power RMS value
QRMS	Reactive power RMS value
SRMS	Apparent power RMS value
THDIL <sub>A</sub>	Total harmonic distortion of $I_A$
THDIL <sub>B</sub>	Total harmonic distortion of $I_B$
THDIL <sub>C</sub>	Total harmonic distortion of $I_C$
THDU <sub>A</sub>	Total harmonic distortion of input $V_A$
THDU <sub>B</sub>	Total harmonic distortion of input $V_B$
THDU <sub>C</sub>	Total harmonic distortion of input $V_C$
fy	Frequency behind circuit breaker
fz	Frequency behind 2nd circuit breaker
$I_A \text{ RMS}$	$I_A$ RMS for average sampling
$I_B \text{ RMS}$	$I_B$ RMS for average sampling

I <sub>C</sub> RMS	I <sub>C</sub> RMS for average sampling
ILmin, ILmax	Minimum and maximum of phase currents
VLNmin, VLNmax	Minimum and maximum of line-to-neutral voltages
VAI1, VAI2, VAI3, VAI4, VAI5	Virtual analog inputs 1, 2, 3, 4, 5 (GOOSE)

Signals available depending on slot 8 options.

### **Eight independent stages**

The relay has eight independent programmable stages. Each programmable stage can be enabled or disabled to fit the intended application.

### **Setting groups**

There are four settings groups available.

See [6.2 General features of protection stages](#) on page 100 for more details.

## 7 Supporting functions

### 7.1 Event log

The event log is a buffer of event codes and time stamps including date and time. For example, each start-on, start-off, trip-on or trip-off of any detection stage has a unique event number code. Such a code and the corresponding time stamp is called an event.

As an example, a typical event of programmable stage trip event is shown in [Table 93 - Example of Pgr1 stage trip on event and its visibility in local panel and communication protocols](#) on page 235.

Table 93 - Example of Pgr1 stage trip on event and its visibility in local panel and communication protocols

EVENT	Description	Local panel	Communication protocols
Code: 01E02	Channel 1, event 2	Yes	Yes
Pgr1 trip on	Event text	Yes	No
2.7 x In	Fault value	Yes	No
2007-01-31	Date	Yes	Yes
08:35:13.413	Time	Yes	Yes

Events are the major data for a SCADA system. SCADA systems are reading events using any of the available communication protocols. The Event log can also be scanned using the front panel or Easergy Pro. With Easergy Pro, the events can be stored to a file especially if the relay is not connected to any SCADA system.

Only the latest event can be read when using communication protocols or Easergy Pro. Every reading increments the internal read pointer to the event buffer. (In case of communication interruptions, the latest event can be reread any number of times using another parameter.) On the local panel, scanning the event buffer back and forth is possible.

#### Event enabling/masking

An uninteresting event can be masked, which prevents it to be written in the event buffer. By default, there is room for 200 latest events in the buffer. The event buffer size can be modified from 50 to 2000. The existing events are lost if the event buffer size is changed.

You can make this modification in the **Local panel conf** setting view.

An indication screen (popup screen) can also be enabled in this same menu in Easergy Pro. The oldest event is overwritten when a new event occurs. The shown resolution of a time stamp is one millisecond, but the actual resolution depends on the particular function creating the event. For example, most detection stages create events with 5 ms, 10 ms or 20 ms resolution. The absolute accuracy of all time stamps depends on the relay's time synchronization.

See [7.4 System clock and synchronization](#) on page 244 for system clock synchronizing.

**Event buffer overflow**

The normal procedure is to poll events from the relay all the time. If this is not done, the event buffer could reach its limits. In that case, the oldest event is deleted and the newest displayed with OVF (overflow) code on the front panel.

Table 94 - Setting parameters for events

Parameter	Value	Description	Note
Count		Number of events	
ClrEv	- Clear	Clear event buffer	Set
Order	Old-New New-Old	Order of the event buffer for local display	Set
FVScal		Scaling of event fault value	Set
	PU	Per unit scaling	
	Pri	Primary scaling	
Display Alarms	On	Indication display is enabled	Set
	Off	No indication display	
Sync		Controls event time format	
	On Off	Event time shown normally if relay is synchronized  Event time is shown in brackets if relay is not synchronized	
<b>FORMAT OF EVENTS ON THE LOCAL DISPLAY</b>			
Code: CHENN		CH = event channel, NN=event code (channel number is not shown in case channel is zero)	
Event description		Event channel and code in plain text	
yyyy-mm-dd		Date  (for available date formats, see <a href="#">7.4 System clock and synchronization</a> on page 244)	
hh:mm:ss.nnn		Time	

**7.2 Disturbance recording**

The disturbance recorder (DR) can be used to record all the measured signals, that is, currents, voltage and the status information of digital inputs (DI) and digital



outputs (DO). If the sample rate is slower than 1/10 ms, also the calculated signals like active power, power factor, negative sequence overcurrent and so on can be recorded. For a complete list of signals, see [Table 95 - Disturbance recording parameters](#) on page 238.

The available recording channels depend on the voltage measurement mode, too. If a channel is added for recording and the added signal is not available because of the used settings, the signal is automatically rejected from the recording channel list.

**NOTE:** When protection stages are enabled or disabled or the recorder signals or recording time changed, the disturbance recordings are deleted from the relay's memory. Therefore, before activating or deactivating stages, store the recordings on your PC.

### Triggering the recording

The recording can be triggered by any start or trip signal from any protection stage, by a digital input, logic output or GOOSE signals. The triggering signal is selected in the output matrix (vertical signal DR). The recording can also be triggered manually. All recordings are time-stamped.

### Reading recordings

The recordings can be uploaded with Easergy Pro program. The recording is in COMTRADE format. This also means that other programs can be used to view and analyse the recordings made by the relay.

### Number of channels

A maximum of 24 records can be stored. Up to 12 channels per record can be stored. Both the digital inputs and the digital outputs (including all inputs and outputs) use one channel out of the total of 12.

Figure 157 - Recorder channels

**RECORDER CHANNELS**

Ch	IL1,IL2,IL3,Io1,DI,DO			
Add recorder channel	IA	IB	IC	IN-1
	VAB	VBC	VCA	VA
	VB	VC	VN	f
	P	Q	S	P.F.
	CosPhi	INcalc	I1	I2
	I2/I1	I2/In	V1	V2
	V2/V1	IL	Vphase	Vline
	DI	DO	TanFii	Prms
	Qrms	Srms	THDIA	THDIB
	THDIC	THDVa	THDVb	THDVc
	IARMS	IBRMS	ICRMS	ILmin
	ILmax	ULLmin	ULLmax	ULNmin
	ULNmax	T	VAy	Ucomm
	IN-1rms	VAI1	VAI2	VAI3
	VAI4	VAI5	VAz	Starts
	Trips	DI3	DO3	

**Parameters**

Table 95 - Disturbance recording parameters

Parameter	Value	Unit	Description	Note
Mode			Behavior in memory full situation:	Set <sup>66</sup>
	Saturated		No more recordings are accepted	
	Overflow		The oldest recording is overwritten	
SR			Sample rate	Set
	32/cycle		Waveform	
	16/cycle		Waveform	
	8/cycle		Waveform	
	1/10ms		One cycle value <sup>67</sup>	
	1/20ms		One cycle value <sup>68</sup>	

Parameter	Value	Unit	Description	Note
	1/200ms		Average	
	1/1s		Average	
	1/5s		Average	
	1/10s		Average	
	1/15s		Average	
	1/30s		Average	
	1/1min		Average	
Time		s	Recording length	Set
PreTrig		%	Amount of recording data before the trig moment	Set
MaxLen		s	Maximum time setting. This value depends on the sample rate, number and type of the selected channels and the configured recording length.	
ReadyRec			Readable recordings	
Status			Status of recording	
	-		Not active	
	Run		Waiting a triggering	
	Trig		Recording	
	FULL		Memory is full in saturated mode	
ManTrig	-, Trig		Manual triggering	Set
ReadyRec	n/m		n = Available recordings / m = maximum number of recordings The value of 'm' depends on the sample rate, number and type of the selected channels and the configured recording length.	

<sup>66</sup> Set = An editable parameter (password needed).

<sup>67</sup> This is the fundamental frequency rms value of one cycle updated every 10 ms.

<sup>68</sup> This is the fundamental frequency rms value of one cycle updated every 20 ms.

Table 96 - Disturbance recording parameters

Parameter	Value	Unit	Description	Average	Wave-form
ClrCh	-, Clear		Remove all channels		
AddCh			Add one channel. The maximum number of channels used simultaneously is 12.		

Parameter	Value	Unit	Description	Average	Wave-form
	$I_A, I_B, I_C$		Phase current	X	X
	$I'_A, I'_B, I'_C$		Phase current (IV side)	X	X
	$V_{AB}, V_{BC}, V_{CA}$		Line-to-line voltage	X	X
	$V_A, V_B, V_C$		Phase-to-neutral voltage	X	X
	$V_N$		Neutral displacement voltage	X	X
	f		Frequency	X	
	P, Q, S		Active, reactive, apparent power	X	
	P.F.		Power factor	X	
	CosPhi		$\cos\phi$	X	
	$I_N \text{ Calc}$		Phasor sum $I_0 = (I_A + I_B + I_C)/3$	X	
	$I_1$		Positive sequence current	X	
	$I_2$		Negative sequence current	X	
	$I_2/I_1$		Relative current unbalance	X	
	$I_2/I_{GN}$		Negative sequence overcurrent [ $\times I_{GN}$ ]	X	
	$I_{AVG}$		Average $(I_A + I_B + I_C) / 3$	X	
	DI		Digital inputs: DI1–20, F1, F2, BIOin, VI1–4, Arc1, Arc2	X	X
	DI_2		Digital inputs: DI21–40	X	X
	DI_3		Virtual inputs: VI5–20, A1–A5, VO1–VO6	X	X
	DO		Digital outputs: T1–15	X	X
	DO_2		Rest of the outputs	X	X
	DO_3		Virtual outputs, VO7–VO20	X	X
	TanPhi		$\tan\phi$	X	
	THDI <sub>A</sub> , THDI <sub>B</sub> , THDI <sub>C</sub>		Total harmonic distortion of $I_A, I_B$ or $I_C$	X	
				X	

Parameter	Value	Unit	Description	Average	Wave-form
	Prms		Active power rms value	X	
	Qrms		Reactive power rms value	X	
	Srms		Apparent power rms value	X	
	fy		Frequency behind circuit breaker	X	
	fz		Frequency behind 2nd circuit breaker	X	
	I <sub>A</sub> RMS, I <sub>B</sub> RMS, I <sub>C</sub> RMS		I <sub>A</sub> , I <sub>B</sub> or I <sub>C</sub> RMS for average sampling	X	
	Arc <sup>69</sup>		Arc detection signals	X	
	Starts		Protection stage start signals	X	X
	Trips		Protection stage trip signals	X	X

<sup>69</sup> Arc events are polled in every 5 ms.

Signal available depending on the slot 8 options.

**NOTE:** The selection of signals depends on the relay type, the used voltage connection and the scaling mode.

### Characteristics

Table 97 - Disturbance recording

Mode of recording	Saturated / Overflow
Sample rate:	-
- Waveform recording	32/cycle, 16/cycle, 8/cycle
- Trend curve recording	10, 20, 200 ms 1, 5, 10, 15, 30 s 1 min
Recording time (one record)	0.1 s–12 000 min (According recorder setting)
Pre-trigger rate	0–100%
Number of selected channels	0–12
File format	IEEE Std C37.111-1999

The recording time and the number of records depend on the time setting and the number of selected channels.

### Configuring the disturbance recorder

**NOTE:** The DR configuration can only be edited when connected to the device via Easergy Pro

To select the channels and sample rate for the disturbance recorder:

1. In Easergy Pro, go to **General > Disturbance recorder**.
2. Click the **Add recorder channel** drop-down list and select the channel you want to add.
3. Click the **Sample rate** drop-down list, and select the desired rate.

To download the disturbance recorder file, select **Tools > Download disturbance records**.

**NOTE:** The default (pre-configured) settings for DR are:

- all analog inputs supported by the relay
- DI, DO
- Sampling rate: 32 s/c
- Recording length: 1 s'
- Output matrix: connection in every trip line to DR

Figure 158 - Configuring the disturbance recorder for the application example

### Writing the setting to the relay

1. On the Easergy Pro toolbar, select **Write settings > Write all settings** to save the configuration in the relay.

**NOTE:** To save the relay's configuration information for later use, also save the Easergy Pro setting file on the PC. Use WaweWin or another customer preferred tool to analyze disturbance recorder file.

### Saving the setting file on your PC

1. On the Easergy Pro toolbar, click the **Save** icon. The **Save a file** window opens.
2. Browse to the folder where you want to save the file. Type a descriptive file name, and click **Save**.

**NOTE:** By default, the setting file \*.epz is saved in the Easergy Pro folder.

## 7.3 Cold load start and magnetizing inrush

### Cold load start

A situation is regarded as cold load when all the three phase currents have been below a given idle value and then at least one of the currents exceeds a given start level within 80 ms. In such a case, the cold load detection signal is activated for the time set as **Maximum time** or until the measured signal returns below the value set as **Pickup current**. This signal is available for the output matrix and blocking matrix. Using virtual outputs of the output matrix setting group control is possible.

### Application for cold load detection

Right after closing a circuit breaker, a given amount of overload can be allowed for a given limited time to take care of concurrent thermostat-controlled loads. The cold load start function does this, for example, by selecting a more coarse setting group for overcurrent stages. It is also possible to use the cold load detection signal to block any set of protection stages for a given time.

### Magnetizing inrush detection

Magnetizing inrush detection is quite similar to the cold load detection but it also includes a condition for second harmonic content of the currents. When all phase currents have been below a given idle value and then at least one of them exceeds a given start level within 80 ms and the second harmonic ratio to fundamental frequency,  $I_{f2}/I_{f1}$ , of at least one phase exceeds the given setting, the inrush detection signal is activated. This signal is available for the output matrix and blocking matrix. Using virtual outputs of the output matrix setting group control is possible.

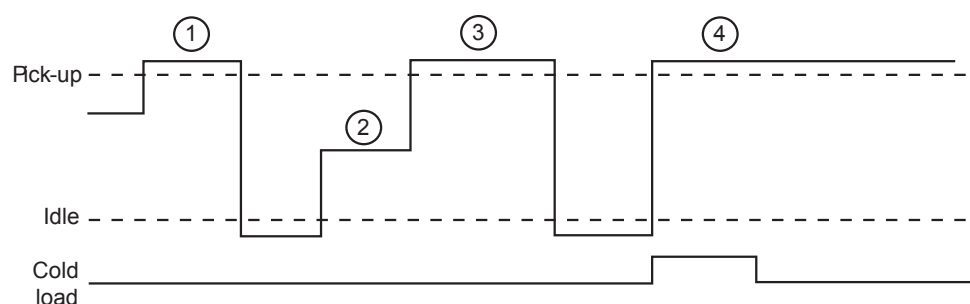
By setting the second harmonic start parameter for  $I_{f2}/I_{f1}$  to zero, the inrush signal will behave equally with the cold load start signal.

### Application for inrush current detection

The inrush current of transformers usually exceeds the start setting of sensitive overcurrent stages and contains a lot of even harmonics. Right after closing a circuit breaker, the start and tripping of sensitive overcurrent stages can be avoided by selecting a more coarse setting group for the appropriate overcurrent stage with an inrush detect signal. It is also possible to use the detection signal to block any set of protection stages for a given time.

**NOTE:** Inrush detection is based on the fundamental component calculation which requires a full cycle of data for analyzing the harmonic content. Therefore, when using the inrush blocking function, the cold load start starting conditions are used for activating the inrush blocking when the current rise is noticed. If a significant ratio of second harmonic components is found in the signal after the first cycle, the blocking is continued. Otherwise, the second-harmonic-based blocking signal is released. Inrush blocking is recommended to be used on time-delayed overcurrent stages while the non-blocked instant overcurrent stage is set to 20 % higher than the expected inrush current. By this scheme, a fast reaction time in short circuit faults during the energization can be achieved while time-delayed stages are blocked by the inrush function.

Figure 159 - Functionality of cold load / inrush current feature.



1. No activation because the current has not been under the set  $I_{DLE}$  current.
2. Current dropped under the  $I_{DLE}$  current level but now it stays between the  $I_{DLE}$  current and the start current for over 80ms.
3. No activation because the phase two lasted longer than 80ms.
4. Now we have a cold load activation which lasts as long as the operate time was set or as long as the current stays above the start setting.

### Characteristics

Table 98 - Magnetizing inrush detection

Cold load settings:	
- Idle current	$0.01 - 0.50 \times I_N$
- Start current	$0.30 - 10.00 \times I_N$
- Maximum time	$0.01^{70} - 300.00 \text{ s (step } 0.01 \text{ s)}$
Inrush settings:	
- Start for 2nd harmonic	0 – 99 %

<sup>70</sup> This is the instantaneous time, that is, the minimum total operate time including the fault detection time and the operate time of the trip contacts. Use the **Accept zero delay** setting in the protection stage setting view in Easergy Pro to accept the zero operate time setting for the DT function.

## 7.4 System clock and synchronization

### Description

The relay's internal clock is used to time-stamp events and disturbance recordings.

The system clock should be externally synchronised to get comparable event time stamps for all the relays in the system.

The synchronizing is based on the difference of the internal time and the synchronizing message or pulse. This deviation is filtered and the internal time is corrected softly towards a zero deviation.

### Time zone offsets

Time zone offset (or bias) can be provided to adjust the relay's local time. The offset can be set as a Positive (+) or Negative (-) value within a range of -15.00 to +15.00 hours and a resolution of 0.01/h. Basically, resolution by a quarter of an hour is enough.

### Daylight saving time (DST)

The relay provides automatic daylight saving adjustments when configured. A daylight saving time (summer time) adjustment can be configured separately and in addition to a time zone offset.



System Clock	
Date	2017-08-29
Day of week	Tuesday
Time of day	15:04:04
Date style	y-m-d
Time zone	0.00 h
Enable DST	Off
Event enabling	On
Status of DST	
Status of DST	inactive
Next DST changes	
Next DSTbegin date	2018-03-25
DSTbegin hour	03:00
Next DSTend date	2017-10-29
DSTend hour (DST)	04:00 DST

Daylight time standards vary widely throughout the world. Traditional daylight/summer time is configured as one (1) hour positive bias. The new US/Canada DST standard, adopted in the spring of 2007 is one (1) hour positive bias, starting at 2:00am on the second Sunday in March, and ending at 2:00am on the first Sunday in November. In the European Union, daylight change times are defined relative to the UTC time of day instead of local time of day (as in U.S.) European customers, carefully check the local country rules for DST.

The daylight saving rules for Finland are the relay defaults (24-hour clock):

- Daylight saving time start: Last Sunday of March at 03.00
- Daylight saving time end: Last Sunday of October at 04.00

DSTbegin rule	
DSTbegin month	Mar
Ordinal of day of week	Last
Day of week	Sunday
DSTbegin hour	3
DSTend rule	
DSTend month	Oct
Ordinal of day of week	Last
Day of week	Sunday
DSTend hour (DST)	4 DST

To ensure proper hands-free year-around operation, automatic daylight time adjustments must be configured using the “Enable DST” and not with the time zone offset option.

### Adapting the auto-adjust function

During tens of hours of synchronizing, the relay learns its average deviation and starts to make small corrections by itself. The target is that when the next synchronizing message is received, the deviation is already near zero. Parameters "AAIntv" and "AvDrft" show the adapted correction time interval of this  $\pm 1$  ms auto-adjust function.

### Time drift correction without external sync

If any external synchronizing source is not available and the system clock has a known steady drift, it is possible to roughly correct the clock deviation by editing the parameters "AAIntv" and "AvDrft". The following equation can be used if the previous "AAIntv" value has been zero.

$$AAIntv = \frac{604.8}{DriftInOneWeek}$$

If the auto-adjust interval "AAIntv" has not been zero, but further trimming is still needed, the following equation can be used to calculate a new auto-adjust interval.

$$AAIntv_{NEW} = \frac{1}{\frac{1}{AAIntv_{PREVIOUS}} + \frac{DriftInOneWeek}{604.8}}$$

The term  $DriftInOneWeek/604.8$  may be replaced with the relative drift multiplied by 1000 if some other period than one week has been used. For example, if the drift has been 37 seconds in 14 days, the relative drift is  $37 \cdot 1000 / (14 \cdot 24 \cdot 3600) = 0.0306$  ms/s.

#### Example 1

If there has been no external sync and the relay's clock is leading sixty-one seconds a week and the parameter AAIntv has been zero, the parameters are set as

$$AvDrft = Lead$$

$$AAIntv = \frac{604.8}{61} = 9.9s$$

With these parameter values, the system clock corrects itself with  $-1$  ms every 9.9 seconds which equals  $-61.091$  s/week.

#### Example 2

If there is no external sync and the relay's clock has been lagging five seconds in nine days and the AAIntv has been 9.9 s, leading, then the parameters are set as

$$AAIntv_{NEW} = \frac{1}{\frac{1}{9.9} - \frac{5000}{9 \cdot 24 \cdot 3600}} = 10.6$$

$$AvDrft = Lead$$

When the internal time is roughly correct – the deviation is less than four seconds – no synchronizing or auto-adjust turns the clock backwards. Instead, if the clock is leading, it is softly slowed down to maintain causality.

Table 99 - System clock parameters

Parameter	Value	Unit	Description	Note
Date			Current date	Set
Time			Current time	Set
Style			Date format	Set
	y-d-m		Year-Month-Day	
	d.m.y		Day.Month.Year	
	m/d/y		Month/Day/Year	
SyncDI	Possible values depends on the types of I/O cards		The digital input used for clock synchronization.	71
	-		DI not used for synchronizing	
			Minute pulse input	
TZone	-15.00 – +15.00 <sup>72</sup>		UTC time zone for SNTP synchronization.  Note: This is a decimal number. For example for state of Nepal the time zone 5:45 is given as 5.75	Set
DST	No; Yes		Daylight saving time for SNTP	Set
SySrc			Clock synchronization source	
	Internal		No sync recognized since 200s	
	DI		Digital input	
	SNTP		Protocol sync	
	SpaBus		Protocol sync	
	ModBus		Protocol sync	
	ModBus TCP		Protocol sync	
	ProfibusDP		Protocol sync	
	IEC101		Protocol sync	
	IEC103		Protocol sync	
	DNP3		Protocol sync	
	IRIG-B003		IRIG timecode B003 <sup>73</sup>	

Parameter	Value	Unit	Description	Note
MsgCnt	0 – 65535, 0 – etc.		The number of received synchronization messages or pulses	
Dev	±32767	ms	Latest time deviation between the system clock and the received synchronization	
SyOS	±10000.000	s	synchronization correction for any constant deviation in the synchronizing source	Set
AAIntv	±1000	s	Adapted auto-adjust interval for 1 ms correction	Set <sup>74</sup>
AvDrft	Lead; Lag		Adapted average clock drift sign	Set <sup>74</sup>
FilDev	±125	ms	Filtered synchronization deviation	

<sup>71</sup> Set the DI delay to its minimum and the polarity such that the leading edge is the synchronizing edge.

<sup>72</sup> A range of -11 h – +12 h would cover the whole ground but because the International Date Line does not follow the 180° meridian, a more wide range is needed.

<sup>73</sup> Relay needs to be equipped with suitable hardware option module to receive IRIG-B clock synchronization signal. ([13.2 Accessories](#) on page 395).

<sup>74</sup> If external synchronization is used, this parameter is set automatically.

Set = An editable parameter (password needed).

### Synchronization with DI

The clock can be synchronized by reading minute pulses from digital inputs, virtual inputs or virtual outputs. The sync source is selected with the **SyncDI** setting. When a rising edge is detected from the selected input, the system clock is adjusted to the nearest minute. The length of the digital input pulse should be at least 50 ms. The delay of the selected digital input should be set to zero.

### Synchronization correction

If the sync source has a known offset delay, it can be compensated with the **SyOS** setting. This is useful for compensating hardware delays or transfer delays of communication protocols. A positive value compensates a lagging external sync and communication delays. A negative value compensates any leading offset of the external sync source.

### Sync source

When the relay receives new sync message, the sync source display is updated. If no new sync messages are received within the next 1.5 minutes, the relay switches over to internal sync mode.

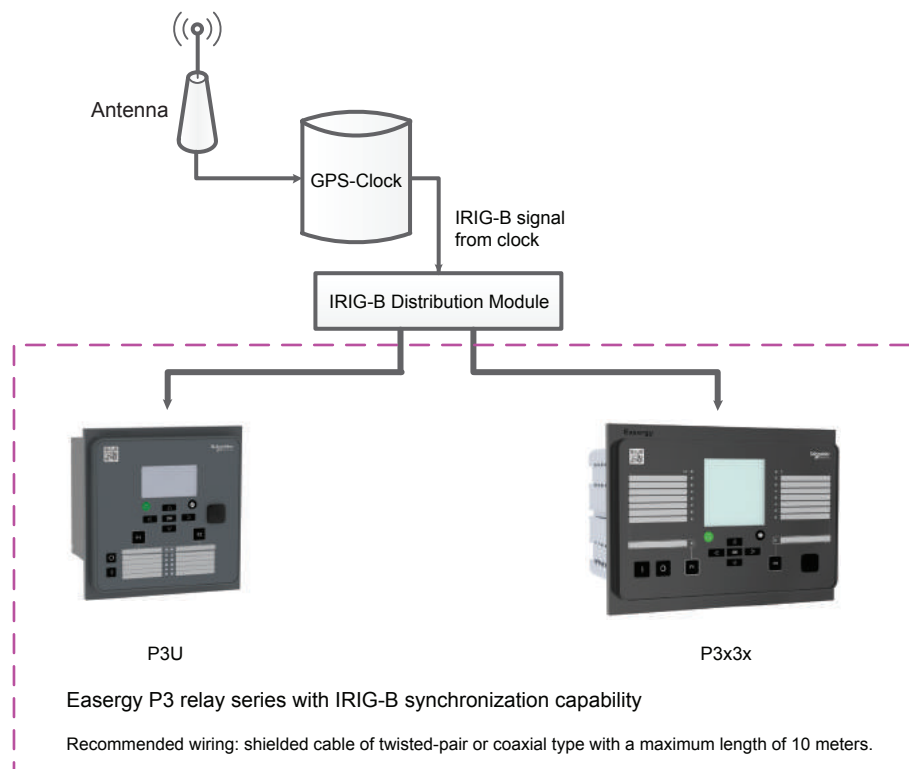
### Sync source: IRIG-B003

IRIG-B003 synchronization is supported with a dedicated communication (See [13.2 Accessories](#) on page 395).

IRIG-B003 input clock signal voltage level is TLLThe input clock signal originated in the GPS receiver must be taken to multiple relays through an IRIG-B distribution module. This module acts as a centralized unit for a point-to-multiple point connection.

**NOTE:** Daisy chain connection of IRIG-B signal inputs in multiple relays must be avoided.

Figure 160 - Easergy P3 relays with IRIG-B synchronization capability



The recommended cable must be shielded and either of coaxial or twisted pair type. Its length must not exceed 10 meters.

### Deviation

The time deviation means how much the system clock time differs from the sync source time. The time deviation is calculated after receiving a new sync message. The filtered deviation means how much the system clock was really adjusted. Filtering takes care of small deviation in sync messages.

### Auto-lag/lead

The relay synchronizes to the sync source, meaning that it starts automatically leading or lagging to stay in perfect sync with the master. The learning process takes a few days.

## 7.5 Voltage sags and swells

### Description

The power quality of electrical networks has become increasingly important. Sophisticated loads (for example computers) require an uninterruptible supply of

“clean” electricity. The Easergy P3G30 and P3G32 protection platform provides many power quality functions that can be used to evaluate and monitor the quality and alarm on the basis of the quality. One of the most important power quality functions is voltage sag and swell monitoring.

Easergy P3G30 and P3G32 provides separate monitoring logs for sags and swells. The voltage log is triggered if any voltage input either goes under the sag limit ( $V<$ ) or exceeds the swell limit ( $V>$ ). There are four registers for both sags and swells in the fault log. Each register contains start time, phase information, duration and the minimum, average and maximum voltage values of each sag and swell event. Furthermore, it contains the total number of sags and swells counters as well as the total number of timers for sags and swells.

The voltage power quality functions are located under the submenu “V”.

Table 100 - Setting parameters of sags and swells monitoring

Parameter	Value	Unit	Default	Description
V>	20 – 150	%	110	Setting value of swell limit
V<	10 – 120	%	90	Setting value of sag limit
Delay	0.04 – 1.00	s	0.06	Delay for sag and swell detection
SagOn	On; Off	-	On	Sag on event
SagOff	On; Off	-	On	Sag off event
SwelOn	On; Off	-	On	Swell on event
SwelOf	On; Off	-	On	Swell off event

Table 101 - Recorded values of sags and swells monitoring

	Parameter	Value	Unit	Description
Recorded values	Count		-	Cumulative sag counter
	Total		-	Cumulative sag time counter
	Count		-	Cumulative swell counter
	Total		-	Cumulative swell time counter
Sag / swell logs 1 – 4	Date		-	Date of the sag/swell
	Time		-	Time stamp of the sag/swell
	Type		-	Voltage inputs that had the sag/swell
	Time		s	Duration of the sag/swell
	Min1		% $V_N$	Minimum voltage value during the sag/swell in the input 1
	Min2		% $V_N$	Minimum voltage value during the sag/swell in the input 2

	Parameter	Value	Unit	Description
	Min3		% $V_N$	Minimum voltage value during the sag/swell in the input 3
	Ave1		% $V_N$	Average voltage value during the sag/swell in the input 1
	Ave2		% $V_N$	Average voltage value during the sag/swell in the input 2
	Ave3		% $V_N$	Average voltage value during the sag/swell in the input 3
	Max1		% $V_N$	Maximum voltage value during the sag/swell in the input 1
	Max2		% $V_N$	Maximum voltage value during the sag/swell in the input 2
	Max3		% $V_N$	Maximum voltage value during the sag/swell in the input 3

### Characteristics

Table 102 - Voltage sag & swell

Voltage sag limit	10 –120% $V_N$ (step 1%)
Voltage swell limit	20 –150% $V_N$ (step 1%)
Definite time function:	DT
- Operate time	0.08–1.00 s (step 0.02 s)
Low voltage blocking	0–50%
Reset time	< 60 ms
Reset ration:	
- Sag	1.03
- Swell	0.97
Block limit	0.5 V or 1.03 (3%)
Inaccuracy:	
- Activation	$\pm 0.5$ V or 3% of the set value
- Activation (block limit)	$\pm 5\%$ of the set value
- Operate time at definite time function	$\pm 1\%$ or $\pm 30$ ms

If one of the line-to-line voltages is below sag limit and above block limit but another line-to-line voltage drops below block limit, blocking is disabled.

## 7.6 Voltage interruptions

### Description

The relay includes a simple function to detect voltage interruptions. The function calculates the number of voltage interruptions and the total time of the voltage-off time within a given calendar period. The period is based on the relay's real-time clock. The available periods are:

- 8 hours, 00:00–08:00, 08:00–16:00, 16:00–24:00
- one day, 00:00–24:00
- one week, Monday 00:00 – Sunday 24:00
- one month, the first day 00:00 – the last day 24:00
- one year, 1st January 00:00 – 31st December 24:00

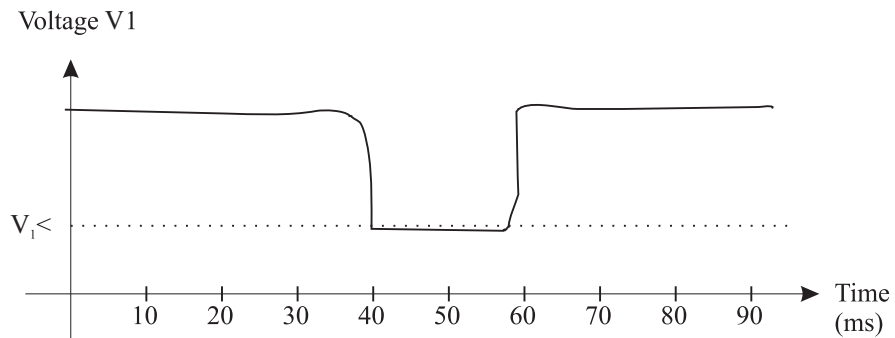
After each period, the number of interruptions and the total interruption time are stored as previous values. The interruption counter and the total time are cleared for a new period. Previous values are overwritten.

Voltage interruption is based on the value of the positive sequence voltage  $V_1$  and a limit value you can define. Whenever the measured  $V_1$  goes below the limit, the interruption counter is increased, and the total time counter starts increasing.

The shortest recognized interruption time is 40 ms. If the voltage-off time is shorter, it may be recognized depending on the relative depth of the voltage dip.

If the voltage has been significantly over the limit  $V_{1<}$  and then there is a small and short under-swing, it is not recognized ([Figure 161 - A short voltage interruption which is probably not recognized on page 252](#)).

Figure 161 - A short voltage interruption which is probably not recognized



On the other hand, if the limit  $V_{1<}$  is high and the voltage has been near this limit, and then there is a short but very deep dip, it is not recognized ([Figure 162 - A short voltage interrupt that will be recognized on page 253](#)).



Figure 162 - A short voltage interrupt that will be recognized

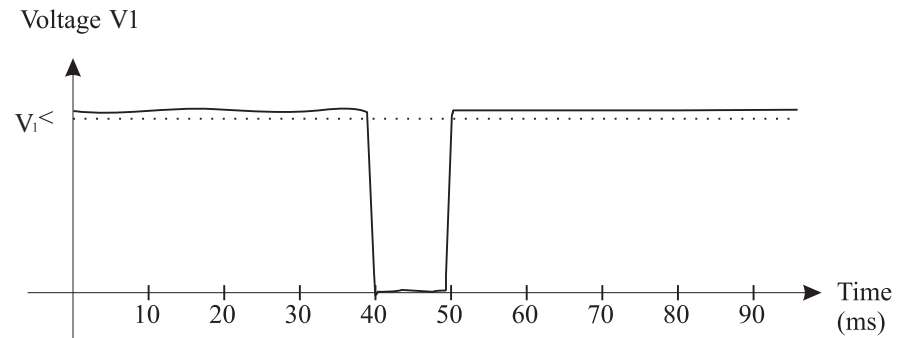


Table 103 - Setting parameters of the voltage sag measurement function

Parameter	Value	Unit	Default	Description
V <sub>1</sub> <	10.0 – 120.0	%	64	Setting value
Period	8h Day Week Month	-	Month	Length of the observation period
Date		-	-	Date
Time		-	-	Time

Table 104 - Measured and recorded values of voltage sag measurement function

	Parameter	Value	Unit	Description
Measured value	Voltage	LOW; OK	-	Current voltage status
	V <sub>1</sub>		%	Measured positive sequence voltage
Recorded values	Count		-	Number of voltage sags during the current observation period
	Prev		-	Number of voltage sags during the previous observation period
	Total		s	Total (summed) time of voltage sags during the current observation period
	Prev		s	Total (summed) time of voltage sags during the previous observation period

**Characteristics**

Table 105 - Voltage interruptions

Voltage low limit ( $V_1$ )	10–120% $V_N$ (step 1%)
Definite time function: - Operate time	DT < 60 ms (Fixed)
Reset time	< 60 ms
Reset ratio	1.03
Inaccuracy: - Activation	3% of the set value

## 7.7 Current transformer supervision (ANSI 60)

**Description**

The relay supervises the current transformers (CTs) and the external wiring between the relay terminals and the CTs. This is a safety function as well, since an open secondary of a CT causes dangerous voltages.

The CT supervision function measures phase currents. If one of the three phase currents drops below the  $I_{MIN}<$  setting while another phase current exceeds the  $I_{MAX}>$  setting, the function issues an alarm after the operation delay has elapsed.

Table 106 - Setting parameters of CT supervision

Parameter	Value	Unit	Default	Description
$I_{max}>$	0.0 – 10.0	xIn	2.0	Upper setting for CT supervision current scaled to primary value, calculated by relay
$I_{min}<$	0.0 – 10.0	xIn	0.2	Lower setting for CT supervision current scaled to primary value, calculated by relay
$t>$	0.02 – 600.0	s	0.10	Operation delay
CT on	On; Off	-	On	CT supervision on event
CT off	On; Off	-	On	CT supervision off event

Table 107 - Measured and recorded values of CT

	Parameter	Value	Unit	Description
Measured value	$\Phi_{max}$		A	Maximum of phase currents
	$\Phi_{min}$		A	Minimum of phase currents
Display	$I_{max}>$ , $I_{min}<$		A	Setting values as primary values

	Parameter	Value	Unit	Description
Recorded values	Date		-	Date of CT supervision alarm
	Time		-	Time of CT supervision alarm
	I <sub>max</sub>		A	Maximum phase current
	I <sub>min</sub>		A	Minimum phase current

### Characteristics

Table 108 - Current transformer supervision

I <sub>MAX</sub> > setting	0.00 – 10.00 x I <sub>N</sub> (step 0.01)
I <sub>MIN</sub> < setting	0.00 – 10.00 x I <sub>N</sub> (step 0.01)
Definite time function:	DT
- Operate time	0.04 – 600.00 s (step 0.02 s)
Reset time	< 60 ms
Reset ratio I <sub>MAX</sub> >	0.97
Reset ratio I <sub>MIN</sub> <	1.03
Inaccuracy:	-
- Activation	±3% of the set value
- Operate time at definite time function	±1% or ±30 ms

## 7.8 Voltage transformer supervision (ANSI 60FL)

### Description

The relay supervises the voltage transformers (VTs) and VT wiring between the relay terminals and the VTs. If there is a fuse in the voltage transformer circuitry, the blown fuse prevents or distorts the voltage measurement. Therefore, an alarm should be issued. Furthermore, in some applications, protection functions using voltage signals should be blocked to avoid false tripping.

The VT supervision function measures three line-to-line voltages and currents. The negative sequence voltage  $V_2$  and the negative sequence current  $I_2$  are calculated. If  $V_2$  exceed the  $V_2>$  setting and at the same time,  $I_2$  is less than the  $I_2<$  setting, the function issues an alarm after the operation delay has elapsed.

Table 109 - Setting parameters of VT supervision

Parameter	Value	Unit	Default	Description
V <sub>2</sub> >	0.0 – 200.0	% V <sub>n</sub>	34.6	Upper setting for VT supervision
I <sub>2</sub> <	0.0 – 200.0	% I <sub>n</sub>	100.0	Lower setting for VT supervision
t>	0.02 – 600.0	s	0.10	Operation delay

Parameter	Value	Unit	Default	Description
VT on	On; Off	-	On	VT supervision on event
VT off	On; Off	-	On	VT supervision off event

Table 110 - Measured and recorded values of VT supervision

	Parameter	Value	Unit	Description
Measured value	V2		%V <sub>N</sub>	Measured negative sequence voltage
	I2		%I <sub>N</sub>	Measured negative sequence current
Recorded Values	Date		-	Date of VT supervision alarm
	Time		-	Time of VT supervision alarm
	V2		%V <sub>N</sub>	Recorded negative sequence voltage
	I2		%I <sub>N</sub>	Recorded negative sequence current

**Characteristics**

Table 111 - Voltage transformer supervision

V <sub>2</sub> > setting	0.0 – 200.0% (step 0.1%)
I <sub>2</sub> < setting	0.0 – 200.0% (step 0.1%)
Definite time function:	DT
- Operate time	0.04 – 600.00 (step 0.02s)
Reset time	< 60 ms
Reset ratio	3% of the start value
Inaccuracy:	-
- Activation V <sub>2</sub> >	±1%-unit
- Activation I <sub>2</sub> <	±1%-unit
- Operate time at definite time function	±1% or ±30 ms

## 7.9 Circuit breaker wear

**Description**

Circuit breaker (CB) wear is a function that monitors CB wear by calculating how much wear the CB can sustain. It raises an alarm about the need for CB maintenance before the condition of the CB becomes critical.

This function records the peak symmetrical current<sup>75</sup> from each phase<sup>76</sup>, and uses that magnitude as the breaking current for that phase to estimate the

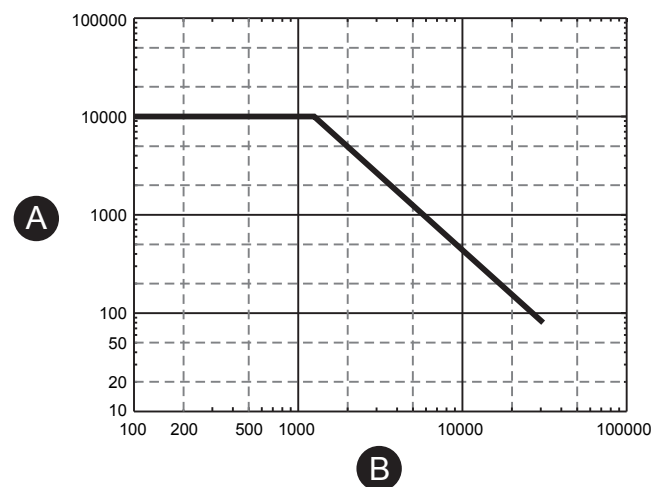
amount of wear on the CB. The function then calculates the estimated number of cycles or trips remaining before the CB needs to be replaced or serviced.

### Permissible cycle diagram

The permissible cycle diagram is usually available in the documentation of the CB manufacturer. This diagram specifies the permissible number of cycles as a function of the breaking current, that is, how much wear occurs in the CB when it trips with a given breaking current. So the maximum number of cycles a CB can trip with this breaking current is used as the measure of wear.

The condition monitoring function must be configured according to this diagram. In the configuration, this diagram is called **Breaker curve**.

Figure 163 - Example permissible cycle diagram



- A. Number of permitted operations
- B. Breaking current (A)

Up to eight points can be selected from the diagram and entered to the device. Each point specifies a breaking current and the associated maximum number of permitted operations. The device assumes there is a straight line between each two consecutive points in the log-log diagram (that is, uses logarithmic interpolation between the points), and thus forms an approximation of the permissible cycle diagram. It should be possible to accurately describe most permissible cycle diagrams in this way.

The values in the example match the diagram in [Figure 163 - Example permissible cycle diagram](#) on page 257.

Table 112 - An example of circuit breaker wear characteristics

Point	Interrupted current (kA)	Number of permitted operations
1	0 (mechanical age)	10000
2	1.25 (rated current)	10000

<sup>75</sup> The used peak current is the magnitude of the fundamental frequency component. This magnitude does not include a possible DC component.

<sup>76</sup> The current is sampled every 10 milliseconds, starting from the moment the monitored trip relay is asserted and ending when the current of every phase has decreased below one quarter of the phase's breaking current or after 500 milliseconds have elapsed, whichever happens first.

Point	Interrupted current (kA)	Number of permitted operations
3	31.0 (maximum breaking current)	80
4	100	1
5	100	1
6	100	1
7	100	1
8	100	1

**Alarm points**

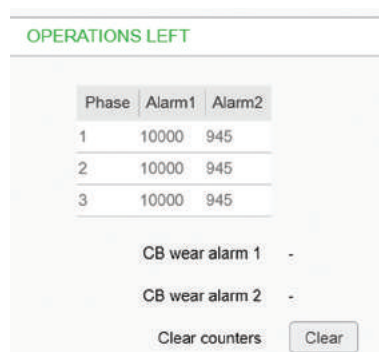
Two alarm points can be configured to notify about the approaching need for CB maintenance.

The number of permissible CB cycles depends on the breaking current that is interrupted by the CB. Larger currents lead to greater wear on the CB and thus to fewer operating cycles.<sup>77</sup>

An alarm point specifies a breaking current and an associated number of permissible cycles. An alarm is raised if the remaining number of permissible cycles at the given breaking current falls below this limit.

The table in the **Operations left** setting view shows the number of operation cycles left before the alarm points are reached. The number of remaining cycles is tracked for each phase separately, and the alarm is raised when any phase runs out of cycles.

Figure 164 - Operations left



The first alarm point can be set, for example, to the CB's nominal current and the second alarm point to a typical fault current.

When an alarm is raised, a signal is asserted in the output matrix. Also, an event is created depending on the settings given in the **Event enabling** setting view.

<sup>77</sup> Each cycle causes mechanical wear on the CB. In addition, large enough currents create arcs inside the CB, which causes erosion of the electrical contacts for each phase. The larger the current, the greater the erosion, and thus the greater the wear on the CB. A worn CB has fewer cycles left at any breaking current.

### Logarithmic interpolation

The permitted number of operations for the currents between the defined points is logarithmically interpolated:

Equation 35

$$C = \frac{a}{I^n}$$

C = permitted operations

I = interrupted current

a = constant according to [Equation 36](#) on page 259

n = constant according to [Equation 37](#) on page 259

Equation 36

$$a = C_k I_k^2$$

Equation 37

$$n = \frac{\ln \frac{C_k}{C_{k+1}}}{\ln \frac{I_{k+1}}{I_k}}$$

ln = natural logarithm function

$C_k, C_{k+1}$  = permitted operations

k = rows 2–7 in [Table 112 - An example of circuit breaker wear characteristics](#) on page 257

$I_k, I_{k+1}$  = corresponding current

k = rows 2–7 in [Table 112 - An example of circuit breaker wear characteristics](#) on page 257

### Example of the logarithmic interpolation

Alarm 2 current is set to 6 kA. The maximum number of operations is calculated as follows.

The current 6 kA lies between points 2 and 3 in the table. That gives value for the index k. Using

$$k = 2$$

$$C_k = 10000$$

$$C_{k+1} = 80$$

$$I_{k+1} = 31 \text{ kA}$$

$$I_k = 1.25 \text{ kA}$$

and [Equation 37](#) on page 259 and [Equation 36](#) on page 259, the device calculates

Equation 38

$$n = \frac{\ln \frac{10000}{80}}{\ln \frac{31000}{1250}} = 1.5038$$

Equation 39

$$a = 10000 \cdot 1250^{1.5038} = 454 \cdot 10^6$$

Using [Equation 35](#) on page 259, the device gets the number of permitted operations for current 6 kA.

Equation 40

$$C = \frac{454 \cdot 10^6}{6000^{1.5038}} = 945$$

Thus, the maximum number of current-breaking operations at 6 kA is 945. This can be verified with the original CB curve in [Figure 163 - Example permissible cycle diagram](#) on page 257. The figure shows that at 6 kA, the operation count is between 900 and 1000. In this case, a useful alarm level for the operations left is 50, for example, which is about 5 percent of the maximum.

#### **Example of operation counter decrementing when the CB breaks a current**

Alarm 2 is set to 6 kA. The CB failure protection supervises trip relay T1, and a trip signal of an overcurrent stage detecting a two-phase fault is connected to this trip relay T1. The interrupted phase currents are 12.5 kA, 12.5 kA and 1.5 kA. By what number are Alarm2 counters decremented?

Using [Equation 35](#) on page 259 and values n and a from the previous example, the device gets the number of permitted operations at 10 kA.

Equation 41

$$C_{10kA} = \frac{454 \cdot 10^6}{12500^{1.5038}} = 313$$

At alarm level 2, 6 kA, the corresponding number of operations is calculated according to:



Equation 42

$$\Delta = \frac{C_{AlarmMax}}{C}$$

$$\Delta_A = \Delta_B = \frac{945}{313} = 3$$

Thus, Alarm2 counters for phases A and B are decremented by 3. In phase A, the current is less than the alarm limit current 6 kA. For such currents, the decrement is 1.

$$\Delta_C = 1$$

Table 113 - Local panel parameters of the CBWEAR function

Parameter	Value	Unit	Description	Set <sup>78</sup>
<b>CBWEAR STATUS</b>				
AI1A			Operations left for - Alarm 1, phase A	
AI1B			- Alarm 1, phase B	
AI1C			- Alarm 1, phase C	
AI2A			- Alarm 2, phase A	
AI2B			- Alarm 2, phase B	
AI2C			- Alarm 2, phase C	
<b>Latest trip</b>				
Date time			Time stamp of the latest trip operation	
I <sub>A</sub>		A	Broken current of phase A	
I <sub>B</sub>		A	Broken current of phase B	
I <sub>C</sub>		A	Broken current of phase C	
<b>CBWEAR SET</b>				
Alarm1				
Current	0.00–100.00	kA	Alarm1 current level	Set
Cycles	100000–1		Alarm1 limit for operations left	Set
Alarm2				
Current	0.00–100.00	kA	Alarm2 current level	Set
Cycles	100000–1		Alarm2 limit for operations left	Set
<b>CBWEAR SET2</b>				

Parameter	Value	Unit	Description	Set <sup>78</sup>
AI1On	On; Off		'Alarm1 on' event enabling	Set
AI1Off	On; Off		'Alarm1 off' event enabling	Set
AI2On	On; Off		'Alarm2 on' event enabling	Set
AI2Off	On; Off		'Alarm2 off' event enabling	Set
Clear	-; Clear		Clearing of cycle counters	Set

<sup>78</sup> Set = An editable parameter (password needed)

## 7.10 Circuit breaker condition monitoring

### Description

Circuit breaker (CB) condition monitoring monitors the CB wear with the help of the cumulative breaking current. It raises an alarm about the need for CB maintenance before the CB's condition becomes critical. This function has two stages.

The approach to calculating the CB condition is different from the approach used by the CB wear function described in [7.9 Circuit breaker wear on page 256](#). CB condition monitoring also provides some additional features for integrating the device with other Schneider Electric products. These functions are based on data analytics for integration into EcoStruxure Asset Advisor cloud-based offers.

### Cumulative breaking current

CB monitoring is activated when the monitored CB opens, and the breaking current is added to the cumulative breaking current. This sum is calculated for each phase separately. This way of estimating the wear on the CB is opposite to the permissible cycles diagram used by the CB wear function. The permissible cycles diagram describes how much more wear the CB can sustain, and this approach describes how much wear the CB has accumulated.

To approximate the shape of the permissible cycles diagram, the cumulative breaking current is also calculated for 5 different bins, so that each bin tracks breaking currents within a given range (see [Figure 165 - Cumulative breaking current on page 263](#)). If a phase's breaking current is within the range of a given bin, this current is added to the phase's cumulative breaking current on that bin.

Each bin also has three counters (one for each phase). Each counter tracks the number of times the CB has opened and something was added to the corresponding sum on that bin (see [Figure 165 - Cumulative breaking current on page 263](#)).

Figure 165 - Cumulative breaking current

CUMULATIVE BREAKING CURRENT							
Low limit	High limit	Sum ph A	Sum ph B	Sum ph C	Cnt ph A	Cnt ph B	Cnt ph C
0.0 kA	4.0 kA	0.00 kA2	0.00 kA2	0.00 kA2	0	0	0
4.0 kA	10.0 kA	0.00 kA2	0.00 kA2	0.00 kA2	0	0	0
10.0 kA	20.0 kA	0.00 kA2	0.00 kA2	0.00 kA2	0	0	0
20.0 kA	80.0 kA	0.00 kA2	0.00 kA2	0.00 kA2	0	0	0
80.0 kA	kA	0.00 kA2	0.00 kA2	0.00 kA2	0	0	0

Cumul. breaking current ph A	<input type="text" value="0.00"/>	kA2
Cumul. breaking current ph B	<input type="text" value="0.00"/>	kA2
Cumul. breaking current ph C	<input type="text" value="0.00"/>	kA2

If all cumulative breaking currents for the bins are zero when the value of the CT primary parameter is changed in the **Scaling** setting view, the breaking current ranges for the bins are automatically set to their default values relative to the new CT primary value. The lower limit for the first bin is set to zero and the upper limit to two times the CT primary value. There is no upper limit for the fifth bin.

The cumulative breaking currents are tracked with greater precision than what is visible on the setting tool, that is, there are hidden decimals stored for each sum. A non-zero sum that is too small to be visible in the setting tool may prevent the bin ranges from getting their default values when the CT primary value is changed.

Each breaking current can be added to one bin.

The cumulative breaking currents can be read over the Modbus protocol as floating-point values (IEEE 754, binary32). These values are represented in two consecutive holding registers, so that the register in the lower address contains the MSB 16 bits. To change the sum by writing a floating-point value, the MSB 16 bits must be written first.

The cumulative breaking currents can be cleared by writing value zero to them.

### Counters for mechanical operations

This function includes a counter that tracks the number of times the monitored CB is opened, and a second counter that tracks how many of those operations were caused by a protection stage trip. This requires that one of the controllable objects (see [5.6 Controllable objects](#) on page 82) has been configured to represent the CB and this object has been selected in the **Monitored object** parameter.

Internally, each object has its own open counter and the counter for the monitored object is shown under **Opening counts**, **Trip counts** and **Rack-out counter** (see [Figure 166 - Counters for mechanical operations](#) on page 264). These open counters are incremented even when this function has been disabled. In contrast, the trip counter is incremented when the monitored object is opened by a protection stage trip and this function is enabled. Thus, if you change the monitored object, the open counter value switches to the counter of the new object, but the trip counter continues from its current value. Both counters' values can be changed.

Figure 166 - Counters for mechanical operations

**OPENING COUNTS**

CBW1 Open count:

**TRIP COUNTS**

CBW1 Trip counter:

**RACK-OUT COUNTER**

DI for rack-out:

Rack-out counter:

The number of times the monitored CB is racked out from the bay is tracked by its own counter. This requires that a digital input is set up to indicate when the CB is racked out<sup>79</sup>. This digital input is selected under **Rack-out counter**. Each digital input has its own counter. The same counter is also found in the **Digital inputs** setting view.

**Operate times logs**

This function records the completion times for the eight previous open, close, and charge operations of the monitored CB. Each operate time is recorded with a timestamp indicating when the operation was completed. This function also keeps a cumulative moving average of 20 previous operate times for each of the three categories.

The completion times are recorded even if this function has been disabled, provided that the monitored object has been selected.

All three logs of completion times can be cleared by the **Clear logs** command.

Figure 167 - CB opening times

**OPERATING TIMES**

Clear logs

**Opening times**

	Date	hh:mm:ss.ms	Op time
[1]	2008-04-25	20:55:27.453	175 ms
[2]	2008-04-25	20:39:23.89	470 ms
[3]	2008-04-25	20:39:15.627	392 ms
[4]	-	-	- ms
[5]	-	-	- ms
[6]	-	-	- ms
[7]	-	-	- ms
[8]	-	-	- ms

Opening avg of last 20    384

The charging times are recorded in seconds whereas the opening and closing times are recorded in milliseconds.

The operate times can be read over the Modbus protocol as floating-point values (IEEE 754, binary32), so that a range of holding registers is used to represent all operate times of a given category, from the newest to oldest. Each operate time is

<sup>79</sup> When the CB is in the bay, this digital input has logical value *false*, and when the CB is racked out, this input has logical value *true*.

represented in two consecutive holding registers, so that the register in the lower address contains the MSB 16 bits.

Empty or unused cells in the log give value zero.

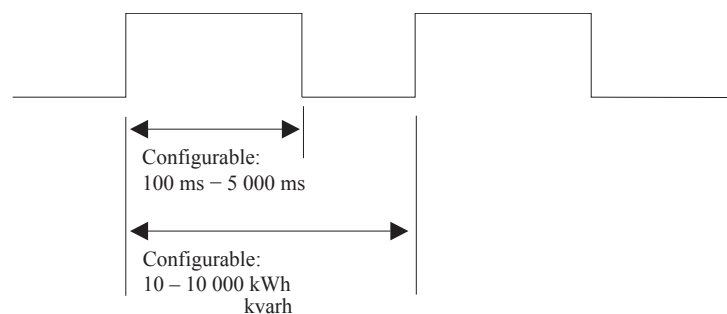
If an opening time or a closing time is greater than 300 milliseconds, this value is given as NaN (not-a-number) when it is read as a floating-point value. Similarly, charging times greater than 60 seconds are given as NaN.

## 7.11 Energy pulse outputs

### Description

The relay can be configured to send a pulse whenever a certain amount of energy has been imported or exported. The principle is presented in [Figure 168 - Principle of energy pulses](#) on page 265. Each time the energy level reaches the pulse size, a digital output is activated and the relay is active as long as defined by a pulse duration setting.

Figure 168 - Principle of energy pulses



The relay has four energy pulse outputs. The output channels are:

- active exported energy
- reactive exported energy
- active imported energy
- reactive imported energy

Each channel can be connected to any combination of the digital outputs using the output matrix. The parameters for the energy pulses can be found in the ENERGY menu "E" under the submenus E-PULSE SIZES and E-PULSE DURATION.

Table 114 - Energy pulse output parameters

	Parameter	Value	Unit	Description
E-PULSE SIZES	E+	10 – 10 000	kWh	Pulse size of active exported energy
	Eq+	10 – 10 000	kvarh	Pulse size of reactive exported energy
	E-	10 – 10 000	kWh	Pulse size of active imported energy
	Eq-	10 – 10 000	kvarh	Pulse size of reactive imported energy
E-PULSE DURATION	E+	100 – 5000	ms	Pulse length of active exported energy
	Eq+	100 – 5000	ms	Pulse length of reactive exported energy
	E-	100 – 5000	ms	Pulse length of active imported energy
	Eq-	100 – 5000	ms	Pulse length of reactive imported energy

### Scaling examples

1. The average active exported power is 250 MW.

The peak active exported power is 400 MW.

The pulse size is 250 kWh.

The average pulse frequency is  $250/0.250 = 1000$  pulses/h.

The peak pulse frequency is  $400/0.250 = 1600$  pulses/h.

Set pulse length to  $3600/1600 - 0.2 = 2.0$  s or less.

The lifetime of the mechanical digital output is  $50 \times 10^6 / 1000$  h = 6 a.

This is not a practical scaling example unless a digital output lifetime of about six years is accepted.

2. The average active exported power is 100 MW.

The peak active exported power is 800 MW.

The pulse size is 400 kWh.

The average pulse frequency is  $100/0.400 = 250$  pulses/h.

The peak pulse frequency is  $800/0.400 = 2000$  pulses/h.

Set pulse length to  $3600/2000 - 0.2 = 1.6$  s or less.

The lifetime of the mechanical digital output is  $50 \times 10^6 / 250$  h = 23 a.

3. Average active exported power is 20 MW.

Peak active exported power is 70 MW.

Pulse size is 60 kWh.

The average pulse frequency is  $25/0.060 = 416.7$  pulses/h.

The peak pulse frequency is  $70/0.060 = 1166.7$  pulses/h.

Set pulse length to  $3600/1167 - 0.2 = 2.8$  s or less.

The lifetime of the mechanical digital output is  $50 \times 10^6 / 417 \text{ h} = 14 \text{ a}$ .

4. Average active exported power is 1900 kW.

Peak active exported power is 50 MW.

Pulse size is 10 kWh.

The average pulse frequency is  $1900/10 = 190$  pulses/h.

The peak pulse frequency is  $50000/10 = 5000$  pulses/h.

Set pulse length to  $3600/5000 - 0.2 = 0.5$  s or less.

The lifetime of the mechanical digital output is  $50 \times 10^6 / 190 \text{ h} = 30 \text{ a}$ .

Figure 169 - Application example of wiring the energy pulse outputs to a PLC having common plus and using an external wetting voltage

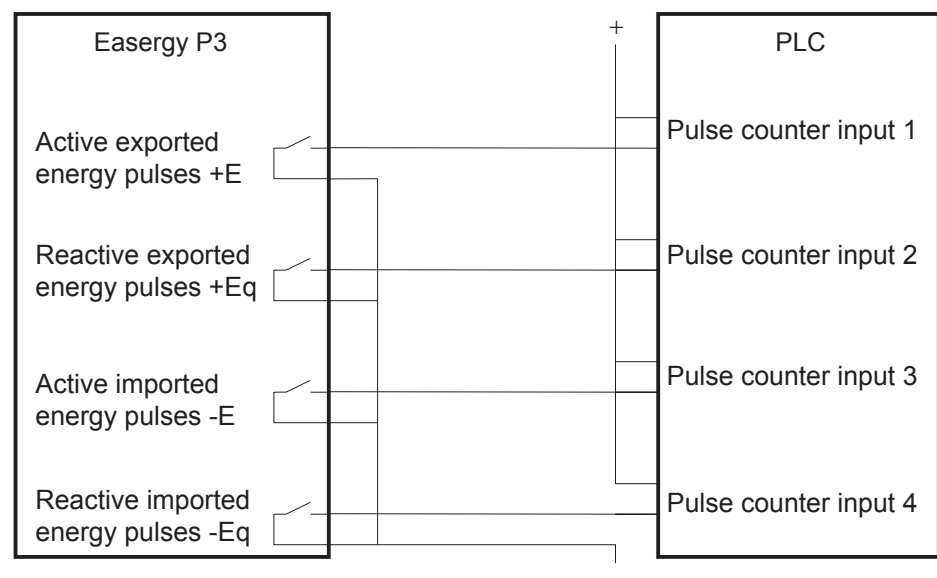


Figure 170 - Application example of wiring the energy pulse outputs to a PLC having common minus and using an external wetting voltage

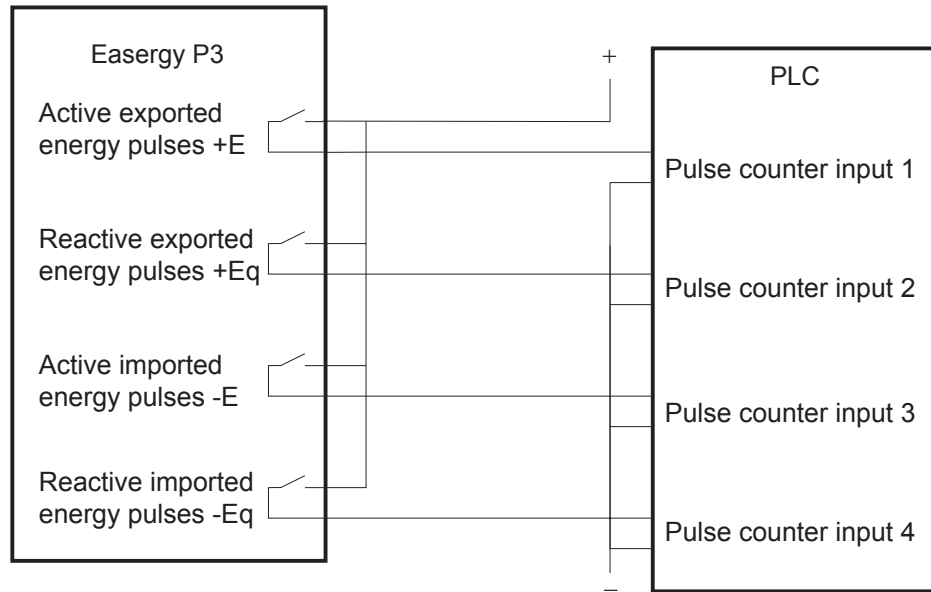
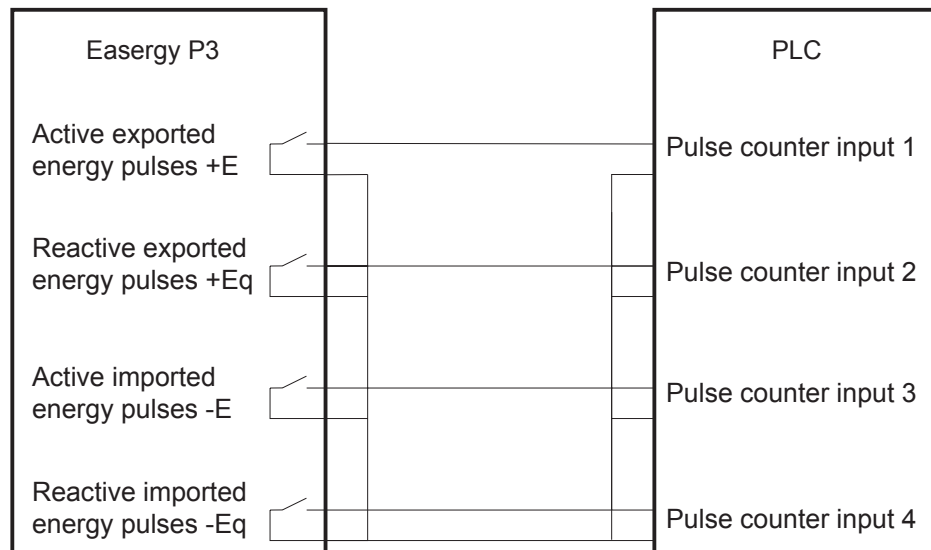


Figure 171 - Application example of wiring the energy pulse outputs to a PLC having common minus and an internal wetting voltage.



## 7.12 Running hour counter

### Description

The running hour counter is typically used to monitor the service time of the motor or appropriate feeder. This function calculates the total active time of the selected digital input, virtual I/O function button, GOOSE signal, POC signal or output matrix output signal. The resolution is ten seconds and the data is stored in the non-volatile memory.



## Parameters

Table 115 - Running hour counter parameters

Parameter	Value	Unit	Description	Note
Runh	0...876000	h	Total active time, hours Note: The label text "Runh" can be edited with Easergy Pro.	(Set) <sup>80</sup>
Runs	0...3599	s	Total active time, seconds	(Set)
Starts	0...65535		Activation counter	(Set)
Status	Stop Run		Current status of the selected digital signal	
Started at			Date and time of the last activation	
Stopped at			Date and time of the last inactivation	

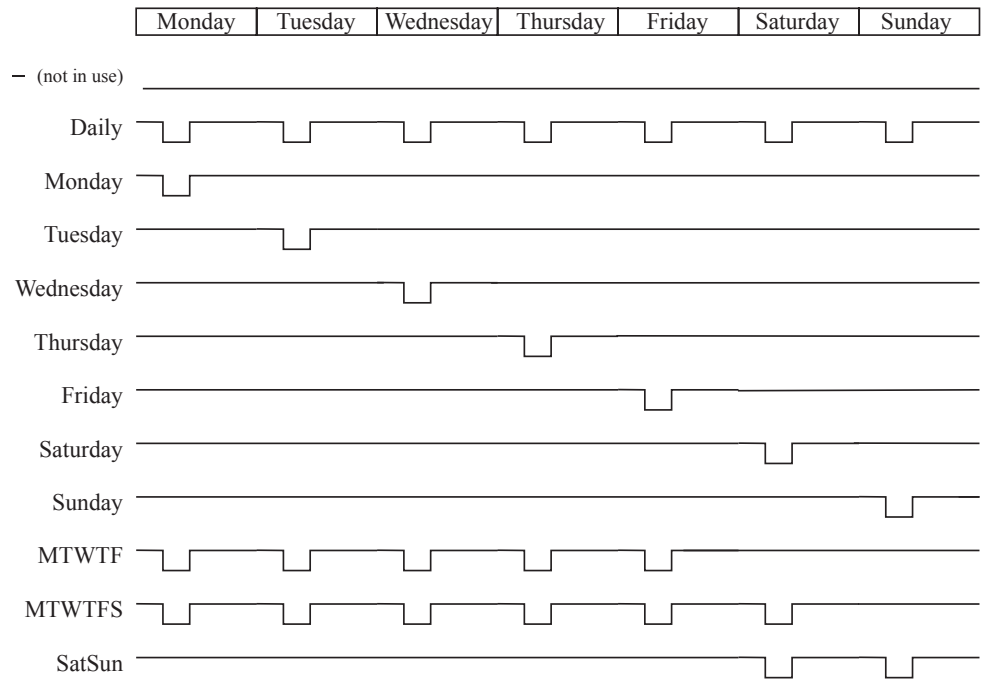
<sup>80</sup> (Set) = An informative value which can be edited as well.

## 7.13 Timers

### Description

The Easergy P3 protection platform includes four settable timers that can be used together with the user's programmable logic or to control setting groups and other applications that require actions based on calendar time. Each timer has its own settings. The selected on-time and off-time is set, after which the activation of the timer can be set to be as daily or according to the day of the week (See the setting parameters for details). The timer outputs are available for logic functions and for the block and output matrix.

Figure 172 - Timer output sequence in different modes



You can force any timer, which is in use, on or off. The forcing is done by writing a new status value. No forcing flag is needed as in forcing for example the digital outputs.

The forced time is valid until the next forcing or until the next reversing timed act from the timer itself.

The status of each timer is stored in the non-volatile memory when the auxiliary power is switched off. At startup, the status of each timer is recovered.

Table 116 - Setting parameters of timers

Parameter	Value	Description
TimerN	-	Timer status
	-	Not in use
	0	Output is inactive
	1	Output is active
On	hh:mm:ss	Activation time of the timer
Off	hh:mm:ss	De-activation time of the timer
Mode		For each four timers there are 12 different modes available:
	-	The timer is off and not running. The output is off i.e. 0 all the time.
	Daily	The timer switches on and off once every day.
	Monday	The timer switches on and off every Monday.
	Tuesday	The timer switches on and off every Tuesday.

Parameter	Value	Description
	Wednesday	The timer switches on and off every Wednesday.
	Thursday	The timer switches on and off every Thursday.
	Friday	The timer switches on and off every Friday.
	Saturday	The timer switches on and off every Saturday.
	Sunday	The timer switches on and off every Sunday.
	MTWTF	The timer switches on and off every day except Saturdays and Sundays
	MTWTFS	The timer switches on and off every day except Sundays.
	SatSun	The timer switches on and off every Saturday and Sunday.

## 7.14 Combined overcurrent status

### Description

This function collects faults, fault types and registered fault currents of all enabled overcurrent stages and shows them in the event log.

The combined overcurrent status can be used as an indication of faults.

Combined o/c indicates the amplitude of the last occurred fault. Also, a separate indication of the fault type is informed during the start and the trip. Active phases during the start and the trip are activated in the output matrix. After the fault is switched off, the active signals release after the set delay "clearing delay" has passed. The combined o/c status refers to the following over current stages: 50/51-1, 50/51-2, 50/51-3, 67-1, 67-2, 67-3, 67-4.

Table 117 - Line fault parameters

Parameter	Value	Unit	Description	Note
IFitLas			Current of the latest overcurrent fault	(Set)
LINE ALARM				
AlrA	-		Start (=alarm) status for each phase.	
AlrB	0		0 = No start since alarm ClrDly	
AlrC	1		1 = Start is on	
OCs	-		Combined overcurrent start status.	
	0		AlrL1 = AlrL2 = AlrL3 = 0	
	1		AlrL1 = 1 or AlrL2 = 1 or AlrL3 = 1	

Parameter	Value	Unit	Description	Note
LxAlarm	- On Off		'On' Event enabling for AlrL1 – 3  Events are enabled  Events are disabled	Set
LxAlarmOff	- On Off		'Off' Event enabling for AlrL1...3  Events are enabled  Events are disabled	Set
OCAAlarm	- On Off		'On' Event enabling for combined o/c starts  Events are enabled  Events are disabled	Set
OCAAlarmOff	- On Off		'Off' Event enabling for combined o/c starts  Events are enabled  Events are disabled	Set
IncFltEvt	- On Off		Disabling several start <u>and</u> trip events of the same fault  Several events are enabled <sup>81</sup>  Several events of an increasing fault is disabled <sup>82</sup>	Set
CirDly	0 – 65535	s	Duration for active alarm status AlrL1, Alr2, AlrL3 and OCs	Set

<sup>81</sup> Used with IEC 60870-105-103 communication protocol. The alarm screen shows the latest fault current if it is the biggest registered fault current, too. Not used with Spabus because Spabus masters usually do not like to have unpaired On/Off events.

<sup>82</sup> Used with SPA-bus protocol because most SPA-bus masters need an off-event for each corresponding on-event.

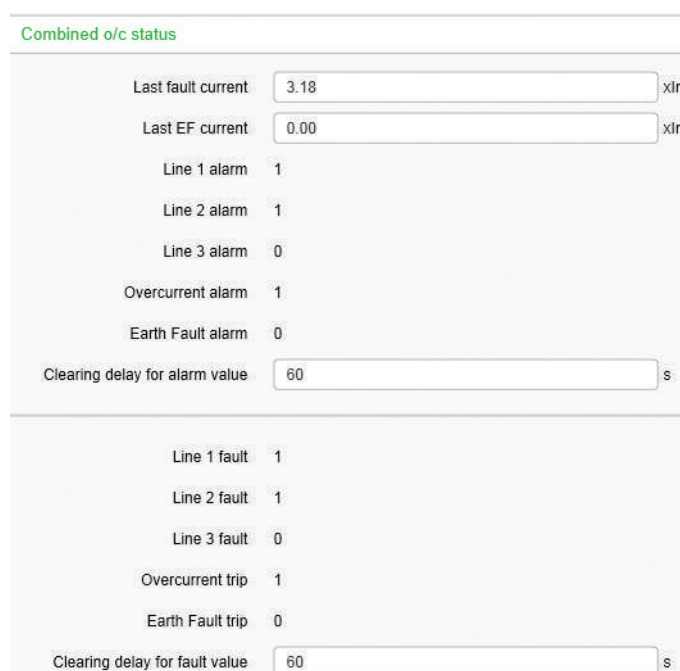
Parameter	Value	Unit	Description	Note
LINE FAULT				
FltL1	-		Fault (=trip) status for each phase.	
FltL2	0		0 = No fault since fault CirDly	
FltL3	1		1 = Fault is on	
OCt	- 0 1		Combined overcurrent trip status.  FltL1 = FltL2 = FltL3 = 0  FltL1 = 1 or FltL2 = 1 or FltL3 = 1	
LxTrip	- On Off		'On' Event enabling for FltL1 – 3  Events are enabled  Events are disabled	Set

Parameter	Value	Unit	Description	Note
LxTripOff	- On Off		'Off' Event enabling for FltL1...3  Events are enabled  Events are disabled	Set
OCTrip	- On Off		'On' Event enabling for combined o/c trips  Events are enabled  Events are disabled	Set
OCTripOff	- On Off		'Off' Event enabling for combined o/c starts  Events are enabled  Events are disabled	Set
IncFltEvt	- On Off		Disabling several events of the same fault  Several events are enabled <sup>83</sup>  Several events of an increasing fault is disabled <sup>84</sup>	Set
ClrDly	0 – 65535		Duration for active alarm status FltL1, Flt2, FltL3 and OCT	Set

<sup>83</sup> Used with IEC 60870-105-103 communication protocol. The alarm screen shows the latest fault current if it is the biggest registered fault current, too. Not used with Spabus because Spabus masters usually do not like to have unpaired On/Off events.

<sup>84</sup> Used with SPA-bus protocol because most SPA-bus masters need an off-event for each corresponding on-event.

Figure 173 - Combined o/c status



The fault that can be seen in the [Figure 173 - Combined o/c status](#) on page 273 was 3.18 times to nominal and it increased in to a two phase short circuit L1-L2.

All signals those are stated as “1” are also activated in the output matrix. After the fault disappears, the activated signals release.

The combined overcurrent status can be found from Easergy Pro through **Protection > Protection stage status 2**.

## 7.15 Trip circuit supervision (ANSI 74)

### Description

Trip circuit supervision is used to ensure that the wiring from the protective relay to a circuit breaker (CB) is in order. Even though the trip circuit is unused most of the time, keeping it in order is important so that the CB can be tripped whenever the relay detects a fault in the network.

The digital inputs of the relay can be used for trip circuit monitoring.

Also the closing circuit can be supervised using the same principle.

**NOTE:** Apply trip circuit supervision using a digital input and its programmable time delay.

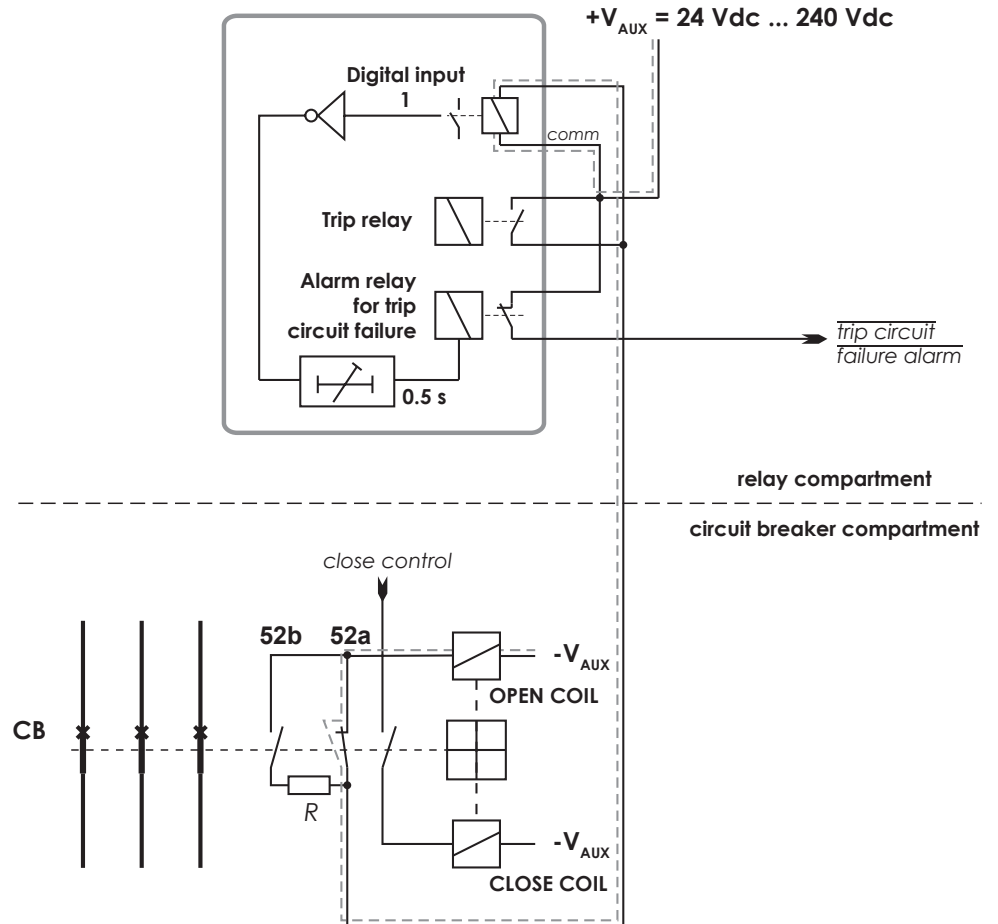
### 7.15.1 Trip circuit supervision with one digital input

The benefits of this scheme are that only one digital inputs is needed and no extra wiring from the relay to the circuit breaker (CB) is needed. Also, supervising a 24 Vdc trip circuit is possible.

The drawback is that an external resistor is needed to supervise the trip circuit on both CB positions. If supervising during the closed position only is enough, the resistor is not needed.

- The digital input is connected parallel to the trip contacts (see [Figure 174 - Trip circuit supervision using a single digital input and an external resistor R on page 275](#)).
- The digital input is configured as normal closed (NC).
- The digital input delay is configured to be longer than the maximum fault time to inhibit any superfluous trip circuit fault alarm when the trip contact is closed.
- The digital input is connected to a relay in the output matrix giving out any trip circuit alarm.
- The trip relay must be configured as non-latched. Otherwise, a superfluous trip circuit fault alarm follows after the trip contact operates, and the relay remains closed because of latching.
- By utilizing an auxiliary contact of the CB for the external resistor, also the auxiliary contact in the trip circuit can be supervised.

Figure 174 - Trip circuit supervision using a single digital input and an external resistor R

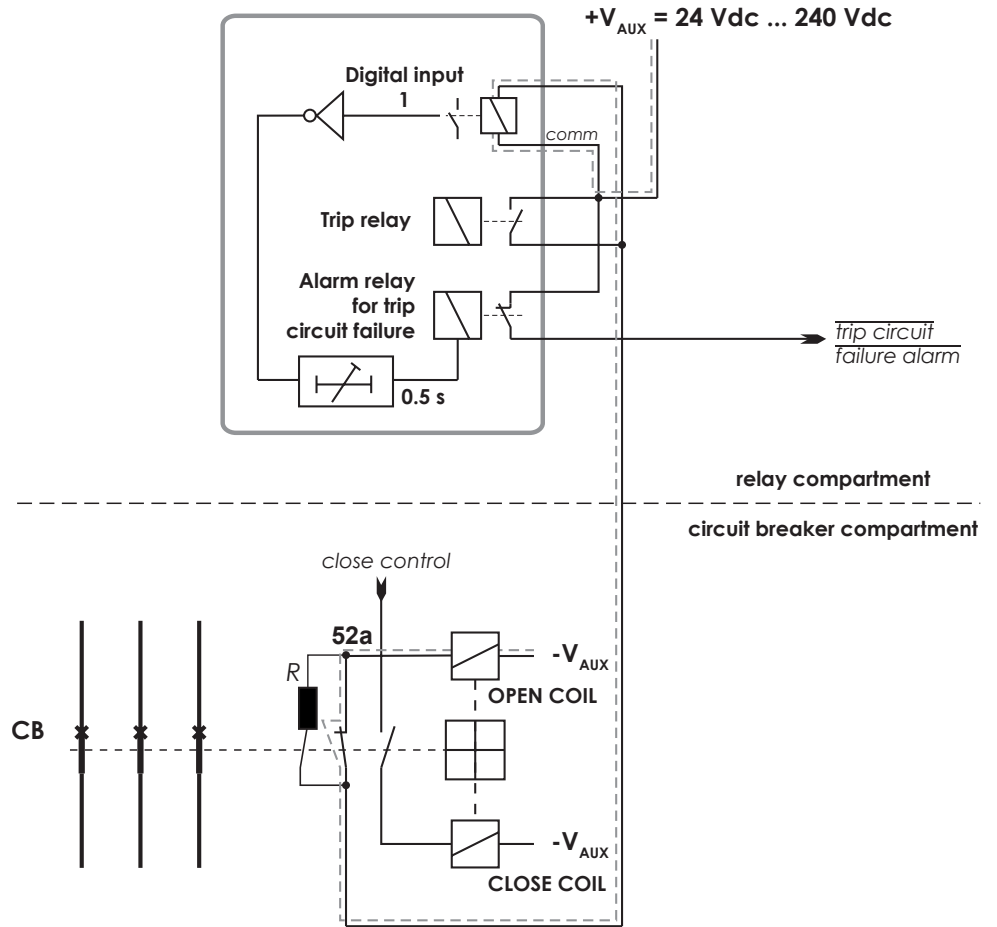


The circuit-breaker is in the closed position. The supervised circuitry in this CB position is double-lined. The digital input is in active state when the trip circuit is complete.

This is applicable to any digital inputs.

**NOTE:** The need for the external resistor R depends on the application and circuit breaker manufacturer's specifications.

Figure 175 - Alternative connection without using circuit breaker 52b auxiliary contacts



Trip circuit supervision using a single digital input and an external resistor R. The circuit breaker is in the closed position. The supervised circuitry in this CB position is double-lined. The digital input is in active state when the trip circuit is complete.

Alternative connection without using circuit breaker 52b auxiliary contacts. This is applicable for any digital inputs.



Figure 176 - Trip circuit supervision using a single digital input when the circuit breaker is in open position

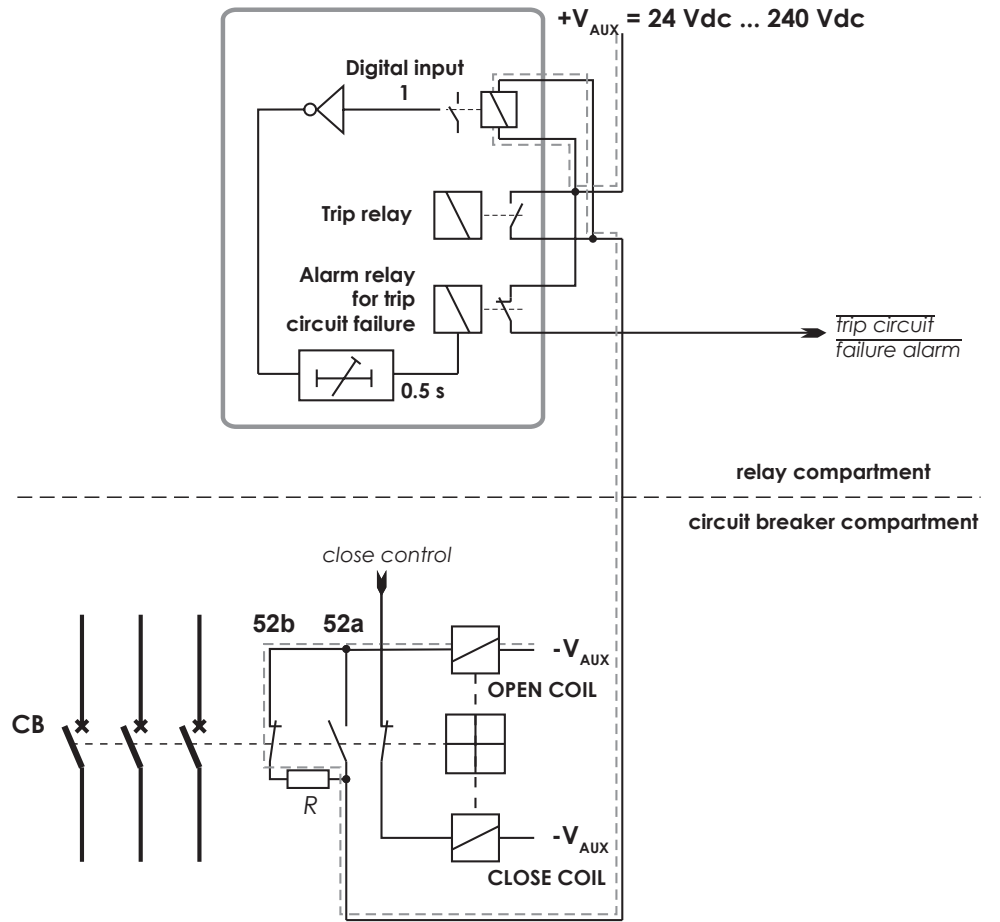


Figure 177 - Alternative connection without using circuit breaker 52b auxiliary contacts. Trip circuit supervision using a single digital input, when the circuit breaker is in open position

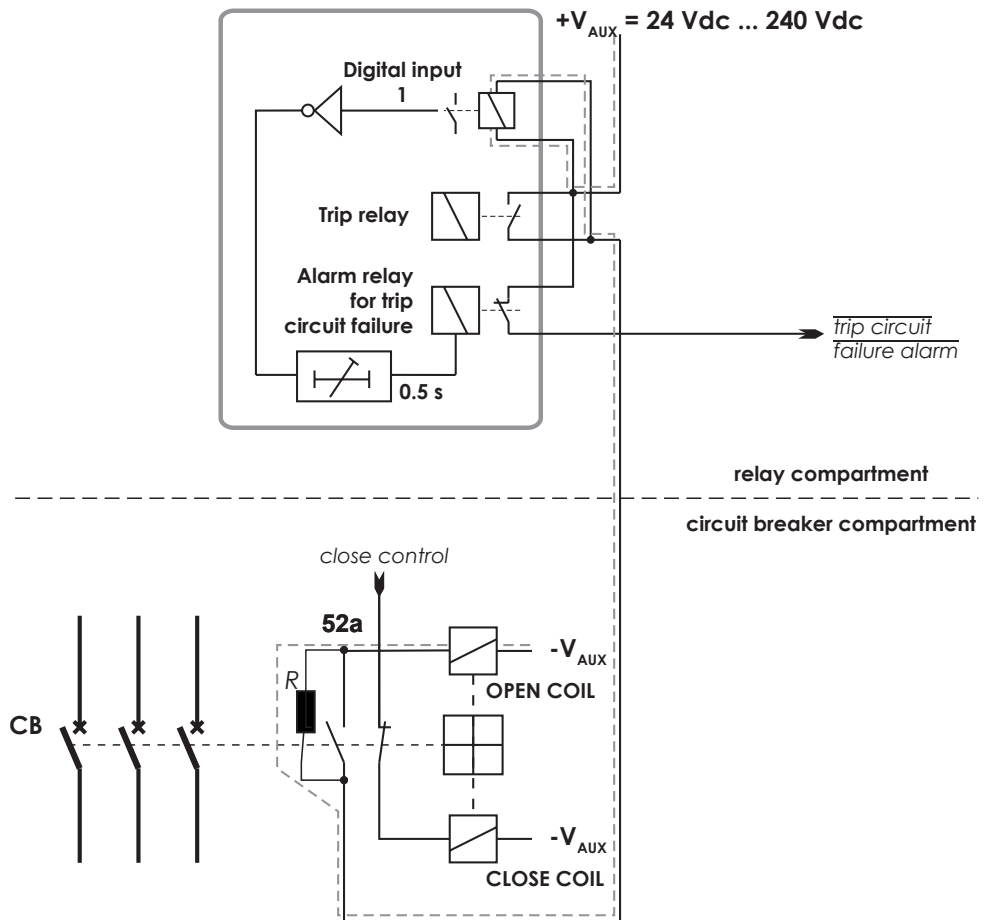
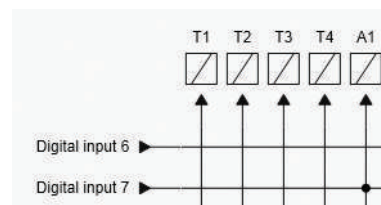


Figure 178 - Example of digital input DI7 configuration for trip circuit supervision with one digital input

DIGITAL INPUTS									
-	Input	State	Polarity	Delay	On Event	Off Event	Alarm display	Counters	
On	1	0	NO	0.00	On	On	On	0	
On	2	0	NO	0.00	On	On	On	0	
On	3	0	NO	0.00	On	On	On	3	
On	4	0	NO	0.00	On	On	On	0	
On	5	0	NO	0.00	On	On	On	0	
On	6	0	NO	0.00	On	On	On	0	
On	7	0	NC	0.50	Off	Off	Off	1	

Figure 179 - Example of output matrix configuration for trip circuit supervision with one digital input



### Example of dimensioning the external resistor R

$V_{AUX} = 110 \text{ Vdc} - 20\% + 10\%$ , Auxiliary voltage with tolerance

$V_{DI} = 18 \text{ Vdc}$ , Threshold voltage of the digital input

$I_{DI} = 3 \text{ mA}$ , Typical current needed to activate the digital input including a 1 mA safety margin.

$P_{COIL} = 50 \text{ W}$ , Rated power of the open coil of the circuit breaker. If this value is not known,  $0 \Omega$  can be used for the  $R_{COIL}$ .

$$V_{MIN} = V_{AUX} - 20\% = 88 \text{ V}$$

$$V_{MAX} = V_{AUX} + 10\% = 121 \text{ V}$$

$$R_{COIL} = V_{AUX}^2 / P_{COIL} = 242 \Omega.$$

The external resistance value is calculated using [Equation 43](#) on page 279:

Equation 43

$$R = \frac{V_{MIN} - V_{DI} - I_{DI} \cdot R_{Coil}}{I_{DI}}$$

$$R = (88 - 18 - 0.003 \times 242) / 0.003 = 23.1 \text{ k}\Omega$$

In practice, the coil resistance has no effect.

By selecting the next smaller standard size, we get **22 kΩ**.

The power rating for the external resistor is estimated using [Equation 44](#) on page 279 and [Equation 45](#) on page 280.

The [Equation 44](#) on page 279 is for the CB open situation including a 100 % safety margin to limit the maximum temperature of the resistor:

Equation 44

$$P = 2 \cdot I_{DI}^2 \cdot R$$

$$P = 2 \times 0.003^2 \times 22000 = 0.40 \text{ W}$$

Select the next bigger standard size, for example **0.5 W**.

When the trip contacts are still closed and the CB is already open, the resistor has to withstand much higher power ([Equation 45 on page 280](#)) for this short time:

Equation 45

$$P = \frac{V_{MAX}^2}{R}$$

$$P = 121^2 / 22000 = 0.67 \text{ W}$$

A 0.5 W resistor is enough for this short time peak power, too. However, if the trip relay is closed for longer than a few seconds, a 1 W resistor should be used.

## 7.15.2 Trip circuit supervision with two digital inputs

The benefit of this scheme is that no external resistor is needed.

The drawbacks are that two digital inputs (DIs) and two extra wires from the relay to the CB compartment are needed. Additionally, the minimum allowed auxiliary voltage is 48 V dc which is more than twice the threshold voltage of the digital input because when the CB is in open position, the two digital inputs are in series.

When two DIs are connected in a series, the switching threshold value used with one DI is too high. Therefore, a lower value must be selected: 24 V if the nominal operation voltage for DI inputs is 110 V or 110 V if the nominal operation voltage is 220 V.

- The first digital input is connected parallel to the auxiliary contact of the circuit breaker's open coil.
- Another auxiliary contact is connected in series with the circuitry of the first digital input. This makes it possible to supervise also the auxiliary contact in the trip circuit.
- The second digital input is connected in parallel with the trip contacts.
- Both inputs are configured as normal closed (NC).
- The user's programmable logic is used to combine the digital input signals with an AND port. The delay is configured to be longer than the maximum fault time to inhibit any superfluous trip circuit fault alarm when the trip contact is closed.
- The output from the logic is connected to a relay in the output matrix giving out any trip circuit alarm.

Figure 180 - Trip circuit supervision with two digital inputs. The CB is closed. The supervised circuitry in this CB position is double-lined. The digital input is in active state when the trip circuit is complete. This is applicable for all digital inputs.

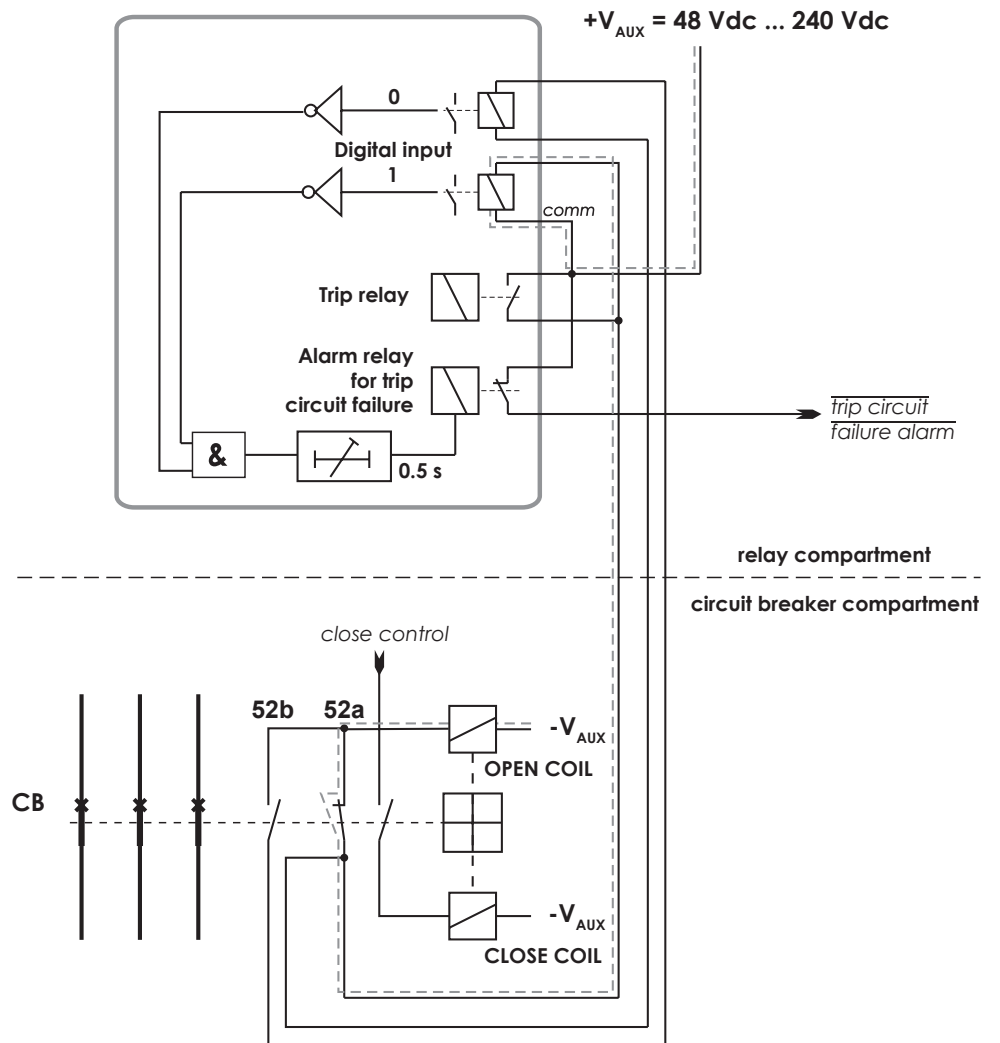


Figure 181 - Trip circuit supervision with two digital inputs. The CB is in the open position. The two digital inputs are now in series.

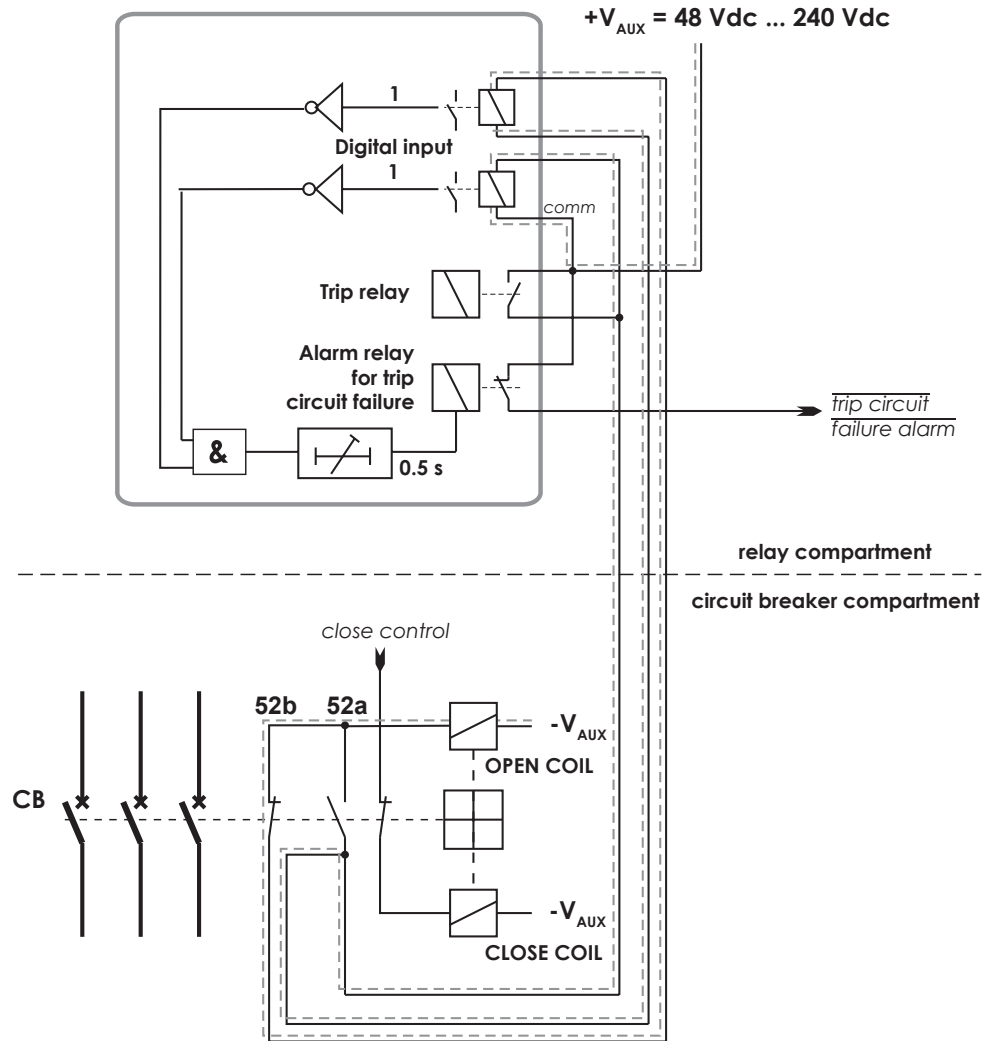


Figure 182 - An example of digital input configuration for trip circuit supervision with two digital inputs DI1 and DI2.

**DIGITAL INPUTS**

Mode: DC

Counters max value: 16 bit

**DIGITAL INPUTS**

Input	Slot	State	Polarity	Delay	On Event	Off Event	Alarm display	Counters
1	2	1	NC	0.00	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	1
2	2	1	NC	0.00	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	1
3	2	0	NO	0.00	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	1
4	2	0	NO	0.00	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	1

Figure 183 - An example of logic configuration for trip circuit supervision with two digital inputs DI1 and DI2.

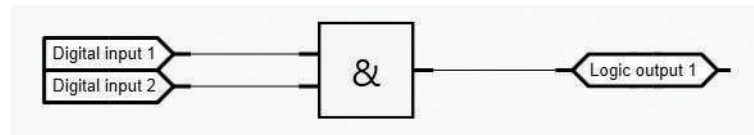
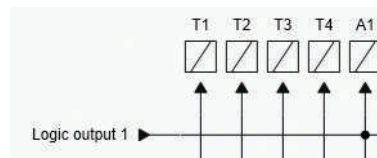


Figure 184 - An example of output matrix configuration for trip circuit supervision with two digital inputs.



## 8 Communication and protocols

### 8.1 Cybersecurity

According to a classic model of information security, the three security goals are:

- confidentiality (prevention of unauthorized disclosure of information)
- integrity (prevention of unauthorized modification of information)
- availability (ensuring that information is always available to authorized users)

These goals may be used as a starting point in designing security solutions for electric power distribution.

We recommend that computer systems used to design or operate electric power distribution systems are designed with the *principle of least privilege*, in other words, that users only have those access rights that they need to perform their duties. All workstations and servers should also have an effective antivirus solution in place, such as a virus scanner. Finally, these computer systems need to be protected with adequate physical security measures to prevent physical tampering of the devices or networks.

<b>NOTICE</b>
<p><b>CYBERSECURITY HAZARD</b></p> <p>To improve cybersecurity:</p> <ul style="list-style-type: none"> <li>• Change all passwords from their default values when taking the protection device into use.</li> <li>• Change all passwords regularly.</li> </ul> <p><b>Failure to follow these instructions can increase the risk of unauthorized access.</b></p>

#### Related topics

[Access to device configuration](#) on page 28

### 8.2 Communication ports

The relay has one fixed communication port: a USB port on the front panel for connection to Easergy Pro setting and configuration tool.

Optionally, the relay may have up to two serial ports, COM 3 and COM 4, for serial protocols (for example IEC 103) and one Ethernet port for Ethernet-based communication protocols (for example IEC 61850).

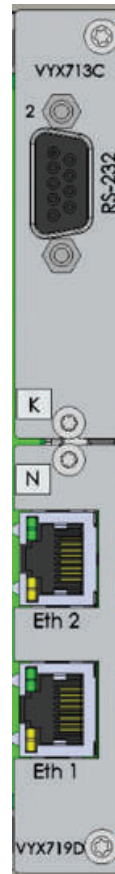
The number of available serial ports depends on the type of the communication option cards.

Each communication port can be individually enabled or disabled with the Configurator access level via:

- the front panel of the Easergy P3 protection device
- Easergy Pro
- the web HMI



Figure 185 - Ethernet, COM 1 and COM 2 ports



**NOTE:** It is possible to have up to 2 serial communication protocols simultaneously in the same D9 and Ethernet connector but restriction is that same protocol can be used only once.

The **Protocol configuration** setting view contains selection for the protocol, port settings and message/error/timeout counters. Only serial communication protocols are valid with RS-232 interface.

Figure 186 - Protocol configuration setting view

COM 1 PORT	
Enable communication port	<input checked="" type="checkbox"/> <span style="float: right;">🔌</span>
COM 1 port protocol	IEC-103 <span style="float: right;">🔌</span>
	- 9600/8N1
Message counter	0 <span style="float: right;">Clear</span>
Error counter	0 <span style="float: right;">Clear</span>
Timeout counter	0 <span style="float: right;">Clear</span>
COM 2 PORT	
Enable communication port	<input checked="" type="checkbox"/> <span style="float: right;">🔌</span>
COM 2 port protocol	ProfibusDP <span style="float: right;">🔌</span>
	- 9600/8N1
Message counter	0 <span style="float: right;">Clear</span>
Error counter	0 <span style="float: right;">Clear</span>
Timeout counter	0 <span style="float: right;">Clear</span>

Table 118 - Parameters

Parameter	Value	Unit	Description	Note
Protocol			Protocol selection for COM port	Set
	None		-	
	SPA-bus		SPA-bus (slave)	
	ProfibusDP		Interface to Profibus DB module VPA 3CG (slave)	
	ModbusSlv		Modbus RTU slave	
	IEC-103		IEC-60870-5-103 (slave)	
	ExternalIO		Modbus RTU master for external I/O-modules	
	IEC 101		IEC-608670-5-101	
	DNP3		DNP 3.0	
	DeviceNet		Interface to DeviceNet module VSE 009	
GetSet		Communicationi protocols for Easergy Pro interface		
Msg#	$0 - 2^{32} - 1$		Message counter since the relay has restarted or since last clearing	Clr
Errors	$0 - 2^{16} - 1$		Protocol interruption since the relay has restarted or since last clearing	Clr
Tout	$0 - 2^{16} - 1$		Timeout interruption since the relay has restarted or since last clearing	Clr
	speed/DPS		Display of current communication parameters. speed = bit/s D = number of data bits P = parity: none, even, odd S = number of stop bits	1.

Set = An editable parameter (password needed)

Clr = Clearing to zero is possible

1. The communication parameters are set in the protocol specific menus. For the local port command line interface the parameters are set in configuration menu.

## 8.2.1 Ethernet port

The Ethernet port is used for Ethernet protocols like IEC61850 and Modbus TCP.

The physical interface is described in [10.6 Connections](#) on page 310.

The parameters for the port can be set via the device's front panel or using Easergy Pro. Two different protocols can be used simultaneously – both protocols use the same IP address and MAC address (but different port number).

## 8.2.2 Disabling the Ethernet communication

### NOTICE

#### CYBERSECURITY HAZARD

To improve cybersecurity, disable the Ethernet communication in environments where effective antimalware solutions have not been taken into use.

**Failure to follow these instructions can increase the risk of unauthorized access.**

1. To disable all Ethernet-based protocols:
  - a. In Easergy Pro, go to **Communication > Protocol configuration**.
  - b. Under **Ethernet port**, disable the Ethernet port by unselecting the **Enable communication port** checkbox.

Figure 187 - Disabling the Ethernet port

The screenshot shows the 'ETHERNET PORT' configuration page. The 'Enable communication port' checkbox is checked. Below it, the MAC address is 001AD3011561. There are checkboxes for 'Enable DHCP service' and 'Enable IP verification service', both of which are unchecked. The IP Address field contains 10.4.128.92, and the NetMask field contains 255.255.240.0. The Gateway ARP max tryouts is set to 5. The Gateway field contains 10.4.128.254, and the NTP server field contains 10.4.128.250. The NTP server (BackUp) field contains 0.0.0.0. The IP port for setting tool is set to 23. The TCP keepalive interval is set to 0. At the bottom, the Ethernet packets received and sent are both 0. The Eth Port1 status and Eth Port2 status are both 'Link down'.

This disables all the Ethernet-based protocols (FTP, HTTP, Telnet, and Ethernet protocols).

2. To disable FTP, HTTP, Telnet, or Ethernet protocols separately:
  - a. Under **Ethernet port**, select the **Enable communication port** checkbox.
  - b. Unselect the **Enable...** checkbox for the servers or protocols you want to disable.

Figure 188 - Disabling individual Ethernet-based protocols

The screenshot displays the configuration page for 'FTP SERVER' and 'Advanced Ethernet options'. The 'FTP SERVER' section includes:
 

- 'Enable FTP server':
- 'FTP password': config
- 'FTP max speed': 4 kbit/s

 The 'Enable HTTP server' section includes:
 

- 'Enable HTTP server':
- 'HTTP server access': Read/Write

 The 'Enable Telnet' section includes:
 

- 'Enable Telnet':

 The 'Advanced Ethernet options' section includes:
 

- 'Send Gratuitous ARP':
- 'Storm protection limit': 1.00 %
- 'Storm protection on Port1':
- 'Storm protection on Port2':
- 'Sniffer mode':
- 'Sniffer Port': EthPort2

 The 'Ethernet Protocol 1' section includes:
 

- 'Enable communication port':
- 'Ethernet port protocol': None

 The 'Ethernet Protocol 2' section includes:
 

- 'Enable communication port':
- 'Ethernet port protocol 2nd inst.': None

## 8.3 Communication protocols

The protocols enable the transfer of the following type of data:

- events
- status information
- measurements
- control commands
- clock synchronization
- some settings through SPA bus, IEC-103, Modbus and IEC-61850 protocols
- disturbance recordings through IEC-103, Modbus and IEC-61850 protocols

### 8.3.1 Modbus RTU and Modbus TCP

Modbus RTU and Modbus TCP protocols are often used in power plants and industrial applications. The difference between these two protocols is the media. Modbus TCP uses Ethernet and Modbus RTU uses RS-485, optic fibre, or RS-232.

Easergy Pro shows a list of all available data items for Modbus. They are also available as a zip file ("Communication parameter protocol mappings.zip").

The information available via Modbus RTU and Modbus TCP includes:

- status values
- control commands
- measurement values
- events
- protection settings
- disturbance recordings

The Modbus communication is activated via a menu selection with the parameter "Protocol". See [8.2 Communication ports](#) on page 284.

For more information on Modbus configuration, see the document *P3APS18025EN Modbus configuration instructions*.

For the Ethernet interface configuration, see [8.2.1 Ethernet port](#) on page 286.

## 8.3.2 Profibus DP

The Profibus DP protocol is widely used in the industry. An external VPA 3CG and VX072 cables are required.

### Device profile "continuous mode"

In this mode, the relay is sending a configured set of data parameters continuously to the Profibus DP master. The benefit of this mode is the speed and easy access to the data in the Profibus master. The drawback is the maximum buffer size of 128 bytes, which limits the number of data items transferred to the master. Some PLCs have their own limitation for the Profibus buffer size, which may further limit the number of transferred data items.

### Device profile "Request mode"

Using the request mode, it is possible to read all the available data from the Easergy P3 relay and still use only a very short buffer for Profibus data transfer. The drawback is the slower overall speed of the data transfer and the need of increased data processing at the Profibus master as every data item must be separately requested by the master.

**NOTE:** In the request mode, it is not possible to read continuously only one single data item. At least two different data items must be read in turn to get updated data from the relay.

There is a separate manual for VPA 3CG for the continuous mode and request mode. The manual is available for downloading on our website.

### Available data

Easergy Pro shows the list of all available data items for both modes. A separate document "Communication parameter protocol mappings.zip" is also available.

The Profibus DP communication is activated usually for remote port via a menu selection with parameter "Protocol". See [8.2 Communication ports](#) on page 284.

## 8.3.3 SPA-bus

The relay has full support for the SPA-bus protocol including reading and writing the setting values. Also, reading multiple consecutive status data bits, measurement values or setting values with one message is supported.

Several simultaneous instances of this protocol, using different physical ports, are possible, but the events can be read by one single instance only.

There is a separate document "Communication parameter protocol mappings.zip" of SPA-bus data items available.

### 8.3.4 IEC 60870-5-103 (IEC-103)

The IEC standard 60870-5-103 "*Companion standard for the informative interface of protection equipment*" provides a standardized communication interface to a primary system (master system).

The unbalanced transmission mode of the protocol is used, and the relay functions as a secondary station (slave) in the communication. Data is transferred to the primary system using the "data acquisition by polling" principle.

**The IEC functionality includes application functions:**

- station initialization
- general interrogation
- clock synchronization
- command transmission.

It is also possible to transfer parameter data and disturbance recordings via the IEC 103 protocol interface.

**The following application service data unit (ASDU) types can be used:**

- ASDU 1: Time-tagged message
- ASDU 3: Measurands I
- ASDU 5: Identification message
- ASDU 6: Time synchronization
- ASDU 8: Termination of general interrogation
- ASDU 10: Generic data

**The relay accepts:**

- ASDU 6: Time synchronization
- ASDU 7: Initiation of general interrogation
- ASDU 10: Generic data
- ASDU 20: General command
- ASDU 21: Generic command
- ASDU 23: Disturbance recorder file transfer

**The data in a message frame is identified by:**

- type identification
- function type
- information number.

These are fixed for data items in the compatible range of the protocol, for example, the trip of I> function is identified by:

- type identification = 1
- function type = 160
- information number = 90

"Private range" function types are used for such data items that are not defined by the standard (for example, the status of the digital inputs and the control of the objects).

The function type and information number used in private range messages is configurable. This enables flexible interfacing to different master systems.

For more information on IEC 60870-5-103 in Easergy P3 relays, see the "IEC 103 Interoperability List.pdf" and "Communication parameter protocol mappings.zip" documents.

### 8.3.5 DNP 3.0

The relay supports communication using the DNP 3.0 protocol. The following DNP 3.0 data types are supported:

- binary input
- binary input change
- double-bit input
- binary output
- analog input
- counters

### 8.3.6 IEC 60870-5-101 (IEC-101)

The IEC 60870-5-101 standard is derived from the IEC 60870-5 protocol standard definition. In Easergy P3 relays, the IEC 60870-5-101 communication protocol is available via menu selection. The relay works as a controlled outstation (slave) unit in unbalanced mode.

The supported application functions include process data transmission, event transmission, command transmission, general interrogation, clock synchronization, transmission of integrated totals, and acquisition of transmission delay.

For more information on IEC 60870-5-101 in Easergy P3 relays, see the "Communication parameter protocol mappings.zip" document.

### 8.3.7 IEC 61850

The IEC 61850 protocol is available with the optional communication module. It can be used to read or write static data from the relay or to receive events and to receive or send GOOSE messages from or to other relays.

The IEC 61850 server interface includes the following features:

- configurable data model: selection of logical nodes corresponding to active application functions
- configurable pre-defined data sets
- supported dynamic data sets created by clients
- supported reporting function with buffered and unbuffered Report Control Blocks
- sending analog values over GOOSE
- supported control modes:
  - direct with normal security
  - direct with enhanced security
  - select before operation with normal security
  - select before operation with enhanced security
- supported horizontal communication with GOOSE: configurable GOOSE publisher data sets, configurable filters for GOOSE subscriber inputs, GOOSE inputs available in the application logic matrix
- 32 data points can be published with GOOSE (two goose control blocks with maximum 16 data points).
- 64 binary data points and five analog data points can be subscribed in GOOSE (maximum five different MAC addresses).

- The maximum number of clients is eight (the maximum number of BRCBs is eight and the maximum number of URCBs is eight).
- Both Ed1 and Ed2 are supported and can be selected with a parameter.

For additional information, see separate documents:

- *IEC 61850 Edition 2 Certificate for Easergy P3*
- *Easergy P3 communication protocol parameter mapping*
- *IEC 61850 configuration instructions*

### 8.3.8 HTTP server – Webset

The Webset HTTPS configuration interface provides the option to configure the relay with a standard web browser such as Internet Explorer, Mozilla Firefox, or Google Chrome. The feature is available when the communication option C, D, N or R is in use.

A subset of the relays's features is available in the Webset interface. The group list and group view from the relay are provided, and most groups, except the LOGIC and the MIMIC groups are configurable.

## 8.4 IP filter

Easergy P3 devices contain a simple IP filter (IP firewall), which can be used to filter incoming TCP/IP connections. This filtering applies only to Modbus TCP, DNP3, and Ethernet/IP, and can be configured via Easergy Pro.

Figure 189 - IP firewall setting view

IP firewall

Enable IP firewall

Index	Enable	Action	Name	IP address	Counter
1	<input type="checkbox"/>	Allow	-	-	0
2	<input type="checkbox"/>	Allow	-	-	0
3	<input type="checkbox"/>	Allow	-	-	0
4	<input type="checkbox"/>	Allow	-	-	0
5	<input type="checkbox"/>	Allow	-	-	0
6	<input type="checkbox"/>	Allow	-	-	0
7	<input type="checkbox"/>	Allow	-	-	0
8	<input type="checkbox"/>	Allow	-	-	0
9	<input type="checkbox"/>	Allow	-	-	0
10	<input type="checkbox"/>	Allow	-	-	0

Default action:

Clear counters:

The IP filter works based on configured rules. Incoming IP packets are compared against the rules, and when a matching rule is found, the packet is handled using the action specified for the rule. If none of the rules matches the packet, the default action is taken on the packet. The IP filter records how many times a packet has matched a rule. The number is shown in the **Counter** column.

On TCP connections, the rules are mostly applied only when a connection is opened.



## 8.4.1 Configuring the IP filter

You can configure up to 10 rules for the IP filter via Easergy Pro and enable each rule individually.

1. In Easergy Pro, go to **Communication > Protocol configuration**.
2. In the **IP firewall** setting view, select the **Enable IP firewall** checkbox to enable the firewall.

Figure 190 - IP firewall setting view

The screenshot shows the 'IP firewall' configuration page. At the top, there is a checkbox labeled 'Enable IP firewall' which is currently unchecked. Below this is a table with the following columns: Index, Enable, Action, Name, IP address, and Counter. The table contains 10 rows, each with an 'Enable' checkbox and an 'Action' dropdown menu set to 'Allow'. The 'Counter' column shows '0' for all rules. Below the table, there is a 'Default action' dropdown menu set to 'Reject' and a 'Clear counters' button.

3. In the **IP firewall** setting view, create a rule.
  - a. In the **Name** column, give the rule a name (maximum 32 characters) that describes its purpose .
  - b. In the **IP address** column, specify an IP address.

The IP address is used to filter the incoming IP packets based on the (apparent) IP address of the source device. There are four options.

Table 119 - IP address for the IP filter

IP address	Description
<b>Any</b>	By writing a dash or value zero in this column, the rule is set to match any source IP address. The column shows a dash.
<b>Single IP address</b>	If a single IP address (such as 192.168.0.10) is written here, the packets (or connections) must originate from this IP address to match the rule.
<b>IP subnet</b>	If all IP addresses in a subnet should match this rule, write the subnet here using the CIDR notation. For example, notation 192.168.0.0/24 matches all IP addresses in the range 192.168.0.0–192.168.0.255.
<b>IP address range</b>	If a range of IP addresses (for example, 192.168.0.20–192.168.0.30) is written here, packets from these addresses match the rule. Both end points of this range are inclusive.

**NOTE:** If the matching range of IP addresses can be expressed using the CIDR notation, the range is expressed in this format, regardless of how the range was entered into the configuration. As a result, the

presentation format of the configuration as it is read from the device might not match the format in which it was entered. This may cause problems with Easergy Pro because this tool expects the presentation format to match exactly. To work around this issue, select the **Reset and read current view** command in Easergy Pro after writing the configuration. This is required to handle the large number of different input formats supported.

- c. In the **Action** column, specify an action for the rule.

There are four options.

Table 120 - Actions for IP filter

Action	Description
<b>Allow</b>	The packet is allowed to continue normally. This means that the specified source devices can use the specified services on the P3 device.
<b>Reject</b> <sup>85</sup>	The packet is blocked and the remote peer is informed about this decision.
<b>Drop</b>	The packet is blocked without informing the remote peer.
<b>Cont.</b>	The processing of the other rules continues on this packet normally.

<sup>85</sup> Because of the implementation details in the Easergy P3 TCP/IP stack, rules that are given the Reject action sometimes behave as if their action was Drop.

### 8.4.2 Unexpected packets

The IP filter also can also detect unexpected packets. For example, if a client attempts to close a connection that does not exist, this is considered an unexpected packet.

Certain techniques used by hackers produce unexpected packets, but such packets may also appear on the network if some packets are lost or dropped because of a malfunctioning network device. Some devices may also have programming errors or bugs produce unexpected packets in their TCP/IP stack.

The unexpected packets feature attempts to distinguish between these two sources based on the number of unexpected packets detected within a configurable “recent period”. If the number of these packets is greater than the configured limit, the selected alarm signal is triggered.

Figure 191 - Unexpected packets setting view

The screenshot shows a configuration window titled "Unexpected packets". It contains the following fields:

- Counter: 0
- Limit: 10
- Recent period: 1 min
- Alarm: -

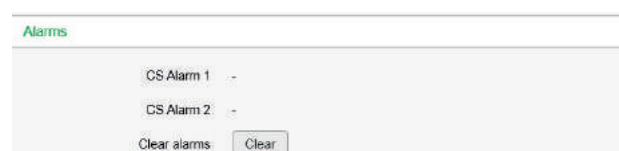
Table 121 - Parameters for unexpected packages

Parameter	Description
Counter	Counts the number of unexpected packets detected within the configured recent period.
Limit	The limit after which an alarm is given
Recent period	The number of unexpected packets counted within this period is compared to the configured limit value <ul style="list-style-type: none"> <li>• Default value: 1 minute</li> <li>• Maximum value: 65535 minutes (45 days)</li> </ul>
Alarm	Select which CS alarm signal (CS Alarm 1/CS Alarm 2) is activated when the set limit is exceeded. The alarms can be assigned to other signals in the output matrix.

### 8.4.3 Alarms

Active cybersecurity (CS) alarms can be viewed in the **Alarms** view. When an alarm signal has been asserted, it remains active until it is cleared with the **Clear alarms** command.

Figure 192 - Alarms



## 9 Applications and configuration examples

This chapter describes the protection functions in different protection applications.

The relay can be used for line/feeder protection of medium voltage networks with a grounded, low-resistance grounded, isolated or a compensated neutral point. The relays have all the required functions to be applied as a backup relay in high-voltage networks or to a transformer differential relay. In addition, the relay includes all the required functions to be applied as a motor protection relay for rotating machines in industrial protection applications.

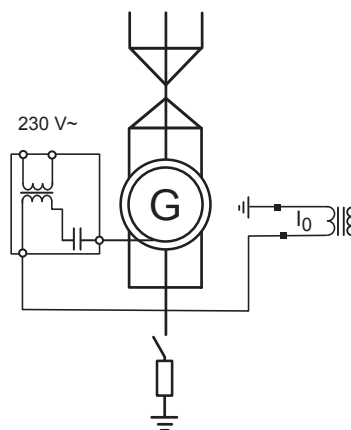
The relays provide a circuit breaker control function. Additional primary switching relays (grounding switches and disconnecter switches) can also be controlled from the front panel or the control or SCADA/automation system. A programmable logic function is also implemented in the relay for various applications, for example interlockings schemes.

### 9.1 Rotor ground fault protection (ANSI 64R)

Rotor ground fault protection can be utilized with an injection source connected between ground and one side of the field circuit with a capacitive coupling. The field circuit is subjected to an alternating potential at substantially the same level throughout. An ground fault anywhere in the field system gives rise to a current that is detected by the protection relay.

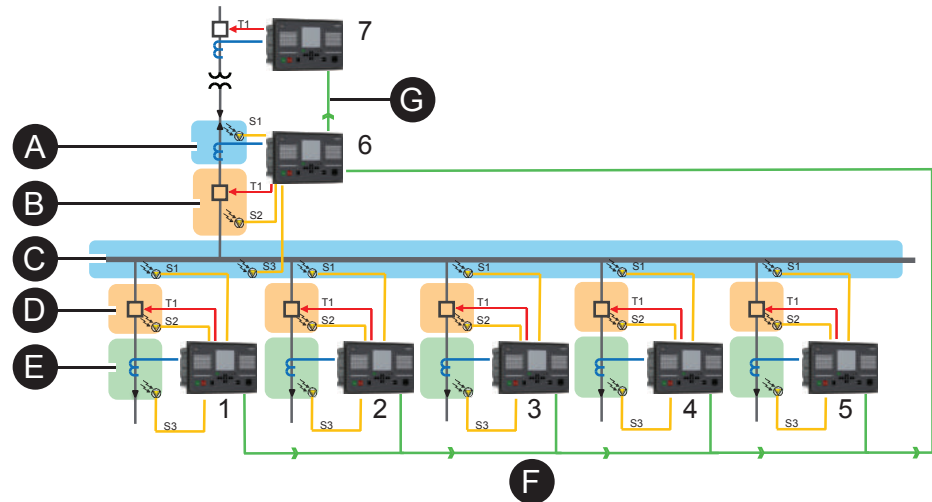
This scheme is suitable for generators that incorporate brushes in the main generator field winding.

Figure 193 - Rotor ground-fault protection principle of field circuit by alternating current injection



## 9.2 Arc flash detection

Figure 194 - Typical arc flash detection scheme with integrated arc flash option card



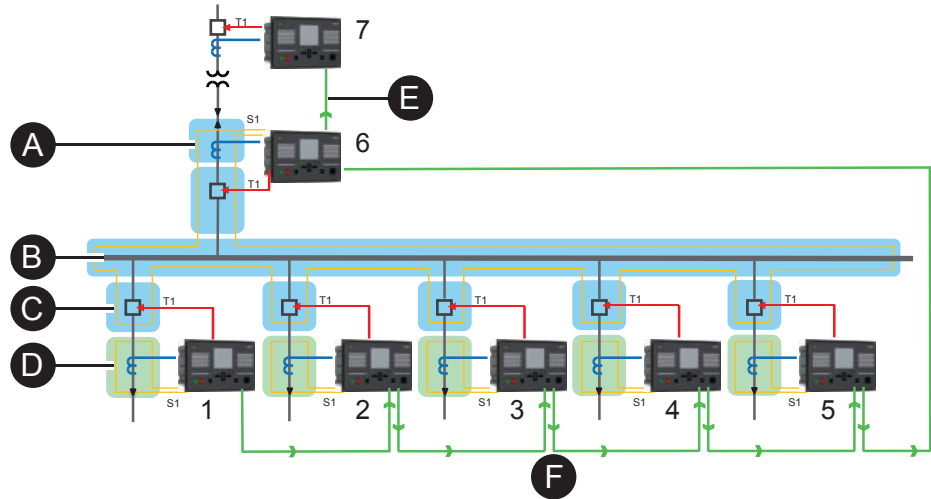
- A. Incomer cable zone
- B. Incomer circuit breaker zone
- C. Busbar zone
- D. Feeder circuit breaker zone
- E. Feeder cable zone
- F. Light information via BIO L> (feeder cable and circuit breaker)
- G. Light information via BIO L> (incomer busbar and circuit breaker)

In this application example, the arc flash sensor for zone E is connected to device 1. If the sensor detects a fault and simultaneously, device 1 detects an overcurrent signal, zone E is isolated by the outgoing feeder breaker.

The arc flash sensor for the second feeder zone E is connected to device 2, and it operates the same way. The arc flash sensors for zones C and D are connected to device 1, 2, 3, 4, or 5. If a sensor detects a fault in zone C or D, the light-only signal is transferred to device 6 which also detects the overcurrent and then trips the main circuit breaker.

An arc flash fault in zone A or B does not necessarily activate the current detection in device 6. However, arc flash detection can be achieved by using the light-only principle. If an arc flash occurs in the cable termination or incomer circuit breaker in zone A or B, the fault is cleared by an overcurrent signal.

Figure 195 - Arc flash detection application example – fiber



- A. Incomer cable zone
- B. Busbar zone
- C. Feeder circuit breaker zone
- D. Feeder cable zone
- E. Light information via BIO L> (incomer busbar and circuit breaker)
- F. Light information via BIO L> (feeder cable and circuit breaker)

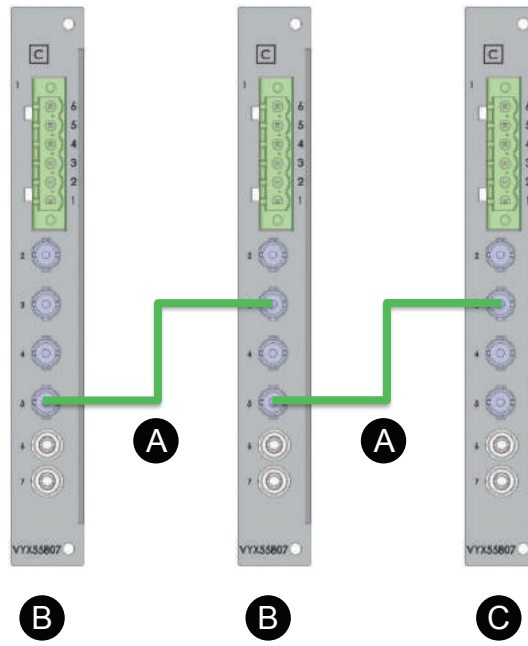
The fiber-loop arc flash sensor for zone D is connected to device 1. If the sensor detects a fault and simultaneously, device 1 detects an overcurrent signal, zone D is isolated by the outgoing feeder breaker.

For the other feeders, the fiber-loop arc flash sensors monitoring zone D are connected to the appropriate feeder relays and they operate the same way as feeder 1.

The fiber loop arc flash sensors for zones C, B and A are connected to device 6. If a sensor detects a fault in zone C, B or A and simultaneously, device 6 detects an overcurrent signal, the fault is cleared by the incoming breaker operation.

Device 7 measures the overcurrent and receives light detection signals from zones A, B, and C. It trips the substation if device 6 is unable to measure the overcurrent.

Figure 196 - Arc flash detection application example – fiber connections



- A. L > (BB & CB) via fibre-optic link
- B. Feeder
- C. Incomer

Figure 197 - Arc matrix – light

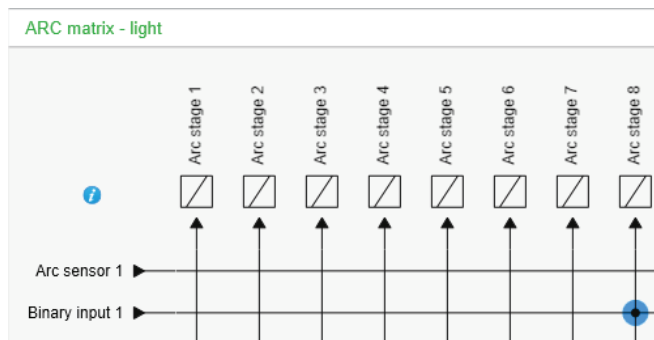
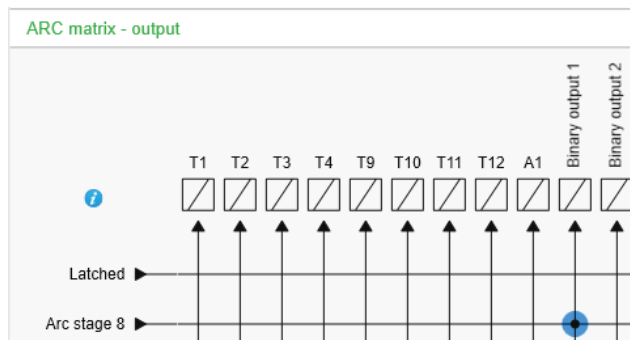


Figure 198 - Arc matrix – output



## 9.3 Using CSH120 and CSH200 with core balance CTs

### General

The CSH120 and CSH200 core balance CTs are for direct ground fault overcurrent measurement. The only difference between them is the diameter. Because of their low-voltage insulation, they can only be used on cables.

These core balance CTs can be connected to the Easergy P3 protection relay range when 0.2 A  $I_N$  input is used. This needs to be determined when ordering the protection relay (select 0.2 A for the ground fault current input in the order code).

### Settings in the Easergy P3 protection relay

When CSH120 or CSH200 is connected to an Easergy P3 protection relay, to secure correct operation of the protection functions and measurement values, use the following values in the **Scaling** setting view:

- $I_{NX}$  CT primary: 470 A
- $I_{NX}$  CT secondary: 1 A
- Nominal  $I_{NX}$  input: 0.2 A

**NOTE:** X refers to the  $I_N$  input channel number (1 or 2).

Figure 199 - Scalings view for  $I_{N2}$  input

Io2 CT primary	<input type="text" value="470"/>	A
Io2 CT secondary	<input type="text" value="1.0"/>	A
Nominal Io2 input	<input type="text" value="0.2"/>	A

### Measuring specifications

When CSH120 or CSH200 is used with Easergy P3 protection relays the measuring range is 0.2 A–300 A of primary current. The minimum setting for primary current is  $0.005 \times I_N$  which in this case means  $0.005 \times 470 \text{ A} = 2.35 \text{ A}$  of primary current.



Figure 200 - Ground fault overcurrent setting view

Io input:

Io1 residual current: 0.000

Status:

Estimated time to trip: 0.0

Start counter:  Clear

Trip counter:  Clear

pu

s

---

Set group 1 DI control:

Set group 2 DI control:

Set group 3 DI control:

Set group 4 DI control:

---

Group:

	Group 1	Group 2	Group 3	Group 4
Pick-up setting [A]	2.35	23.50	23.50	23.50
Pick-up setting [pu]	0.005	0.050	0.050	0.050
Delay curve family	DT	DT	DT	DT
Delay type	DT	DT	DT	DT
Operation delay [s]	1.00	1.00	1.00	1.00

# 10 Installation

## 10.1 Safety in installation

This page contains important safety instructions that must be followed precisely before attempting to install, repair, service or maintain electrical equipment. Carefully read and follow the safety instructions described below. Only qualified personnel, equipped with appropriate individual protection equipment, may work on or operate the equipment. Qualified personnel are individuals who:

- are familiar with the installation, commissioning, and operation of the equipment and of the system to which it is being connected.
- are able to safely perform switching operations in accordance with accepted safety engineering practices and are authorised to energize and de-energize equipment and to isolate, ground, and label it.
- are trained in the care and use of safety apparatus in accordance with safety engineering practices.
- are trained in emergency procedures (first aid).

### DANGER

#### HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH BEFORE PERFORMING ANY INTERVENTION:

- Turn off all power supplying the protection relay and the equipment in which it is installed before working on it.
- Always use a properly rated voltage sensing device to confirm that power is off.
- Replace all devices, doors, and covers before turning on power to this equipment.
- Apply appropriate personal protective equipment and follow safe electrical work practices. See local regulation.
- Do not install this product in ATEX class 0, 1 and 2 areas.

**Failure to follow this instruction will result in death or serious injury.**

### DANGER

#### HAZARD OF FIRE

Insufficient tightening causes high contact resistance and overheat with current, in extreme cases, even loose and ineffective connections and fire hazard. Tighten all the electric connections with specified torque.

**Failure to follow these instructions will result in death or serious injury.**

**⚠ WARNING****HAZARD OF UNEXPECTED OPERATION**

Do not energize the primary circuit before this protection relay is properly configured.

**Failure to follow these instructions can result in death, serious injury, or equipment damage.**

**⚠ CAUTION****HAZARD OF FIRE, DAMAGE TO ELECTRONICS OR MALFUNCTION**

If you are authorized to withdraw the relay:

- Disconnect the power supply before removing or replacing a module or the withdrawable part of the protection relay.
- Never touch electronic parts (electrostatic discharge).
- Before replacing the withdrawable part, visually check the cleanliness and if there are any foreign objects in the case, the withdrawable part and the connectors.

**Failure to follow these instructions can result in injury or equipment damage.**

**Protection Class I equipment**

Before energizing the equipment it must be grounded using the protective conductor terminal, if provided, or the appropriate termination of the supply plug in the case of plug connected equipment.

The protective conductor (ground) connection must not be removed since the protection against electric shock provided by the equipment would be lost.

When the protective (ground) conductor terminal (PCT) is also used to terminate cable screens, etc., it is essential that the integrity of the protective (ground) conductor is checked after the addition or removal of such functional ground connections. For M4 stud PCTs the integrity of the protective (ground) connections should be ensured by use of a locknut or similar.

The recommended minimum protective conductor (ground) wire size is 2.5 mm<sup>2</sup> (AWG 14) (3.3 mm<sup>2</sup> (AWG 12) for North America) unless otherwise stated in the technical data section of the equipment documentation, or otherwise required by local or country wiring regulations.

The protective conductor (ground) connection must be low-inductance and as short as possible. All connections to the equipment must have a defined potential. Connections that are pre-wired, but not used, should preferably be grounded when binary inputs and output relays are isolated. When binary inputs and output relays are connected to common potential, the pre-wired but unused connections should be connected to the common potential of the grouped connections.

## 10.2 Checking the consignment

- Check that the unit packaging and the seal are intact at the receipt of the delivery. Our products leave the factory in closed, sealed packaging. If the

transport packaging is open or the seal is broken, the confidentiality and authenticity of the information contained in the products cannot be ensured.

## 10.3 Product identification

Each Easergy P3 relay is delivered in a separate package containing:

- Easergy P3 protection relay with the necessary terminal connectors
- Production testing certificate
- Quick Start manual

Optional accessories are delivered in separate packages.

To identify an Easergy P3 protection relay, see the labels on the package and on the side of the relay.

### Serial number label

Figure 201 - Serial number label

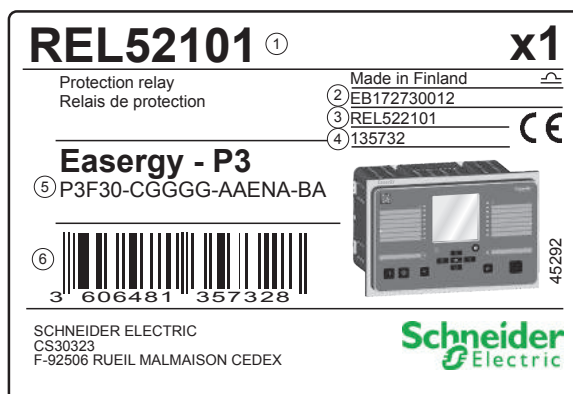


1. Rated voltage  $V_n$
2. Rated frequency  $f_n$
3. Rated phase current  $I_n$
4. Rated ground fault current  $I_{01n}$
5. Rated phase current ( $I'_n$  \*)
6. Rated ground fault current  $I_{02n}$
7. Rated ground fault current  $I_{03n}$  <sup>86\*</sup>
8. Power consumption
9. Power supply operating range  $V_{AUX}$
10. Order code
11. Serial number
12. Manufacturing date
13. MAC address for TCP/IP communication
14. Production identification

<sup>86</sup> \*)Available in P3M32, P3T32 and P3G32 models only

## Unit package label

Figure 202 - P3x3x Unit package label



1. Short order code
2. Serial number
3. Short order code
4. Internal product code
5. Order code
6. EAN13 bar code

## 10.4 Storage

Store the relay in its original packaging in a closed, sheltered location with the following ambient conditions:

- ambient temperature: -40 °C to +70 °C (or -40 °F to +158 °F)
- humidity < 90 %.

Check the ambient conditions and the packaging yearly.

## 10.5 Mounting

### DANGER

#### HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

- Wear your personal protective equipment (PPE) and comply with the safe electrical work practices. For clothing refer applicable local standards.
- Only qualified personnel should install this equipment. Such work should be performed only after reading this entire set of instructions and checking the technical characteristics of the relay.
- NEVER work alone.
- Turn off all power supplying this equipment before working on or inside it. Consider all sources of power, including the possibility of backfeeding.
- Always use a properly rated voltage sensing relay to ensure that all power is off.
- Do not open the secondary circuit of a live current transformer.
- Connect the relay's protective ground to functional ground according to the connection diagrams presented in this document.

**Failure to follow this instruction will result in death or serious injury.**

### CAUTION

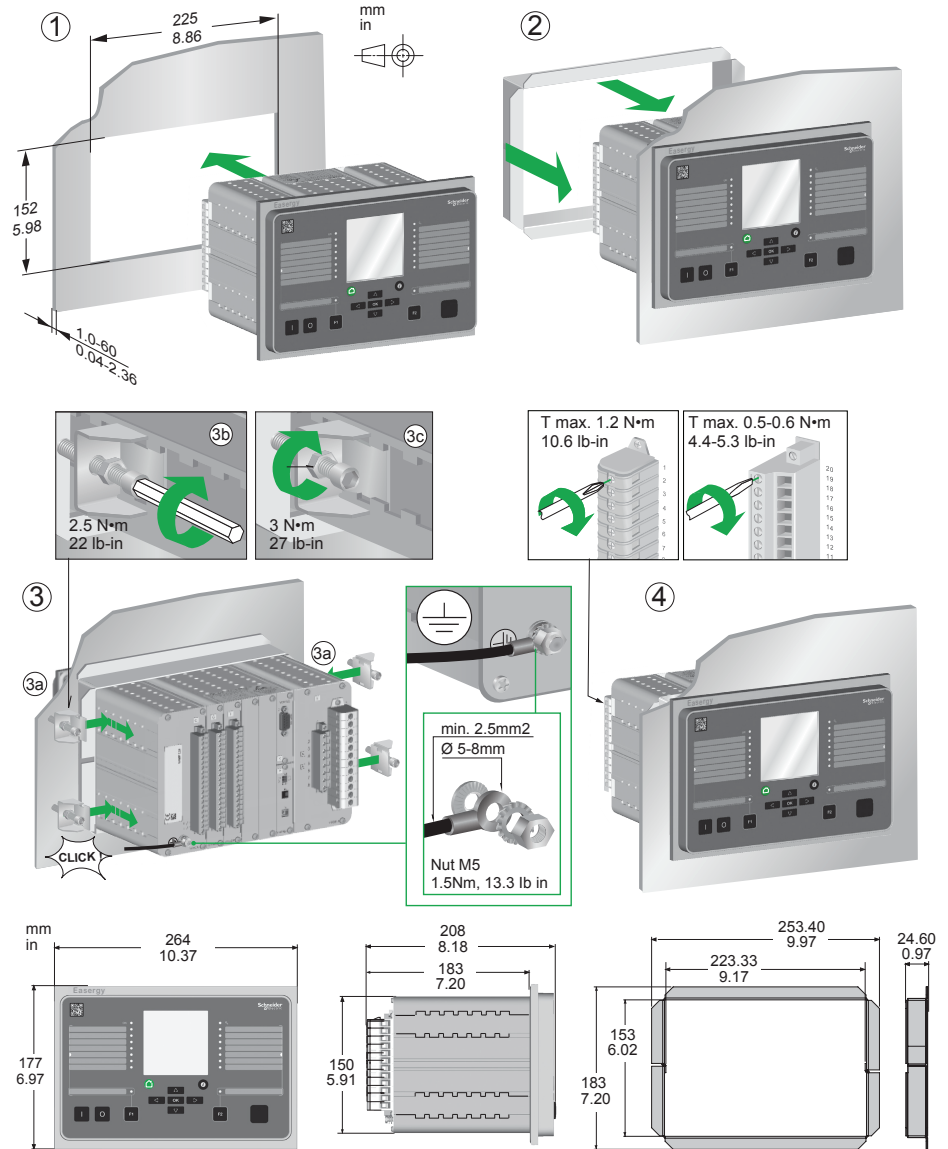
#### HAZARD OF CUTS

Trim the edges of the cut-out plates to remove any jagged edges.

**Failure to follow these instructions can result in injury.**

**Panel mounting**

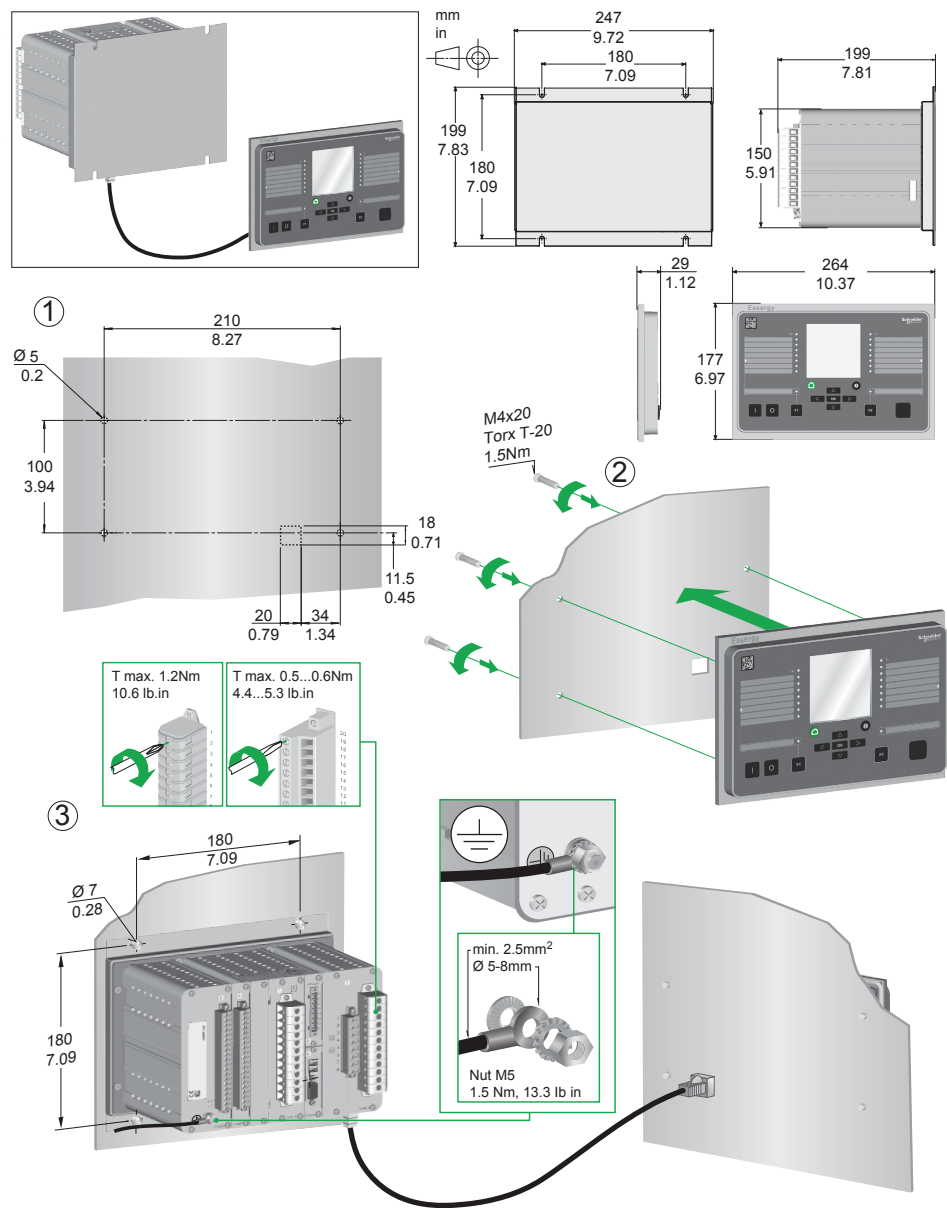
Figure 203 - Panel mounting



The conventional mounting technique has always been installing the relay on the secondary compartment's door. A limitation of this approach could be that the door construction is not strong enough for the relay's weight and wiring a large amount of secondary and communication cabling could be challenging.

**Panel mounting with detachable display**

Figure 204 - Panel mounting with detachable display

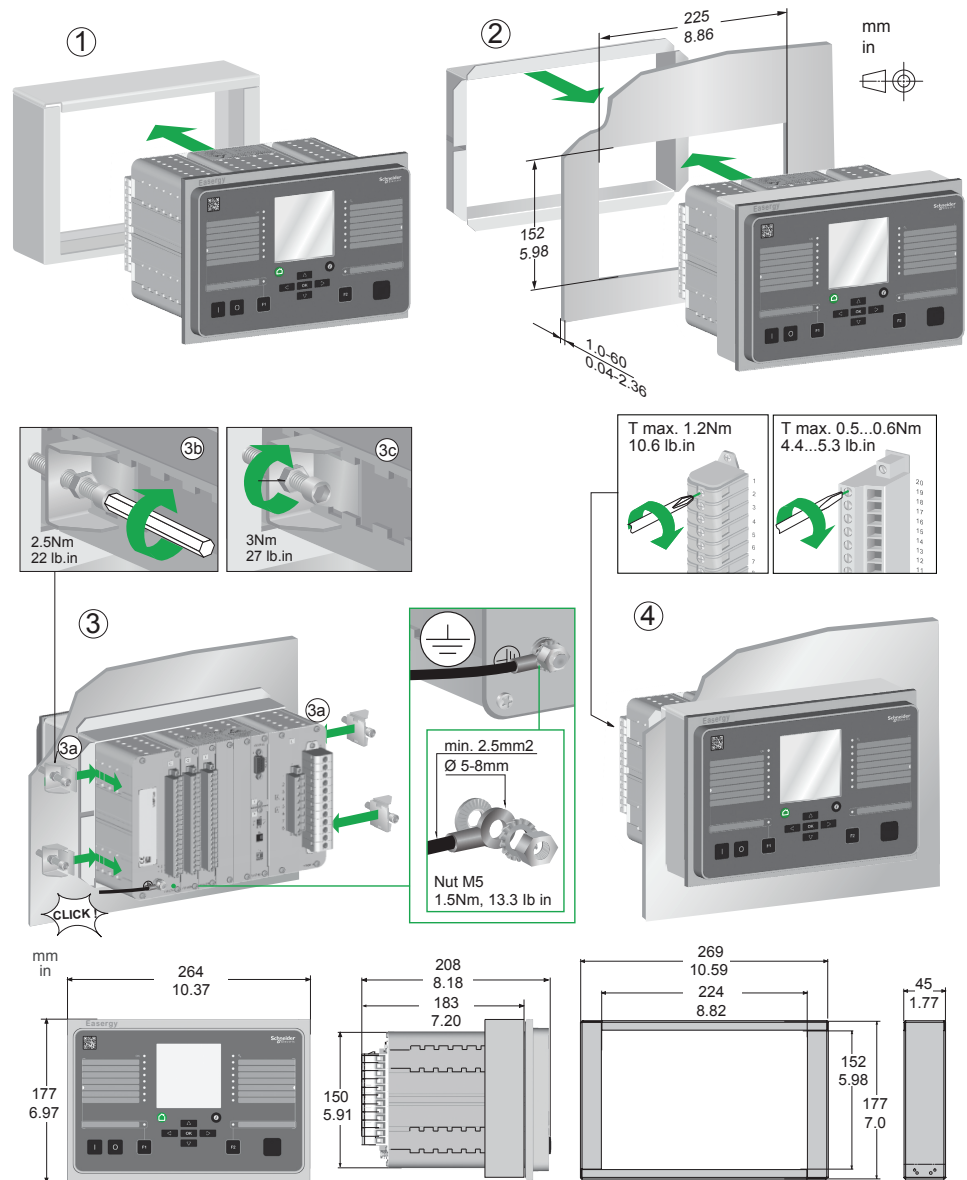


This mounting technique allows the door to be lighter as the relay's frame is installed on the back of the secondary compartment. Normally, the relay is mounted by the terminal blocks, hence the secondary wiring is short. Communication cabling is easier, too, as the door movement does not need to be considered. In this case, only the communication between relay base and display have to be wired.



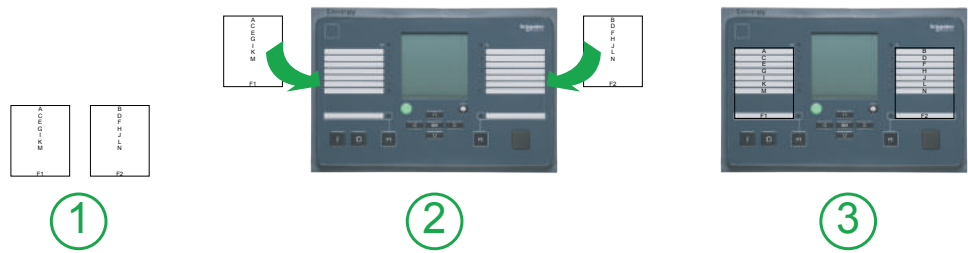
### Projection mounting

Figure 205 - Projection mounting



If the depth dimension behind the compartment door is limited, the relay can be equipped with a frame around the collar. This arrangement reduces the depth inside the compartment by 45 mm. For more details, see [11.5 Environmental conditions](#) on page 385.

**Example of the P3 alarm facial label insertion**



See "P3 Advanced Series facial label instruction" document for more information.

**Protective film**

<b>NOTICE</b>
<p><b>RISK OF DESTRUCTION OF THE RELAY</b></p> <p>The protective film on the relay's display is plastic and can melt if exposed to high temperatures intensive sunlight. Remove the protective film after mounting the relay.</p> <p><b>Failure to follow these instructions can result in equipment damage.</b></p>

**10.6 Connections**

The Easergy P3G30 and P3G32 has a fixed combination of analog interface, power supply, digital input and output, communication and arc flash detection cards as per the chosen order code. Do not remove cards from the relay's card slots in any circumstances.

<p><b>CARD SLOT ARRANGEMENT</b></p> <p><b>WARNING! DO NOT REMOVE CARDS!</b></p>	<p><b>ATTENTION</b></p> <p>OBSERVE PRECAUTIONS FOR HANDLING ELECTROSTATIC SENSITIVE DEVICES</p> <p><small>VY197B</small></p>
---	--

### 10.6.1 Supply voltage cards

#### Auxiliary voltage

**⚡⚡ DANGER**

**HAZARD OF ELECTRIC SHOCK**

Before connecting the devices, disconnect the supply voltage to the unit.

**Failure to follow these instructions will result in death or serious injury.**

The external auxiliary voltage  $V_{AUX}$  (110–240 V ac/dc, or optionally 24–48 V dc) of the relay is connected to the pins 1/C/1:1–2 or 1/D/1:1–2.

**NOTICE**

**LOSS OF PROTECTION OR RISK OF NUISANCE TRIPPING**

- If the relay is no longer supplied with power or is in permanent fault state, the protection functions are no longer active and all the Easergy P3 digital outputs are dropped out.
- Check that the operating mode and SF relay wiring are compatible with the installation.

**Failure to follow these instructions can result in equipment damage and unwanted shutdown of the electrical installation.**

Figure 206 - Example of supply voltage card Power C 110-240

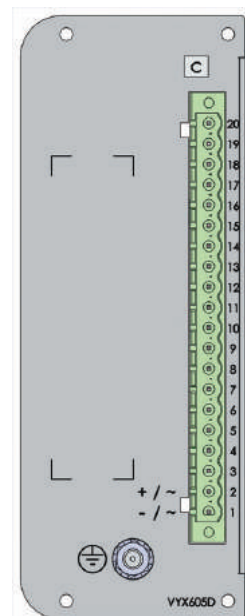




Table 122 - Supply voltage card Power C 110-240 & Power D 24-48

Pin No.	Symbol	Description
20	T12	Heavy duty trip relay 12 for arc protection
19	T12	Heavy duty trip relay 12 for arc protection

Pin No.	Symbol	Description
18	T11	Heavy duty trip relay 11 for arc protection
17	T11	Heavy duty trip relay 11 for arc protection
16	T10	Heavy duty trip relay 10 for arc protection
15	T10	Heavy duty trip relay 10 for arc protection
14	T9	Heavy duty trip relay 9 for arc protection
13	T9	Heavy duty trip relay 9 for arc protection
12	T1	Heavy duty trip relay 1 for arc protection
11	T1	Heavy duty trip relay 1 for arc protection
10	A1 NO	Signal relay 1, normal open connector
9	A1 NC	Signal relay 1, normal closed connector
8	A1 COMMON	Signal relay 1, common connector
7	SF NC	Service status output, normal closed
6	SF NO	Service status output, normal open
5	SF COMMON	Service status output, common
4		No connection
3		No connection
2	L / + / ~	Auxiliary voltage
1	N / - / ~	Auxiliary voltage



**  DANGER**

**HAZARD OF ELECTRICAL SHOCK**

Connect the device's protective ground to functional ground according to the connection diagrams presented in this document.

**Failure to follow these instructions will result in death or serious injury.**

### 10.6.2 Analog measurement cards

**  DANGER**

**HAZARD OF ELECTRICAL SHOCK**

Do not open the secondary circuit of a live current transformer.

Disconnecting the secondary circuit of a live current transformer may cause dangerous overvoltages.

**Failure to follow these instructions will result in death or serious injury.**

### 10.6.2.1 Analog measurement card 1 (slot 8)

This card contains connections for current transformers for measuring of the phase currents A–C and two ground fault overcurrents  $I_N$ , and four voltage transformers for measuring the  $V_N$ , VLL or VLN.

The relay is able to measure three phase currents, and two ground fault overcurrents. It also measures up to four voltage signals: line-to-line, line-to-neutral, neutral displacement voltage and voltage from another side (synchrocheck). See the voltage modes selection below:

- 3LN, 3LN+ $V_N$ , 3LN+LL $_Y$ , 3LN+LN $_Y$
- 2LL+ $V_N$ , 2LL+ $V_N$ +LL $_Y$ , 2LL+ $V_N$ +LN $_Y$
- LL+ $V_{N0}$ +LL $_Y$ +LL $_Z$ , LN+ $V_N$ +LN $_Y$ +LN $_Z$

Figure 207 - Analog measurement card “1 = 3L(5A) + 2Io (5/1A+1/0,2A) ring lug + 4U”

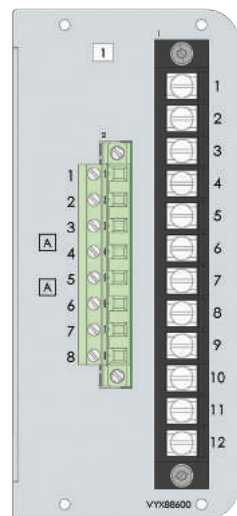


Table 123 - Terminal pins 8/1/1:1–12

Pin No.	Symbol	Description
1	$I_A$ (S1)	Phase current A 5 A (S1)
2	$I_A$ (S2)	Phase current A 5 A (S2)
3	$I_B$ (S1)	Phase current B 5 A (S1)
4	$I_B$ (S2)	Phase current B 5 A (S2)
5	$I_C$ (S1)	Phase current C 5 A (S1)
6	$I_C$ (S2)	Phase current C 5 A (S2)
7	$I_{N1}$ (S1)	Ground fault overcurrent $I_{N1}$ (S1) common for 5 A and 1 A
8	$I_{N1}$ (S2)	Ground fault overcurrent $I_{N1}$ 5 A (S2)
9	$I_{N1}$ (S2)	Ground fault overcurrent $I_{N1}$ 1 A (S2)
10	$I_{N2}$ (S1)	Ground fault overcurrent $I_{N2}$ (S1) common for 1 A and 0.2 A

Pin No.	Symbol	Description
11	$I_{N2}$ (S2)	Ground fault overcurrent $I_{N2}$ 1 A (S2)
12	$I_{N2}$ (S2)	Ground fault overcurrent $I_{N2}$ 0.2 A (S2)

Table 124 - Terminal pins 8/1/2:1–8

Pin No.	Symbol	Description
1	VLL/VLN	Voltage VLL (a) /VLN (a)
2	VLL/VLN	Voltage VLL (b) /VLN (n)
3	VLL/VLN	Voltage VLL (a) /VLN (a)
4	VLL/VLN	Voltage VLL (b) /VLN (n)
5	$V_N$ /VLL/VLN	Voltage $V_N$ (a) / VLL (a) /VLN (a)
6	$V_N$ /VLL/VLN	Voltage $V_N$ (b) /VLL (b) /VLN (n)
7	$V_N$ /VLN/VLL	Voltage $V_N$ (da) / VLL (a) / VLN (n)
8	$V_N$ /VLN/VLL	Voltage $V_N$ (dn) / VLL (b) / VLN (n)

### 10.6.2.2 Analog measurement card 2 (slot 8)

This card contains connections for current transformers for measuring the phase currents  $I_A$ – $I_C$  and two ground fault overcurrents  $I_N$  and four voltage transformers for measuring the  $V_N$ , VLL or VLN.

The relay is able to measure three phase currents, and two ground fault overcurrents. It also measures up to four voltage signals: line-to-line, line-to-neutral, zero-sequence voltage and voltage from another side (synchro-check).

See the voltage modes selection below:

- 3LN, 3LN+ $V_N$ , 3LN+LL $_Y$ , 3LN+LN $_Y$
- 2LL+ $V_N$ , 2LL+ $V_N$ +LL $_Y$ , 2LL+ $V_N$ +LN $_Y$
- LL+ $V_N$ +LL $_Y$ +LL $_Z$ , LN+ $V_N$ +LN $_Y$ +LN $_Z$

Figure 208 - Analog measurement card “2 = 3L(1A) + 2Io (5/1A+1/0.2A) ring lug + 4U”

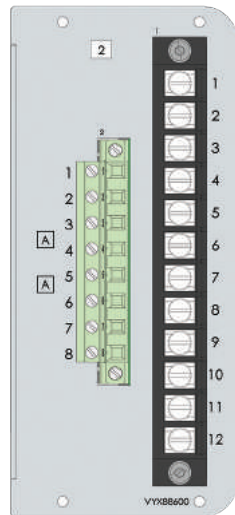


Table 125 - Terminal pins 8/2/1:1–12

Pin No.	Symbol	Description
1	$I_A$ (S1)	Phase current A1 1 A (S1)
2	$I_A$ (S2)	Phase current A1 1 A (S2)
3	$I_B$ (S1)	Phase current B1 1 A (S1)
4	$I_B$ (S2)	Phase current B1 1 A (S2)
5	$I_C$ (S1)	Phase current C1 1 A (S1)
6	$I_C$ (S2)	Phase current C1 1 A (S2)
7	$I_{N1}$ (S1)	Ground fault overcurrent $I_{N1}$ (S1) common for 5 A and 1 A
8	$I_{N1}$ (S2)	Ground fault overcurrent $I_{N1}$ 5 A (S2)
9	$I_{N1}$ (S2)	Ground fault overcurrent $I_{N1}$ 1 A (S2)
10	$I_{N2}$ (S1)	Ground fault overcurrent $I_{N2}$ (S1) common for 1 A and 0.2 A
11	$I_{N2}$ (S2)	Ground fault overcurrent $I_{N2}$ 1 A (S2)
12	$I_{N2}$ (S2)	Ground fault overcurrent $I_{N2}$ 0.2 A (S2)

Table 126 - Terminal pins 8/2/2:1–8

Pin No.	Symbol	Description
1	VLL/VLN	Voltage VLL (a) /VLN (a)
2	VLL/VLN	Voltage VLL (b) /VLN (n)
3	VLL/VLN	Voltage VLL (a) /VLN (a)
4	VLL/VLN	Voltage VLL (b) /VLN (n)
5	VLL/VLN	Voltage VLL (a) /VLN (a)

Pin No.	Symbol	Description
6	VLL/VLN	Voltage VLL (b) /VLN (n)
7	V <sub>N</sub> /VLL/VLN	V <sub>N</sub> (da) / VLL (a) / VLN (a)
8	V <sub>N</sub> /VLL/VLN	V <sub>N</sub> (dn) / VLL (b) / VLN (n)

### 10.6.2.3 Analog measurement card 1 (slot 4)

**NOTE:** L1, L2, and L3 are IEC phase names. For NEMA, the phases are as follows: L1=A, L2=B, and L3=C.

This card contains connections for current measurement transformers for measuring the phase currents L1, L2 and L3 and ground fault overcurrent I<sub>N</sub>.

Totally, the relay is able to measure six phase currents, three ground fault overcurrents and additionally four voltages.

Figure 209 - Analog measurement card "1 = 3xI (5/1A) ring lug + Io (5/1A)"

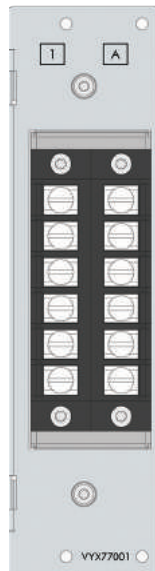


Table 127 - Pins 4/1/1:1–12

Pin No.	Symbol	Description
1	IA-2	Phase current I <sub>A-2</sub> (S1), common for 1 A and 5 A
2	IA-2 / 5A	Phase current I <sub>A-2</sub> (S2)
3	IA-2 / 1A	Phase current I <sub>A-2</sub> (S2)
4	IB-2	Phase current I <sub>B-2</sub> (S1), common for 1 A and 5 A
5	IB-2 / 5A	Phase current I <sub>B-2</sub> (S2)
6	IB-2 / 1A	Phase current I <sub>CB2</sub> (S2)
7	IC-2	Phase current I <sub>C-2</sub> (S1), common for 1 A and 5 A
8	IC-2 / 5A	Phase current I <sub>C-2</sub> (S2)
9	IC-2 / 1A	Phase current I <sub>C-2</sub> (S2)



Pin No.	Symbol	Description
10	IN3	Ground fault overcurrent $I_{N3}$ (S1), common for 1 A and 5 A
11	IN3 / 5A	Ground fault overcurrent $I_{N3}$ (S2)
12	IN3 / 1A	Ground fault overcurrent $I_{N3}$ (S2)

### 10.6.3 I/O cards

#### 10.6.3.1 I/O card “B = 3BIO+2Arc”

This card contains connections to two arc light sensors (for example, VA 1 DA), three binary inputs and three binary outputs.

The option card also has three normal open trip contacts that can be controlled either with the relay’s normal trip functions or using the fast arc matrix.

Figure 210 - I/O card “B = 3BIO+2Arc”

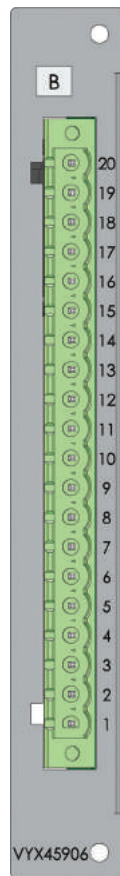


Table 128 - Slots 2/B/1:1–20

Pin no.	Symbol	Description
20	T4	Trip relay 4 for arc detection (normal open)
19	T4	Trip relay 4 for arc detection (normal open)
18	T3	Trip relay 3 for arc detection (normal open)

Pin no.	Symbol	Description
17	T3	Trip relay 3 for arc detection (normal open)
16	T2	Trip relay 2 for arc detection (normal open)
15	T2	Trip relay 2 for arc detection (normal open)
14	BI3	Binary input 3
13	BI3	Binary input 3
12	BI2	Binary input 2
11	BI2	Binary input 2
10	BI1	Binary input 1
9	BI1	Binary input 1
8	BO COMMON	Binary output 1–3 common GND
7	BO3	Binary output 3, +30 V dc
6	BO2	Binary output 2, +30 V dc
5	BO1	Binary output 1, +30 V dc
4	Sen 2 -	Arc sensor channel 2 negative terminal
3	Sen 2 +	Arc sensor channel 2 positive terminal
2	Sen 1 -	Arc sensor channel 1 negative terminal
1	Sen 1 -	Arc sensor channel 1 positive terminal

### 10.6.3.2 I/O card “C = F2BIO+1Arc”

This card contains connections to one arc fiber sensor, two fiber binary inputs, two fiber binary outputs and three fast trip relays.

Arc loop sensor input is used with Arc-SLm sensor. The sensor's sensitivity can be set in the **Arc protection** setting view in Easergy Pro.

Binary inputs and outputs are designed to be used with 50/125 µm, 62.5/125 µm, 100/140 µm, and 200 µm fiber sizes (Connector type: ST).

The option card also has three normal open trip contacts that can be controlled either with the relay's normal trip functions or using the fast arc matrix.

Figure 211 - I/O card "C = F2BIO+1Arc"



Table 129 - Fiber 2 x BI/BO, 1 x Arc loop sensor, T2, T3, T4 I/O card pins (slot 2)

Connector / Pin no.	Symbol	Description
1:6	T4	Trip relay 4 for arc detection (normal open)
1:5	T4	Trip relay 4 for arc detection (normal open)
1:4	T3	Trip relay 3 for arc detection (normal open)
1:3	T3	Trip relay 3 for arc detection (normal open)
1:2	T2	Trip relay 2 for arc detection (normal open)
1:1	T2	Trip relay 2 for arc detection (normal open)
2	BI2	Fiber binary input 2
3	BI1	Fiber binary input 1
4	BO2	Fiber binary output 2
5	BO1	Fiber binary output 1
6	Arc sensor 1	Arc sensor 1 Rx
7	Arc sensor 1	Arc sensor 1 Tx

### 10.6.3.3 I/O card “D = 2IGBT”

This card contains two semiconductor outputs.

Figure 212 - I/O card “D = 2IGBT”

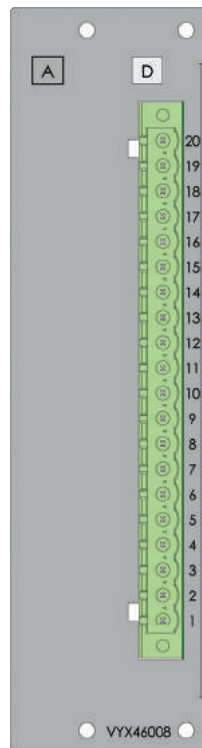


Table 130 - Slots 4/D/1:1–20

Pin no.	Symbol	Description	
19–20	NC	No connection	
18 <sup>87</sup>	HSO2	HSO output 2 terminal 2	
17 <sup>87</sup>			
16 <sup>87</sup>		HSO output 2 terminal 1	
15 <sup>87</sup>			
8–14	NC	No connection	
7	HSO1	HSO output 1 terminal 2	
6			
5		HSO output 1 terminal 1	
4			
1–3	NC	No connection	

<sup>87</sup> Terminals 18-17 and 16-15 are interconnected, so it is sufficient to connect the wiring to terminals 15 and 17 or 16 and 18 only.

### 10.6.3.4 I/O option card “D=4Arc”

This card contains four arc point connections to four arc light sensors (for example. VA 1 DA). The card provides sensors 3 to 6.

Figure 213 - I/O option card “D= 4Arc”

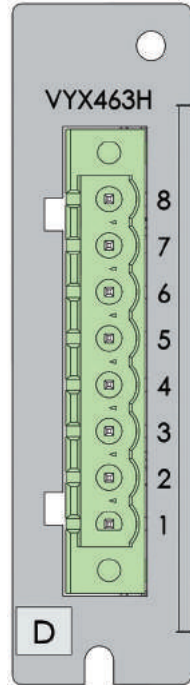


Table 131 - Pins 6/D/1:1–8 (slot 6)

Pin no.	Symbol	Description
8	Sen 6 -	Arc sensor 6 negative terminal
7	Sen 6 +	Arc sensor 6 positive terminal
6	Sen 5 -	Arc sensor 5 negative terminal
5	Sen 5 +	Arc sensor 5 positive terminal
4	Sen 4 -	Arc sensor 4 negative terminal
3	Sen 4 +	Arc sensor 4 positive terminal
2	Sen 3 -	Arc sensor 3 negative terminal
1	Sen 3 +	Arc sensor 3 positive terminal

### 10.6.3.5 I/O card “G = 6DI+4DO”

This card provides six digital inputs and four relay outputs. The threshold level is selectable in the order code.

The card is equipped with six dry digital inputs with hardware-selectable activation/threshold voltage and four trip contacts. Input and output contacts are normally open.

Figure 214 - I/O card "G = 6DI+4DO"



Table 132 - Channel numbering for "C" or "D" power module and four "G" cards in slots 2–5/G-G-G-G

Pin no.	Trip "T" output numbering				
	Power supply	Slot 2	Slot 3	Slot 4	Slot 5
<b>Card type</b>	<b>C or D</b>	<b>G</b>	<b>G</b>	<b>G</b>	<b>G</b>
19, 20	12	16	20	24	28
17, 18	11	15	19	23	27
15, 16	10	14	18	22	26
13, 14	9	13	17	21	25
11, 12	1				
	<b>DI channel numbering</b>				
11, 12		6	12	18	24
9, 10		5	11	17	23
7, 8		4	10	16	22
5, 6		3	9	15	21
3, 4		2	8	14	20
1, 2		1	7	13	19

**NOTE:** Digital inputs are polarity-free, which means that you can freely choose "-" and "+" terminals for each digital input.

Table 133 - Channel numbering for "C" or "D" power module, "B" or "C" arc sensor interface card and three "G" cards in slots 3–5/G-G-G

Pin no.	Trip "T" output numbering					
	Power supply	Slot 2		Slot 3	Slot 4	Slot 5
Card type	C or D	B	C	G	G	G
19, 20	12	4				
17, 18	11	3				
15, 16	10	2				
13, 14	9					
11, 12	1					
5, 6			4			
3, 4			3			
1, 2			2			
19, 20				16	20	24
17, 18				15	19	23
15, 16				14	18	22
13, 14				13	17	21
	DI channel numbering					
11, 12				6	12	18
9, 10				5	11	17
7, 8				4	10	16
5, 6				3	9	15
3, 4				2	8	14
1, 2				1	7	13

**NOTE:** Digital inputs are polarity-free, which means that you can freely choose "-" and "+" terminals for each digital input.

### 10.6.3.6 I/O card "H = 6DI + 4DO (NC)"

This card provides six digital inputs and four relays outputs that are normally closed (NC). The threshold level is selectable in the order code.

The 6xDI+4xDO option card is equipped with six dry digital inputs with hardware-selectable activation/threshold voltage and four normally closed (NC) trip contacts.



### 10.6.3.7 I/O card “I = 10DI”

This card provides 10 digital inputs. The threshold level is selectable in the order code.



Figure 215 - I/O card "I = 10DI"

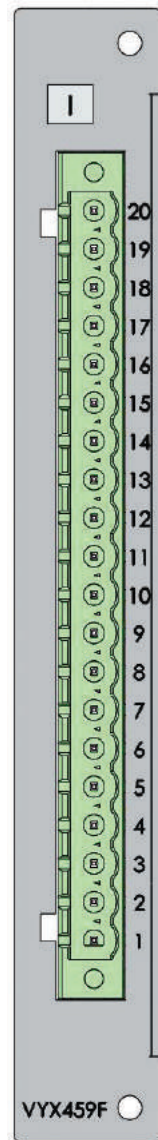


Table 134 - Channel numbering for slots 2–5/G-I-I-I/1:1–20 when one "G" and three "I" cards are used

Pin no.	DI numbering			
	Slot 2	Slot 3	Slot 4	Slot 5
<b>Card type</b>	<b>G</b>	<b>I</b>	<b>I</b>	<b>I</b>
19, 20		16	26	36
17, 18		15	25	35
15, 16		14	24	34
13, 14		13	23	33
11, 12	6	12	22	32
9, 10	5	11	21	31
7, 8	4	10	20	30
5, 6	3	9	19	29

Pin no.	DI numbering			
3, 4	2	8	18	28
1, 2	1	7	17	27

**NOTE:** Digital inputs are polarity-free, which means that you can freely choose "-" and "+" terminals for each digital input.

### 10.6.4 Arc flash sensor

**⚠ DANGER**

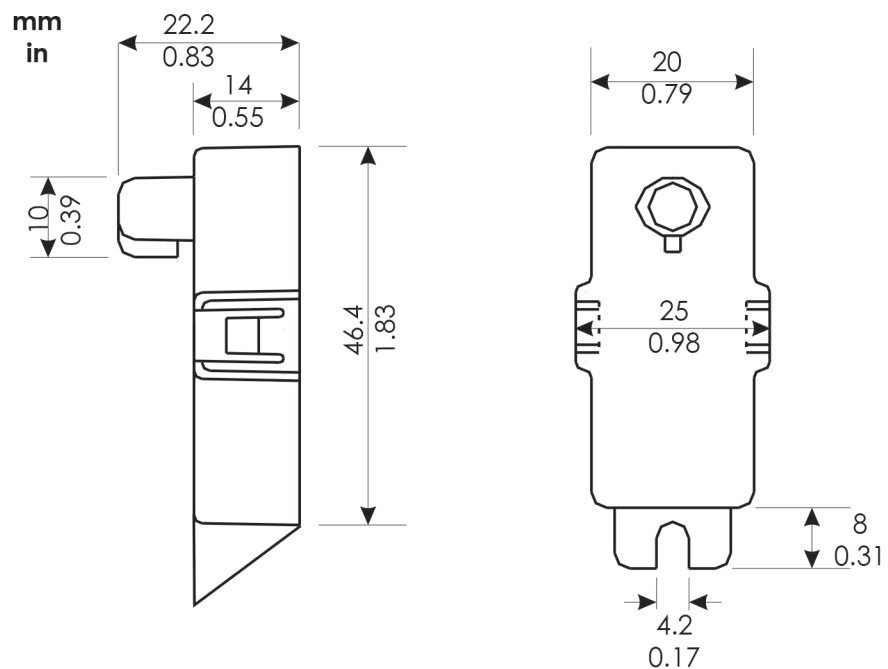
**HAZARD OF NON-DETECTED LIGHT**

Clean the arc sensor periodically as instructed in this user manual and after an arc flash fault.

**Failure to follow these instructions will result in death or serious injury.**

VA 1 DA is a point-type arc flash sensor. The sensor activated by strong light. It transforms the light information into the current signal that is used by the device to detect arc flash light.

Figure 216 - Sensor dimensions



The sensor features include:

- standard 8000–10000 lux visible light sensitivity
- wide area arc flash detection
- maximum 2 ms detection time
- standard cable length 6 m (236.22 in) or 20 m (787.40 in) (cut to length on site)
- easy to install (two-wired non-polarity sensitive connection)

**⚠ DANGER****HAZARD OF NON-DETECTED LIGHT**

Never attempt to extend the length of arc flash sensor cables.

**Failure to follow these instructions will result in death or serious injury.**

**10.6.4.1 Mounting the sensors to the switchgear****⚠⚠ DANGER****HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

- Apply appropriate personal protective equipment (PPE) and follow safe electrical work practices. See NFPA 70E, NOM-029-STPS-2011, or CSA Z462.
- The arc fault detection system is not a substitute for proper PPE when working on or near equipment being monitored by the system.
- Information on this product is offered as a tool for conducting arc flash hazard analysis. It is intended for use only by qualified persons who are knowledgeable about power system studies, power distribution equipment, and equipment installation practices. It is not intended as a substitute for the engineering judgement and adequate review necessary for such activities.
- Only qualified personnel should install and service this equipment. Read this entire set of instructions and check the technical characteristics of the device before performing such work.
- Perform wiring according to national standards (NEC) and any requirements specified by the customer.
- Observe any separately marked notes and warnings.
- NEVER work alone.
- Before performing visual inspections, tests, or maintenance on this equipment, disconnect all sources of electric power. Assume all circuits are live until they are completely de-energized, tested, and tagged. Pay particular attention to the design of the power system. Consider all sources of power, including the possibility of backfeeding.
- Always use a properly rated voltage sensing relay to ensure that all power is off.
- The equipment must be grounded.
- Connect the device's protective ground to functional earth according to the connection diagrams presented in this document.
- Do not open the device. It contains no user-serviceable parts.
- Install all devices, doors and covers before turning on the power to this device.

**Failure to follow these instructions will result in death or serious injury.**

Install arc flash sensors inside the switchgear. There are two options for mounting the sensors:

- in customer-drilled holes on the switchgear
- on VYX001 Z-shape or VYX002 L-shape mounting plates available from Schneider Electric or locally fabricated from supplied drawings

Figure 217 - VYX 001 mounting plate for sensor

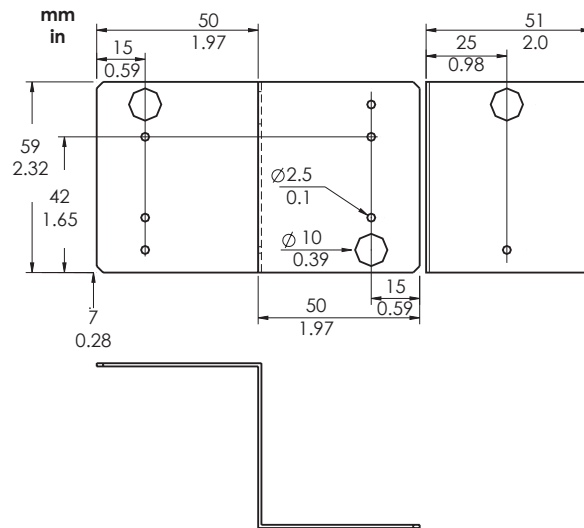


Figure 218 - VYX 002 mounting plate for sensor

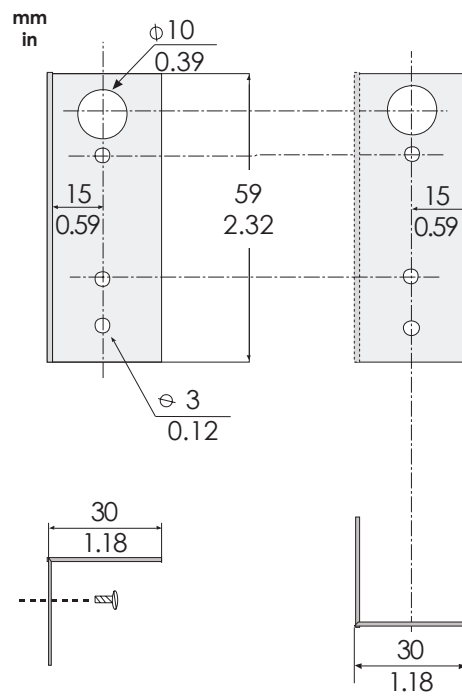
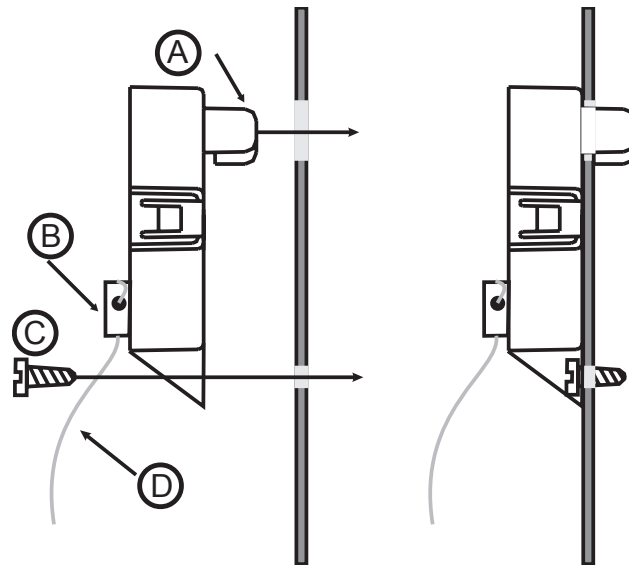


Figure 219 - Mounting the sensor



- A. Active part of the sensor
- B. Cable clamp
- C. Fastening screw 4 x 15 mm
- D. Sensor cable

1. Press the active part of the sensor through the 10 mm hole in the panel surface.
2. Fix it using a 4 mm screw.

#### 10.6.4.2 Connecting the sensors to the device

The sensors are delivered with 6 or 20 m cables.

### ⚠ DANGER

#### HAZARD OF NON-DETECTED LIGHT

Never attempt to extend the length of arc flash sensor cables.

**Failure to follow these instructions will result in death or serious injury.**

After mounting the sensors, connect them to the device.

1. Route the wire to the nearest device using the shortest route possible.  
Cut the wire to a suitable length.  
Take into account the wiring methods inside the equipment. This should be compliant with local regulations.
2. Connect the arc sensors to the screw terminals.  
The polarity of the arc sensor cables is not critical.

Figure 220 - Point sensor connections

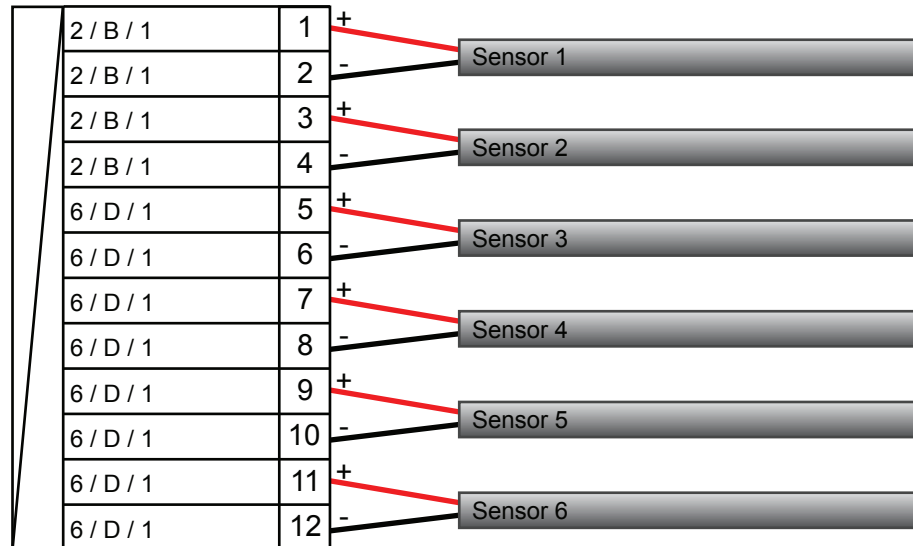


Table 135 - Point sensor connections

Card	Pin no.	Symbol	Description
<b>B</b>	4	Sen 2 -	Arc sensor channel 2 negative terminal
	3	Sen 2 +	Arc sensor channel 2 positive terminal
	2	Sen 1 -	Arc sensor channel 1 negative terminal
	1	Sen 1 +	Arc sensor channel 1 positive terminal
<b>D</b>	8	Sen 6 -	Arc sensor 6 negative terminal
	7	Sen 6 +	Arc sensor 6 positive terminal
	6	Sen 5 -	Arc sensor 5 negative terminal
	5	Sen 5 +	Arc sensor 5 positive terminal
	4	Sen 4 -	Arc sensor 4 negative terminal
	3	Sen 4 +	Arc sensor 4 positive terminal
	2	Sen 3 -	Arc sensor 3 negative terminal
	1	Sen 3 +	Arc sensor 3 positive terminal

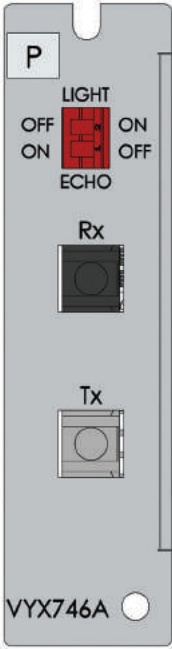

Table 136 - Fiber sensor connections





Card	Pin no.	Sensor	Description
<b>C</b>	6	Arc sensor 1	Arc sensor 1 Rx
	7	Arc sensor 1	Arc sensor 1 Tx

3. Connect the cable shield to the corresponding connector on X2 terminal when using shielded cable on the sensors.


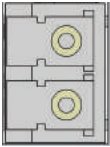
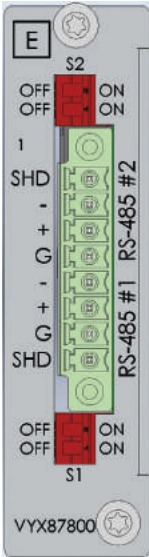
### 10.6.5 Communication cards

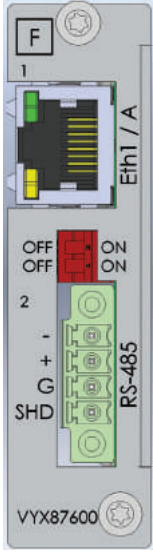
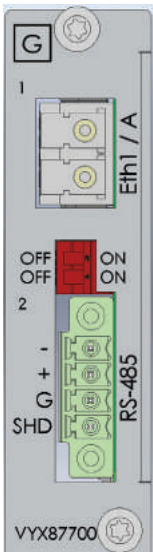
Table 137 - Communication card types and their pin numbering

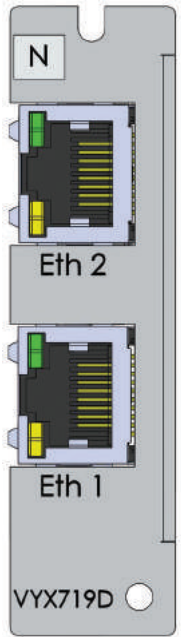
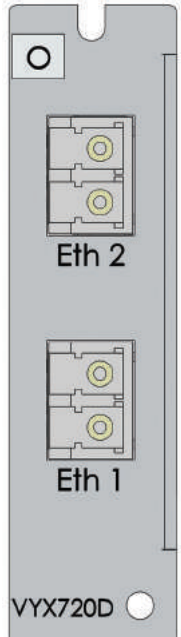
Type	Communication ports	Signal levels	Connectors	Pin usage
P = Fibre PP (slot 9)	Plastic fibre interface COM 3 port (if slot 9 card)		Versatile Link fiber 	
R = Fibre GG (slot 9)	Glass fibre interface (62.5/125 µm) COM 3 port (if slot 9 card)		ST 	

Type	Communication ports	Signal levels	Connectors	Pin usage
K = RS-232 (slot 6)	COM 1 / COM 2	RS-232	D-connector 	1 = TX COM 2 2 = TX COM 1 3 = RX COM 1 4 = IRIG-B 5 = IRIG-B GND 7 = GND 8 = RX COM 2 9 = +12V
B = RS-232 (slot 9)	COM 3 / COM 4	RS-232	D-connector 	1 = TX COM 4 2 = TX COM 3 3 = RX COM 3 4 = IRIG-B 5 = IRIG-B GND 6 = 7 = GND 8 = RX COM 4 9 = +12V
C = RS-232+Eth RJ (slot 9)	COM 3 / COM 4	RS-232	D-connector 	1 = TX COM 4 2 = TX COM 3 3 = RX COM 3 4 = IRIG-B 5 = IRIG-B GND 6 = 7 = GND 8 = RX COM 4 9 = +12V
	ETHERNET	ETHERNET 100 Mbps	RJ-45 	1 = Transmit + 2 = Transmit - 3 = Receive + 4 = 5 = 6 = Receive - 7 = 8 =



Type	Communication ports	Signal levels	Connectors	Pin usage
D = RS-232+Eth LC (slot 9)	COM 3 / COM 4	RS-232	D-connector 	1 = TX COM 4 2 = TX COM 3 3 = RX COM 3 4 = IRIG-B 5 = IRIG-B GND 6 = 7 = GND 8 = RX COM 4 9 = +12V
	ETHERNET	Light 100 Mbps	LC fiber connector 	1 = Receive 2 = Transmit
E = 2 x RS-485 (slot 9)	COM 3 (RS-485 interface 1) COM 4 (RS-485 interface 2)	RS-485		<p><b>S2 DIP switch for termination resistors of the RS-485 interface 2</b></p> 8 = RS-485 interface 2 cable shield connection 7 = RS-485 interface 2 “-” connection 6 = RS-485 interface 2 “+” connection 5 = RS-485 interface 2 ground terminal 4 = RS-485 interface 1 “-” connection 3 = RS-485 interface 1 “+” connection 2 = RS-485 interface 1 ground terminal 1 = RS-485 interface 1 cable shield connection <p><b>S1 DIP switch for termination resistors of the RS-485 interface 1</b></p> <p>* RS-485 interfaces 1 and 2 galvanically isolated from each other</p>

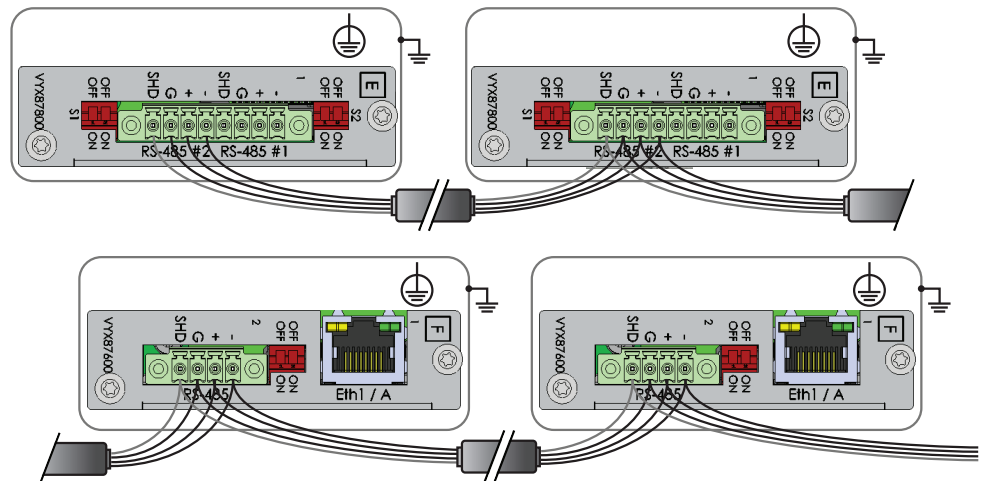
Type	Communication ports	Signal levels	Connectors	Pin usage
<p>F = RS-485+RJ (slot 9)</p>	<p>ETHERNET COM 3 (RS-485 interface 1)</p>	<p>ETHERNET 100 Mbps RS-485</p>		<p><b>RJ45 connector from top:</b></p> <p>1 = Transmit+</p> <p>2 =Transmit-</p> <p>3 =Receive+</p> <p>4 =</p> <p>5 =</p> <p>6 = Receive-</p> <p>7 =</p> <p>8=</p> <p><b>DIP switch for termination resistors of the RS-485 interface 1</b></p> <p>4 = RS-485 interface 1 “-“ connection</p> <p>3 = RS-485 interface 1 “+“ connection</p> <p>2 = RS-485 interface 1 ground terminal</p> <p>1 = RS-485 interface 1 cable shield connection</p>
<p>G = RS-485+LC (slot 9)</p>	<p>ETHERNET COM 3 (RS-485 interface 1)</p>	<p>Light 100 Mbps RS-485</p>		<p><b>LC connector from top:</b></p> <p>1 = Receive</p> <p>2 = Transmit</p> <p><b>DIP switch for termination resistors of the RS-485 interface 1</b></p> <p>4 = RS-485 interface 1 “-“ connection</p> <p>3 = RS-485 interface 1 “+“ connection</p> <p>2 = RS-485 interface 1 ground terminal</p> <p>1= RS-485 interface 1 cable shield connection</p>

Type	Communication ports	Signal levels	Connectors	Pin usage
N = 2EthRJ (slot 9)	100 Mbps Ethernet interface with IEC 61850	ETHERNET 100 Mbps	2 x RJ-45 	1=Transmit+ 2=Transmit- 3=Receive+ 4= 5= 6=Receive- 7= 8=
O = 2EthLC (slot 9)	100 Mbps Ethernet fibre interface with IEC 61850	Light 100 Mbps	2 x LC 	LC-connector from top: -Port 2 Rx -Port 2 Tx -Port 1 Rx -Port 1 Tx

**NOTE:** When a communication option module of type B, C, D, E, F or G are used in slot 9, serial ports COM 3 / COM 4 are available.

### RS-485 connections

Figure 221 - All shields connected through and grounded at one end



### DIP switches

Figure 222 - DIP switches in optic fibre options

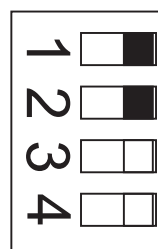


Table 138 - DIP switches in optic fibre options

DIP switch number	Switch position	Function Fibre optics
1	Left	Echo off
1	Right	Echo on
2	Left	Light on in idle state
2	Right	Light off in idle state
3	Left	Not applicable
3	Right	Not applicable
4	Left	Not applicable
4	Right	Not applicable

### 10.6.5.1 COM 3 – COM 4 ports

COM 3 and COM 4 are ports for serial communication protocols. The type of the physical interface on these ports depends on the type of the selected communication option module. The use of some protocols may require a certain type of option module. The parameters for these ports are set via the front panel or with Easergy Pro in the **COM 3 PORT – COM 4 PORT** setting views.

Communication information is normally sent to the control system (SCADA), but it is also possible to use certain communication-related notifications internally, for example alarms. This is can be done for example via the logic and different matrices.

Figure 223 - Communication-related notifications can be connected to trip contacts in the Output matrix setting view

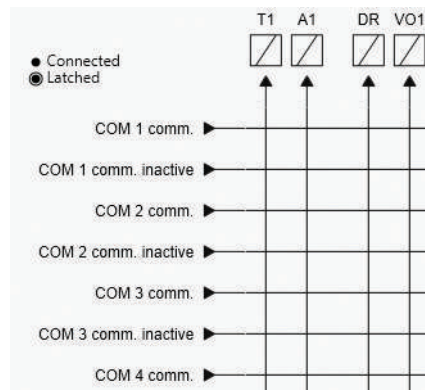




Table 139 - COM 3 port

Type	External module	Order code	Cable / order code	Typically used protocols
232+00 or 232+Eth RJ or 232+Eth LC	None	None	None	- None - IEC-101 - IRIG-B - GetSet
(Slot 9)	VSE-009	VSE009	None	- None - DeviceNet
	VIO12-AB and VSE-002	VIO 12 AB - VSE002	None	- None - ExternalIO
	VIO12-AC and VSE-002	VIO 12 AC - VSE002	None	- None - ExternalIO

Type	External module	Order code	Cable / order code	Typically used protocols
	VIO12-AD and VSE-002	VIO 12 AD - VSE002	None	- None - ExternalIO
	VSE-001	VSE001	None	- None - IEC-103 - ModbusSlv - SpaBus
	VSE-002	VSE002	None	- None - IEC-103 - ModbusSlv - SpaBus - DNP3
	VPA-3CG	VPA3CG	VX072	- None - ProfibusDP

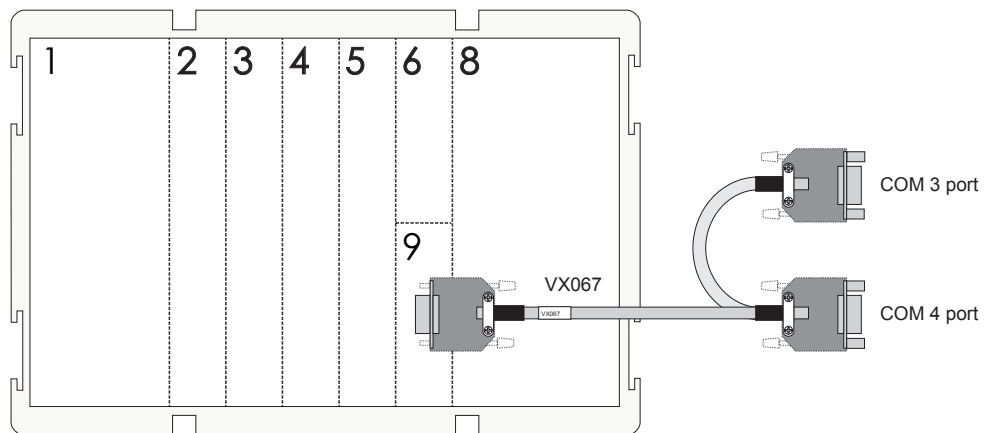
Table 140 - COM 4 port

Type	External module	Order code	Cable / order code	Typically used protocols
232+00 or 232+Eth RJ or 232+Eth LC +VX067 (Split cable) (Slot 9)	None	None	None	- None - IEC-101 - IRIG-B - GetSet
	VSE-009	VSE-009	None	- None - DeviceNet
	VIO12-AB and VSE-002	VIO 12 AB - VSE002	None	- None - ExternalIO
	VIO12-AC and VSE-002	VIO 12 AC - VSE002	None	- None - ExternalIO
	VIO12-AD and VSE-002	VIO 12 AD - VSE002	None	- None - ExternalIO

Type	External module	Order code	Cable / order code	Typically used protocols
	VSE-001	VSE001	None	- None - IEC-103 - ModbusSlv - SpaBus
	VSE-002	VSE002	None	- None - IEC-103 - ModbusSlv - SpaBus - DNP3
	VPA-3CG	VPA3CG	VX068	- None - ProfibusDP

To be able to use COM 3 and COM 4 ports, the RS-232 communication interface (option B, C or D) has to be split in two by using a VX067 cable.

Figure 224 - VX067 cable on the D-connector of slot 9 option card



**NOTE:** It is possible to use two serial communication protocols simultaneously, but the restriction is that the same protocol can be used only once.

Use a VX086 cable to interface simultaneously with two protocols and IRIG-B.

The **Communication > Protocol configuration** setting view contains the selection for the protocol, port settings and message/error/timeout counters. Only serial communication protocols are valid with the RS-232 interface.

Figure 225 - Protocol configuration setting view

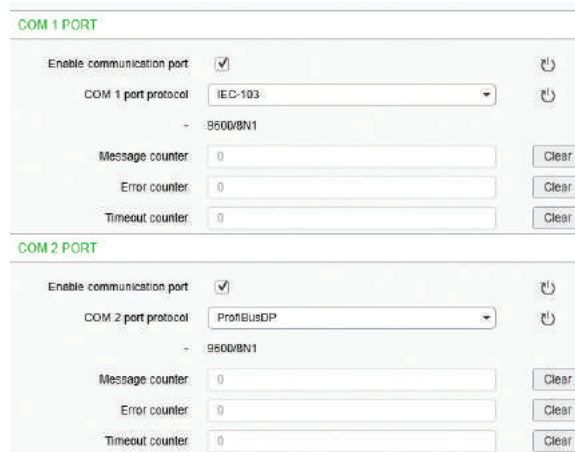


Table 141 - Parameters

Parameter	Value	Unit	Description	Note
Protocol			Protocol selection for COM port	Set
	None		-	
	SPA-bus		SPA-bus (slave)	
	ProfibusDP		Interface to Profibus DB module VPA 3CG (slave)	
	ModbusSlv		Modbus RTU slave	
	IEC-103		IEC-60870-5-103 (slave)	
	ExternalIO		Modbus RTU master for external I/O-modules	
	IEC 101		IEC-608670-5-101	
	DNP3		DNP 3.0	
	DeviceNet		Interface to DeviceNet module VSE 009	
GetSet		Communicationi protocols for interface		
Msg#	0–2 <sup>32</sup> - 1		Message counter since the relay has restarted or since last clearing	Clr
Errors	0–2 <sup>16</sup> - 1		Protocol interruption since the relay has restarted or since last clearing	Clr



Parameter	Value	Unit	Description	Note
Tout	$0-2^{16} - 1$		Timeout interruption since the relay has restarted or since last clearing	Clr
	speed/DPS		Display of current communication parameters. speed = bit/s D = number of data bits P = parity: none, even, odd S = number of stop bits	1.

Set = An editable parameter (password needed). Clr = Clearing to zero is possible.

1. The communication parameters are set in the protocol-specific menus. For the local port command line interface, the parameters are set in the configuration menu.

## 10.6.6 Local port

The relay has a USB port in the front panel.

### Protocol for the USB port

The front panel USB type B port is always using the command line protocol for Easergy Pro.

The speed of the interface is defined in the CONF/DEVICE SETUP menu via the front panel. The default settings for the relay are 38400/8N1.

It is possible to change the front USB port's bit rate. This setting is visible only on the relay's local display. The bit rate can be set between 1200 and 187500. This changes the bit rate of the relay, and the Easergy Pro bit rate has to be set separately. If the bit rate in the setting tool is incorrect, it takes a longer time to establish the communication.

**NOTE:** Use the same bit rate in the relay and the Easergy Pro setting tool.

## 10.6.7 Connection data

Table 142 - Auxiliary power supply

$V_{AUX}$	110 (-20%) – 240 (+10%) V ac/dc 110/120/220/240 V ac 110/125/220 V dc or 24–48 $\pm$ 20% V dc 24/48 V dc
Power consumption - Normal state - Maximum state (all outputs activated)	— < 20 W < 28 W
Terminal block: - MSTB2.5–5.08	Wire cross section: Maximum 2.5 mm <sup>2</sup> (13–14 AWG) Minimum 1.5 mm <sup>2</sup> (15–16 AWG) Wire type: single strand or stranded with insulated crimp terminal

Table 143 - Digital inputs technical data

Number of inputs	As per the order code
Voltage withstand	255 V ac/dc
(as per the order code letters) Nominal operation voltage for DI inputs	A: 24–230 V ac/dc (max. 255 V ac/dc) B: 110–230 V ac/dc (max. 255 V ac/dc) C: 220–230 V ac/dc (max. 255 V ac/dc)
Typical switching threshold (as per order code letters)	A: 12 V dc B: 75 V dc C: 155 V dc  <b>NOTE:</b> For trip circuit supervision with two digital inputs, select a lower switching threshold (24 V or 110 V).
Current drain	< 4 mA (typical approx. 3mA)
Cycle time	10 ms
Activation time dc/ac	< 11 ms / < 15 ms

Reset time dc/ac	< 11 ms / < 15 ms
Terminal block: - MSTB2.5–5.08	Wire cross section: Maximum 2.5 mm <sup>2</sup> (13–14 AWG) Minimum 1.5 mm <sup>2</sup> (15–16 AWG) Wire type: single strand or stranded with insulated crimp terminal

**NOTE:** Set the dc/ac mode according to the used voltage in Easergy Pro.

Table 144 - Trip contact, high break

Number of contacts	5 normal open contacts
Rated voltage	250 V ac/dc
Continuous carry	5 A
Minimum making current	100 mA @ 24 Vdc
Make and carry, 0.5 s at duty cycle 10%	30 A
Make and carry, 3 s at duty cycle 10%	15 A
Breaking capacity, AC	2 000 VA
Breaking capacity, DC (L/R=40ms)	-
at 48 V dc:	5 A
at 110 V dc:	3 A
at 220 V dc	1 A
Contact material	AgNi 90/10
Terminal block: - MSTB2.5–5.08	Wire cross section: Maximum 2.5 mm <sup>2</sup> (13–14 AWG) Minimum 1.5 mm <sup>2</sup> (15–16 AWG) Wire type: single strand or stranded with insulated crimp terminal

**NOTE:** High-break trip contacts exist in power module C and D only.

Table 145 - Trip contact, Tx

Number of contacts	As per the order code
Rated voltage	250 V ac/dc
Continuous carry	5 A
Minimum making current	100 mA at 24 Vdc

Make and carry, 0.5 s	30 A
Make and carry, 3 s	15 A
Breaking capacity, ac	2 000 VA
Breaking capacity, dc (L/R = 40ms)	
at 48 V dc:	1.15 A
at 110 V dc:	0.5 A
at 220 V dc:	0.25 A
Contact material	AgNi 90/10
Terminal block: - MSTB2.5 - 5.08	Wire cross section: Maximum $\Phi 0.06$ in. (2.5 mm <sup>2</sup> ) (14 AWG) Minimum $\Phi 0.05$ in. (1.5 mm <sup>2</sup> ) (16 AWG) Wire type: single strand or stranded with insulated crimp terminal

Table 146 - Signal contact, A1

Number of contacts:	1
Rated voltage	250 V ac/dc
Continuous carry	5 A
Minimum making current	100 mA at 24 V ac/dc
Make and carry, 0.5 s	30 A
Make and carry, 3 s	15 A
Breaking capacity, ac	2 000 VA
Breaking capacity, dc (L/R = 40ms)	
at 48 V dc:	1 A
at 110 V dc:	0.3 A
at 220 V dc:	0.15 A

Contact material	AgNi 0.15
Terminal block - MSTB2.5 - 5.08	Wire cross section  Maximum $\Phi 0.06$ in. ( $2.5 \text{ mm}^2$ ) (14 AWG)  Minimum $\Phi 0.05$ in. ( $1.5 \text{ mm}^2$ ) (16 AWG)  Wire type: single strand or stranded with insulated crimp terminal

Table 147 - Signal contact, SF

Number of contacts:	1
Rated voltage	250 V ac/dc
Continuous carry	5 A
Minimum making current	100 mA @ 24 V ac/dc
Breaking capacity, DC (L/R = 40ms)	
at 48 V dc:	1 A
at 110 V dc:	0.3 A
at 220 V dc	0.15 A
Terminal block - MSTB2.5 - 5.08	Wire cross section  Maximum $\Phi 0.06$ in. ( $2.5 \text{ mm}^2$ ) (14 AWG)  Minimum $\Phi 0.05$ in. ( $1.5 \text{ mm}^2$ ) (16 AWG)  Wire type: single strand or stranded with insulated crimp terminal
Contact material	AgNi 0.15

Table 148 - Solid state outputs, HSO

Number of contacts	As per order code
Rated voltage	250 V ac/dc
Continuous carry	5 A
Maximum making current	-
Make and carry, 0.5 s	30 A
Make and carry, 3 s	15 A
Typical operate time (applies only to arc output matrix controlled outputs)	2 ms

Breaking capacity, DC (L/R = 40 ms) <ul style="list-style-type: none"> <li>• at 48 V dc</li> <li>• at 110 V dc</li> <li>• at 220 V dc</li> </ul>	<ul style="list-style-type: none"> <li>• 5 A</li> <li>• 3 A</li> <li>• 1 A</li> </ul>
Solid state	IGBT
Terminal block <ul style="list-style-type: none"> <li>• MSTB2.5–5.08</li> </ul>	Wire dimension: Maximum 2.5 mm <sup>2</sup> (13–14 AWG) Minimum 1.5 mm <sup>2</sup> (15–16 AWG)

Table 149 - Local serial communication port

Number of ports	1 on front
Electrical connection	USB
Data transfer rate	200 – 187 500 b/s
Protocols	GetSet

Table 150 - COM 3-4 serial communication port

Number of physical ports	0–1 on rear panel (option)
Electrical connection	RS-232 (option, IRIG-B included) RS-485 (option) Profibus (option, external module) Glass fibre connection (option, external module)
Protocols	Modbus RTU, master Modbus RTU, slave Spabus, slave IEC 60870-5-103 IEC 61870-5-101 Profibus DP DNP 3.0 IRIG-B

Table 151 - Ethernet communication port

Number of ports	0–2 on rear panel (option)
Electrical connection	RJ-45 100 Mbps (option) LC 100Mbps (option)
Protocols	IEC 61850 Modbus TCP DNP 3.0 IEC 61870-5-101

Table 152 - Fiber Ethernet communication port

Number of ports	0 or 2 on rear panel (option)
Connection type	LC 100 Mbps
Optical characteristics	Operates with 62.5/125 $\mu\text{m}$ and 50/125 $\mu\text{m}$ multimode fiber Center Wavelength: 1300 nm typical Output Optical Power: <ul style="list-style-type: none"> <li>• Fiber: 62.5/125 <math>\mu\text{m}</math>, NA = 0.275 23.0 dBm</li> <li>• Fiber: 50/125 <math>\mu\text{m}</math>, NA = 0.20 26.0 dBm</li> </ul> Input Optical Power: -31 dBm
Protocols	IEC 61850 Modbus TCP DNP 3.0 IEC 61870-5-101

Table 153 - Arc sensor inputs

Number of inputs	As per the order code
Supply to sensor	Isolated 12 V dc

Table 154 - Measuring circuits

Phase current inputs I' (5/1 A)	<b>Slot 4:</b> $T = 3 \times I (5/1A) + I_N (5/1A)$	
Rated phase current	5 A	1 A
- Current measuring range	0.05–250 A	0.02–50 A
- Thermal withstand		-
• continuously	20 A	4 A
• 10 s	100 A	20 A
• 1 s	500 A	100 A
• 10 ms	1250 A	250 A
- Burden	0.075 VA	0.02 VA
- Impedance	0.003 Ohm	0.02 Ohm
$I_N$ input (5A and 1A)		
Rated ground fault overcurrent	5 A	1 A
- Current measuring range	0.05–250 A	0.02–50 A
- Thermal withstand		
• continuously	20 A	4 A
• 10 s	100 A	20 A
• 1 s	500 A	100 A
- Burden	0.075 VA	0.02 VA
- Impedance	0.003 Ohm	0.02 Ohm
<b>Phase current inputs I (1 A, 5 A)</b>	<b>Slot 8:</b> $E = 3L (5A) + 4V + 2I_N (5/1A+1/0.2A)$	$F = 3L (1 A) + 4V + 2I_N (5/1A+1/0.2A)$
Rated phase current	5 A	1A
- Current measuring range	0.05–250 A	0.02–50 A
- Thermal withstand		
• continuously	20 A	4 A
• 10 s	100 A	20 A
• 1 s	500 A	100 A
• 10 ms	1250 A	250 A
- Burden	0.075 VA	0.02 VA
- Impedance	0.003 Ohm	0.02 Ohm
$I_N$ input (5 A)	<b>Slot 8:</b> $E = 3L (5/1A) + 4V + 2I_N (5/1A+1/0.2A)$	



Rated ground fault overcurrent	5 A
- Current measuring range	0.015–50 A
- Thermal withstand	
● continuously	20 A
● 10 s	100 A
● 1 s	500 A
- Burden	0.075 VA
- Impedance	0.003 Ohm
<b>I<sub>N</sub> input (1 A)</b>	<b>Slot 8:</b> <b>E = 3L (5/1A) + 4V + 2I<sub>N</sub> (5/1A+1/0.2A)</b>
Rated ground fault overcurrent	1 A (configurable for CT secondaries 0.1–10.0 A)
- Current measuring range	0.003–10 A
- Thermal withstand	
● continuously	4 A
● 10 s	20 A
● 1 s	100 A
- Burden	0.02 VA
- Impedance	0.02 Ohm
<b>I<sub>N</sub> input (0.2 A)</b>	<b>Slot 8:</b> <b>E = 3L (5/1A) + 4V+ 2I<sub>N</sub> (5/1A+1/0.2A)</b>
Rated ground fault overcurrent	0.2 A (configurable for CT secondaries 0.1 – 10.0 A)
- Current measuring range	0.0006–2 A
- Thermal withstand	
● continuously	0.8 A
● 10 s	4 A
● 1 s	20 A
- Burden	0.02 VA
- Impedance	0.02 Ohm
<b>Voltage inputs</b>	
Rated voltage V <sub>N</sub>	100 V (configurable for VT secondaries 50–250 V)
- Voltage measuring range	0.5–190 V
- Thermal withstand	
● continuously	250 V
● 10 s	600 V
- Burden	< 0.5 VA

<b>Frequency</b>	
Rated frequency $f_N$	45–65 Hz (protection operates accurately)
Measuring range	16–95 Hz < 44Hz / > 66Hz (other protection is not steady except frequency protection)


**Analog interface cross section and tightening torque**

Table 155 - Analog interface cross-section and tightening torque

<b>Terminal characteristics</b>			
	Current inputs		Voltage inputs
	Screw clamp	Ring lug	
Maximum wire cross-section, mm <sup>2</sup> (AWG)	4 (10-12)	(12–22)	2.5 (13-14)
Maximum wiring screw tightening torque Nm (lb-in)	1.2 (10.6)	0.79 (7)	0.5-0.6 (4.4-5.3)
Maximum connector retention tightening torque Nm (lb-in)	-		0.3-0.4 (2.7-3.5)
Wire type	Single strand or stranded with insulated crimp terminal		
Ring lug width (mm) and screw size	-	8.0, M3.5	

**10.6.8 External option modules**

**10.6.8.1 VSE-001 fiber optic interface module**

** DANGER**

**HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

- This equipment must only be installed or serviced by qualified electrical personnel.
- Turn off all power supplying this device and the equipment in which it is installed before working on the device or equipment.
- Connect protective ground before turning on any power supplying this device.

**Failure to follow these instructions will result in death or serious injury.**

An external fiber optic module VSE-001 is used to connect the relay to a fiber optic loop or a fiber optic star. There are four different types of serial fiber optic modules:

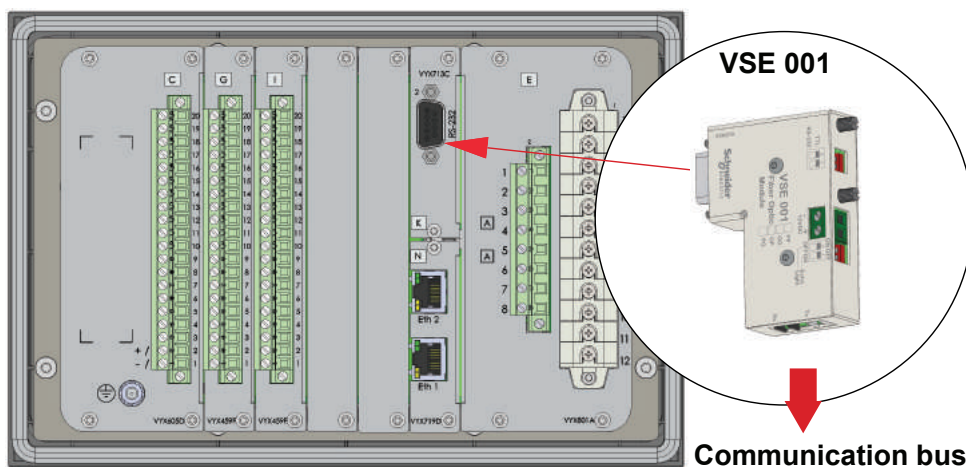
- VSE001PP (Plastic - plastic)
- VSE001GG (Glass - glass)

The modules provide a serial communication link up to 1 km (0.62 miles) with VSE 001 GG. With a serial fibre interface module it is possible to have the following serial protocols in use:

- None
- IEC-103
- Modbus slave
- SpaBus

The power for the module is taken from pin 9 of the D-connector or from an external power supply interface.

Figure 226 - The VSE-001 module brings a serial-fiber interface to the relay. The Module is connected to the RS-232 serial port.



**Module interface to the relay**

The physical interface of the VSE-001 is a 9-pin D-connector. The signal level is RS-232.

**NOTE:** The product manual for VSE-001 can be found on our website.

**10.6.8.2 VSE-002 RS-485 interface module**

**⚠ ⚠ DANGER**

**HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

- This equipment must only be installed or serviced by qualified electrical personnel.
- Turn off all power supplying this device and the equipment in which it is installed before working on the device or equipment.
- Connect protective ground before turning on any power supplying this device.

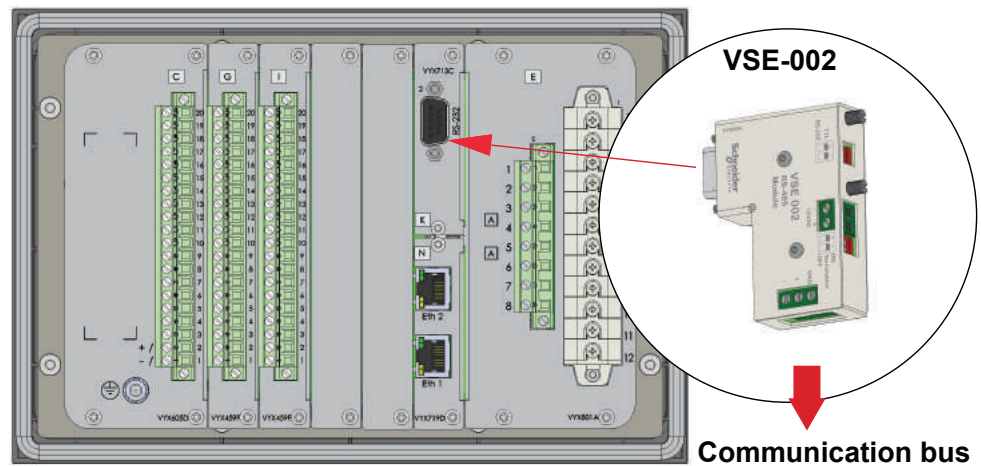
**Failure to follow these instructions will result in death or serious injury.**

An external RS-485 module VSE-002 (VSE002) is used to connect Easergy P3 protection relays to RS-485 bus. With the RS-485 serial interface module, the following serial protocols can be used:

- None
- IEC-103
- ModbusSlv
- SpaBus

The power for the module is taken from pin 9 of the D-connector or from an external power supply interface.

Figure 227 - The VSE-002 module brings a serial RS-485 interface to the relay. The module is connected to the RS-232 serial port.



### Module interface to the relay

The physical interface of the VSE-002 is a 9-pin D-connector. The signal level is RS-232 and therefore, the interface type for the module has to be selected as **RS-232**.

It is possible to connect multiple relays in daisychain. “Termination” has to be selected as **on** for the last unit in the chain. The same applies when only one unit is used.

VSE-002 operates with the relay in RS-232 mode. Therefore the “interface type” has to be selected as RS-232.

Figure 228 - RS-232 and TTL interface

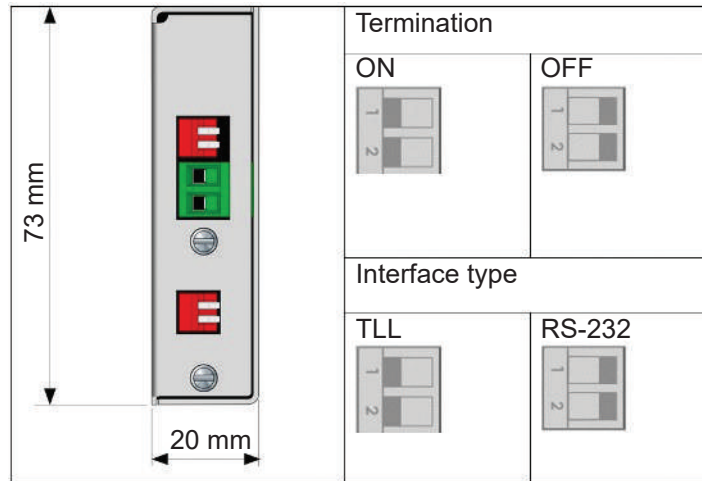


Table 156 - RS-232 and TTL interface

Pin number	TTL mode	RS-232 mode
1	-	-
2	RXD (in)	RXD (in)
3	TXD (out)	TXD (out)
4	RTS (in)	RTS (in)
5		
6		
7	GND	GND
8		
9	+8V (in)	+8V (in)

### 10.6.8.3 VSE-009 DeviceNet interface module

⚠️ ⚠️ DANGER

HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

- This equipment must only be installed or serviced by qualified electrical personnel.
- Turn off all power supplying this device and the equipment in which it is installed before working on the device or equipment.
- Connect protective ground before turning on any power supplying this device.

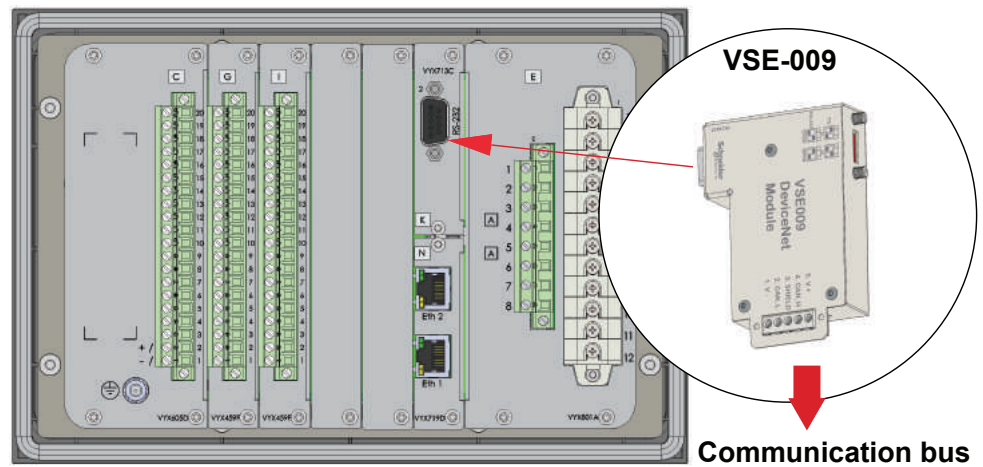
Failure to follow these instructions will result in death or serious injury.

VSE-009 (VSE009) is a DeviceNet interface module for the Easergy P3G30 and P3G32 relays. The relay can be connected to the network using DeviceNet as the protocol. VSE-009 is attached to the RS-232 D-connector at the back of the relay. With the DeviceNet interface module, the following protocols can be used:

- None
- DeviceNet

An external +24VDC power supply interface is required.

Figure 229 - The VSE-009 module



### 10.6.8.4 VPA-3CG Profibus interface module

**⚡ ⚠ DANGER**

**HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

- This equipment must only be installed or serviced by qualified electrical personnel.
- Turn off all power supplying this device and the equipment in which it is installed before working on the device or equipment.
- Connect protective ground before turning on any power supplying this device.

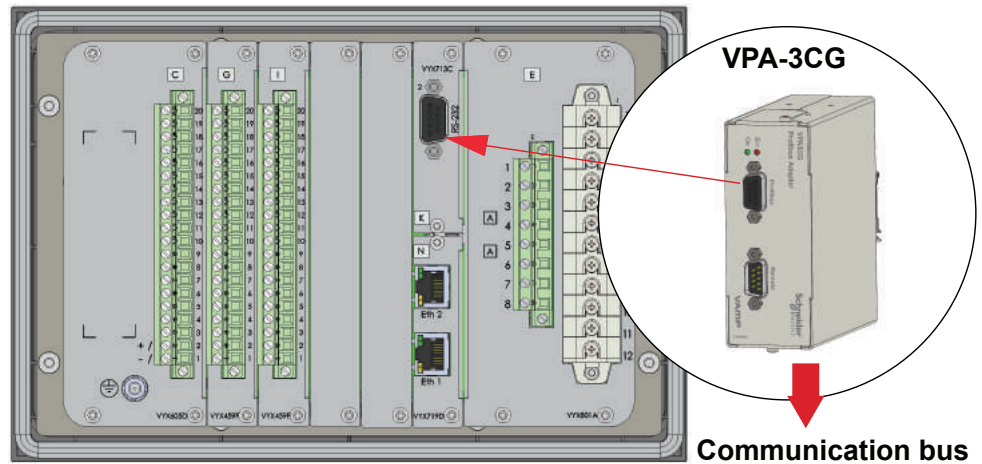
**Failure to follow these instructions will result in death or serious injury.**

Easergy P3G30 and P3G32 can be connected to Profibus DP by using an external Profibus interface module VPA-3CG (VPA3CG). The relay can then be monitored from the host system. VPA-3CG is attached to the RS-232 D-connector at the back of the relay with a VX-072 (VX072) cable. With the Profibus interface module, the following protocols can be used:

- None
- ProfibusDP

The power for the module is taken from an external power supply interface.

Figure 230 - VPA-3CG module brings a Profibus interface to the relay. The module is connected to the RS-232 serial port with a VX-072 cable.



### Module interface to the relay

The physical interface of the VPA-3CG Profibus interface module is a 9-pin D-connector.

Profibus devices are connected in a bus structure. Up to 32 stations (master or slave) can be connected in one segment. The bus is terminated by an active bus terminator at the beginning and end of each segments. When more than 32 stations are used, repeaters (line amplifiers) must be used to connect the individual bus segments.

The maximum cable length depends on the transmission speed and cable type. The specified cable length can be increased by the use of repeaters. The use of more than 3 repeaters in a series is not recommended.

A separate product manual for VPA-3CG can be found on our website.

### 10.6.8.5 VIO 12A RTD and analog input / output modules

VIO 12A I/O modules can be connected to Easergy P3G30 and P3G32 using VSE 001 or VSE 002 interface modules.

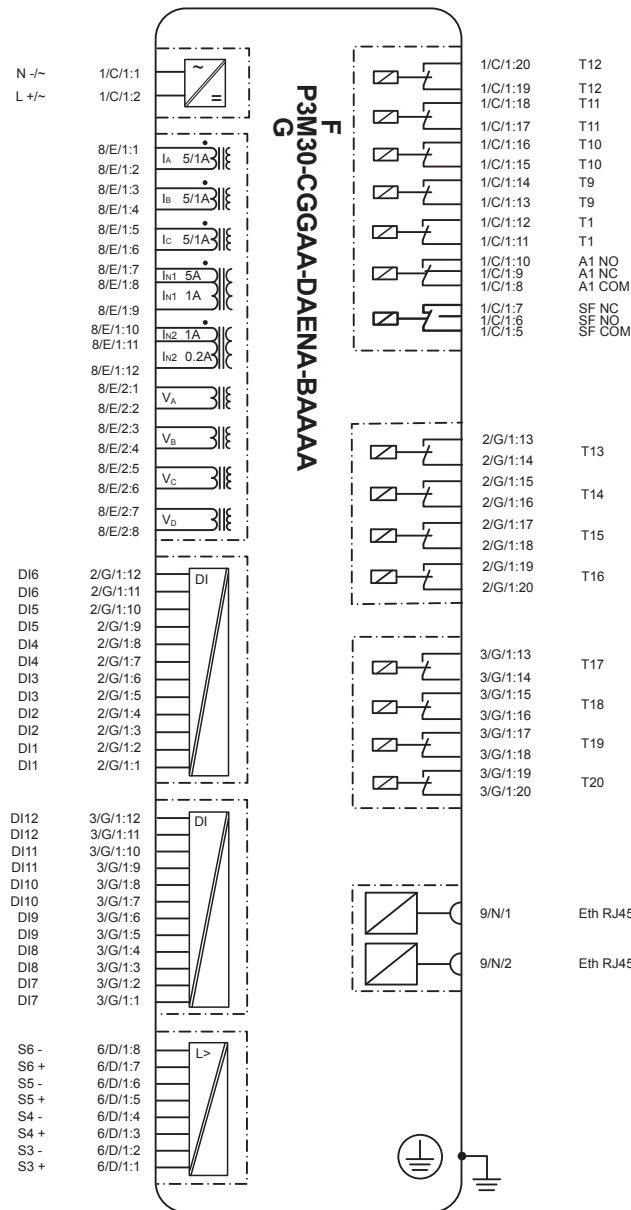
VIO 12A I/O modules can be connected to Easergy P3U20 and P3U30 using RS-485 connection in interface modules. Alternatively VIO 12A I/O modules can be connected to Easergy P3U20 and P3U30 using RS-232 connection. If RS-232 connection is used a separate VX082 or VX083 connection cable and VSE001 or VSE002 option module are needed.

A separate product manual for VIO 12A is available.

## 10.6.9 Block diagrams

The status of the output contacts is shown when the relay is energized but none of the protection, controlling or self-supervision elements are activated.

Figure 231 - Typical block diagram for P3F30, P3M30 and P3G30 relays



**⚡ DANGER**

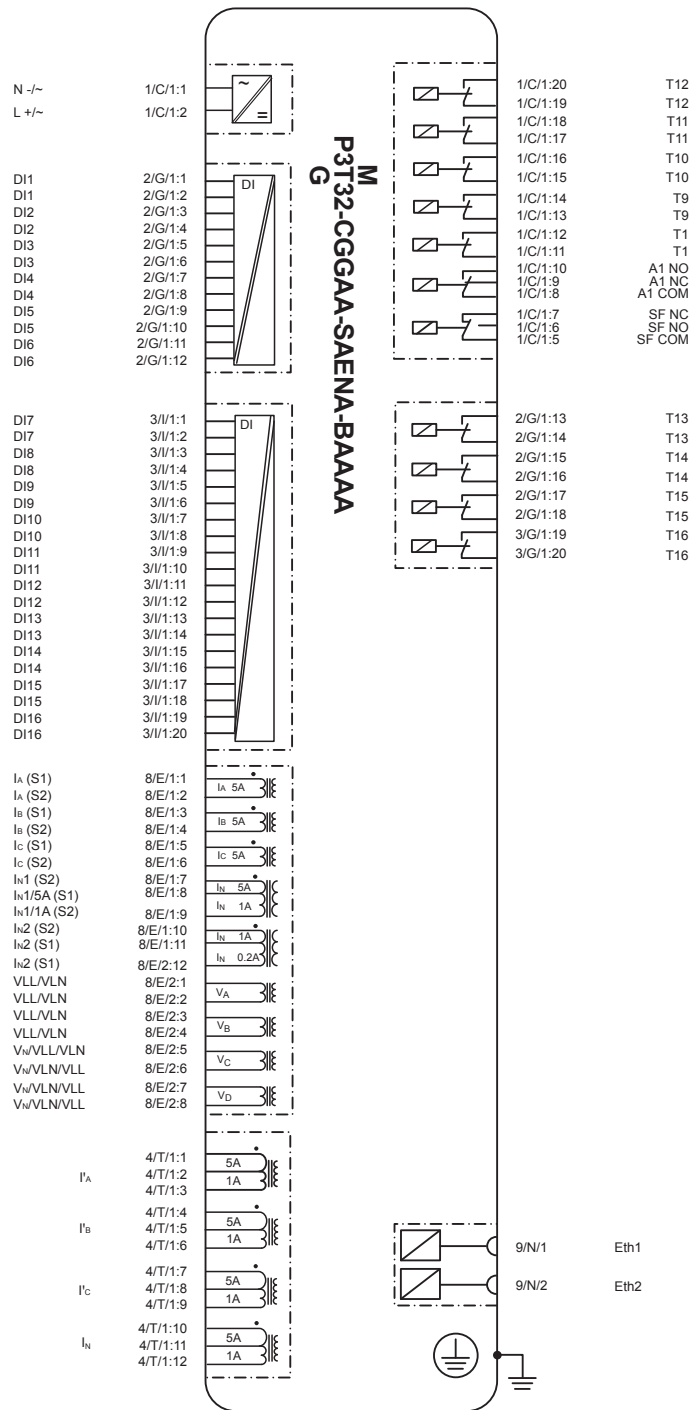
**HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

Connect the relay's protective ground to functional ground according to the connection diagrams presented in this document.

**Failure to follow this instruction will result in death or serious injury.**



Figure 232 - Typical block diagram for P3M32, P3T32 and P3G32 relays



**⚡ ⚡ DANGER**

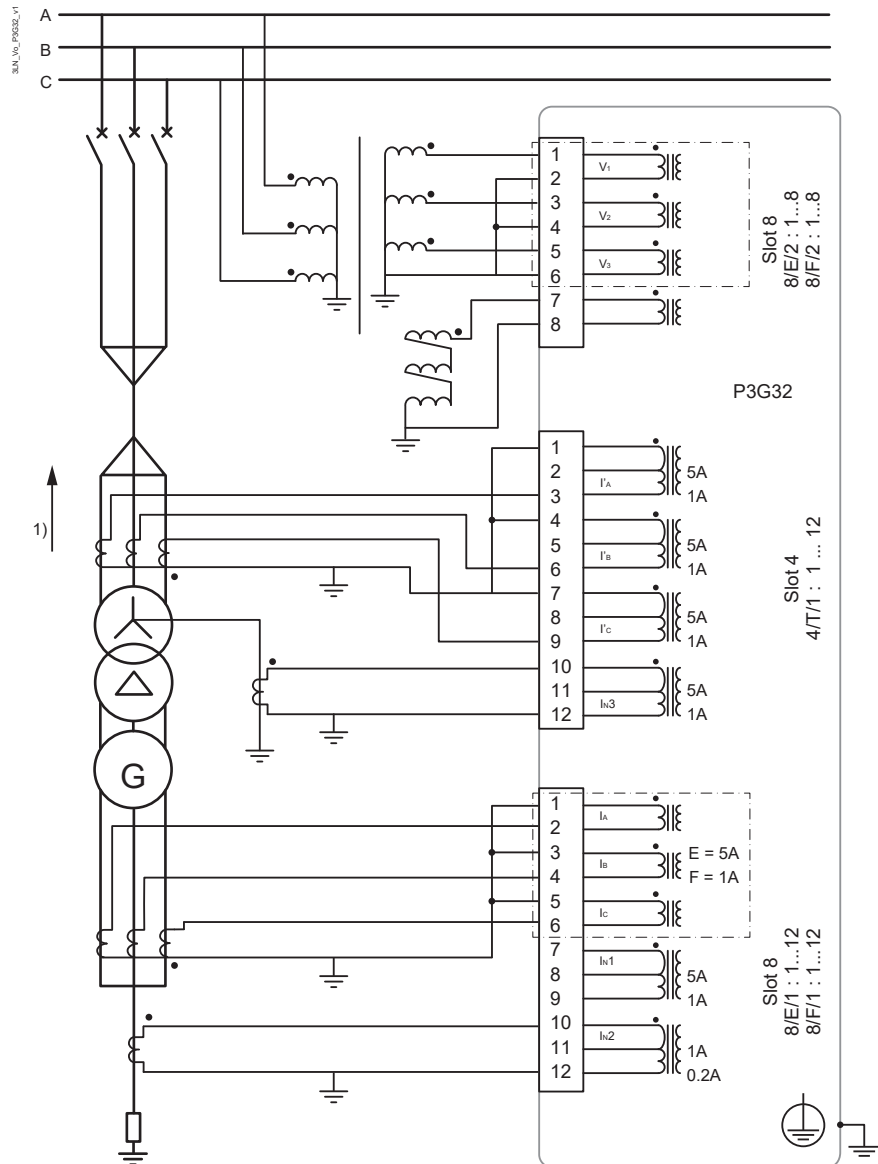
**HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

Connect the relay's protective ground to functional ground according to the connection diagrams presented in this document.

**Failure to follow this instruction will result in death or serious injury.**

### 10.6.10 Connection examples

Figure 233 - Generator-block transformer connection with machine differential



1) Power direction

## ⚠️ ⚠️ DANGER

**HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

- Always connect the polarity of the current transformer (CT) and the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional ground according to the connection diagrams presented in this document.

**Failure to follow this instruction will result in death or serious injury.**

## 10.7 Arc flash detection system setup and testing

### 10.7.1 Setting up the arc flash system

**⚠️ ⚠️ DANGER**

**HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

- Apply appropriate personal protective equipment (PPE) and follow safe electrical work practices. See NFPA 70E, NOM-029-STPS-2011, or CSA Z462.
- The arc fault detection system is not a substitute for proper PPE when working on or near equipment being monitored by the system.
- Information on this product is offered as a tool for conducting arc flash hazard analysis. It is intended for use only by qualified persons who are knowledgeable about power system studies, power distribution equipment, and equipment installation practices. It is not intended as a substitute for the engineering judgement and adequate review necessary for such activities.
- Only qualified personnel should install and service this equipment. Read this entire set of instructions and check the technical characteristics of the device before performing such work.
- Perform wiring according to national standards (NEC) and any requirements specified by the customer.
- Observe any separately marked notes and warnings.
- NEVER work alone.
- Before performing visual inspections, tests, or maintenance on this equipment, disconnect all sources of electric power. Assume all circuits are live until they are completely de-energized, tested, and tagged. Pay particular attention to the design of the power system. Consider all sources of power, including the possibility of backfeeding.
- Always use a properly rated voltage sensing relay to ensure that all power is off.
- The equipment must be grounded.
- Connect the device's protective ground to functional earth according to the connection diagrams presented in this document.
- Do not open the device. It contains no user-serviceable parts.
- Install all devices, doors and covers before turning on the power to this device.

**Failure to follow these instructions will result in death or serious injury.**

Before setting up the arc flash system:

- Mount and connect all components and sensors.
  - Make sure that you understand the customer application.
1. Identify the wiring connection of sensors to the device's connectors.
  2. Identify the wiring connection to breaking devices.
  3. Identify binary I/O wiring connections.
  4. Proceed with configuration in Easergy Pro with consideration of the customer application.
  5. Power up the device.

6. Reset the device by pushing the reset button.
7. Verify LED indication as described with consideration of the customer application.
8. If connecting two devices through MT in and MT out:

**⚠ DANGER**

**HAZARD OF LOSS OF SIGNAL**

The MT in and MT out connections are not monitored. You must to determine if external monitoring is required to detect broken or disconnected wires.

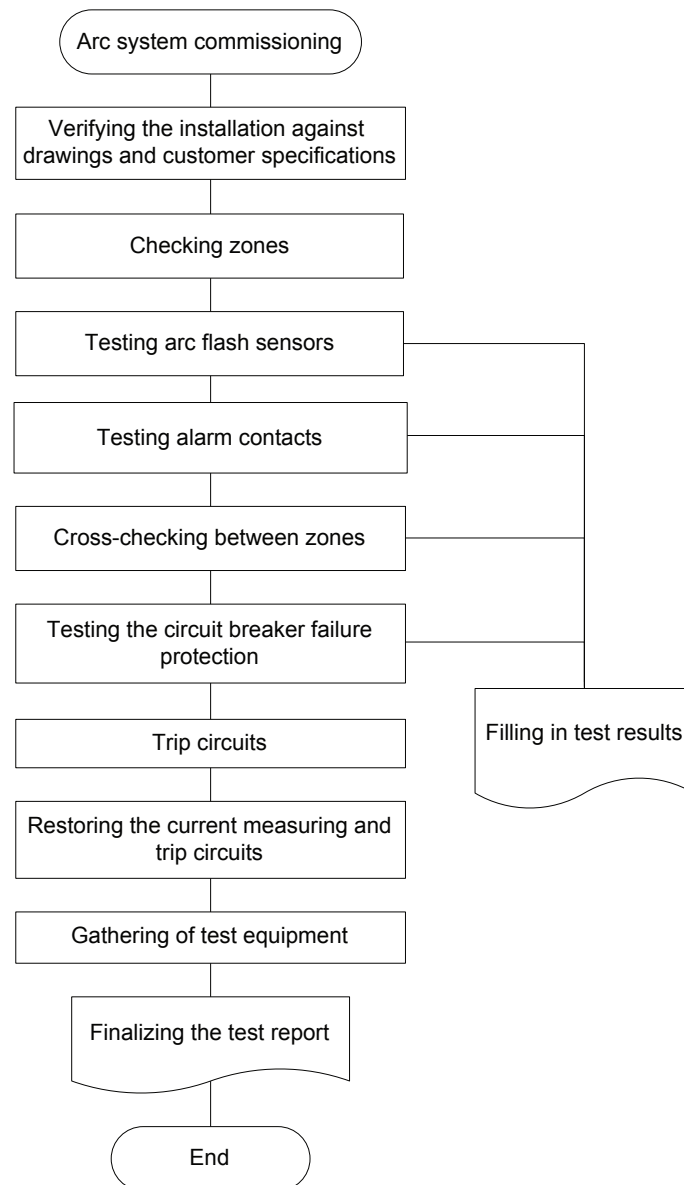
**Failure to follow these instructions will result in death or serious injury.**

- a. Verify the MT in MT out connections.
- b. Set the related dip switch configuration.
- c. Verify the LED indications.

## 10.7.2 Commissioning and testing

This section contains the commissioning testing instructions. The figure below shows the testing sequence.

Figure 234 - Testing sequence



### 10.7.2.1 Checking zones

1. Check the protected zones where sensors have been installed and compare them against the drawings.
2. Consult the customer if the configuration does not match with the drawings.

### 10.7.2.2 Disconnecting trip circuits

#### **DANGER**

##### **HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

Removing trip wires may cause loss of protection. Review system drawings and diagrams before disconnecting trip circuits.

**Failure to follow this instruction will result in death or serious injury.**

- Disconnect the trip signals to the circuit breakers that may disturb other parts of the system during the test.
- Also disconnect trip signals routed to other parts of the system, such as the breaker failure (ANSI 50BF) backup trip to upstream breakers and the transfer trip signals.
- Test the disconnected trip signals with a multimeter.

### 10.7.2.3 Sensor testing

## DANGER

### HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH

- Apply appropriate personal protective equipment (PPE) and follow safe electrical work practices. See NFPA 70E, NOM-029-STPS-2011, or CSA Z462.
- The arc fault detection system is not a substitute for proper PPE when working on or near equipment being monitored by the system.
- Information on this product is offered as a tool for conducting arc flash hazard analysis. It is intended for use only by qualified persons who are knowledgeable about power system studies, power distribution equipment, and equipment installation practices. It is not intended as a substitute for the engineering judgement and adequate review necessary for such activities.
- Only qualified personnel should install and service this equipment. Read this entire set of instructions and check the technical characteristics of the device before performing such work.
- Perform wiring according to national standards (NEC) and any requirements specified by the customer.
- Observe any separately marked notes and warnings.
- NEVER work alone.
- Before performing visual inspections, tests, or maintenance on this equipment, disconnect all sources of electric power. Assume all circuits are live until they are completely de-energized, tested, and tagged. Pay particular attention to the design of the power system. Consider all sources of power, including the possibility of backfeeding.
- Always use a properly rated voltage sensing relay to ensure that all power is off.
- The equipment must be grounded.
- Connect the device's protective ground to functional earth according to the connection diagrams presented in this document.
- Do not open the device. It contains no user-serviceable parts.
- Install all devices, doors and covers before turning on the power to this device.

**Failure to follow these instructions will result in death or serious injury.**

Testing the arc flash sensors with the light-only criteria operates the trip outputs of the device or the I/O units for the protected zone.

Testing the arc flash sensors with the light and current criteria, without an injected current, only generates an indication on the unit that protects the zone. The indication of the arc fault is registered by the possible main unit and I/O unit.

**NOTE:** Testing the arc flash sensors using a light source can trip the neighboring zones.

**NOTE:** For more information on viewing and resetting indications, see the corresponding sensor user manual or [www.schneider-electric.com](http://www.schneider-electric.com).

**NOTE:** Because of their placement, some sensors cannot be tested without dismantling parts of the system. After completing the testing, reassemble the

parts and validate the compliance with original mounting. Consult the equipment manufacturer before dismantling any parts.

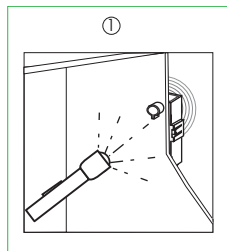
#### 10.7.2.3.1 Testing the sensors

Test the sensors with the main device. See *VAMP 125 Arc Flash Protection Device User Manual*.

Reset the main device before the test.

**NOTE:** Because of their placement, some sensors cannot be tested without dismantling parts of the system. After completing the testing, reassemble the parts and validate the compliance with original mounting. Consult the equipment manufacturer before dismantling any parts.

Figure 235 - Testing point sensors



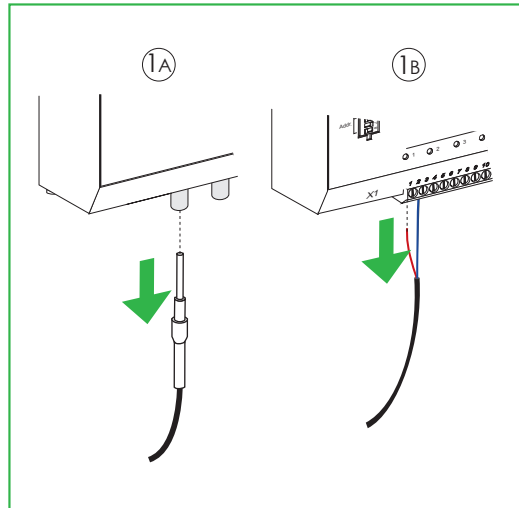
1. Point light to each arc flash sensor, one at a time, with a powerful light source such as camera flash unit or flashlight.
2. Check the light sensor indication from the device.
3. Check the light sensor address from the device.
4. Compare the light sensor address information from the device with the sensor location map.
5. Fill in the test result in the test report.  
See *VAMP Arc Flash Protection Testing Manual*.
6. Reset the device.
7. Repeat the procedure with the next sensor.

#### 10.7.2.3.2 Testing the sensor supervision

Test the sensors with the main device.



Figure 236 - Testing the sensor's self-supervision



1. Disconnect one wire from one point sensor, one for each unit, to see that the self-supervision system recognizes the fault in the sensor.
2. Wait until the arc fault indication appears.  
Depending on the device, this can take several minutes. See *HMI functions and indications* in the device user manual.
3. Check that the service status output operates.
4. Fill in the test results in the test report.  
See the test report template in *VAMP Arc Flash Protection Testing Manual*.
5. Reconnect the wire and reset the system.
6. Repeat the procedure with the other units.

#### 10.7.2.3.3 Testing the binary I/O connectivity

BI/O signals such as light and overcurrent information are transmitted between devices through dedicated inputs/output.

1. Activate the signal outputs in the binary I/O by generating arc fault light signal, overcurrent pickup or both.
2. Check the configuration modes used for the customer application.
3. Fill in the test result in the test report.
4. Reset the main unit.
5. Repeat the procedure with all connected I/O's.

## 10.7.3 Test report

### 10.7.3.1 Filling in the test report

1. Download the test report template from the Schneider Electric Web site.

2. Fill in all the required information about the system, the tested arc flash units and the test results.

### 10.7.3.2 Test report example

Figure 237 - Test report example

Easergy P3x3x Arc stage commissioning and testing report						
Customer Information	Customer name			Substation		
	Customer address			Bay		
Unit	Device name:		Device location:			
	Serial number:		Order code:			
	Program version:		IP Address:			
	NetMask:		Gateway:			
	MAC address:		NTP Server:			
Scaling	CT primary current input:		A	Pick-up setting: xIn		
	CT secondary current input:		A	Pick-up value: A		
	CT residual current primary input:		A	Pick-up setting: xIn		
	CT residual current secondary input:		A	Pick-up value: A		
Arc sensors	Sensor	Arc sensor status		Tested	Remarks	
	1	<input type="checkbox"/> OK	<input type="checkbox"/> NA	<input type="checkbox"/>		
	2	<input type="checkbox"/> OK	<input type="checkbox"/> NA	<input type="checkbox"/>		
	3	<input type="checkbox"/> OK	<input type="checkbox"/> NA	<input type="checkbox"/>		
	4	<input type="checkbox"/> OK	<input type="checkbox"/> NA	<input type="checkbox"/>		
	5	<input type="checkbox"/> OK	<input type="checkbox"/> NA	<input type="checkbox"/>		
	6	<input type="checkbox"/> OK	<input type="checkbox"/> NA	<input type="checkbox"/>		
Arc stages	Stage number	Activation criteria			Tested	Remarks
	1	<input type="checkbox"/> Light	<input type="checkbox"/> I>int	<input type="checkbox"/> IoI>int	<input type="checkbox"/>	
	2	<input type="checkbox"/> Light	<input type="checkbox"/> I>int	<input type="checkbox"/> IoI>int	<input type="checkbox"/>	
	3	<input type="checkbox"/> Light	<input type="checkbox"/> I>int	<input type="checkbox"/> IoI>int	<input type="checkbox"/>	
	4	<input type="checkbox"/> Light	<input type="checkbox"/> I>int	<input type="checkbox"/> IoI>int	<input type="checkbox"/>	
	5	<input type="checkbox"/> Light	<input type="checkbox"/> I>int	<input type="checkbox"/> IoI>int	<input type="checkbox"/>	
	6	<input type="checkbox"/> Light	<input type="checkbox"/> I>int	<input type="checkbox"/> IoI>int	<input type="checkbox"/>	
	7	<input type="checkbox"/> Light	<input type="checkbox"/> I>int	<input type="checkbox"/> IoI>int	<input type="checkbox"/>	
	8	<input type="checkbox"/> Light	<input type="checkbox"/> I>int	<input type="checkbox"/> IoI>int	<input type="checkbox"/>	
CBFP	Stage number	Delay setting / ms		Tested	Remarks	
	1			<input type="checkbox"/>		
	2			<input type="checkbox"/>		
	3			<input type="checkbox"/>		
	4			<input type="checkbox"/>		
	5			<input type="checkbox"/>		
	6			<input type="checkbox"/>		
	7			<input type="checkbox"/>		
	8			<input type="checkbox"/>		
Trip relays	Trip relay	Tested		CBFP	Remarks	
	T1	<input type="checkbox"/> OK	<input type="checkbox"/> NA	<input type="checkbox"/>		
	T2	<input type="checkbox"/> OK	<input type="checkbox"/> NA	<input type="checkbox"/>		
	T3	<input type="checkbox"/> OK	<input type="checkbox"/> NA	<input type="checkbox"/>		
	T4	<input type="checkbox"/> OK	<input type="checkbox"/> NA	<input type="checkbox"/>		
	T9	<input type="checkbox"/> OK	<input type="checkbox"/> NA	<input type="checkbox"/>		
	T10	<input type="checkbox"/> OK	<input type="checkbox"/> NA	<input type="checkbox"/>		
	T11	<input type="checkbox"/> OK	<input type="checkbox"/> NA	<input type="checkbox"/>		
	T12	<input type="checkbox"/> OK	<input type="checkbox"/> NA	<input type="checkbox"/>		
	HS01	<input type="checkbox"/> OK	<input type="checkbox"/> NA	<input type="checkbox"/>		
HS02	<input type="checkbox"/> OK	<input type="checkbox"/> NA	<input type="checkbox"/>			
Led indications	Led name	Tested		Led name	Tested	
	A	<input type="checkbox"/> Yes	<input type="checkbox"/> NA	B	<input type="checkbox"/> Yes	<input type="checkbox"/> NA
	C	<input type="checkbox"/> Yes	<input type="checkbox"/> NA	D	<input type="checkbox"/> Yes	<input type="checkbox"/> NA
	E	<input type="checkbox"/> Yes	<input type="checkbox"/> NA	F	<input type="checkbox"/> Yes	<input type="checkbox"/> NA
	G	<input type="checkbox"/> Yes	<input type="checkbox"/> NA	H	<input type="checkbox"/> Yes	<input type="checkbox"/> NA
	I	<input type="checkbox"/> Yes	<input type="checkbox"/> NA	J	<input type="checkbox"/> Yes	<input type="checkbox"/> NA
	K	<input type="checkbox"/> Yes	<input type="checkbox"/> NA	L	<input type="checkbox"/> Yes	<input type="checkbox"/> NA
	M	<input type="checkbox"/> Yes	<input type="checkbox"/> NA	N	<input type="checkbox"/> Yes	<input type="checkbox"/> NA
Testing device	Device			Calibration date		
Signatures	Commissioner(s)					
	Supervisor					
	Date					

## 10.7.4 Troubleshooting

This table describes some common problems in the arc flash system and how they can be solved.

Table 157 - Troubleshooting

Problem	Possible cause	Solution
The trip signal does not reach the circuit breaker.	Faulty trip circuit wiring	Check that the wiring of the trip circuit is not faulty.
The protection does not trip even when a sufficient light signal is provided.	The protection needs both light and current information to trip.	Check the dip switch configuration. The protection may be configured to require both the light and current condition to trip.
Faulty sensor wiring detected by the self-supervision	Loose sensor wire	Check the sensor wiring. The sensor wire may have loosened in the terminal blocks.
Error message indicating blocked sensor channel	Light pulse to the arc flash sensor is too long.	<p>Check that the light pulse to the arc flash sensor is not too long.</p> <p>If light is supplied to the arc flash sensor for more than three seconds, the self-supervision function activates and switches the light sensor channel to daylight blocking mode, and the sensor channel is blocked. The sensor channel indication activates an error message indication on the LED.</p> <p>Remove the light source to reset the blocked channel.</p>

## 10.8 Voltage system configuration

Depending on the application and available voltage transformers, the relay can be connected either to zero-sequence voltage, line-to-line voltage or line-to-neutral voltage. The configuration parameter "Voltage measurement mode" must be set according to the type of connection used.

### Voltage measuring modes correlation for E and F analog measurement cards

V1, V2, V3 and V4 are voltage channels for the relay.

The physical voltage transformer connection in the Easergy P3G30 and P3G32 depends on the used voltage transformer connection mode. This setting is defined in the scalings setting view. See [Table 158 - Correlation between voltage measuring mode and physical voltage input in Terminals 8/E/1 and 8/F/2](#) on page 369.

Figure 238 - Example of Terminal 8/E/1 and 8/E/2

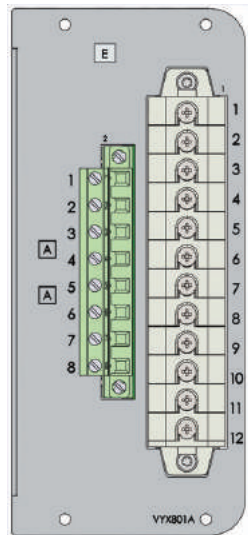


Table 158 - Correlation between voltage measuring mode and physical voltage input in Terminals 8/E/1 and 8/F/2

Terminal	1	2	3	4	5	6	7	8
Voltage channel	$V_1$		$V_2$		$V_3$		$V_4$	
Mode / Used voltage								
3LN	$V_A$		$V_B$		$V_C$		Not in use	
3LN+ $V_N$							$V_N$	
3LN+LLy							LLy	
3LN+LNy							LNy	
2LL+ $V_N$	$V_{AB}$		$V_{BC}$		$V_N$		Not in use	
2LL+ $V_N$ +LLy							LLy	
2LL+ $V_N$ +LNy							LNy	
LL+LLy+ $V_N$ +LLz			$V_{ABz}$					
LN+LNy+ $V_N$ +LNz	$V_A$		$V_{Ay}$				$V_{Az}$	

### 10.8.1 Multiple channel voltage measurement

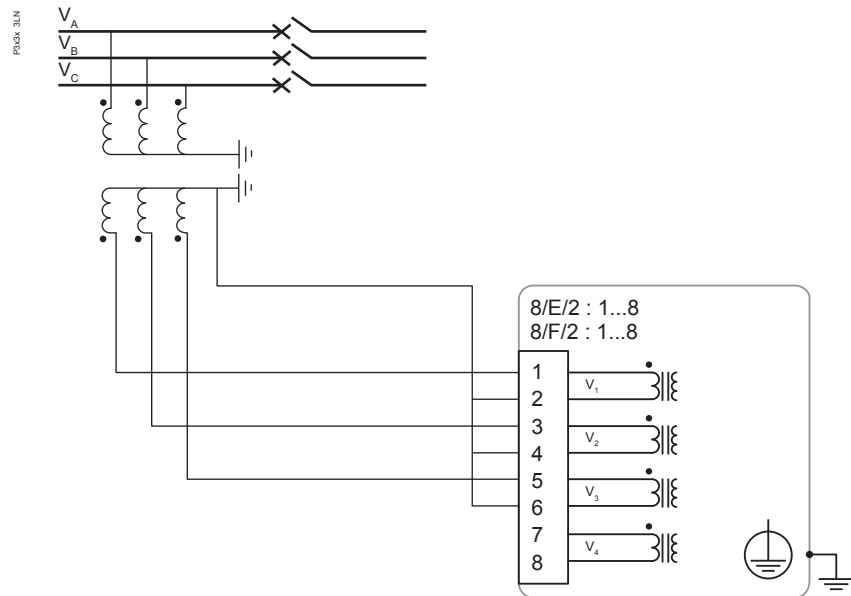
Slot 8 can accommodate four different analog measurement cards. Each of them have four voltage measurement channels.

This section introduces various voltage connections and the required voltage measuring modes for the connections. The settings are defined in the **Scalings** view.

**3LN**

- Voltages measured by VTs:  $V_A, V_B, V_C$
- Values calculated:  $V_{AB}, V_{BC}, V_{CA}, V_1, V_2, V_2/V_1, f, V_N$
- Measurements available: All
- Protection functions not available: ANSI 25

Figure 239 - 3LN



**⚡ ⚠ DANGER**

**HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

- Always connect the polarity of the current transformer (CT) and the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional ground according to the connection diagrams presented in this document.

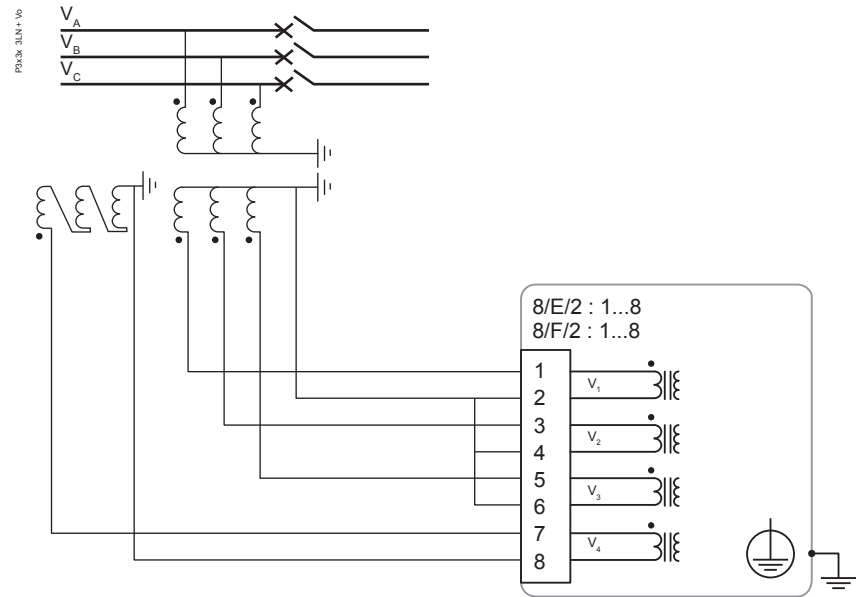
**Failure to follow this instruction will result in death or serious injury.**

**3LN+ $V_N$**

This connection is typically used for feeder and motor protection schemes.

- Voltages measured by VTs:  $V_A, V_B, V_C, V_N$
- Values calculated:  $V_{AB}, V_{BC}, V_{CA}, V_1, V_2, V_2/V_1, f$
- Measurements available: All
- Protection functions not available: ANSI 25

Figure 240 - 3LN+V<sub>N</sub>



**⚠ ⚠ DANGER**

**HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

- Always connect the polarity of the current transformer (CT) and the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional ground according to the connection diagrams presented in this document.

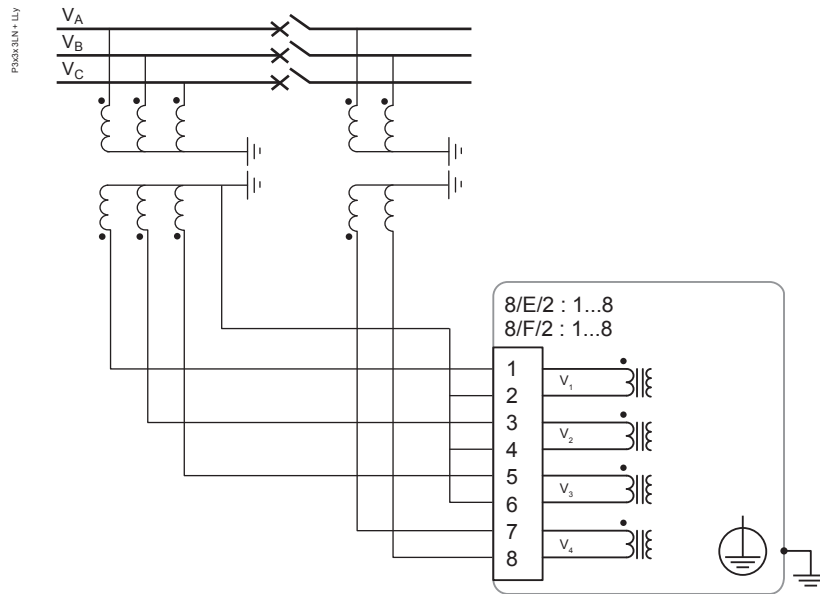
**Failure to follow this instruction will result in death or serious injury.**

**3LN+LLy**

Connection of voltage transformers for synchrocheck application. The other side of the CB has line-to-line connection for reference voltage.

- Voltages measured by VTs:  $V_A, V_B, V_C, V_{ABy}$
- Values calculated:  $V_{AB}, V_{BC}, V_{CA}, V_1, V_2, V_2/V_1, f, V_N$
- Measurements available: All
- Protection functions not available: ANSI 78PS

Figure 241 - 3LN+LLy



**⚠️ DANGER**

**HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

- Always connect the polarity of the current transformer (CT) and the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional ground according to the connection diagrams presented in this document.

**Failure to follow this instruction will result in death or serious injury.**

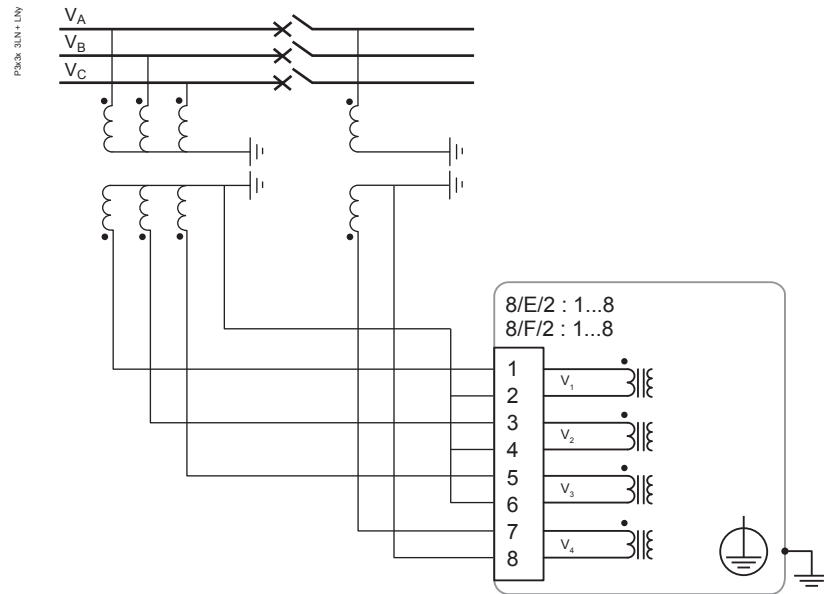
**3LN+LNy**

This connection is typically used for feeder protection scheme where line-to-neutral voltage is required for synchrocheck application.

- Voltages measured by VTs:  $V_A, V_B, V_C, V_{Ay}$
- Values calculated:  $V_{AB}, V_{BC}, V_{CA}, V_1, V_2, V_2/V_1, f, V_N$
- Measurements available: All
- Protection functions not available: ANSI 78PS



Figure 242 - 3LN+LNy



**⚡ ⚡ DANGER**

**HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

- Always connect the polarity of the current transformer (CT) and the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional ground according to the connection diagrams presented in this document.

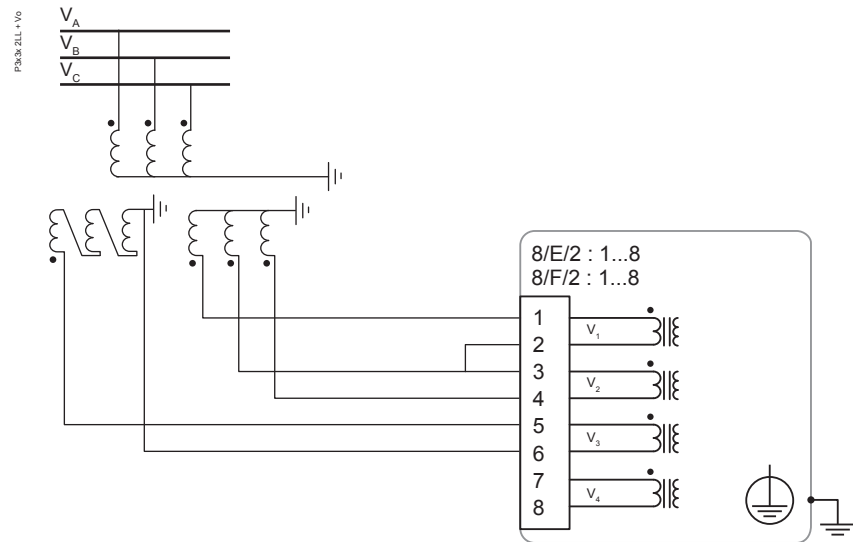
**Failure to follow this instruction will result in death or serious injury.**

**2LL+VN**

Connection of two line-to-line and neutral displacement voltage measurement schemes.

- Voltages measured by VTs:  $V_{AB}$ ,  $V_{BC}$ ,  $V_N$
- Values calculated:  $V_{CA}$ ,  $V_A$ ,  $V_B$ ,  $V_C$ ,  $V_1$ ,  $V_2$ ,  $V_2/V_1$ ,  $f$
- Measurements available: All
- Protection functions not available: ANSI 25, ANSI 78PS

Figure 243 - 2LL+V<sub>N</sub>



**⚡ ⚠ DANGER**

**HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

- Always connect the polarity of the current transformer (CT) and the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional ground according to the connection diagrams presented in this document.

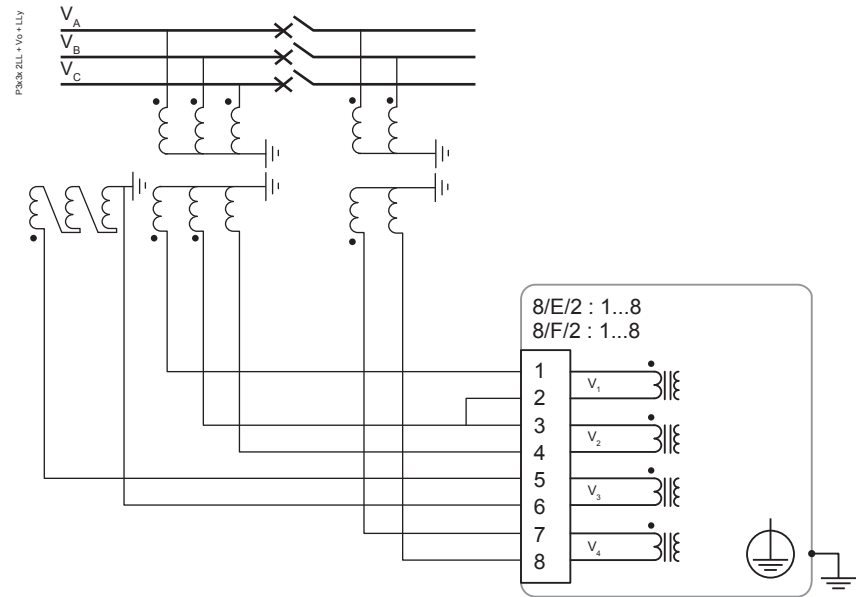
**Failure to follow this instruction will result in death or serious injury.**

**2LL+V<sub>N</sub>+LLy**

Connection of two line-to-line and neutral displacement voltage schemes. Line-to-line reference voltage is taken from the other side of the CB for synchrocheck scheme.

- Voltages measured by VTs: V<sub>AB</sub>, V<sub>BC</sub>, V<sub>N</sub>, V<sub>ABy</sub>
- Values calculated: V<sub>CA</sub>, V<sub>A</sub>, V<sub>B</sub>, V<sub>C</sub>, V<sub>1</sub>, V<sub>2</sub>, V<sub>2</sub>/V<sub>1</sub>, f
- Measurements available: All
- Protection functions not available: - ANSI 78PS

Figure 244 - 2LL+V<sub>N</sub>+LLy



**⚡ ⚡ DANGER**

**HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

- Always connect the polarity of the current transformer (CT) and the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional ground according to the connection diagrams presented in this document.

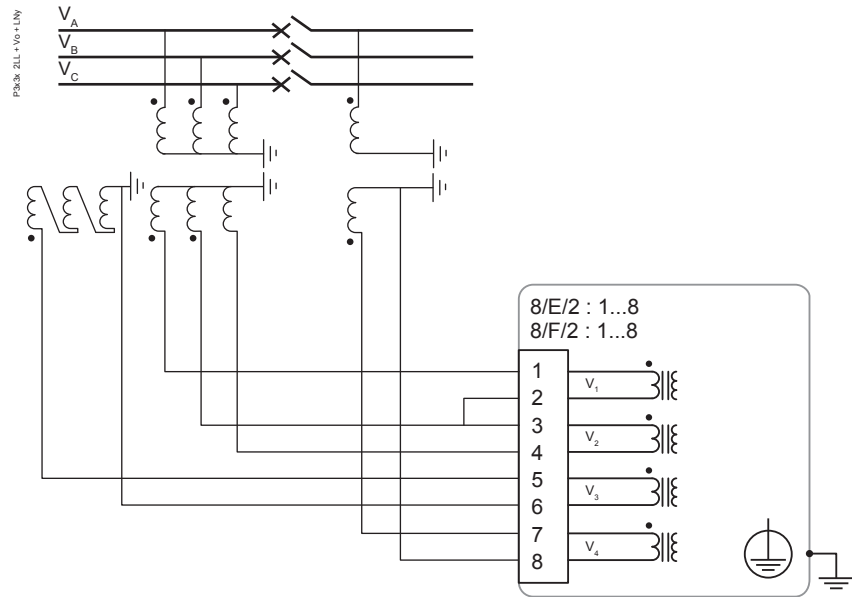
**Failure to follow this instruction will result in death or serious injury.**

**2LL+V<sub>N</sub>+LNy**

Connection of two line-to-line and neutral displacement voltage schemes. The other side of the CB has phase-to-neutral connection for synchrocheck.

- Voltages measured by VTs:  $V_{AB}$ ,  $V_{BC}$ ,  $V_N$ ,  $V_{Ay}$
- Values calculated:  $V_{CA}$ ,  $V_A$ ,  $V_B$ ,  $V_C$ ,  $V_1$ ,  $V_2$ ,  $V_2/V_1$ ,  $f$
- Measurements available: All
- Protection functions not available: - ANSI 78PS

Figure 245 - 2LL+V<sub>N</sub>+LNy



**⚡ ⚠ DANGER**

**HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

- Always connect the polarity of the current transformer (CT) and the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional ground according to the connection diagrams presented in this document.

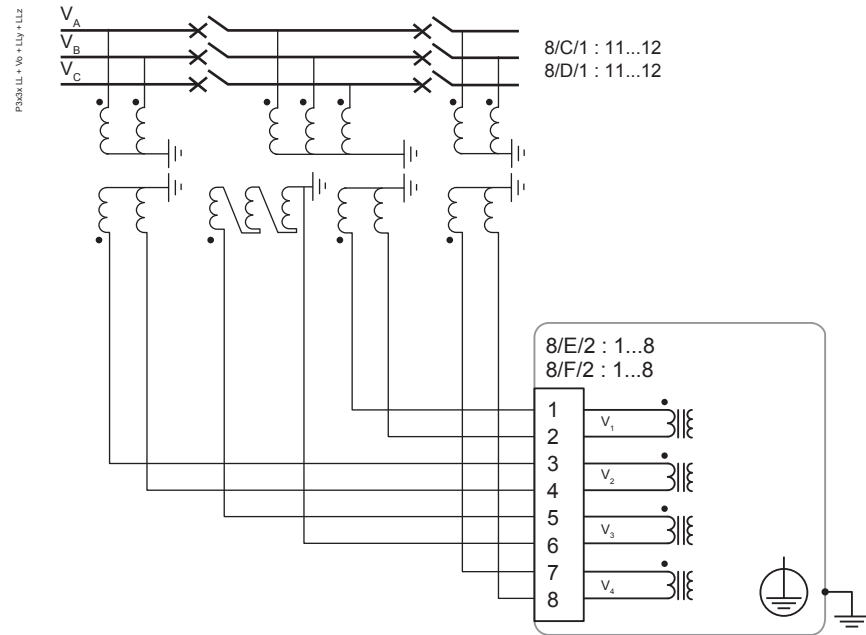
**Failure to follow this instruction will result in death or serious injury.**

**LL+V<sub>N</sub>+LLy+LLz**

This scheme has two CBs to be synchronized. The left side of the bus bar has line-to-line and the right side line-to-line connection for synchrocheck's reference voltages. In the middle, the system voltages are measured by phase-to-neutral and open delta connection.

- Voltages measured by VTs:  $V_{AB}$ ,  $V_N$ ,  $V_{ABy}$ ,  $V_{ABz}$
- Values calculated:  $V_A$ ,  $V_B$ ,  $V_C$ ,  $f$
- Measurements available: -
- Protection functions not available: ANSI 67, ANSI 78PS

Figure 246 - LL+V<sub>N</sub>+LLy+LLz



**⚠ ⚠ DANGER**

**HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

- Always connect the polarity of the current transformer (CT) and the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional ground according to the connection diagrams presented in this document.

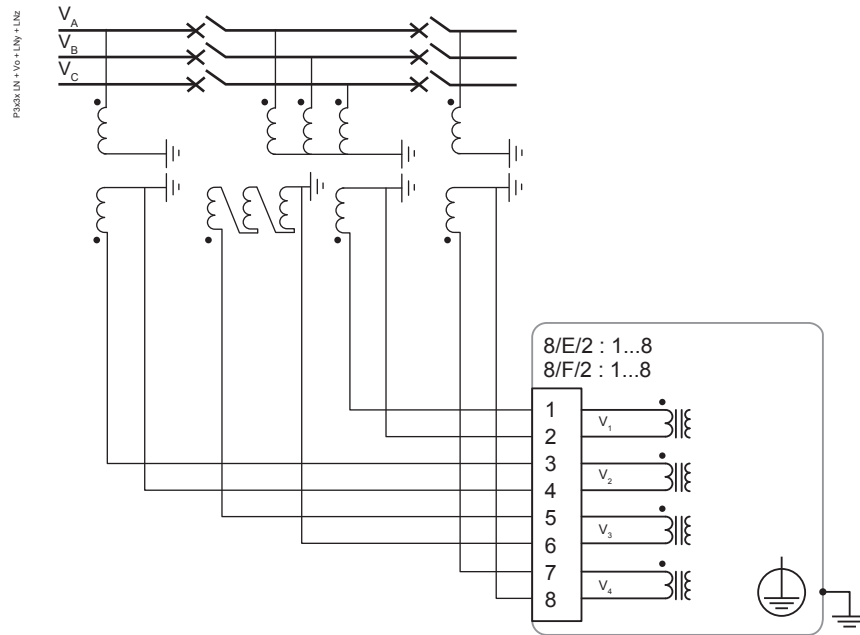
**Failure to follow this instruction will result in death or serious injury.**

**LN+V<sub>N</sub>+LNy+LNz**

This scheme has two CBs to be synchronized. The left and right sides of the bus bar have line-to-neutral connections for synchrocheck's reference voltages. In the middle, system voltages are measured by phase-to-neutral and broken delta connection.

- Voltages measured by VTs:  $V_L, V_N, V_{Ly}, V_{Lz}$
- Values calculated:  $V_{AB}, V_{BC}, V_{CA}, f$
- Measurements available: -
- Protection functions not available: ANSI 67, ANSI 78PS

Figure 247 - LN+V<sub>N</sub>+LNy+LNz



**⚡ ⚠ DANGER**

**HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

- Always connect the polarity of the current transformer (CT) and the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional ground according to the connection diagrams presented in this document.

**Failure to follow this instruction will result in death or serious injury.**

## 10.9 CSH120 and CSH200 Core balance CTs

### Function

The specifically designed CSH120 and CSH200 core balance CTs are for direct ground fault overcurrent measurement. The difference between CSH120 and CSH200 is the inner diameter.

Because of their low-voltage insulation, they can only be used on cables.

Figure 248 - CSH120 and CSH200 core balance CTs

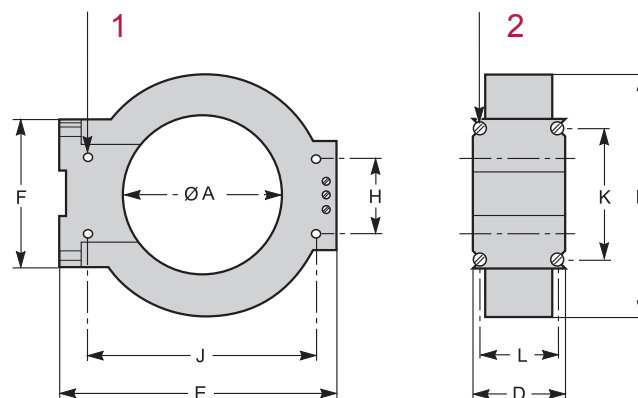


**Characteristics**

	<b>CSH120</b>	<b>CSH200</b>
Inner diameter	120 mm (4.7 in)	200 mm (7.9 in)
Weight	0.6 kg (1.32 lb)	1.4 kg (3.09 lb)
Accuracy	±5% at 20°C (68°F) ±6% max. from -25°C to 70°C (-13°F to +158°F)	
Transformation ratio	1/470	
Maximum permissible current	20 kA - 1 s	
Operating temperature	-25°C to +70°C (-13°F to +158°F)	
Storage temperature	-40°C to +85°C (-40°F to +185°F)	

**Dimensions**

Figure 249 - Dimensions



(1): 4 horizontal mounting holes Ø 6

(2): 4 vertical mounting holes Ø 6

Dimensions	A	B	D	E	F	H	J	K	L
CSH120 (in)	120 (4.75)	164 (6.46)	44 (1.73)	190 (7.48)	80 (3.14)	40 (1.57)	166 (6.54)	65 (2.56)	35 (1.38)
CSH200 (in)	196 (7.72)	256 (10.1)	46 (1.81)	274 (10.8)	120 (4.72)	60 (2.36)	254 (10)	104 (4.09)	37 (1.46)

**⚠️ DANGER**

**HAZARD OF ELECTRIC SHOCK, ELECTRIC ARC OR BURNS**

- Only qualified personnel should install this equipment. Such work should be performed only after reading this entire set of instructions and checking the technical characteristics of the device.
- NEVER work alone.
- Turn off all power supplying this equipment before working on or inside it. Consider all sources of power, including the possibility of backfeeding.
- Always use a properly rated voltage sensing device to confirm that all power is off.
- Only CSH120 and CSH200 core balance CTs can be used for direct ground fault overcurrent measurement.
- Install the core balance CTs on insulated cables.
- Cables with a rated voltage of more than 1000 V must also have an grounded shielding.

**Failure to follow these instructions will result in death or serious injury.**

**Assembly**

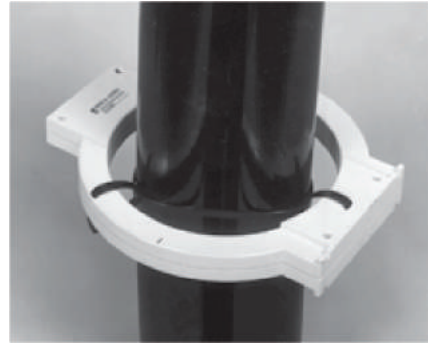
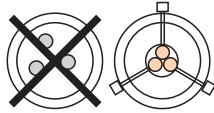
Group the MV cable (or cables) in the middle of the core balance CT.

Use non-conductive binding to hold the cables.

Remember to insert the three medium-voltage cable shielding grounding cables through the core balance CT.

Figure 250 - Assembly on MV cables





## ⚠ CAUTION

### HAZARD OF NON-OPERATION

Connect the secondary circuit and the cable shielding of the CSH core balance CTs to ground in the shortest possible manner according to the connection diagram presented in this document.

**Failure to follow these instructions can result in equipment damage.**

### Connection

Connection to Easergy P3G30 and P3G32

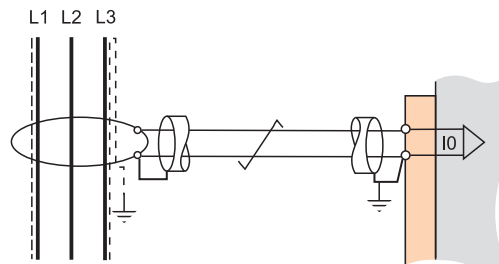
To ground fault current  $I_N$  input, on connector X1, terminals 9 and 10 (shielding).

### Recommended cable

- Sheathed cable, shielded by tinned copper braid
- Minimum cable cross-section  $0.93 \text{ mm}^2$  (AWG 18)
- Resistance per unit length  $< 100 \text{ m}\Omega/\text{m}$  ( $30.5 \text{ m}\Omega/\text{ft}$ )
- Minimum dielectric strength:  $1000 \text{ V}$  ( $700 \text{ Vrms}$ )
- Connect the cable shielding in the shortest manner possible to Easergy P3G30 and P3G32
- Flatten the connection cable against the metal frames of the cubicle.

The connection cable shielding is grounded in Easergy P3G30 and P3G32.

The maximum resistance of the Easergy P3G30 and P3G32 connection wiring must not exceed  $4 \Omega$  (i.e. 20 m maximum for  $100 \text{ m}\Omega/\text{m}$  or 66 ft maximum for  $30.5 \text{ m}\Omega/\text{ft}$ ).



# 11 Test and environmental conditions

## 11.1 Disturbance tests

Table 159 - Disturbance tests

Test	Standard & Test class / level	Test value
<b>Emission</b>	<b>IEC/EN 60255-26 (ed3)</b>	
Conducted	Class A / CISPR 22	0.15–30 MHz
Emitted	Class A / CISPR 11	30–1000 MHz
<b>Immunity</b>	<b>IEC/EN 60255-26 (ed3)</b>	
Slow damped oscillatory wave 1 MHz	IEC/EN 61000-4-18 IEEE C37.90.1	±2.5kVp CM ±2.5kVp DM
Fast damped oscillatory wave 3 MHz, 10 MHz and 30 MHz	IEC/EN 61000-4-18	±2.5kVp CM
Static discharge (ESD)	IEC/EN 61000-4-2 Level 4	±8 kV contact ±15 kV air
Emitted HF field	IEC/EN 61000-4-3 Level 3 IEEE C37.90.2	80–2700 MHz, 10 V/m 80–1000 MHz, 20 V/m
Fast transients (EFT)	IEC/EN 61000-4-4 Level 4 IEEE C37.90.1	±4 kV, 5/50 ns, 5 kHz
Surge	IEC/EN 61000-4-5 Level 4	±4 kV, 1.2/50 µs, CM ±2 kV, 1.2/50 µs, DM
Conducted HF field	IEC/EN 61000-4-6 Level 3	0.15–80 MHz, 10 Vrms
Power-frequency magnetic field	IEC/EN 61000-4-8	300 A/m (continuous) 1000 A/m 1–3 s
Pulse magnetic field	IEC/EN 61000-4-9 Level 5	1000 A/m, 1.2/50 µs

Test	Standard & Test class / level	Test value
ac and dc voltage dips	IEC/EN 61000-4-29, IEC/EN 61000-4-11	0% of rated voltage - Criteria A <ul style="list-style-type: none"> <li>ac: <math>\geq 0.5</math> cycle</li> <li>dc: <math>\geq 10</math> ms</li> </ul>
		40% of rated voltage - Criteria C <ul style="list-style-type: none"> <li>ac: 10 cycles</li> <li>dc: 200 ms</li> </ul>
		70% of rated voltage - Criteria C <ul style="list-style-type: none"> <li>ac: 25 cycles</li> <li>dc: 500 ms</li> </ul>
ac and dc voltage interruptions	IEC/EN 61000-4-29, IEC/EN 61000-4-11	100% interruption - Criteria C <ul style="list-style-type: none"> <li>ac: 250 cycles</li> <li>dc: 5 s</li> </ul>
Voltage alternative component	IEC/EN 61000-4-17	15% of operating voltage (dc) / 10 min

## 11.2 Electrical safety tests

Table 160 - Electrical safety tests

Test	Standard & Test class / level	Test value
Impulse voltage withstand	IEC/EN 60255-27, Class III	5 kV, 1.2/50 $\mu$ s, 0.5 J 1 kV, 1.2/50 $\mu$ s, 0.5 J Communication
Dielectric test	IEC/EN 60255-27, Class III	2 kV, 50 Hz 0.5 kV, 50 Hz Communication
Insulation resistance	IEC/EN 60255-27	> 100 M $\Omega$ at 500 Vdc using only electronic/brushless insulation tester
Protective bonding resistance	IEC/EN 60255-27	shall not exceed 0,1 $\Omega$
Clearance and creepage distance	Design criteria for distances as per IEC 60255-27 Annex C (pollution degree 2, overvoltage category 3)	
Burden	IEC 60255-1	
Contact performance	IEC 60255-1	

## 11.3 Mechanical tests

Table 161 - Mechanical tests

Test	Standard & Test class / level	Test value
<b>Device in operation</b>		
Vibrations	IEC 60255-21-1, Class II / IEC 60068-2-6, Fc	1 Gn, 10 Hz – 150 Hz
Shocks	IEC 60255-21-2, Class II / IEC 60068-2-27, Ea	10 Gn / 11 ms
Seismic	IEC 60255-21-3 Method A, Class II	2 G horizontal / 1 G vertical , 1–35 Hz
<b>Device de-energized</b>		
Vibrations	IEC 60255-21-1, Class II / IEC 60068-2-6, Fc	2 Gn, 10 Hz – 150 Hz
Shocks	IEC 60255-21-2, Class II / IEC 60068-2-27, Ea	30 Gn / 11 ms
Bump	IEC 60255-21-2, Class II / IEC 60068-2-27, Ea	20 Gn / 16 ms

## 11.4 Environmental tests

Table 162 - Environmental tests

Test	Standard & Test class / level	Test value
<b>Device in operation</b>		
Dry heat	EN / IEC 60068-2-2, Bd	70°C (158°F)
Cold	EN / IEC 60068-2-1, Ad	-40°C (-40°F)
Damp heat, cyclic	EN / IEC 60068-2-30, Db	From 25°C (77°F) to 55°C (131°F) From 93% RH to 98% RH Testing duration: 6 days
Damp heat, static	EN / IEC 60068-2-78, Cab	40°C (104°F) 93% RH Testing duration: 10 days
Change of temperature	IEC / EN 60068-2-14, Nb	Lower temp -40°C Upper temp 70°C 5 cycles
Flowing mixed gas corrosion test, method 1	IEC 60068-2-60, Ke	25° C (77° F), 75 % RH 21 days 100 ppb H2S, 500 ppb SO2

Test	Standard & Test class / level	Test value
Flowing mixed gas corrosion test, method 4	IEC 60068-2-60, Ke	25° C (77° F), 75 % RH 21 days 10 ppb H <sub>2</sub> S, 200 ppb NO <sub>2</sub> , 10 ppb CL <sub>2</sub> , 200 ppb SO <sub>2</sub>
<b>Device in storage</b>		
Dry heat	EN / IEC 60068-2-2, Bb	70° C (158° F)
Cold	EN / IEC 60068-2-1, Ab	-40° C (-40° F)

## 11.5 Environmental conditions

Table 163 - Environmental conditions

Condition	Value
Ambient temperature, in-service <sup>88 89 90</sup>	-40 – 60° C (-40 – 140° F) <sup>91</sup>
Ambient temperature, storage	-40 – 70° C (-40 – 158° F)
Relative air humidity	< 95%, no condensation allowed
Maximum operating altitude	2000 m (6561.68 ft)

<sup>88</sup> The display contrast is affected by ambient temperatures below -25° C (-13° F).

<sup>89</sup> After a cold start, in temperatures below -30° C (-22° F), allow the relay to stabilize for a few minutes to achieve the specified accuracy.

<sup>90</sup> 55° C Max ambient temperature according to UL 508

<sup>91</sup> Recommended values with VYX 695 projection mounting frame:


- device with 1 x raising frame → maximum ambient temperature 55° C
- device with 2 x raising frame → maximum ambient temperature 50° C

## 11.6 Casing

Table 164 - Casing

Parameter	Value
Degree of protection (IEC 60529)	IP54 Front panel, IP20 rear side
Dimensions (W x H x D)	270 x 176 x 230 mm / 10.63 x 6.93 x 9.06 in
Weight	4.2 kg (9.272 lb) or higher (depends of options)

## 12 Maintenance

** DANGER**

**HAZARD OF ELECTRIC SHOCK, EXPLOSION, OR ARC FLASH**

- Wear your personal protective equipment (PPE) and comply with the safe electrical work practices. For clothing, see applicable local standards.
- Only qualified personnel should install this equipment. Such work should be performed only after reading this entire set of instructions and checking the technical characteristics of the device.
- NEVER work alone.
- Turn off all power supplying this equipment before working on or inside it. Consider all sources of power, including the possibility of backfeeding.
- Always use a properly rated voltage sensing device to ensure that all power is off.
- Do not open the secondary circuit of a live current transformer.
- Always connect the polarity of the current transformer (CT) and the voltage transformer (VT) and their secondary ground wiring according to the connection diagrams presented in this document.
- Connect the relay's protective ground to functional ground according to the connection diagrams presented in this document.

**Failure to follow this instruction will result in death or serious injury.**

The Easergy P3 protection relays and arc flash detection products together with their extension units, communication accessories, arc flash detection sensors and cabling, later called “device”, require maintenance in work according to their specification. Keep a record of the maintenance actions. The maintenance can include, but is not limited to:

- preventive maintenance
- periodic testing
- hardware cleaning
- system status messages
- spare parts
- self-supervision

### 12.1 Preventive maintenance

Check the device visually when the switch gear is de-energized. During the inspection, pay attention to:

- dirty components
- loose wire connections
- damaged wiring
- indicator lights
- other mechanical connections

Perform visual inspection every three (3) years minimum.

#### **Related topics**

[Testing the LEDs and LCD screen](#) on page 36

## 12.2 Periodic testing

Test the device periodically according to the end user's safety instructions and national safety instructions or law. Carry out functional testing every five (5) years minimum.

Conduct the testing with a secondary injection principle for the protection stages used in the device and its extension units.

In corrosive or offshore environments, carry out functional testing every three (3) years. For the testing procedures, see separate testing manuals.

## 12.3 Hardware cleaning

Special attention must be paid that the device do not become dirty. If cleaning is required, wipe out dirt from the units.

## 12.4 System status messages

If the device's self checking detects an unintended system status, it will in most cases provide an alarm by activating the service LED and indication status notification on the LCD screen. If this happens, store the possible message and contact your local representative for further guidance.

## 12.5 Spare parts

Use an entire unit as a spare part for the device to be replaced. Always store spare parts in storage areas that meet the requirements stated in the user documentation.

## 12.6 Self-supervision

### **NOTICE**

#### **LOSS OF PROTECTION OR RISK OF NUISANCE TRIPPING**

- If the relay is no longer supplied with power or is in permanent fault state, the protection functions are no longer active and all the Easergy P3 digital outputs are dropped out.
- Check that the operating mode and SF relay wiring are compatible with the installation.

**Failure to follow these instructions can result in equipment damage and unwanted shutdown of the electrical installation.**

#### **Description**

The electronic parts and the associated circuitry as well as the program execution are supervised by means of a separate watchdog circuit. Besides supervising the device, the watchdog circuit attempts to restart the microcontroller in an

inoperable situation. If the microcontroller does not restart, the watchdog issues a self-supervision signal indicating a permanent internal condition.

When the watchdog circuit detects a permanent fault, it always blocks any control of other digital outputs (except for the self-supervision SF output). In addition, the internal supply voltages are supervised. Should the auxiliary supply of the device disappear, an indication is automatically given because the device status inoperative (SF) output functions on a working current principle. This means that the SF relay is energized, the 1/C/1:5–7 (or 1/D/1:5-7) contact closed, when the auxiliary supply is on and the Easergy P3G30 and P3G32 device is fully operational.

In addition to the dedicated self-supervision function, the protection relay has several alarm signals that can be connected to outputs through the output matrix. The alarms include:

- remote communication inactive
- extension I/O communication inactive
- communication Port 1 down
- communication Port 2 down
- selfdiag 1, 2 or 3 alarm
- password open

**NOTE:** SF output is referenced as "service status output" in the setting tool.

To get self-supervision alarms to SF output contact, they must be linked in the DIAGNOSIS setting view's section SELFDIAG SIGNAL CONFIGURATION. Required alarms are first linked to a Selfdiag1, Selfdiag2 or Selfdiag3 group ([Figure 251 - Selfdiag alarm signal configuration on page 389](#)).



Figure 251 - Selfdiag alarm signal configuration

SELFDIAG SIGNAL CONFIGURATION	
SecPulse	Selfdiag1
Relays	Selfdiag1
E2PROM	Selfdiag1
Stack usage	Selfdiag1
Memory check	Selfdiag1
Background task	Selfdiag1
Parameter range check	Selfdiag1
CPU load	Selfdiag1
Internal voltage +	Selfdiag1
Low auxiliary voltage	Selfdiag1
Internal temperature	Selfdiag1
ADC check 1	Selfdiag1
COM buffer	Selfdiag1
Slot card	Selfdiag1
Order code	Selfdiag1
FPGA version	Selfdiag2
FPGA configuration	Selfdiag2
Arc sensor	Selfdiag2
BI	Selfdiag2

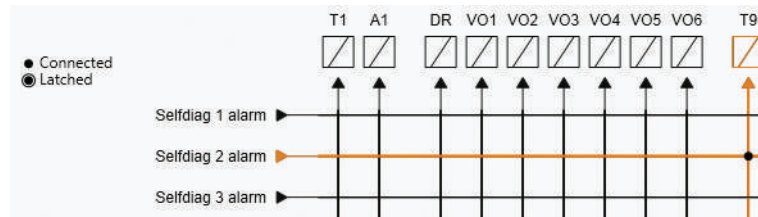
Having the Seldiag alarm grouping made, the appropriate alarms can be assigned to SF relay. By default, selfdiag alarm 2 is linked to SF relay ([Figure 252 - Linking Selfdiag alarm 1-3 to SF relay on page 389](#)). The function of this default setup is the same as in the older systems where this configuration was not possible.

Figure 252 - Linking Selfdiag alarm 1-3 to SF relay

Link selfdiag 1 to SF relay	<input type="checkbox"/>
Link selfdiag 2 to SF relay	<input checked="" type="checkbox"/>
Link selfdiag 3 to SF relay	<input type="checkbox"/>

It is possible to choose what selfdiag alarms 1-3 do when activated. This option can be done through the output matrix ([Figure 253 - Selecting selfdiag 1-3 actions. The number of outputs varies depending on the device and order code on page 390](#)). This allows you to categorize and prioritize actions for each selfdiag alarms individually. For example, in this configuration, selfdiag alarm 2 activates T9.

Figure 253 - Selecting selfdiag 1-3 actions. The number of outputs varies depending on the device and order code



## 12.6.1 Diagnostics

The device runs self-diagnostic tests for hardware and software in boot sequence and also performs runtime checking.

### Permanent inoperative state

If a permanent inoperative state has been detected, the device releases an SF relay contact and the service LED is set on. The local panel also displays a detected fault message. The permanent inoperative state is entered when the device is not able to handle main functions.

### Temporal inoperative state

When the self-diagnostic function detects a temporal inoperative state, a Selfdiag matrix signal is set and an event (E56) is generated. If the inoperative state was only temporary, an off event is generated (E57). The self-diagnostic state can be reset via the front panel.

### Diagnostic registers

There are four 16-bit diagnostic registers which are readable through remote protocols.

Table 165 - Readable registers through remote communication protocols

Register	Bit	Code	Description
SelfDiag1	0 (LSB)	(Reserved)	(Reserved)
	1	(Reserved)	(Reserved)
	2	T1	Detected digital output fault
	3	T2	
	4	T3	
	5	T4	
	6	T5	
	7	T6	

Register	Bit	Code	Description
	8	T7	
	9	T8	
	10	A1	
	11	A2	
	12	A3	
	13	A4	
	14	A5	
	15	T9	
SelfDiag2	0 (LSB)	T10	Detected digital output fault
	1	T11	
	2	T12	
	3	T13	
	4	T14	
	5	T15	
	6	T16	
	7	T17	
	8	T18	
	9	T19	
	10	T20	
	11	T21	
	12	T22	
	13	T23	
	14	T24	
SelfDiag4	0 (LSB)	+12V	Detected internal voltage fault
	1	ComBuff	BUS: detected buffer error
	2	Order Code	Detected order code error
	3	Slot card	Detected option card error
	4	FPGA conf.	Detected FPGA configuration error

Register	Bit	Code	Description
	5	I/O unit	Detected ARC I/O unit error
	6	Arc sensor	Detected faulty arc sensor
	7	QD-card error	Detected QD-card error
	8	BI	Detected ARC BI error
	9	LowAux	Low auxiliary supply voltage

The code is displayed in self-diagnostic events and on the diagnostic menu on the local panel and Easergy Pro.

**NOTE:** All signals are not necessarily available in every Easergy P3 product.

## 12.7 Arc flash detection system maintenance

The device requires maintenance to ensure that it works according to the specification.

**⚠ DANGER**

**HAZARD OF UNEXPECTED SYSTEM OPERATION**

Carry out periodic system testing as per the testing recommendation in this manual or if the protection system scheme has been changed.

**Failure to follow these instructions will result in death or serious injury.**

**⚠ DANGER**

**HAZARD OF UNEXPECTED SYSTEM OPERATION**

- If the arc flash detection unit is no longer supplied with power or is in permanent non-operational state, the protection functions are no longer active and all the output contacts are dropped out.
- To detect a power-off or a permanent fault state, connect the watchdog (SF) output contact to a monitoring device such as SCADA or DCS.

**Failure to follow these instructions will result in death or serious injury.**

Keep record of the maintenance actions performed for the system.

The maintenance can include but is not limited to:

- visual inspection
- periodic testing
- hardware cleaning
- sensor condition and positioning check
- checking the obstruction of sensors

## 12.7.1 Visual inspection

Do visual inspection once every three (3) years minimum.

1. De-energize the switchgear.
2. Inspect the device, sensors and cabling.

Pay attention to:

- possible dirty arc sensors
- loose wire connections
- damaged wiring
- indicator lights (device start-up)
- other mechanical connections

## 12.7.2 Hardware cleaning

Pay special attention to ensure that the device, its extension units and sensors do not become dirty.

### **DANGER**

#### **HAZARD OF UNEXPECTED SYSTEM OPERATION**

- Do not use any type of solvents or gasoline to clean the device, sensors or cables.
- When cleaning the sensor, make sure that the cleaning solution does not contact anything other than the sensor.

**Failure to follow these instructions will result in death or serious injury.**

- If cleaning is required, wipe out dirt from the device.
- Use a dry cleaning cloth or equivalent together with mild soapy water to clean any residues from the light sensor.

## 12.7.3 Sensor condition and positioning check

Always check that the sensor positioning remains as it was originally designed after:

- commissioning
- sensor replacement
- modification procedure
- cleaning
- arc flash fault
- periodic testing

Check for obstruction of the sensors.

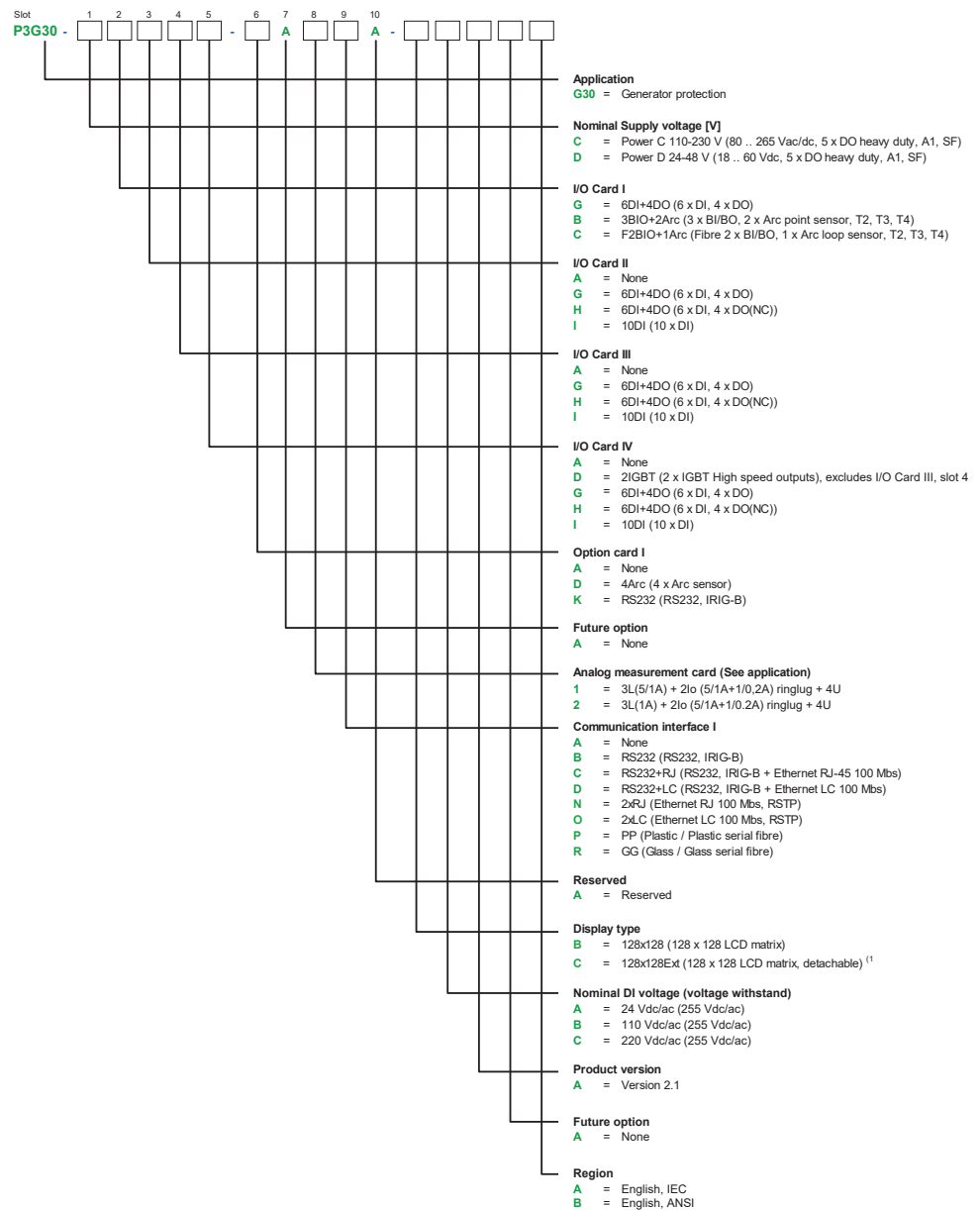
# 13 Order codes and accessories

## 13.1 Order codes

When ordering, state:

- Order code of the relay
- Quantity
- Accessories (see the order codes in section Accessories)

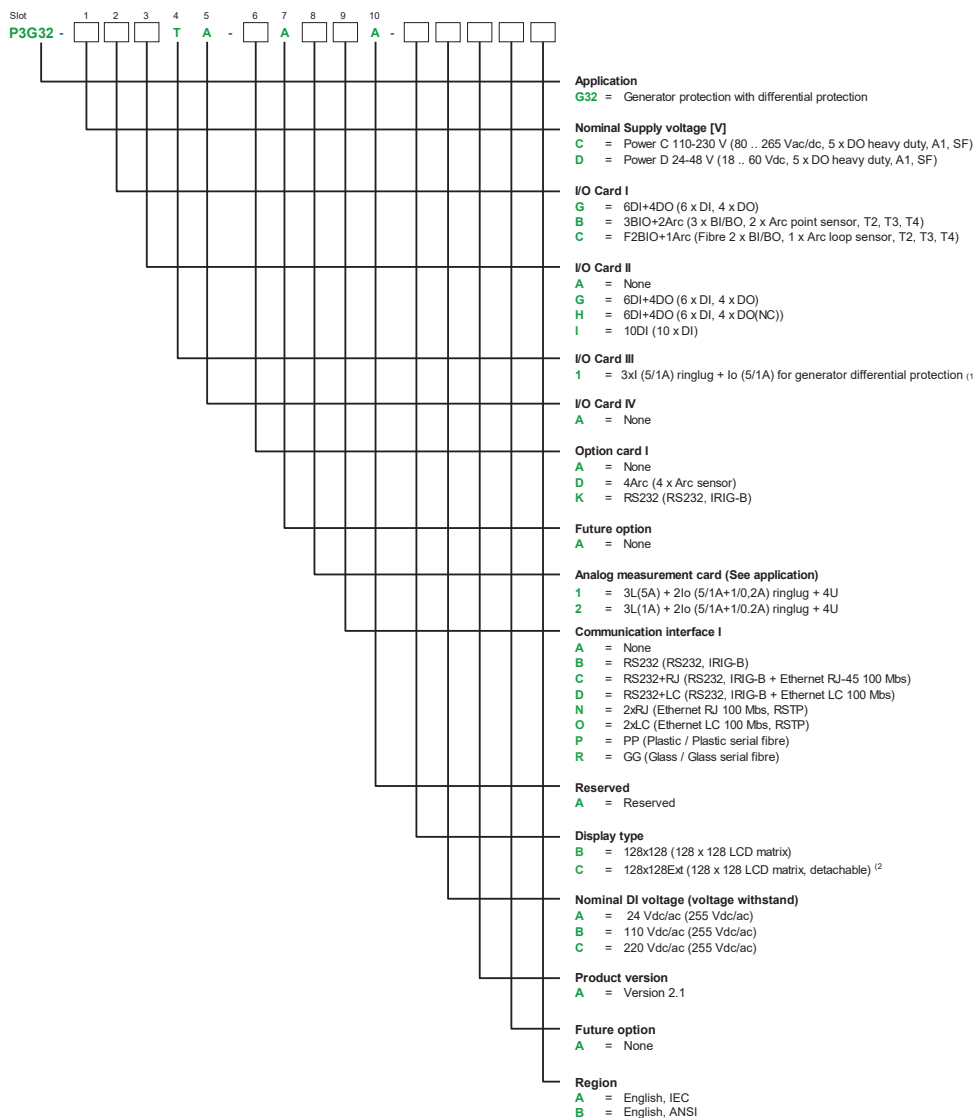
Figure 254 - P3G30 order code



1) By default, the cable length is 2 m (6.56 ft). You can order cables of other length separately: VX001-1 (1 m/3.28 ft), Vx001-3 (3 m/9.84 ft) or VX001-5 (5 m/ 16.40 ft).

**NOTE:** All PCBA cards are conformally coated.

Figure 255 - P3G32 order code



1) If slot 8 = 1 or 2, then slot 4 = 1

2) By default, the cable length is 2 m (6.56 ft). You can order cables of other length separately: VX001-1 (1 m/3.28 ft), Vx001-3 (3 m/9.84 ft) or VX001-5 (5 m/ 16.40 ft).

**NOTE:** All PCBA cards are conformally coated.

## 13.2 Accessories

Table 166 - Easergy P3G30 and P3G32 accessories

Order code	Product Reference	Description
REL52801	VA1DA-20	Arc sensor, 20 m (66 ft)
REL52803	VA1DA-20S	Arc sensor, 20 m (66 ft), shielded
REL52804	VA1DA-6	Arc sensor, 6 m (20 ft) connect cable
REL52806	VA1DA-6S	Arc sensor, 6 m (20 ft), shielded

<b>Order code</b>	<b>Product Reference</b>	<b>Description</b>
REL52807	VA1EH-20	Arc sensor, 20 m (66 ft) pipe sensor
REL52809	VA1EH-6	Arc sensor, 6 m (20 ft) pipe sensor
REL52812	VIO12ABSE	RTD module, 12pcs RTD inputs, RS485
REL52813	VIO12ACSE	RTD module, 12pcs RTD inputs, mA in/out
REL52814	VIO12ADSE	RTD module, 12pcs RTD inputs, mA in/out
REL52815	VPA3CGSE	Profibus interface module
REL52816	VSE001-GGSE	Fiber optic module (Glass - Glass)
REL52819	VSE001-PPSE	Fiber optic module (Plastic - Plastic)
REL52820	VSE002	RS485 module
REL52821	VSE009	DeviceNet module
REL52822	VX052-3	USB programming cable (eSetup Easergy Pro)
REL52823	VX067	P3x split cable for COM1-2&COM3-4 ports
REL52824	VX072	P3x Profibus cable
REL52832	VYX695	Raising frame, P3x, 45 mm (1.8 in)



## 14 Firmware revision

Table 167 - Firmware revisions

FW revision	Changes
<b>Version:</b> 30.201 <b>Release date:</b> January 2020	Cybersecurity improvements: <ul style="list-style-type: none"> <li>• passwords are stored as salted hash</li> <li>• password resetting procedure changed</li> <li>• new user account Administrator added</li> </ul>
<b>Version:</b> 30.111 <b>Release date:</b> October 2019	<ul style="list-style-type: none"> <li>• Improved menu titles for COM ports and Ethernet ports in the <b>Protocol Configuration</b> menu</li> <li>• IEC-61850 speed optimizations</li> <li>• Added IRIG-B support for option 'K' in slot 6</li> <li>• Support for eight (8) controllable objects and protocol parameters for Modbus, IEC 61850, IEC 103, IEC 101, Device Net, Profibus, DNP 3, and SPABus</li> <li>• Modbus:               <ul style="list-style-type: none"> <li>◦ registers to include protection function status</li> <li>◦ added LED status information</li> </ul> </li> </ul>
<b>Version:</b> 30.110 <b>Release date:</b> August 2019	<ul style="list-style-type: none"> <li>• ANSI terminology</li> <li>• Digital inputs 33–36 added to DNP and IEC 101 protocol</li> <li>• Phase-wise cumulative breaking current over IEC 61850</li> <li>• Temperature LN to IEC 61850</li> <li>• Add VI5-20 and VO7-20 added to IEC 103 protocol mapping</li> <li>• EtherNet/IP protocol removed</li> </ul>
<b>Version:</b> 30.109 <b>Release date:</b> March 2019	<ul style="list-style-type: none"> <li>• Arc protection <math>I_{0&gt;int}</math> start setting changed to be relative to CT primary instead of application nominal current.</li> <li>• Unit for start setting of <math>I_{0&gt;int}</math> arc protection changed to "pu".</li> <li>• Negative sequence voltage 47-1, 47-2, and 47-3(ANSI 47) stages added.</li> <li>• Maximum number of disturbance records increased from 12 to 24.</li> <li>• IEC 61850 logical nodes added for digital inputs 32....36.</li> <li>• Digital inputs 33...36 added to IEC 103 protocol.</li> <li>• BIO and IGBT support added to P3x3x models.</li> </ul>

FW revision	Changes
<p><b>Version:</b> 30.108</p> <p><b>Release date:</b> December 2018</p>	<ul style="list-style-type: none"> <li>• Intermittent ground fault (ANSI 67NI) changed: <ul style="list-style-type: none"> <li>◦ New start setting "Sensitive/Normal" and <math>V_N</math> check for trip added</li> </ul> </li> <li>• CB condition monitoring upgraded with opening counts and opening, closing and charging times</li> <li>• Fault locator enhanced to allow multiple line segments.</li> <li>• LED matrix in P3x3x enhanced: <ul style="list-style-type: none"> <li>◦ LEDs can now be configured more flexibly.</li> <li>◦ It is now possible to select for each individual LED whether it should be blinking, latched, or non-volatile (keep its state over reboot).</li> <li>◦ Each LED also has a configurable description, one for green colour and another for red.</li> </ul> </li> <li>• COMTRADE files can be read over Modbus.</li> <li>• Product and vendor data changed to Schneider Electric in EDS file. This change affects CIP protocols: DeviceNet and EtherNet/IP.</li> <li>• Pole slip protection (ANSI 78) added for P30G and P3G32.</li> <li>• New CBFP functions added: "CBFP1" and "CBFP2".</li> <li>• Restricted ground fault protection (ANSI 64REF) for P3T32 and P3G32.</li> <li>• Faulty phase detection added for ANSI 67N (<math>I_0Dir</math>) stage.</li> <li>• Ethernet's redundancy protocols are now in separate menus.</li> </ul>
<p><b>Version:</b> 30.106</p> <p><b>Release date:</b> 16.5.2018</p>	<ul style="list-style-type: none"> <li>• The setting "Inv. time coefficient k" in stages 50/51-1, 67N-1, 67N-2, 50N/51N-1, 67N-1, 67N-2, 67N-3 has three decimals instead of two and the minimum value for the ground fault overcurrent was changed from 0.05 to 0.025.</li> <li>• Communication protocol updates</li> </ul>
<p><b>Version:</b> 30.104</p> <p><b>Release date:</b> 2.10.2017</p>	<p>First release</p>



## Schneider Electric

35 rue Joseph Monier  
92500 Rueil Malmaison - France  
Phone: +33 (0) 1 41 29 70 00  
[www.schneider-electric.com](http://www.schneider-electric.com)

As standards, specifications, and designs change from time to time,  
please ask for confirmation of the information given in this publication.

© 2020 Schneider Electric All Rights Reserved.

P3G/en M/F006 — 02/2020