Relion® 670 SERIES

Generator protection REG670
Version 2.2 ANSI
Application manual
Copyright

This document and parts thereof must not be reproduced or copied without written permission from ABB, and the contents thereof must not be imparted to a third party, nor used for any unauthorized purpose.

The software and hardware described in this document is furnished under a license and may be used or disclosed only in accordance with the terms of such license.

This product includes software developed by the OpenSSL Project for use in the OpenSSL Toolkit. (http://www.openssl.org/) This product includes cryptographic software written/developed by: Eric Young (eay@cryptsoft.com) and Tim Hudson (tjh@cryptsoft.com).

Trademarks

ABB and Relion are registered trademarks of the ABB Group. All other brand or product names mentioned in this document may be trademarks or registered trademarks of their respective holders.

Warranty

Please inquire about the terms of warranty from your nearest ABB representative.
Disclaimer

The data, examples and diagrams in this manual are included solely for the concept or product description and are not to be deemed as a statement of guaranteed properties. All persons responsible for applying the equipment addressed in this manual must satisfy themselves that each intended application is suitable and acceptable, including that any applicable safety or other operational requirements are complied with. In particular, any risks in applications where a system failure and/or product failure would create a risk for harm to property or persons (including but not limited to personal injuries or death) shall be the sole responsibility of the person or entity applying the equipment, and those so responsible are hereby requested to ensure that all measures are taken to exclude or mitigate such risks.

This document has been carefully checked by ABB but deviations cannot be completely ruled out. In case any errors are detected, the reader is kindly requested to notify the manufacturer. Other than under explicit contractual commitments, in no event shall ABB be responsible or liable for any loss or damage resulting from the use of this manual or the application of the equipment.
Conformity

This product complies with the directive of the Council of the European Communities on the approximation of the laws of the Member States relating to electromagnetic compatibility (EMC Directive 2004/108/EC) and concerning electrical equipment for use within specified voltage limits (Low-voltage directive 2006/95/EC). This conformity is the result of tests conducted by ABB in accordance with the product standard EN 60255-26 for the EMC directive, and with the product standards EN 60255-1 and EN 60255-27 for the low voltage directive. The product is designed in accordance with the international standards of the IEC 60255 series and ANSI C37.90. The DNP protocol implementation in the IED conforms to "DNP3 Intelligent Electronic Device (IED) Certification Procedure Subset Level 2", available at www.dnp.org.
# Table of contents

## Section 1 Introduction
- 1.1 This manual ........................................... 23
- 1.2 Intended audience ..................................... 23
- 1.3 Product documentation .............................. 24
- 1.3.1 Product documentation set ....................... 24
- 1.3.2 Document revision history ....................... 25
- 1.3.3 Related documents .................................. 26
- 1.4 Document symbols and conventions ............. 26
- 1.4.1 Symbols ............................................... 26
- 1.4.2 Document conventions ........................... 27
- 1.5 IEC 61850 edition 1 / edition 2 mapping ...... 27

## Section 2 Application
- 2.1 General IED application ............................. 37
- 2.2 Main protection functions ............................ 44
- 2.3 Back-up protection functions ....................... 45
- 2.4 Control and monitoring functions ................. 47
- 2.5 Communication ........................................ 53
- 2.6 Basic IED functions .................................... 55

## Section 3 Configuration
- 3.1 Description of REG670 ......................... 57
- 3.1.1 Introduction ........................................ 57
- 3.1.1.1 Description of configuration A20 .......... 57
- 3.1.1.2 Description of configuration B30 .......... 58
- 3.1.1.3 Description of configuration C30 .......... 61

## Section 4 Analog inputs
- 4.1 Introduction ........................................... 63
- 4.2 Setting guidelines ..................................... 63
- 4.2.1 Setting of the phase reference channel ....... 63
- 4.2.1.1 Example .......................................... 64
- 4.2.2 Setting of current channels ...................... 64
- 4.2.2.1 Example 1 ........................................ 64
- 4.2.2.2 Example 2 ........................................ 65
- 4.2.2.3 Example 3 ........................................ 65
- 4.2.2.4 Examples on how to connect, configure and set CT inputs for most commonly used CT connections .... 69
- 4.2.2.5 Example on how to connect a wye connected three-phase CT set to the IED .... 70
4.2.6 Example how to connect delta connected three-phase CT set to the IED.............. 74
4.2.7 Example how to connect single-phase CT to the IED............................................... 76
4.2.3 Relationships between setting parameter Base Current, CT rated primary current and minimum pickup of a protection IED.............................................................. 77
4.2.4 Setting of voltage channels............................................................................................. 78
4.2.4.1 Example....................................................................................................................... 78
4.2.4.2 Examples how to connect, configure and set VT inputs for most commonly used VT connections........................................................................................................... 78
4.2.4.3 Examples on how to connect a three phase-to-ground connected VT to the IED.... 79
4.2.4.4 Example on how to connect a phase-to-phase connected VT to the IED................. 81
4.2.4.5 Example on how to connect an open delta VT to the IED for high impedance grounded or ungrounded networks...................................................................................... 83
4.2.4.6 Example how to connect the open delta VT to the IED for low impedance grounded or solidly grounded power systems............................................................................... 85
4.2.4.7 Example on how to connect a neutral point VT to the IED........................................... 88

Section 5 Local HMI............................................................................................................. 91
5.1 Display............................................................................................................................... 92
5.2 LEDs.................................................................................................................................. 93
5.3 Keypad.............................................................................................................................. 94
5.4 Local HMI functionality.................................................................................................... 96
5.4.1 Protection and alarm indication..................................................................................... 96
5.4.2 Parameter management ............................................................................................... 97
5.4.3 Front communication.................................................................................................... 98

Section 6 Wide area measurement system........................................................................... 99
6.1 C37.118 Phasor Measurement Data Streaming Protocol Configuration PMUCONF...... 99
6.1.1 Identification.................................................................................................................. 99
6.1.2 Application.................................................................................................................... 99
6.1.3 Operation principle....................................................................................................... 99
6.1.3.1 Short guidance for use of TCP.................................................................................... 100
6.1.3.2 Short guidance for use of UDP................................................................................... 101
6.2 Protocol reporting via IEEE 1344 and C37.118 PMUREPORT..................................... 102
6.2.1 Identification................................................................................................................ 102
6.2.2 Application.................................................................................................................. 103
6.2.3 Operation principle..................................................................................................... 105
6.2.3.1 Frequency reporting.................................................................................................. 106
6.2.3.2 Reporting filters....................................................................................................... 107
6.2.3.3 Scaling Factors for ANALOGREPORT channels..................................................... 108
6.2.3.4 PMU Report Function Blocks Connection Rules in PCM600 Application Configuration Tool (ACT)............................................................................................. 110
6.2.4 Setting guidelines....................................................................................................... 115

Section 7 Differential protection........................................................................................... 119
Table of contents

Section 8 Impedance protection ..................................................................................... 171

8.1 Full-scheme distance measuring, Mho characteristic ZMHPDIS (21) ....................... 171
8.1.1 Identification ................................................................................................................................. 171
8.1.2 Application ...................................................................................................................................... 171
8.1.2.1 Generator underimpedance protection application ......................................................... 171
8.1.3 Setting guidelines ........................................................................................................................... 171
8.1.3.1 Configuration ............................................................................................................................ 171
8.1.3.2 Settings ...................................................................................................................................... 172
8.2 High speed distance protection ZMFPDIS (21) ................................................................. 175
8.2.1 Identification ................................................................................................................................. 175
8.2.2 Application ..................................................................................................................................... 176
8.2.2.1 System grounding ................................................................................................................... 176
8.2.2.2 Fault infeed from remote end ............................................................................................... 179
8.2.2.3 Load encroachment ............................................................................................................... 180
8.2.2.4 Short line application ............................................................................................................. 180
8.2.2.5 Long transmission line application ...................................................................................... 181
8.2.2.6 Parallel line application with mutual coupling ................................................................. 181
8.2.2.7 Tapped line application ........................................................................................................... 188
8.2.3 Setting guidelines ......................................................................................................................... 190
8.2.3.1 General ...................................................................................................................................... 190
8.2.3.2 Setting of zone 1 ....................................................................................................................... 190
8.2.3.3 Setting of overreaching zone ............................................................................................... 190
8.2.3.4 Setting of reverse zone ........................................................................................................... 191
8.2.3.5 Setting of zones for parallel line application ....................................................................... 192
8.2.3.6 Setting the reach with respect to load .................................................................................. 193
8.2.3.7 Zone reach setting lower than minimum load impedance .................................................. 194
8.2.3.8 Zone reach setting higher than minimum load impedance .................................................. 195
8.2.3.9 Other settings .......................................................................................................................... 196
8.2.3.10 ZMMMXU settings ................................................................................................................... 199
8.3 High speed distance protection for series compensated lines ZMFCPDIS (21) ...... 200
8.3.1 Identification ................................................................................................................................. 200
<table>
<thead>
<tr>
<th>Section</th>
<th>Title</th>
<th>Pages</th>
</tr>
</thead>
<tbody>
<tr>
<td>8.3.2</td>
<td>Application</td>
<td>200</td>
</tr>
<tr>
<td>8.3.2.1</td>
<td>System grounding</td>
<td>200</td>
</tr>
<tr>
<td>8.3.2.2</td>
<td>Fault infeed from remote end</td>
<td>202</td>
</tr>
<tr>
<td>8.3.2.3</td>
<td>Load encroachment</td>
<td>203</td>
</tr>
<tr>
<td>8.3.2.4</td>
<td>Short line application</td>
<td>204</td>
</tr>
<tr>
<td>8.3.2.5</td>
<td>Long transmission line application</td>
<td>205</td>
</tr>
<tr>
<td>8.3.2.6</td>
<td>Parallel line application with mutual coupling</td>
<td>205</td>
</tr>
<tr>
<td>8.3.2.7</td>
<td>Tapped line application</td>
<td>212</td>
</tr>
<tr>
<td>8.3.3</td>
<td>Series compensation in power systems</td>
<td>214</td>
</tr>
<tr>
<td>8.3.3.1</td>
<td>Steady state voltage regulation and increase of voltage collapse limit</td>
<td>214</td>
</tr>
<tr>
<td>8.3.3.2</td>
<td>Increase in power transfer</td>
<td>215</td>
</tr>
<tr>
<td>8.3.3.3</td>
<td>Voltage and current inversion</td>
<td>216</td>
</tr>
<tr>
<td>8.3.3.4</td>
<td>Impact of series compensation on protective IED of adjacent lines</td>
<td>223</td>
</tr>
<tr>
<td>8.3.3.5</td>
<td>Distance protection</td>
<td>225</td>
</tr>
<tr>
<td>8.3.3.6</td>
<td>Underreaching and overreaching schemes</td>
<td>225</td>
</tr>
<tr>
<td>8.3.4</td>
<td>Setting guidelines</td>
<td>231</td>
</tr>
<tr>
<td>8.3.4.1</td>
<td>General</td>
<td>231</td>
</tr>
<tr>
<td>8.3.4.2</td>
<td>Setting of zone 1</td>
<td>231</td>
</tr>
<tr>
<td>8.3.4.3</td>
<td>Setting of overreaching zone</td>
<td>232</td>
</tr>
<tr>
<td>8.3.4.4</td>
<td>Setting of reverse zone</td>
<td>232</td>
</tr>
<tr>
<td>8.3.4.5</td>
<td>Series compensated and adjacent lines</td>
<td>233</td>
</tr>
<tr>
<td>8.3.4.6</td>
<td>Setting of zones for parallel line application</td>
<td>237</td>
</tr>
<tr>
<td>8.3.4.7</td>
<td>Setting of reach in resistive direction</td>
<td>238</td>
</tr>
<tr>
<td>8.3.4.8</td>
<td>Load impedance limitation, without load encroachment function</td>
<td>239</td>
</tr>
<tr>
<td>8.3.4.9</td>
<td>Zone reach setting higher than minimum load impedance</td>
<td>240</td>
</tr>
<tr>
<td>8.3.4.10</td>
<td>Parameter setting guidelines</td>
<td>241</td>
</tr>
<tr>
<td>8.3.4.11</td>
<td>ZMMMXU settings</td>
<td>243</td>
</tr>
<tr>
<td>8.4</td>
<td>Pole slip protection PSPPAM (78)</td>
<td>244</td>
</tr>
<tr>
<td>8.4.1</td>
<td>Identification</td>
<td>244</td>
</tr>
<tr>
<td>8.4.2</td>
<td>Application</td>
<td>244</td>
</tr>
<tr>
<td>8.4.3</td>
<td>Setting guidelines</td>
<td>247</td>
</tr>
<tr>
<td>8.4.3.1</td>
<td>Setting example for line application</td>
<td>248</td>
</tr>
<tr>
<td>8.4.3.2</td>
<td>Setting example for generator application</td>
<td>252</td>
</tr>
<tr>
<td>8.5</td>
<td>Out-of-step protection OOSPPAM (78)</td>
<td>256</td>
</tr>
<tr>
<td>8.5.1</td>
<td>Identification</td>
<td>256</td>
</tr>
<tr>
<td>8.5.2</td>
<td>Application</td>
<td>256</td>
</tr>
<tr>
<td>8.5.3</td>
<td>Setting guidelines</td>
<td>259</td>
</tr>
<tr>
<td>8.6</td>
<td>Loss of excitation LEXPDIS(40)</td>
<td>261</td>
</tr>
<tr>
<td>8.6.1</td>
<td>Identification</td>
<td>261</td>
</tr>
<tr>
<td>8.6.2</td>
<td>Application</td>
<td>262</td>
</tr>
<tr>
<td>8.6.3</td>
<td>Setting guidelines</td>
<td>267</td>
</tr>
<tr>
<td>8.7</td>
<td>Sensitive rotor earth fault protection, injection based ROTIPHIZ (64R)</td>
<td>270</td>
</tr>
<tr>
<td>8.7.1</td>
<td>Identification</td>
<td>270</td>
</tr>
</tbody>
</table>
Table of contents

<table>
<thead>
<tr>
<th>Section</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>8.7.2</td>
<td>Application</td>
<td>270</td>
</tr>
<tr>
<td>8.7.2.1</td>
<td>Rotor earth fault protection function</td>
<td>271</td>
</tr>
<tr>
<td>8.7.3</td>
<td>Setting guidelines</td>
<td>273</td>
</tr>
<tr>
<td>8.7.3.1</td>
<td>Setting injection unit REX060</td>
<td>273</td>
</tr>
<tr>
<td>8.7.3.2</td>
<td>Connecting and setting voltage inputs</td>
<td>274</td>
</tr>
<tr>
<td>8.7.3.3</td>
<td>Settings for sensitive rotor earth fault protection, ROTIPHIZ (64R)</td>
<td>276</td>
</tr>
<tr>
<td>8.8</td>
<td>100% stator earth fault protection, injection based STTIPHIZ (64S)</td>
<td>277</td>
</tr>
<tr>
<td>8.8.1</td>
<td>Identification</td>
<td>277</td>
</tr>
<tr>
<td>8.8.2</td>
<td>Application</td>
<td>277</td>
</tr>
<tr>
<td>8.8.2.1</td>
<td>100% Stator earth fault protection function</td>
<td>278</td>
</tr>
<tr>
<td>8.8.3</td>
<td>Setting guidelines</td>
<td>283</td>
</tr>
<tr>
<td>8.8.3.1</td>
<td>Setting injection unit REX060</td>
<td>283</td>
</tr>
<tr>
<td>8.8.3.2</td>
<td>Connecting and setting voltage inputs</td>
<td>284</td>
</tr>
<tr>
<td>8.8.3.3</td>
<td>100% stator earth fault protection</td>
<td>285</td>
</tr>
<tr>
<td>8.9</td>
<td>Under impedance protection for generators and transformers ZGVPDIS</td>
<td>286</td>
</tr>
<tr>
<td>8.9.1</td>
<td>Identification</td>
<td>286</td>
</tr>
<tr>
<td>8.9.2</td>
<td>Application</td>
<td>286</td>
</tr>
<tr>
<td>8.9.2.1</td>
<td>Operating zones</td>
<td>288</td>
</tr>
<tr>
<td>8.9.2.2</td>
<td>Zone 1 operation</td>
<td>289</td>
</tr>
<tr>
<td>8.9.2.3</td>
<td>Zone 2 operation</td>
<td>289</td>
</tr>
<tr>
<td>8.9.2.4</td>
<td>Zone 3 operation</td>
<td>290</td>
</tr>
<tr>
<td>8.9.2.5</td>
<td>CT and VT positions</td>
<td>290</td>
</tr>
<tr>
<td>8.9.2.6</td>
<td>Undervoltage seal-in function</td>
<td>290</td>
</tr>
<tr>
<td>8.9.2.7</td>
<td>Load encroachment for zone 2 and zone 3</td>
<td>291</td>
</tr>
<tr>
<td>8.9.2.8</td>
<td>External block signals</td>
<td>291</td>
</tr>
<tr>
<td>8.9.3</td>
<td>Setting Guidelines</td>
<td>292</td>
</tr>
<tr>
<td>8.9.3.1</td>
<td>General</td>
<td>292</td>
</tr>
<tr>
<td>8.9.3.2</td>
<td>Load encroachment</td>
<td>293</td>
</tr>
<tr>
<td>8.9.3.3</td>
<td>Under voltage seal-in</td>
<td>294</td>
</tr>
<tr>
<td>8.10</td>
<td>Rotor ground fault protection (64R) using CVGAPC</td>
<td>294</td>
</tr>
</tbody>
</table>

Section 9

Current protection........................................................................................................ 297

9.1    Instantaneous phase overcurrent protection PHPIOC (50).................................297
| 9.1.1 | Identification                                                               | 297  |
| 9.1.2 | Application                                                                  | 297  |
| 9.1.3 | Setting guidelines                                                           | 297  |
| 9.1.3.1 | Meshed network without parallel line                                        | 298  |
| 9.1.3.2 | Meshed network with parallel line                                           | 300  |
| 9.2    Directional phase overcurrent protection, four steps OC4PTOC(51_67)......... 301
| 9.2.1 | Identification                                                               | 302  |
| 9.2.2 | Application                                                                  | 302  |
| 9.2.3 | Setting guidelines                                                           | 303  |
| 9.2.3.1 | Settings for each step                                                      | 304  |

© Copyright 2017 ABB. All rights reserved
<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>9.2.3.2 Setting example</td>
<td>307</td>
</tr>
<tr>
<td>9.3 Instantaneous residual overcurrent protection EFPIOC (50N)</td>
<td>312</td>
</tr>
<tr>
<td>9.3.1 Identification</td>
<td>312</td>
</tr>
<tr>
<td>9.3.2 Application</td>
<td>312</td>
</tr>
<tr>
<td>9.3.3 Setting guidelines</td>
<td>312</td>
</tr>
<tr>
<td>9.4 Directional residual overcurrent protection, four steps EF4PTOC (51N/67N)</td>
<td>315</td>
</tr>
<tr>
<td>9.4.1 Identification</td>
<td>315</td>
</tr>
<tr>
<td>9.4.2 Application</td>
<td>315</td>
</tr>
<tr>
<td>9.4.3 Setting guidelines</td>
<td>317</td>
</tr>
<tr>
<td>9.4.3.1 Common settings for all steps</td>
<td>317</td>
</tr>
<tr>
<td>9.4.3.2 2nd harmonic restrain</td>
<td>318</td>
</tr>
<tr>
<td>9.4.3.3 Parallel transformer inrush current logic</td>
<td>319</td>
</tr>
<tr>
<td>9.4.3.4 Switch onto fault logic</td>
<td>319</td>
</tr>
<tr>
<td>9.4.3.5 Settings for each step (x = 1, 2, 3 and 4)</td>
<td>320</td>
</tr>
<tr>
<td>9.4.3.6 Transformer application example</td>
<td>322</td>
</tr>
<tr>
<td>9.5 Four step directional negative phase sequence overcurrent protection NS4PTOC (4 6i2)</td>
<td>326</td>
</tr>
<tr>
<td>9.5.1 Identification</td>
<td>326</td>
</tr>
<tr>
<td>9.5.2 Application</td>
<td>326</td>
</tr>
<tr>
<td>9.5.3 Setting guidelines</td>
<td>327</td>
</tr>
<tr>
<td>9.5.3.1 Settings for each step</td>
<td>327</td>
</tr>
<tr>
<td>9.5.3.2 Common settings for all steps</td>
<td>328</td>
</tr>
<tr>
<td>9.6 Sensitive directional residual overcurrent and power protection SDEPSDE (67N)</td>
<td>330</td>
</tr>
<tr>
<td>9.6.1 Identification</td>
<td>331</td>
</tr>
<tr>
<td>9.6.2 Application</td>
<td>332</td>
</tr>
<tr>
<td>9.6.3 Setting guidelines</td>
<td>333</td>
</tr>
<tr>
<td>9.7 Thermal overload protection, two time constants TRPTTR (49)</td>
<td>331</td>
</tr>
<tr>
<td>9.7.1 Identification</td>
<td>341</td>
</tr>
<tr>
<td>9.7.2 Application</td>
<td>341</td>
</tr>
<tr>
<td>9.7.3 Setting guidelines</td>
<td>342</td>
</tr>
<tr>
<td>9.7.3.1 Setting example</td>
<td>344</td>
</tr>
<tr>
<td>9.8 Breaker failure protection CCRBRF(50BF)</td>
<td>346</td>
</tr>
<tr>
<td>9.8.1 Identification</td>
<td>346</td>
</tr>
<tr>
<td>9.8.2 Application</td>
<td>346</td>
</tr>
<tr>
<td>9.8.3 Setting guidelines</td>
<td>346</td>
</tr>
<tr>
<td>9.9 Pole discrepancy protection CCPDSC(52PD)</td>
<td>354</td>
</tr>
<tr>
<td>9.9.1 Identification</td>
<td>354</td>
</tr>
<tr>
<td>9.9.2 Application</td>
<td>354</td>
</tr>
<tr>
<td>9.9.3 Setting guidelines</td>
<td>355</td>
</tr>
<tr>
<td>9.10 Directional underpower protection GUPPDUP (37)</td>
<td>356</td>
</tr>
<tr>
<td>9.10.1 Identification</td>
<td>356</td>
</tr>
<tr>
<td>9.10.2 Application</td>
<td>356</td>
</tr>
<tr>
<td>9.10.3 Setting guidelines</td>
<td>358</td>
</tr>
</tbody>
</table>
Table of contents

9.11 Directional overpower protection GOPPDOP (32) ................................................................. 361
9.11.1 Identification ............................................................................................................. 361
9.11.2 Application ............................................................................................................... 361
9.11.3 Setting guidelines ................................................................................................. 363
9.12 Negativ sequence time overcurrent protection for machines NS2PTOC (46I2) ............. 366
9.12.1 Identification ......................................................................................................... 366
9.12.2 Application ............................................................................................................. 366
9.12.2.1 Features ............................................................................................................. 367
9.12.2.2 Generator continuous unbalance current capability ........................................ 368
9.12.3 Setting guidelines ................................................................................................. 370
9.12.3.1 Operate time characteristic .............................................................................. 370
9.12.3.2 Pickup sensitivity ............................................................................................. 371
9.12.3.3 Alarm function ................................................................................................ 371
9.13 Accidental energizing protection for synchronous generator AEGPVOC (50AE) .... 372
9.13.1 Identification ........................................................................................................ 372
9.13.2 Application ........................................................................................................... 372
9.13.3 Setting guidelines ................................................................................................. 372
9.14 Voltage-restrained time overcurrent protection VRPVOC (51V) ............................... 373
9.14.1 Identification ........................................................................................................ 373
9.14.2 Application ........................................................................................................... 373
9.14.2.1 Base quantities ............................................................................................... 374
9.14.2.2 Application possibilities .................................................................................. 374
9.14.2.3 Undervoltage seal-in ..................................................................................... 374
9.14.3 Setting guidelines ................................................................................................. 375
9.14.3.1 Explanation of the setting parameters .............................................................. 375
9.14.3.2 Voltage-restrained overcurrent protection for generator and step-up transformer.................. 376
9.14.3.3 General settings ............................................................................................. 377
9.14.3.4 Overcurrent protection with undervoltage seal-in ......................................... 377
9.15 Generator stator overload protection GSPTTR (49S) .................................................... 378
9.15.1 Identification ........................................................................................................ 378
9.15.2 Application ........................................................................................................... 378
9.16 Generator rotor overload protection GRPTTR (49R) .................................................... 378
9.16.1 Identification ........................................................................................................ 378
9.16.2 Application ........................................................................................................... 379
9.16.3 Setting guideline ................................................................................................... 379

**Section 10 Voltage protection** ................................................................................... 383

10.1 Two step undervoltage protection UV2PTUV (27) ...................................................... 383
10.1.1 Identification ........................................................................................................ 383
10.1.2 Application ........................................................................................................... 383
10.1.3 Setting guidelines ................................................................................................. 384
10.1.3.1 Equipment protection, such as for motors and generators ................................. 384
<table>
<thead>
<tr>
<th>Section</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>10.1.3.2</td>
<td>Disconnected equipment detection</td>
<td>384</td>
</tr>
<tr>
<td>10.1.3.3</td>
<td>Power supply quality</td>
<td>384</td>
</tr>
<tr>
<td>10.1.3.4</td>
<td>Voltage instability mitigation</td>
<td>384</td>
</tr>
<tr>
<td>10.1.3.5</td>
<td>Backup protection for power system faults</td>
<td>384</td>
</tr>
<tr>
<td>10.1.3.6</td>
<td>Settings for two step undervoltage protection</td>
<td>384</td>
</tr>
<tr>
<td>10.2</td>
<td>Two step overvoltage protection OV2PTOV (59)</td>
<td>386</td>
</tr>
<tr>
<td>10.2.1</td>
<td>Identification</td>
<td>386</td>
</tr>
<tr>
<td>10.2.2</td>
<td>Application</td>
<td>386</td>
</tr>
<tr>
<td>10.2.3</td>
<td>Setting guidelines</td>
<td>387</td>
</tr>
<tr>
<td>10.2.3.1</td>
<td>Equipment protection, such as for motors, generators, reactors and transformers</td>
<td>387</td>
</tr>
<tr>
<td>10.2.3.2</td>
<td>Equipment protection, capacitors</td>
<td>387</td>
</tr>
<tr>
<td>10.2.3.3</td>
<td>Power supply quality</td>
<td>387</td>
</tr>
<tr>
<td>10.2.3.4</td>
<td>High impedance grounded systems</td>
<td>387</td>
</tr>
<tr>
<td>10.2.3.5</td>
<td>The following settings can be done for the two step overvoltage protection</td>
<td>388</td>
</tr>
<tr>
<td>10.3</td>
<td>Two step residual overvoltage protection ROV2PTOV (59N)</td>
<td>389</td>
</tr>
<tr>
<td>10.3.1</td>
<td>Identification</td>
<td>389</td>
</tr>
<tr>
<td>10.3.2</td>
<td>Application</td>
<td>389</td>
</tr>
<tr>
<td>10.3.3</td>
<td>Setting guidelines</td>
<td>390</td>
</tr>
<tr>
<td>10.3.3.1</td>
<td>Equipment protection, such as for motors, generators, reactors and transformers</td>
<td>390</td>
</tr>
<tr>
<td>10.3.3.2</td>
<td>Equipment protection, capacitors</td>
<td>390</td>
</tr>
<tr>
<td>10.3.3.3</td>
<td>Stator ground-fault protection based on residual voltage measurement</td>
<td>390</td>
</tr>
<tr>
<td>10.3.3.4</td>
<td>Power supply quality</td>
<td>394</td>
</tr>
<tr>
<td>10.3.3.5</td>
<td>High impedance grounded systems</td>
<td>394</td>
</tr>
<tr>
<td>10.3.3.6</td>
<td>Direct grounded system</td>
<td>395</td>
</tr>
<tr>
<td>10.3.3.7</td>
<td>Settings for two step residual overvoltage protection</td>
<td>395</td>
</tr>
<tr>
<td>10.4</td>
<td>Overexcitation protection OEXPVPH (24)</td>
<td>397</td>
</tr>
<tr>
<td>10.4.1</td>
<td>Identification</td>
<td>397</td>
</tr>
<tr>
<td>10.4.2</td>
<td>Application</td>
<td>397</td>
</tr>
<tr>
<td>10.4.3</td>
<td>Setting guidelines</td>
<td>399</td>
</tr>
<tr>
<td>10.4.3.1</td>
<td>Recommendations for input and output signals</td>
<td>399</td>
</tr>
<tr>
<td>10.4.3.2</td>
<td>Settings</td>
<td>400</td>
</tr>
<tr>
<td>10.4.3.3</td>
<td>Service value report</td>
<td>401</td>
</tr>
<tr>
<td>10.4.3.4</td>
<td>Setting example</td>
<td>401</td>
</tr>
<tr>
<td>10.5</td>
<td>Voltage differential protection VDCPTOV (60)</td>
<td>402</td>
</tr>
<tr>
<td>10.5.1</td>
<td>Identification</td>
<td>402</td>
</tr>
<tr>
<td>10.5.2</td>
<td>Application</td>
<td>402</td>
</tr>
<tr>
<td>10.5.3</td>
<td>Setting guidelines</td>
<td>404</td>
</tr>
<tr>
<td>10.6</td>
<td>100% Stator ground fault protection, 3rd harmonic based STEPHIZ (59THD)</td>
<td>405</td>
</tr>
<tr>
<td>10.6.1</td>
<td>Identification</td>
<td>405</td>
</tr>
<tr>
<td>10.6.2</td>
<td>Application</td>
<td>405</td>
</tr>
<tr>
<td>10.6.3</td>
<td>Setting guidelines</td>
<td>409</td>
</tr>
</tbody>
</table>
## Section 11 Frequency protection

<table>
<thead>
<tr>
<th>subsection</th>
<th>title</th>
<th>page</th>
</tr>
</thead>
<tbody>
<tr>
<td>11.1</td>
<td>Identification of Underfrequency protection SAPTUF (81)</td>
<td>411</td>
</tr>
<tr>
<td>11.1.1</td>
<td>Identification</td>
<td>411</td>
</tr>
<tr>
<td>11.1.2</td>
<td>Application</td>
<td>411</td>
</tr>
<tr>
<td>11.1.3</td>
<td>Setting guidelines</td>
<td>411</td>
</tr>
<tr>
<td>11.2</td>
<td>Identification of Overfrequency protection SAPTOF (81)</td>
<td>412</td>
</tr>
<tr>
<td>11.2.1</td>
<td>Identification</td>
<td>412</td>
</tr>
<tr>
<td>11.2.2</td>
<td>Application</td>
<td>412</td>
</tr>
<tr>
<td>11.2.3</td>
<td>Setting guidelines</td>
<td>412</td>
</tr>
<tr>
<td>11.3</td>
<td>Rate-of-change of frequency protection SAPFRC (81)</td>
<td>413</td>
</tr>
<tr>
<td>11.3.1</td>
<td>Identification</td>
<td>413</td>
</tr>
<tr>
<td>11.3.2</td>
<td>Application</td>
<td>413</td>
</tr>
<tr>
<td>11.3.3</td>
<td>Setting guidelines</td>
<td>414</td>
</tr>
<tr>
<td>11.4</td>
<td>Frequency time accumulation protection function FTAQFVR (81A)</td>
<td>415</td>
</tr>
<tr>
<td>11.4.1</td>
<td>Identification</td>
<td>415</td>
</tr>
<tr>
<td>11.4.2</td>
<td>Application</td>
<td>415</td>
</tr>
<tr>
<td>11.4.3</td>
<td>Setting guidelines</td>
<td>417</td>
</tr>
</tbody>
</table>

## Section 12 Multipurpose protection

<table>
<thead>
<tr>
<th>subsection</th>
<th>title</th>
<th>page</th>
</tr>
</thead>
<tbody>
<tr>
<td>12.1</td>
<td>General current and voltage protection CVGAPC</td>
<td>419</td>
</tr>
<tr>
<td>12.1.1</td>
<td>Identification</td>
<td>419</td>
</tr>
<tr>
<td>12.1.2</td>
<td>Application</td>
<td>419</td>
</tr>
<tr>
<td>12.1.2.1</td>
<td>Current and voltage selection for CVGAPC function</td>
<td>420</td>
</tr>
<tr>
<td>12.1.2.2</td>
<td>Base quantities for CVGAPC function</td>
<td>422</td>
</tr>
<tr>
<td>12.1.2.3</td>
<td>Application possibilities</td>
<td>423</td>
</tr>
<tr>
<td>12.1.2.4</td>
<td>Inadvertent generator energization</td>
<td>423</td>
</tr>
<tr>
<td>12.1.3</td>
<td>Setting guidelines</td>
<td>424</td>
</tr>
<tr>
<td>12.1.3.1</td>
<td>Directional negative sequence overcurrent protection</td>
<td>425</td>
</tr>
<tr>
<td>12.1.3.2</td>
<td>Negative sequence overcurrent protection</td>
<td>426</td>
</tr>
<tr>
<td>12.1.3.3</td>
<td>Generator stator overload protection in accordance with IEC or ANSI standards</td>
<td>428</td>
</tr>
<tr>
<td>12.1.3.4</td>
<td>Open phase protection for transformer, lines or generators and circuit breaker</td>
<td>430</td>
</tr>
<tr>
<td>12.1.3.5</td>
<td>Voltage restrained overcurrent protection for generator and step-up transformer</td>
<td>430</td>
</tr>
<tr>
<td>12.1.3.6</td>
<td>Loss of excitation protection for a generator</td>
<td>431</td>
</tr>
<tr>
<td>12.1.3.7</td>
<td>Inadvertent generator energization</td>
<td>432</td>
</tr>
<tr>
<td>12.1.3.8</td>
<td>Undercurrent protection for capacitor bank</td>
<td>434</td>
</tr>
<tr>
<td>12.1.3.9</td>
<td>General settings of the instance</td>
<td>434</td>
</tr>
<tr>
<td>12.1.3.10</td>
<td>Settings for OC1</td>
<td>434</td>
</tr>
<tr>
<td>12.1.3.11</td>
<td>Setting for OC2</td>
<td>435</td>
</tr>
<tr>
<td>12.1.3.12</td>
<td>Setting for UC1</td>
<td>435</td>
</tr>
<tr>
<td>12.1.3.13</td>
<td>Setting for UC2</td>
<td>435</td>
</tr>
<tr>
<td>12.1.3.14</td>
<td>Settings for OV1</td>
<td>435</td>
</tr>
</tbody>
</table>
## Table of contents

### 15.1 Synchronism check, energizing check, and synchronizing SESRSYN (25)
- 15.1.1 Identification ................................................. 457
- 15.1.2 Application ....................................................... 457
- 15.1.3 Application examples ........................................ 462
  - 15.1.3.1 Single circuit breaker with single busbar .......... 463
  - 15.1.3.2 Single circuit breaker with double busbar, external voltage selection ...... 464
  - 15.1.3.3 Single circuit breaker with double busbar, internal voltage selection ...... 465
  - 15.1.3.4 Double circuit breaker .................................... 466
  - 15.1.3.5 Breaker-and-a-half ....................................... 467
- 15.1.4 Setting guidelines ............................................. 469

### 15.2 Apparatus control .................................................. 474
- 15.2.1 Application ....................................................... 474
- 15.2.2 Bay control QCBAY ........................................... 478
- 15.2.3 Switch controller SCSWI ...................................... 479
- 15.2.4 Switches SXCBR/SXSWI ..................................... 480
- 15.2.5 Proxy for signals from switching device via GOOSE XLNPROXY ................. 481
- 15.2.6 Reservation function (QCRSV and RESIN) .............. 483
- 15.2.7 Interaction between modules ............................... 485
- 15.2.8 Setting guidelines ............................................. 487
  - 15.2.8.1 Bay control (QCBAY) ..................................... 487
  - 15.2.8.2 Switch controller (SCSWI) ............................. 488
  - 15.2.8.3 Switch (SXCBR/SXSWI) ............................... 489
  - 15.2.8.4 Proxy for signals from switching device via GOOSE XLNPROXY ............ 489
- 15.2.8.5 Bay Reserve (QCRSV) ..................................... 490
- 15.2.8.6 Reservation input (RESIN) ............................... 490

### 15.3 Interlocking (3) ...................................................... 490
- 15.3.1 Configuration guidelines .................................... 491
- 15.3.2 Interlocking for line bay ABC_LINE (3) ............... 491
  - 15.3.2.1 Application .................................................. 491
- 15.3.3 Interlocking for bus-coupler bay ABC_BC (3) ......... 496
  - 15.3.3.1 Application .................................................. 497
- 15.3.4 External fuse failure ......................................... 461

© Copyright 2017 ABB. All rights reserved
15.3.4 Interlocking for transformer bay AB_TRAFO (3) .................................................................................. 502
  15.3.4.1 Application................................................................................................................................. 502
  15.3.4.2 Signals from bus-coupler ........................................................................................................ 502
  15.3.4.3 Configuration setting .............................................................................................................. 503
15.3.5 Interlocking for bus-section breaker A1A2_BS (3) ........................................................................... 504
  15.3.5.1 Application................................................................................................................................. 504
  15.3.5.2 Signals from all feeders ........................................................................................................... 504
  15.3.5.3 Configuration setting .............................................................................................................. 507
15.3.6 Interlocking for bus-section disconnector A1A2_DC (3) .................................................................. 507
  15.3.6.1 Application................................................................................................................................. 508
  15.3.6.2 Signals in single breaker arrangement ...................................................................................... 508
  15.3.6.3 Signals in double-breaker arrangement .................................................................................... 511
  15.3.6.4 Signals in breaker and a half arrangement ................................................................................ 513
15.3.7 Interlocking for busbar grounding switch BB_ES (3) ........................................................................ 514
  15.3.7.1 Application................................................................................................................................. 514
  15.3.7.2 Signals in single breaker arrangement ...................................................................................... 514
  15.3.7.3 Signals in double-breaker arrangement .................................................................................... 518
  15.3.7.4 Signals in breaker and a half arrangement ................................................................................ 519
15.3.8 Interlocking for double CB bay DB (3) .......................................................................................... 519
  15.3.8.1 Application................................................................................................................................. 519
  15.3.8.2 Configuration setting .............................................................................................................. 520
15.3.9 Interlocking for breaker-and-a-half diameter BH (3) ..................................................................... 521
  15.3.9.1 Application................................................................................................................................. 521
  15.3.9.2 Configuration setting .............................................................................................................. 521
15.4 Voltage control .................................................................................................................................... 522
  15.4.1 Identification................................................................................................................................. 522
  15.4.2 Application................................................................................................................................. 522
  15.4.3 Setting guidelines......................................................................................................................... 553
    15.4.3.1 TCMYLTC and TCLYLTC (84) general settings ......................................................................... 553
15.5 Logic rotating switch for function selection and LHMI presentation SLGAPC .................................... 554
  15.5.1 Identification................................................................................................................................. 554
  15.5.2 Application................................................................................................................................. 554
  15.5.3 Setting guidelines......................................................................................................................... 554
15.6 Selector mini switch VSGAPC ........................................................................................................... 555
  15.6.1 Identification................................................................................................................................. 555
  15.6.2 Application................................................................................................................................. 555
  15.6.3 Setting guidelines......................................................................................................................... 556
15.7 Generic communication function for Double Point indication DPGAPC ............................................. 556
  15.7.1 Identification................................................................................................................................. 556
  15.7.2 Application................................................................................................................................. 556
  15.7.3 Setting guidelines......................................................................................................................... 557
15.8 Single point generic control 8 signals SPC8GAPC ............................................................................... 557
  15.8.1 Identification................................................................................................................................. 557
## Table of contents

<table>
<thead>
<tr>
<th>Section</th>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>15.8.2</td>
<td>Application</td>
<td>557</td>
</tr>
<tr>
<td>15.8.3</td>
<td>Setting guidelines</td>
<td>557</td>
</tr>
<tr>
<td>15.9</td>
<td>AutomationBits, command function for DNP3.0 AUTOBITS</td>
<td>558</td>
</tr>
<tr>
<td>15.9.1</td>
<td>Identification</td>
<td>558</td>
</tr>
<tr>
<td>15.9.2</td>
<td>Application</td>
<td>558</td>
</tr>
<tr>
<td>15.9.3</td>
<td>Setting guidelines</td>
<td>558</td>
</tr>
<tr>
<td>15.10</td>
<td>Single command, 16 signals SINGLECMD</td>
<td>558</td>
</tr>
<tr>
<td>15.10.1</td>
<td>Identification</td>
<td>558</td>
</tr>
<tr>
<td>15.10.2</td>
<td>Application</td>
<td>559</td>
</tr>
<tr>
<td>15.10.3</td>
<td>Setting guidelines</td>
<td>560</td>
</tr>
</tbody>
</table>

## Section 16 Logic

<table>
<thead>
<tr>
<th>Subsection</th>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>16.1</td>
<td>Tripping logic SMPPTRC (94)</td>
<td>563</td>
</tr>
<tr>
<td>16.1.1</td>
<td>Identification</td>
<td>563</td>
</tr>
<tr>
<td>16.1.2</td>
<td>Application</td>
<td>563</td>
</tr>
<tr>
<td>16.1.2.1</td>
<td>Three-pole tripping</td>
<td>564</td>
</tr>
<tr>
<td>16.1.2.2</td>
<td>Single- and/or three-pole tripping</td>
<td>564</td>
</tr>
<tr>
<td>16.1.2.3</td>
<td>Single-, two- or three-pole tripping</td>
<td>566</td>
</tr>
<tr>
<td>16.1.2.4</td>
<td>Lock-out</td>
<td>566</td>
</tr>
<tr>
<td>16.1.2.5</td>
<td>Example of directional data</td>
<td>566</td>
</tr>
<tr>
<td>16.1.2.6</td>
<td>Blocking of the function block</td>
<td>568</td>
</tr>
<tr>
<td>16.1.3</td>
<td>Setting guidelines</td>
<td>568</td>
</tr>
<tr>
<td>16.2</td>
<td>Trip matrix logic TMAGAPC</td>
<td>568</td>
</tr>
<tr>
<td>16.2.1</td>
<td>Identification</td>
<td>568</td>
</tr>
<tr>
<td>16.2.2</td>
<td>Application</td>
<td>568</td>
</tr>
<tr>
<td>16.2.3</td>
<td>Setting guidelines</td>
<td>569</td>
</tr>
<tr>
<td>16.3</td>
<td>Logic for group alarm ALMICALH</td>
<td>569</td>
</tr>
<tr>
<td>16.3.1</td>
<td>Identification</td>
<td>569</td>
</tr>
<tr>
<td>16.3.2</td>
<td>Application</td>
<td>569</td>
</tr>
<tr>
<td>16.3.3</td>
<td>Setting guidelines</td>
<td>569</td>
</tr>
<tr>
<td>16.4</td>
<td>Logic for group alarm WRNCALH</td>
<td>569</td>
</tr>
<tr>
<td>16.4.1</td>
<td>Identification</td>
<td>569</td>
</tr>
<tr>
<td>16.4.1.1</td>
<td>Application</td>
<td>570</td>
</tr>
<tr>
<td>16.4.1.2</td>
<td>Setting guidelines</td>
<td>570</td>
</tr>
<tr>
<td>16.5</td>
<td>Logic for group indication INDCALH</td>
<td>570</td>
</tr>
<tr>
<td>16.5.1</td>
<td>Identification</td>
<td>570</td>
</tr>
<tr>
<td>16.5.1.1</td>
<td>Application</td>
<td>570</td>
</tr>
<tr>
<td>16.5.1.2</td>
<td>Setting guidelines</td>
<td>570</td>
</tr>
<tr>
<td>16.6</td>
<td>Configurable logic blocks</td>
<td>570</td>
</tr>
<tr>
<td>16.6.1</td>
<td>Application</td>
<td>570</td>
</tr>
<tr>
<td>16.6.2</td>
<td>Setting guidelines</td>
<td>571</td>
</tr>
<tr>
<td>16.6.2.1</td>
<td>Configuration</td>
<td>571</td>
</tr>
<tr>
<td>16.7</td>
<td>Fixed signal function block FXDSIGN</td>
<td>572</td>
</tr>
</tbody>
</table>
16.13 Elapsed time integrator with limit transgression and overflow supervision TEIGAPC... 579
16.13.1 Identification................................................................. 579
16.13.2 Application...................................................................... 579
16.13.3 Setting guidelines............................................................. 579
16.14 Comparator for integer inputs - INTCOMP............................. 580
16.14.1 Identification................................................................. 580
16.14.2 Application...................................................................... 580
16.14.3 Setting guidelines............................................................. 580
16.14.4 Setting example............................................................... 580
16.15 Comparator for real inputs - REALCOMP.................................. 581
16.15.1 Identification................................................................. 581
16.15.2 Application...................................................................... 581
16.15.3 Setting guidelines............................................................. 581
16.15.4 Setting example............................................................... 582

Section 17 Monitoring.......................................................................................... 583
17.1 Measurement.................................................................................. 583
17.1.1 Identification.......................................................................... 583
17.1.2 Application............................................................................. 583
17.1.3 Zero clamping.......................................................................... 585
17.1.4 Setting guidelines................................................................. 585
17.1.4.1 Setting examples............................................................. 588
17.2 Gas medium supervision SSIMG (63)............................................. 594
17.2.1 Identification.......................................................................... 594
17.2.2 Application............................................................................. 594
Table of contents

17.2.3 Setting guidelines................................................................................................................................. 594
17.3 Liquid medium supervision SSIML (71)........................................................................................................ 595
17.3.1 Identification........................................................................................................................................ 595
17.3.2 Application........................................................................................................................................... 595
17.3.3 Setting guidelines................................................................................................................................. 595
17.4 Breaker monitoring SSCBR...................................................................................................................... 596
17.4.1 Identification........................................................................................................................................ 596
17.4.2 Application........................................................................................................................................... 596
17.4.3 Setting guidelines................................................................................................................................. 598
17.4.3.1 Setting procedure on the IED........................................................................................................... 599
17.5 Event function EVENT............................................................................................................................. 600
17.5.1 Identification........................................................................................................................................ 600
17.5.2 Application........................................................................................................................................... 600
17.5.3 Setting guidelines................................................................................................................................. 600
17.6 Disturbance report DRPRDRE................................................................................................................... 601
17.6.1 Identification........................................................................................................................................ 601
17.6.2 Application........................................................................................................................................... 601
17.6.3 Setting guidelines................................................................................................................................. 601
17.6.3.1 Recording times............................................................................................................................... 604
17.6.3.2 Binary input signals......................................................................................................................... 605
17.6.3.3 Analog input signals......................................................................................................................... 605
17.6.3.4 Sub-function parameters................................................................................................................ 606
17.6.3.5 Consideration.................................................................................................................................. 607
17.7 Logical signal status report BINSTATREP.............................................................................................. 607
17.7.1 Identification........................................................................................................................................ 607
17.7.2 Application........................................................................................................................................... 607
17.7.3 Setting guidelines................................................................................................................................. 607
17.8 Limit counter L4UFCNT............................................................................................................................ 608
17.8.1 Identification........................................................................................................................................ 608
17.8.2 Application........................................................................................................................................... 608
17.8.3 Setting guidelines................................................................................................................................. 609
17.9 Running hour-meter TEILGAPC............................................................................................................. 609
17.9.1 Identification........................................................................................................................................ 609
17.9.2 Application........................................................................................................................................... 609
17.9.3 Setting guidelines................................................................................................................................. 609
17.10 Estimation of transformer insulation life LOLSPTR (26/49HS)............................................................ 609
17.10.1 Application........................................................................................................................................ 610
17.10.2 Setting guidelines................................................................................................................................. 614
17.10.3 Setting example................................................................................................................................... 621
17.10.3.1 Transformer Rated Data................................................................................................................ 621
17.10.3.2 Setting parameters for insulation loss of life calculation function (LOL1).................................... 621
17.11 Through fault monitoring PTRSTHR (51TF)......................................................................................... 626
17.11.1 Identification...................................................................................................................................... 626
### Section 17: Generator protection REG670

17.1.1 Application................................................................................................................. 626
17.1.2 Setting guidelines........................................................................................................ 627
17.1.3 Setting procedure on the IED..................................................................................... 627
17.1.4 Consideration of zero sequence currents................................................................. 627
17.1.5 On-line correction with on-load tap changer position............................................. 628
17.1.6 Through fault detection............................................................................................. 629
17.1.7 Through fault $I^2t$ alarms....................................................................................... 629
17.1.8 Initial values for cumulative $I^2t$ and number of through faults............................ 630
17.1.9 Setting examples....................................................................................................... 631
17.1.10 Typical main CT connections for transformer....................................................... 631
17.1.11 Application examples for power transformers....................................................... 632
17.1.12 Application example for OHL................................................................................ 641
17.1.13 Current harmonic monitoring CHMMHAI(ITHD).................................................... 641
17.1.14 Identification............................................................................................................. 641
17.1.15 Application................................................................................................................. 641
17.1.16 Setting guidelines..................................................................................................... 642
17.1.17 Setting procedure on the IED.................................................................................. 643
17.1.18 Voltage harmonic monitoring VHMMHAI(VTHD).................................................... 644
17.1.19 Identification............................................................................................................. 644
17.1.20 Application................................................................................................................. 644
17.1.21 Setting guidelines..................................................................................................... 644
17.1.22 Setting procedure on the IED.................................................................................. 645

### Section 18: Metering......................................................................................................... 647

18.1 Pulse-counter logic PCFCNT.......................................................................................... 647
18.1.1 Identification............................................................................................................. 647
18.1.2 Application................................................................................................................. 647
18.1.3 Setting guidelines..................................................................................................... 647
18.2 Function for energy calculation and demand handling ETPMMTR.............................. 648
18.2.1 Identification............................................................................................................. 648
18.2.2 Application................................................................................................................. 648
18.2.3 Setting guidelines..................................................................................................... 649

### Section 19: Ethernet-based communication....................................................................... 651

19.1 Access point.................................................................................................................. 651
19.1.1 Application................................................................................................................. 651
19.1.2 Setting guidelines..................................................................................................... 651
19.2 Redundant communication............................................................................................ 652
19.2.1 Identification............................................................................................................. 652
19.2.2 Application................................................................................................................. 652
19.2.3 Setting guidelines..................................................................................................... 654
19.3 Merging unit.................................................................................................................. 654
19.3.1 Application................................................................................................................. 654

---

© Copyright 2017 ABB. All rights reserved
Table of contents

19.3.2 Setting guidelines ........................................................................................................ 655
19.4 Routes ............................................................................................................................... 655
19.4.1 Application .................................................................................................................. 655
19.4.2 Setting guidelines ....................................................................................................... 655

Section 20 Station communication ......................................................................................... 657
20.1 Communication protocols ............................................................................................ 657
20.2 IEC 61850-8-1 communication protocol .................................................................... 657
20.2.1 Application IEC 61850-8-1 ....................................................................................... 657
20.2.2 Setting guidelines ..................................................................................................... 659
20.2.3 Horizontal communication via GOOSE ................................................................. 659
20.2.3.1 Sending data .......................................................................................................... 659
20.2.3.2 Receiving data ..................................................................................................... 660
20.2.3.3 Specific settings related to the IEC/UCA 61850-9-2LE communication ............... 664
20.2.3.4 Setting examples for IEC/UCA 61850-9-2LE and time synchronization ............. 667
20.3 IEC/UCA 61850-9-2LE communication protocol ..................................................... 660
20.3.1 Introduction ................................................................................................................ 660
20.3.2 Faulty merging unit for bay in service ...................................................................... 662
20.3.3 Bay out of service for maintenance ......................................................................... 663
20.3.4 Setting guidelines ..................................................................................................... 664
20.3.4.1 Specific settings related to the IEC/UCA 61850-9-2LE communication ............... 664
20.3.4.2 Setting examples for IEC/UCA 61850-9-2LE and time synchronization ............. 667
20.4 LON communication protocol ...................................................................................... 672
20.4.1 Application ................................................................................................................ 672
20.4.2 MULTICMDRCV and MULTICMDSND ................................................................. 673
20.4.2.1 Identification ......................................................................................................... 673
20.4.2.2 Application ........................................................................................................... 674
20.4.2.3 Setting guidelines ................................................................................................. 674
20.5 SPA communication protocol ....................................................................................... 674
20.5.1 Application ................................................................................................................ 674
20.5.2 Setting guidelines ..................................................................................................... 675
20.6 IEC 60870-5-103 communication protocol ................................................................ 676
20.6.1 Application ................................................................................................................ 676
20.6.1.1 Functionality ........................................................................................................ 676
20.6.1.2 Design .................................................................................................................. 676
20.6.2 Settings ....................................................................................................................... 679
20.6.2.1 Settings for RS485 and optical serial communication .......................................... 679
20.6.2.2 Settings from PCM600 ......................................................................................... 680
20.6.3 Function and information types ................................................................................ 682
20.7 DNP3 Communication protocol .................................................................................. 683
20.7.1 Application ................................................................................................................ 683

Section 21 Remote communication ....................................................................................... 685
21.1 Binary signal transfer .................................................................................................... 685
21.1.1 Identification ............................................................................................................. 685
## Section 22 Security

<table>
<thead>
<tr>
<th>Section 22</th>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>22.1</td>
<td>Authority status ATHSTAT</td>
<td>693</td>
</tr>
<tr>
<td>22.1.1</td>
<td>Application</td>
<td>693</td>
</tr>
<tr>
<td>22.2</td>
<td>Self supervision with internal event list</td>
<td>693</td>
</tr>
<tr>
<td>22.2.1</td>
<td>Application</td>
<td>693</td>
</tr>
<tr>
<td>22.3</td>
<td>Change lock CHNGLCK</td>
<td>694</td>
</tr>
<tr>
<td>22.3.1</td>
<td>Application</td>
<td>694</td>
</tr>
<tr>
<td>22.4</td>
<td>Denial of service SCHLCCH/RCHLCCH</td>
<td>695</td>
</tr>
<tr>
<td>22.4.1</td>
<td>Application</td>
<td>695</td>
</tr>
<tr>
<td>22.4.2</td>
<td>Setting guidelines</td>
<td>695</td>
</tr>
</tbody>
</table>

## Section 23 Basic IED functions

<table>
<thead>
<tr>
<th>Section 23</th>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>23.1</td>
<td>IED identifiers TERMINALID</td>
<td>697</td>
</tr>
<tr>
<td>23.1.1</td>
<td>Application</td>
<td>697</td>
</tr>
<tr>
<td>23.2</td>
<td>Product information PRODINF</td>
<td>697</td>
</tr>
<tr>
<td>23.2.1</td>
<td>Application</td>
<td>697</td>
</tr>
<tr>
<td>23.2.2</td>
<td>Factory defined settings</td>
<td>697</td>
</tr>
<tr>
<td>23.3</td>
<td>Measured value expander block RANGE_XP</td>
<td>698</td>
</tr>
<tr>
<td>23.3.1</td>
<td>Identification</td>
<td>698</td>
</tr>
<tr>
<td>23.3.2</td>
<td>Application</td>
<td>698</td>
</tr>
<tr>
<td>23.3.3</td>
<td>Setting guidelines</td>
<td>699</td>
</tr>
<tr>
<td>23.4</td>
<td>Parameter setting groups</td>
<td>699</td>
</tr>
<tr>
<td>23.4.1</td>
<td>Application</td>
<td>699</td>
</tr>
<tr>
<td>23.4.2</td>
<td>Setting guidelines</td>
<td>699</td>
</tr>
<tr>
<td>23.5</td>
<td>Rated system frequency PRIMVAL</td>
<td>699</td>
</tr>
<tr>
<td>23.5.1</td>
<td>Identification</td>
<td>699</td>
</tr>
<tr>
<td>23.5.2</td>
<td>Application</td>
<td>700</td>
</tr>
<tr>
<td>23.5.3</td>
<td>Setting guidelines</td>
<td>700</td>
</tr>
<tr>
<td>23.6</td>
<td>Summation block 3 phase 3PHSUM</td>
<td>700</td>
</tr>
<tr>
<td>23.6.1</td>
<td>Application</td>
<td>700</td>
</tr>
<tr>
<td>23.6.2</td>
<td>Setting guidelines</td>
<td>700</td>
</tr>
<tr>
<td>23.7</td>
<td>Global base values GBASVAL</td>
<td>700</td>
</tr>
<tr>
<td>23.7.1</td>
<td>Identification</td>
<td>701</td>
</tr>
<tr>
<td>23.7.2</td>
<td>Application</td>
<td>701</td>
</tr>
<tr>
<td>23.7.3</td>
<td>Setting guidelines</td>
<td>701</td>
</tr>
<tr>
<td>23.8</td>
<td>Signal matrix for binary inputs SMBI</td>
<td>701</td>
</tr>
<tr>
<td>23.8.1</td>
<td>Application</td>
<td>701</td>
</tr>
<tr>
<td>23.8.2</td>
<td>Setting guidelines</td>
<td>701</td>
</tr>
<tr>
<td>23.9</td>
<td>Signal matrix for binary outputs SMBO</td>
<td>702</td>
</tr>
</tbody>
</table>
Table of contents

23.9.1 Application ......................................................................................................................... 702
23.9.2 Setting guidelines .................................................................................................................. 702
23.10 Signal matrix for mA inputs SMMI .......................................................................................... 702
23.10.1 Application .......................................................................................................................... 702
23.10.2 Setting guidelines .................................................................................................................. 702
23.11 Signal matrix for analog inputs SMAl ......................................................................................... 702
23.11.1 Application .......................................................................................................................... 702
23.11.2 Frequency values ................................................................................................................... 703
23.11.3 Setting guidelines .................................................................................................................. 704
23.12 Test mode functionality TESTMODE ...................................................................................... 708
23.12.1 Application .......................................................................................................................... 708
23.12.1.1 IEC 61850 protocol test mode ............................................................................................ 709
23.12.2 Setting guidelines .................................................................................................................. 710
23.13 Time synchronization TIMESYNCHGEN ............................................................................ 710
23.13.1 Application .......................................................................................................................... 710
23.13.2 Setting guidelines .................................................................................................................. 711
23.13.2.1 System time ............................................................................................................................ 711
23.13.2.2 Synchronization .................................................................................................................... 712
23.13.2.3 Process bus IEC/UCA 61850-9-2LE synchronization .......................................................... 714

Section 24 Requirements ..................................................................................................................... 717

24.1 Current transformer requirements ............................................................................................... 717
24.1.1 Current transformer basic classification and requirements ..................................................... 717
24.1.2 Conditions ............................................................................................................................... 718
24.1.3 Fault current ............................................................................................................................ 719
24.1.4 Secondary wire resistance and additional load ........................................................................ 719
24.1.5 General current transformer requirements ............................................................................ 720
24.1.6 Rated equivalent secondary e.m.f. requirements ..................................................................... 720
24.1.6.1 Guide for calculation of CT for generator differential protection ................................... 720
24.1.6.2 Transformer differential protection ...................................................................................... 725
24.1.6.3 Breaker failure protection .................................................................................................... 726
24.1.6.4 Restricted ground fault protection (low impedance differential) ........................................ 727
24.1.7 Current transformer requirements for CTs according to other standards ............................ 729
24.1.7.1 Current transformers according to IEC 61869-2, class P, PR ............................................ 730
24.1.7.2 Current transformers according to IEC 61869-2, class PX, PXR (and old IEC 60044-6, class TPS and old British Standard, class X) ................................................................. 730
24.1.7.3 Current transformers according to ANSI/IEEE .................................................................. 730
24.1.8 Current transformer requirements for generator differential protection .............................. 730
24.2 Voltage transformer requirements ............................................................................................. 731
24.3 SNTP server requirements ........................................................................................................ 731
24.4 PTP requirements ....................................................................................................................... 731
24.5 Sample specification of communication requirements for the protection and control terminals in digital telecommunication networks ................................................................................. 732
24.6 IEC/UCA 61850-9-2LE Merging unit requirements ................................................................. 733
Section 1  introduction

1.1  This manual

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

1.2  Intended audience

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

The protection and control engineer must be experienced in electrical power engineering and have knowledge of related technology, such as protection schemes and communication principles.
1.3  

Product documentation

1.3.1  

Product documentation set

---

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

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

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

The commissioning manual contains instructions on how to commission the IED. The manual can also be used by system engineers and maintenance personnel for assistance during the testing phase. The manual provides procedures for the checking of external circuitry and energizing the IED, parameter setting and configuration as well as verifying settings by secondary injection. The manual describes the process of testing an IED in a substation which is not in service. The chapters are organized in the chronological order in which the IED should be commissioned. The relevant procedures may be followed also during the service and maintenance activities.
The operation manual contains instructions on how to operate the IED once it has been commissioned. The manual provides instructions for the monitoring, controlling and setting of the IED. The manual also describes how to identify disturbances and how to view calculated and measured power grid data to determine the cause of a fault.

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

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

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

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

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

### Document revision history

<table>
<thead>
<tr>
<th>Document revision</th>
<th>Date</th>
<th>Product revision</th>
<th>History</th>
</tr>
</thead>
<tbody>
<tr>
<td>-</td>
<td>2017-05</td>
<td>2.2.0</td>
<td>First release for product version 2.2</td>
</tr>
<tr>
<td>A</td>
<td>2017-10</td>
<td>2.2.1</td>
<td>Ethernet ports with RJ45 connector added. Enhancements/updates made to GENPDDIF, ZMFPDIS and ZMFCPDIS.</td>
</tr>
<tr>
<td>B</td>
<td>2017-03</td>
<td>2.2.1</td>
<td>Document enhancements and corrections</td>
</tr>
<tr>
<td>C</td>
<td>2018–06</td>
<td>2.2.2</td>
<td>LDCM galvanic X.21 added. Function PTRSTHR added. Ordering section updated.</td>
</tr>
<tr>
<td>D</td>
<td>2018-11</td>
<td>2.2.3</td>
<td>Functions CHMMHAI, VHMMHAI, DELVSPVC, DELISPVC and DELSPVC added. Updates/enhancements made to REALCOMP, and FNKEYMDx. Ordering section updated.</td>
</tr>
<tr>
<td>E</td>
<td></td>
<td></td>
<td>Document not released</td>
</tr>
<tr>
<td>F</td>
<td>2019-05</td>
<td>2.2.3</td>
<td>PTP enhancements and corrections</td>
</tr>
</tbody>
</table>
1.3.3 Related documents

<table>
<thead>
<tr>
<th>Documents related to REG670</th>
<th>Document numbers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Application manual</td>
<td>1MRK 502 071-UUS</td>
</tr>
<tr>
<td>Commissioning manual</td>
<td>1MRK 502 073-UUS</td>
</tr>
<tr>
<td>Product guide</td>
<td>1MRK 502 074-BEN</td>
</tr>
<tr>
<td>Technical manual</td>
<td>1MRK 502 072-UUS</td>
</tr>
<tr>
<td>Type test certificate</td>
<td>1MRK 502 074-TUS</td>
</tr>
</tbody>
</table>

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

1.4 Document symbols and conventions

1.4.1 Symbols

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

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

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

Class 1 Laser product. Take adequate measures to protect the eyes and do not view directly with optical instruments.
The caution icon indicates important information or warning related to the concept discussed in the text. It might indicate the presence of a hazard which could result in corruption of software or damage to equipment or property.

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

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

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

1.4.2 Document conventions

- Abbreviations and acronyms in this manual are spelled out in the glossary. The glossary also contains definitions of important terms.
- Push button navigation in the LHMI menu structure is presented by using the push button icons.
  For example, to navigate between the options, use ↑ and ↓.
- HMI menu paths are presented in bold.
  For example, select Main menu/Settings.
- LHMI messages are shown in Courier font.
  For example, to save the changes in non-volatile memory, select Yes and press ↵.
- Parameter names are shown in italics.
  For example, the function can be enabled and disabled with the Operation setting.
- Each function block symbol shows the available input/output signal.
  - the character ^ in front of an input/output signal name indicates that the signal name may be customized using the PCM600 software.
  - the character * after an input signal name indicates that the signal must be connected to another function block in the application configuration to achieve a valid application configuration.
- Dimensions are provided both in inches and millimeters. If it is not specifically mentioned then the dimension is in millimeters.

1.5 IEC 61850 edition 1 / edition 2 mapping

Function block names are used in ACT and PST to identify functions. Respective function block names of Edition 1 logical nodes and Edition 2 logical nodes are shown in the table below.
<table>
<thead>
<tr>
<th>Function block name</th>
<th>Edition 1 logical nodes</th>
<th>Edition 2 logical nodes</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEGPVOC</td>
<td>AEGGAPC</td>
<td>AEGPVOC</td>
</tr>
<tr>
<td>AGSAL</td>
<td>AGSAL SECLLN0</td>
<td>AGSAL</td>
</tr>
<tr>
<td>ALMICALH</td>
<td>ALMCALH</td>
<td>ALMCALH</td>
</tr>
<tr>
<td>ALTIM</td>
<td>-</td>
<td>ALTIM</td>
</tr>
<tr>
<td>ALTMS</td>
<td>-</td>
<td>ALTMS</td>
</tr>
<tr>
<td>ALTRK</td>
<td>-</td>
<td>ALTRK</td>
</tr>
<tr>
<td>BCZPDIF</td>
<td>BCZPDIF</td>
<td>BCZPDIF</td>
</tr>
<tr>
<td>BCZSPDIF</td>
<td>BCZSPDIF</td>
<td>BCZSPDIF</td>
</tr>
<tr>
<td>BCZTPDIF</td>
<td>BCZTPDIF</td>
<td>BCZTPDIF</td>
</tr>
<tr>
<td>BDCGAPC</td>
<td>SWSGGIO</td>
<td>BBCSWI</td>
</tr>
<tr>
<td>BDZSGAPC</td>
<td>BB56LLN0 BDZSGAPC</td>
<td>LLN0 BDZSGAPC</td>
</tr>
<tr>
<td>BFPTRC_F01</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F02</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F03</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F04</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F05</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F06</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F07</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F08</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F09</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F10</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F11</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F12</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F13</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F14</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F15</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F16</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F17</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F18</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F19</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F20</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F21</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F22</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F23</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BFPTRC_F24</td>
<td>BFPTRC</td>
<td>BFPTRC</td>
</tr>
<tr>
<td>BICPTRC_01</td>
<td>BICPTRC</td>
<td>BICPTRC</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Function block name</th>
<th>Edition 1 logical nodes</th>
<th>Edition 2 logical nodes</th>
</tr>
</thead>
<tbody>
<tr>
<td>BICPTRC_02</td>
<td>BICPTRC</td>
<td>BICPTRC</td>
</tr>
<tr>
<td>BICPTRC_03</td>
<td>BICPTRC</td>
<td>BICPTRC</td>
</tr>
<tr>
<td>BICPTRC_04</td>
<td>BICPTRC</td>
<td>BICPTRC</td>
</tr>
<tr>
<td>BICPTRC_05</td>
<td>BICPTRC</td>
<td>BICPTRC</td>
</tr>
<tr>
<td>BRCPTOC</td>
<td>BRCPTOC</td>
<td>BRCPTOC</td>
</tr>
<tr>
<td>BRPTOC</td>
<td>BRPTOC</td>
<td>BRPTOC</td>
</tr>
<tr>
<td>BTIGAPC</td>
<td>B16IFCVI</td>
<td>BTIGAPC</td>
</tr>
<tr>
<td>BUSPTRC_B1</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B2</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B3</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B4</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B5</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B6</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B7</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B8</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B9</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B10</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B11</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B12</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B13</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B14</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B15</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B16</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B17</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B18</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B19</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B20</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B21</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B22</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B23</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUSPTRC_B24</td>
<td>BUSPTRC</td>
<td>BUSPTRC</td>
</tr>
<tr>
<td>BUTPTRC_B1</td>
<td>BUTPTRC</td>
<td>BUTPTRC</td>
</tr>
<tr>
<td>BUTPTRC_B2</td>
<td>BUTPTRC</td>
<td>BUTPTRC</td>
</tr>
<tr>
<td>BUTPTRC_B3</td>
<td>BUTPTRC</td>
<td>BUTPTRC</td>
</tr>
<tr>
<td>BUTPTRC_B4</td>
<td>BUTPTRC</td>
<td>BUTPTRC</td>
</tr>
<tr>
<td>BUTPTRC_B5</td>
<td>BUTPTRC</td>
<td>BUTPTRC</td>
</tr>
<tr>
<td>BUTPTRC_B6</td>
<td>BUTPTRC</td>
<td>BUTPTRC</td>
</tr>
<tr>
<td>BUTPTRC_B7</td>
<td>BUTPTRC</td>
<td>BUTPTRC</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Function block name</th>
<th>Edition 1 logical nodes</th>
<th>Edition 2 logical nodes</th>
</tr>
</thead>
<tbody>
<tr>
<td>BUTPTRC_B8</td>
<td>BUTPTRC</td>
<td>BUTPTRC</td>
</tr>
<tr>
<td>BZISGGIO</td>
<td>BZISGGIO</td>
<td>BZISGAPC</td>
</tr>
<tr>
<td>BZITGGIO</td>
<td>BZITGGIO</td>
<td>BZITGAPC</td>
</tr>
<tr>
<td>BZNPDIF_Z1</td>
<td>BZNPDIF</td>
<td>BZNPDIF</td>
</tr>
<tr>
<td>BZNPDIF_Z2</td>
<td>BZNPDIF</td>
<td>BZNPDIF</td>
</tr>
<tr>
<td>BZNPDIF_Z3</td>
<td>BZNPDIF</td>
<td>BZNPDIF</td>
</tr>
<tr>
<td>BZNPDIF_Z4</td>
<td>BZNPDIF</td>
<td>BZNPDIF</td>
</tr>
<tr>
<td>BZNPDIF_Z5</td>
<td>BZNPDIF</td>
<td>BZNPDIF</td>
</tr>
<tr>
<td>BZNPDIF_Z6</td>
<td>BZNPDIF</td>
<td>BZNPDIF</td>
</tr>
<tr>
<td>BZNSPDIF_A</td>
<td>BZNSPDIF</td>
<td>BZASGAPC</td>
</tr>
<tr>
<td></td>
<td></td>
<td>BZASPDIF</td>
</tr>
<tr>
<td></td>
<td></td>
<td>BZNSGAPC</td>
</tr>
<tr>
<td></td>
<td></td>
<td>BZNSPDIF</td>
</tr>
<tr>
<td>BZNSPDIF_B</td>
<td>BZNSPDIF</td>
<td>BZBSPDIF</td>
</tr>
<tr>
<td></td>
<td></td>
<td>BZNSGAPC</td>
</tr>
<tr>
<td></td>
<td></td>
<td>BZNSPDIF</td>
</tr>
<tr>
<td>BZNTPDIF_A</td>
<td>BZNTPDIF</td>
<td>BZATGAPC</td>
</tr>
<tr>
<td></td>
<td></td>
<td>BZATPDIF</td>
</tr>
<tr>
<td></td>
<td></td>
<td>BZNTGAPC</td>
</tr>
<tr>
<td></td>
<td></td>
<td>BNZTPDIF</td>
</tr>
<tr>
<td>BZNTPDIF_B</td>
<td>BZNTPDIF</td>
<td>BZBTGAPC</td>
</tr>
<tr>
<td></td>
<td></td>
<td>BZBTPDIF</td>
</tr>
<tr>
<td></td>
<td></td>
<td>BZNTGAPC</td>
</tr>
<tr>
<td></td>
<td></td>
<td>BZNTPDIF</td>
</tr>
<tr>
<td>CBPGAPC</td>
<td>CBPLLNO</td>
<td>CBPMMXU</td>
</tr>
<tr>
<td></td>
<td>CBPPTRC</td>
<td>CBPPTRC</td>
</tr>
<tr>
<td></td>
<td>HOLPTOV</td>
<td>HOLPTOV</td>
</tr>
<tr>
<td></td>
<td>HPHTPTOV</td>
<td>HPHTPTOV</td>
</tr>
<tr>
<td></td>
<td>PH3PTUC</td>
<td>PH3PTUC</td>
</tr>
<tr>
<td></td>
<td>PH3PTOC</td>
<td>PH3PTOC</td>
</tr>
<tr>
<td></td>
<td>RP3PDOP</td>
<td>RP3PDOP</td>
</tr>
<tr>
<td>CCPDSC</td>
<td>CCRPLD</td>
<td>CCPDSC</td>
</tr>
<tr>
<td>CCRBRF</td>
<td>CCRBRF</td>
<td>CCRBRF</td>
</tr>
<tr>
<td>CCRWRBREF</td>
<td>CCRWRBREF</td>
<td>CCRWRBREF</td>
</tr>
<tr>
<td>CCSRBREF</td>
<td>CCSRBREF</td>
<td>CCSRBREF</td>
</tr>
<tr>
<td>CCSSPVC</td>
<td>CCSDIF</td>
<td>CCSSPVC</td>
</tr>
<tr>
<td>CMMXU</td>
<td>CMMXU</td>
<td>CMMXU</td>
</tr>
<tr>
<td>CMSQI</td>
<td>CMSQI</td>
<td>CMSQI</td>
</tr>
<tr>
<td>COUVGAPC</td>
<td>COUULLNO</td>
<td>COUVPTOV</td>
</tr>
<tr>
<td></td>
<td>COUVPDTOV</td>
<td>COUVPTOV</td>
</tr>
<tr>
<td></td>
<td>COUVPTUV</td>
<td>COUVPTUV</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Function block name</th>
<th>Edition 1 logical nodes</th>
<th>Edition 2 logical nodes</th>
</tr>
</thead>
<tbody>
<tr>
<td>CVGAPC</td>
<td>GF2LLN0</td>
<td>GF2MMXN</td>
</tr>
<tr>
<td></td>
<td>GF2MMXN</td>
<td>GF2PHAR</td>
</tr>
<tr>
<td></td>
<td>GF2PTOV</td>
<td>GF2PTUC</td>
</tr>
<tr>
<td></td>
<td>GF2PTUV</td>
<td>GF2PTUC</td>
</tr>
<tr>
<td></td>
<td>GF2PVOC</td>
<td>GF2PTUC</td>
</tr>
<tr>
<td></td>
<td>PH1PTRC</td>
<td>PH1PTRC</td>
</tr>
<tr>
<td>CVMMXN</td>
<td>CVMMXN</td>
<td>CVMMXN</td>
</tr>
<tr>
<td>D2PTOC</td>
<td>D2LLN0</td>
<td>D2PTOC</td>
</tr>
<tr>
<td></td>
<td>D2PTOC</td>
<td>PH1PTRC</td>
</tr>
<tr>
<td>DPGAPC</td>
<td>DPGGIO</td>
<td>DPGAPC</td>
</tr>
<tr>
<td>DRPRDRE</td>
<td>DRPRDRE</td>
<td>DRPRDRE</td>
</tr>
<tr>
<td>ECPSC8</td>
<td>ECPSC8</td>
<td>ECPSC8</td>
</tr>
<tr>
<td>ECRWPSCH</td>
<td>ECRWPSCH</td>
<td>ECRWPSCH</td>
</tr>
<tr>
<td>EF2PTOC</td>
<td>EF2LLN0</td>
<td>EF2PTOC</td>
</tr>
<tr>
<td></td>
<td>EF2PTOC</td>
<td>EF2RDIR</td>
</tr>
<tr>
<td></td>
<td>EF2PTOC</td>
<td>GEN2PHAR</td>
</tr>
<tr>
<td></td>
<td>GEN2PHAR</td>
<td>PH1PTOC</td>
</tr>
<tr>
<td>EF4PTOC</td>
<td>EF4LLN0</td>
<td>EF4PTOC</td>
</tr>
<tr>
<td></td>
<td>EF4PTOC</td>
<td>EF4RDIR</td>
</tr>
<tr>
<td></td>
<td>EF4PTOC</td>
<td>GEN4PHAR</td>
</tr>
<tr>
<td></td>
<td>GEN4PHAR</td>
<td>PH1PTOC</td>
</tr>
<tr>
<td>EFPIOC</td>
<td>EFPIOC</td>
<td>EFPIOC</td>
</tr>
<tr>
<td>EFRWPIOC</td>
<td>EFRWPIOC</td>
<td>EFRWPIOC</td>
</tr>
<tr>
<td>ETPMMTR</td>
<td>ETPMMTR</td>
<td>ETPMMTR</td>
</tr>
<tr>
<td>FDPSPDIS</td>
<td>FDPSPDIS</td>
<td>FDPSPDIS</td>
</tr>
<tr>
<td>FMPSPDIS</td>
<td>FMPSPDIS</td>
<td>FMPSPDIS</td>
</tr>
<tr>
<td>FRPSPDIS</td>
<td>FRPSPDIS</td>
<td>FRPSPDIS</td>
</tr>
<tr>
<td>FTAQFVR</td>
<td>FTAQFVR</td>
<td>FTAQFVR</td>
</tr>
<tr>
<td>FUFSVNC</td>
<td>SDGFDFU</td>
<td>FUFSVNC</td>
</tr>
<tr>
<td>GENPDIF</td>
<td>GENPDIF</td>
<td>GENPDIF</td>
</tr>
<tr>
<td></td>
<td>GENPDIF</td>
<td>GENPDIF</td>
</tr>
<tr>
<td></td>
<td>GENPDIF</td>
<td>GENPDIF</td>
</tr>
<tr>
<td></td>
<td>GENPDIF</td>
<td>GENPDIF</td>
</tr>
<tr>
<td></td>
<td>GENPDIF</td>
<td>GENPDIF</td>
</tr>
<tr>
<td>GOPPDOP</td>
<td>GOPPDOP</td>
<td>GOPPDOP</td>
</tr>
<tr>
<td>GRPTTR</td>
<td>GRPTTR</td>
<td>GRPTTR</td>
</tr>
<tr>
<td>GSPTTR</td>
<td>GSPTTR</td>
<td>GSPTTR</td>
</tr>
<tr>
<td>GUPPDUP</td>
<td>GUPPDUP</td>
<td>GUPPDUP</td>
</tr>
<tr>
<td></td>
<td>GUPPDUP</td>
<td>PH1PTRC</td>
</tr>
<tr>
<td>HZPDIF</td>
<td>HZPDIF</td>
<td>HZPDIF</td>
</tr>
<tr>
<td>INDICMLCH</td>
<td>INDICMLCH</td>
<td>INDICMLCH</td>
</tr>
<tr>
<td>ITBGAPC</td>
<td>IB16FCVB</td>
<td>ITBGAPC</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Function block name</th>
<th>Edition 1 logical nodes</th>
<th>Edition 2 logical nodes</th>
</tr>
</thead>
<tbody>
<tr>
<td>L3CPDIF</td>
<td>L3CPDIF</td>
<td>L3CGAPC L3CPDIF L3CPHAR L3CPTRC</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>L4CPDIF</td>
<td>L4CLLN0 L4CPDIF L4CPTRC</td>
<td>LLN0 L4CGAPC L4CPDIF L4CP5CH L4CPTRC</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>L4UFCNT</td>
<td>L4UFCNT</td>
<td>L4UFCNT</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>L6CPDIF</td>
<td>L6CPDIF</td>
<td>L6CGAPC L6CPDIF L6CPHAR L6CPTRC</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LAPPGAPC</td>
<td>LAPPPLL0 LAPPDDUP LAPPUPF</td>
<td>LAPPDDUP LAPPUPPF</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LCCRPTRC</td>
<td>LCCRPTRC</td>
<td>LCCRPTRC</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LCNSPTOC</td>
<td>LCNSPTOC</td>
<td>LCNSPTOC</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LCNSPTOV</td>
<td>LCNSPTOV</td>
<td>LCNSPTOV</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LCP3PTOC</td>
<td>LCP3PTOC</td>
<td>LCP3PTOC</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LCP3PTUC</td>
<td>LCP3PTUC</td>
<td>LCP3PTUC</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LCPTTR</td>
<td>LCPTTR</td>
<td>LCPTTR</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LCZSPTOC</td>
<td>LCZSPTOC</td>
<td>LCZSPTOC</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LCZSPTOV</td>
<td>LCZSPTOV</td>
<td>LCZSPTOV</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LD0LLN0</td>
<td>LLN0</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LDLPSCH</td>
<td>LDLPSCH</td>
<td>LDLPSCH</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LDRGFC</td>
<td>STSGGIO</td>
<td>LDRGFC</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LEXPDIS</td>
<td>LEXPDIS</td>
<td>LEXPDIS LEXPTRC</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LFPTTR</td>
<td>LFPTTR</td>
<td>LFPTTR</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LMBRFLO</td>
<td>LMBRFLO</td>
<td>LMBRFLO</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LOLSPTR</td>
<td>LOLSPTR</td>
<td>LOLSPTR</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LOVPTUV</td>
<td>LOVPTUV</td>
<td>LOVPTUV</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LPHD</td>
<td>LPHD</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LPTTR</td>
<td>LPTTR</td>
<td>LPTTR</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LT3CPDIF</td>
<td>LT3CPDIF</td>
<td>LT3CGAPC LT3CPDIF LT3CPHAR LT3CPTRC</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LT6CPDIF</td>
<td>LT6CPDIF</td>
<td>LT6CGAPC LT6CPDIF LT6CPHAR LT6CPTRC</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MVGAPC</td>
<td>MVGGIO</td>
<td>MVGAPC</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Function block name</th>
<th>Edition 1 logical nodes</th>
<th>Edition 2 logical nodes</th>
</tr>
</thead>
<tbody>
<tr>
<td>NS2PTOC</td>
<td>NS2LLN0</td>
<td>NS2PTOC</td>
</tr>
<tr>
<td></td>
<td>NS2PTOC</td>
<td>NS2PTRC</td>
</tr>
<tr>
<td>NS4PTOC</td>
<td>EF4LLN0</td>
<td>EF4PTRC</td>
</tr>
<tr>
<td></td>
<td>EF4PTRC</td>
<td>EF4RDIR</td>
</tr>
<tr>
<td></td>
<td>GEN4PHAR</td>
<td>PH1PTOC</td>
</tr>
<tr>
<td></td>
<td>GEN4PHAR</td>
<td>PH3PTOC</td>
</tr>
<tr>
<td></td>
<td>PH3PTRC</td>
<td></td>
</tr>
<tr>
<td>O2RWPTOV</td>
<td>GEN2LLN0</td>
<td></td>
</tr>
<tr>
<td></td>
<td>O2RWPTOV</td>
<td></td>
</tr>
<tr>
<td></td>
<td>PH1PTRC</td>
<td></td>
</tr>
<tr>
<td>OC4PTOC</td>
<td>OC4LLN0</td>
<td></td>
</tr>
<tr>
<td></td>
<td>GEN4PHAR</td>
<td></td>
</tr>
<tr>
<td></td>
<td>PH3PTOC</td>
<td></td>
</tr>
<tr>
<td></td>
<td>PH3PTRC</td>
<td></td>
</tr>
<tr>
<td>OEXPVPH</td>
<td>OEXPVPH</td>
<td>OEXPVPH</td>
</tr>
<tr>
<td>OOSPPAM</td>
<td>OOSPPAM</td>
<td>OOSPPAM</td>
</tr>
<tr>
<td></td>
<td></td>
<td>OOSPTOC</td>
</tr>
<tr>
<td>OV2PTOV</td>
<td>GEN2LLN0</td>
<td></td>
</tr>
<tr>
<td></td>
<td>OV2PTOV</td>
<td></td>
</tr>
<tr>
<td></td>
<td>PH1PTRC</td>
<td></td>
</tr>
<tr>
<td>PAPGAPC</td>
<td>PAPGAPC</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PH4SPTOC</td>
<td>GEN4PHAR</td>
<td></td>
</tr>
<tr>
<td></td>
<td>OCNDLLN0</td>
<td></td>
</tr>
<tr>
<td></td>
<td>PH1BPTOC</td>
<td></td>
</tr>
<tr>
<td></td>
<td>PH1PTRC</td>
<td></td>
</tr>
<tr>
<td>PFCNT</td>
<td>PCGGIO</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PHPIOC</td>
<td>PHPIOC</td>
<td></td>
</tr>
<tr>
<td>PSLPSCH</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PSLPPAM</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>QCBAZ</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>QCRSV</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RCHLCCH</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>REFPDIF</td>
<td></td>
<td></td>
</tr>
<tr>
<td>ROTIPHIZ</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ROV2PTOV</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SAP FRC</td>
<td>SAP FRC</td>
<td></td>
</tr>
<tr>
<td>SAP TOF</td>
<td>SAP TOF</td>
<td></td>
</tr>
<tr>
<td>SAP TUF</td>
<td>SAP TUF</td>
<td></td>
</tr>
<tr>
<td>SCLCVTOC</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SCLCVTOC</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SCLCCH</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SCLCCH</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SCILO</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SCILO</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SCSWI</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SCSWI</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Function block name</th>
<th>Edition 1 logical nodes</th>
<th>Edition 2 logical nodes</th>
</tr>
</thead>
<tbody>
<tr>
<td>SDEPSDE</td>
<td>SDEPSDE</td>
<td>SDEPSDE</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SDEPTOC</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SDEPTOV</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SDEPTRC</td>
</tr>
<tr>
<td>SESRSYN</td>
<td>RSY1LLN0</td>
<td>AUT1RSYN</td>
</tr>
<tr>
<td></td>
<td>AUT1RSYN</td>
<td>MAN1RSYN</td>
</tr>
<tr>
<td></td>
<td>MAN1RSYN</td>
<td>SYNRSYN</td>
</tr>
<tr>
<td>SLGAPC</td>
<td>SLGGIO</td>
<td>SLGAPC</td>
</tr>
<tr>
<td>SMBRREC</td>
<td>SMBRREC</td>
<td>SMBRREC</td>
</tr>
<tr>
<td>SMPPTRC</td>
<td>SMPPTRC</td>
<td>SMPPTRC</td>
</tr>
<tr>
<td>SP16GAPC</td>
<td>SP16GGIO</td>
<td>SP16GAPC</td>
</tr>
<tr>
<td>SPC8GAPC</td>
<td>SPC8GGIO</td>
<td>SPC8GAPC</td>
</tr>
<tr>
<td>SPGAPC</td>
<td>SPGGIO</td>
<td>SPGAPC</td>
</tr>
<tr>
<td>SSCBR</td>
<td>SSCBR</td>
<td>SSCBR</td>
</tr>
<tr>
<td>SSIMG</td>
<td>SSIMG</td>
<td>SSIMG</td>
</tr>
<tr>
<td>SSIML</td>
<td>SSIML</td>
<td>SSIML</td>
</tr>
<tr>
<td>PTRSTHR</td>
<td>PTRSTHR</td>
<td>PTRSTHR</td>
</tr>
<tr>
<td>STBPTOC</td>
<td>STBPTOC</td>
<td>BBPMSS</td>
</tr>
<tr>
<td></td>
<td></td>
<td>STBPTOC</td>
</tr>
<tr>
<td>STEFPHIZ</td>
<td>STEFPHIZ</td>
<td>STEFPHIZ</td>
</tr>
<tr>
<td>STTIPHIZ</td>
<td>STTIPHIZ</td>
<td>STTIPHIZ</td>
</tr>
<tr>
<td>SXCBR</td>
<td>SXCBR</td>
<td>SXCBR</td>
</tr>
<tr>
<td>SXSWI</td>
<td>SXSWI</td>
<td>SXSWI</td>
</tr>
<tr>
<td>T2WPDIF</td>
<td>T2WPDIF</td>
<td>T2WAGAPC</td>
</tr>
<tr>
<td></td>
<td></td>
<td>T2WPDIF</td>
</tr>
<tr>
<td></td>
<td></td>
<td>T2WPHAR</td>
</tr>
<tr>
<td></td>
<td></td>
<td>T2WPTRC</td>
</tr>
<tr>
<td>T3WPDIF</td>
<td>T3WPDIF</td>
<td>T3WAGAPC</td>
</tr>
<tr>
<td></td>
<td></td>
<td>T3WPDIF</td>
</tr>
<tr>
<td></td>
<td></td>
<td>T3WPHAR</td>
</tr>
<tr>
<td></td>
<td></td>
<td>T3WPTRC</td>
</tr>
<tr>
<td>TCLYLTC</td>
<td>TCLYLTC</td>
<td>TCLYLTC</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TCSLTC</td>
</tr>
<tr>
<td>TCMYLTCC</td>
<td>TCMYLTCC</td>
<td>TCMYLTCC</td>
</tr>
<tr>
<td>TEIGAPC</td>
<td>TEIGGIO</td>
<td>TEIGAPC</td>
</tr>
<tr>
<td></td>
<td></td>
<td>TEIGGIO</td>
</tr>
<tr>
<td>TEILGAPC</td>
<td>TEILGGIO</td>
<td>TEILGAPC</td>
</tr>
<tr>
<td>TMAGAPC</td>
<td>TMAGGIO</td>
<td>TMAGAPC</td>
</tr>
<tr>
<td>TPPIOC</td>
<td>TPPIOC</td>
<td>TPPIOC</td>
</tr>
<tr>
<td>TRIATCC</td>
<td>TRIATCC</td>
<td>TRIATCC</td>
</tr>
<tr>
<td>TR8ATCC</td>
<td>TR8ATCC</td>
<td>TR8ATCC</td>
</tr>
<tr>
<td>TRPTTR</td>
<td>TRPTTR</td>
<td>TRPTTR</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Function block name</th>
<th>Edition 1 logical nodes</th>
<th>Edition 2 logical nodes</th>
</tr>
</thead>
<tbody>
<tr>
<td>U2RWPTUV</td>
<td>GEN2LLN0</td>
<td>PH1PTRC</td>
</tr>
<tr>
<td></td>
<td>PH1PTRC</td>
<td>U2RWPTUV</td>
</tr>
<tr>
<td></td>
<td>U2RWPTUV</td>
<td></td>
</tr>
<tr>
<td>UV2PTUV</td>
<td>GEN2LLN0</td>
<td>PH1PTRC</td>
</tr>
<tr>
<td></td>
<td>PH1PTRC</td>
<td>UV2PTUV</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>VDCPTOV</td>
<td>VDCPTOV</td>
<td>VDCPTOV</td>
</tr>
<tr>
<td>VDSPVC</td>
<td>VDRFUF</td>
<td>VDSPVC</td>
</tr>
<tr>
<td>VMMXU</td>
<td>VMMXU</td>
<td>VMMXU</td>
</tr>
<tr>
<td>VMSQI</td>
<td>VMSQI</td>
<td>VMSQI</td>
</tr>
<tr>
<td>VNMMXU</td>
<td>VNMMXU</td>
<td>VNMMXU</td>
</tr>
<tr>
<td>VRPVOC</td>
<td>VRLLN0</td>
<td>PH1PTRC</td>
</tr>
<tr>
<td></td>
<td>PH1PTRC</td>
<td>VRPVOC</td>
</tr>
<tr>
<td></td>
<td>PH1PTUV</td>
<td></td>
</tr>
<tr>
<td></td>
<td>VRPVOC</td>
<td></td>
</tr>
<tr>
<td>VSGAPC</td>
<td>VSGGIO</td>
<td>VSGAPC</td>
</tr>
<tr>
<td>WRNCALH</td>
<td>WRNCALH</td>
<td>WRNCALH</td>
</tr>
<tr>
<td>ZC1PPSCH</td>
<td>ZPCPSCH</td>
<td>ZPCPSCH</td>
</tr>
<tr>
<td>ZC1WPSCH</td>
<td>ZPCWPSCH</td>
<td>ZPCWPSCH</td>
</tr>
<tr>
<td>ZCLCPSCCH</td>
<td>ZCLCPLAL</td>
<td>ZCLCPSCH</td>
</tr>
<tr>
<td>ZCPSCH</td>
<td>ZCPSCH</td>
<td>ZCPSCH</td>
</tr>
<tr>
<td>ZCRWPSCH</td>
<td>ZCRWPSCH</td>
<td>ZCRWPSCH</td>
</tr>
<tr>
<td>ZCVPSOF</td>
<td>ZCVPSOF</td>
<td>ZCVPSOF</td>
</tr>
<tr>
<td>ZGVPDIS</td>
<td>ZGVLLN0</td>
<td>PH1PTRC</td>
</tr>
<tr>
<td></td>
<td>PH1PTRC</td>
<td>ZGVPDIS</td>
</tr>
<tr>
<td></td>
<td>ZGVPTUV</td>
<td></td>
</tr>
<tr>
<td></td>
<td>ZGVPDIS</td>
<td></td>
</tr>
<tr>
<td>ZMCAPDIS</td>
<td>ZMCAPDIS</td>
<td>ZMCAPDIS</td>
</tr>
<tr>
<td>ZMCPDIS</td>
<td>ZMCPDIS</td>
<td>ZMCPDIS</td>
</tr>
<tr>
<td>ZMFCPDIS</td>
<td>ZMFCLLN0</td>
<td>PSFPDIS</td>
</tr>
<tr>
<td></td>
<td>PSFPDIS</td>
<td>ZMFPDIS</td>
</tr>
<tr>
<td></td>
<td>ZMFDDIS</td>
<td>ZMFPDIS</td>
</tr>
<tr>
<td></td>
<td>ZMFPTRC</td>
<td>ZMFPTRC</td>
</tr>
<tr>
<td></td>
<td>ZMMMXU</td>
<td>ZMMMXU</td>
</tr>
<tr>
<td>ZMFPPDIS</td>
<td>ZMFLLNO</td>
<td>PSFPDIS</td>
</tr>
<tr>
<td></td>
<td>PSFPDIS</td>
<td>ZMFPPDIS</td>
</tr>
<tr>
<td></td>
<td>ZMFDDIS</td>
<td>ZMFPPDIS</td>
</tr>
<tr>
<td></td>
<td>ZMFPRC</td>
<td>ZMFPPDIS</td>
</tr>
<tr>
<td></td>
<td>ZMMMXU</td>
<td>ZMFPPDIS</td>
</tr>
<tr>
<td>ZMHPDIS</td>
<td>ZMHPDIS</td>
<td>ZMHPDIS</td>
</tr>
<tr>
<td>ZMMAPDIS</td>
<td>ZMMAPDIS</td>
<td>ZMMAPDIS</td>
</tr>
<tr>
<td>ZMMPDIS</td>
<td>ZMPDIS</td>
<td>ZMPDIS</td>
</tr>
<tr>
<td>ZMQAPDIS</td>
<td>ZMQAPDIS</td>
<td>ZMQAPDIS</td>
</tr>
<tr>
<td>ZMQPDIS</td>
<td>ZMQPDIS</td>
<td>ZMQPDIS</td>
</tr>
<tr>
<td>ZMRAPDIS</td>
<td>ZMRAPDIS</td>
<td>ZMRAPDIS</td>
</tr>
<tr>
<td>Function block name</td>
<td>Edition 1 logical nodes</td>
<td>Edition 2 logical nodes</td>
</tr>
<tr>
<td>---------------------</td>
<td>-------------------------</td>
<td>-------------------------</td>
</tr>
<tr>
<td>ZMRPDIS</td>
<td>ZMRPDIS</td>
<td>ZMRPDIS</td>
</tr>
<tr>
<td>ZMRPSB</td>
<td>ZMRPSB</td>
<td>ZMRPSB</td>
</tr>
<tr>
<td>ZSMGAPC</td>
<td>ZSMGAPC</td>
<td>ZSMGAPC</td>
</tr>
</tbody>
</table>
Section 2 Application

2.1 General IED application

The REG670 is used for protection, control and monitoring of generators and generator-transformer blocks from relatively small units up to the largest generating units. The IED has a comprehensive function library, covering the requirements for most generator applications. The large number of analog inputs available enables, together with the large functional library, integration of many functions in one IED. In typical applications two IED units can provide total functionality, also providing a high degree of redundancy. REG670 can as well be used for protection and control of shunt reactors.

Stator ground fault protection, both traditional 95% as well as 100% injection and 3rd harmonic based are included. When the injection based protection is used, 100% of the machine stator winding, including the star point, is protected under all operating modes. The 3rd harmonic based 100% stator earth fault protection uses 3rd harmonic differential voltage principle. Injection based 100% stator ground fault protection can operate even when machine is at standstill. Well proven algorithms for pole slip, underexcitation, rotor ground fault, negative sequence current protections, and so on, are included in the IED.

The generator differential protection in the REG670 adapted to operate correctly for generator applications where factors as long DC time constants and requirement on short trip time have been considered.

As many of the protection functions can be used as multiple instances there are possibilities to protect more than one object in one IED. It is possible to have protection for an auxiliary power transformer integrated in the same IED having main protections for the generator. The concept thus enables very cost effective solutions.

The REG670 also enables valuable monitoring possibilities as many of the process values can be transferred to an operator HMI.

The wide application flexibility makes this product an excellent choice for both new installations and for refurbishment in existing power plants.

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

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

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

Communication via optical connections ensures immunity against disturbances.
By using patented algorithm REG670 (or any other product from 670 series) can track the power system frequency in quite wide range from 9Hz to 95Hz (for 50Hz power system). In order to do that preferably the three-phase voltage signal from the generator terminals shall be connected to the IED. Then IED can adopt its filtering algorithm in order to properly measure phasors of all current and voltage signals connected to the IED. This feature is essential for proper operation of the protection during generator start-up and shut-down procedure.

REG670 can be used in applications with the IEC/UCA 61850-9-2LE process bus with up to eight merging units (MU) depending on the other functionality included in the IED.

This adaptive filtering is ensured by proper configuration and settings of all relevant pre-processing blocks, see figure 348 and 349. Note that in all pre-configured REG670 IEDs such configuration and settings are already made and that three-phase voltage at the generator terminals are used for frequency tracking. With such settings REG670 will be able to properly estimate the magnitude and the phase angle of measured current and voltage phasors in this wide frequency range.

Note that the following functions will then operate properly in the whole frequency interval:

- Generator differential
- Transformer differential
- Four step overcurrent protection (DFT based measurement)
- Four step residual overcurrent protection
- Over/under voltage protection (DFT based measurement)
- Residual overvoltage protection
- Overexcitation protection
- General current and voltage protection
- Directional over/under power function
- Measurement function (that is, MMXU)
- and so on

Note that during secondary injection testing of this feature, it is absolutely necessary to also inject the voltage signals used for frequency tracking even when a simple overcurrent protection is tested.

If protection for lower frequencies than 9Hz is required (for example, for pump-storage schemes) four step overcurrent protection with RMS measurement shall be used. This function is able to operate for current signals within frequency range from 1Hz up to 100Hz and it is not at all dependent on any voltage signal. Its pickup for very low frequency is only determined by main CT capability to transfer low frequency current signal to the secondary side. However it shall be noted that during such low frequency conditions this function will react on the measured current peak values instead of usual RMS value and that its operation shall be instantaneous (that is, without any intentional time delay). Function can be used either as normal overcurrent function or even as generator differential function when currents from two generator sides are summed and connected to the four step overcurrent function. Typically for such installations dedicated overcurrent steps are used during such low frequency conditions while some other overcurrent steps with different setting for pickup value and time delay are used during normal machine operation. Such logic can be easily arranged in REG670 application configuration tool.

Four step overcurrent protection with RMS measurement shall also be used as machine overcurrent and differential protection during electrical braking. During such operating condition intentional three-phase short-circuit is made at the machine terminal. This will effectively force voltages at the machine terminal to zero and effectively disabled voltage based frequency tracking in REG670. Similar logic as described for pump-storage scheme above can be used.
Figure 2: Generator protection application with generator differential, 100% stator ground fault and back-up protection
Figure 3: Generator protection application for generator with split winding including
generator phase differential, 100% stator ground fault and back-up protection
Figure 4: Generator protection application for generator with split winding including generator phase differential, generator split-phase differential, 100% stator ground fault and back-up protection
Figure 5: Unit protection application with overall differential, generator differential, 100% stator ground fault and back-up protection. Stator winding grounded via grounding transformer.
Figure 6: Unit protection application with overall differential, unit transformer differential, generator differential, 100% stator ground fault and back-up protection. Ungrounded stator winding.
Figure 7: Unit protection application with overall differential, unit transformer differential, generator differential, 100% stator ground fault and back-up protection. Stator winding grounded via primary resistor.

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

### 2.2 Main protection functions

#### Table 2: Example of quantities

<table>
<thead>
<tr>
<th>Code</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>number of basic instances</td>
</tr>
<tr>
<td>0-3</td>
<td>option quantities</td>
</tr>
<tr>
<td>3-A03</td>
<td>optional function included in packages A03 (refer to ordering details)</td>
</tr>
</tbody>
</table>
### Differential protection

<table>
<thead>
<tr>
<th>IEC 61850 or function name</th>
<th>ANSI</th>
<th>Function description</th>
<th>Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td>T2WPDIF</td>
<td>87T</td>
<td>Transformer differential protection, two winding</td>
<td>0-2</td>
</tr>
<tr>
<td>T3WPDIF</td>
<td>87T</td>
<td>Transformer differential protection, three winding</td>
<td>0-2</td>
</tr>
<tr>
<td>HZPDIF</td>
<td>87</td>
<td>High impedance differential protection, single phase</td>
<td>00-06</td>
</tr>
<tr>
<td>GENPDIF</td>
<td>87G</td>
<td>Generator differential protection</td>
<td>0-2</td>
</tr>
<tr>
<td>REFPDIF</td>
<td>87N</td>
<td>Restricted earth fault protection, low impedance</td>
<td>0-3</td>
</tr>
</tbody>
</table>

### Impedance protection

<table>
<thead>
<tr>
<th>IEC 61850 or function name</th>
<th>ANSI</th>
<th>Function description</th>
<th>Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZMHPDIS</td>
<td>21</td>
<td>Full-scheme distance protection, mho characteristic</td>
<td>0-4</td>
</tr>
<tr>
<td>ZDMRDIR</td>
<td>21D</td>
<td>Directional impedance element for mho characteristic</td>
<td>0-2</td>
</tr>
<tr>
<td>ZMFPDIS</td>
<td>21</td>
<td>High speed distance protection, quad and mho characteristic</td>
<td>0-1</td>
</tr>
<tr>
<td>ZMFCPDIS</td>
<td>21</td>
<td>High speed distance protection for series comp. lines, quad and mho characteristic</td>
<td>0-1</td>
</tr>
<tr>
<td>PSPPPAM</td>
<td>78</td>
<td>Poleslip/out-of-step protection</td>
<td>0-1</td>
</tr>
<tr>
<td>OOSPPAM</td>
<td>78</td>
<td>Out-of-step protection</td>
<td>0-1</td>
</tr>
<tr>
<td>LEXPDIS</td>
<td>40</td>
<td>Loss of excitation</td>
<td>0-2</td>
</tr>
<tr>
<td>ROTIPHIZ</td>
<td>64R</td>
<td>Sensitive rotor ground fault protection, injection based</td>
<td>0-1</td>
</tr>
<tr>
<td>STTIPHIZ</td>
<td>64S</td>
<td>100% stator ground fault protection, injection based</td>
<td>0-1</td>
</tr>
<tr>
<td>ZGVPDIS</td>
<td>21</td>
<td>Underimpedance protection for generators and transformers</td>
<td>0-2</td>
</tr>
</tbody>
</table>

### 2.3 Back-up protection functions

<table>
<thead>
<tr>
<th>IEC 61850 or function name</th>
<th>ANSI</th>
<th>Function description</th>
<th>Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td>PHPIOC</td>
<td>50</td>
<td>Instantaneous phase overcurrent protection</td>
<td>0-4</td>
</tr>
<tr>
<td>OC4PTOC</td>
<td>51, 67</td>
<td>Directional phase overcurrent protection, four steps</td>
<td>0-6</td>
</tr>
<tr>
<td>EFPIOC</td>
<td>50N</td>
<td>Instantaneous residual overcurrent protection</td>
<td>0-2</td>
</tr>
<tr>
<td>EF4PTOC</td>
<td>51N, 67</td>
<td>Directional residual overcurrent protection, four steps</td>
<td>0-2</td>
</tr>
<tr>
<td>NS4PTOC</td>
<td>46I2</td>
<td>Four step directional negative phase sequence overcurrent protection</td>
<td>0-2</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>IEC 61850 or function name</th>
<th>ANSI</th>
<th>Function description</th>
<th>REG670 (Customized)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SDEPSDE</td>
<td>67N</td>
<td>Sensitive directional residual overcurrent and power protection</td>
<td>0-2</td>
</tr>
<tr>
<td>TRPTTR</td>
<td>49</td>
<td>Thermal overload protection, two time constants</td>
<td>0-3</td>
</tr>
<tr>
<td>CCRBRF</td>
<td>50BF</td>
<td>Breaker failure protection</td>
<td>0-4</td>
</tr>
<tr>
<td>CCPDSC</td>
<td>52PD</td>
<td>Pole discordance protection</td>
<td>0-4</td>
</tr>
<tr>
<td>GUPPDUP</td>
<td>37</td>
<td>Directional underpower protection</td>
<td>0-4</td>
</tr>
<tr>
<td>GOPPDOP</td>
<td>32</td>
<td>Directional overpower protection</td>
<td>0-4</td>
</tr>
<tr>
<td>NS2PTOC</td>
<td>46I2</td>
<td>Negative sequence time overcurrent protection for machines</td>
<td>0-2</td>
</tr>
<tr>
<td>AEGPVOC</td>
<td>50AE</td>
<td>Accidental energizing protection for synchronous generator</td>
<td>0-2</td>
</tr>
<tr>
<td>VRPVOC</td>
<td>51V</td>
<td>Voltage restrained overcurrent protection</td>
<td>0-3</td>
</tr>
<tr>
<td>GSPTTR</td>
<td>49S</td>
<td>Stator overload protection</td>
<td>0-1</td>
</tr>
<tr>
<td>GRPTTR</td>
<td>49R</td>
<td>Rotor overload protection</td>
<td>0-1</td>
</tr>
<tr>
<td><strong>Voltage protection</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>UV2PTUV</td>
<td>27</td>
<td>Two step undervoltage protection</td>
<td>0-2</td>
</tr>
<tr>
<td>OV2PTOV</td>
<td>59</td>
<td>Two step overvoltage protection</td>
<td>0-2</td>
</tr>
<tr>
<td>ROV2PTOV</td>
<td>59N</td>
<td>Two step residual overvoltage protection</td>
<td>0-3</td>
</tr>
<tr>
<td>OEXPVPH</td>
<td>24</td>
<td>Overexcitation protection</td>
<td>0-2</td>
</tr>
<tr>
<td>VDCPTOV</td>
<td>60</td>
<td>Voltage differential protection</td>
<td>0-2</td>
</tr>
<tr>
<td>STEFPHIZ</td>
<td>59THD</td>
<td>100% stator earth fault protection, 3rd harmonic based</td>
<td>0-1</td>
</tr>
<tr>
<td><strong>Frequency protection</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SAPTUF</td>
<td>81</td>
<td>Underfrequency protection</td>
<td>0-6</td>
</tr>
<tr>
<td>SAPTOF</td>
<td>81</td>
<td>Overfrequency protection</td>
<td>0-6</td>
</tr>
<tr>
<td>SAPFRC</td>
<td>81</td>
<td>Rate-of-change of frequency protection</td>
<td>0-6</td>
</tr>
<tr>
<td>FTAQFVR</td>
<td>81A</td>
<td>Frequency time accumulation protection</td>
<td>0-12</td>
</tr>
<tr>
<td><strong>Multipurpose protection</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CVGAPC</td>
<td></td>
<td>General current and voltage protection</td>
<td>0-9</td>
</tr>
<tr>
<td><strong>General calculation</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SMAIHPAC</td>
<td></td>
<td>Multipurpose filter</td>
<td>0-6</td>
</tr>
</tbody>
</table>

1) 67 requires voltage
2) 67N requires voltage
# 2.4 Control and monitoring functions

<table>
<thead>
<tr>
<th>IEC 61850 or function name</th>
<th>ANSI</th>
<th>Function description</th>
<th>Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>REG670</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>(Customized)</td>
</tr>
<tr>
<td>Control</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SESRSYN</td>
<td>25</td>
<td>Synchrocheck, energizing check and synchronizing</td>
<td>0-2</td>
</tr>
<tr>
<td>APC30</td>
<td>3</td>
<td>Control functionality for up to 6 bays, max 30 objects (6CBs), including interlocking (see Table 4)</td>
<td>0-1</td>
</tr>
<tr>
<td>QCBAY</td>
<td></td>
<td>Bay control</td>
<td>1+5/APC30</td>
</tr>
<tr>
<td>LOCREM</td>
<td></td>
<td>Handling of LR-switch positions</td>
<td>1+5/APC30</td>
</tr>
<tr>
<td>LOCREMCTRL</td>
<td></td>
<td>LHMI control of PSTO</td>
<td>1</td>
</tr>
<tr>
<td>SXCBR</td>
<td></td>
<td>Circuit breaker</td>
<td>18</td>
</tr>
<tr>
<td>TCMYLTC</td>
<td>84</td>
<td>Tap changer control and supervision, 6 binary inputs</td>
<td>0-4</td>
</tr>
<tr>
<td>TCLYLTC</td>
<td>84</td>
<td>Tap changer control and supervision, 32 binary inputs</td>
<td>0-4</td>
</tr>
<tr>
<td>SLGAPC</td>
<td></td>
<td>Logic rotating switch for function selection and LHMI presentation</td>
<td>15</td>
</tr>
<tr>
<td>VSGAPC</td>
<td></td>
<td>Selector mini switch</td>
<td>30</td>
</tr>
<tr>
<td>DPGAPC</td>
<td></td>
<td>Generic communication function for Double Point indication</td>
<td>32</td>
</tr>
<tr>
<td>SPC8GAPC</td>
<td></td>
<td>Single point generic control function 8 signals</td>
<td>5</td>
</tr>
<tr>
<td>AUTOBITS</td>
<td></td>
<td>Automation bits, command function for DNP3.0</td>
<td>3</td>
</tr>
<tr>
<td>SINGLECMD</td>
<td></td>
<td>Single command, 16 signals</td>
<td>8</td>
</tr>
<tr>
<td>I103CMD</td>
<td></td>
<td>Function commands for IEC 60870-5-103</td>
<td>1</td>
</tr>
<tr>
<td>I103GENCMD</td>
<td></td>
<td>Function commands generic for IEC 60870-5-103</td>
<td>50</td>
</tr>
<tr>
<td>I103POSCMD</td>
<td></td>
<td>iED commands with position and select for IEC 60870-5-103</td>
<td>50</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>IEC 61850 or function name</th>
<th>ANSI</th>
<th>Function description</th>
<th>Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td>I103POSCMDV</td>
<td></td>
<td>IED direct commands with position for IEC 60870-5-103</td>
<td>50</td>
</tr>
<tr>
<td>I103IEDCMD</td>
<td></td>
<td>IED commands for IEC 60870-5-103</td>
<td>1</td>
</tr>
<tr>
<td>I103USRCMD</td>
<td></td>
<td>Function commands user defined for IEC 60870-5-103</td>
<td>4</td>
</tr>
</tbody>
</table>

**Secondary system supervision**

<table>
<thead>
<tr>
<th>Function name</th>
<th>ANSI</th>
<th>Description</th>
<th>Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td>CC5SPVC</td>
<td>87</td>
<td>Current circuit supervision</td>
<td>0-5</td>
</tr>
<tr>
<td>FU5SPVC</td>
<td></td>
<td>Fuse failure supervision</td>
<td>0-3</td>
</tr>
<tr>
<td>VD5SPVC</td>
<td>60</td>
<td>Fuse failure supervision based on voltage difference</td>
<td>0-2</td>
</tr>
<tr>
<td>DELVSPVC</td>
<td>7V_78V</td>
<td>Voltage delta supervision, 2 phase</td>
<td>4</td>
</tr>
<tr>
<td>DELISPVC</td>
<td>71</td>
<td>Current delta supervision, 2 phase</td>
<td>4</td>
</tr>
<tr>
<td>DELSPVC</td>
<td>78</td>
<td>Real delta supervision, real</td>
<td>4</td>
</tr>
</tbody>
</table>

**Logic**

<table>
<thead>
<tr>
<th>Function name</th>
<th>ANSI</th>
<th>Description</th>
<th>Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td>SMPPTRC</td>
<td>94</td>
<td>Tripping logic</td>
<td>12</td>
</tr>
<tr>
<td>SMAGAPC</td>
<td></td>
<td>General start matrix block</td>
<td>12</td>
</tr>
<tr>
<td>TMAGAPC</td>
<td></td>
<td>Trip matrix logic</td>
<td>12</td>
</tr>
<tr>
<td>ALMCALH</td>
<td></td>
<td>Logic for group alarm</td>
<td>5</td>
</tr>
<tr>
<td>WRNCALH</td>
<td></td>
<td>Logic for group warning</td>
<td>5</td>
</tr>
<tr>
<td>INDCALH</td>
<td></td>
<td>Logic for group indication</td>
<td>5</td>
</tr>
<tr>
<td>AND, GATE, INV, LLD, OR, PULSETIMER, RSMEMORY, Srmemory, TIMERSET, XOR</td>
<td></td>
<td>Basic configurable logic blocks (see Table 3)</td>
<td>40-420</td>
</tr>
<tr>
<td>ANDQT, INDCOMBSQQT, INDEXTSPQQT, INVALIDQT, INVERTERQT, ORQT, PULSETIMERQT, RSMEMORYQT, SrmemoryQT, TIMERSETQT, XORQT</td>
<td></td>
<td>Configurable logic blocks Q/T (see Table 5)</td>
<td>0-1</td>
</tr>
</tbody>
</table>

Table continues on next page
### IEC 61850 or function name

<table>
<thead>
<tr>
<th>ANSI</th>
<th>Function description</th>
<th>Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td><strong>REG670</strong> (Customized)</td>
<td>0-1</td>
</tr>
<tr>
<td>AND, GATE, INV, LLD, OR, PULSETIMER, RSMemory, SLGAPC, SRMEmory, TIMERSET, VSGAPC, XOR</td>
<td>Extension logic package (see Table 6)</td>
<td></td>
</tr>
<tr>
<td>FXDSIGN</td>
<td>Fixed signal function block</td>
<td>1</td>
</tr>
<tr>
<td>B16I</td>
<td>Boolean to integer conversion, 16 bit</td>
<td>18</td>
</tr>
<tr>
<td>BTIGAPC</td>
<td>Boolean to integer conversion with logical node representation, 16 bit</td>
<td>16</td>
</tr>
<tr>
<td>IB16</td>
<td>Integer to Boolean 16 conversion</td>
<td>18</td>
</tr>
<tr>
<td>ITBGAPC</td>
<td>Integer to Boolean 16 conversion with Logic Node representation</td>
<td>16</td>
</tr>
<tr>
<td>TIGAPC</td>
<td>Delay on timer with input signal integration</td>
<td>30</td>
</tr>
<tr>
<td>TEIGAPC</td>
<td>Elapsed time integrator with limit transgression and overflow supervision</td>
<td>12</td>
</tr>
<tr>
<td>INTCOMP</td>
<td>Comparator for integer inputs</td>
<td>30</td>
</tr>
<tr>
<td>REALCOMP</td>
<td>Comparator for real inputs</td>
<td>30</td>
</tr>
</tbody>
</table>

**Table 3:** Total number of instances for basic configurable logic blocks

<table>
<thead>
<tr>
<th>Basic configurable logic block</th>
<th>Total number of instances</th>
</tr>
</thead>
<tbody>
<tr>
<td>AND</td>
<td>280</td>
</tr>
<tr>
<td>GATE</td>
<td>40</td>
</tr>
<tr>
<td>INV</td>
<td>420</td>
</tr>
<tr>
<td>LLD</td>
<td>40</td>
</tr>
<tr>
<td>OR</td>
<td>298</td>
</tr>
<tr>
<td>PULSETIMER</td>
<td>40</td>
</tr>
<tr>
<td>RSMemory</td>
<td>40</td>
</tr>
<tr>
<td>SRMEmory</td>
<td>40</td>
</tr>
<tr>
<td>TIMERSET</td>
<td>60</td>
</tr>
<tr>
<td>XOR</td>
<td>40</td>
</tr>
</tbody>
</table>
Table 4: Number of function instances in APC30

<table>
<thead>
<tr>
<th>Function name</th>
<th>Function description</th>
<th>Total number of instances</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCILO</td>
<td>Interlocking</td>
<td>30</td>
</tr>
<tr>
<td>BB_ES</td>
<td></td>
<td>6</td>
</tr>
<tr>
<td>A1A2_BS</td>
<td></td>
<td>4</td>
</tr>
<tr>
<td>A1A2_DC</td>
<td></td>
<td>6</td>
</tr>
<tr>
<td>ABC_BC</td>
<td></td>
<td>2</td>
</tr>
<tr>
<td>BH_CONN</td>
<td></td>
<td>2</td>
</tr>
<tr>
<td>BH_LINE_A</td>
<td></td>
<td>2</td>
</tr>
<tr>
<td>BH_LINE_B</td>
<td></td>
<td>2</td>
</tr>
<tr>
<td>DB_BUS_A</td>
<td></td>
<td>3</td>
</tr>
<tr>
<td>DB_BUS_B</td>
<td></td>
<td>3</td>
</tr>
<tr>
<td>DB_LINE</td>
<td></td>
<td>3</td>
</tr>
<tr>
<td>ABC_LINE</td>
<td></td>
<td>6</td>
</tr>
<tr>
<td>AB_TRAFO</td>
<td></td>
<td>4</td>
</tr>
<tr>
<td>SCSWI</td>
<td>Switch controller</td>
<td>30</td>
</tr>
<tr>
<td>SXSWI</td>
<td>Circuit switch</td>
<td>24</td>
</tr>
<tr>
<td>QCRSV</td>
<td>Apparatus control</td>
<td>6</td>
</tr>
<tr>
<td>RESIN1</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>RESIN2</td>
<td></td>
<td>59</td>
</tr>
<tr>
<td>POS_EVAL</td>
<td>Evaluation of position indication</td>
<td>30</td>
</tr>
<tr>
<td>QCBAY</td>
<td>Bay control</td>
<td>5</td>
</tr>
<tr>
<td>LOCREM</td>
<td>Handling of LR-switch positions</td>
<td>5</td>
</tr>
<tr>
<td>XLNPROXY</td>
<td>Proxy for signals from switching device via GOOSE</td>
<td>42</td>
</tr>
<tr>
<td>GOOSEXLNRVC</td>
<td>GOOSE function block to receive a switching device</td>
<td>42</td>
</tr>
</tbody>
</table>

Table 5: Total number of instances for configurable logic blocks Q/T

<table>
<thead>
<tr>
<th>Configurable logic blocks Q/T</th>
<th>Total number of instances</th>
</tr>
</thead>
<tbody>
<tr>
<td>ANDQT</td>
<td>120</td>
</tr>
<tr>
<td>INDCOMBSPQT</td>
<td>20</td>
</tr>
<tr>
<td>INDEXTSPQT</td>
<td>20</td>
</tr>
<tr>
<td>INVALIDQT</td>
<td>22</td>
</tr>
<tr>
<td>INVERTERQT</td>
<td>120</td>
</tr>
<tr>
<td>ORQT</td>
<td>120</td>
</tr>
<tr>
<td>PULSETIMERQT</td>
<td>40</td>
</tr>
<tr>
<td>RSMEMORYQT</td>
<td>40</td>
</tr>
<tr>
<td>SRMEMORYQT</td>
<td>40</td>
</tr>
<tr>
<td>TIMERSETQT</td>
<td>40</td>
</tr>
<tr>
<td>XORQT</td>
<td>40</td>
</tr>
</tbody>
</table>
### Table 6: Total number of instances for extended logic package

<table>
<thead>
<tr>
<th>Extended configurable logic block</th>
<th>Total number of instances</th>
</tr>
</thead>
<tbody>
<tr>
<td>AND</td>
<td>220</td>
</tr>
<tr>
<td>GATE</td>
<td>49</td>
</tr>
<tr>
<td>INV</td>
<td>220</td>
</tr>
<tr>
<td>LLD</td>
<td>49</td>
</tr>
<tr>
<td>OR</td>
<td>220</td>
</tr>
<tr>
<td>PULSETIMER</td>
<td>89</td>
</tr>
<tr>
<td>RSMEMORY</td>
<td>40</td>
</tr>
<tr>
<td>SLGAPC</td>
<td>74</td>
</tr>
<tr>
<td>SRMEMORY</td>
<td>130</td>
</tr>
<tr>
<td>TIMERSET</td>
<td>113</td>
</tr>
<tr>
<td>VSGAPC</td>
<td>120</td>
</tr>
<tr>
<td>XOR</td>
<td>89</td>
</tr>
</tbody>
</table>

### IEC 61850 or function name

<table>
<thead>
<tr>
<th>Function description</th>
<th>Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power system</td>
<td>REG670</td>
</tr>
<tr>
<td>Measurement</td>
<td>(Customized)</td>
</tr>
</tbody>
</table>

### Monitoring

<table>
<thead>
<tr>
<th>Function name</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>CVMMXN</td>
<td>Power system measurement</td>
</tr>
<tr>
<td>CMMXU</td>
<td>Current measurement</td>
</tr>
<tr>
<td>VMMXU</td>
<td>Voltage measurement phase-phase</td>
</tr>
<tr>
<td>CMSQI</td>
<td>Current sequence measurement</td>
</tr>
<tr>
<td>VMSQI</td>
<td>Voltage sequence measurement</td>
</tr>
<tr>
<td>VNMMXU</td>
<td>Voltage measurement phase-ground</td>
</tr>
<tr>
<td>AISVBAS</td>
<td>General service value presentation of analog inputs</td>
</tr>
<tr>
<td>EVENT</td>
<td>Event function</td>
</tr>
<tr>
<td>DRPRDRE,</td>
<td>Disturbance report</td>
</tr>
<tr>
<td>A4RADR,</td>
<td>1</td>
</tr>
<tr>
<td>B1RBDR-B22RBDR</td>
<td></td>
</tr>
<tr>
<td>SPGAPC</td>
<td>Generic communication function for Single Point indication</td>
</tr>
<tr>
<td>SP16GAPC</td>
<td>Generic communication function for Single Point indication 16 inputs</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>IEC 61850 or function name</th>
<th>ANSI</th>
<th>Function description</th>
<th>Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td>MVGAPC</td>
<td></td>
<td>Generic communication function for measured values</td>
<td>24 REG670 (Customized)</td>
</tr>
<tr>
<td>BINSTATREP</td>
<td></td>
<td>Logical signal status report</td>
<td>3</td>
</tr>
<tr>
<td>RANGE_XP</td>
<td></td>
<td>Measured value expander block</td>
<td>66</td>
</tr>
<tr>
<td>SSIMG</td>
<td>63</td>
<td>Insulation supervision for gas medium</td>
<td>21</td>
</tr>
<tr>
<td>SSIML</td>
<td>71</td>
<td>Insulation supervision for liquid medium</td>
<td>3</td>
</tr>
<tr>
<td>SSCBR</td>
<td></td>
<td>Circuit breaker condition monitoring</td>
<td>0-12</td>
</tr>
<tr>
<td>LOLSPTTR</td>
<td>26/49 HS</td>
<td>Transformer insulation loss of life monitoring</td>
<td>0-4</td>
</tr>
<tr>
<td>I103MEAS</td>
<td></td>
<td>Measurands for IEC 60870-5-103</td>
<td>1</td>
</tr>
<tr>
<td>I103MEASUSR</td>
<td></td>
<td>Measurands user defined signals for IEC 60870-5-103</td>
<td>3</td>
</tr>
<tr>
<td>I103AR</td>
<td></td>
<td>Function status auto-recloser for IEC 60870-5-103</td>
<td>1</td>
</tr>
<tr>
<td>I103EF</td>
<td></td>
<td>Function status earth-fault for IEC 60870-5-103</td>
<td>1</td>
</tr>
<tr>
<td>I103FLTPROT</td>
<td></td>
<td>Function status fault protection for IEC 60870-5-103</td>
<td>1</td>
</tr>
<tr>
<td>I103IED</td>
<td></td>
<td>IED status for IEC 60870-5-103</td>
<td>1</td>
</tr>
<tr>
<td>I103SUPERV</td>
<td></td>
<td>Supervision status for IEC 60870-5-103</td>
<td>1</td>
</tr>
<tr>
<td>I103USRDEF</td>
<td></td>
<td>Status for user defined signals for IEC 60870-5-103</td>
<td>20</td>
</tr>
<tr>
<td>L4UFCNT</td>
<td></td>
<td>Event counter with limit supervision</td>
<td>30</td>
</tr>
<tr>
<td>TEILGAPC</td>
<td></td>
<td>Running hour meter</td>
<td>6</td>
</tr>
<tr>
<td>PTRSTHR</td>
<td>51TF</td>
<td>Through fault monitoring</td>
<td>0-2</td>
</tr>
<tr>
<td>CHMMHAI</td>
<td>ITHD</td>
<td>Current harmonic monitoring, 3 phase</td>
<td>0-3</td>
</tr>
<tr>
<td>VHMMHAI</td>
<td>VTHD</td>
<td>Voltage harmonic monitoring, 3 phase</td>
<td>0-3</td>
</tr>
</tbody>
</table>

Table continues on next page
### 2.5 Communication

<table>
<thead>
<tr>
<th>IEC 61850 or function name</th>
<th>ANSI</th>
<th>Function description</th>
<th>Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>REG670</td>
</tr>
<tr>
<td><strong>Metering</strong></td>
<td></td>
<td></td>
<td>(Customized)</td>
</tr>
<tr>
<td>PCFCNT</td>
<td></td>
<td>Pulse-counter logic</td>
<td>16</td>
</tr>
<tr>
<td>ETPMMTR</td>
<td></td>
<td>Function for energy calculation and demand handling</td>
<td>6</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>IEC 61850 or function name</th>
<th>ANSI</th>
<th>Function description</th>
<th>Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>REG670</td>
</tr>
<tr>
<td><strong>Station communication</strong></td>
<td></td>
<td></td>
<td>(Customized)</td>
</tr>
<tr>
<td>ADE</td>
<td></td>
<td>LON communication protocol</td>
<td>1</td>
</tr>
<tr>
<td>HORZCOMM</td>
<td></td>
<td>Network variables via LON</td>
<td>1</td>
</tr>
<tr>
<td>IEC 61850-8-1</td>
<td>IEC 61850</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>GOOSEINTLKRCV</td>
<td></td>
<td>Horizontal communication via GOOSE for interlocking</td>
<td>59</td>
</tr>
<tr>
<td>GOOSEBINRCV</td>
<td></td>
<td>GOOSE binary receive</td>
<td>16</td>
</tr>
<tr>
<td>GOOSEDPRCV</td>
<td></td>
<td>GOOSE function block to receive a double point value</td>
<td>64</td>
</tr>
<tr>
<td>GOOSEINTRCV</td>
<td></td>
<td>GOOSE function block to receive an integer value</td>
<td>32</td>
</tr>
<tr>
<td>GOOSEMVRCV</td>
<td></td>
<td>GOOSE function block to receive a measurand value</td>
<td>60</td>
</tr>
<tr>
<td>GOOSESPRCV</td>
<td></td>
<td>GOOSE function block to receive a single point value</td>
<td>64</td>
</tr>
<tr>
<td>MULTICMDRCV, MULTICMDSND</td>
<td></td>
<td>Multiple command and transmit</td>
<td>60/10</td>
</tr>
<tr>
<td>AGSAL</td>
<td></td>
<td>Generic security application component</td>
<td>1</td>
</tr>
<tr>
<td>LDOLLN0</td>
<td>IEC 61850 LDO LLN0</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>SYSLLN0</td>
<td>IEC 61850 SYS LLN0</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>LPHD</td>
<td></td>
<td>Physical device information</td>
<td>1</td>
</tr>
<tr>
<td>PCMACCS</td>
<td></td>
<td>IED configuration protocol</td>
<td>1</td>
</tr>
<tr>
<td>FSTACCS</td>
<td></td>
<td>Field service tool access</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>IEC 61850-9-2 Process bus communication, 8 merging units</td>
<td>0-1</td>
<td></td>
</tr>
<tr>
<td>ACTIVLOG</td>
<td></td>
<td>Activity logging</td>
<td>1</td>
</tr>
<tr>
<td>ALTRK</td>
<td></td>
<td>Service tracking</td>
<td>1</td>
</tr>
<tr>
<td>PRP</td>
<td>IEC 62439-3 Parallel redundancy protocol</td>
<td>0-1</td>
<td></td>
</tr>
<tr>
<td>HSR</td>
<td>IEC 62439-3 High-availability seamless redundancy</td>
<td>0-1</td>
<td></td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>IEC 61850 or function name</th>
<th>ANSI</th>
<th>Function description</th>
<th>Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td>PMUCONF, PMUREPORT, PHASORREPORT1, ANALOGREPORT1, BINARYREPORT1, SMAI1 - SMAI12, 3PHSUM, PMUSTATUS</td>
<td></td>
<td>Synchrophasor report, 16 phasors (see Table 7)</td>
<td>REG670 (Customized)</td>
</tr>
<tr>
<td>PTP</td>
<td></td>
<td>Precision time protocol</td>
<td>1</td>
</tr>
<tr>
<td>SCHLCCH</td>
<td></td>
<td>Access point diagnostic for non-redundant Ethernet port</td>
<td>6</td>
</tr>
<tr>
<td>RCHLCCH</td>
<td></td>
<td>Access point diagnostic for redundant Ethernet ports</td>
<td>3</td>
</tr>
<tr>
<td>Remote communication</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>BinSignRec1_1, BinSignRec1_2, BinSignReceive2</td>
<td></td>
<td>Binary signal transfer receive</td>
<td>3/3/6</td>
</tr>
<tr>
<td>BinSignTrans1_1, BinSignTrans1_2, BinSignTransm2</td>
<td></td>
<td>Binary signal transfer transmit</td>
<td>3/3/6</td>
</tr>
<tr>
<td>BinSigRec1_12M, BinSigRec1_22M, BinSigTrans1_12M, BinSigTrans1_22M</td>
<td></td>
<td>Binary signal transfer, 2Mbit receive/transmit</td>
<td>3</td>
</tr>
<tr>
<td>LDCMTRN</td>
<td></td>
<td>Transmission of analog data from LDCM</td>
<td>1</td>
</tr>
<tr>
<td>LDCMTRN_2M</td>
<td></td>
<td>Transmission of analog data from LDCM, 2Mbit</td>
<td>6</td>
</tr>
<tr>
<td>LDCMRRecBinStat1, LDCMRRecBinStat2, LDCMRRecBinStat3</td>
<td></td>
<td>Receive binary status from remote LDCM</td>
<td>6/3/3</td>
</tr>
<tr>
<td>LDCMRRecBinS2_2M</td>
<td></td>
<td>Receive binary status from LDCM, 2Mbit</td>
<td>3</td>
</tr>
<tr>
<td>LDCMRRecBinS3_2M</td>
<td></td>
<td>Receive binary status from remote LDCM, 2Mbit</td>
<td>3</td>
</tr>
</tbody>
</table>

Table 7: Number of function instances in Synchrophasor report, 16 phasors

<table>
<thead>
<tr>
<th>Function name</th>
<th>Function description</th>
<th>Number of instances</th>
</tr>
</thead>
<tbody>
<tr>
<td>PMUCONF</td>
<td>Configuration parameters for C37.118 2011 and IEEE1344 protocol</td>
<td>1</td>
</tr>
<tr>
<td>PMUREPORT</td>
<td>Protocol reporting via IEEE 1344 and C37.118</td>
<td>2</td>
</tr>
<tr>
<td>PHASORREPORT1</td>
<td>Protocol reporting of phasor data via IEEE 1344 and C37.118, phasors 1-8</td>
<td>2</td>
</tr>
<tr>
<td>ANALOGREPORT1</td>
<td>Protocol reporting of analog data via IEEE 1344 and C37.118, analogs 1-8</td>
<td>2</td>
</tr>
<tr>
<td>BINARYREPORT1</td>
<td>Protocol reporting of binary data via IEEE 1344 and C37.118, binary 1-8</td>
<td>2</td>
</tr>
<tr>
<td>SMAI1 - SMAI12</td>
<td>Signal matrix for analog inputs</td>
<td>1</td>
</tr>
<tr>
<td>3PHSUM</td>
<td>Summation block 3 phase</td>
<td>6</td>
</tr>
<tr>
<td>PMUSTATUS</td>
<td>Diagnostics for C37.118 2011 and IEEE1344 protocol</td>
<td>1</td>
</tr>
</tbody>
</table>
## 2.6 Basic IED functions

### Table 8: Basic IED functions

<table>
<thead>
<tr>
<th>IEC 61850 or function name</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>INTERRSIG</td>
<td>Self supervision with internal event list</td>
</tr>
<tr>
<td>TIMESYNCHGEN</td>
<td>Time synchronization module</td>
</tr>
<tr>
<td>BININPUT, SYNCHCAN, SYNCHGPS, SYNCHCMPPS, SYNCHLON, SYNCHPPH, SYNCHPPS, Sntp, SYNCHSPA</td>
<td>Time synchronization</td>
</tr>
<tr>
<td>TIMEZONE</td>
<td>Time synchronization</td>
</tr>
<tr>
<td>IRIG-B</td>
<td>Time synchronization</td>
</tr>
<tr>
<td>SETGRPS</td>
<td>Number of setting groups</td>
</tr>
<tr>
<td>ACTVGRP</td>
<td>Parameter setting groups</td>
</tr>
<tr>
<td>TESTMODE</td>
<td>Test mode functionality</td>
</tr>
<tr>
<td>CHNGLCK</td>
<td>Change lock function</td>
</tr>
<tr>
<td>SMBI</td>
<td>Signal matrix for binary inputs</td>
</tr>
<tr>
<td>SMBO</td>
<td>Signal matrix for binary outputs</td>
</tr>
<tr>
<td>SMMI</td>
<td>Signal matrix for mA inputs</td>
</tr>
<tr>
<td>SMAI1 - SMAI12</td>
<td>Signal matrix for analog inputs</td>
</tr>
<tr>
<td>3PHSUM</td>
<td>Summation block 3 phase</td>
</tr>
<tr>
<td>ATHSTAT</td>
<td>Authority status</td>
</tr>
<tr>
<td>ATHCHCK</td>
<td>Authority check</td>
</tr>
<tr>
<td>AUTHMAN</td>
<td>Authority management</td>
</tr>
<tr>
<td>FTPACCS</td>
<td>FTP access with password</td>
</tr>
<tr>
<td>GBASVAL</td>
<td>Global base values for settings</td>
</tr>
<tr>
<td>ALTMS</td>
<td>Time master supervision</td>
</tr>
<tr>
<td>ALTIM</td>
<td>Time management</td>
</tr>
<tr>
<td>COMSTATUS</td>
<td>Protocol diagnostic</td>
</tr>
</tbody>
</table>

### Table 9: Local HMI functions

<table>
<thead>
<tr>
<th>IEC 61850 or function name</th>
<th>ANSI</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>LHMICTRL</td>
<td></td>
<td>Local HMI signals</td>
</tr>
<tr>
<td>LANGUAGE</td>
<td></td>
<td>Local human machine language</td>
</tr>
<tr>
<td>SCREEN</td>
<td></td>
<td>Local HMI Local human machine screen behavior</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>IEC 61850 or function name</th>
<th>ANSI</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>FNKEYTY1–FNKEYTY5</td>
<td></td>
<td>Parameter setting function for HMI in PCM600</td>
</tr>
<tr>
<td>FNKEYMD1–FNKEYMD5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>LEDGEN</td>
<td></td>
<td>General LED indication part for LHMI</td>
</tr>
<tr>
<td>OPENCLOSE_LED</td>
<td></td>
<td>LHMI LEDs for open and close keys</td>
</tr>
<tr>
<td>GRP1_LED1–GRP1_LED15</td>
<td></td>
<td>Basic part for CP HW LED indication module</td>
</tr>
<tr>
<td>GRP2_LED1–GRP2_LED15</td>
<td></td>
<td></td>
</tr>
<tr>
<td>GRP3_LED1–GRP3_LED15</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Section 3 Configuration

3.1 Description of REG670

3.1.1 Introduction

3.1.1.1 Description of configuration A20

REG670 A20 configuration is used in applications where only generator protection within one IED is required. REG670 A20 is always delivered in 1/2 of 19” case size. Thus only 12 analogue inputs are available. This configuration includes generator low impedance, differential protection and all other typically required generator protection functions. Note that 100% stator earth fault function and Pole Slip protection function are optional.

REG670 A20 functional library includes additional functions, which are not configured, such as additional Overcurrent protection, additional Multipurpose protection functions, Synchronizing function, and so on. It is as well possible to order optional two-winding transformer differential or high impedance differential protection functions which than can be used instead of basic low-impedance generator differential protection. Note that REG670 A20 must be re-configured if any additional or optional functions are used.
Figure 8: Typical generator protection application with generator differential and back-up protection, including 12 analog inputs transformers in half 19” case size.

3.1.1.2 Description of configuration B30

REG670 B30 configuration is used in applications where generator protection and backup protection for surrounding primary equipment within one IED is required. REG670 B30 is always...
delivered in 1/1 of 19" case size. Thus 24 analogue inputs are available. This configuration includes
generator low impedance, differential protection and all other typically required generator
protection functions. In figure 9, this configuration is shown.

REG670 B30 functional library includes additional functions, which are not configured, such as
additional Multipurpose protection functions, Synchrocheck function, second generator
differential protection function, and so on. It is as well possible to order optional two- or three-
winding transformer differential protection function, which than can be used as transformer or
block (that is overall) differential protection. Note that REG670 B30 must be re-configured if any
additional or optional functions are used.
**Figure 9:** Enhanced generator protection application with generator differential and back-up protection, including 24 analog inputs in full 19" case size. Optional pole slip protection, 100% stator earth fault protection and overall differential protection can be added.
3.1.1.3 Description of configuration C30

REG670 C30 configuration is used in applications where generator-transformer block protection within one IED is required. REG670 C30 is always delivered in 1/1 of 19" case size. Thus 24 analog inputs are available. This configuration includes generator low impedance, differential protection, transformer differential protection and overall differential protection functions. Note that Pole Slip protection function is optional. See figure 10, example of one possible application.

REG670 C30 functional library includes additional functions, which are not configured, such as additional Multipurpose protection functions, Synchrocheck function, second generator differential protection function, and so on. Note that REG670 C30 must be re-configured if any additional or optional functions are used.
Figure 10: Unit protection including generator and generator transformer protection with 24 analog inputs in full 19" case size. Optional pole slip protection and 100% stator earthfault protection can be added.
Section 4 Analog inputs

4.1 Introduction

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

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

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

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

4.2 Setting guidelines

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

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

4.2.1 Setting of the phase reference channel

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

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

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

4.2.2 Setting of current channels

The direction of a current to the IED is depending on the connection of the CT. Unless indicated otherwise, the main CTs are supposed to be Wye (star) connected and can be connected with the grounding point to the object or from the object. This information must be set in the IED. The convention of the directionality is defined as follows: A positive value of current, power, and so on means that the quantity has the direction into the object and a negative value means direction out from the object. For directional functions the direction into the object is defined as Forward and the direction out from the object is defined as Reverse. See Figure 11.

A positive value of current, power, and so on (forward) means that the quantity flows towards the object. A negative value of current, power, and so on (reverse) means that the quantity flows away from the object. See Figure 11.

![Diagram of directionality](en05000456-2.vsd)

*Figure 11: Internal convention of the directionality in the IED*

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

4.2.2.1 Example 1

Two IEDs used for protection of two objects.
4.2.2.2 Example 2

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

Figure 13: Example how to set CT_WyePoint parameters in the IED

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

4.2.2.3 Example 3

One IED used to protect two objects.
Figure 14: Example how to set CT_WyePoint parameters in the IED

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

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

If the IED has sufficient number of analog current inputs, an alternative solution is shown in Figure 15. The same currents are fed to two separate groups of inputs and the line and transformer protection functions are configured to the different inputs. The CT direction for the current channels to the line protection is set with the line as reference object and the directional functions of the line protection shall be set to Forward to protect the line.
Transformer and Line protection

Setting of current input for transformer functions:
Set parameter CT_WyePoint with Transformer as reference object.
Correct setting is "ToObject"

Setting of current input for line functions:
Set parameter CT_WyePoint with Line as reference object.
Correct setting is "FromObject"

Figure 15: Example how to set CT_WyePoint parameters in the IED
Figure 16: Example how to set CT_WyePoint parameters in the IED

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

The first solution will be to use busbar as a reference object. In that case for all CT inputs marked with 1 in Figure 16, set CT_WyePoint = ToObject, and for all CT inputs marked with 2 in Figure 16, set CT_WyePoint = FromObject.

The second solution will be to use all connected bays as reference objects. In that case for all CT inputs marked with 1 in Figure 16, set CT_WyePoint = FromObject, and for all CT inputs marked with 2 in Figure 16, set CT_WyePoint = ToObject.

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

The main CT ratios must also be set. This is done by setting the two parameters CTsec and CTprim for each current channel. For a 1000/5 A CT, the following settings shall be used:
• $CT_{prim} = 1000$ (value in A)
• $CT_{sec} = 5$ (value in A).

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

Figure 17 defines the marking of current transformer terminals commonly used around the world:

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

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{en06000641.vsd}
\caption{Commonly used markings of CT terminals}
\end{figure}

Where:
\begin{itemize}
  \item [a)] is symbol and terminal marking used in this document. Terminals marked with a square indicates the primary and secondary winding terminals with the same (that is, positive) polarity
  \item [b)] and \item [c)] are equivalent symbols and terminal marking used by IEC (ANSI) standard for CTs. Note that for these two cases the CT polarity marking is correct!
\end{itemize}

It shall be noted that depending on national standard and utility practices, the rated secondary current of a CT has typically one of the following values:
\begin{itemize}
  \item 1A
  \item 5A
\end{itemize}

However, in some cases, the following rated secondary currents are used as well:
\begin{itemize}
  \item 2A
  \item 10A
\end{itemize}

The IED fully supports all of these rated secondary values.
It is recommended to:

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

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

Figure 18 gives an example about the wiring of a wye connected two-phase CT set to the IED. It gives an overview of the actions which are needed to make this measurement available to the built-in protection and control functions within the IED as well.

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

Figure 18: Wye connected three-phase CT set with wye point towards the protected object
Where:

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

2) The current inputs are located in the TRM. It shall be noted that for all these current inputs the following setting values shall be entered for the example shown in Figure 18.
   - CTprim=600A
   - CTsec=5A
   - CTStarPoint=ToObject
   
   Ratio of the first two parameters is only used inside the IED. The third parameter (CTStarPoint=ToObject) as set in this example causes no change on the measured currents. In other words, currents are already measured towards the protected object.

3) These three connections are the links between the three current inputs and the three input channels of the preprocessing function block 4). Depending on the type of functions, which need this current information, more than one preprocessing block might be connected in parallel to the same three physical CT inputs.

4) The preprocessing block that has the task to digitally filter the connected analog inputs and calculate:
   - fundamental frequency phasors for all three input channels
   - harmonic content for all three input channels
   - positive, negative and zero sequence quantities by using the fundamental frequency phasors for the first three input channels (channel one taken as reference for sequence quantities)

   These calculated values are then available for all built-in protection and control functions within the IED, which are connected to this preprocessing function block. For this application most of the preprocessing settings can be left to the default values. If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in power plants), then the setting parameters DFTReference shall be set accordingly. Section SMAI in this manual provides information on adaptive frequency tracking for the signal matrix for analogue inputs (SMAI).

5) A13P in the SMAI function block is a grouped signal which contains all the data about the phases A, B, C and neutral quantity; in particular the data about fundamental frequency phasors, harmonic content and positive sequence, negative and zero sequence quantities are available.

   AI1, AI2, AI3, AI4 are the output signals from the SMAI function block which contain the fundamental frequency phasors and the harmonic content of the corresponding input channels of the preprocessing function block.

   AIN is the signal which contains the fundamental frequency phasors and the harmonic content of the neutral quantity. In this example, GRP2N is not connected so this data is calculated by the preprocessing function block on the basis of the inputs GRP_A, GRP_B and GRP_C. If GRP2N is connected, the data reflects the measured value of GRP2N.

Another alternative is to have the wye point of the three-phase CT set as shown in figure 19:
Figure 19: Wye connected three-phase CT set with its wye point away from the protected object

In the example, everything is done in a similar way as in the above described example (Figure 18). The only difference is the setting of the parameter CTStarPoint of the used current inputs on the TRM (item 2 in Figure 19 and 18):

- \( CT\text{prim}=600\text{A} \)
- \( CT\text{sec}=5\text{A} \)
- \( CT\text{WyePoint}=\text{FromObject} \)

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

A third alternative is to have the residual/neutral current from the three-phase CT set connected to the IED as shown in Figure 19.
Figure 20: Wye connected three-phase CT set with its wye point away from the protected object and the residual/neutral current connected to the IED

Where:

1) Shows how to connect three individual phase currents from a wye connected three-phase CT set to the three CT inputs of the IED.

2) Shows how to connect residual/neutral current from the three-phase CT set to the fourth input in the IED. It shall be noted that if this connection is not made, the IED will still calculate this current internally by vectorial summation of the three individual phase currents.

3) Is the TRM where these current inputs are located. It shall be noted that for all these current inputs the following setting values shall be entered.

- $CT_{prim}=800A$
- $CT_{sec}=1A$
- $CTStarPoint=FromObject$
- $ConnectionType=Ph-N$

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

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

Table continues on next page
5) Is a connection made in the Signal Matrix tool (SMT) and Application configuration tool (ACT), which connects the residual/neutral current input to the fourth input channel of the preprocessing function block 6). Note that this connection in SMT shall not be done if the residual/neutral current is not connected to the IED.

6) Is a Preprocessing block that has the task to digitally filter the connected analog inputs and calculate:
   • fundamental frequency phasors for all input channels
   • harmonic content for all input channels
   • positive, negative and zero sequence quantities by using the fundamental frequency phasors of the first three input channels (channel one taken as reference for sequence quantities)

These calculated values are then available for all built-in protection and control functions within the IED, which are connected to this preprocessing function block in the configuration tool. For this application, most of the preprocessing settings can be left to the default values. If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in the generating stations), then the setting parameters DFTReference shall be set accordingly.

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

Figure 21 gives an example how to connect a delta connected three-phase CT set to the IED. It gives an overview of the required actions by the user in order to make this measurement available to the built-in protection and control functions in the IED as well.

For correct terminal designations, see the connection diagrams valid for the delivered IED.
**Figure 21:** Delta DAB connected three-phase CT set

Where:

1) shows how to connect three individual phase currents from a delta connected three-phase CT set to three CT inputs of the IED.

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

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

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

3) are three connections made in Signal Matrix Tool (SMT), Application configuration tool (ACT), which connect these three current inputs to first three input channels of the preprocessing function block 4).

4) is a Preprocessing block that has the task to digitally filter the connected analog inputs and calculate:

   - fundamental frequency phasors for all three input channels
   - harmonic content for all three input channels
   - positive, negative and zero sequence quantities by using the fundamental frequency phasors for the first three input channels (channel one taken as reference for sequence quantities)

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

If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in the generating stations) then the setting parameters $DFTReference$ shall be set accordingly.
Another alternative is to have the delta connected CT set as shown in figure 22:

![Diagram of Delta DAC connected three-phase CT set](image)

**Figure 22: Delta DAC connected three-phase CT set**

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

- $CT_{prim}=800A$
- $CT_{sec}=1A$
- $CTWyePoint=ToObject$
- $ConnectionType=Ph-Ph$

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

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

Figure 23 gives an example how to connect the single-phase CT to the IED. It gives an overview of the required actions by the user in order to make this measurement available to the built-in protection and control functions within the IED as well.

For correct terminal designations, see the connection diagrams valid for the delivered IED.
Figure 23: Connections for single-phase CT input

Where:

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

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

For connection (a) shown in Figure 23:
- \( CT_{prim} = 1000 \) A
- \( CT_{sec} = 1 \) A
- \( CT_{WyePoint} = ToObject \)

For connection (b) shown in Figure 23:
- \( CT_{prim} = 1000 \) A
- \( CT_{sec} = 1 \) A
- \( CT_{WyePoint} = FromObject \)

3) shows the connection made in SMT tool, which connect this CT input to the fourth input channel of the preprocessing function block 4).

4) is a Preprocessing block that has the task to digitally filter the connected analog inputs and calculate values. The calculated values are then available for all built-in protection and control functions within the IED, which are connected to this preprocessing function block.

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

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

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

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

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

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

### 4.2.4 Setting of voltage channels

As the IED uses primary system quantities, the main VT ratios must be known to the IED. This is done by setting the two parameters \( V_{Tsec} \) and \( V_{Tprim} \) for each voltage channel. The phase-to-phase value can be used even if each channel is connected to a phase-to-ground voltage from the VT.

#### 4.2.4.1 Example

Consider a VT with the following data:

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

(Equation 1)

The following setting should be used: \( V_{Tprim}=132 \) (value in kV) \( V_{Tsec}=120 \) (value in V)

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

Figure 24 defines the marking of voltage transformer terminals commonly used around the world.
Figure 24: Commonly used markings of VT terminals

Where:

a) is the symbol and terminal marking used in this document. Terminals marked with a square indicate the primary and secondary winding terminals with the same (positive) polarity.

b) is the equivalent symbol and terminal marking used by IEC (ANSI) standard for phase-to-ground connected VTs.

c) is the equivalent symbol and terminal marking used by IEC (ANSI) standard for open delta connected VTs.

d) is the equivalent symbol and terminal marking used by IEC (ANSI) standard for phase-to-phase connected VTs.

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

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

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

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

Figure 25 gives an example on how to connect the three phase-to-ground connected VT to the IED. It gives an overview of required actions by the user in order to make this measurement available to the built-in protection and control functions within the IED.

For correct terminal designations, see the connection diagrams valid for the delivered IED.
Figure 25: A Three phase-to-ground connected VT

Figure 26: A two phase-to-earth connected VT
Where:

1) shows how to connect three secondary phase-to-ground voltages to three VT inputs on the IED

2) is the TRM where these three voltage inputs are located. For these three voltage inputs, the following setting values shall be entered:

\[ V_{Tprim} = 132 \text{ kV} \]
\[ V_{Tsec} = 110 \text{ V} \]

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

\[ \frac{66}{110} = \frac{66/\sqrt{3}}{110/\sqrt{3}} \]

(Equation 2)

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

4) shows that in this example the fourth (that is, residual) input channel of the preprocessing block is not connected in SMT tool. Thus the preprocessing block will automatically calculate 3Vo inside by vectorial sum from the three phase to ground voltages connected to the first three input channels of the same preprocessing block. Alternatively, the fourth input channel can be connected to open delta VT input, as shown in Figure 28.

5) is a Preprocessing block that has the task to digitally filter the connected analog inputs and calculate:

- fundamental frequency phasors for all input channels
- harmonic content for all input channels
- positive, negative and zero sequence quantities by using the fundamental frequency phasors for the first three input channels (channel one taken as reference for sequence quantities)

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

\[ V_{Base} = 66 \text{ kV} \] (that is, rated Ph-Ph voltage)

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

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

Figure 27 gives an example how to connect a phase-to-phase connected VT to the IED. It gives an overview of the required actions by the user in order to make this measurement available to the built-in protection and control functions within the IED. It shall be noted that this VT connection is only used on lower voltage levels (that is, rated primary voltage below 40 kV).
Figure 27: A Two phase-to-phase connected VT

Where:
1) shows how to connect the secondary side of a phase-to-phase VT to the VT inputs on the IED
2) is the TRM where these three voltage inputs are located. It shall be noted that for these three voltage inputs the following setting values shall be entered:
   \[ VT_{prim} = 13.8 \text{ kV} \]
   \[ VT_{sec} = 120 \text{ V} \]
   Please note that inside the IED only ratio of these two parameters is used.

Table continues on next page
3) are three connections made in the Signal Matrix tool (SMT), Application configuration tool (ACT), which connects these three voltage inputs to first three input channels of the preprocessing function block 5). Depending on the type of functions, which need this voltage information, more than one preprocessing block might be connected in parallel to these three VT inputs.

4) shows that in this example the fourth (that is, residual) input channel of the preprocessing block is not connected in SMT. Note. If the parameters \( V_A, V_B, V_C, V_N \) should be used the open delta must be connected here.

5) Preprocessing block has a task to digitally filter the connected analog inputs and calculate:

- fundamental frequency phasors for all four input channels
- harmonic content for all four input channels
- positive, negative and zero sequence quantities by using the fundamental frequency phasors for the first three input channels (channel one taken as reference for sequence quantities)

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

- \( \text{ConnectionType}=\text{Ph-Ph} \)
- \( \text{VBase}=13.8 \text{ kV} \)

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

### 4.2.4.5 Example on how to connect an open delta VT to the IED for high impedance grounded or ungrounded networks

Figure 28 gives an example about the wiring of an open delta VT to the IED for high impedance grounded or ungrounded power systems. It shall be noted that this type of VT connection presents a secondary voltage proportional to 3\( V_0 \) to the IED.

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

\[
3V_0 = \sqrt{3} \cdot V_{\text{Ph-Ph}} = 3 \cdot V_{\text{Ph-Gnd}}
\]

(Equation 3)

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

Figure 28 gives overview of required actions by the user in order to make this measurement available to the built-in protection and control functions within the IED as well.
Figure 28: Open delta connected VT in high impedance grounded power system
Where:

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

+3Vo shall be connected to the IED

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

\[ VT_{prim} = \sqrt{3} \times 6.6 = 11.43kV \]  
(Equation 4)

\[ VT_{sec} = 3 \times \frac{110}{3} = 110V \]  
(Equation 5)

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

\[ \frac{\sqrt{3} \times 6.6}{110} = \frac{6.6}{\sqrt{3}} \frac{110}{3} \]  
(Equation 6)

3) shows that in this example the first three input channel of the preprocessing block is not connected in SMT tool or ACT tool.

4) shows the connection made in Signal Matrix Tool (SMT), Application configuration tool (ACT), which connect this voltage input to the fourth input channel of the preprocessing function block 5).

5) is a Preprocessing block that has the task to digitally filter the connected analog input and calculate:

- fundamental frequency phasors for all four input channels
- harmonic content for all four input channels
- positive, negative and zero sequence quantities by using the fundamental frequency phasors for the first three input channels (channel one taken as reference for sequence quantities)

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

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

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

Figure 29 gives an example about the connection of an open delta VT to the IED for low impedance grounded or solidly grounded power systems. It shall be noted that this type of VT connection presents secondary voltage proportional to 3V0 to the IED.
In case of a solid ground fault close to the VT location the primary value of \(3V_0\) will be equal to:

\[
3V_0 = \frac{V_{p-p}}{\sqrt{3}} = V_{ph-gnd}
\]

(Equation 7)

The primary rated voltage of such VT is always equal to \(V_{ph-gnd}\). Therefore, three series connected VT secondary windings will give the secondary voltage equal only to one individual VT secondary winding rating. Thus the secondary windings of such open delta VTs quite often has a secondary rated voltage close to rated phase-to-phase VT secondary voltage, that is, 115V or \(115/\sqrt{3}\)V as in this particular example. Figure 29 gives an overview of the actions which are needed to make this measurement available to the built-in protection and control functions within the IED.

Figure 29: Open delta connected VT in low impedance or solidly grounded power system
Where:
1) shows how to connect the secondary side of open delta VT to one VT input in the IED.

+3Vo shall be connected to the IED.

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

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

(Equation 8)

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

(Equation 9)

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

\[ \frac{138}{115} = \frac{138/\sqrt{3}}{115/\sqrt{3}} \]

(Equation 10)

3) shows that in this example the first three input channel of the preprocessing block is not connected in SMT tool.

4) shows the connection made in Signal Matrix Tool (SMT), which connect this voltage input to the fourth input channel of the preprocessing function block.

5) preprocessing block has a task to digitally filter the connected analog inputs and calculate:

- fundamental frequency phasors for all four input channels
- harmonic content for all four input channels
- positive, negative and zero sequence quantities by using the fundamental frequency phasors for the first three input channels (channel one taken as reference for sequence quantities)

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

If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in the generating stations) then the setting parameters \textit{DFTReference} shall be set accordingly.
4.2.4.7 Example on how to connect a neutral point VT to the IED

Figure 30 gives an example on how to connect a neutral point VT to the IED. This type of VT connection presents secondary voltage proportional to $V_0$ to the IED.

In case of a solid ground fault in high impedance grounded or ungrounded systems the primary value of $V_0$ voltage will be equal to:

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

(Equation 11)

Figure 30 gives an overview of required actions by the user in order to make this measurement available to the built-in protection and control functions within the IED.
Figure 30: Neutral point connected VT
Where:

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

\[ V_0 \] shall be connected to the IED.

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

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

(Equation 12)

\[ VT_{sec} = 100V \]

(Equation 13)

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

3) shows that in this example the first three input channel of the preprocessing block is not connected in SMT tool or ACT tool.

4) shows the connection made in Signal Matrix Tool (SMT), Application configuration tool (ACT), which connects this voltage input to the fourth input channel of the preprocessing function block 5).

5) is a preprocessing block that has the task to digitally filter the connected analog inputs and calculate:

- fundamental frequency phasors for all four input channels
- harmonic content for all four input channels
- positive, negative and zero sequence quantities by using the fundamental frequency phasors for the first three input channels (channel one taken as reference for sequence quantities)

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

If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in the generating stations) then the setting parameters \( DFTReference \) shall be set accordingly.
Section 5  Local HMI

Figure 31:  Local human-machine interface
The LHMI of the IED contains the following elements

- Keypad
- Display (LCD)
- LED indicators
- Communication port for PCM600
The LHMI is used for setting, monitoring and controlling.

5.1 Display

The LHMI includes a graphical monochrome liquid crystal display (LCD) with a resolution of 320 x 240 pixels. The character size can vary.

The display view is divided into four basic areas.

![Display layout](image)

**Figure 32: Display layout**

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

The function key button panel shows on request what actions are possible with the function buttons. Each function button has a LED indication that can be used as a feedback signal for the function button control action. The LED is connected to the required signal with PCM600.
Figure 33: Function button panel

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

Figure 34: Indication LED panel

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

5.2 LEDs

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

There are 3 separate panels of LEDs available. The 15 physical three-color LEDs in one LED group can indicate 45 different signals. Altogether, 135 signals can be indicated since there are three LED groups. The LEDs are lit according to priority, with red being the highest and green the lowest priority. For example, if on one panel there is an indication that requires the green LED to be lit, and on another panel there is an indication that requires the red LED to be lit, the red LED takes priority and is lit. The LEDs can be configured with PCM600 and the operation mode can be selected with the LHMI or PCM600.

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

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

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

![Image](IEC16000076-1-en.vsd)

*Figure 35: OPENCLOSE_LED connected to SXCBR*

### 5.3 Keypad

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

The keypad also contains programmable push-buttons that can be configured either as menu shortcut or control buttons.
Figure 36: LHMI keypad with object control, navigation and command push-buttons and RJ-45 communication port

1...5 Function button
6 Close
7 Open
8 Escape
9 Left
10 Down
11 Up
12 Right
13 Key
14 Enter
15 Remote/Local
16 Uplink LED
17 Not in use
18 Multipage
19 Menu
20 Clear
21 Help
5.4 Local HMI functionality

5.4.1 Protection and alarm indication

Protection indicators

The protection Target LEDs are Normal, Pickup and Trip.

The yellow and red status LEDs are configured in the digital fault recorder function, DRPRDRE, by connecting a pickup or trip signal from the actual function to a BxRBDR binary input function block using the PCM600 and configure the setting to Disabled, Pickup or Trip for that particular signal.

<table>
<thead>
<tr>
<th>Table 10: Normal LED (green)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LED state</td>
</tr>
<tr>
<td>Disabled</td>
</tr>
<tr>
<td>Enabled</td>
</tr>
<tr>
<td>Flashing</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Table 11: Pickup LED (yellow)</th>
</tr>
</thead>
<tbody>
<tr>
<td>LED state</td>
</tr>
<tr>
<td>Disabled</td>
</tr>
<tr>
<td>Enabled</td>
</tr>
<tr>
<td>Flashing</td>
</tr>
</tbody>
</table>
### Table 12: Trip LED (red)

<table>
<thead>
<tr>
<th>LED state</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Disabled</td>
<td>Normal operation.</td>
</tr>
<tr>
<td>Enabled</td>
<td>A protection function has tripped. An indication message is displayed if the auto-indication feature is enabled in the local HMI. The trip indication is latching and must be reset via communication, LHMI or binary input on the LEDGEN component. To open the reset menu on the LHMI, press [Clear].</td>
</tr>
<tr>
<td>Flasing</td>
<td>Configuration mode.</td>
</tr>
</tbody>
</table>

### Alarm indicators

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

### Table 13: Alarm indications

<table>
<thead>
<tr>
<th>LED state</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Disabled</td>
<td>Normal operation. All activation signals are Disabled.</td>
</tr>
</tbody>
</table>
| Enabled   | - Follow-S sequence: The activation signal is Enabled.  
- LatchedColl-S sequence: The activation signal is Enabled, or it is off but the indication has not been acknowledged.  
- LatchedAck-F-S sequence: The indication has been acknowledged, but the activation signal is still Enabled.  
- LatchedAck-S-F sequence: The activation signal is Enabled, or it is off but the indication has not been acknowledged.  
- LatchedReset-S sequence: The activation signal is Enabled, or it is off but the indication has not been acknowledged. |
| Flasing   | - Follow-F sequence: The activation signal is Enabled.  
- LatchedAck-F-S sequence: The activation signal is Enabled, or it is off but the indication has not been acknowledged.  
- LatchedAck-S-F sequence: The indication has been acknowledged, but the activation signal is still Enabled. |

### 5.4.2 Parameter management

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

- Numerical values
- String values
- Enumerated values

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

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

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

![Diagram of RJ-45 port and green indicator LED](image)

*Figure 37: RJ-45 communication port and green indicator LED*

1. RJ-45 connector
2. Green indicator LED

The default IP address for the IED front port is 10.1.150.3 and the corresponding subnetwork mask is 255.255.254.0. It can be set through the local HMI path *Main menu/Configuration/Communication/Ethernet configuration/Front port/AP_FRONT*.

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

- Do not connect the IED front port to a LAN. Connect only a single local PC with PCM600 to the front port. It is only intended for temporary use, such as commissioning and testing.
Section 6  Wide area measurement system

6.1  C37.118 Phasor Measurement Data Streaming Protocol
Configuration PMUCONF

6.1.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Configuration parameters for IEEE 1344 and C37.118 protocol</td>
<td>PMUCONF</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

6.1.2 Application

The IED supports the following IEEE synchrophasor standards:

- IEEE 1344-1995 (Both measurements and data communication)
- IEEE Std C37.118-2005 (Both measurements and data communication)
- IEEE Std C37.118.1-2011 and C37.118.1a-2014 (Measurements)
- IEEE Std C37.118.2-2011 (Data communication)

PMUCONF contains the PMU configuration parameters for both IEEE C37.118 and IEEE 1344 protocols. This means all the required settings and parameters in order to establish and define a number of TCP and/or UDP connections with one or more PDC clients (synchrophasor client). This includes port numbers, TCP/UDP IP addresses, and specific settings for IEEE C37.118 as well as IEEE 1344 protocols.

6.1.3 Operation principle

The Figure 38 demonstrates the communication configuration diagram. As can be seen, the IED can support communication with maximum 8 TCP clients and 6 UDP client groups, simultaneously. Every client can communicate with only one instance of the two available PMUREPORT function block instances at a time. It means that one client cannot communicate with both PMUREPORT:1 and PMUREPORT:2 at the same time. However, multiple clients can communicate with the same instance of PMUREPORT function block at the same time. For TCP clients, each client can decide to communicate with an existing instance of PMUREPORT by knowing the corresponding PMU ID for that PMUREPORT instance. Whereas, for UDP clients, the PMUREPORT instance for each UDP channel is defined by the user in the PMU and the client has to know the PMU ID corresponding to that instance in order to be able to communicate. More information is available in the sections Short guidance for the use of TCP and Short guidance for the use of UDP.
### 6.1.3.1 Short guidance for use of TCP

Port 7001 is used by the SPA on TCP/IP (field service tool). If the port is used for any other protocol, for example C37.118, the SPA on TCP/IP stops working.

The IED supports 8 concurrent TCP connections using IEEE1344 and/or C37.118 protocol. The following parameters are used to define the TCP connection between the IED and the TCP clients:

1. **1344TCPport** – TCP port for control of IEEE 1344 data for TCP clients
2. **C37.118TCPport** – TCP port for control of IEEE C37.118 data for TCP clients

As can be seen, there are two separate parameters in the IED for selecting port numbers for TCP connections; one for IEEE1344 protocol (**1344TCPport**) and another one for C37.118 protocol (**C37.118TCPport**). Client can communicate with the IED over IEEE1344 protocol using the selected TCP port defined in **1344TCPport**, and can communicate with the IED over IEEE C37.118 protocol using the selected TCP port number in **C37.118TCPport**.

All the frames (the header frame, configuration frame, command frame and data frame) are communicated over the same TCP port. The client can request (by sending a command frame) a configuration and/or header via the TCP channel and the requested configuration and/or header will be sent back to the client (as Configuration frame/Header frame) over the same TCP channel.

Once the TCP client connects to the IED, the client has to necessarily send a command frame to start a communication. As shown in Figure 38, the IED can support 2 PMUREPORT instances and the client has to specify the PMU ID Code in order to know which PMUREPORT data needs to be...
sent out to that client. In this figure, X and Y are referring to the user-defined PMU ID Codes for PMUREPORT instances 1 or 2, respectively. It is up to the TCP client to decide which PMUREPORT function block shall communicate with that client. Upon successful reception of the first command by the IED, the PMU ID will be extracted out of the command; if there is a PMUREPORT instance configured in the IED with matching PMU ID, then the client connection over TCP with the IED will be established and further communication will take place. Otherwise, the connection will be terminated and the TCPCtrlCfgErrCnt is incremented in the PMU Diagnostics on the Local HMI under **Main menu/Diagnostics/Communication/PMU diagnostics/PMUSTATUS:1**.

It is possible to turn off/on the TCP data communication by sending a IEEE1344 or C37.118 command frame remotely from the client to the PMU containing RTDOFF/RTDON command.

At any given point of time maximum of 8 TCP clients can be connected to the IED for IEEE1344/ C37.118 protocol. If there is an attempt made by the 9th client, the connection to the new client will be terminated without influencing the connection of the other clients already connected. A list of active clients can be seen on the Local HMI in the diagnostics menu under **Main menu/Diagnostics/Communication/PMU diagnostics/PMUSTATUS:1**.

### 6.1.3.2 Short guidance for use of UDP

The IED supports maximum of 6 concurrent UDP streams. They can be individually configured to send IEEE1344 or C37.118 data frames as unicast / multicast. Note that [x] at the end of each parameter is referring to the UDP stream number (UDP client group) and is a number between 1 and 6. Each of the 6 UDP groups in the IED has the following settings:

1. *SendDataUDP[x]* – Enable / disable UDP data stream
2. *ProtocolOnUDP[x]* – Send IEEE1344 or C37.118 on UDP
3. *PMUReportUDP[x]* – Instance number of PMUREPORT function block that must send data on this UDP stream (UDP client group[x])
4. *UDPDestAddres[x]* – UDP destination address for UDP client group[x] (unicast / multicast address range)
5. *UDPDestPort[x]* – UDP destination port number for UDP client group[x]
6. *TCPportUDPdataCtrl[x]* – TCP port to control of data sent over UDP client group[x], i.e. to receive commands and send configuration frames
7. *SendCfgOnUDP[x]* – Send configuration frame 2 (CFG-2) on UDP for client group[x]

It is possible to turn off/on the UDP data communication either by setting the parameter SendDataUDP[x] to Disable/Enable locally in the PMU or by sending a C37.118 or IEEE1344 command frame (RTDOFF/RTDON) remotely from the client to the PMU as defined in IEEE 1344/ C37.118 standard.

However, such a remote control to stop the streams from the client is only possible when the parameter SendDataUDP[x] is set to SetByProtocol. The command RTDOFF/RTDON sent by the client is stored in the IED, i.e. if the IED is rebooted for some reason, the state of the stream will remain the same.

If the parameter SendDataUDP[x] is set to Enable the RTDOFF/RTDON commands received from the clients are ignored in the IED.

It is recommended not to set the parameter SendDataUDP[x] to SetByProtocol in case of a multicast. This is because if one of the clients sends the RTDOFF command, all the clients will stop receiving the frames.

The UDP implementation in the IED is a UDP_TCP. This means that by default, only the data frames are sent out on UDP stream and the header frame, configuration frame and command frame are
sent over TCP. This makes the communication more reliable especially since commands are sent
over TCP which performs request/acknowledgment exchange to ensure that no data (command in
this case) is lost.

However, by setting the parameter SendCfgOnUDP[x] to Enable, the configuration frame 2 (CFG-2)
of IEEEc37.118 data stream is cyclically sent on the corresponding UDP stream (UDP client
group[x]) once per minute. This is useful in case of multicast UDP data stream when a lot of PMU
clients are receiving the same UDP stream from the same UDP group (UDP client group[x]).

As shown in Figure 38, there are maximum 2 instances of PMUREPORT function blocks available in
the IED. Each UDP client group[x] can only connect to one of the PMUREPORT instances at the
same time. This is defined in the PMU by the parameter PMUReportUDP[x] which is used to define
the instance number of PMUREPORT function block that must send data on this UDP stream (UDP
client group[x]).

The data streams in the IED can be sent as unicast or as multicast. The user-defined IP address set
in the parameter UDPDestAddress[x] for each UDP stream defines if it is a Unicast or Multicast.
The address range 224.0.0.0 to 239.255.255.255 (Class D IP addresses) is treated as multicast. Any
other IP address outside this range is treated as unicast and the UDP data will be only sent to that
specific unicast IP address. In addition to UDPDestAddress[x] parameter, UDPDestPort[x]
parameter is used to define the UDP destination port number for UDP client group[x].

In case of multicast IP, it will be the network switches and routers that take care of replicating the
packet to reach multiple receivers. Multicast mechanism uses network infrastructure efficiently by
requiring the IED to send a packet only once, even if it needs to be delivered to a large number of
receivers.

If there are more than one UDP client group defined as multicast, the user shall set different
multicast IP addresses for each UDP group.

The PMU clients receiving the UDP frames can also connect to the IED to request (command
frame) config frame 1, config frame 2, config frame 3, or header frame, and to disable/enable real
time data. This can be done by connecting to the TCP port selected in TCPportUDPdataCtrl[x] for
each UDP group. This connection is done using TCP. The IED allows 4 concurrent client
connections for every TCPportUDPdataCtrl[x] port (for each UDP client group[x]).

If the client tries to connect on TCPportUDPdataCtrl[x] port using a PMU-ID other than what is
configured for that PMUREPORT instance (PMUReportUDP[x]), then that client is immediately
disconnected and the UDPCtrlCfgErrCnt is incremented in PMU Diagnostics on LHMI at Main
menu/Diagnostics/Communication/PMU diagnostics/PMUSTATUS:1

Even if the parameter SendDataUDP[x] is set to Disable it is still possible for the clients to connect
on the TCP port and request the configuration frames.

6.2 Protocol reporting via IEEE 1344 and C37.118
PMUREPORT

6.2.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Protocol reporting via IEEE 1344 and C37.118</td>
<td>PMUREPORT</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>
6.2.2 Application

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

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

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

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

Multiple PMU functionality can be configured in the IED, which can stream out same or different data at different reporting rates or different performance (service) classes. There are 2 instances of PMU functionality available in the IED. Each instance of PMU functionality includes a set of PMU reporting function blocks tagged by the same instance number (1 or 2). As shown in the following figures, each set of PMU reporting function blocks includes PMUREPORT, PHASORREPORT1-4, ANALOGREPORT1-3, and BINARYREPORT1-3 function blocks. In general, each instance of PMU functionality has 32 configurable phasor channels (PHASORREPORT1–4 blocks), 24 analog channels (ANALOGREPORT1-3 blocks), and 28 digital channels (24 digital-report channels in BINARYREPORT1-3 and 4 trigger-report channels in PMUREPORT function block). Special rules shall be taken into account in PCM600 for Application Configuration and Parameter Settings of multiple PMUREPORT blocks. These rules are explained in the the Application Manual in section PMU Report Function Blocks Connection Rules.

Figure 39 shows both instances of the PMUREPORT function block. As seen, each PMUREPORT instance has 4 predefined binary input signals corresponding to the Bits 03-00: Trigger Reason defined in STAT field of the Data frame in IEEE C37.118.2 standard. These are predefined inputs for Frequency Trigger, Rate of Change of Frequency trigger, Magnitude High and Magnitude Low triggers.

Figure 39: Multiple instances of PMUREPORT function block

Figure 40 shows both instances of the PHASORREPORT function blocks. The instance number is visible in the bottom of each function block. For each instance, there are four separate PHASORREPORT blocks including 32 configurable phasor channels (8 phasor channels in each PHASORREPORT block). Each phasor channel can be configured as a 3-phase (symmetrical components positive/negative/zero) or single-phase phasor (A/B/C).
Figure 40: Multiple instances of PHASORREPORT blocks

Figure 41 shows both instances of ANALOGREPORT function blocks. The instance number is visible in the bottom of each function block. For each instance, there are three separate ANALOGREPORT blocks capable of reporting up to 24 Analog signals (8 Analog signals in each ANALOGREPORT block). These can include for example transfer of active and reactive power or reporting the milliampere input signals to the PDC clients as defined in IEEE C37.118 data frame format.

Figure 41: Multiple instances of ANALOGREPORT blocks

Figure 42 shows both instances of BINARYREPORT function blocks. The instance number is visible in the bottom of each function block. For each instance, there are three separate BINARYREPORT blocks capable of reporting up to 24 Binary signals (8 Binary signals in each BINARYREPORT block). These binary signals can be for example dis-connector or breaker position indications or internal/external protection alarm signals.
6.2.3 Operation principle

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

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

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

\[
TVE = \sqrt{\left(X_r(n) - X_r\right)^2 + \left(X_i(n) - X_i\right)^2} / \sqrt{X_r^2 + X_i^2}
\]

(Equation 14)

where,

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

In order to comply with TVE requirements, special calibration is done in the factory on the analog input channels of the PMU, resulting in increased accuracy of the measurements. The IEEE C37.118 standard also imposes a variety of steady state and dynamic requirements which are fulfilled in the IED with the help of high accuracy measurements and advanced filtering techniques.

Figure 43 shows an overview of the PMU functionality and operation. In this figure, only one instance of PMUREPORT (PMUREPORT1) is shown. Note that connection of different signals to the PMUREPORT, in this figure, is only an example and the actual connections and reported signals on the IEEE C37.118/1344 can be defined by the user.
Figure 43: Overview of reporting functionality (PMUREPORT)

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

### 6.2.3.1 Frequency reporting

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

This adaptive filtering is ensured by proper configuration and settings of all relevant pre-processing blocks, see Signal matrix for analog inputs in the Application manual. Note that in all preconfigured IEDs such configuration and settings are already made and the three-phase voltage are used as master for frequency tracking. With such settings the IED will be able to properly estimate the magnitude and the phase angle of measured current and voltage phasors in this wide frequency range.
One of the important functions of a PMU is reporting a very accurate system frequency to the PDC client. In the IED, each of the PMUREPORT instances is able to report an accurate frequency. Each voltage-connected preprocessor block (SMAI block) delivers the frequency data, derived from the analog input AC voltage values, to the respective voltage phasor channel. Every phasor channel has a user-settable parameter (PhasorXUseFreqSrc) to be used as a source of frequency data for reporting to the PDC client. It is very important to set this parameter to On for the voltage-connected phasor channels. There is an automatic frequency source selection logic to ensure an uninterrupted reporting of the system frequency to the PDC client. In this frequency source selection logic, the following general rules are applied:

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

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

It is possible to monitor the status of the frequency reference channel (frequency source) for the respective PMUREPORT instance on Local HMI under Test/Function status/Communication/Station Communication/PMU Report/PMUREPORT:1/Outputs, where the FREQREFCHSEL output shows the selected channel as the reference for frequency and FREQREFCHERR output states if the reference frequency is good, or if there is an error or if the reference channel is unavailable. For more information refer to the table PMUREPORT monitored data.

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

### 6.2.3.2 Reporting filters

The PMUREPORT function block implements the reporting filters designed to avoid aliasing as the reporting frequency is lower than the sample/calculation frequency. This means, the
The synchrophasor measurement is adaptive as it follows the fundamental frequency over a wide range despite the reporting rate.

For example, when the synchrophasor measurement follows the fundamental frequency beyond the fixed Nyquist limits in C37.118 standard, the anti-aliasing filter stopband moves with the measured fundamental frequency. This has to be considered in connection with C37.118, where the passband is defined relative to a fixed nominal frequency as shown in the equation 15.

\[
f_0 = \frac{F_s}{2}
\]

(Equation 15)

where,

\( f_0 \) is the nominal frequency
\( F_s \) is the reporting rate

### 6.2.3.3 Scaling Factors for ANALOGREPORT channels

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

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

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

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

\[
Scalefactor = \frac{AnalogXRange \times 2}{65535.0}
\]

offset = 0.0

65535.0 = 16 bit integer range

According to the IEEE C37.118.2 standard, the scale factors (conversion factor) for analog channels are defined in configuration frame 2 (CFG-2) and configuration frame 3 (CFG-3) frames as follows:
• **CFG-2 frame**: The field ANUNIT (4 bytes) specifies the conversion factor as a signed 24 bit word for user defined scaling. Since it is a 24 bit integer, in order to support the floating point scale factor, the scale factor itself is multiplied in 10, so that a minimum of 0.1 scale factor can be sent over the CFG-2 frame. The resulting scale factor is rounded to the nearest decimal value. The clients receiving the Analog scale factor over CFG-2 should divide the received scale factor by 10 and then apply it to the corresponding analog data value.

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

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

The following examples show how the scale factor is calculated.

**Example 1:**

AnalogXRange = 3277.0

The scale factor is calculated as follows:

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

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

**Example 2:**

AnalogXRange = 4915.5

The scale factor is calculated as follows:

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

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

**Example 3:**

AnalogXRange = 10000000000

The scale factor is calculated as follows:

$$scalefactor = \frac{(10000000000 \times 2.0)}{65535.5} = 305180.43 \text{ and } offset = 0.0$$
The scale factor will be sent as 3051804 on configuration frame 2, and 305180.43 on configuration frame 3. The range of analog values that can be transmitted in this case is -305181 to -10000000000 and +305181 to +10000000000.

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

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

Rule 1:

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

Figure 44 shows an example of correct connection of SMAI and PHASORREPORT blocks in ACT where both function blocks are working on 0.9 ms cycle time.

Violation of rule 1 results in PMU applications not running at all. The reason is the inconsistent cycle time. For example, in Figure 45, the SMAI block is updating its output every 3 ms while the PHASORREPORT block is expecting input every 0.9 ms. The PHASORREPORT filtering window is designed to receive updated input every 0.9 ms and therefore the application will fail.

Rule 2:

The same SMAI or 3PHSUM block can be connected to more than one PHASORREPORT block only if all the connected PHASORREPORT blocks have similar instance number or only if all the connected blocks have the same cycle time.
PHASORREPORT blocks have similar settings for SvcClass and ReportRate. Figure 46 shows the settings for PMUREPORT function block demonstrated by PCM600 Parameter Setting Tool (PST).

![PMUREPORT settings in PCM600 PST](IEC140000126-2-en.vsd)

**Figure 46:** PMUREPORT settings in PCM600 PST

Figure 47 shows an example of correct connection of SMAI and PHASORREPORT blocks in ACT where two different SMAI blocks are connected to different PHASORREPORT blocks with different instance numbers. In this example, as the PHASORREPORT blocks have different instance numbers and different settings for SvcClass and ReportRate, a separate SMAI block is used for each PHASORREPORT block.

![An example of correct connection of SMAI and PHASORREPORT blocks in ACT](IEC140000127-2-en.vsd)

**Figure 47:** An example of correct connection of SMAI and PHASORREPORT blocks in ACT

Figure 48 shows an example of wrong connection of SMAI and PHASORREPORT blocks in ACT where the same SMAI block is connected to different PHASORREPORT blocks with different instance numbers. Such connection will be only correct if both connected PHASORREPORT blocks have similar settings for SvcClass and ReportRate. If settings for PMUREPORT instances differ for SvcClass or ReportRate, then PHASOR1 connection in PHASORREPORT1 instance 2 will not be compliant with IEEE C37.118 standard. The reason is that the filtering in SMAI/3PHSUM block is adapted according to the performance class (SvcClass) and reporting rate of the connected instance of PHASORREPORT function block. In this example, SMAI1 will adapt its filtering...
according to PHASORREPORT instance 1 (because of higher priority) and therefore PHASORREPORT instance 2 will receive data which does not match its performance class and report rate.

Figure 48: An example of wrong connection of SMAI and PHASORREPORT blocks in ACT

Rule 3:

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

Figure 49 shows an example of correct connection of 3PHSUM and PHASORREPORT blocks in ACT where SMAI3 is configured as the reference block for DFT reference external out (DFTRefExtOut) and 3PHSUM uses external DFT reference (from SMAI3). Figures 50 and 51 show the corresponding setting parameters.
Figure 49: An example of correct connection of 3PHSUM and PHASORREPORT blocks in ACT

Figure 50: SMAI1 setting parameters example-showing that SMAI3 is selected as the DFT reference (DFTRefGrp3)
Figure 51: 3PHSUM setting parameters example—showing that 3PHSUM is using the External DFT reference coming indirectly from SMAI3

Figure 51 shows an example of wrong connection of 3PHSUM and PHASORREPORT blocks in ACT where SMAI3 is configured as the reference block for DFT reference external out (DFTRefExtOut) and 3PHSUM uses external DFT reference (from SMAI3).

Figure 52: An example of wrong connection of 3PHSUM and PHASORREPORT blocks in ACT

If settings for PMUREPORT instances (PHASORREPORT1 instances 1 and 2 above) differ for SvcClass or ReportRate, then the synchrophasor reported by PHASOR2 connection from PHASORREPORT1 instance 2 will not be compliant with IEEE C37.118 standard. The reason is as in the rule 2, the filtering in SMAI/3PHSUM block is adapted according to the performance class (SvcClass) and reporting rate of the connected instance of PHASORREPORT function block. On the other hand, when 3PHSUM uses external DFT reference, it also adapts its filtering according to the SMAI reference block. Therefore, in order to avoid two different filtering applied to the 3PHSUM block, both SMAI reference block and 3PHSUM shall be connected to the same PHASORREPORT instance. In this example (Figure 52), SMAI3 adapts its filtering according to PHASORREPORT1 instance 2 (due to connection) and 3PHSUM is adapting its filtering according to PHASORREPORT1 instance 1. On the other hand, since 3PHSUM is set to receive external DFT reference from SMAI3, therefore if settings for PHASORREPORT1 instances 1 and 2 above differ for SvcClass or
ReportRate, then 3PHSUM block will be affected by two different filtering at the same time which is not possible. For example in Figure 52, PHASOR2 from PHASORREPORT1 instance 1 may not be fully compliant with IEEE C37.118 standard.

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

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

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

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

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

### 6.2.4 Setting guidelines

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

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

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

1. **PMUREPORT** is the main function block which controls the operation of other PMU reporting function blocks. Each instance of PMUREPORT function block has the following parameters:

   - *Operation:* Enables/Disables the operation of the corresponding instance of PMU reporting functionality by choosing On/Off setting.
   - *SvcClass:* It refers to the 1-byte SVC_CLASS field of the configuration frame 3 (CFG-3) organization defined in IEEE C37.118.2 message format. Here the user can select the performance class (service class) used for synchrophasor data measurement according to IEEE C37.118.1 standard. The options are *P class or M class.*

   **Note:** There are 2 PMUREPORT instances available (PMUREPORT:1 and PMUREPORT:2) corresponding to 2 independent data streams. The user can set different or identical service class for each data stream. In case of different service classes, special rules shall be considered in PCM600 ACT for the connection of preprocessor blocks (SMAI) and 3PHSUM blocks to PHASORREPORT blocks. More details are available under section **PMU**
Report Function Blocks Connection Rules in PCM600 Application Configuration Tool (ACT).

- **Global_PMU_ID:** It refers to the 16-byte G_PMU_ID field of the configuration frame 3 (CFG-3) organization defined in IEEE C37.118.2 message format. It is a 16-character (128 bits) user-assigned value which can be sent with the configuration 3 message. It allows uniquely identifying PMUs in a system that has more than 65535 PMUs. The coding for the 16 bytes is left to the user for assignment.

- **PMUdataStreamIDCODE:** It refers to the 2-byte IDCODE field of the configuration frame and data frame organization defined in IEEE C37.118.2 message format. It is a user-assigned ID number (1-65534) for each data stream sent out from the PMU. This is especially important when having multiple data streams (multiple PMU functionality).

  **Note:** The data stream IDCODE is a unique code for each and every data stream in one physical PMU device. In the IED, there are 2 PMUREPORT instances available (PMUREPORT:1 and PMUREPORT:2) corresponding to 2 independent data streams. The user must set different IDCODEs for each instance.

- **PhasorFormat:** It refers to the Bit 0 of the FORMAT field of the configuration frames 1, 2 and 3 organization defined in IEEE C37.118.2 message format. Here the user can select the format of the calculated synchrophasors. The options are **Rectangular or Polar format.** Rectangular format represents the synchrophasor as real and imaginary values, real value first \((a + bj)\) while the Polar format represents the synchrophasor as magnitude and angle, magnitude first \((A e^{j\alpha})\).

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

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

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

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

- **FrequencyDataType:** It refers to the Bit 3 of the FORMAT field of the configuration frames 1, 2 and 3 organization defined in IEEE C37.118.2 message format. Here the user can select the type of the frequency-deviation and rate-of-change-of-frequency data (FREQ/DFREQ) which can be reported along with the synchrophasor data over IEEE C37.118.2 message. The options are **Integer or Float data** corresponding to the 16-bit integer or 32-bit IEEE floating-point value, respectively. The frequency-deviation and rate-of-change-of-frequency data are sent via the FREQ and DFREQ fields of data frame organization of IEEE C37.118.2 message format.
Depends on the selected data type, the size of each field can be 2 (Integer) or 4 (Float) bytes per IEEE C37.118.2 message. The data sent via the FREQ field is frequency deviation from nominal frequency (50 Hz or 60 Hz), in mHz. It is ranged from –32.767 to +32.767 Hz. Integer data type for frequency-deviation data represents 16-bit signed integers, range –32 767 to +32 767 32, and Float data type represents actual frequency value in IEEE floating-point format. The data sent via the DFREQ field is Rate Of Change Of Frequency (ROCOF), in Hertz per second times 100. It is ranged from –327.67 to +327.67 Hz per second. Integer data type for ROCOF data represents 16-bit signed integers, range –32 767 to +32 767 32, and Float data type represents actual value in IEEE floating-point format.

- **SendFreqInfo**: Enables/Disables sending of the frequency-deviation and Rate Of Change Of Frequency (ROCOF) data by choosing On/Off setting.
- **ReportRate**: It refers to the 2-byte DATA_RATE field of the configuration frames 1, 2 and 3 organization defined in IEEE C37.118.2 message format. The DATA_RATE field is identifying the Rate of phasor data transmissions by a 2-byte integer word (–32 767 to +32 767). Here the user can select the synchrophasor data reporting rate from the PMU based on the number of frames per second. In general, the IED has 5 different reporting rates (10, 25, 50, 100, 200 fr/s) on the 50 Hz system frequency, and has 8 different reporting rates (10, 12, 15, 20, 30, 60, 120, 240 fr/s) on the 60 Hz system frequency. The options are as follows:
  - 10/10 fr/s (60/50Hz)
  - 12/10 fr/s (60/50Hz)
  - 15/10 fr/s (60/50Hz)
  - 20/25 fr/s (60/50Hz)
  - 30/25 fr/s (60/50Hz)
  - 60/50 fr/s (60/50Hz)
  - 120/100 fr/s (60/50Hz)
  - 240/200 fr/s (60/50Hz)

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

- **RptTimetag**: It refers to the method of time-tagging used in the IED which is related to the phasor estimation and filtering technique. The options are **FirstSample**, **MiddleSample** and **LastSample**. The time-stamp of the PMU output represents the phasor equivalent, frequency, and ROCOF of the power system signal at the time it is applied to the PMU input. All of these estimates must be compensated for PMU processing delays including analog input filtering, sampling, and estimation group delay. If the sample time tags are compensated for all input delays, the time tag of the sample in the middle of the estimation window can be used for the phasor estimation (output) time tag as long as the filtering coefficients are symmetrical across the filtering window.

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

2. **PHASORREPORT** is the function block responsible for reporting the synchrophasors. Each instance of PMUREPORT function block has 32 phasor channels with the following setting parameters; where X is a number from 1 to 32:

- **PhasorXReport**: Enables/Disables the phasor channel X (reporting of PhasorX) by choosing On/Off setting.
- **PhasorX**: The group selector for PhasorX. Here, the user can select the type of reported synchrophasor from the phasor channel X as either a 3-phase symmetrical component or a single-phase phasor. The options are as follows:
- A
- B
- C
- NEGSEQ
- POSSEQ
- ZEROSEQ

- PhasorXUseFreqSrc: Enables/Disables the contribution of Phasor channel X in automatic frequency source selection by choosing On/Off setting. Each voltage-connected preprocessor block delivers the frequency data, derived from the analog input AC voltage values, to the respective voltage phasor channel. Every phasor channel has a user-settable parameter (PhasorXUseFreqSrc) to be used as a source of frequency data for reporting to the PDC client. It is very important to set this parameter to On for the voltage-connected phasor channels. There is an automatic frequency source selection logic to ensure an uninterrupted reporting of the system frequency to the PDC client. More information is available under the section Frequency reporting.

3. ANALOGREPORT is the function block responsible for reporting the analog values. Each instance of ANALOGREPORT function block has 24 analog channels with the following setting parameters; where X is a number from 1 to 24:

- AnalogXRange: This parameter defines a range between -AnalogXRange and +AnalogXRange for AnalogX value. The range will be used by the IED to apply a proper scale factor to the AnalogX values when Integer format is used. It refers to the 4-byte ANUNIT field of the configuration frames 1, 2 organization and the 8-byte ANSCALE field of the configuration frame 3 organization defined in IEEE C37.118.2 message format. The AnalogXRange value can be a number between 3277.0 and 10000000000. This setting is only important if the AnalogDataType setting is selected as Integer. More information is available under the section Scaling Factors for ANALOGREPORT channels.
- AnalogXUnitType: Unit type for analog signal X. It refers to the 4-byte ANUNIT field of the configuration frames 1, 2 organization defined in IEEE C37.118.2 message format. The options are Single point-on-wave, RMS of analog input and Peak of analog input.
Section 7  Differential protection

7.1  Transformer differential protection T2WPDIF and T3WPDIF (87T)

7.1.1  Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transformer differential protection, two-winding</td>
<td>T2WPDIF</td>
<td></td>
<td>87T</td>
</tr>
<tr>
<td>Transformer differential protection, three-winding</td>
<td>T3WPDIF</td>
<td></td>
<td>87T</td>
</tr>
</tbody>
</table>

7.1.2  Application

The transformer differential protection is a unit protection. It serves as the main protection of transformers in case of winding failure. The protective zone of a differential protection includes the transformer itself, the bus-work or cables between the current transformers and the power transformer. When bushing current transformers are used for the differential IED, the protective zone does not include the bus-work or cables between the circuit breaker and the power transformer.

In some substations there is a current differential protection relay for the busbar. Such a busbar protection will include the bus-work or cables between the circuit breaker and the power transformer. Internal electrical faults are very serious and will cause immediate damage. Short circuits and ground faults in windings and terminals will normally be detected by the differential protection. Interturn faults are flashovers between conductors within the same physical winding. It is possible to detect interturn faults if sufficient number of turns are short-circuited. Interturn faults are the most difficult transformer winding fault to detect with electrical protections. A small interturn fault including just a few turns will result in an undetectable amount of current until it develops into an ground or phase fault. For this reason it is important that the differential protection has a high level of sensitivity and that it is possible to use a sensitive setting without causing unwanted operations during external faults.

It is important that the faulty transformer be disconnected as fast as possible. As the differential protection is a unit protection it can be designed for fast tripping, thus providing selective disconnection of the faulty transformer. The differential protection should never operate on faults outside the protective zone.
A transformer differential protection compares the current flowing into the transformer with the current leaving the transformer. A correct analysis of fault conditions by the differential protection must take into consideration changes due to the voltage, current and phase angle caused by the protected transformer. Traditional transformer differential protection functions required auxiliary transformers for correction of the phase shift and ratio. The numerical microprocessor based differential algorithm as implemented in the IED compensates for both the turn-ratio and the phase shift internally in the software. No auxiliary current transformers are necessary.

The differential current should theoretically be zero during normal load or external faults if the turn-ratio and the phase shift are correctly compensated. However, there are several different phenomena other than internal faults that will cause unwanted and false differential currents. The main reasons for unwanted differential currents may be:

- mismatch due to varying tap changer positions
- different characteristics, loads and operating conditions of the current transformers
- zero sequence currents that only flow on one side of the power transformer
- normal magnetizing currents
- magnetizing inrush currents
- overexcitation magnetizing currents

### 7.1.3 Setting guidelines

The parameters for the Transformer differential protection function are set via the local HMI or Protection and Control IED Manager (PCM600).

#### 7.1.3.1 Restrained and unrestrained differential protection

To make a differential IED as sensitive and stable as possible, restrained differential protections have been developed and are now adopted as the general practice in the protection of power transformers. The protection should be provided with a proportional bias, which makes the protection operate for a certain percentage differential current related to the current through the transformer. This stabilizes the protection under through fault conditions while still permitting the system to have good basic sensitivity. The bias current can be defined in many different ways. One classical way of defining the bias current has been $I_{bias} = (I_1 + I_2) / 2$, where $I_1$ is the magnitude of the power transformer primary current, and $I_2$ the magnitude of the power transformer secondary current. However, it has been found that if the bias current is defined as the highest power transformer current this will reflect the difficulties met by the current transformers much better. The differential protection function uses the highest current of all restrain inputs as bias current. For applications where the power transformer rated current and the CT primary rated current can differ considerably, (applications with T-connections), measured currents in the T connections are converted to pu value using the rated primary current of the CT, but one additional "measuring" point is introduced as sum of this two T currents. This summed current is converted to pu value using the power transformer winding rated currents. After that the highest pu value is taken as bias current in pu. In this way the best possible combination between sensitivity and security for differential protection function with T connection is obtained. The main philosophy behind the principle with the operate bias characteristic is to increase the pickup level when the current transformers have difficult operating conditions. This bias quantity gives the best stability against an unwanted operation during external faults.

The usual practice for transformer protection is to set the bias characteristic to a value of at least twice the value of the expected spill current under through faults conditions. These criteria can vary considerably from application to application and are often a matter of judgment. The second slope is increased to ensure stability under heavy through fault conditions which could lead to
increased differential current due to saturation of current transformers. Default settings for the operating characteristic with $id_{Min} = 0.3pu$ of the power transformer rated current can be recommended as a default setting in normal applications. If the conditions are known more in detail, higher or lower sensitivity can be chosen. The selection of suitable characteristic should in such cases be based on the knowledge of the class of the current transformers, availability of information on the load tap changer position, short circuit power of the systems, and so on.

The second section of the restrain characteristic has an increased slope in order to deal with increased differential current due to additional power transformer losses during heavy loading of the transformer and external fault currents. The third section of the restrain characteristic decreases the sensitivity of the restrained differential function further in order to cope with CT saturation and transformer losses during heavy through faults. A default setting for the operating characteristic with $id_{Min} = 0.3 * I_{Base}$ is recommended in normal applications. If the conditions are known in more detail, higher or lower sensitivity can be chosen. The selection of suitable characteristic should in such cases be based on the knowledge of the class of the current transformers, availability of information on the tap changer position, short circuit power of the systems, and so on.

Transformers can be connected to buses in such ways that the current transformers used for the differential protection will be either in series with the power transformer windings or the current transformers will be in breakers that are part of the bus, such as a breaker-and-a-half or a ring bus scheme. For current transformers with primaries in series with the power transformer winding, the current transformer primary current for external faults will be limited by the transformer impedance. When the current transformers are part of the bus scheme, as in the breaker-and-a-half or the ring bus scheme, the current transformer primary current is not limited by the power transformer impedance. High primary currents may be expected. In either case, any deficiency of current output caused by saturation of one current transformer that is not matched by a similar deficiency of another current transformer will cause a false differential current to appear. Differential protection can overcome this problem if the bias is obtained separately from each set of current transformer circuits. It is therefore important to avoid paralleling of two or more current transformers for connection to a single restraint input. Each current connected to the IED is available for biasing the differential protection function.

The unrestrained operation level has a default value of $id_{Unre} = 10pu$, which is typically acceptable for most of the standard power transformer applications. In the following case, this setting need to be changed accordingly:

- For differential applications on HV shunt reactors, due to the fact that there is no heavy through-fault condition, the unrestrained differential operation level can be set to $id_{Unre} = 1.75pu$

The overall operating characteristic of the transformer differential protection is shown in figure 53.
Section 7
Differential protection

Figure 53: Representation of the restrained, and the unrestrained operate characteristics

\[ \text{slope} = \frac{\Delta I_{\text{operate}}}{\Delta I_{\text{restrain}}} \times 100\% \]  

(Equation 16)

and where the restrained characteristic is defined by the settings:

1. \(\text{IdMin}\)
2. \(\text{EndSection1}\)
3. \(\text{EndSection2}\)
4. \(\text{SlopeSection2}\)
5. \(\text{SlopeSection3}\)

7.1.3.2 Elimination of zero sequence currents

A differential protection may operate undesirably due to external ground-faults in cases where the zero sequence current can flow on only one side of the power transformer, but not on the other side. This is the case when zero sequence current cannot be properly transformed to the other side of the power transformer. Power transformer connection groups of the Wye/Delta or Delta/Wye type cannot transform zero sequence current. If a delta winding of a power transformer
is grounded via a grounding transformer inside the zone protected by the differential protection. There will be an unwanted differential current in case of an external ground-fault. The same is true for an grounded star winding. Even if both the wye and delta winding are earthed, the zero sequence current is usually limited by the grounding transformer on the delta side of the power transformer, which may result in differential current as well. To make the overall differential protection insensitive to external ground-faults in these situations the zero sequence currents must be eliminated from the power transformer IED currents on the grounded windings, so that they do not appear as differential currents. This had once been achieved by means of interposing auxiliary current transformers. The elimination of zero sequence current is done numerically by setting ZSCurrSubtrWx=Disabled or Enabled and doesn't require any auxiliary transformers or zero sequence traps. Instead it is necessary to eliminate the zero sequence current from every individual winding by proper setting of setting parameters ZSCurrSubtrWx=Disabled or Enabled.

In case of a zig-zag winding, use one of the two following options:

- A delta winding
- A wye winding with zero sequence subtraction set to ON

### 7.1.3.3 Inrush restraint methods

With a combination of the second harmonic restraint and the waveform restraint methods it is possible to get a protection with high security and stability against inrush effects and at the same time maintain high performance in case of heavy internal faults even if the current transformers are saturated. Both these restraint methods are used by the IED. The second harmonic restraint function has a settable level. If the ratio of the second harmonic to the fundamental in the differential current is above the settable limit, the operation of the differential protection is restrained. It is recommended to set parameter $i2/i1Ratio = 15\%$ as default value in case no special reasons exist to choose another value.

### 7.1.3.4 Overexcitation restraint method

In case of an overexcited transformer, the winding currents contain odd harmonic components because the currents waveform are symmetrical relative to the time axis. As the third harmonic currents cannot flow into a delta winding, the fifth harmonic is the lowest harmonic which can serve as a criterion for overexcitation. The differential protection function is provided with a fifth harmonic restraint to prevent the protection from operation during an overexcitation condition of a power transformer. If the ratio of the fifth harmonic to the fundamental in the differential current is above a settable limit the operation is restrained. It is recommended to use $i5/i1Ratio = 25\%$ as default value in case no special reasons exist to choose another setting.

Transformers likely to be exposed to overvoltage or underfrequency conditions (that is, generator step-up transformers in power stations) should be provided with a dedicated overexcitation protection based on V/Hz to achieve a trip before the core thermal limit is reached.

### 7.1.3.5 Cross-blocking between phases

Basic definition of the cross-blocking is that one of the three phases can block operation (that is, tripping) of the other two phases due to the harmonic pollution of the differential current in that phase (waveform, 2nd or 5th harmonic content). In the algorithm the user can control the cross-blocking between the phases via the setting parameter CrossBlockEn. When parameter CrossBlockEn is set to Enabled, cross blocking between phases will be introduced. There are no
time related settings involved, but the phase with the operating point above the set bias characteristic will be able to cross-block the other two phases if it is self-blocked by any of the previously explained restrained criteria. As soon as the operating point for this phase is below the set bias characteristic cross blocking from that phase will be inhibited. In this way cross-blocking of the temporary nature is achieved. It should be noted that this is the default (recommended) setting value for this parameter. When parameter CrossBlockEn is set to Disabled, any cross blocking between phases will be disabled.

7.1.3.6 External/Internal fault discriminator

The external/internal fault discriminator operation is based on the relative position of the two phasors (in case of a two-winding transformer) representing the W1 and W2 negative sequence current contributions, defined by matrix expression see the technical reference manual. It practically performs a directional comparison between these two phasors.

In order to perform a directional comparison of the two phasors their magnitudes must be high enough so that one can be sure that they are due to a fault. On the other hand, in order to guarantee a good sensitivity of the internal/external fault discriminator, the value of this minimum limit must not be too high. Therefore this limit value (IMinNegSeq) is settable in the range from 1% to 20% of the differential protections IBasecurrent, which is in our case the power transformer HV side rated current. The default value is 4%. Only if the magnitude of both negative sequence current contributions are above the set limit, the relative position between these two phasors is checked. If either of the negative sequence current contributions, which should be compared, is too small (less than the set value for IMinNegSeq), no directional comparison is made in order to avoid the possibility to produce a wrong decision.

This magnitude check, guarantees stability of the algorithm when the power transformer is energized. In cases where the protected transformer can be energized with a load connected on the LV side (e.g. a step-up transformer in a power station with directly connected auxiliary transformer on its LV side) the value for this setting shall be increased to at least 12%. This is necessary in order to prevent unwanted operation due to LV side currents during the transformer inrush.

The setting NegSeqROA represents the so-called Relay Operate Angle, which determines the boundary between the internal and external fault regions. It can be selected in the range from 30 degrees to 90 degrees, with a step of 1 degree. The default value is 60 degrees. The default setting 60 degrees somewhat favors security in comparison to dependability. If the user has no well-justified reason for another value, 60 degrees shall be applied.

If the above conditions concerning magnitudes are fulfilled, the internal/external fault discriminator compares the relative phase angle between the negative sequence current contributions from the HV side and LV side of the power transformer using the following two rules:

- If the negative sequence currents contributions from HV and LV sides are in phase or at least in the internal fault region, the fault is internal.
- If the negative sequence currents contributions from HV and LV sides are 180 degrees out of phase or at least in the external fault region, the fault is external.

Under external fault condition and with no current transformer saturation, the relative angle is theoretically equal to 180 degrees. During internal fault and with no current transformer saturation, the angle shall ideally be 0 degrees, but due to possible different negative sequence source impedance angles on HV and LV side of power transformer, it may differ somewhat from the ideal zero value.
The internal/external fault discriminator has proved to be very reliable. If a fault is detected, that is, PICKUP signals set by ordinary differential protection, and at the same time the internal/external fault discriminator characterizes this fault as an internal, any eventual blocking signals produced by either the harmonic or the waveform restraints are ignored.

If the bias current is more than 110% of IBase, the negative sequence threshold (IMinNegSeq) is increased internally. This assures response times of the differential protection below one power system cycle (below 16.66 ms for 60 Hz system) for all more severe internal faults. Even for heavy internal faults with severely saturated current transformers this differential protection operates well below one cycle, since the harmonic distortions in the differential currents do not slow down the differential protection operation. Practically, an unrestrained operation is achieved for all internal faults.

External faults happen ten to hundred times more often than internal ones as far as the power transformers are concerned. If a disturbance is detected and the internal/external fault discriminator characterizes this fault as an external fault, the conventional additional criteria are posed on the differential algorithm before its trip is allowed. This assures high algorithm stability during external faults. However, at the same time the differential function is still capable of tripping quickly for evolving faults.

The principle of the internal/external fault discriminator can be extended to autotransformers and transformers with three windings. If all three windings are connected to their respective networks then three directional comparisons are made, but only two comparisons are necessary in order to positively determine the position of the fault with respect to the protected zone. The directional comparisons which are possible, are: W1 - (W2+W3) and W2 - (W1+W3). The rule applied by the internal/external fault discriminator in case of three-winding power transformers is:

- If any comparison indicates an internal fault, then it is an internal fault.
- If any comparison indicates an external fault, then it is an external fault

If one of the windings is not connected, the algorithm automatically reduces to the two-winding version. Nevertheless, the whole power transformer is protected, including the non-connected winding.

### 7.1.3.7 On-line compensation for on-load tap-changer position

The Transformer differential function in the IED has a built-in facility to on-line compensate for on-load tap-changer operation. The following parameters which are set under general settings are related to this compensation feature:

- **Parameter LocationOLTC1** defines the winding where first OLTC (OLTC1) is physically located. The following options are available: Not Used / Winding 1 / Winding 2 / Winding 3. When value Not Used is selected the differential function will assume that OLTC1 does not exist and it will disregard all other parameters related to first OLTC
- **Parameter LowTapPosOLTC1** defines the minimum end tap position for OLTC1 (typically position 1)
- **Parameter RatedTapOLTC1** defines the rated (for example, mid) position for OLTC1 (for example, 11 for OLTC with 21 positions) This tap position shall correspond to the values for rated current and voltage set for that winding
- **Parameter HighTapPsOLTC1** defines the maximum end tap position for OLTC1 (for example, 21 for OLTC with 21 positions)
- **Parameter TapHighVoltTC1** defines the end position for OLTC1 where highest no-load voltage for that winding is obtained (for example, position with maximum number of turns)
- **Parameter StepSizeOLTC1** defines the voltage change per OLTC1 step (for example, 1.5%)
The above parameters are defined for OLTC1. Similar parameters shall be set for second on-load tap-changer designated with OLTC2 in the parameter names, for three–winding differential protection.

### 7.1.3.8 Differential current alarm

Differential protection continuously monitors the level of the fundamental frequency differential currents and gives an alarm if the pre-set value is simultaneously exceeded in all three phases. This feature can be used to monitor the integrity of on-load tap-changer compensation within the differential function. The threshold for the alarm pickup level is defined by setting parameter \( IDiffAlarm \). This threshold should be typically set in such way to obtain operation when on-load tap-changer measured value within differential function differs for more than two steps from the actual on-load tap-changer position. To obtain such operation set parameter \( IDiffAlarm \) equal to two times the on-load tap-changer step size (For example, typical setting value is 5% to 10% of base current). Set the time delay defined by parameter \( tAlarmDelay \) two times longer than the on-load tap-changer mechanical operating time (For example, typical setting value 10s).

### 7.1.3.9 Open CT detection

The Generator differential function has a built-in, advanced open CT detection feature. This feature can block the unexpected operation created by the Generator differential function in case of open CT secondary circuit under normal load condition. An alarm signal can also be issued to station operational personnel to make remedy action once the open CT condition is detected.

The following setting parameters are related to this feature:

- Setting parameter \( OpenCTEnable \) enables/disables this feature
- Setting parameter \( tOCTAlarmDelay \) defines the time delay after which the alarm signal will be given
- Setting parameter \( tOCTReset \) defines the time delay after which the open CT condition will reset once the defective CT circuits have been rectified
- Once the open CT condition has been detected, then all the differential protection functions are blocked except the unrestraint (instantaneous) differential protection

The outputs of open CT condition related parameters are listed below:

- **OpenCT**: Open CT detected
- **OpenCTAlarm**: Alarm issued after the setting delay
- **OpenCTIN**: Open CT in CT group inputs (1 for input 1 and 2 for input 2)
- **OpenCTPH**: Open CT with phase information (1 for phase A, 2 for phase B, 3 for phase C)

### 7.1.3.10 Switch onto fault feature

The Transformer differential function in the IED has a built-in, advanced switch onto fault feature. This feature can be enabled or disabled by the setting parameter \( SOTFMode \). When \( SOTFMode = Enabled \) this feature is enabled. It shall be noted that when this feature is enabled it is not possible to test the 2\(^{nd}\) harmonic blocking feature by simply injecting one current with superimposed second harmonic. In that case the switch on to fault feature will operate and the differential protection will trip. However for a real inrush case the differential protection function will properly restrain from operation.
For more information about the operating principles of the switch onto fault feature please read the Technical Manual.

### 7.1.4 Setting example

#### 7.1.4.1 Introduction

Differential protection for power transformers has been used for decades. In order to correctly apply transformer differential protection proper compensation is needed for:

- power transformer phase shift (vector group compensation)
- CT secondary currents magnitude difference on different sides of the protected transformer (ratio compensation)
- zero sequence current elimination (zero sequence current reduction) shall be done. In the past this was performed with help of interposing CTs or special connection of main CTs (delta connected CTs). With numerical technology all these compensations are done in IED software.

The Differential transformer protection is capable to provide differential protection for all standard three-phase power transformers without any interposing CTs. It has been designed with assumption that all main CTs will be wye connected. For such applications it is then only necessary to enter directly CT rated data and power transformer data as they are given on the power transformer nameplate and differential protection will automatically balance itself.

These are internal compensations within the differential function. The protected power transformer data are always entered as they are given on the nameplate. Differential function will by itself correlate nameplate data and properly select the reference windings.

However the IED can also be used in applications where some of the main CTs are connected in delta. In such cases the ratio for the main CT connected in delta shall be intentionally set for $\sqrt{3}=1.732$ times smaller than actual ratio of individual phase CTs (for example, instead of 800/5 set 462/5) In case the ratio is 800/2.88A, often designed for such typical delta connections, set the ratio as 800/5 in the IED. At the same time the power transformer vector group shall be set as Yy0 because the IED shall not internally provide any phase angle shift compensation. The necessary phase angle shift compensation will be provided externally by delta connected main CT. All other settings should have the same values irrespective of main CT connections. It shall be noted that irrespective of the main CT connections (wye or delta) on-line reading and automatic compensation for actual load tap changer position can be used in the IED.

#### 7.1.4.2 Typical main CT connections for transformer differential protection

Three most typical main CT connections used for transformer differential protection are shown in figure 54. It is assumed that the primary phase sequence is A-B-C.
Figure 54: Commonly used main CT connections for Transformer differential protection.

For wye connected main CTs, secondary currents fed to the IED:
- are directly proportional to the measured primary currents
- are in phase with the measured primary currents
- contain all sequence components including zero sequence current component

For wye connected main CTs, the main CT ratio shall be set as it is in actual application. The “WyePoint” parameter, for the particular wye connection shown in figure 54, shall be set ToObject. If wye connected main CTs have their wye point away from the protected transformer this parameter should be set FromObject.

For delta DAC connected main CTs, secondary currents fed to the IED:
- are increased $\sqrt{3}$ times (1.732 times) in comparison with wye connected CTs
- lag by 30° the primary winding currents (this CT connection rotates currents by 30° in clockwise direction)
- do not contain zero sequence current component

For DAC delta connected main CTs, ratio shall be set for $\sqrt{3}$ times smaller than the actual ratio of individual phase CTs. The “WyePoint” parameter, for this particular connection shall be set ToObject. It shall be noted that delta DAC connected main CTs must be connected exactly as shown in figure 54.

For delta DAB connected main CTs, secondary currents fed to the IED:
- are increased $\sqrt{3}$ times (1.732 times) in comparison with wye connected CTs
- lead by 30° the primary winding currents (this CT connection rotates currents by 30° in anti-clockwise direction)
- do not contain zero sequence current component
For DAB delta connected main CT ratio shall be set for $\sqrt{3}$ times smaller in RET 670 than the actual ratio of individual phase CTs. The “WyePoint” parameter, for this particular connection shall be set ToObject. It shall be noted that delta DAB connected main CTs must be connected exactly as shown in figure 54.

For more detailed info regarding CT data settings please refer to the three application examples presented in section "Application Examples".

### 7.1.4.3 Application Examples

Three application examples will be given here. For each example two differential protection solutions will be presented:

- First solution will be with all main CTs wye connected.
- Second solution will be with delta connected main CT on Y (that is, wye) connected sides of the protected power transformer.

For each differential protection solution the following settings will be given:

1. Input CT channels on the transformer input modules.
2. General settings for the transformer differential protection where specific data about protected power transformer shall be entered.

Finally the setting for the differential protection characteristic will be given for all presented applications.

**Example 1: Wye-delta connected power transformer without on-load tap-changer**

Single line diagrams for two possible solutions for such type of power transformer with all relevant application data are given in figure 55.
For this particular power transformer the 69 kV side phase-to-ground no-load voltages lead by 30 degrees the 12.5 kV side phase-to-ground no-load voltages. Thus when external phase angle shift compensation is done by connecting main HV CTs in delta, as shown in the right-hand side in figure 55, it must be ensured that the HV currents are rotated by 30° in clockwise direction. Thus the DAC delta CT connection must be used for 69 kV CTs in order to put 69 kV & 12.5 kV currents in phase.

To ensure proper application of the IED for this power transformer it is necessary to do the following:

1. Check that HV & LV CTs are connected to 5 A CT inputs in the IED.
2. For second solution make sure that HV delta connected CTs are DAC connected.
3. For wye connected CTs make sure how they are stared (that is, grounded) to/from protected transformer.
4. Enter the following settings for all three CT input channels used for the LV side CTs see table 15.

Table 15: CT input channels used for the LV side CTs

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Selected value for both solutions</th>
</tr>
</thead>
<tbody>
<tr>
<td>CTprim</td>
<td>800</td>
</tr>
<tr>
<td>CTsec</td>
<td>5</td>
</tr>
<tr>
<td>CT_WyePoint</td>
<td>ToObject</td>
</tr>
</tbody>
</table>
5. Enter the following settings for all three CT input channels used for the HV side CTs, see table 16.

**Table 16: CT input channels used for the HV side CTs**

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Selected value for solution 1 (wye connected CT)</th>
<th>Selected value for solution 2 (delta connected CT)</th>
</tr>
</thead>
</table>
| CTprim            | 300                                           | $\frac{300}{\sqrt{3}} = 173$  
(Equation 17) |
| CTsec             | 5                                             | 5                                             |
| CT_WyePoint       | From Object                                   | ToObject                                      |

To compensate for delta connected CTs, see equation 17.

6. Assume GBASVAL:1 is used for winding 1 (W1, HV-side) base values: Set Ibase = 175 A (rated current), Ubase= 69 kV (rated voltage).

7. Assume GBASVAL:2 is used for winding 2 (W2, LV-side) base values: Set Ibase = 965 A (rated current), Ubase= 12.5 kV (rated voltage).

8. Enter the following values for the general settings of the Transformer differential protection function, see table 17.

**Table 17: General settings of the differential protection function**

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Select value for solution 1 (wye connected CT)</th>
<th>Selected value for solution 2 (delta connected CT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>GlobalBaseSelW1</td>
<td>1 (GBASVAL:1)</td>
<td>1 (GBASVAL:1)</td>
</tr>
<tr>
<td>GlobalBaseSelW2</td>
<td>2 (GBASVAL:2)</td>
<td>2 (GBASVAL:2)</td>
</tr>
<tr>
<td>ConnectTypeW1</td>
<td>WYE (Y)</td>
<td>WYE (Y)</td>
</tr>
<tr>
<td>ConnectTypeW2</td>
<td>delta=d</td>
<td>wy=es 1)</td>
</tr>
<tr>
<td>ClockNumberW2</td>
<td>1 [30 deg lag]</td>
<td>0 [0 deg] 1)</td>
</tr>
<tr>
<td>ZSCurrSubtrW1</td>
<td>On</td>
<td>Off 2)</td>
</tr>
<tr>
<td>ZSCurrSubtrW2</td>
<td>Off</td>
<td>Off</td>
</tr>
<tr>
<td>TconfigForW1</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>TconfigForW2</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>LocationOLTC1</td>
<td>Not used</td>
<td>Not used</td>
</tr>
<tr>
<td>Other Parameters</td>
<td>Not relevant for this application. Use default value.</td>
<td>Not relevant for this application. Use default value.</td>
</tr>
</tbody>
</table>

1) To compensate for delta connected CTs
2) Zero-sequence current is already removed by connecting main CTs in delta

**Delta-wye connected power transformer without tap changer**

Single line diagrams for two possible solutions for such type of power transformer with all relevant application data are given in figure 56.
Figure 56: Two differential protection solutions for delta-wye connected power transformer

For this particular power transformer the 115 kV side phase-to-ground no-load voltages lead by 30° the 24.9 kV side phase-to-ground no-load voltages. Thus when external phase angle shift compensation is done by connecting main 24.9 kV CTs in delta, as shown in the right-hand side in figure 56, it must be ensured that the 24.9 kV currents are rotated by 30° in anti-clockwise direction. Thus, the DAB CT delta connection (see figure 56) must be used for 24.9 kV CTs in order to put 115 kV & 24.9 kV currents in phase.

To ensure proper application of the IED for this power transformer it is necessary to do the following:

1. Check that HV & LV CTs are connected to 5 A CT inputs in the IED.
2. For second solution make sure that LV delta connected CTs are DAB connected.
3. For wye connected CTs make sure how they are 'star'ed (that is, grounded) to/from protected transformer.
4. Enter the following settings for all three CT input channels used for the HV side CTs, see table 18.

Table 18: CT input channels used for the HV side CTs

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Selected value for both solutions</th>
</tr>
</thead>
<tbody>
<tr>
<td>CTprim</td>
<td>400</td>
</tr>
<tr>
<td>CTsec</td>
<td>5</td>
</tr>
<tr>
<td>CT_WyePoint</td>
<td>ToObject</td>
</tr>
</tbody>
</table>
5. Enter the following settings for all three CT input channels used for the LV side CTs, see table "CT input channels used for the LV side CTs".

### CT input channels used for the LV side CTs

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Selected value for Solution 1 (wye connected CT)</th>
<th>Selected value for Solution 2 (delta connected CT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CTprim</td>
<td>1500</td>
<td>$\frac{1500}{\sqrt{3}} = 866$ (^\text{(Equation 18)})</td>
</tr>
<tr>
<td>CTsec</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>CT_WyePoint</td>
<td>ToObject</td>
<td>ToObject</td>
</tr>
</tbody>
</table>

To compensate for delta connected CTs, see equation \(^{18}\).

6. Assume GBASVAL:1 is used for winding 1 (W1, HV-side) base values: Set $I_{\text{base}} = 301$ A (rated current), $U_{\text{base}} = 115$ kV (rated voltage).

7. Assume GBASVAL:2 is used for winding 2 (W2, LV-side) base values: Set $I_{\text{base}} = 1391$ A (rated current), $U_{\text{base}} = 24.9$ kV (rated voltage).

8. Enter the following values for the general settings of the differential protection function, see table\(^{19}\).

#### Table 19: General settings of the differential protection

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>selected value for both Solution 1 (wye connected CT)</th>
<th>Selected value for both Solution 2 (delta connected CT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>GlobalBaseSelW1</td>
<td>1 (GBASVAL:1)</td>
<td>1 (GBASVAL:1)</td>
</tr>
<tr>
<td>GlobalBaseSelW2</td>
<td>2 (GBASVAL:2)</td>
<td>2 (GBASVAL:2)</td>
</tr>
<tr>
<td>ConnectTypeW1</td>
<td>Delta (D)</td>
<td>WYE (Y) (^{1)})</td>
</tr>
<tr>
<td>ConnectTypeW2</td>
<td>wye=y</td>
<td>wye=y</td>
</tr>
<tr>
<td>ClockNumberW2</td>
<td>1 [30 deg lag]</td>
<td>0 [0 deg] (^{1)})</td>
</tr>
<tr>
<td>ZSCurrSubtrW1</td>
<td>Off</td>
<td>Off</td>
</tr>
<tr>
<td>ZSCurrSubtrW2</td>
<td>On</td>
<td>On (^{2)})</td>
</tr>
<tr>
<td>TconfigForW1</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>TconfigForW2</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>LocationOLTC1</td>
<td>Not Used</td>
<td>Not Used</td>
</tr>
<tr>
<td>Other parameters</td>
<td>Not relevant for this application. Use default value.</td>
<td>Not relevant for this application. Use default value.</td>
</tr>
</tbody>
</table>

\(^{1)}\) To compensate for delta connected CTs.

\(^{2)}\) Zero-sequence current is already removed by connecting main CTs in delta.
**Wye-wye connected power transformer with load tap changer and tertiary not loaded delta winding**

Single line diagrams for two possible solutions for such type of power transformer with all relevant application data are given in figure 57. It shall be noted that this example is applicable for protection of autotransformer with not loaded tertiary delta winding as well.

---

**Figure 57: Two differential protection solutions for wye-wye connected transformer.**

For this particular power transformer the 110 kV side phase-to-ground no-load voltages are exactly in phase with the 36.75 kV side phase-to-ground no-load voltages. Thus, when external phase angle shift compensation is done by connecting main CTs in delta, both set of CTs must be identically connected (that is, either both DAC or both DAB as shown in the right-hand side in figure 57) in order to put 110 kV & 36.75 kV currents in phase.

To ensure proper application of the IED for this power transformer it is necessary to do the following:

1. Check that HV CTs are connected to 1 A CT inputs in the IED.
2. Check that LV CTs are connected to 5 A CT inputs in the IED.
3. When delta connected CTs are used make sure that both CT sets are identically connected (that is, either both DAC or both DAB).
4. For wye connected CTs make sure how they are 'star'ed (that is, grounded) towards or away from the protected transformer.
5. Enter the following settings for all three CT input channels used for the HV side CTs, see table 20.
Table 20: CT input channels used for the HV side CTs

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Selected value for both solution 1 (wye connected CTs)</th>
<th>Selected value for both solution 2 (delta connected CTs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CTprim</td>
<td>200</td>
<td>[ \frac{200}{\sqrt{3}} = 115 ] \hspace{1cm} (Equation 19)</td>
</tr>
<tr>
<td>CTsec</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>CT_WyePoint</td>
<td>FromObject</td>
<td>ToObject</td>
</tr>
</tbody>
</table>

To compensate for delta connected CTs, see equation 19.

6. Enter the following settings for all three CT input channels used for the LV side CTs

7. Assume GBASVAL:1 is used for winding 1 (W1, HV-side) base values: Set Ibase = 165 A (rated current), Ubase= 110 kV (rated voltage).

8. Assume GBASVAL:2 is used for winding 2 (W2, LV-side) base values: Set Ibase = 495 A (rated current), Ubase= 36.75 kV (rated voltage).

Table 21: CT input channels used for the LV side CTs

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Selected value for both solution 1 (wye connected)</th>
<th>Selected value for both solution 2 (delta connected)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CTprim</td>
<td>500</td>
<td>[ \frac{500}{\sqrt{3}} = 289 ] \hspace{1cm} (Equation 20)</td>
</tr>
<tr>
<td>CTsec</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>CT_WyePoint</td>
<td>ToObject</td>
<td>ToObject</td>
</tr>
</tbody>
</table>

To compensate for delta connected CTs, see equation 20.

9. Enter the following values for the general settings of the differential protection function, see table 22

Table 22: General settings of the differential protection function

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Selected value for both solution 1 (wye connected)</th>
<th>Selected value for both solution 2 (delta connected)</th>
</tr>
</thead>
<tbody>
<tr>
<td>GlobalBaseSelW1</td>
<td>1 (GBASVAL:1)</td>
<td>1 (GBASVAL:1)</td>
</tr>
<tr>
<td>GlobalBaseSelW2</td>
<td>2 (GBASVAL:2)</td>
<td>2 (GBASVAL:2)</td>
</tr>
<tr>
<td>ConnectTypeW1</td>
<td>WYE (Y)</td>
<td>WYE (Y)</td>
</tr>
<tr>
<td>ConnectTypeW2</td>
<td>wye=y</td>
<td>wye=y</td>
</tr>
<tr>
<td>ClockNumberW2</td>
<td>0 [0 deg]</td>
<td>0 [0 deg]</td>
</tr>
</tbody>
</table>

Table continues on next page
### Setting Parameter Configuration

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Selected value for both Solution 1 (wye connected)</th>
<th>Selected value for both Solution 2 (delta connected)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZSCurrSubtrW1</td>
<td>On</td>
<td>Off 1)</td>
</tr>
<tr>
<td>ZSCurrSubtrW2</td>
<td>On</td>
<td>Off 1)</td>
</tr>
<tr>
<td>TconfigForW1</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>TconfigForW2</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>LocationOLT1</td>
<td>Winding 1 (W1)</td>
<td>Winding 1 (W1)</td>
</tr>
<tr>
<td>LowTapPosOLTC1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>RatedTapOLTC1</td>
<td>12</td>
<td>12</td>
</tr>
<tr>
<td>HighTapPsOLTC1</td>
<td>23</td>
<td>23</td>
</tr>
<tr>
<td>TapHighVoltTC1</td>
<td>23</td>
<td>23</td>
</tr>
<tr>
<td>StepSizeOLTC1</td>
<td>1.5%</td>
<td>1.5%</td>
</tr>
<tr>
<td>Other parameters</td>
<td>Not relevant for this application. Use default value.</td>
<td>Not relevant for this application. Use default value.</td>
</tr>
</tbody>
</table>

1) Zero-sequence current is already removed by connecting main CTs in delta.

### 7.1.4.4 Summary and conclusions

The IED can be used for differential protection of three-phase power transformers with main CTs either wye or delta connected. However the IED has been designed with the assumption that all main CTs are wye connected. The IED can be used in applications where the main CTs are delta connected. For such applications the following shall be kept in mind:

1. The ratio for delta connected CTs shall be set $\sqrt{3}=1.732$ times smaller than the actual individual phase CT ratio.
2. The power transformer phase-shift shall typically be set as Yy0 because the compensation for power transformer the actual phase shift is provided by the external delta CT connection.
3. The zero sequence current is eliminated by the main CT delta connections. Thus on sides where CTs are connected in delta the zero sequence current elimination shall be set to Off in the IED.

The following table summarizes the most commonly used wye-delta phase-shift around the world and provides information about the required type of main CT delta connection on the wye side of the protected transformer.
<table>
<thead>
<tr>
<th>IEC vector group</th>
<th>ANSI designation</th>
<th>Positive sequence no-load voltage phasor diagram</th>
<th>Required delta CT connection type on wye side of the protected power transformer and internal vector group setting in the IED</th>
</tr>
</thead>
<tbody>
<tr>
<td>YNd1</td>
<td>YD&lt;sub&gt;AC&lt;/sub&gt;</td>
<td><img src="image" alt="YD_AC" /></td>
<td>DAC/Yy0</td>
</tr>
<tr>
<td>Dyn1</td>
<td>D&lt;sub&gt;AB&lt;/sub&gt;Y</td>
<td><img src="image" alt="D_AB_Y" /></td>
<td>DAB/Yy0</td>
</tr>
<tr>
<td>YNd11</td>
<td>YD&lt;sub&gt;AB&lt;/sub&gt;</td>
<td><img src="image" alt="YD_AB" /></td>
<td>DAB/Yy0</td>
</tr>
<tr>
<td>Dyn11</td>
<td>D&lt;sub&gt;AC&lt;/sub&gt;Y</td>
<td><img src="image" alt="D_AC_Y" /></td>
<td>DAC/Yy0</td>
</tr>
<tr>
<td>YNd5</td>
<td>YD150</td>
<td><img src="image" alt="YD_150" /></td>
<td>DAB/Yy6</td>
</tr>
<tr>
<td>Dyn5</td>
<td>DY150</td>
<td><img src="image" alt="DY_150" /></td>
<td>DAC/Yy6</td>
</tr>
</tbody>
</table>
7.2 High impedance differential protection, single phase HZPDIF (87)

7.2.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>High impedance differential protection, single phase</td>
<td>HZPDIF</td>
<td>Id</td>
<td>87</td>
</tr>
</tbody>
</table>

7.2.2 Application

The 1Ph High impedance differential protection function HZPDIF (87) can be used as:

- Generator differential protection
- Reactor differential protection
- Busbar differential protection
- Autotransformer differential protection (for common and serial windings only)
- T-feeder differential protection
- Capacitor differential protection
- Restricted ground fault protection for transformer, generator and shunt reactor windings
- Restricted ground fault protection

The application is dependent on the primary system arrangements and location of breakers, available CT cores and so on.
7.2.2.1 The basics of the high impedance principle

The high impedance differential protection principle has been used for many years and is well documented in literature publicly available. Its operating principle provides very good sensitivity and high speed operation. One main benefit offered by the principle is an absolute stability (that is, no operation) for external faults even in the presence of heavy CT saturation. The principle is based on the CT secondary current circulating between involved current transformers and not through the IED due to high impedance in the measuring branch. This stabilizing resistance is in the range of hundreds of ohms and sometimes above one kilo Ohm. When an internal fault occurs the current cannot circulate and is forced through the measuring branch causing relay operation.

It should be remembered that the whole scheme, its built-in components and wiring must be adequately maintained throughout the lifetime of the equipment in order to be able to withstand the high voltage peaks (that is, pulses) which may appear during an internal fault. Otherwise any flash-over in CT secondary circuits or any other part of the scheme may prevent correct operation of the high impedance differential relay for an actual internal fault.

![Diagram of high impedance differential protection](en05000164_ansi.vsd)

*Figure 58: Different applications of a 1Ph High impedance differential protection HZPDIF (87) function*

*Figure 59: Example for the high impedance restricted earth fault protection application*

For a through fault one current transformer might saturate when the other CTs still will feed current. For such a case a voltage will be developed across the measuring branch. The calculations
are made with the worst situations in mind and a minimum operating voltage $V_R$ is calculated according to equation 21

$$VR > IF_{\text{max}} \cdot (Rct + RL)$$

(Equation 21)

where:
- $IF_{\text{max}}$ is the maximum through fault current at the secondary side of the CT
- $Rct$ is the current transformer secondary winding resistance and
- $RL$ is the maximum loop resistance of the circuit at any CT.

The minimum operating voltage has to be calculated (all loops) and the IED function is set higher than the highest achieved value (setting $TripPickup$). As the loop resistance is the value to the connection point from each CT, it is advisable to do all the CT core summations in the switchgear to have shortest possible loops. This will give lower setting values and also a better balanced scheme. The connection in to the control room can then be from the most central bay.

For an internal fault, all involved CTs will try to feed current through the measuring branch. Depending on the size of current transformer, relatively high voltages will be developed across the series resistor. Note that very high peak voltages can appear. To prevent the risk of flashover in the circuit, a voltage limiter must be included. The voltage limiter is a voltage dependent resistor (Metrosil).

The external unit with stabilizing resistor has a value of either 6800 ohms or 1800 ohms (depending on ordered alternative) with a sliding link to allow adjustment to the required value. Select a suitable value of the resistor based on the VR voltage calculated. A higher resistance value will give a higher sensitivity and a lower value a lower sensitivity of the relay.

The function has a recommended operating current range 40 mA to 1.0A for 1 A inputs and 200 mA to 5A for 5A inputs. This, together with the selected and set value, is used to calculate the required value of current at the set $TripPickup$ and $R$ series values.

The CT inputs used for 1Ph High impedance differential protection HZPDIF (87) function, shall be set to have ratio 1:1. So the parameters $CT_{secx}$ and $CT_{primx}$ of the relevant channel x of TRM and/or AIM shall be set equal to 1 A by PST in PCM600; The parameter $CTStarPointx$ may be set to ToObject.

The tables 23, 24 below show, the operating currents for different settings of operating voltages and selected resistances. Adjust as required based on tables 23, 24 or to values in between as required for the application.

Minimum ohms can be difficult to adjust due to the small value compared to the total value.

Normally the voltage can be increased to higher values than the calculated minimum $TripPickup$ with a minor change of total operating values as long as this is done by adjusting the resistor to a higher value. Check the sensitivity calculation below for reference.
### Table 23: 1 A channels: input with minimum operating down to 40 mA

<table>
<thead>
<tr>
<th>Operating voltage</th>
<th>Stabilizing resistor R ohms</th>
<th>Operating current level 1 A</th>
<th>Stabilizing resistor R ohms</th>
<th>Operating current level 1 A</th>
</tr>
</thead>
<tbody>
<tr>
<td>20 V</td>
<td>500</td>
<td>0.040 A</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>40 V</td>
<td>1000</td>
<td>0.040 A</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>60 V</td>
<td>1500</td>
<td>0.040 A</td>
<td>600</td>
<td>0.100 A</td>
</tr>
<tr>
<td>80 V</td>
<td>2000</td>
<td>0.040 A</td>
<td>800</td>
<td>0.100 A</td>
</tr>
<tr>
<td>100 V</td>
<td>2500</td>
<td>0.040 A</td>
<td>1000</td>
<td>0.100 A</td>
</tr>
<tr>
<td>150 V</td>
<td>3750</td>
<td>0.040 A</td>
<td>1500</td>
<td>0.100 A</td>
</tr>
<tr>
<td>200 V</td>
<td>5000</td>
<td>0.040 A</td>
<td>2000</td>
<td>0.100 A</td>
</tr>
</tbody>
</table>

### Table 24: 5 A channels: input with minimum operating down to 100 mA

<table>
<thead>
<tr>
<th>Operating voltage</th>
<th>Stabilizing resistor R ohms</th>
<th>Operating current level 5 A</th>
<th>Stabilizing resistor R ohms</th>
<th>Operating current level 5 A</th>
</tr>
</thead>
<tbody>
<tr>
<td>20 V</td>
<td>200</td>
<td>0.100 A</td>
<td>100</td>
<td>0.200 A</td>
</tr>
<tr>
<td>40 V</td>
<td>400</td>
<td>0.100 A</td>
<td>200</td>
<td>0.200 A</td>
</tr>
<tr>
<td>60 V</td>
<td>600</td>
<td>0.100 A</td>
<td>300</td>
<td>0.200 A</td>
</tr>
<tr>
<td>80 V</td>
<td>800</td>
<td>0.100 A</td>
<td>400</td>
<td>0.200 A</td>
</tr>
<tr>
<td>100 V</td>
<td>1000</td>
<td>0.100 A</td>
<td>500</td>
<td>0.200 A</td>
</tr>
<tr>
<td>150 V</td>
<td>1500</td>
<td>0.100 A</td>
<td>750</td>
<td>0.200 A</td>
</tr>
<tr>
<td>200 V</td>
<td>2000</td>
<td>0.100 A</td>
<td>1000</td>
<td>0.200 A</td>
</tr>
</tbody>
</table>

The current transformer saturation voltage must be at least $2 \times \text{TripPickup}$ to have sufficient operating margin. This must be checked after calculation of TripPickup.

When the R value has been selected and the TripPickup value has been set, the sensitivity of the scheme IP can be calculated. The IED sensitivity is decided by the total current in the circuit according to equation 22.

$$IP = n \cdot (IR + Ires + \sum Imag)$$

(Equation 22)

where:

- $n$ is the CT ratio
- $IP$ primary current at IED pickup,
- $IR$ IED pickup current ($U>Trip/\text{SeriesResistor}$)
- $Ires$ is the current through the voltage limiter and
- $\sum Imag$ is the sum of the magnetizing currents from all CTs in the circuit (for example, 4 for restricted earth fault protection, 2 for reactor differential protection, 3-5 for autotransformer differential protection).
It should be remembered that the vectorial sum of the currents must be used (IEDs, Metrosil and resistor currents are resistive). The current measurement is insensitive to DC component in fault current to allow the use of only the AC components of the fault current in the above calculations.

The voltage dependent resistor (Metrosil) characteristic is shown in Figure 66.

**Series resistor thermal capacity**
The series resistor is dimensioned for 200 W. Care shall be exercised while testing to ensure that if current needs to be injected continuously or for a significant duration of time, check that the heat dissipation Vxxx Series Resistance value does not exceed 200 W. Otherwise injection time shall be reduced to the minimum.
Figure 60: The high impedance principle for one phase with two current transformer inputs
7.2.3 Connection examples for high impedance differential protection

**WARNING! USE EXTREME CAUTION!** Dangerously high voltages might be present on this equipment, especially on the plate with resistors. De-energize the primary object protected with this equipment before connecting or disconnecting wiring or performing any maintenance. The plate with resistors should be provided with a protective cover, mounted in a separate box or in a locked cubicle. National law and standards shall be followed.

7.2.3.1 Connections for three-phase high impedance differential protection

Generator, reactor or busbar differential protection is a typical application for three-phase high impedance differential protection. Typical CT connections for three-phase high impedance differential protection scheme are shown in figure 61.

<table>
<thead>
<tr>
<th>Pos</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Scheme grounding point</td>
</tr>
</tbody>
</table>

It is important to insure that only one grounding point exist in this scheme.

**Figure 61:** CT connections for high impedance differential protection
Three-phase plate with setting resistors and metrosils. Protective ground is a separate 4 mm screw terminal on the plate.

Necessary connection for three-phase metrosil set.

Position of optional test switch for secondary injection into the high impedance differential IED.

Necessary connection for setting resistors.

Factory-made star point on a three-phase setting resistor set.

The star point connector must be removed for installations with 670 series IEDs. This star point is required for RADHA schemes only.

Connections of three individual phase currents for high impedance scheme to three CT inputs in the IED.

7.2.3.2 Connections for 1Ph High impedance differential protection HZPDIF (87)

Restricted earth fault protection is a typical application for 1Ph High impedance differential protection HZPDIF (87). Typical CT connections for the high impedance based protection scheme are shown in figure 62.
<table>
<thead>
<tr>
<th>Pos</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Scheme grounding point</td>
</tr>
</tbody>
</table>

Ensure that only one grounding point exists in this scheme.

| 2   | One-phase plate with stabilizing resistor and metrosil. Protective ground is a separate 4 mm screw terminal on the plate. |
| 3   | Necessary connection for the metrosil. |
| 4   | Position of optional test switch for secondary injection into the high impedance differential IED. |
| 5   | Necessary connection for stabilizing resistor. |
| 6   | How to connect the high impedance restricted earth fault protection scheme to one CT input in IED. |

### 7.2.4 Setting guidelines

The setting calculations are individual for each application. Refer to the different application descriptions below.

#### 7.2.4.1 Configuration

The configuration is done in the Application Configuration tool.

#### 7.2.4.2 Settings of protection function

*Operation*: The operation of the high impedance differential function can be switched *Enabled* or *Disabled*.

*AlarmPickup*: Set the alarm level. The sensitivity can roughly be calculated as a certain percentage of the selected Trip level. A typical setting is 10% of *TripPickup*. This alarm stage can be used for scheme CT supervision.

*tAlarm*: Set the time delay for the alarm. A typical setting is 2-3 seconds.

*TripPickup*: Set the trip level according to the calculations (see examples below for a guidance). The level is selected with margin to the calculated required voltage to achieve stability. Values can be within 20V - 400V range dependent on the application.

*R series*: Set the value of the used stabilizing series resistor. Calculate the value according to the examples for each application. Adjust the resistor as close as possible to the calculated value. Measure the value achieved and set this value for this parameter.

The value shall always be high impedance. This means for example, for 1A circuits say bigger than 400 ohms (400 VA) and for 5 A circuits say bigger than 100 ohms (2500 VA). This ensures that the current will circulate and not go through the differential circuit at through faults.
That the settings of U>Alarm, U>Trip and SeriesResistor must be chosen such that both U>Alarm/SeriesResistor and U>Trip/SeriesResistor are >4% of IRated of the used current input. Normally the settings shall also be such that U>Alarm/SeriesResistor and U>Trip/SeriesResistor both gives a value <4*IRated of the used current input. If not, the limitation in how long time the actual current is allowed to persist not to overload the current input must be considered especially during the secondary testing.

7.2.4.3 T-feeder protection

In many busbar arrangements such as breaker-and-a-half, ring breaker, mesh corner, there will be a T-feeder from the current transformer at the breakers up to the current transformers in the feeder circuit (for example, in the transformer bushings). It is often required to separate the protection zones that the feeder is protected with one scheme while the T-zone is protected with a separate differential protection scheme. The 1Ph high impedance differential HZPDIF (87) function in the IED allows this to be done efficiently, see Figure 63.
Figure 63: The protection scheme utilizing the high impedance function for the T-feeder

Normally this scheme is set to achieve a sensitivity of around 20 percent of the used CT primary rating so that a low ohmic value can be used for the series resistor.
It is strongly recommended to use the highest tap of the CT whenever high impedance protection is used. This helps in utilizing maximum CT capability, minimize the secondary fault current, thereby reducing the stability voltage limit. Another factor is that during internal faults, the voltage developed across the selected tap is limited by the non-linear resistor but in the unused taps, owing to auto-transformer action, voltages induced may be much higher than design limits.

**Setting example**

**Basic data:**

- Current transformer ratio: 2000/5A
- CT Class: C800 (At max tap of 2000/5A)
- Secondary resistance: 0.5 Ohm (2000/5A tap)
- Cable loop resistance: 2
- Max fault current: Equal to switchgear rated fault current 40 kA

**Calculation:**

\[
VR > \frac{40000}{400} \times 0.5 \times 0.4 = 90V
\]

(Equation 23)

Select a setting of TripPickup = 100 V.

The current transformer saturation voltage must be at least twice the set operating voltage TripPickup.

\[
V_{kneeANSI} > (0.5 + 8) \times 100 \times 0.7 = 595V
\]

(Equation 24)

that is, bigger than \(2 \times TripPickup\)

Check from the table of selected resistances the required series stabilizing resistor value to use. As this application requires to be so sensitive select \(R_{Series} = 500\) ohm, which gives an IED operating current of 200 mA.

Calculate the primary sensitivity at operating voltage using the following equation.

\[
IP = \frac{2000}{5} \times 200 \times (0^\circ + 3 \times 50^\circ - 60^\circ) \times 10^{-3} \leq approx. 100A
\]

(Equation 25)

where

- 100 mA is the current drawn by the IED circuit and
- 10 mA is the current drawn by each CT just at pickup
- 20 mA is current drawn bymetrosil at pickup
The magnetizing current is taken from the magnetizing curve for the current transformer cores which should be available. The current value at TripPickup is taken.

It can clearly be seen that the sensitivity is not so much influenced by the selected voltage level so a sufficient margin should be used. The selection of the stabilizing resistor and the level of the magnetizing current (mostly dependent of the number of turns) are the most important factors.

### 7.2.4.4 Tertiary reactor protection

Reactive power equipment (for example shunt reactors and/or shunt capacitors) can be connected to the tertiary winding of the power transformers. The 1Ph High impedance differential protection function HZPDIF (87) can be used to protect the tertiary reactor for phase faults as well as ground faults if the power system of the tertiary winding is direct or low impedance grounded.

![Figure 64: Application of the 1Ph High impedance differential protection HZPDIF (87) function on a reactor](ANSI05000176-2-en.vsd)
**Setting example**

It is strongly recommended to use the highest tap of the CT whenever high impedance protection is used. This helps in utilizing maximum CT capability, minimize the secondary fault, thereby reducing the stability voltage limit. Another factor is that during internal faults, the voltage developed across the selected tap is limited by the non-linear resistor but in the unused taps, owing to auto-transformer action, voltages much higher than design limits might be induced.

**Basic data:**
- Current transformer ratio: 100/5 A (Note: Must be the same at all locations)
- CT Class: C200
- Secondary resistance: 0.1 Ohms (At 100/5 Tap)
- Cable loop resistance: <100 ft AWG10 (one way between the junction point and the farthest CT) to be limited to approximately 0.1 Ohms at 75deg C
- Note! Only one way as the tertiary power system grounding is limiting the ground-fault current. If high ground-fault current exists use two way cable length.
- Max fault current: The maximum through fault current is limited by the reactor reactance and the inrush will be the worst for a reactor for example, 800 A.

**Calculation:**

\[
VR > \frac{800}{20} \cdot (0.1 + 0.1) = 8
\]

(Equation 26)

Select a setting of \( TripPickup = 30 \) V.

The current transformer knee point voltage must be at least, twice the set operating voltage \( TripPickup \).

\[
V_{kneeANSI} > (2 + 0.1) \cdot 100 \cdot 0.7 = 147 \text{ V}
\]

(Equation 27)

that is, greater than 2 \( \times TripPickup \).

Check from the table of selected resistances the required series stabilizing resistor value to use. Since this application requires good sensitivity, select \( R_{Series} = 100 \) ohm, which gives an IED current of 200 mA.

To calculate the sensitivity at operating voltage, refer to equation 28, which gives an acceptable value, ignoring the current drawn by the non-linear resistor. A little lower sensitivity could be selected by using a lower resistance value.
\[ IP = \frac{100}{5} \cdot (200 + 2 \cdot 30) \leq \text{approx.} 5.2A \]

(Equation 28)

Where 200mA is the current drawn by the IED circuit and 50mA is the current drawn by each CT just at pickup. The magnetizing current is taken from the magnetizing curve of the current transformer cores, which should be available. The current value at TripPickup is taken.

### 7.2.4.5 Restricted earth fault protection (87N)

For solidly grounded systems a restricted earth fault protection REFPDIF (87N) is often provided as a complement to the normal transformer differential function. The advantage with the restricted ground fault functions is the high sensitivity for internal earth faults in the transformer winding. Sensitivities of 2-8% can be achieved whereas the normal differential function will have sensitivities of 20-40%. The sensitivity for high impedance restricted ground fault function is mostly dependent on the current transformers magnetizing currents.

The connection of a restricted earth fault function is shown in Figure 65. It is connected across each directly or low impedance grounded transformer winding.

![Diagram of restricted earth fault protection](en05000177_ansi.vsd)

*Figure 65: Application of HZPDIF (87) function as a restricted earth fault protection for a star connected winding of an YNd transformer*
Setting example

It is strongly recommended to use the highest tap of the CT whenever high impedance protection is used. This helps in utilizing maximum CT capability, minimize the current, thereby reducing the stability voltage limit. Another factor is that during internal faults, the voltage developed across the selected tap is limited by the non-linear resistor but in the unused taps, owing to auto-transformer action, voltages much higher than design limits might be induced.

**Basic data:**

- Transformer rated current on HV winding: 250 A
- Current transformer ratio: 600-300/5A (Note: Must be the same at all locations)
- CT Class: C200
- Secondary resistance: 0.66 ohms
- Cable loop resistance: <50 ft AWG10 (one way between the junction point and the farthest CT) to be limited to approx. 0.05 Ohms at 75° C gives loop resistance \(2 \times 0.05 = 0.1\) Ohms
- Max fault current: The maximum through fault current is limited by the transformer reactance, use 15 \(\times\) rated current of the transformer

**Calculation:**

\[
VR > 15 \times \frac{250}{600/5} \times (0.1 + 0.1) = 6.25V
\]  
(Equation 29)

Select a setting of \(TripPickup=40\ V\).

The current transformer knee point voltage can roughly be calculated from the rated values. Considering knee point voltage to be about 70% of the accuracy limit voltage.

\[
V_{knee\text{ANSI}} > (0.1 + 2) \times 100 = 210V
\]  
(Equation 30)

that is, greater than 2 \(\times\) \(TripPickup\)

Check from the table of selected resistances the required series stabilizing resistor value to use. Since this application requires high sensitivity, select \(R\text{series}= 100\ ohm\) which gives a current of 200 mA.

To calculate the sensitivity at operating voltage, refer to equation 31 which is acceptable as it gives around 10% minimum operating current, ignoring the current drawn by the non-linear resistor.
\[ IP = \frac{600}{5} \cdot (200[0^\circ] + 4 \cdot 20[-60^\circ]) \leq \text{approx.}5.4A \]

(Equation 31)

Where 200mA is the current drawn by the IED circuit and 50mA is the current drawn by each CT just at pickup. The magnetizing current is taken from the magnetizing curve for the current transformer cores which should be available. The current value at \textit{TripPickup} is taken.

### 7.2.4.6 Alarm level operation

The 1Ph High impedance differential protection HZPDIF (87) function has a separate alarm level, which can be used to give alarm for problems with an involved current transformer circuit. The setting level is normally selected to be around 10% of the operating voltage \textit{TripPickup}.

As seen in the setting examples above the sensitivity of HZPDIF (87) function is normally high, which means that the function will in many cases operate also for short circuits or open current transformer secondary circuits. However the stabilizing resistor can be selected to achieve sensitivity higher than normal load current and/or separate criteria can be added to the operation, like a check zone. This can be either another IED, with the same HZPDIF (87) function, or be a check about the fault condition, which is performed by a ground overcurrent function or neutral point voltage function.

For such cases where operation is not expected during normal service the alarm output should be used to activate an external shorting of the differential circuit avoiding continuous high voltage in the circuit. A time delay of a few seconds is used before the shorting and alarm are activated. Auxiliary relays with contacts that can withstand high voltage shall be used, like RXMVB types.

The metrosil operating characteristic is given in the following figure.

\[ \text{Figure 66: Current voltage characteristics for the non-linear resistors, in the range 10-200 V, the average range of current is: } 0.01-10 \text{ mA} \]
### 7.3 Generator differential protection GENPDIF (87G)

#### 7.3.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator differential protection</td>
<td>GENPDIF</td>
<td>$I_d &gt;$</td>
<td>87G</td>
</tr>
</tbody>
</table>

#### 7.3.2 Application

Short circuit between the phases of the stator windings causes normally very large fault currents. The short circuit generates risk of damages on insulation, windings and stator core. The large short circuit currents cause large current forces, which can damage other components in the power plant, such as turbine and generator-turbine shaft. The short circuit can also initiate explosion and fire. When a short circuit occurs in a generator there is a damage that has to be repaired. The severity and thus the repair time are dependent on the degree of damage, which is highly dependent on the fault time. Fast fault clearance of this fault type is therefore of greatest importance to limit the damages and thus the economic loss.

To limit the damages in connection to stator winding short circuits, the fault clearance time must be as fast as possible (instantaneous). Both the fault current contributions from the external power system (via the generator and/or the block circuit breaker) and from the generator itself must be disconnected as fast as possible. A fast reduction of the mechanical power from the turbine is of great importance. If the generator is connected to the power system close to other generators, the fast fault clearance is essential to maintain the transient stability of the non-faulted generators.

Normally, the short circuit fault current is very large, that is, significantly larger than the generator rated current. There is a risk that a short circuit can occur between phases close to the neutral point of the generator, thus causing a relatively small fault current. The fault current fed from the generator itself can also be limited due to low excitation of the generator. This is normally the case at running up of the generator, before synchronization to the network. Therefore, it is desired that the detection of generator phase-to-phase short circuits shall be relatively sensitive, thus detecting small fault currents.

It is also of great importance that the generator short circuit protection does not trip for external faults, when large fault current is fed from the generator. In order to combine fast fault clearance, sensitivity and selectivity the Generator current differential protection GENPDIF (87G) is normally the best choice for phase-to-phase generator short circuits.

The risk of unwanted operation of the differential protection, caused by current transformer saturation, is a universal differential protection problem. If the generator is tripped in connection to an external short circuit, this can first give an increased risk of power system collapse. Besides that, there can be a production loss for every unwanted trip of the generator. Hence, there is a great economic value to prevent unwanted disconnection of power generation.
The generator application allows a special situation, where the short circuit fault current with a large DC component, can have the first zero crossing of the current, after several periods. This is due to the long DC time constant of the generator (up to 1000 ms), see figure 67.

GENPDIF (87G) is also well suited to give fast, sensitive and selective fault clearance, if used for protection of shunt reactors and small busbars.

![Graph showing I(t) over time](image)

*Figure 67: Typical for generators are long DC time constants. Their relation can be such that the instantaneous fault current is more than 100% offset in the beginning.*

### 7.3.3 Setting guidelines

Generator differential protection GENPDIF (87G) makes evaluation in different sub-functions in the differential function.

- Percentage restrained differential analysis
- DC, 2\textsuperscript{nd} and 5\textsuperscript{th} harmonic analysis
- Internal/external fault discriminator

Adaptive frequency tracking must be properly configured and set for the Signal Matrix for analog inputs (SMAI) preprocessing blocks in order to ensure proper operation of the generator differential protection function during varying frequency conditions.
### 7.3.3.1 General settings

*IBase:* Set as the rated current of the generator in primary A.

*GlobalBaseSel:* Selects the global base value group used by the function to define *(IBase), (UBase)* and *(SBase)*.

*InvertCT2Curr:* It is normally assumed that the secondary winding of the CTs of the generator are grounded towards the generator, as shown in figure 68. In this case the parameter *InvertCT2Curr* is set to *No*.

![Figure 68: Position of current transformers](image)

If Generator differential protection GENPDIF (87G) is used in conjunction with a transformer differential protection within the same IED, the direction of the terminal CT may be referred towards the step-up transformer. This will give wrong reference direction for the generator differential protection. This can be adjusted by setting the parameter *InvertCT2curr* to *Yes*.

*Operation:* GENPDIF (87G) is set *Enabled* or *Disabled* with this setting.

### 7.3.3.2 Percentage restrained differential operation

The characteristic of the restrain differential protection is shown in figure 69. The characteristic is defined by the settings:

- *IdMin*
- *EndSection1*
- *EndSection2*
- *SlopeSection2*
- *SlopeSection3*
In section 1 the risk of false differential current is very low. This is the case, at least up to 1.25 times the generator rated current. \( \text{EndSection1} \) is proposed to be set to 1.25 times the generator rated current.

In section 2, a certain minor slope is introduced which is supposed to cope with false differential currents proportional to higher than normal currents through the current transformers. \( \text{EndSection2} \) is proposed to be set to about 3 times the generator rated current. The \( \text{SlopeSection2} \), defined as the percentage value of \( \Delta I_{\text{diff}} / \Delta I_{\text{Bias}} \), is proposed to be set to 40%, if no deeper analysis is done.

In section 3, a more pronounced slope is introduced which is supposed to cope with false differential currents related to current transformer saturation. The \( \text{SlopeSection3} \), defined as the percentage value of \( \Delta I_{\text{diff}} / \Delta I_{\text{Bias}} \), is proposed to be set to 80%, if no deeper analysis is done.

\( \text{IdUnre} \). \( \text{IdUnre} \) is the sensitivity of the unrestrained differential protection stage. The choice of setting value can be based on calculation of the largest short circuit current from the generator at fault in the external power system (normally three-phase short circuit just outside of the generator)
protection zone on the LV side of the step-up transformer). \( IdUnre \) is set as a multiple of the generator rated current.

\textit{OpCrossBlock}: If \textit{OpCrossBlock} is set to Yes, and PICKUP signal is active, activation of the harmonic blocking in that phase will block the other phases as well.

### 7.3.3.3 Negative sequence internal/external fault discriminator feature

\textit{OpNegSeqDiff}: \textit{OpNegSeqDiff} is set to Yes for activation of the negative sequence differential features, both the internal or external fault discrimination and the sensitive negative sequence differential current feature. It is recommended to have this feature enabled.

\textit{IMinNegSeq}: \textit{IMinNegSeq} is the setting of the smallest negative sequence current when the negative sequence based functions shall be active. This sensitivity can normally be set down to 0.04 times the generator rated current, to enable very sensitive protection function. As the sensitive negative sequence differential protection function is blocked at high currents the high sensitivity does not give risk of unwanted function.

\textit{NegSeqROA}: \textit{NegSeqROA} is the “Relay Operate Angle”, as described in figure 70.

The default value 60° is recommended as optimum value for dependability and security.

![Diagram showing the Negative sequence internal/external fault discriminator feature](image)

\textit{Figure 70}: \textit{NegSeqROA}: \textit{NegSeqROA} determines the boundary between the internal- and external fault regions

### 7.3.3.4 Open CT detection

The Generator differential function has a built-in, advanced open CT detection feature. This feature can block the unexpected operation created by the Generator differential function in case
of open CT secondary circuit under normal load condition. An alarm signal can also be issued to station operational personnel to make remedy action once the open CT condition is detected.

The following setting parameters are related to this feature:

- Setting parameter `OpenCTEnable` enables/disables this feature
- Setting parameter `tOCTAlarmDelay` defines the time delay after which the alarm signal will be given
- Setting parameter `tOCTReset` defines the time delay after which the open CT condition will reset once the defective CT circuits have been rectified
- Once the open CT condition has been detected, then all the differential protection functions are blocked except the unrestraint (instantaneous) differential protection

The outputs of open CT condition related parameters are listed below:

- `OpenCT`: Open CT detected
- `OpenCTAlarm`: Alarm issued after the setting delay
- `OpenCTIN`: Open CT in CT group inputs (1 for input 1 and 2 for input 2)
- `OpenCTPH`: Open CT with phase information (1 for phase A, 2 for phase B, 3 for phase C)

### 7.3.3.5 Other additional options

`HarmDistLimit`: This setting is the total harmonic distortion (2\textsuperscript{nd} and 5\textsuperscript{th} harmonic) for the harmonic restrain pick-up. The default limit 10\% can be used in normal cases. In special application, for example, close to power electronic converters, a higher setting might be used to prevent unwanted blocking.

`TempIdMin`: If the binary input raise pick-up (DESENSIT) is activated the operation level of `IdMin` is increased to the `TempIdMin`.

---

© Copyright 2017 ABB. All rights reserved
**Figure 71:** The value of TempIdMin

*AddTripDelay:* If the input DESENSIT is activated the operation time of the protection function can also be increased by the setting *AddTripDelay.*

*OperDCBiasing:* If enabled the DC component of the differential current will be included in the bias current with a slow decay. The option can be used to increase security if the primary system DC time constant is very long, thus giving risk of current transformer saturation, even for small currents. It is recommended to set *OperDCBiasing = Enabled* if the current transformers on the two sides of the generator are of different make with different magnetizing characteristics. It is also recommended to set the parameter *OperDCBiasing = Enabled* for all shunt reactor applications.

The DC component is always calculated from the instantaneous differential current for each phase in primary Amperes. The value of DC component can be read from function outputs: IDDCL1, IDDCL2 and IDDCL3. For special purpose, the DC component from phase currents can also be calculated by GENPDIF function. In this case, only one current group should be connected to GENPDIF and the rest current group inputs should be connected to GRP_OFF as shown in Figure 72.
7.4 Low impedance restricted earth fault protection REFPDIF (87N)

7.4.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Restricted earth fault protection, low impedance</td>
<td>REFPDIF</td>
<td>IdN/I</td>
<td>87N</td>
</tr>
</tbody>
</table>

7.4.2 Application

A breakdown of the insulation between a transformer winding and the core or the tank may result in a large fault current which causes severe damage to the windings and the transformer core. A high gas pressure may develop, damaging the transformer tank.

Fast and sensitive detection of ground faults in a power transformer winding can be obtained in solidly grounded or low impedance grounded networks by the restricted earth fault protection. The only requirement is that the power transformer winding is connected to ground in the star
point (in case of wye-connected windings) or through a separate grounding transformer (in case of delta-connected windings).

The low impedance restricted ground fault protection REFPDIF (87N) is a winding protection function. It protects the power transformer winding against faults involving ground. Observe that single phase-to-ground faults are the most common fault types in transformers. Therefore, a sensitive ground fault protection is desirable.

A restricted ground fault protection is the fastest and the most sensitive protection, a power transformer winding can have and will detect faults such as:

- ground faults in the transformer winding when the network is grounded through an impedance
- ground faults in the transformer winding in solidly grounded network when the point of the fault is close to the winding star point.

The restricted ground fault protection is not affected, as a differential protection, with the following power transformer related phenomena:

- magnetizing inrush currents
- overexcitation magnetizing currents
- load tap changer
- external and internal phase faults which do not involve ground
- symmetrical overload conditions

Due to its features, REFPDIF (87N) is often used as a main protection of the transformer winding for all faults involving ground.

**7.4.2.1 Transformer winding, solidly grounded**

The most common application is on a solidly grounded transformer winding. The connection is shown in Figure 73.
7.4.2.2 Transformer winding, grounded through Zig-Zag grounding transformer

A common application is for low reactance grounded transformer where the grounding is through separate Zig-Zag grounding transformers. The fault current is then limited to typical 800 to 2000 A for each transformer. The connection for this application is shown in figure 74.
Autotransformer winding, solidly grounded

Autotransformers can be protected with the low impedance restricted ground fault protection function REFPDIF. The complete transformer will then be protected including the HV side, the neutral connection and the LV side. The connection of REFPDIF (87N) for this application is shown in figure 75.
Figure 75: Connection of restricted ground fault, low impedance function REFPDIF (87N) for an autotransformer, solidly grounded

7.4.2.4 Reactor winding, solidly grounded

Reactors can be protected with restricted ground fault protection, low impedance function REFPDIF (87N). The connection of REFPDIF (87N) for this application is shown in figure 76.
Multi-breaker applications

Multi-breaker arrangements including ring, one breaker-and-a-half, double breaker and mesh corner arrangements have two sets of current transformers on the phase side. The restricted earth-fault protection, low impedance function REFPDIF (87N) has inputs to allow two current inputs from each side of the transformer. The second winding set is only applicable for autotransformers.

A typical connection for a star-delta transformer is shown in figure 77.
7.4.2.6 CT grounding direction

To make the restricted earth fault protection REFPDIF (87N) operate correctly, the main CTs are always supposed to be wye-connected. The main CT's neutral (star) formation can be positioned in either way, ToObject or FromObject. However, internally REFPDIF (87N) always uses reference directions towards the protected transformers, as shown in Figure 77. Thus the IED always measures the primary currents on all sides and in the neutral of the power transformer with the same reference direction towards the power transformer windings.

The grounding can be freely selected for each of the involved current transformers.

7.4.3 Setting guidelines

7.4.3.1 Setting and configuration

**Recommendation for analog inputs**

I3P: Neutral point current (All analog inputs connected as 3Ph groups in ACT).

I3PW1CT1: Phase currents for winding 1 first current transformer set.

I3PW1CT2: Phase currents for winding 1 second current transformer set for multi-breaker arrangements. When not required configure input to "GRP-OFF".

I3PW2CT1: Phase currents for winding 2 first current transformer set. Used for autotransformers.

---

Figure 77: Connection of Restricted earth fault, low impedance function REFPDIF (87N) in multi-breaker arrangements
I3PW2CT2: Phase currents for winding 2 second current transformer set for multi-breaker arrangements. Used when protecting an autotransformer. When not required, configure input to "GRP-OFF".

Recommendation for Binary input signals
Refer to the pre-configured configurations for details.

BLOCK: The input will block the operation of the function. It can be used, for example, to block the operation during special service conditions for a limited time.

Recommendation for output signals
Refer to pre-configured configurations for details.

PICKUP: The pickup output indicates that \( \Delta i \) is in the operate region of the characteristic.

TRIP: The trip output is activated when all operating criteria are fulfilled.

DIR_INT: The output is activated when the directional criteria has been fulfilled.

BLK2H: The output is activated when the function is blocked due to high level of second harmonic.

### 7.4.3.2 Settings

The parameters for the restricted earth fault protection, low impedance function \( \text{REFPDIF (87N)} \) are set via the local HMI or PCM600.

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

\( \text{GlobalBaseSel} \): It is used to select a GBASVAL function for reference of base values.

**Operation**: The operation of \( \text{REFPDIF (87N)} \) can be switched Enabled/Disabled.

\( \text{IdMin} \): The setting gives the minimum operation value. The setting is in percent of the \( I_{\text{Base}} \) value of the chosen \( \text{GlobalBaseSel} \). For function operation, the neutral current must be larger than half of this value. A recommended setting is 30% of power transformer-winding rated current for a solidly grounded winding.

**ROA**: Relay operate angle for zero sequence directional feature. It is used to differentiate an internal fault and an external fault based on measured zero sequence current and neutral current.

**CTFactorPri1**: A factor to allow a sensitive function also at multi-breaker arrangement where the rating in the bay is much higher than the rated current of the transformer winding. The stabilizing can then be high so an unnecessary high fault level can be required. The setting is normally 1.0 but in multi-breaker arrangement the setting shall be CT primary rating/\( I_{\text{Base}} \).

**CTFactorPri2**: A factor to allow a sensitive function also at multi-breaker arrangement where the rating in the bay is much higher than the rated current of the transformer winding. The stabilizing can then be high so an unnecessary high fault level can be required. The setting is normally 1.0 but in multi-breaker arrangement the setting shall be CT primary rating/\( I_{\text{Base}} \).

**CTFactorSec1**: See setting **CTFactorPri1**. Only difference is that **CTFactorSec1** is related to W2 side.

**CTFactorSec2**: See setting **CTFactorPri2**. Only difference is that **CTFactorSec2** is related to W2 side.
Section 8 Impedance protection

8.1 Full-scheme distance measuring, Mho characteristic ZMHPDIS (21)

8.1.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Full-scheme distance protection, mho characteristic</td>
<td>ZMHPDIS</td>
<td></td>
<td>21</td>
</tr>
</tbody>
</table>

8.1.2 Application

8.1.2.1 Generator underimpedance protection application

For generator protection schemes is often required to use under-impedance protection in order to protect generator against sustained faults. The mho distance protection in REG670 can be used for this purpose if the following guidelines are followed. Configuration for every zone is identical.

8.1.3 Setting guidelines

8.1.3.1 Configuration

First of all it is required to configure the Mho function in the way shown in figure 78. Note that a directional function block (that is ZDMPDIR) and a required number of zones (that is ZMHPDIS) shall only be configured. In this figure, three underimpedance zones are included.
8.1.3.2 Settings

Full-scheme distance measuring, Mho characteristic ZMHPDIS (21) used as an under-impedance function shall be set for the application example shown in figure 79.
The first under-impedance protection zone shall cover 100% of the step-up transformer impedance with a time delay of 1.0s.

Calculate the step-up transformer impedance, in primary ohms, from the 13kV side as follows:
Then the reach in primary ohms shall be set to 100% of transformer impedance. Thus the reach shall be set to 0,26Ω primary.

Set the first zone of Full-scheme distance measuring, Mho characteristic ZMHPDIS (21) to disable phase-to-ground loops and enable phase-to-phase loops:

- The parameter GlobalBaseSel shall be set in order to select the global base value group GBASVAL where the base voltage UBaseVBase and the base current IBase are defined; UBaseVBase is the generator rated phase-phase voltage (VBase=13,2kV) and IBase is the generator rated phase current (IBase=3062A).
- Parameter DirMode shall be set to Offset.
- Parameter OffsetMhoDir shall be set to Non-directional.
- The phase-to-ground measuring loops shall be disabled by setting OpModePG=Disabled
- The phase-to-phase measuring loops shall be enabled and corresponding settings in primary ohms for forward and reserve reach and time delay shall be entered accordingly:
  - Parameter ZPP shall be set to 0,260Ω.
  - Parameter ZrevPP shall be set to 0,260Ω.
  - Parameter tPP shall be set to 1,0000s.
  - Parameter ZAngPP shall be set to default value 85 Deg.

Set the following for the directional element ZDMRDIR:

- The parameter GlobalBaseSel shall be set in order to select the global base value group GBASVAL where the base voltage UBaseVBase and the base current IBase are defined; UBaseVBase is the generator rated phase-phase voltage (VBase=13,2kV) and IBase is the generator rated phase current (IBase=3062A).
- Parameter DirEvalType shall be set to Imp/Comp.
- Other settings can be left on the default values.

By doing this offset mho characteristic for zone one will be achieved as shown in figure 80. Note that for this particular example ZPP=ZRevPP=0,26Ω. Thus the operating characteristic for this particular application will be a circle with a centre in the impedance plane origo.

By following the same procedure other mho zones can be set.
8.2 High speed distance protection ZMFPDIS (21)

ZMFPDIS can be used according to the application description below only if VT and CT of the line feeder are wired to REG670.

8.2.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>High speed distance protection zone</td>
<td>ZMFPDIS</td>
<td>ZMFPDIS</td>
<td>21</td>
</tr>
</tbody>
</table>
8.2.2 Application

The fast distance protection function ZMFPDIS in the IED is designed to provide sub-cycle, down to half-cycle operating time for basic faults. At the same time, it is specifically designed for extra care during difficult conditions in high-voltage transmission networks, like faults on long heavily loaded lines and faults generating heavily distorted signals. These faults are handled with utmost security and dependability, although sometimes with a reduced operating speed.

8.2.2.1 System grounding

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

**Solidly grounded networks**

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

![Solidly grounded network](image)

**Figure 81: Solidly grounded network**

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

The ground-fault current at single phase-to-ground in phase A can be calculated as equation 33:

\[
3I_g = \frac{3 \cdot V_A}{Z_1 + Z_2 + Z_0 + 3Z_f} = \frac{V_A}{Z_1 + Z_2 + Z_0 + Z_f}
\]

(Equation 33)

Where:
- \(V_A\) is the phase-to-ground voltage (kV) in the faulty phase before fault
- \(Z_1\) is the positive sequence impedance (Ω/phase)
- \(Z_2\) is the negative sequence impedance (Ω/phase)
- \(Z_0\) is the zero sequence impedance (Ω/phase)
- \(Z_f\) is the fault impedance (Ω), often resistive
- \(Z_N\) is the ground-return impedance defined as \((Z_0 - Z_1)/3\)
The voltage on the healthy phases during line to ground fault is generally lower than 140% of the nominal phase-to-ground voltage. This corresponds to about 80% of the nominal phase-to-phase voltage.

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

**Effectively grounded networks**

A network is defined as effectively grounded if the ground-fault factor $f_e$ is less than 1.4. The ground-fault factor is defined according to equation 34.

\[
 f_e = \frac{V_{\text{max}}}{V_{pn}} 
\]

(Equation 34)

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

Another definition for effectively grounded network is when the following relationships between the symmetrical components of the network impedances are valid, see equation 35 and 36.

\[
 X_0 < 3 \cdot X_r 
\]

(Equation 35)

\[
 R_0 \leq R_1 
\]

(Equation 36)

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

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

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

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

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

The magnitude of the total fault current can be calculated according to equation 37.

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

(Equation 37)

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

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

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

(Equation 38)

*Figure 82: High impedance grounded network*

The operation of high impedance grounded networks is different compared to solid grounded networks, where all major faults have to be cleared very fast. In high impedance grounded networks, some system operators do not clear single phase-to-ground faults immediately; they clear the line later when it is more convenient. In case of cross-country faults, many network operators want to selectively clear one of the two ground faults.
In this type of network, it is mostly not possible to use distance protection for detection and clearance of ground faults. The low magnitude of the ground-fault current might not give pickup of the zero-sequence measurement elements or the sensitivity will be too low for acceptance. For this reason a separate high sensitive ground-fault protection is necessary to carry out the fault clearance for single phase-to-ground fault. For cross-country faults and when using phase preference, it is necessary to make sure that the distance protection is operating in the phase-to-earth loops independently, whenever possible. See guidelines for setting INReleasePE.

### 8.2.2.2 Fault infeed from remote end

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

With reference to figure 83, the equation for the bus voltage \( V_A \) at A side is:

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

(Equation 39)

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

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

(Equation 40)

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

*Figure 83: Influence of fault current infeed from remote line end*

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

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

In some cases the measured load impedance might enter the set zone characteristic without any fault on the protected line. This phenomenon is called load encroachment and it might occur when an external fault is cleared and high emergency load is transferred onto the protected line. The effect of load encroachment is illustrated on the left in figure 84. A load impedance within the characteristic would cause an unwanted trip. The traditional way of avoiding this situation is to set the distance zone resistive reach with a security margin to the minimum load impedance. The drawback with this approach is that the sensitivity of the protection to detect resistive faults is reduced.

The IED has a built in feature which shapes the characteristic according to the characteristic shown in figure 84. The load encroachment algorithm will increase the possibility to detect high fault resistances, especially for phase-to-ground faults at remote line end. For example, for a given setting of the load angle \( \text{LdAngle} \), the resistive blinder for the zone measurement can be set according to figure 84 affording higher fault resistance coverage without risk for unwanted operation due to load encroachment. Separate resistive blinder settings are available in forward and reverse direction.

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

\[ \text{RLdRv} = \text{RLdRvFactor} \times \text{RLdFw} \]

Figure 84: Load encroachment phenomena and shaped load encroachment characteristic

8.2.2.4 Short line application

Transmission line lengths for protection application purposes are classified as short, medium and long. The definition of short, medium and long lines is found in IEEE Std C37.113-1999. The length classification is defined by the ratio of the source impedance at the protected line's terminal to the protected line's impedance (SIR). SIR's of about 4 or greater generally define a short line. Medium lines are those with SIR's greater than 0.5 and less than 4.
In short line applications, the major concern is to get sufficient fault resistance coverage. Load encroachment is not such a common problem. The line length that can be recognized as a short line is not a fixed length; it depends on system parameters such as voltage and source impedance, see table 25.

Table 25: Definition of short and very short line

<table>
<thead>
<tr>
<th>Line category</th>
<th>Vn</th>
<th>Vn</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>110 kV</td>
<td>500 kV</td>
</tr>
<tr>
<td>Very short line</td>
<td>0.75 -3.5 miles</td>
<td>3-15 miles</td>
</tr>
<tr>
<td>Short line</td>
<td>4-7 miles</td>
<td>15-30 miles</td>
</tr>
</tbody>
</table>

The IED’s ability to set resistive and reactive reach independent for positive and zero sequence fault loops and individual fault resistance settings for phase-to-phase and phase-to-ground fault together with load encroachment algorithm improves the possibility to detect high resistive faults without conflict with the load impedance.

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

8.2.2.5 Long transmission line application

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

What can be recognized as long lines with respect to the performance of distance protection can generally be described as in table 26. Long lines have Source impedance ratio (SIR’s) less than 0.5.

Table 26: Definition of long and very long lines

<table>
<thead>
<tr>
<th>Line category</th>
<th>Vn</th>
<th>Vn</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>110 kV</td>
<td>500 kV</td>
</tr>
<tr>
<td>Long lines</td>
<td>45-60 miles</td>
<td>200-250 miles</td>
</tr>
<tr>
<td>Very long lines</td>
<td>&gt;60 miles</td>
<td>&gt;250 miles</td>
</tr>
</tbody>
</table>

The IED’s ability to set resistive and reactive reach independent for positive and zero sequence fault loops and individual fault resistance settings for phase-to-phase and phase-to-ground fault together with load encroachment algorithm improves the possibility to detect high resistive faults at the same time as the security is improved (risk for unwanted trip due to load encroachment is eliminated), see figure 84.

8.2.2.6 Parallel line application with mutual coupling
General
Introduction of parallel lines in the network is increasing due to difficulties to get necessary land to build new lines.

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

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

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

The different network configuration classes are:

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

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

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

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

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

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

Most multi circuit lines have two parallel operating circuits.

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

The three most common operation modes are:

1. Parallel line in service.
2. Parallel line out of service and grounded.
3. Parallel line out of service and not grounded.
Parallel line in service
This type of application is very common and applies to all normal sub-transmission and transmission networks.

Let us analyze what happens when a fault occurs on the parallel line see figure 85.

From symmetrical components, we can derive the impedance $Z$ at the relay point for normal lines without mutual coupling according to equation 41.

\[
Z = \frac{V_{ph}}{I_{ph}} = \frac{V_{ph}}{L_{0} + 3I_{0}} \cdot \frac{Z_{1}}{3 \cdot Z_{0}}
\]

(Equation 41)

Where:
- $V_{ph}$ is phase to ground voltage at the relay point
- $I_{ph}$ is phase current in the faulty phase
- $3I_{0}$ is ground fault current
- $Z_{1}$ is positive sequence impedance
- $Z_{0}$ is zero sequence impedance

![Figure 85: Class 1, parallel line in service](en05000221_ansl.vsd)

The equivalent circuit of the lines can be simplified, see figure 86.

![Figure 86: Equivalent zero sequence impedance circuit of the double-circuit, parallel, operating line with a single phase-to-ground fault at the remote busbar](iec09000253_1_en.vsd)

When mutual coupling is introduced, the voltage at the relay point A will be changed according to equation 42.
\[ V_{ph} = \overline{Z}_{1L} \cdot \left( I_{ph} + 3I_0 \cdot \frac{Z_0_L - \overline{Z}_{1L}}{3 \cdot \overline{Z}_{1L}} + 3I_{0p} \cdot \frac{Z_0_n}{3 \cdot \overline{Z}_{1L}} \right) \]  

(Equation 42)

By dividing equation 42 by equation 41 and after some simplification we can write the impedance present to the relay at A side as:

\[ Z = \overline{Z}_{1L} \left( 1 + \frac{3I_0 \cdot KNm}{I_{ph} + 3I_0 \cdot KN} \right) \]  

(Equation 43)

Where:

\[ KNm = \frac{Z_0m}{3 \cdot Z_{1L}} \]

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

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

Maximum overreach will occur if the fault current infeed from remote line end is weak. If considering a single phase-to-ground fault at 'p' unit of the line length from A to B on the parallel line for the case when the fault current infeed from remote line end is zero, the voltage \( V_A \) in the faulty phase at A side as in equation 44.

\[ \overline{V}_d = p \cdot \overline{Z}_{1L} \left( I_{ph} + K_y \cdot 3I_0 + K_{sm} \cdot 3I_{0p} \right) \]  

(Equation 44)

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

\[ 3I_0 \cdot Z_0_L = 3I_{0p} \cdot Z_0_L \left( 2 - p \right) \]  

(Equation 45)

Simplification of equation 45, solving it for \( 3I_{0p} \) and substitution of the result into equation 44 gives that the voltage can be drawn as:

\[ \overline{V}_d = p \cdot \overline{Z}_{1L} \left( I_{ph} + K_y \cdot 3I_0 + K_{sm} \cdot 3I_{0p} \right) \left( \frac{3I_{0p}}{2 - p} \right) \]  

(Equation 46)

If we finally divide equation 46 with equation 41 we can draw the impedance present to the IED as
Calculation for a 400 kV line, where we for simplicity have excluded the resistance, gives with 
X1L=0.48 Ohm/Mile, X0L=1.4Ohms/Mile, zone 1 reach is set to 90% of the line reactance p=71%
that is, the protection is underreaching with approximately 20%.

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

Parallel line out of service and grounded

**Figure 87:** The parallel line is out of service and grounded

When the parallel line is out of service and grounded at both line ends on the bus bar side of the
line CTs so that zero sequence current can flow on the parallel line, the equivalent zero sequence
circuit of the parallel lines will be according to figure 88.

**Figure 88:** Equivalent zero sequence impedance circuit for the double-circuit line that
operates with one circuit disconnected and grounded at both ends

Here the equivalent zero-sequence impedance is equal to \(Z_0-Z_{0m}\) in parallel with \((Z_0-Z_{0m})/Z_0-Z_{0m}\)
+\(Z_{0m}\) which is equal to equation 48.
\[
Z_k = \frac{Z_0 - Z_{0m}}{Z_0}
\]

(Equation 48)

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

All expressions below are proposed for practical use. They assume the value of zero sequence, mutual resistance \( R_{0m} \) equals to zero. They consider only the zero sequence, mutual reactance \( X_{0m} \).

Calculate the equivalent \( X_{0E} \) and \( R_{0E} \) zero sequence parameters according to equation 49 and equation 50 for each particular line section and use them for calculating the reach for the underreaching zone.

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

(Equation 49)

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

(Equation 50)

**Parallel line out of service and not grounded**

\[
\frac{-R}{Z_k} = \frac{-Z_0 - Z_{0m}}{Z_0}
\]

**Figure 89: Parallel line is out of service and not grounded**

When the parallel line is out of service and not grounded, the zero sequence on that line can only flow through the line admittance to the ground. The line admittance is high which limits the zero-sequence current on the parallel line to very low values. In practice, the equivalent zero-sequence impedance circuit for faults at the remote bus bar can be simplified to the circuit shown in figure 89.

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

\[ \bar{K}_u = \left( \frac{\left(2 \cdot \overline{Z}_1 + \overline{Z}_0 \cdot E\right) + R_f}{\left(2 \cdot \overline{Z}_1 + \overline{Z}_0\right)} \right) = 1 - \frac{Z_{m0}^2}{Z_0 \cdot (2 \cdot \overline{Z}_1 + \overline{Z}_0 + 3R_f)} \]

(Equation 51)

This means that the reach is reduced in reactive and resistive directions. If the real and imaginary components of the constant A are equal to equation 52 and equation 53.

\[ \text{Re}(\overline{A}) = R_0 \cdot (2 \cdot R_1 + R_0 + 3 \cdot R_f) - X_0 \cdot (X_0 + 2 \cdot X_1) \]

(Equation 52)

\[ \text{Im}(\overline{A}) = X_0 \cdot (2 \cdot R_1 + R_0 + 3 \cdot R_f) + R_0 \cdot (2 \cdot X_1 + X_0) \]

(Equation 53)

The real component of the Ku factor is equal to equation 54.

\[ \text{Re}(\overline{K}_u) = 1 + \frac{\text{Re}(\overline{A}) \cdot X_{m0}^2}{\left[ \text{Re}(\overline{A}) \right]^2 + \left[ \text{Im}(\overline{A}) \right]^2} \]

(Equation 54)

The imaginary component of the same factor is equal to equation 55.

\[ \text{Im}(\overline{K}_u) = \frac{\text{Im}(\overline{A}) \cdot X_{m0}^2}{\left[ \text{Re}(\overline{A}) \right]^2 + \left[ \text{Im}(\overline{A}) \right]^2} \]

(Equation 55)

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

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

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

(Equation 56)

\[
\overline{Z}_C = \overline{Z}_{Tf} + (\overline{Z}_{CT} + \frac{\overline{I}_A + \overline{I}_C}{\overline{I}_C} \cdot \overline{Z}_{TB}) \cdot \left(\frac{V_2}{V_1}\right)^2
\]

(Equation 57)

Where:
- \(Z_{AT}\) and \(Z_{CT}\) is the line impedance from the A respective C station to the T point.
- \(I_A\) and \(I_C\) is fault current from A respective C station for fault between T and B.

Table continues on next page
V2/V1

Transformation ratio for transformation of impedance at V1 side of the transformer to the measuring side V2 (it is assumed that current and voltage distance function is taken from V2 side of the transformer).

$Z_{TF}$

is the line impedance from the T point to the fault (F).

$Z_{Trf}$

Transformer impedance

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

Another complication that might occur depending on the topology is that the current from one end can have a reverse direction for fault on the protected line. For example, for faults at T the current from B might go in reverse direction from B to C depending on the system parameters (see the dotted line in figure 94), given that the distance protection in B to T will measure wrong direction.

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

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

**Fault resistance**

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

$$R_{arc} = \frac{2870 \cdot L}{I^{1.4}}$$

(Equation 58)

where:

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

I is the actual fault current in A.

In practice, the setting of fault resistance for both phase-to-ground $RFPGZx$ and phase-to-phase $RFPPZx$ should be as high as possible without interfering with the load impedance in order to obtain reliable fault detection.
8.2.3 Setting guidelines

8.2.3.1 General

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

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

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

8.2.3.2 Setting of zone 1

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

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

8.2.3.3 Setting of overreaching zone

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

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

- The impedance corresponding to the protected line, plus the first zone reach of the shortest adjacent line.
- The impedance corresponding to the protected line, plus the impedance of the maximum number of transformers operating in parallel on the bus at the remote end of the protected line.
Larger overreach than the mentioned 80% can often be acceptable due to fault current infeed from other lines. This requires however analysis by means of fault calculations.

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

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

If a fault occurs at point F see figure 92, the IED at point A senses the impedance:

\[
Z_{AF} = \frac{V_A}{I_A} = Z_{AC} + \frac{I_A + I_C}{I_A} \cdot Z_{CF} + \frac{I_A + I_C + I_B}{I_A} \cdot R_f = Z_{AC} \left( 1 + \frac{I_C}{I_A} \right) \cdot Z_{CF} + \left( 1 + \frac{I_C + I_B}{I_A} \right) \cdot R_f
\]

(Equation 59)

![Figure 92: Setting of overreaching zone](ANS05/000457-3-en.vsd)

8.2.3.4 Setting of reverse zone

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

Consider the possible enlarging factor that might exist due to fault infeed from adjacent lines. Equation 60 can be used to calculate the reach in reverse direction when the zone is used for blocking scheme, weak-end infeed, and so on.

\[
Z_{rev} \geq 1.2 \cdot \left( Z_L - Z_{2\text{rem}} \right)
\]

(Equation 60)

Where:
- \( Z_L \) is the protected line impedance
- \( Z_{2\text{rem}} \) is zone 2 setting at remote end of protected line.
In many applications it might be necessary to consider the enlarging factor due to fault current infeed from adjacent lines in the reverse direction in order to obtain certain sensitivity.

### 8.2.3.5 Setting of zones for parallel line application

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

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

**Parallel line in service – setting of zone 2**
Overreaching zones (in general, zones 2 and 3) must overreach the protected circuit in all cases. The greatest reduction of a reach occurs in cases when both parallel circuits are in service with a single phase-to-ground fault located at the end of a protected line. The equivalent zero sequence impedance circuit for this case is equal to the one in figure 86 in section Parallel line in service.

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

\[ R_{0E} = R_0 + R_{m0} \]  
*Equation 61*

\[ X_{0E} = X_0 + X_{m0} \]  
*Equation 62*

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

\[ K' = 1 - \frac{Z_{0m}}{2 \cdot Z_1 + Z_0 + R_f} \]  
*Equation 63*

If the denominator in equation 63 is called B and Z0m is simplified to X0m, then the real and imaginary part of the reach reduction factor for the overreaching zones can be written as:

\[ \text{Re}\left( K' \right) = 1 - \frac{X_{0m} \cdot \text{Re}(B)}{\text{Re}(B)^2 + \text{Im}(B)^2} \]  
*Equation 64*

\[ \text{Im}\left( K' \right) = \frac{X_{0m} \cdot \text{Im}(B)}{\text{Re}(B)^2 + \text{Im}(B)^2} \]  
*Equation 65*
Parallel line is out of service and grounded in both ends

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

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

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

(Equation 66)

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

(Equation 67)

8.2.3.6 Setting the reach with respect to load

Set separately the expected fault resistance for phase-to-phase faults \(RFPPZ_x\) and for the phase-to-ground faults \(RFPGZ_x\) for each zone. For each distance zone, set all remaining reach setting parameters independently of each other.

The final reach in the resistive direction for phase-to-ground fault loop measurement automatically follows the values of the line-positive and zero-sequence resistance, and at the end of the protected zone is equal to equation 68.

\[
R = \frac{1}{3} \left(2 \cdot R1 + R0\right) + RFPG
\]

(Equation 68)

\[
\phi_{loop} = \arctan \left[\frac{2 \cdot X1Zx + X0Zx}{2 \cdot R1Zx + R0Zx}\right]
\]

(Equation 69)

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

\[
RFPG \leq 4.5 \cdot X1
\]

(Equation 70)

The fault resistance for phase-to-phase faults is normally quite low compared to the fault resistance for phase-to-ground faults. To minimize the risk for overreaching, limit the setting of the zone1 reach in the resistive direction for phase-to-phase loop measurement based on equation 71.

\[
RFPPZ_x \leq 6 \cdot X1Zx
\]

(Equation 71)
The setting $X_{Ld}$ is primarily there to define the border between what is considered a fault and what is just normal operation. See figure 93. In this context, the main examples of normal operation are reactive load from reactive power compensation equipment or the capacitive charging of a long high-voltage power line. $X_{Ld}$ needs to be set with some margin towards normal apparent reactance; not more than 90% of the said reactance or just as much as is needed from a zone reach point of view.

As with the settings $RLdFwd$ and $RldRev$, $X_{Ld}$ is representing a per-phase load impedance of a symmetrical star-coupled representation. For a symmetrical load or three-phase and phase-to-phase faults, this means per-phase, or positive-sequence, impedance. During a phase-to-earth fault, it means the per-loop impedance, including the earth return impedance.

### 8.2.3.7 Zone reach setting lower than minimum load impedance

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

The maximum permissible resistive reach for any zone must be checked to ensure that there is a sufficient setting margin between the boundary and the minimum load impedance. The minimum load impedance ($\Omega$/phase) is calculated with equation 72.

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

(Equation 72)

Where:
- $V$ the minimum phase-to-phase voltage in kV
- $S$ the maximum apparent power in MVA.

The load impedance ($\Omega$/phase) is a function of the minimum operation voltage and the maximum load current:

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

(Equation 73)

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

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

To avoid load encroachment for the phase-to-ground measuring elements, the set resistive reach of any distance protection zone must be less than 80% of the minimum load impedance.
RFPG $\leq 0.8 \cdot Z_{\text{load}}$

(Equation 74)

This equation is applicable only when the loop characteristic angle for the single phase-to-ground faults is more than three times as large as the maximum expected load-impedance angle. For the case when the loop characteristic angle is less than three times the load-impedance angle, more accurate calculations are necessary according to equation 75.

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

(Equation 75)

Where:

$\vartheta$ is a maximum load-impedance angle, related to the maximum load power.

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

$$RFPPZx \leq 1.6 \cdot Z_{\text{load}}$$

(Equation 76)

Equation 76 is applicable only when the loop characteristic angle for the phase-to-phase faults is more than three times as large as the maximum expected load-impedance angle. For other cases more accurate calculations are necessary according to equation 77.

$$RFPPZx \leq 1.6 \cdot Z_{\text{load min}} \cdot \left[ \cos \vartheta - \frac{R1Zx}{X1Zx} \cdot \sin \vartheta \right]$$

(Equation 77)

### 8.2.3.8 Zone reach setting higher than minimum load impedance

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

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

The load encroachment settings are related to a per-phase load impedance in a symmetrical star-coupled representation. For symmetrical load or three-phase and phase-to-phase faults, this corresponds to the per-phase, or positive-sequence, impedance. For a phase-to-ground fault, it corresponds to the per-loop impedance, including the ground return impedance.
Figure 93: Load impedance limitation with load encroachment

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

8.2.3.9 Other settings

IMinOpPGZx and IMinOpPPZx

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

The output of a phase-to-phase loop $m_n$ is blocked if $I_{mn} < I_{\text{MinOpPP}}(Zx)$. $I_{mn}$ is the RMS value of the vector difference between phase currents m and Ln.

Both current limits $I_{\text{MinOpPGZx}}$ and $I_{\text{MinOpPPZx}}$ are automatically reduced to 75% of regular set values if the zone is set to operate in reverse direction, that is, $\text{OperationDir}$ is set to $\text{Reverse}$.

OpModePPZx and OpModePEZx

These settings, two per zone ($x=1,2,..,5 RV$), with options {Off, Quadrilateral, Mho, Offset}, are used to set the operation and characteristic for phase-to-earth and phase-to-phase faults, respectively.

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

This setting defines the operating direction for zones Z3, Z4 and Z5 (the directionality of zones Z1, Z2 and ZRV is fixed). The options are Non-directional, Forward or Reverse. The result from respective set value is illustrated in figure 94, where the positive impedance corresponds to the direction out on the protected line.

![Diagram of DirModeZx](image)

**Figure 94: Directional operating modes of the distance measuring zones 3 to 5**

tPPZx, tPGZx, TimerModeZx, ZoneLinkPU and TimerLinksZx

The logic for the linking of the timer settings can be described with a module diagram. The following figure shows only the case when TimerModeZx is selected to Ph-Ph and Ph-G.
Figure 95: Logic for linking of timers

CVT type

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

Passive type

For CVTs that use a nonlinear component, like a saturable inductor, to limit overvoltages (caused by ferro-resonance). This component is practically idle during normal load and fault conditions, hence the name “passive.” CVTs that have a high resistive burden to mitigate ferro-resonance also fall into this category.

Any

This option is primarily related to the so-called active type CVT, which uses a set of reactive components to form a filter circuit that essentially attenuates frequencies other than the nominal to restrain the ferro-resonance. The name “active” refers to this circuit always being involved during transient conditions, regardless of the voltage level. This option should also be used for the types that do not fall under the other two categories, for example, CVTs with power electronic damping devices, or if the type cannot be identified at all.

None

(Magnetic)

This option should be selected if the voltage transformer is fully magnetic.

3I0Enable_PG
This setting opens up an opportunity to enable phase-to-ground measurement for phase-to-phase-ground faults. It determines the level of residual current (3I0) above which phase-to-ground measurement is activated (and phase-to-phase measurement is blocked). The relations are defined by equation 78.

\[
3I_0 \geq \frac{3I0_{\text{Enable \_ PG}}}{100} \cdot I_{\text{ph max}}
\]

(Equation 78)

Where:
- \(3I0_{\text{Enable \_ PG}}\) the setting for the minimum residual current needed to enable operation in the phase-to-ground fault loops in %
- \(I_{\text{ph max}}\) the maximum phase current in any of the three phases

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

One specific situation where the \(3I0_{\text{Enable \_ PG}}\) setting should be altered is for cross-country faults in high impedance grounded networks, in order to make sure that operation is phase-to-ground. This is particularly important when using phase preference logic, since it is only working per phase, not for phase-to-phase measurement. The limit should be set so that it will be exceeded during a cross-country fault.

### 8.2.3.10 ZMMMXU settings

**ZZeroDb**

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

**ZHiHiLim, ZHiLim, ZLowLim and ZLowLowLim**

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

**ZLimHys**

Hysteresis value in % of range \((ZMax-ZMin)\), common for all limits. It is used to avoid the frequent update of the value for the attribute “range”.

**ZMax**

Estimated maximum impedance value. An impedance that is higher than \(ZMax\) has the quality attribute as “Out of Range”.

**ZMin**

Estimated minimum impedance value. An impedance that is lower than \(ZMin\) has the quality attribute as “Out of Range”. 
8.3 High speed distance protection for series compensated lines ZMFCPDIS (21)

ZMFCPDIS can be used according to the application description below only if VT and CT of the line feeder are wired to REG670.

8.3.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>High speed distance protection zone (zone 1-6)</td>
<td>ZMFCPDIS</td>
<td></td>
<td>21</td>
</tr>
</tbody>
</table>

8.3.2 Application

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

The high speed distance protection function (ZMFCPDIS) in the IED is designed to provide sub-cycle, down to half-cycle operate time for basic faults. At the same time, it is specifically designed for extra care during difficult conditions in high voltage transmission networks, like faults on long heavily loaded lines and faults generating heavily distorted signals. These faults are handled with utmost security and dependability, although sometimes with reduced operating speed.

8.3.2.1 System grounding

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

Solidly grounded networks

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

Figure 96: Solidly grounded network
The ground-fault current is as high or even higher than the short-circuit current. The series impedances determine the magnitude of the fault current. The shunt admittance has very limited influence on the ground-fault current. The shunt admittance may, however, have some marginal influence on the ground-fault current in networks with long transmission lines.

The ground-fault current at single phase-to-ground in phase A can be calculated as equation 79:

\[ 3I_0 = \frac{3 \cdot V_A}{Z_1 + Z_2 + Z_0 + 3Z_f} = \frac{V_A}{Z_1 + Z_0 + Z_f} \]

(Equation 79)

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

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

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

**Effectively grounded networks**

A network is defined as effectively grounded if the ground-fault factor \( f_e \) is less than 1.4. The ground-fault factor is defined according to equation 80:

\[ f_e = \frac{V_{\text{max}}}{V_{\text{pn}}} \]

(Equation 80)

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

Another definition for effectively grounded network is when the following relationships between the symmetrical components of the network impedances are valid, see equations 81 and 82:
\[ X_0 < 3 \cdot X_i \]  
\[ R_0 \leq R_i \]

(Equation 81)

(Equation 82)

Where

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

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

**High impedance grounded networks**

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

### 8.3.2.2 Fault infeed from remote end

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

The equation for the bus voltage \( V_A \) at A side is:

\[
\bar{V}_A = \bar{I}_d \cdot p \cdot Z_L + (\bar{I}_d + \bar{I}_b) \cdot R_f
\]

(Equation 83)

If we divide \( V_A \) by \( I_A \) we get Z present to the IED at A side:

\[
\bar{Z}_d = \frac{\bar{V}_A}{\bar{I}_d} = p \cdot Z_L + \frac{\bar{I}_d + \bar{I}_b}{\bar{I}_d} \cdot R_f
\]

(Equation 84)
The infeed factor \((I_A + I_B)/I_A\) can be very high, 10-20 depending on the differences in source impedances at local and remote end.

![Diagram of fault current infeed from remote line end]

**Figure 97: Influence of fault current infeed from remote line end**

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

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

### 8.3.2.3 Load encroachment

In some cases the load impedance might enter the zone characteristic without any fault on the protected line. The phenomenon is called load encroachment and it might occur when an external fault is cleared and high emergency load is transferred on the protected line. The effect of load encroachment is illustrated in the left part of figure 98. A load impedance within the characteristic would cause an unwanted trip. The traditional way of avoiding this situation is to set the distance zone resistive reach with a security margin to the minimum load impedance. The drawback with this approach is that the sensitivity of the protection to detect resistive faults is reduced.

The IED has a built-in function which shapes the characteristic according to the right part of figure 98. The load encroachment algorithm will increase the possibility to detect high fault resistances, especially for phase-to-ground faults at remote line end. For example, for a given setting of the load angle \(LdAngle\) the resistive blinder for the zone measurement can be expanded according to the right part of the figure 98, given higher fault resistance coverage without risk for unwanted operation due to load encroachment. This is valid in both directions.

The use of the load encroachment feature is essential for long heavily loaded lines, where there might be a conflict between the necessary emergency load transfer and necessary sensitivity of the distance protection. The function can also preferably be used on heavy loaded medium long lines. For short lines, the major concern is to get sufficient fault resistance coverage. Load encroachment is not a major problem. Nevertheless, always set \(RldFwd\), \(RldRev\) and \(LdAngle\) according to the expected maximum load since these settings are used internally in the function as reference points to improve the performance of the phase selection.
8.3.2.4 Short line application

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

In short line applications, the major concern is to get sufficient fault resistance coverage. Load encroachment is not so common. The line length that can be recognized as a short line is not a fixed length; it depends on system parameters such as voltage and source impedance, see table 27.

<table>
<thead>
<tr>
<th>Line category</th>
<th>Vn</th>
<th>Vn</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>110 kV</td>
<td>500 kV</td>
</tr>
<tr>
<td>Very short line</td>
<td>0.75 - 3.5 miles</td>
<td>3-15 miles</td>
</tr>
<tr>
<td>Short line</td>
<td>4-7 miles</td>
<td>15-30 miles</td>
</tr>
</tbody>
</table>

The IED’s ability to set resistive and reactive reach independent for positive and zero sequence fault loops and individual fault resistance settings for phase-to-phase and phase-to-ground fault together with load encroachment algorithm improves the possibility to detect high resistive faults without conflict with the load impedance, see figure 98.

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

Load encroachment is normally no problem for short line applications.
8.3.2.5 Long transmission line application

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

What can be recognized as long lines with respect to the performance of distance protection can generally be described as in table 28, long lines have source impedance ratio (SIR's) less than 0.5.

<table>
<thead>
<tr>
<th>Line category</th>
<th>Vn</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>110 kV</td>
</tr>
<tr>
<td>Long lines</td>
<td>45-60 miles</td>
</tr>
<tr>
<td>Very long lines</td>
<td>&gt;60 miles</td>
</tr>
</tbody>
</table>

The IED's ability to set resistive and reactive reach independent for positive and zero sequence fault loops and individual fault resistance settings for phase-to-phase and phase-to-ground fault together with load encroachment algorithm improves the possibility to detect high resistive faults at the same time as the security is improved (risk for unwanted trip due to load encroachment is eliminated), see figure 99.

![Diagram](en05000220_ansi.vsd)

Figure 99: Characteristic for zone measurement for a long line

8.3.2.6 Parallel line application with mutual coupling

**General**

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

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

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

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

The different network configuration classes are:

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

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

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

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

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

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

Most multi circuit lines have two parallel operating circuits.

**Parallel line applications**

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

The three operation modes are:

1. Parallel line in service.
2. Parallel line out of service and grounded.
3. Parallel line out of service and not grounded.
Parallel line in service
This type of application is very common and applies to all normal sub-transmission and transmission networks.

Let us analyze what happens when a fault occurs on the parallel line see figure 100.

From symmetrical components, we can derive the impedance $Z$ at the relay point for normal lines without mutual coupling according to equation 85.

\[
Z = \frac{-V_{ph}}{I_{ph} + 3I_0} = \frac{-V_{ph}}{Z_1 + 3I_0 \cdot K}
\]

(Equation 85)

Where:
- $V_{ph}$ is phase to ground voltage at the relay point.
- $I_{ph}$ is phase current in the faulty phase.
- $3I_0$ is ground fault current.
- $Z_1$ is positive sequence impedance.
- $Z_0$ is zero sequence impedance.

![Figure 100: Class 1, parallel line in service](image1.png)

The equivalent circuit of the lines can be simplified, see figure 101.

![Figure 101: Equivalent zero sequence impedance circuit of the double-circuit, parallel, operating line with a single phase-to-ground fault at the remote busbar](image2.png)

When mutual coupling is introduced, the voltage at the relay point A will be changed according to equation 86.
By dividing equation 86 by equation 85 and after some simplification we can write the impedance present to the relay at A side as:

\[ Z = \frac{Z_{1L}}{Z_{1L}} \left( 1 + \frac{3I_{0} \cdot KNm}{I_{ph} + 3I_{0} \cdot KN} \right) \]

(Equation 87)

Where:

\[ KNm = \frac{Z_{0m}}{3 \cdot Z_{1L}} \]

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

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

Maximum overreach will occur if the fault current infeed from remote line end is weak. If considering a single phase-to-ground fault at 'p' unit of the line length from A to B on the parallel line for the case when the fault current infeed from remote line end is zero, the voltage \( V_A \) in the faulty phase at A side as in equation 88.

\[ \overline{V}_d = p \cdot Z_{1L} \left( I_{ph} + \overline{K_y} \cdot 3I_{0} + \overline{K_{0m}} \cdot 3I_{0p} \right) \]

(Equation 88)

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

\[ 3I_{0} \cdot Z_{0L} = 3I_{0p} \cdot Z_{0L} \left( 2 - p \right) \]

(Equation 89)

Simplification of equation 89, solving it for \( 3I_{0p} \) and substitution of the result into equation 88 gives that the voltage can be drawn as:

\[ \overline{V}_d = p \cdot Z_{1L} \left( I_{ph} + \overline{K_y} \cdot 3I_{0} + \overline{K_{0m}} \cdot \frac{3I_{0p}}{2 - p} \right) \]

(Equation 90)

If we finally divide equation 90 with equation 85 we can draw the impedance present to the IED as
Calculation for a 400 kV line, where we for simplicity have excluded the resistance, gives with 
\(X_{1L}=0.48 \text{ Ohm/Mile}, X_{0L}=1.4\text{Ohms/Mile},\) zone 1 reach is set to 90% of the line reactance \(p=71\%\) 
that is, the protection is underreaching with approximately 20%.

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

**Parallel line out of service and grounded**

![Diagram](en05000222_ansi.vsd)

*Figure 102: The parallel line is out of service and grounded*

When the parallel line is out of service and grounded at both line ends on the bus bar side of the 
line CTs so that zero sequence current can flow on the parallel line, the equivalent zero sequence 
circuit of the parallel lines will be according to figure 103.

![Diagram](IEC09000252_1_en.vsd)

*Figure 103: Equivalent zero sequence impedance circuit for the double-circuit line that 
operates with one circuit disconnected and grounded at both ends*

Here the equivalent zero-sequence impedance is equal to \(Z_0-Z_{0m}\) in parallel with \((Z_0-Z_{0m})/Z_0-Z_{0m}\) 
+\(Z_{0m}\) which is equal to equation 92.
\[ Z_k = \frac{Z_0 - Z_{0m}}{Z_0} \]

(Equation 92)

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

All expressions below are proposed for practical use. They assume the value of zero sequence, mutual resistance \( R_{0m} \) equals to zero. They consider only the zero sequence, mutual reactance \( X_{0m} \).

Calculate the equivalent \( X_{0E} \) and \( R_{0E} \) zero sequence parameters according to equation 93 and equation 94 for each particular line section and use them for calculating the reach for the underreaching zone.

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

(Equation 93)

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

(Equation 94)

Parallel line out of service and not grounded

![Diagram](en05000223_ansi.vsd)

Figure 104: Parallel line is out of service and not grounded

When the parallel line is out of service and not grounded, the zero sequence on that line can only flow through the line admittance to the ground. The line admittance is high which limits the zero-sequence current on the parallel line to very low values. In practice, the equivalent zero-sequence impedance circuit for faults at the remote bus bar can be simplified to the circuit shown in figure 104.

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

\[
K_u = \frac{1}{3} \left( \frac{2 \cdot Z_1 + Z_{0E}}{Z_0} \right) + R_f
\]

(Equation 95)

The reduction of the reach is equal to equation 95.

This means that the reach is reduced in reactive and resistive directions. If the real and imaginary components of the constant A are equal to equation 96 and equation 97.

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

(Equation 96)

\[
\text{Im}(A) = X_0 \cdot (2 \cdot R_1 + R_0 + 3 \cdot R_i) + R_0 \cdot (2 \cdot X_1 + X_0)
\]

(Equation 97)

The real component of the KU factor is equal to equation 98.

\[
\text{Re}(K_U) = 1 + \frac{\text{Re}(A) \cdot X_{m0}^2}{\left[ \text{Re}(A) \right]^2 + \left[ \text{Im}(A) \right]^2}
\]

(Equation 98)

The imaginary component of the same factor is equal to equation 99.

\[
\text{Im}(K_U) = \frac{\text{Im}(A) \cdot X_{m0}^2}{\left[ \text{Re}(A) \right]^2 + \left[ \text{Im}(A) \right]^2}
\]

(Equation 99)

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

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

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

(Equation 100)

\[
\bar{Z}_C = \bar{Z}_{Trf} + (\bar{Z}_{CT} + \frac{\bar{I}_A + \bar{I}_C}{\bar{I}_C} \cdot \bar{Z}_{TB}) \cdot \left(\frac{\sqrt{2}}{V1}\right)^2
\]

(Equation 101)

Where:
\(Z_{AT}\) and \(Z_{CT}\) is the line impedance from the A respective C station to the T point.
\(I_A\) and \(I_C\) is fault current from A respective C station for fault between T and B.

Figure 106: Example of tapped line with Auto transformer
V2/V1  Transformation ratio for transformation of impedance at V1 side of the transformer to the measuring side V2 (it is assumed that current and voltage distance function is taken from V2 side of the transformer).

$Z_{TF}$  is the line impedance from the T point to the fault (F).

$Z_{Trf}$  is transformer impedance.

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

Another complication that might occur depending on the topology is that the current from one end can have a reverse direction for fault on the protected line. For example, for faults at T the current from B might go in reverse direction from B to C depending on the system parameters (see the dotted line in figure 106), given that the distance protection in B to T will measure wrong direction.

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

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

**Fault resistance**

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

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

(Equation 102)

Where:

- $L$ represents the length of the arc (in meters). This equation applies for the distance protection zone 1. Consider approximately three times arc foot spacing for zone 2 to get a reasonable margin against the influence of wind.

- $I$ is the actual fault current in A.

In practice, the setting of fault resistance for both phase-to-ground RFPE and phase-to-phase RFPP should be as high as possible without interfering with the load impedance in order to obtain reliable fault detection.
8.3.3 Series compensation in power systems

The main purpose of series compensation in power systems is virtual reduction of line reactance in order to enhance the power system stability and increase loadability of transmission corridors. The principle is based on compensation of distributed line reactance by insertion of series capacitor (SC). The generated reactive power provided by the capacitor is continuously proportional to the square of the current flowing at the same time through the compensated line and series capacitor. This means that the series capacitor has a self-regulating effect. When the system loading increases, the reactive power generated by series capacitors increases as well. The response of SCs is automatic, instantaneous and continuous.

The main benefits of incorporating series capacitors in transmission lines are:

- Steady state voltage regulation and raise of voltage collapse limit
- Increase power transfer capability by raising the dynamic stability limit
- Improved reactive power balance
- Increase in power transfer capacity
- Reduced costs of power transmission due to decreased investment costs for new power lines

8.3.3.1 Steady state voltage regulation and increase of voltage collapse limit

A series capacitor is capable of compensating the voltage drop of the series inductance in a transmission line, as shown in figure 107. During low loading, the system voltage drop is lower and at the same time, the voltage drop on the series capacitor is lower. When the loading increases and the voltage drop become larger, the contribution of the series capacitor increases and therefore the system voltage at the receiving line end can be regulated.

Series compensation also extends the region of voltage stability by reducing the reactance of the line and consequently the SC is valuable for prevention of voltage collapse. Figure 108 presents the voltage dependence at receiving bus B (as shown in figure 107) on line loading and compensation degree \( K_C \), which is defined according to equation 103. The effect of series compensation is in this particular case obvious and self explanatory.

\[
K_C = \frac{X_C}{X_{\text{Line}}}
\]

(Equation 103)

A typical 500 km long 500 kV line is considered with source impedance

\[
Z_{\text{Sth}} = 0
\]

(Equation 104)

Figure 107: A simple radial power system
8.3.3.2 Increase in power transfer

The increase in power transfer capability as a function of the degree of compensation for a transmission line can be explained by studying the circuit shown in figure 109. The power transfer on the transmission line is given by the equation 105:

\[
P = \frac{V_A|V_B| \sin(\delta)}{X_{\text{Line}} - X_C} = \frac{V_A|V_B| \sin(\delta)}{X_{\text{Line}} \cdot (1 - K_C)}
\]  

(Equation 105)

The compensation degree \(K_C\) is defined as equation

\[
P = \frac{V_A|V_B| \sin(\delta)}{X_{\text{Line}} - X_C} = \frac{V_A|V_B| \sin(\delta)}{X_{\text{Line}} \cdot (1 - K_C)}
\]

\[
Q = \frac{V_A|V_B| \cos(\delta)}{X_{\text{Line}} - X_C} = \frac{V_A|V_B| \cos(\delta)}{X_{\text{Line}} \cdot (1 - K_C)}
\]

\[
\Delta V = V_A - V_B
\]

Figure 109: Transmission line with series capacitor

The effect on the power transfer when considering a constant angle difference (\(\delta\)) between the line ends is illustrated in figure 110. Practical compensation degree runs from 20 to 70 percent. Transmission capability increases of more than two times can be obtained in practice.

Figure 108: Voltage profile for a simple radial power line with 0, 30, 50 and 70% of compensation
8.3.3.3 Voltage and current inversion

Series capacitors influence the magnitude and the direction of fault currents in series compensated networks. They consequently influence phase angles of voltages measured in different points of series compensated networks and this performances of different protection functions, which have their operation based on properties of measured voltage and current phasors.

**Voltage inversion**

Figure 111 presents a part of series compensated line with reactance $X_{L1}$ between the IED point and the fault in point F of series compensated line. The voltage measurement is supposed to be on the bus side, so that series capacitor appears between the IED point and fault on the protected line. Figure 112 presents the corresponding phasor diagrams for the cases with bypassed and fully inserted series capacitor.

Voltage distribution on faulty lossless serial compensated line from fault point F to the bus is linearly dependent on distance from the bus, if there is no capacitor included in scheme (as shown in figure 112). Voltage $V_M$ measured at the bus is equal to voltage drop $\Delta V_L$ on the faulty line and lags the current $I_F$ by 90 electrical degrees.

The situation changes with series capacitor included in circuit between the IED point and the fault position. The fault current $I_F$ (see figure 112) is increased due to the series capacitor, generally decreases total impedance between the sources and the fault. The reactive voltage drop $\Delta V_L$ on $X_{L1}$ line impedance leads the current by 90 degrees. Voltage drop $\Delta V_C$ on series capacitor lags the fault current by 90 degrees. Note that line impedance $X_{L1}$ could be divided into two parts: one between the IED point and the capacitor and one between the capacitor and the fault position. The resulting voltage $V_M$ in IED point is this way proportional to sum of voltage drops on partial impedances between the IED point and the fault position F, as presented by

$$V_M = I_F \cdot j(X_{L1} - X_C)$$

(Equation 106)
It is obvious that voltage $V_M$ will lead the fault current $I_F$ as long as $X_{L1} > X_C$. This situation corresponds, from the directionality point of view, to fault conditions on line without series capacitor. Voltage $V_M$ in IED point will lag the fault current $I_F$ in case when:

$$X_{L1} < X_C < X_S + X_{L1}$$

(Equation 107)

Where

$X_S$ is the source impedance behind the IED

The IED point voltage inverses its direction due to presence of series capacitor and its dimension. It is a common practice to call this phenomenon voltage inversion. Its consequences on operation of different protections in series compensated networks depend on their operating principle. The most known effect has voltage inversion on directional measurement of distance IEDs (see chapter "Distance protection" for more details), which must for this reason comprise special measures against this phenomenon.
There will be no voltage inversion phenomena for reverse faults in system with VTs located on the bus side of series capacitor. The allocation of VTs to the line side does not eliminate the phenomenon, because it appears again for faults on the bus side of IED point.

**Current inversion**

Figure 113 presents part of a series compensated line with corresponding equivalent voltage source. It is generally anticipated that fault current $I_F$ flows on non-compensated lines from power source towards the fault F on the protected line. Series capacitor may change the situation.

![Figure 113: Current inversion on series compensated line](image)

The relative phase position of fault current $I_F$ compared to the source voltage $V_S$ depends in general on the character of the resultant reactance between the source and the fault position. Two possibilities appear:

\[ X_S - X_C + X_{L1} > 0 \]
\[ X_S - X_C + X_{L1} < 0 \]

(Equation 108)

The first case corresponds also to conditions on non compensated lines and in cases, when the capacitor is bypassed either by spark gap or by the bypass switch, as shown in phasor diagram in figure 114. The resultant reactance is in this case of inductive nature and the fault currents lags source voltage by 90 electrical degrees.

The resultant reactance is of capacitive nature in the second case. Fault current will for this reason lead the source voltage by 90 electrical degrees, which means that reactive current will flow from series compensated line to the system. The system conditions are in such case presented by equation 109

\[ X_C > X_S + X_{L1} \]

(Equation 109)
Figure 114: Phasor diagrams of currents and voltages for the bypassed and inserted series capacitor during current inversion

It is a common practice to call this phenomenon current inversion. Its consequences on operation of different protections in series compensated networks depend on their operating principle. The most known effect has current inversion on operation of distance IEDs (as shown in section "Distance protection" for more details), which cannot be used for the protection of series compensated lines with possible current inversion. Equation 109 shows also big dependence of possible current inversion on series compensated lines on location of series capacitors. $X_{L1} = 0$ for faults just behind the capacitor when located at line IED and only the source impedance prevents current inversion. Current inversion has been considered for many years only a theoretical possibility due to relatively low values of source impedances (big power plants) compared to the capacitor reactance. The possibility for current inversion in modern networks is increasing and must be studied carefully during system preparatory studies.

The current inversion phenomenon should not be studied only for the purposes of protection devices measuring phase currents. Directional comparison protections, based on residual (zero sequence) and negative sequence currents should be considered in studies as well. Current inversion in zero sequence systems with low zero sequence source impedance (a number of power transformers connected in parallel) must be considered as practical possibility in many modern networks.

Location of instrument transformers
Location of instrument transformers relative to the line end series capacitors plays an important role regarding the dependability and security of a complete protection scheme. It is on the other hand necessary to point out the particular dependence of those protection schemes, which need for their operation information on voltage in IED point.

Protection schemes with their operating principle depending on current measurement only, like line current differential protection are relatively independent on CT location. Figure 115 shows schematically the possible locations of instrument transformers related to the position of line-end series capacitor.
Figure 115: Possible positions of instrument transformers relative to line end series capacitor

Bus side instrument transformers
CT1 and VT1 on figure 115 represent the case with bus side instrument transformers. The protection devices are in this case exposed to possible voltage and current inversion for line faults, which decreases the required dependability. In addition to this may series capacitor cause negative apparent impedance to distance IEDs on protected and adjacent lines as well for close-in line faults (see also figure 117 LOC=0%), which requires special design of distance measuring elements to cope with such phenomena. The advantage of such installation is that the protection zone covers also the series capacitor as a part of protected power line, so that line protection will detect and cleared also parallel faults on series capacitor.

Line side instrument transformers
CT2 and VT2 on figure 115 represent the case with line side instrument transformers. The protective devices will not be exposed to voltage and current inversion for faults on the protected line, which increases the dependability. Distance protection zone 1 may be active in most applications, which is not the case when the bus side instrument transformers are used.

Distance IEDs are exposed especially to voltage inversion for close-in reverse faults, which decreases the security. The effect of negative apparent reactance must be studied seriously in case of reverse directed distance protection zones used by distance IEDs for teleprotection schemes. Series capacitors located between the voltage instruments transformers and the buses reduce the apparent zero sequence source impedance and may cause voltage as well as current inversion in zero sequence equivalent networks for line faults. It is for this reason absolutely necessary to study the possible effect on operation of zero sequence directional ground-fault overcurrent protection before its installation.

Dual side instrument transformers
Installations with line side CT2 and bus side VT1 are not very common. More common are installations with line side VT2 and bus side CT1. They appear as de facto installations also in switchyards with double-bus double-breaker and breaker-and-a-half arrangement. The advantage of such schemes is that the unit protections cover also for shunt faults in series capacitors and at the same time the voltage inversion does not appear for faults on the protected line.

Many installations with line-end series capacitors have available voltage instrument transformers on both sides. In such case it is recommended to use the VTs for each particular protection function to best suit its specific characteristics and expectations on dependability and security. The line side VT can for example be used by the distance protection and the bus side VT by the directional residual OC ground fault protection.

Apparent impedances and MOV influence
Series capacitors reduce due to their character the apparent impedance measured by distance IEDs on protected power lines. Figure 116 presents typical locations of capacitor banks on power lines together with corresponding compensation degrees. Distance IED near the feeding bus will
see in different cases fault on remote end bus depending on type of overvoltage protection used on capacitor bank (spark gap or MOV) and SC location on protected power line.

Figure 116: Typical locations of capacitor banks on series compensated line

Implementation of spark gaps for capacitor overvoltage protection makes the picture relatively simple, because they either flash over or not. The apparent impedance corresponds to the impedance of non-compensated line, as shown in figure 117 case $K_C = 0\%$.

Figure 117: Apparent impedances seen by distance IED for different SC locations and spark gaps used for overvoltage protection
Figure 118: MOV protected capacitor with examples of capacitor voltage and corresponding currents

The impedance apparent to distance IED is always reduced for the amount of capacitive reactance included between the fault and IED point, when the spark gap does not flash over, as presented for typical cases in figure 117. Here it is necessary to distinguish between two typical cases:

• Series capacitor only reduces the apparent impedance, but it does not cause wrong directional measurement. Such cases are presented in figure 117 for 50% compensation at 50% of line length and 33% compensation located on 33% and 66% of line length. The remote end compensation has the same effect.

• The voltage inversion occurs in cases when the capacitor reactance between the IED point and fault appears bigger than the corresponding line reactance, Figure 117, 80% compensation at local end. A voltage inversion occurs in IED point and the distance IED will see wrong direction towards the fault, if no special measures have been introduced in its design.

The situation differs when metal oxide varistors (MOV) are used for capacitor overvoltage protection. MOVs conduct current, for the difference of spark gaps, only when the instantaneous voltage drop over the capacitor becomes higher than the protective voltage level in each half-cycle separately, see figure 118. Extensive studies at Bonneville Power Administration in USA (ref. Goldsworthy, D.L “A Linearized Model for MOV-Protected series capacitors” Paper 86SM357–8 IEEE/PES summer meeting in Mexico City July 1986) have resulted in construction of a non-linear equivalent circuit with series connected capacitor and resistor. Their value depends on complete line (fault) current and protection factor \( k_p \). The later is defined by equation 110.
\[ k_p = \frac{V_{MOV}}{V_{NC}} \]

(Equation 110)

Where

- \( V_{MOV} \) is the maximum instantaneous voltage expected between the capacitor immediately before the MOV has conducted or during operation of the MOV, divided by \( \sqrt{2} \)
- \( V_{NC} \) is the rated voltage in RMS of the series capacitor

**Figure 119: Equivalent impedance of MOV protected capacitor in dependence of protection factor \( K_p \)**

Figure 119 presents three typical cases for series capacitor located at line end (case LOC=0% in figure 117).

- **Series capacitor prevails the scheme as long as the line current remains lower or equal to its protective current level \( (I \leq k_p \cdot I_{NC}) \). Line apparent impedance is in this case reduced for the complete reactance of a series capacitor.**

- **50% of capacitor reactance appears in series with resistance, which corresponds to approximately 36% of capacitor reactance when the line current equals two times the protective current level \( (I \leq 2 \cdot k_p \cdot I_{NC}) \). This information has high importance for setting of distance protection IED reach in resistive direction, for phase to ground fault measurement as well as for phase to phase measurement.**

- **Series capacitor becomes nearly completely bridged by MOV when the line current becomes higher than 10-times the protective current level \( (I \leq 10 \cdot k_p \cdot I_{NC}) \).**

### 8.3.3.4 Impact of series compensation on protective IED of adjacent lines

Voltage inversion is not characteristic for the buses and IED points closest to the series compensated line only. It can spread also deeper into the network and this way influences the selection of protection devices (mostly distance IEDs) on remote ends of lines adjacent to the series compensated circuit, and sometimes even deeper in the network.
Voltage at the B bus (as shown in figure 120) is calculated for the loss-less system according to the equation below.

\[ V_B = V_D + I_B \cdot jX_{Lb} = (I_A + I_B) \cdot j(X_{LF} - X_C) + I_B \cdot jX_{LB} \]  
(Equation 111)

Further development of equation 111 gives the following expressions:

\[ V_B = jI_B \left[ X_{LB} + \left( \frac{I_A}{I_B} \right) \cdot (X_{LF} - X_C) \right] \]  
(Equation 112)

\[ X_C \left( V_B = 0 \right) = \frac{X_{LB}}{1 + \frac{I_A}{I_B}} + X_{LF} \]  
(Equation 113)

Equation 112 indicates the fact that the infeed current \( I_A \) increases the apparent value of capacitive reactance in system: bigger the infeed of fault current, bigger the apparent series capacitor in a complete series compensated network. It is possible to say that equation 113 indicates the deepness of the network to which it will feel the influence of series compensation through the effect of voltage inversion.

It is also obvious that the position of series capacitor on compensated line influences in great extent the deepness of voltage inversion in adjacent system. Line impedance \( X_{LF} \) between D bus and the fault becomes equal to zero, if the capacitor is installed near the bus and the fault appears just behind the capacitor. This may cause the phenomenon of voltage inversion to be expanded very deep into the adjacent network, especially if on one hand the compensated line is very long with high degree of compensation, and the adjacent lines are, on the other hand, relatively short.

Extensive system studies are necessary before final decision is made on implementation and location of series capacitors in network. It requires to correctly estimate their influence on performances of (especially) existing distance IEDs. It is possible that the costs for number of protective devices, which should be replaced by more appropriate ones due to the effect of applied series compensation, influences the future position of series capacitors in power network.

Possibilities for voltage inversion at remote buses should not be studied for short circuits with zero fault resistance only. It is necessary to consider cases with higher fault resistances, for which spark gaps or MOVs on series capacitors will not conduct at all. At the same time this kind of
investigation must consider also the maximum sensitivity and possible resistive reach of distance protection devices, which on the other hand simplifies the problem.

Application of MOVs as non-linear elements for capacitor overvoltage protection makes simple calculations often impossible. Different kinds of transient or dynamic network simulations are in such cases unavoidable.

### 8.3.3.5 Distance protection

Distance protection due to its basic characteristics, is the most used protection principle on series compensated and adjacent lines worldwide. It has at the same time caused a lot of challenges to protection society, especially when it comes to directional measurement and transient overreach.

Distance IED in fact does not measure impedance or quotient between line current and voltage. Quantity 1= Operating quantity - Restrain quantity Quantity 2= Polarizing quantity. Typically Operating quantity is the replica impedance drop. Restraining quantity is the system voltage Polarizing quantity shapes the characteristics in different way and is not discussed here.

Distance IEDs comprise in their replica impedance only the replicas of line inductance and resistance, but they do not comprise any replica of series capacitor on the protected line and its protection circuits (spark gap and or MOV). This way they form wrong picture of the protected line and all “solutions” related to distance protection of series compensated and adjacent lines are concentrated on finding some parallel ways, which may help eliminating the basic reason for wrong measurement. The most known of them are decrease of the reach due to presence of series capacitor, which apparently decreases the line reactance, and introduction of permanent memory voltage in directional measurement.

Series compensated and adjacent lines are often the more important links in a transmission networks and delayed fault clearance is undesirable. This makes it necessary to install distance protection in combination with telecommunication. The most common is distance protection in Permissive Overreaching Transfer Trip mode (POTT).

### 8.3.3.6 Underreaching and overreaching schemes

It is a basic rule that the underreaching distance protection zone should under no circumstances overreach for the fault at the remote end bus, and the overreaching zone should always, under all system conditions, cover the same fault. In order to obtain section selectivity, the first distance (underreaching) protection zone must be set to a reach less than the reactance of the compensated line in accordance with figure 121.

![Figure 121: Underreaching (Zone 1) and overreaching (Zone 2) on series compensated line](en06000618.vsd)

The underreaching zone will have reduced reach in cases of bypassed series capacitor, as shown in the dashed line in figure 121. The overreaching zone (Zone 2) can this way cover bigger portion of
the protected line, but must always cover with certain margin the remote end bus. Distance protection Zone 1 is often set to

$$X_{Z1} = K_S \cdot (X_{11} + X_{12} - X_C)$$

(Equation 114)

Here $K_S$ is a safety factor, presented graphically in figure 122, which covers for possible overreaching due to low frequency (sub-harmonic) oscillations. Here it should be noted separately that compensation degree $K_C$ in figure 122 relates to total system reactance, inclusive line and source impedance reactance. The same setting applies regardless MOV or spark gaps are used for capacitor overvoltage protection.

Equation 114 is applicable for the case when the VTs are located on the bus side of series capacitor. It is possible to remove $X_C$ from the equation in cases of VTs installed in line side, but it is still necessary to consider the safety factor $K_S$.

If the capacitor is out of service or bypassed, the reach with these settings can be less than 50% of protected line dependent on compensation degree and there will be a section, $G$ in figure 121, of the power line where no tripping occurs from either end.

![Figure 122: Underreaching safety factor $K_S$ in dependence on system compensation degree $K_C$](en06000619.vsd)

For that reason permissive underreaching schemes can hardly be used as a main protection. Permissive overreaching distance protection or directional or unit protection must be used.

The overreach must be of an order so it overreaches when the capacitor is bypassed or out of service. Figure 123 shows the permissive zones. The first underreaching zone can be kept in the total protection but it only has the feature of a back-up protection for close up faults. The overreach is usually of the same order as the permissive zone. When the capacitor is in operation the permissive zone will have a very high degree of overreach which can be considered as a disadvantage from a security point of view.

![Figure 123: Permissive overreach distance protection scheme](en06000620_ansi.vsd)
**Negative IED impedance, positive fault current (voltage inversion)**

Assume in equation 115

\[ X_{11} < X_C < X_S + X_{11} \]  

(Equation 115)

and in figure 124

a three phase fault occurs beyond the capacitor. The resultant IED impedance seen from the \( D_B \) IED location to the fault may become negative (voltage inversion) until the spark gap has flashed.

Distance protections of adjacent power lines shown in figure 124 are influenced by this negative impedance. If the intermediate infeed of short circuit power by other lines is taken into consideration, the negative voltage drop on \( X_C \) is amplified and a protection far away from the faulty line can maloperate by its instantaneous operating distance zone, if no precaution is taken. Impedances seen by distance IEDs on adjacent power lines are presented by equations 116 to 119.

\[ I = I_1 + I_2 + I_3 \]  

(Equation 116)

\[ X_{DA1} = \frac{I_F}{I_{A1}} \cdot (X_C - X_{11}) \]  

(Equation 117)

\[ X_{DA2} = X_{A2} + \frac{I_F}{I_{A2}} \cdot (X_C - X_{11}) \]  

(Equation 118)

\[ X_{DA3} = X_{A3} + \frac{I_F}{I_{A3}} \cdot (X_C - X_{11}) \]  

(Equation 119)

*Figure 124: Distance IED on adjacent power lines are influenced by the negative impedance*
Normally the first zone of this protection must be delayed until the gap flashing has taken place. If the delay is not acceptable, some directional comparison must also be added to the protection of all adjacent power lines. As stated above, a good protection system must be able to operate correctly both before and after gap flashing occurs. Distance protection can be used, but careful studies must be made for each individual case. The rationale described applies to both conventional spark gap and MOV protected capacitors.

Special attention should be paid to selection of distance protection on shorter adjacent power lines in cases of series capacitors located at the line end. In such case the reactance of a short adjacent line may be lower than the capacitor reactance and voltage inversion phenomenon may occur also on remote end of adjacent lines. Distance protection of such line must have built-in functionality which applies normally to protection of series compensated lines.

It usually takes a bit of a time before the spark gap flashes, and sometimes the fault current will be of such a magnitude that there will not be any flashover and the negative impedance will be sustained. If equation 120 is valid

\[ X_{11} < X_C < X_S + X_{11} \]  

(Equation 120)

in figure 125, the fault current will have the same direction as when the capacitor is bypassed. So, the directional measurement is correct but the impedance measured is negative and if the characteristic crosses the origin shown in figure 125 the IED cannot operate. However, if there is a memory circuit designed so it covers the negative impedance, a three phase fault can be successfully cleared by the distance protection. As soon as the spark gap has flashed the situation for protection will be as for an ordinary fault. However, a good protection system should be able to operate correctly before and after gap flashing occurs.

If the distance protection is equipped with a ground-fault measuring unit, the negative impedance occurs when

\[ |3 \cdot X_C| > |2 \cdot X_{11} + X_{0,11}| \]  

(Equation 121)
Cross-polarized distance protection (either with mho or quadrilateral characteristic) will normally handle ground-faults satisfactory if the negative impedance occurs inside the characteristic. The operating area for negative impedance depends upon the magnitude of the source impedance and calculations must be made on a case by case basis, as shown in figure 125. Distance IEDs with separate impedance and directional measurement offer additional setting and operational flexibility when it comes to measurement of negative apparent impedance (as shown in figure 126).

**Negative IED impedance, negative fault current (current inversion)**

If equation 122 is valid in Figure 113 and a fault occurs behind the capacitor, the resultant reactance becomes negative and the fault current will have an opposite direction compared with fault current in a power line without a capacitor (current inversion). The negative direction of the fault current will persist until the spark gap has flashed. Sometimes there will be no flashover at all, because the fault current is less than the setting value of the spark gap. The negative fault current will cause a high voltage on the network. The situation will be the same even if a MOV is used. However, depending upon the setting of the MOV, the fault current will have a resistive component.

\[ X_C > X_S + X_{11} \]

(Equation 122)

The problems described here are accentuated with a three phase or phase-to-phase fault, but the negative fault current can also exist for a single-phase fault. The condition for a negative current in case of a ground fault can be written as follows:

\[ |3 \cdot X_C| > \left|2 \cdot X_{1\_\_1} + X_{0\_\_1} + 2 \cdot X_{0\_\_s} + X_{1\_\_s}\right| \]

(Equation 123)

All designations relates to figure 113. A good protection system must be able to cope with both positive and negative direction of the fault current, if such conditions can occur. A distance protection cannot operate for negative fault current. The directional element gives the wrong direction. Therefore, if a problem with negative fault current exists, distance protection is not a suitable solution. In practice, negative fault current seldom occurs. In normal network configurations the gaps will flash in this case.

**Double circuit, parallel operating series compensated lines**

Two parallel power lines running in electrically close vicinity to each other and ending at the same busbar at both ends (as shown in figure 127) causes some challenges for distance protection because of the mutual impedance in the zero sequence system. The current reversal phenomenon also raises problems from the protection point of view, particularly when the power lines are short and when permissive overreach schemes are used.

**Figure 127: Double circuit, parallel operating line**

Zero sequence mutual impedance \( Z_{mp} \) cannot significantly influence the operation of distance protection as long as both circuits are operating in parallel and all precautions related to settings of distance protection on series compensated line have been considered. Influence of
disconnected parallel circuit, which is grounded at both ends, on operation of distance protection on operating circuit is known.

Series compensation additionally exaggerates the effect of zero sequence mutual impedance between two circuits, see figure 128. It presents a zero sequence equivalent circuit for a fault at B bus of a double circuit line with one circuit disconnected and grounded at both IEDs. The effect of zero sequence mutual impedance on possible overreaching of distance IEDs at A bus is increased compared to non compensated operation, because series capacitor does not compensate for this reactance. The reach of underreaching distance protection zone 1 for phase-to-ground measuring loops must further be decreased for such operating conditions.

![Diagram of zero sequence equivalent circuit](en06000628_vsd)

**Figure 128:** Zero sequence equivalent circuit of a series compensated double circuit line with one circuit disconnected and grounded at both IEDs

Zero sequence mutual impedance may disturb also correct operation of distance protection for external evolving faults, when one circuit has already been disconnected in one phase and runs non-symmetrical during dead time of single pole autoreclosing cycle. All such operating conditions must carefully be studied in advance and simulated by dynamic simulations in order to fine tune settings of distance IEDs.

If the fault occurs in point F of the parallel operating circuits, as presented in figure 129, than also one distance IED (operating in POTT teleprotection scheme) on parallel, healthy circuit will send a carrier signal CSAB to the remote line end, where this signal will be received as a carrier receive signal CRBB.

![Diagram of current reversal phenomenon](en06000629_ansi_vsd)

**Figure 129:** Current reversal phenomenon on parallel operating circuits

It is possible to expect faster IED operation and breaker opening at the bus closer to fault, which will reverse the current direction on the healthy circuit. Distance IED RBB will suddenly detect fault in forward direction and, if CRBB signal is still present due to long reset time of IED RAB and especially telecommunication equipment, trip its related circuit breaker, since all conditions for POTT have been fulfilled. Zero sequence mutual impedance will additionally influence this process, since it increases the magnitude of fault current in healthy circuit after the opening of first circuit breaker. The so called current reversal phenomenon may cause unwanted operation of protection on healthy circuit and this way endangers even more the complete system stability.

To avoid the unwanted tripping, some manufacturers provide a feature in their distance protection which detects that the fault current has changed in direction and temporarily blocks distance protection. Another method employed is to temporarily block the signals received at the healthy line as soon as the parallel faulty line protection initiates tripping. The second mentioned method has an advantage in that not the whole protection is blocked for the short period. The disadvantage is that a local communication is needed between two protection devices in the neighboring bays of the same substation.
Distance protection used on series compensated lines must have a high overreach to cover the whole transmission line also when the capacitors are bypassed or out of service. When the capacitors are in service, the overreach will increase tremendously and the whole system will be very sensitive for false teleprotection signals. Current reversal difficulties will be accentuated because the ratio of mutual impedance against self-impedance will be much higher than for a non-compensated line.

If non-unit protection is to be used in a directional comparison mode, schemes based on negative sequence quantities offer the advantage that they are insensitive to mutual coupling. However, they can only be used for phase-to-ground and phase-to-phase faults. For three-phase faults an additional protection must be provided.

8.3.4 Setting guidelines

8.3.4.1 General

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

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

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

8.3.4.2 Setting of zone 1

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

In case of parallel lines, consider the influence of the mutual coupling according to section "Parallel line application with mutual coupling" and select the case(s) that are valid in the particular application. By proper setting it is possible to compensate for the cases when the parallel line is in operation, out of service and not grounded and out of service and grounded in both ends. The setting of the ground-fault reach should be <85% also when the parallel line is out of service and grounded at both ends (the worst case).
8.3.4.3 Setting of overreaching zone

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

The setting must not exceed 80% of the following impedances:

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

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

If the chosen zone 2 reach gives such a value that it will interfere with zone 2 on adjacent lines, the time delay of zone 2 must be increased by approximately 200 ms to avoid unwanted operation in cases when the telecommunication for the short adjacent line at the remote end is down during faults. The zone 2 must not be reduced below 120% of the protected line section. The whole line must be covered under all conditions.

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

If a fault occurs at point F, see figure 130, the IED at point A senses the impedance:

\[
\overline{Z}_{AF} = \overline{V}_{I_A} \overline{Z}_{AC} + \frac{\overline{I}_A + \overline{I}_C}{I_A} \cdot \overline{Z}_{CF} + \left(\frac{\overline{I}_A + \overline{I}_C + \overline{I}_B}{I_A}\right) \cdot R_F = \overline{Z}_{AC} + \left(1 + \frac{\overline{I}_C}{I_A}\right) \cdot \overline{Z}_{CF} + \left(1 + \frac{\overline{I}_C + \overline{I}_B}{I_A}\right) \cdot R_F
\]

(Equation 124)

Figure 130: Setting of overreaching zone

8.3.4.4 Setting of reverse zone

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

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

\[ Z_{rev} \geq 1.2 \times (Z_{2rem} - Z_L) \]

(Equation 125)

Where:

- \( Z_L \) is the protected line impedance.
- \( Z_{2rem} \) is the zone 2 setting (zone used in the POTT scheme) at the remote end of the protected line.

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

### 8.3.4.5 Series compensated and adjacent lines

#### Setting of zone 1

A voltage reversal can cause an artificial internal fault (voltage zero) on faulty line as well as on the adjacent lines. This artificial fault always have a resistive component, this is however small and can mostly not be used to prevent tripping of a healthy adjacent line.

An independent tripping zone 1 facing a bus which can be exposed to voltage reversal have to be set with reduced reach with respect to this false fault. When the fault can move and pass the bus, the zone 1 in this station must be blocked. Protection further out in the net must be set with respect to this apparent fault as the protection at the bus.

Different settings of the reach for the zone (ZMFCPDIS, 21) characteristic in forward and reverse direction makes it possible to optimize the settings in order to maximize dependability and security for independent zone1.

Due to the sub-harmonic oscillation swinging caused by the series capacitor at fault conditions the reach of the under-reaching zone 1 must be further reduced. Zone 1 can only be set with a percentage reach to the artificial fault according to the curve in 131.
Figure 131: Reduced reach due to the expected sub-harmonic oscillations at different degrees of compensation

\[ c = \text{degree of compensation} \left( \frac{X_C}{X_1} \right) \]

(Equation 126)

$X_C$ is the reactance of the series capacitor

\( p \) is the maximum allowable reach for an under-reaching zone with respect to the sub-harmonic swinging related to the resulting fundamental frequency reactance the zone is not allowed to over-reach.

The degree of compensation \( C \) in figure 131 has to be interpreted as the relation between series capacitor reactance \( X_C \) and the total positive sequence reactance \( X_1 \) to the driving source to the fault. If only the line reactance is used the degree of compensation will be too high and the zone 1 reach unnecessary reduced. The highest degree of compensation will occur at three phase fault and therefore the calculation need only to be performed for three phase faults.

The compensation degree in ground return path is different than in phases. It is for this reason possible to calculate a compensation degree separately for the phase-to-phase and three-phase faults on one side and for the single phase-to-ground fault loops on the other side. Different settings of the reach for the ph-ph faults and ph-G loops makes it possible to minimise the necessary decrease of the reach for different types of faults.
Figure 132: Measured impedance at voltage inversion

Forward direction:

Where

- $X_{L_{LOC}}$ equals line reactance up to the series capacitor (in the picture approximate 33% of $X_{Line}$)
- $X_{IFw}$ is set to $(X_{Line} - X_C) \cdot \frac{p}{100}$.
- $X_{IRv} = \max(1.5 \times (X_C - X_{L_{LOC}}); X_{IFw})$ is defined according to figure 131

When the calculation of $X_{IFw}$ gives a negative value the zone 1 must be permanently blocked.

For protection on non-compensated lines facing series capacitor on next line. The setting is thus:

- $X_{IFw}$ is set to $(X_{Line} - X_C \cdot K) \cdot \frac{p}{100}$.
- $X_{IRv}$ can be set to the same value as $X_{IFw}$
• $K$ equals side infeed factor at next busbar.

When the calculation of $X_{1Fw}$ gives a negative value the zone 1 must be permanently blocked.

**Fault resistance**
The resistive reach is, for all affected applications, restricted by the set reactive reach and the load impedance and same conditions apply as for a non-compensated network.

However, special notice has to be taken during settings calculations due to the ZnO because 50% of capacitor reactance appears in series with resistance, which corresponds to approximately 36% of capacitor reactance when the line current equals two times the protective current level. This information has high importance for setting of distance protection IED reach in resistive direction, for phase to ground- fault measurement as well as, for phase-to-phase measurement.

**Overreaching zone 2**
In series compensated network where independent tripping zones will have reduced reach due to the negative reactance in the capacitor and the sub-harmonic swinging the tripping will to a high degree be achieved by the communication scheme.

With the reduced reach of the under-reaching zones not providing effective protection for all faults along the length of the line, it becomes essential to provide over-reaching schemes like permissive overreach transfer trip (POTT) or blocking scheme can be used.

Thus it is of great importance that the zone 2 can detect faults on the whole line both with the series capacitor in operation and when the capacitor is bridged (short circuited). It is supposed also in this case that the reactive reach for phase-to-phase and for phase-to-ground faults is the same. The $X_{1Fw}$, for all lines affected by the series capacitor, are set to:

• $X_{1} \geq 1.5 \cdot X_{\text{Line}}$

The safety factor of 1.5 appears due to speed requirements and possible under reaching caused by the sub harmonic oscillations.

The increased reach related to the one used in non compensated system is recommended for all protections in the vicinity of series capacitors to compensate for delay in the operation caused by the sub harmonic swinging.

Settings of the resistive reaches are limited according to the minimum load impedance.

**Reverse zone**
The reverse zone that is normally used in the communication schemes for functions like fault current reversal logic, weak-in-feed logic or issuing carrier send in blocking scheme must detect all faults in the reverse direction which is detected in the opposite IED by the overreaching zone 2. The maximum reach for the protection in the opposite IED can be achieved with the series capacitor in operation.

The reactive reach can be set according to the following formula: $X_{1}=1.3 \cdot (X_{12 \text{Rem}} - 0.5(X_{L} - X_{C}))$

Settings of the resistive reaches are according to the minimum load impedance:
Optional higher distance protection zones
When some additional distance protection zones (zone 4, for example) are used they must be set according to the influence of the series capacitor.

8.3.4.6 Setting of zones for parallel line application

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

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

Parallel line in service – setting of zone 2
Overreaching zones (in general, zones 2 and 3) must overreach the protected circuit in all cases. The greatest reduction of a reach occurs in cases when both parallel circuits are in service with a single phase-to-ground fault located at the end of a protected line. The equivalent zero sequence impedance circuit for this case is equal to the one in figure 101.

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

\[ R_{0E} = R_0 + R_{m0} \]

(Equation 127)

\[ X_{0E} = X_0 + X_{m0} \]

(Equation 128)

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

\[ K0 = 1 - \frac{Z_{0m}}{2 \cdot Z1 + Z0 + R_f} \]

(Equation 129)

If the denominator in equation 129 is called B and Z0m is simplified to X0m, then the real and imaginary part of the reach reduction factor for the overreaching zones can be written as:

\[ \text{Re}(K0) = 1 - \frac{X_{0m} \cdot \text{Re}(B)}{\text{Re}(B)^2 + \text{Im}(B)^2} \]

(Equation 130)

\[ \text{Im}(K0) = \frac{X_{0m} \cdot \text{Im}(B)}{\text{Re}(B)^2 + \text{Im}(B)^2} \]

(Equation 131)
**Parallel line is out of service and grounded in both ends**

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

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

\[
R_{0E} = R_0 \times \left( 1 + \frac{X_{m0}^2}{R_0^2 + X_0^2} \right) \\
X_{0E} = X_0 \times \left( 1 - \frac{X_{m0}^2}{R_0^2 + X_0^2} \right)
\]

(Equation 132)

(Equation 133)

### 8.3.4.7 Setting of reach in resistive direction

Set the resistive reach \( R1 \) independently for each zone.

Set separately the expected fault resistance for phase-to-phase faults \( RFPP \) and for the phase-to-ground faults \( RFPG \) for each zone. For each distance zone, set all remaining reach setting parameters independently of each other.

The final reach in resistive direction for phase-to-ground fault loop measurement automatically follows the values of the line-positive and zero-sequence resistance, and at the end of the protected zone is equal to equation 134.

\[
R = \frac{1}{3} \left( 2 \cdot R_1 + R_0 \right) + RFPG
\]

(Equation 134)

\[
\phi_{loop} = \arctan \left( \frac{2 \cdot X1Zx + X0Zx}{2 \cdot R1Zx + R0Zx} \right)
\]

(Equation 135)

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

\[
RFPG \leq 4.5 \cdot X1
\]

(Equation 136)

The fault resistance for phase-to-phase faults is normally quite low, compared to the fault resistance for phase-to-ground faults. To minimize the risk for overreaching, limit the setting of the zone 1 reach in resistive direction for phase-to-phase loop measurement to:
8.3.4.8 Load impedance limitation, without load encroachment function

The following instructions are valid when setting the resistive reach of the distance zone itself with a sufficient margin towards the maximum load, that is, without the common load encroachment characteristic (set by $RLdFwd$, $RldRev$ and $ArgLd$). Observe that even though the zones themselves are set with a margin, $RLdFwd$ and $RldRev$ still have to be set according to maximum load for the phase selection to achieve the expected performance.

Check the maximum permissible resistive reach for any zone to ensure that there is a sufficient setting margin between the boundary and the minimum load impedance. The minimum load impedance ($\Omega$/phase) is calculated as:

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

(Equation 138)

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

The load impedance ($\Omega$/phase) is a function of the minimum operation voltage and the maximum load current:

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

(Equation 139)

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

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

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

(Equation 140)
This equation is applicable only when the loop characteristic angle for the single phase-to-ground faults is more than three times as large as the maximum expected load-impedance angle. For the case when the loop characteristic angle is less than three times the load-impedance angle, more accurate calculations are necessary according to equation 141.

\[
RFPG \leq 0.8 \cdot Z_{load \min} \cdot \left[ \cos \vartheta - \frac{2 \cdot R1 + R0}{2 \cdot X1 + X0} \cdot \sin \vartheta \right]
\]

(Equation 141)

Where:

\( \vartheta \) is a maximum load-impedance angle, related to the maximum load power.

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

\[
RFPPZx \leq 1.6 \cdot Z_{load}
\]

(Equation 142)

Equation 142 is applicable only when the loop characteristic angle for the phase-to-phase faults is more than three times as large as the maximum expected load-impedance angle. More accurate calculations are necessary according to equation 143.

\[
RFPPZx \leq 1.6 \cdot Z_{load \min} \cdot \cos \vartheta - \frac{R1Zx}{X1Zx} \cdot \sin \vartheta
\]

(Equation 143)

All this is applicable for all measuring zones when no Power swing detection function ZMRPSB (78) is activated in the IED. Use an additional safety margin of approximately 20% in cases when a ZMRPSB (78) function is activated in the IED, refer to the description of Power swing detection function ZMRPSB (78).

8.3.4.9 Zone reach setting higher than minimum load impedance

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

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

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

8.3.4.10 Parameter setting guidelines

**IminOPPGZx and IminOPPPZx**

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

The output of a phase-to-phase loop mn is blocked if \( I_{mn} < I_{\text{MinOPPPZx}} \). \( I_{mn} \) is the RMS value of the vector difference between phase currents m and n.

Both current limits \( I_{\text{MinOPPGZx}} \) and \( I_{\text{MinOPPPZx}} \) are automatically reduced to 75% of regular set values if the zone is set to operate in reverse direction, that is, \( \text{OperationDir}=\text{Reverse} \).

**OpModePPZx and OpModePEZx**

These settings, two per zone \( (x=1,2,5) \), with options {Off, Quadrilateral, Mho, Offset}, are used to set the operation and characteristic for phase-to-earth and phase-to-phase faults, respectively.

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

These settings define the operating direction for Zones Z3, Z4 and Z5 (the directionality of zones Z1, Z2 and ZRV is fixed). The options are *Non-directional*, *Forward* or *Reverse*. The result from respective set value is illustrated in figure 134 below, where positive impedance corresponds to the direction out on the protected line.

![Diagram of directional operating modes of Zones 3 to 5](IEC05000182-2-en.vsdx)

**Figure 134: Directional operating modes of the distance measuring zones 3 to 5**

tPPZx, tPGZx, TimerModeZx, ZoneLinkPU and TimerLinksZx

Refer to chapter Simplified logic schemes in Technical Manual for the application of these settings.

**OperationSC**

Choose the setting value *SeriesComp* if the protected line or adjacent lines are compensated with series capacitors. Otherwise maintain the *NoSeriesComp* setting value.

**CVTtype**

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

- **Passive type** For CVTs that use a non-linear component, like a saturable inductor, to limit overvoltages (caused by ferro-resonance). This component is practically idle during normal load and fault conditions, hence the name ‘passive’. CVTs that have a high resistive burden to mitigate ferro-resonance also fall in to this category.

- **Any** This option is primarily related to the so-called active type CVT, which uses a set of reactive components to form a filter circuit that essentially attenuates frequencies other than the nominal in order to restrain the ferro-resonance. The name ‘active’ refers to the fact that this circuit is always involved during transient conditions, regardless of voltage level. This option should also be used for types that do not fall under the other two categories, for example, CVTs with power electronic damping devices, or if the type cannot be identified at all.

- **None (Magnetic)** This option should be selected if the voltage transformer is fully magnetic.
$$3I0_{\text{Enable}_\text{PG}}$$

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

$$|3I0| \geq \frac{3I0_{\text{Enable}_\text{PG}}}{100} \cdot I_{\text{ph max}}$$

(Equation 144)

Where:

- $3I0_{\text{Enable}_\text{PG}}$ is the setting for the minimum residual current needed to enable operation in the phase-to-ground fault loops in %
- $I_{\text{ph max}}$ is the maximum phase current in any of three phases

By default this setting is set excessively high to always enable phase-to-phase measurement for phase-to-phase-ground faults. Maintain this default setting value unless there are very specific reasons to enable phase-to-ground measurement. Please note that, even with the default setting value, phase-to-ground measurement is activated whenever appropriate, like in the case of simultaneous faults: two ground faults at the same time, one each on the two circuits of a double line.

**Transient directional element**

There are no special settings for the transient directional element. However, since this element is activated only when phase selector release the phases, the settings for phase selector such as $UBase$, $IBase$, $RLdFw$, $RLdRvFactor$, $ArgLd$ will affect the performance of the element.

The directionalities given by the transient directional element are suitable for the permissive overreaching transfer trip (POTT) scheme. By cooperation with the remote end directionalities through a directional comparison scheme, it can clear faults on 100% of the transmission lines.

While applying directional comparison scheme, it is NOT recommended to mix the directional output STFWLx and STRVLx (where, $x = 1-3$) or start from distance zones (STZx) calculated from fundamental frequency component with the directional outputs STTDFWLx and STTDRVLx (where, $x = 1-3$) from transient method (on the same channel).

### 8.3.4.11 ZMMMXU settings

**ZZeroDb**

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

$ZHiHiLim$, $ZHiLim$, $ZLowLim$ and $ZLowLowLim$

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

Hysteresis value in % of range \((ZMax-ZMin)\), common for all limits. It is used to avoid the frequent update of the value for the attribute “range”.

ZMax

Estimated maximum impedance value. An impedance that is higher than \(ZMax\) has the quality attribute as “Out of Range”.

ZMin

Estimated minimum impedance value. An impedance that is lower than \(ZMin\) has the quality attribute as “Out of Range”.

8.4 Pole slip protection PSPPPPAM (78)

8.4.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pole slip protection</td>
<td>PSPPPPAM</td>
<td>(U_{\cos})</td>
<td>78</td>
</tr>
</tbody>
</table>

8.4.2 Application

Normally, the generator operates synchronously with the power system, that is, all the generators in the system have the same angular velocity and approximately the same phase angle difference. If the phase angle between the generators gets too large the stable operation of the system cannot be maintained. In such a case the generator loses the synchronism (pole slip) to the external power system.

The situation with pole slip of a generator can be caused by different reasons.

A short circuit occurs in the external power grid, close to the generator. If the fault clearance time is too long, the generator will accelerate so much, so the synchronism cannot be maintained. The relative generator phase angle at a fault and pole slip, relative to the external power system, is shown in figure 135.
**Figure 135: Relative generator phase angle at a fault and pole slip relative to the external power system**

The relative angle of the generator is shown for different fault duration at a three-phase short circuit close to the generator. As the fault duration increases the angle swing amplitude increases. When the critical fault clearance time is reached the stability cannot be maintained.

Un-damped oscillations occur in the power system, where generator groups at different locations, oscillate against each other. If the connection between the generators is too weak the amplitude of the oscillations will increase until the angular stability is lost. At the moment of pole slip there will be a centre of this pole slip, which is equivalent with distance protection impedance measurement of a three-phase. If this point is situated in the generator itself, the generator should be tripped as fast as possible. If the locus of the out of step centre is located in the power system outside the generators the power system should, if possible, be split into two parts, and the generators should be kept in service. This split can be made at predefined locations (trip of predefined lines) after function from pole slip protection (PSPPPAM,78) in the line protection IED.
Figure 136: Undamped oscillations causing pole slip

The relative angle of the generator is shown a contingency in the power system, causing undamped oscillations. After a few periods of the oscillation the swing amplitude gets to large and the stability cannot be maintained.

If the excitation of the generator gets too low there is a risk that the generator cannot maintain synchronous operation. The generator will slip out of phase and operate as an induction machine. Normally the under-excitation protection will detect this state and trip the generator before the pole slip. For this fault the under-excitation protection and PSPPPAM (78) function will give mutual redundancy.

The operation of a generator having pole slip will give risk of damages to the generator block.

- At each pole slip there will be significant torque impact on the generator-turbine shaft.
- In asynchronous operation there will be induction of currents in parts of the generator normally not carrying current, thus resulting in increased heating. The consequence can be damages on insulation and stator/rotor iron.
- At asynchronous operation the generator will absorb a significant amount of reactive power, thus risking overload of the windings.

PSPPPAM (78) function shall detect out of step conditions and trip the generator as fast as possible if the locus of the pole slip is inside the generator. If the centre of pole slip is outside the generator, situated out in the power grid, the first action should be to split the network into two
parts, after line protection action. If this fails there should be operation of the generator pole slip protection, to prevent further damages to the generator block.

### 8.4.3 Setting guidelines

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

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

*MeasureMode:* The voltage and current used for the impedance measurement is set by the parameter *MeasureMode*. The setting possibilities are: *PosSeq*, *AB*, *BC*, or *CA*. If all phase voltages and phase currents are fed to the IED the *PosSeq* alternative is recommended (default).

Further settings can be illustrated in figure 137.

*Figure 137: Settings for the Pole slip detection function*
The *ImpedanceZA* is the forward impedance as shown in figure 137. *ZA* should be the sum of the transformer impedance *XT* and the equivalent impedance of the external system *ZS*. The impedance is given in % of the base impedance, according to equation 146.

\[
Z_{\text{Base}} = \frac{U_{\text{Base}}}{I_{\text{Base}}} / \sqrt{3}
\]

(Equation 146)

The *ImpedanceZB* is the reverse impedance as shown in figure 137. *ZB* should be equal to the generator transient reactance *X’d*. The impedance is given in % of the base impedance, see equation 146.

The *ImpedanceZC* is the forward impedance giving the borderline between zone 1 and zone 2. *ZC* should be equal to the transformer reactance *ZT*. The impedance is given in % of the base impedance, see equation 146.

The angle of the impedance line *ZB – ZA* is given as *AnglePhi* in degrees. This angle is normally close to 90°.

*StartAngle*: An alarm is given when movement of the rotor is detected and the rotor angle exceeds the angle set for *StartAngle*. The default value 110° is recommended. It should be checked so that the points in the impedance plane, corresponding to the chosen *StartAngle* does not interfere with apparent impedance at maximum generator load.

*TripAngle*: If a pole slip has been detected: change of rotor angle corresponding to slip frequency 0.2 – 8 Hz, the slip line *ZA – ZB* is crossed and the direction of rotation is the same as at start, a trip is given when the rotor angle gets below the set *TripAngle*. The default value 90° is recommended.

*N1Limit*: The setting *N1Limit* gives the number of pole slips that should occur before trip, if the crossing of the slip line *ZA – ZB* is within zone 1, that is, the node of the pole slip is within the generator transformer block. The default value 1 is recommended to minimize the stress on the generator and turbine at out of step conditions.

*N2Limit*: The setting *N2Limit* gives the number of pole slips that should occur before trip, if the crossing of the slip line *ZA – ZB* is within zone 2, that is, the node of the pole slip is in the external network. The default value 3 is recommended give external protections possibility to split the network and thus limit the system consequences.

*Reset Time*: The setting *Reset Time* gives the time for (PSPPPAM, 78) function to reset after start when no pole slip been detected. The default value 5s is recommended.

**8.4.3.1 Setting example for line application**

In case of out of step conditions this shall be detected and the line between substation 1 and 2 shall be tripped.
If the apparent impedance crosses the impedance line ZB – ZA this is the detection criterion of out of step conditions, see figure 139.

The setting parameters of the protection is:

\[ Z_A: \] Line + source impedance in the forward direction

\[ Z_B: \] The source impedance in the reverse direction

\[ Z_C: \] The line impedance in the forward direction

\[ \text{AnglePhi} \]: The impedance phase angle
Use the following data:

$U_{\text{Base}}$: 400 kV

$S_{\text{Base}}$ set to 1000 MVA

Short circuit power at station 1 without infeed from the protected line: 5000 MVA (assumed to a pure reactance)

Short circuit power at station 2 without infeed from the protected line: 5000 MVA (assumed to a pure reactance)

Line impedance: $2 + j20$ ohm

With all phase voltages and phase currents available and fed to the protection IED, it is recommended to set the MeasureMode to positive sequence.

The impedance settings are set in pu with $Z_{\text{Base}}$ as reference:

$$
Z_{\text{Base}} = \frac{U_{\text{Base}}^2}{S_{\text{Base}}} = \frac{400^2}{1000} = 160 \text{ ohm}
$$

(Equation 147)

$$
Z_A = Z(\text{line}) + Z_{\text{sc (station2)}} = 2 + j20 + j \frac{400^2}{5000} = 2 + j52 \text{ ohm}
$$

(Equation 148)

This corresponds to:

$$
Z_A = \frac{2 + j52}{160} = 0.0125 + j0.325 \text{ pu} = 0.325 \angle 88^\circ \text{ pu}
$$

(Equation 149)

Set $Z_A$ to 0.32.

$$
Z_B = Z_{\text{sc (station1)}} = j \frac{400^2}{5000} = j32 \text{ ohm}
$$

(Equation 150)

This corresponds to:

$$
Z_B = \frac{j32}{160} = j0.20 \text{ pu} = 0.20 \angle 90^\circ \text{ pu}
$$

(Equation 151)

Set $Z_B$ to 0.2

This corresponds to:
Set ZC to 0.13 and Angle\(\Phi\) to 88°

The warning angle (\textit{StartAngle}) should be chosen not to cross into normal operating area. The maximum line power is assumed to be 2000 MVA. This corresponds to apparent impedance:

\[
Z = \frac{U^2}{S} = \frac{400^2}{2000} = 80 \text{ ohm}
\]

(Equation 153)

Simplified, the example can be shown as a triangle, see figure 140.

\[
\text{angle}_\text{Start} \geq \arctan \left( \frac{Z_B}{Z_{load}} \right) + \arctan \left( \frac{Z_A}{Z_{load}} \right) = \arctan \left( \frac{32}{80} \right) + \arctan \left( \frac{52}{80} \right) = 21.8° + 33.0° = 55°
\]

(Equation 154)

In case of minor damped oscillations at normal operation we do not want the protection to start. Therefore we set the start angle with large margin.
Set `StartAngle` to 110°

For the `TripAngle` it is recommended to set this parameter to 90° to assure limited stress for the circuit breaker.

In a power system it is desirable to split the system into predefined parts in case of pole slip. The protection is therefore situated at lines where this predefined split shall take place.

Normally the `N1Limit` is set to 1 so that the line will be tripped at the first pole slip.

If the line shall be tripped at all pole slip situations also the parameter `N2Limit` is set to 1. In other cases a larger number is recommended.

8.4.3.2 Setting example for generator application

In case of out of step conditions this shall be checked if the pole slip centre is inside the generator (zone 1) or if it is situated in the network (zone 2).

![Diagram showing the generator application of pole slip protection]

*Figure 141: Generator application of pole slip protection*

If the apparent impedance crosses the impedance line ZB – ZA this is the detected criterion of out of step conditions, see figure 142.
The setting parameters of the protection are:

- $Z_A$: Block transformer + source impedance in the forward direction
- $Z_B$: The generator transient reactance
- $Z_C$: The block transformer reactance
- $\text{AnglePhi}$: The impedance phase angle

Use the following generator data:

- $V_{\text{Base}}$: 20 kV
- SBase set to 200 MVA
- $X_d'$: 25%

Use the following block transformer data:

- $V_{\text{Base}}$: 20 kV (low voltage side)
- SBase set to 200 MVA
- $e_k$: 15%
Short circuit power from the external network without infeed from the protected line: 5000 MVA (assumed to a pure reactance).

We have all phase voltages and phase currents available and fed to the protection IED. Therefore it is recommended to set the MeasureMode to positive sequence.

The impedance settings are set in pu with ZBase as reference:

\[
Z_{\text{Base}} = \frac{U_{\text{Base}}^2}{S_{\text{Base}}} = \frac{20^2}{200} = 2.0 \text{ohm}
\]

(Equation 155)

\[
Z_A = Z_{\text{transf}} + Z_{\text{sc network}} = j\frac{20^2}{200} \cdot 0.15 + j\frac{20^2}{5000} = j0.38 \text{ohm}
\]

(Equation 156)

This corresponds to:

\[
Z_A = \frac{j0.38}{2.0} = j0.19 \text{ pu} = 0.19 \angle 90^\circ \text{ pu}
\]

(Equation 157)

Set ZA to 0.19

\[
Z_B = jX_d' = j\frac{20^2}{200} \cdot 0.25 = j0.5 \text{ohm}
\]

(Equation 158)

This corresponds to:

\[
Z_B = \frac{j0.5}{2.0} = j0.25 \text{ pu} = 0.25 \angle 90^\circ \text{ pu}
\]

(Equation 159)

Set ZB to 0.25

\[
Z_C = jX_f = j\frac{20^2}{200} \cdot 0.15 = j0.3 \text{ohm}
\]

(Equation 160)

This corresponds to:

\[
Z_C = \frac{j0.3}{2.0} = j0.15 \text{ pu} = 0.15 \angle 90^\circ \text{ pu}
\]

(Equation 161)
Set ZC to 0.15 and $AnglePhi$ to $90^\circ$.

The warning angle ($StartAngle$) should be chosen not to cross into normal operating area. The maximum line power is assumed to be 200 MVA. This corresponds to apparent impedance:

$$Z = \frac{U^2}{S} = \frac{20^2}{200} = 2\text{ohm}$$

(Equation 162)

Simplified, the example can be shown as a triangle, see figure 143.

$$\text{angleStart} \geq \arctan \frac{Z_{B}}{Z_{load}} + \arctan \frac{Z_{A}}{Z_{load}} = \arctan \frac{0.25}{2} + \arctan \frac{0.19}{2} = 7.1^\circ + 5.4^\circ = 12.5^\circ$$

(Equation 163)

In case of minor damped oscillations at normal operation we do not want the protection to start. Therefore we set the start angle with large margin.

Set $StartAngle$ to $110^\circ$.

For the $TripAngle$ it is recommended to set this parameter to $90^\circ$ to assure limited stress for the circuit breaker.
If the centre of pole slip is within the generator block set \textit{N1Limit} to 1 to get trip at first pole slip.

If the centre of pole slip is within the network set \textit{N2Limit} to 3 to get enable split of the system before generator trip.

8.5 Out-of-step protection OOSPPAM (78)

8.5.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Out-of-step protection</td>
<td>OOSPPAM</td>
<td></td>
<td>78</td>
</tr>
</tbody>
</table>

8.5.2 Application

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

The out-of-step phenomenon occurs when a phase opposition occurs periodically between different parts of a power system. This is often shown in a simplified way as two equivalent generators connected to each other via an equivalent transmission line and the phase difference between the equivalent generators is 180 electrical degrees.
The center of the electromechanical oscillation can be in the generator unit (or generator-transformer unit) or outside, somewhere in the power system. When the center of the electromechanical oscillation occurs within the generator it is essential to trip the generator immediately. If the center of the electromechanical oscillation is outside any of the generators in the power system, the power system should be split into two different parts; so each part may have the ability to restore stable operating conditions. This is sometimes called “islanding”. The objective of islanding is to prevent an out-of-step condition from spreading to the healthy parts of the power system. For this purpose, uncontrolled tripping of interconnections or generators must be prevented. It is evident that a reasonable strategy for out-of-step relaying as well as, appropriate choice of other protection relays, their locations and settings require detailed stability studies for each particular power system and/or subsystem. On the other hand, if severe swings occur, from which a fast recovery is improbable, an attempt should be made to isolate the affected area from the rest of the system by opening connections at predetermined points. The electrical system parts swinging to each other can be separated with the lines closest to the center of the power swing allowing the two systems to be stable as separated islands. The main problem involved with systemic islanding of the power system is the difficulty, in some cases, of predicting the optimum splitting points, because they depend on the fault location and the pattern of generation and load at the respective time. It is hardly possible to state general rules for out-of-step relaying, because they shall be defined according to the particular design and needs of each electrical network. The reason for the existence of two zones of operation is selectivity, required for successful islanding. If there are several out-of-step relays in the power system, then selectivity between separate relays is obtained by the relay reach (for example zone 1) rather then by time grading.

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

Undamped oscillations occur in power systems, where generator groups at different locations are not strongly electrically connected and can oscillate against each other. If the connection between the generators is too weak the magnitude of the oscillations may increase until the angular stability is lost. More often, a three-phase short circuit (unsymmetrical faults are much less dangerous in this respect) may occur in the external power grid, electrically close to the generator. If the fault clearing time is too long, the generator accelerates so much, that the synchronism
cannot be maintained even if the power system is restored to the pre-fault configuration, see Figure 145.

![Generator rotational speed in per unit vs time in milliseconds](IEC10000108-2-en.vsd)

**Figure 145: Stable and unstable case. For the fault clearing time $t_{cl} = 200$ ms, the generator remains in synchronism, for $t_{cl} = 260$ ms, the generator loses step.**

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

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

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

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

The setting example for generator protection application shows how to calculate the most important settings \( \text{ForwardR} \), \( \text{ForwardX} \), \( \text{ReverseR} \), and \( \text{ReverseX} \).

Table 29: An example how to calculate values for the settings \( \text{ForwardR} \), \( \text{ForwardX} \), \( \text{ReverseR} \), and \( \text{ReverseX} \)

<table>
<thead>
<tr>
<th>Data required</th>
<th>Generator</th>
<th>Step-up transformer</th>
<th>Single power line</th>
<th>Power system</th>
</tr>
</thead>
<tbody>
<tr>
<td>VBase = ( Vg ) = 13.8 kV</td>
<td>V1 = 13.8 kV</td>
<td>Vline = 230 kV</td>
<td>Vnom = 230 kV</td>
<td></td>
</tr>
<tr>
<td>IBase = ( Ig ) = 8367 A</td>
<td>Vusc = 10%</td>
<td>Xl = 0.4289 Ω/km</td>
<td>SC level = 5000 MVA</td>
<td></td>
</tr>
<tr>
<td>Xd' = 0.2960 pu</td>
<td>V2 = 230 kV</td>
<td>Rl = 0.0659 Ω/km</td>
<td>SC current = 12 551 A</td>
<td></td>
</tr>
<tr>
<td>Rs = 0.0029 pu</td>
<td>I1 = 12 551 A</td>
<td>Ze = 10.5801 Ω</td>
<td>φ = 84.289°</td>
<td></td>
</tr>
<tr>
<td>ZBase = 0.9522 Ω</td>
<td>Xl = 0.1000 pu (transf. ZBase)</td>
<td>Re = Ze \cdot \cos (φ) = 1.05 Ω</td>
<td>Xe = 10.52 Ω</td>
<td></td>
</tr>
<tr>
<td>Rs = 0.0029 \cdot 0.952 = 0.003 Ω</td>
<td>Rl = 0.0054 pu (transf. ZBase)</td>
<td>(X and R referred to 230 kV basis)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Xc = 0.100 \cdot 0.6348 = 0.064 Ω</td>
<td>Xline = 300 \cdot 0.4289 = 128.7 Ω</td>
<td>Xe = 10.52 \cdot (13.8/230)^2 = 0.038 Ω</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rs = 0.0029 \cdot 0.952 = 0.003 Ω</td>
<td>Xl = 0.0054 \cdot 0.635 = 0.003 Ω</td>
<td>Re = 1.05 \cdot (13.8/230)^2 = 0.004 Ω</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1-st step in calculation</td>
<td>2-nd step in calculation</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Xd' = 0.2960 \cdot 0.952 = 0.282 Ω</td>
<td>X = 10.52 \cdot (13.8/230)^2 = 0.038 Ω</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rs = 0.0029 \cdot 0.952 = 0.003 Ω</td>
<td>Re = 1.05 \cdot (13.8/230)^2 = 0.004 Ω</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3-rd step in calculation</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ForwardX = X + Xline + Xe</td>
<td>X and R referred to 13.8 kV</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>ForwardR = R + Rline + Re</td>
<td>(X and R referred to 13.8 kV)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Final resulted settings</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Settings \( \text{ForwardR} \), \( \text{ForwardX} \), \( \text{ReverseR} \), and \( \text{ReverseX} \):

- A precondition in order to be able to use the Out-of-step protection and construct a suitable lens characteristic is that the power system in which the Out-of-step protection is installed, is modeled as a two-machine equivalent system, or as a single machine – infinite bus equivalent power system. Then the impedances from the position of the Out-of-step protection in the direction of the normal load flow can be taken as forward.
- The settings \( \text{ForwardX} \), \( \text{ForwardR} \), \( \text{ReverseX} \) and \( \text{ReverseR} \) must, if possible, take into account, the post-disturbance configuration of the simplified power system. This is not always easy, in particular with islanding. But for the two machine model as in Table 29, the most probable scenario is that only one line is in service after the fault on one power line has been cleared by line protections. The settings \( \text{ForwardX} \), \( \text{ForwardR} \) must therefore take into account the reactance and resistance of only one power line.
- All the reactances and resistances must be referred to the voltage level where the Out-of-step relay is installed; for the example case shown in Table 29, this is the generator nominal voltage \( VBase = 13.8 \text{ kV} \). This affects all the forward reactances and resistances in Table 29.
• All reactances and resistances must be finally expressed in percent of ZBase, where ZBase is for the example shown in Table 29 the base impedance of the generator, ZBase = 0.9522 Ω. Observe that the power transformer’s base impedance is different, ZBase = 0.6348 Ω. Observe that this latter power transformer ZBase = 0.6348 Ω must be used when the power transformer reactance and resistance are transformed.

• For the synchronous machines as the generator in Table 29, the transient reactance Xd' shall be used. This due to the relatively slow electromechanical oscillations under out-of-step conditions.

• Sometimes the equivalent resistance of the generator is difficult to get. A good estimate is 1 percent of transient reactance Xd'. No great error is done if this resistance is set to zero (0).

• Inclination of the Z-line, connecting points SE and RE, against the real (R) axis can be calculated as arctan \( \frac{(ReverseX + ForwardX)}{(ReverseR + ForwardR)} \), and is for the case in Table 29 equal to 84.55 degrees, which is a typical value.

Other settings:

• \( ReachZ1 \): Determines the reach of the zone 1 in the forward direction. Determines the position of the X-line which delimits zone 1 from zone 2. Set in % of \( ForwardX \). In the case shown in Table 29, where the reactance of the step-up power transformer is 11.32 % of the total \( ForwardX \), the setting \( ReachZ1 \) should be set to \( ReachZ1 = 12 \% \). This means that the generator – step-up transformer unit would be in the zone 1. In other words, if the centre of oscillation would be found to be within the zone 1, only a very limited number of pole-slips would be allowed, usually only one.

• \( pick up Angle \): Angle between the two equivalent rotors induced voltages (that is, the angle between the two internal induced voltages \( E1 \) and \( E2 \) in an equivalent simplified two-machine system) to get the pickup signal, in degrees. The width of the lens characteristic is determined by the value of this setting. Whenever the complex impedance \( Z(R, X) \) enters the lens, this is a sign of instability. The angle recommended is 110 or 120 degrees, because it is at this rotor angle where problems with dynamic stability usually begin. Power angle 120 degrees is sometimes called “the angle of no return” because if this angle is reached under generator swings, the generator is most likely to lose synchronism. When the complex impedance \( Z(R, X) \) enters the lens the start output signal (PICKUP) is set to 1 (TRUE).

• \( TripAngle \): The setting \( TripAngle \) specifies the value of the rotor angle where the trip command is sent to the circuit breaker in order to minimize the stress to which the breaker is exposed when breaking the currents. The range of this value is from 15° to 90°, with higher values suitable for longer breaker opening times. If a breaker opening is initiated at for example 60°, then the circuit breaker opens its contacts closer to 0°, where the currents are smaller. If the breaker opening time \( tBreaker \) is known, then it is possible to calculate more exactly when opening must be initiated in order to open the circuit breaker contacts as close as possible to 0°, where the currents are smallest. If the breaker opening time \( tBreaker \) is specified (that is, higher than the default 0.0 s, where 0.0 s means that \( tBreaker \) is unknown), then this alternative way to determine the moment when a command to open the breaker is sent, is automatically chosen instead of the more approximate method, based on the \( TripAngle \).

• \( tReset \): Interval of time since the last pole-slip detected, when the Out-of-step protection is reset. If there is no more pole slips detected under the time interval specified by \( tReset \) since the previous one, the function is reset. All outputs are set to 0 (FALSE). If no pole slip at all is detected under interval of time specified by \( tReset \) since the pickup signal has been set (for example a stable case with synchronism retained), the function is as well reset, which includes the pickup output signal (PICKUP), which is reset to 0 (FALSE) after \( tReset \) interval of time has elapsed. However, the measurements of analogue quantities such as \( R, X, P, Q \), and so on continue without interruptions. Recommended setting of \( tReset \) is in the range of 6 to 12 seconds.
8.6 Loss of excitation LEXPDIS(40)

8.6.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Loss of excitation</td>
<td>LEXPDIS</td>
<td></td>
<td>40</td>
</tr>
</tbody>
</table>

- **NoOfSlipsZ1**: Maximum number of pole slips with centre of electromechanical oscillation within zone 1 required for a trip. Usually, NoOfSlipsZ1 = 1.
- **NoOfSlipsZ2**: Maximum number of pole slips with centre of electromechanical oscillation within zone 2 required for a trip. The reason for the existence of two zones of operation is selectivity, required particularly for successful islanding. If there are several pole slip (out-of-step) relays in the power system, then selectivity between relays is obtained by the relay reach (for example zone 1) rather then by time grading. In a system, as in Table 29, the number of allowed pole slips in zone 2 can be the same as in zone 1. Recommended value: NoOfSlipsZ2 = 2 or 3.
- **Operation**: With the setting Operation OOSPPAM function can be set On/Off.
- **OperationZ1**: Operation zone 1 Enabled, Disabled. If OperationZ1 = Disabled, all pole-slips with centre of the electromagnetic oscillation within zone 1 are ignored. Default setting = Enabled. More likely to be used is the option to extend zone 1 so that zone 1 even covers zone 2. This feature is activated by the input to extend the zone 1 (EXTZ1).
- **OperationZ2**: Operation zone 2 Enabled, Disabled. If OperationZ1 = Disabled, all pole-slips with centre of the electromagnetic oscillation within zone 2 are ignored. Default setting = Enabled.
- **tBreaker**: Circuit breaker opening time. Use the default value tBreaker = 0.000 s if unknown. If the value is known, then a value higher than 0.000 is specified, for example tBreaker = 0.040 s: the out-of-step function gives a trip command approximately 0.040 seconds before the currents reach their minimum value. This in order to decrease the stress imposed to the circuit breaker.
- **VBase**: This is the voltage at the point where the Out-of-step protection is installed. If the protection is installed on the generator output terminals, then VBase is the nominal (rated) phase to phase voltage of the protected generator. All the resistances and reactances are measured and displayed referred to voltage VBase. Observe that ReverseX, ForwardX, ReverseR, and ForwardR must be given referred to VBase. IBase is the protected generator nominal (rated) current, if the Out-of-step protection belongs to a generator protection scheme.
- **InvertCTCurr**: If the currents fed to the Out-of-step protection are measured on the protected generator neutral side (LV-side) then inversion is not necessary (InvertCTCurr = Disabled), provided that the CT’s orientation complies with ABB recommendations, as shown in Table 29. If the currents fed to the Out-of-step protection are measured on the protected generator output terminals side (HV-side), then inversion is necessary (InvertCTCurr = Enabled), provided that the CT’s actual direction complies with ABB recommendations, as shown in Table 29.
There are limits for the loss of excitation of a synchronous machine. A reduction of the excitation current weakens the electromagnetic coupling between the generator rotor and stator, hence, the external power system. The machine may lose the synchronism and starts to operate like an induction machine. Then, the reactive consumption will increase. Even if the machine does not lose synchronism it may not be acceptable to operate in this state for a long time. Loss of excitation increases the generation of heat in the end region of the synchronous machine. The local heating may damage the insulation of the stator winding and even the iron core.

A generator connected to a power system can be represented by an equivalent single phase circuit as shown in figure 146. For simplicity the equivalent shows a generator having round rotor, \((X_d \approx X_q)\).

\[ I, (P, Q) \]

\[ + \]

\[ E \]

\[ jX_d \]

\[ V \]

\[ jX_{net} \]

\[ + \]

\[ E_{net} \]

\[ - \]

\[ - \]

\[ + \]

\[ - \]

Figure 146: A generator connected to a power system, represented by an equivalent single phase circuit

where:

- \(E\) represents the internal voltage in the generator,
- \(X_d\) is the stationary reactance of the generator,
- \(X_{net}\) is an equivalent reactance representing the external power system and
- \(E_{net}\) is an infinite voltage source representing the lumped sum of the generators in the system.

The active power out from the generator can be formulated according to equation 164:

\[
P = \frac{E \cdot E_{net}}{X_d + X_{net}} \cdot \sin \delta
\]

(Equation 164)

where:

- The angle \(\delta\) is the phase angle difference between the voltages \(E\) and \(E_{net}\).

If the excitation of the generator is decreased (loss of field), the voltage \(E\) becomes low. In order to maintain the active power output the angle \(\delta\) must be increased. It is obvious that the maximum power is achieved at 90\(^\circ\). If the active power cannot be reached at 90\(^\circ\) static stability cannot be maintained.
The complex apparent power from the generator, at different angles $\delta$ is shown in figure 147. The line corresponding to $90^\circ$ is the steady state stability limit. It must be noticed that the power limitations shown below is highly dependent on the network impedance.

![Diagram showing complex apparent power from the generator at different angles](en06000322.vsd)

**Figure 147: The complex apparent power from the generator, at different angles $\delta$**

To prevent damages to the generator block, the generator should be tripped at low excitation. A suitable area, in the PQ-plane, for protection operation is shown in figure 148. In this example limit is set to a small negative reactive power independent of active power.
Figure 148: Suitable area, in the PQ-plane, for protection operation

Often the capability curve of a generator describes also low excitation capability of the generator, see figure 149.
where:

- **AB** = Field current limit
- **BC** = Stator current limit
- **CD** = End region heating limit of stator, due to leakage flux
- **BH** = Possible active power limit due to turbine output power limitation
- **EF** = Steady-state limit without AVR
- **X_s** = Source impedance of connected power system

Loss of excitation protection can be based on directional power measurement or impedance measurement.

The straight line EF in the P-Q plane can be transferred into the impedance plane by using the relation shown in equation 165.

\[
\vec{Z} = \frac{\vec{V}}{\vec{T}} = \frac{\vec{V} \cdot \vec{V}^*}{\vec{T} \cdot \vec{P}^*} = \frac{V^2 \cdot S^*}{S^* \cdot S} = \frac{V^2 \cdot P + j \cdot V^2 \cdot Q}{P^2 + Q^2} = R + jX
\]

(Equation 165)

The straight line in the PQ-diagram will be equivalent with a circle in the impedance plane, see figure 150. In this example the circle is corresponding to constant Q, that is, characteristic parallel with P-axis.
Figure 150: The straight line in the PQ-diagram is equivalent with a circle in the impedance plane

LEXPDIS (40) in the IED is realised by two impedance circles and a directional restraint possibility as shown in figure 151.
8.6.3 Setting guidelines

Here is described the setting when there are two zones activated of the protection. Zone Z1 will give a fast trip in case of reaching the dynamic limitation of the stability. Zone 2 will give a trip after a longer delay if the generator reaches the static limitation of stability. There is also a directional criterion used to prevent trip at close in external faults in case of zones reaching into the impedance area as shown in figure 151.

*Operation*: With the setting *Operation LEXPDIS (40)* function can be set *Enabled/Disabled*.

*IBase*, (refer to *GlobalBaseSel*): The setting *IBase* is set to the generator rated Current in A, see equation 166.

\[
IBase = \frac{S_N}{\sqrt{3} \cdot V_N}
\]

(Equation 166)

*VBase*: The setting *VBase* is set to the generator rated Voltage (phase-phase) in kV.

*OperationZ1, OperationZ2*: With the settings *OperationZ1* and *OperationZ2* each zone can be set *Enabled* or *Disabled*.
For the two zones the impedance settings are made as shown in figure 152.

Figure 152: Impedance settings for the fast (Z1) and slow (Z2) zone

The impedances are given in pu of the base impedance calculated according to equation 167.

\[ Z_{\text{Base}} = \frac{V_{\text{Base}}}{\sqrt{3}} \frac{\sqrt{3}}{I_{\text{Base}}} \]  

(Equation 167)

\( X_{\text{OffsetZ1}} \) and \( X_{\text{OffsetZ2}} \), offset of impedance circle top along the X axis, are given negative value if \( X < 0 \).

\( X_{\text{OffsetZ1}} \): It is recommended to set \( X_{\text{OffsetZ1}} = -X_d/2 \) and \( Z_{\text{1diameter}} = 100\% \) of \( Z_{\text{Base}} \).

\( tZ1 \): \( tZ1 \) is the setting of trip delay for \( Z1 \) and this parameter is recommended to set 0.1 s.
Figure 153: Loss of excitation characteristics recommended by IEEE

It is recommended to set $X_{\text{offsetZ2}}$ equal to $-X_d/2$ and $Z2\text{diameter}$ equal to $X_d$.

$tZ2$: $tZ2$ is the setting of trip delay for Z2 and this parameter is recommended to set 2.0 s not to risk unwanted trip at oscillations with temporary apparent impedance within the characteristic.

$DirSuperv$: The directional restrain characteristic allows impedance setting with positive X value without the risk of unwanted operation of the under-excitation function. To enable the directional restrain option the parameter $DirSuperv$ shall be set $Enabled$.

$X_{\text{offsetDirLine}}, Dir\text{Angle}$: The settings $X_{\text{offsetDirLine}}$ and $Dir\text{Angle}$ are shown in figure 154. $X_{\text{offsetDirLine}}$ is set in % of the base impedance according to equation 167.

$X_{\text{offsetDirLine}}$ is given a positive value if $X > 0$. $Dir\text{Angle}$ is set in degrees with negative value in the 4th quadrant. Typical value is -13°.
8.7 Sensitive rotor earth fault protection, injection based ROTIPHIZ (64R)

8.7.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sensitive rotor earth fault protection, injection based</td>
<td>ROTIPHIZ</td>
<td>Rre&lt;</td>
<td>64R</td>
</tr>
</tbody>
</table>

8.7.2 Application

The sensitive rotor earth fault protection, injection based (ROTIPHIZ, 64R), is used to detect ground faults in the rotor windings of generators and motors. An independent signal with a frequency different from the generator rated frequency is injected into the rotor circuit.
To implement the above concept, a separate injection device is required. The injection device generates a square wave voltage signal which is fed into the rotor winding of the generator.

The magnitude of the injected voltage signal is measured at the injection point; the magnitude of the injected current is measured through a resistive shunt located within REX060. These two measurements are fed to the IED. Based on these two measured quantities, the IED determines the rotor winding resistance to ground. The resistance value is then compared to the preset fault resistance alarm and trip levels.

The protection function can detect ground faults in the entire rotor winding and associated connections. The function can also detect excitation system ground faults on the AC side of the excitation rectifier. The measuring principle used is not influenced by the generator operating mode and is fully functional even with the generator at standstill.

8.7.2.1 Rotor earth fault protection function

The injection to the rotor is schematically shown in figure 155.

![Figure 155: Equivalent diagram for Sensitive rotor earth fault protection principle](ANSI11000065_1_en.vsd)

The impedance \( Z_{\text{Measured}} \) is equal to the capacitive reactance between the rotor winding and ground \( (1/\omega C_{\text{rot}}) \) and the ground fault resistance \( (R_f) \). The series resistance in the injection circuit is eliminated. \( R_f \) is very large in the non-faulted case and the measured impedance, called the rotor reference impedance, can be calculated as:

\[
Z_{\text{ref}} = -j \frac{1}{\omega C_{\text{rot}}}
\]

alternative

\[
\frac{1}{Z_{\text{ref}}} = j \omega C_{\text{rot}}
\]

Where:

\[
\omega = 2\pi \cdot f_{\text{inj}}
\]
The injected frequency \(f_{\text{inj}}\) of the square wave, is a set value, different from the fundamental frequency (50 or 60 Hz). The injected frequency can be set within the range 75 – 250 Hz with the recommended value 113 Hz in 50 Hz systems and 137 Hz in 60 Hz systems.

\(R_{\text{series}}\) is a resistance in the REX061 unit used to protect against overvoltage to the injection unit. Such overvoltages can occur if the unit is fed from static excitation system.

The injection unit REX060 is connected to the generator and to IED as shown in figure 156.

![Connection of REX060 for rotor earth fault protection](image)

**Figure 156: Connection of REX060 for rotor earth fault protection**

1. Generator unit consisting of a synchronous generator and a step-up transformer
2. Generator field winding
3. Capacitor coupling unit which is used to provide insulation barrier between rotor circuit and injection equipment
4. Cable used to inject the square-wave signal into the rotor circuit
5. Connection for measurement of injected current. This signal is amplified in REX060 before it is passed on to IED for evaluation.
6. Connection for measurement of injected voltage. This signal is amplified in REX060 before it is passed on to IED for evaluation.
7. Two VT inputs into IED which are used to measure injected current and voltage
8. Protection for excessive over-voltages posed by generator. REX060 can withstand without damage maximum voltage of 120V and when used together with REX062 up to 240V.

The measured impedance \(Z_{\text{measured}}\) is calculated by the complex equation:

\[
Z_{\text{measured}} = K_1 \times Z_{\text{bare}} + K_2
\]

Where:
The factors $k_1$ and $k_2$ [Ω] are derived during the calibration measurements under commissioning. As support for the calibration, the Injection Commissioning tool must be used. This tool is an integrated part of the PCM600 tool.

In connection to this calibration, the reference impedance is also derived. In case of a rotor ground fault with fault impedance $Z_f$, the measured admittance is:

\[
\frac{1}{Z_{\text{measured}}} = \frac{1}{Z_{\text{ref}}} + \frac{1}{Z_f}
\]

\[
\frac{1}{Z_f} = \frac{1}{Z_{\text{measured}}} - \frac{1}{Z_{\text{ref}}}
\]

The real part gives the fault conductance.

\[
\frac{1}{R_f} = \text{Re} \left( \frac{1}{Z_{\text{measured}}} - \frac{1}{Z_{\text{ref}}} \right)
\]

$R_{\text{Alarm}}$ and $R_{\text{Trip}}$ are the two resistance levels given in the settings. The values of $R_{\text{Alarm}}$ and $R_{\text{Trip}}$ are given in Ω.

An alarm signal ALARM is given after a set delay $t_{\text{Alarm}}$ if $R_f < R_{\text{Alarm}}$.

A initiate signal BFI is given if $R_f < R_{\text{Trip}}$.

For the tripping times, see figure 159.

Accuracy for ROTIPHIZ (64R) is installation dependent because harmonics in static excitation system, large variation of the ambient temperature and variation of rotor capacitance and conductance to ground between standstill and fully loaded machine will limit the possible setting level for the alarm stage. As a consequence 50 kΩ sensitivity can be typically reached without problem. Depending on particular installation alarm sensitivity of up to 500 kΩ may be reached.

### 8.7.3 Setting guidelines

#### 8.7.3.1 Setting injection unit REX060

The rotor injection module (RIM) in the REX060 generates a square wave signal for injection into the field winding circuit (rotor circuit). The injected voltage and current are connected to the measuring part of REX060. The signals are amplified giving voltage signals for both the injected voltage and current, adapted to analogue inputs of IED.
Frequency, current and voltage gain are settable and stored in non-volatile memory. If value is out of range, the limit value will be stored. Last stored setting values are shown in display.

**Table 30: Necessary settings for REX060**

<table>
<thead>
<tr>
<th>Setting</th>
<th>Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>System frequency</td>
<td>50/60 Hz</td>
</tr>
<tr>
<td>Injected frequency</td>
<td>One set for rotor circuit injection</td>
</tr>
<tr>
<td>Gain factor</td>
<td>Four steps for the rotor ground-fault protection</td>
</tr>
</tbody>
</table>

Injection frequency can be set as integer in range 75 to 250 Hz for a rotor. When selected, only one digit can be adjusted at the time by the Up or Down buttons. Store the new value by Enter button, or alternatively recover the last stored value by Clear button.

Gain setting can be set in four discreet steps in the main menu. The selected step result in predefined voltage and current gain factors. In other words, voltage and current gain cannot be set independently. Store the new gain by the Enter button, or alternatively recover to the last stored gain by the Clear button.

Rotor gain factor for both voltage and current is dependent on the highest voltage that may occur at the injection point (exciter connection) due to disturbances of thyristor rectifiers and mains frequency from fault in rectifier source.

U max at sensing input is the sum of the maximum allowed voltage that may occur at the voltage and current sense input points of REX060.

**Table 31: Rotor gain**

<table>
<thead>
<tr>
<th>Gain factor</th>
<th>Note</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Extreme</td>
</tr>
<tr>
<td>2</td>
<td>Enhanced</td>
</tr>
<tr>
<td>3</td>
<td>Default</td>
</tr>
<tr>
<td>4</td>
<td>Reduced</td>
</tr>
</tbody>
</table>

Always start with default gain. Other gains shall be used only if requested during commissioning procedure by the ICT tool.

### 8.7.3.2 Connecting and setting voltage inputs

The RIM module of REX060 has two analog output channels that shall be connected to two voltage input channels of the IED.

If both stator and rotor protection are used, there are two possible methods to perform the connection.

1. The recommended connection require four analog channels of the IED: two IED voltage channels are used for the measured quantities for ROTIPHIZ; two more IED voltage channels are used for the measured quantities for STTIPHIZ.
2. It is possible to use a mixed connection that requires only two IED voltage channels for both ROTIPHIZ and STTIPHIZ. REX060 outputs are connected in series. This connection is not recommended and can be used only in applications where it is prove the possibility to use it. The use of this connection leads to reduced performances of both ROTIPHIZ and STTIPHIZ.

Some settings are required for the analog voltage inputs. Set the voltage ratio for the inputs to 1/1, for example, VTSecx = 100 V VTPrimx = 0.1 kV

Figure 157: Separate analog inputs for stator STTIPHIZ (64S) and rotor ROTIPHIZ (64R) protection

Figure 158: Connection to IED with two analogue voltage inputs
The analog inputs are linked to a pre-processor block in the Signal Matrix Tool. This pre-processor block must have the same cycle time, 8 ms, as the function blocks for STTIPHIZ (64S) and ROTIPHIZ (64R).

The default parameter settings are used for the pre-processor block.

It is possible to connect two REG670 IEDs in parallel to the REX060 injection unit in order to obtain redundant measurement in the two IEDs. However, at commissioning, both IEDs must be connected during the calibration procedure.

It is important that REX060, REX061 and REX062 chassis are solidly grounded. Protective ground is a separate 0.15" screw terminal that is a part of the metallic chassis.

Avoid touching the enclosure of the coupling capacitor REX061 unit and the shunt resistor REX062 unit. The surface may be hot during normal operation. The temperature can rise 50°C in REX061 and 65°C in REX062 above the ambient temperature.

**8.7.3.3 Settings for sensitive rotor earth fault protection, ROTIPHIZ (64R)**

Operation to be set Enabled to activate the sensitive rotor earth-fault protection

\( R_{Trip} \) is the resistance level, set directly in primary Ohms, for activation of the trip-function.

\( R_{Alarm} \) is the resistance level, set directly in primary Ohms, for activation of the alarm-function.

\( t_{Alarm} \) is the time delay to activate the ALARM signal output when the measured fault resistance is below the set \( R_{Alarm} \) level

\( FactACLim \) is the scale factor for ground fault on AC side of exiter

\( t_{TripAC} \) is the time delay for TRIP signal on the AC side of exiter

\( V_{LimRMS} \) setting is not used in rotor protection application.

\( FreqInjected \) to be set on the injection unit REX060 for the stator earth-fault protection. The setting range is 75 – 250 Hz in steps of 0.001 Hz. In the choice of the injection frequency harmonics of the fundamental frequency (50 or 60 Hz) should be avoided as well as other harmonics related to other frequencies in the power system, for instance railway electrical systems with the fundamental frequency 16 2/3 Hz or 20 Hz. The recommended setting is 113Hz in 50Hz power system and 137Hz in 60Hz power system. The setting is fine tuned in connection to the commissioning calibration measurement and analysis in the ICT tool.

The complex factors \( k1Real, k1Imag, k2Real, k2Imag \) are setting parameters. The factors \( k1 \) and \( k2 \) as well as the reference impedances, \( RefR1, RefX1 \) and \( RefR2, RefX2 \), are derived from the calibration measurements during commissioning. ICT (Injection Commissioning Tool) must be used for the calibration process due to the complex nature of analysis and calculations. This tool is an integrated part of the PCM600.

\( FilterLength \) should be left at its default value; any change of this parameter should be defined under ABB supervision.
FilterLength setting affects the TRIP signal, see figure 159.

![Graph showing trip time characteristic as function of fault resistance](image)

**Figure 159: Trip time characteristic as function of fault resistance**

## 8.8 100% stator earth fault protection, injection based STTIPHIZ (64S)

### 8.8.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>100% stator earth fault protection, injection based</td>
<td>STTIPHIZ</td>
<td>Rse&lt;</td>
<td>64S</td>
</tr>
</tbody>
</table>

### 8.8.2 Application

The 100% stator earth-fault protection (STTIPHIZ, 64S) is used to detect the ground faults in the stator windings of generators and motors. STTIPHIZ (64S) is applicable for generators connected to the power system through a unit transformer in a block connection. An independent signal with a certain frequency different from the generator rated frequency is injected into the stator circuit. The response of this injected signal is used to detect stator ground faults.

To implement the above concept, a separate injection box is required. The injection box generates a square wave voltage signal which for example, can be fed into the secondary winding of the...
generator neutral point voltage transformer or the grounding transformer. This signal is propagated through the transformer into the stator circuit. Thus, any connection or interference into the existing stator primary circuit or re-arrangement of the primary resistor is not required.

The magnitude of the injected voltage signal is measured at the injection point. In addition, the resulting injected current is measured through a resistive shunt located within the injection device. These two measurements are fed to the IED. Based on these two measured quantities, the protection IED determines the stator winding resistance to ground. The resistance value is then compared with the preset fault resistance alarm or trip levels.

When the synchronous machine is at standstill, the protection function can not only detect the ground fault at the generator star point, but also along the stator windings and at the generator terminals, including the connected components such as voltage transformers, circuit breakers, excitation transformer and so on. The protection function is fully operative in all operating conditions when stable measurements are achieved. Both functions STTIPHIZ and ROV2PTOV shall be configured and shall operate in parallel in the same REG670 in order to perform the 100% stator earth-fault protection function. STTIPHIZ performs the earth-fault protection based on the injection principle to protect the section of the stator windings close to the generator neutral point; the function ROV2PTOV performs the standard 95% stator earth-fault protection based on the neutral point fundamental frequency voltage displacement.

For a detailed description of 100% stator earth fault protection STTIPHIZ (64S) and sensitive rotor earth fault protection, see document no 1MRG005030 “Application example for injection based 100% Stator EF and Sensitive Rotor EF protection.”

8.8.2.1 100% Stator earth fault protection function

The injection to the stator is schematically shown in figure 160. It should be observed that in this figure injection equivalent circuit is also shown with all impedances and injection generator related to the primary side of the neutral point voltage transformer. Points a & b indicate connection terminals for the injection equipment. Similar equivalent circuit can be drawn for all other types of generator stator grounding shown in latter figures.
Figure 160: High-resistance generator grounding with a neutral point resistor

There are some alternatives for connection of the neutral point resistor as shown in figure 161 (low voltage neutral point resistor connected via a DT).
**Figure 161: Effective high-resistance generator grounding via a distribution transformer**

Another alternative is shown in figure 162 (High-resistance grounding via a grounded wye-broken delta transformer). In this case the transformer must withstand the large secondary current caused by primary ground fault. The resistor typically has to be divided as shown in figure 162 to limit the voltage to the injection equipment in case of ground fault at the generator terminal. This voltage is often in the range 400 – 500 V. As the open delta connection gives three times the zero sequence phase voltage this gives too high voltage at the injection point if the resistance is not divided as shown in the figure 162. By dividing the resistor in two parts it shall be ensured that maximum voltage imposed back on injection equipment is equal to or less than 240V.
Figure 162: High-resistance generator grounding via a grounded wye-broken delta transformer

It is also possible to make the injection via VT open delta connection, as shown in figure 163.
It must be observed that the resistor $R_d$ is normally applied for ferro-resonance damping. The resistance $R_d$ is will have very little contribution to the ground fault current as it has high resistance. This injection principle can be used for applications with various generator system grounding methods. It is therefore recommended to make the injection via the open delta VT on the terminal side in most applications.

Accuracy for STTIPHIZ (64S) is installation dependent and it mainly depends on the characteristic of grounding or voltage transformer used to inject signal into the stator. Note that large variation of the ambient temperature and variation of stator capacitance and conductance to ground between standstill and fully loaded machine will also limit the possible setting level for the alarm stage. As a consequence 10 kΩ sensitivity can be typically reached without problem. Depending on
particular installation alarm sensitivity of up to 50 kΩ may be reached at steady state operating condition of the machine.

Note that it is possible to connect two REG670 in parallel to the REX060 injection unit in order to obtain redundant measurement in two separate IEDs. However, at commissioning both REG670 IEDs must be connected during calibration procedure.

8.8.3 Setting guidelines

8.8.3.1 Setting injection unit REX060

The 100% stator earth fault protection module in the REX060 generate a square wave signal for injection into the stator windings of the generator via the neutral point. The injected voltage and current are connected to the measurement parts of REX060. The signals are amplified giving voltage signals for both the injected voltage and current, adapted to analogue inputs of IED.

Frequency, current and voltage gain are settable and stored in non-volatile memory. If value is outside range, then the limited value will be stored. Last stored settings are shown in display.

Table 32: Necessary settings for REX060

<table>
<thead>
<tr>
<th>Setting</th>
<th>Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>System frequency</td>
<td>50/60 Hz</td>
</tr>
<tr>
<td>Injected frequency</td>
<td>50 to 250 Hz</td>
</tr>
<tr>
<td>VmaxEF [V]</td>
<td>Four steps for the 100% stator earth fault protection</td>
</tr>
</tbody>
</table>

Injection frequency can be set as integer in range 50 to 250 Hz. When selected, only one digit can be adjusted at the time by the Up or Down buttons. Store the new value by Enter button, or alternatively recover to the last stored value by Clear button.

Gain setting can be set in four discreet steps for SIM in the main menu. These selectable steps, in turn result in pre defined voltage and current gain factors. The gain can be adjusted by the Up or Down buttons when selected. Store the new gain by the Enter button, or alternatively recover to the last stored gain by the Clear button.

Stator gain should be set to the VT/DT rating. That voltage is dependent on the VT/DT ratio and the highest possible voltage at neutral point. Gain factor (VmaxEF) shall be selected to correspond to this voltage which shall be at least the same as VT/DT value in table below.

Table 33: Stator gain

<table>
<thead>
<tr>
<th>UmaxEF [V]</th>
<th>Note</th>
</tr>
</thead>
<tbody>
<tr>
<td>240</td>
<td></td>
</tr>
<tr>
<td>200</td>
<td></td>
</tr>
<tr>
<td>160</td>
<td>Default value</td>
</tr>
<tr>
<td>up to 120</td>
<td></td>
</tr>
</tbody>
</table>
8.8.3.2 Connecting and setting voltage inputs

The SIM module of REX060 has two analog output channels that shall be connected to two voltage input channels of the IED.

If both stator and rotor protection are used, there are two possible methods to perform the connection.

1. The recommended connection requires four analog channels of the IED: two IED voltage channels are used for the measured quantities for STTIPHIZ; two more IED voltage channels are used for the measured quantities for ROTIPHIZ.

![Diagram of IED and REX060 connections](IEC11000209-1-en.vsd)

**Figure 164: Separate analogue inputs for stator (STTIPHIZ, 64S)) and rotor (ROTIPHIZ, 64R)) protection**

2. It is possible to use a mixed connection that requires only two IED voltage channels for both ROTIPHIZ and STTIPHIZ. REX060 outputs are connected in series. This connection is not recommended and can be used only in applications where it is proved the possibility to use it. The use of this connection leads to reduced performances of both ROTIPHIZ and STTIPHIZ.
Some settings are required for the analog voltage inputs in the IED. The voltage ratio for the inputs shall be set 1/1, for example, VTSecx = 100 V VTPrimx = 0.1 kV

The analogue inputs are linked to a pre-processor (SMAI) block in the Signal Matrix Tool. This pre-processor block must have the same cycle time, 8 ms, as the function block for STTIPHIZ (64S).

The default parameter settings shall be used for the pre-processor block.

### 8.8.3.3 100% stator earth fault protection

*Operation* to be set Enabled to activate the stator earth-fault protection

*R*Trip is the resistance level, set directly in primary Ohms, for activation of the trip-function.

*R*Alarm is the resistance level, set directly in primary Ohms, for activation of the alarm-function.

*t*Alarm is the time delay to activate the ALARM signal output when the measured fault resistance is below the set *R*Alarm level

*V*Lim*RMS* is a setting that controls the output VRMSSTAT: if the total RMS voltage measured by the function at the injection point is above the setting *V*Lim*RMS* then the output VRMSSTAT is set to TRUE. The output VRMSSTAT can be used in the logic that selects the active reference impedance. The possibility to use this feature and the setting of *V*Lim*RMS* shall be defined during the commissioning of the protection system.

*Freq*Injected shall be set to the same value as on the injection unit REX060 for the stator earth-fault protection. The setting range is 50 – 250 Hz in steps of 0.001 Hz. Values which corresponds to the harmonics of the fundamental frequency (50 or 60 Hz) should be avoided, as well as other harmonics related to other frequencies in the power system. For instance railway electrical systems with the power supply frequency 16 2/3 Hz or 25 Hz. The recommended setting is 87 Hz.
for 50 Hz system and 103 Hz for 60 Hz system. The setting is fine tuned at commissioning during calibration measurement and analysis in the ICT tool.

The complex factors $k1\text{Real}$, $k1\text{Imag}$, $k2\text{Real}$, $k2\text{Imag}$ and the real and imaginary part of the reference impedances RefR1...RefR5 and RefX1...RefX5 are setting parameters. The factors $k1$ and $k2$ as well as the first reference impedance (RefR1, RefX1) are defined while performing the three steps of the calibration by ICT (Injection Commissioning Tool). The other 4 reference impedances (RefR2, RefX2)...(RefR5, RefX5) are defined through the Commissioning tab of ICT according to the needs of the machine during the commissioning of the protection system. ICT must be used for the calibration since this tool perform necessary calculations to derive above factors. This tool is an integrated part of the PCM600 tool.

$\text{FilterLength}$ the setting affects the length of samples used to calculate $R_f$. Default value 1s shall normally be used. Leave $\text{FilterLength}$ at its default value; any change of this parameter shall be defined under ABB supervision.

### 8.9 Under impedance protection for generators and transformers ZGVPDIS

#### 8.9.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE identification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Under impedance function for generators and transformers</td>
<td>ZGVPDIS</td>
<td></td>
<td>21G</td>
</tr>
</tbody>
</table>

#### 8.9.2 Application

Under impedance protection for generator is generally used as back up protection for faults on generator, transformer and transmission lines. Zone 1 can be used to provide high speed protection for phase faults in the generator, bus ducts or cables and part of the generator transformer. Zone 2 can be used to cover generator transformer and power plant’s substation bus-bar. Zone 3 can be used to cover power system faults.

The under impedance protection is provided with undervoltage detection feature in order to provide the seal-in for the impedance based trip. Additionally, it is provided with load encroachment feature in order to avoid tripping of the protection during heavy load conditions. The load encroachment functionality is based on the positive sequence components of voltage and current.

#### Characteristics of backup impedance protection

Characteristics of zone 1, zone 2 and zone 3 are shown in figure 166. All zones have offset mho characteristics with adjustable reach in forward and reverse direction. The characteristic angle for all three zones is common and adjustable. A load encroachment blinder feature is provided for zone 2 and zone 3.
Protection designed to operate for below types of faults

Faults in the generator, generator terminal connections to the step-up transformer and in the low voltage (LV) side of the generator step-up transformer are:

1. Phase-to-phase faults in generator
2. Three-phase faults in generator
3. Phase-to-phase faults in the LV winding of the generator transformer or inter-connecting bus or cables
4. Three-phase faults in the LV winding of the generator transformer or inter-connecting bus or cables

Faults in the system in the high voltage (HV) side of generator transformer are:

1. Phase-to-ground faults in the HV side of generator transformer and in the power system
2. Phase-to-phase faults in the HV side of generator transformer and in the power system
3. Phase-phase-ground faults in the HV side of generator transformer and in the power system
4. Three-phase faults in the HV side of generator transformer and in the power system
8.9.2.1 Operating zones

A) Power system model

B) Typical setting of zones for under impedance relay

**Figure 166:** Zone characteristics and typical power system model
The settings of all the zones is provided in terms of percentage of impedance based on current and voltage ratings of the generator.

### 8.9.2.2 Zone 1 operation

Zone 1 is used as fast selective tripping for phase-to-phase faults and three-phase faults in the generator, on the terminal leads and delta side of generator transformer. Since generator is high impedance grounded, the fault current for phase-to-ground faults will be too low and impedance protection is not intended to operate for these faults.

The measuring loops used for zone 1 are given below.

Zone 1 measuring loops for phase-to-phase faults and three-phase faults on the primary side of the generator transformer are:

<table>
<thead>
<tr>
<th>Sl.No</th>
<th>Phase-to-phase loop</th>
<th>Voltage phasor</th>
<th>Current phasor</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>A–B</td>
<td>VAB</td>
<td>IAB</td>
</tr>
<tr>
<td>2</td>
<td>B–C</td>
<td>VBC</td>
<td>IBC</td>
</tr>
<tr>
<td>3</td>
<td>C–A</td>
<td>VCA</td>
<td>ICA</td>
</tr>
</tbody>
</table>

VAB, VBC, VCA are three phase-to-phase voltages. IAB, IBC, ICA are the three phase-to-phase currents.

For this application the zone 1 element is typically set to see 75% of the transformer impedance.

### 8.9.2.3 Zone 2 operation

Zone 2 can be used to cover up to the HV side of the transformer and the HV bus bar, and is usually set to cover 125% of the generator transformer impedance. The time to trip must be provided in order to coordinate with the zone 1 element on the shortest outgoing line from the bus.

Two options are provided for measuring loops used for zone 2, which is set by the user. The measuring loops used for zone 2 with different options are:

**Phase-to-phase loops**

<table>
<thead>
<tr>
<th>Phase-to-phase loop</th>
<th>Voltage phasor</th>
<th>Current phasor</th>
</tr>
</thead>
<tbody>
<tr>
<td>A–B</td>
<td>VAB</td>
<td>IAB</td>
</tr>
<tr>
<td>B–C</td>
<td>VBC</td>
<td>IBC</td>
</tr>
<tr>
<td>C–A</td>
<td>VCA</td>
<td>ICA</td>
</tr>
</tbody>
</table>

**Enhanced reach loop**

<table>
<thead>
<tr>
<th>Max current</th>
<th>Loop selected</th>
<th>Voltage phasor</th>
<th>Current phasor</th>
</tr>
</thead>
<tbody>
<tr>
<td>IA</td>
<td>A–G</td>
<td>VAG-V0</td>
<td>IA</td>
</tr>
<tr>
<td>IB</td>
<td>B–G</td>
<td>VBG-V0</td>
<td>IB</td>
</tr>
<tr>
<td>IC</td>
<td>C–G</td>
<td>VCG-V0</td>
<td>IC</td>
</tr>
</tbody>
</table>
If the currents are equal, A–G loop has higher priority than B–G and B–G loop has higher priority than C–G. VAG, VBG, VCG are three phase-to-ground voltages and IA, IB, IC are three phase currents and V0 is zero sequence voltage.

To measure correct impedance for phase-to-phase faults on HV side of the generator transformer, it is recommended that EnhancedReach option (phase-to-ground loop with maximum current loop) is used. For three-phase faults on HV side, phase-to-phase loop measures correct impedance.

In EnhancedReach, compensation signal V0 is used to prevent zone 2 operating for ground faults in the generator. In the absence of this compensation, when a ground fault takes place in the generator side, the voltage drops and the load current in the machine leads due to which zone 2 element picks up resulting in misleading indications. Zone 2 is not intended to operate for the generator winding ground faults. The protection for generator winding ground fault is provided by sensitive ground fault relays that are time delayed. To prevent such an operation, the phase-to-ground measuring voltage is compensated with zero sequence voltage V0. This prevents the function from operating during the generator stator ground faults.

**8.9.2.4 Zone 3 operation**

Zone 3 covers the HV side of the transformer, interconnecting station bus to the network and outgoing lines. Within its operating zone, the tripping time for this relay should be coordinated with the longest time delay of the phase distance relays on the transmission lines connected to the generating substation bus. It is normally set to about 80% of the load impedance considering maximum short time overload on the generator.

Zone 3 provides protection for phase-to-ground, phase-to-phase and three phase faults on the HV side of the system. Hence, all these faults can be detected using three phase-to-phase loops or three phase-to-ground loops similar to zone 2. These options can be selected in the function and their operation is quite similar to the operation of zone 2.

**8.9.2.5 CT and VT positions**

Voltage transformer is located at the terminals of the generator, but current transformer can be located either at neutral side of the stator winding or at the terminals of the generator.

If the current transformer is located at the neutral side of the generator winding, the forward reach will be of the generator, transformer and connected power system impedance. If the current transformers are located at the terminal of the generator always the forward reach is only generator impedance and reverse reach comprises of transformer impedance and the connected transmission lines impedance.

**8.9.2.6 Undervoltage seal-in function**

For faults close to generating terminals the CTs might go in to saturation. The problem is due to very long DC constant of the generators. The persistent DC component of primary currents even if relatively small has a tendency to drive current transformers into saturation. The ZGVPDIS under this condition might reset for some duration. A reliable backup protection is provided under these conditions by providing an undervoltage seal-in feature.

The undervoltage function is enabled from zone 2 or zone 3 pickup.
8.9.2.7 Load encroachment for zone 2 and zone 3

As zone 2 and zone 3 have larger reaches, there is a possibility of load impedance encroaching into mho characteristics during heavy load conditions. Hence zone 2 and zone 3 are provided with load encroachment blinder feature which is to be enabled by the user. This feature measures the impedance based on positive sequence voltage and current. As the load from the generator corresponds to the positive sequence signals. Positive sequence voltage and current will be used for load encroachment blocking logic.

Figure 167 shows the implemented load encroachment characteristic.

![Load encroachment characteristic](Image)

Figure 167: Load Encroachment characteristic in under Impedance function

The resistive settings of this function is also provided in percentage of \( Z_{base} \).

It is calculated according to equation 168.

\[
Z_{base} = \left(\frac{V_{rated}}{\sqrt{3}}\right) / I_{rated}
\]

(Equation 168)

The \( LdAngle \) is a separate setting.

8.9.2.8 External block signals

The under impedance function will have to be blocked in the event of PT fuse fail. A BLKZ input for this purpose is provided. Also a BLOCK input is provided.
8.9.3 Setting Guidelines

8.9.3.1 General

The settings for the underimpedance protection for generator (ZGVPDIS) are done in percentage and base impedance is calculated from the \( V_{\text{Base}} \) and \( I_{\text{Base}} \) settings. The base impedance is calculated according to equation 169.

\[
\frac{V_{\text{Base}}}{Z_{\text{Base}}} = \frac{\sqrt{3}}{I_{\text{Base}}}
\]

(Equation 169)

**ImpedanceAng**: The common characteristic angle for all the three zone distance elements

**IMinOp**: The minimum operating current in %\( I_{\text{Base}} \).

**Zone 1**

ZGVPDIS function has an offset mho characteristic and it can evaluate three phase-to-phase impedance measuring loops.

\( \text{OpModeZ1} \): Zone 1 distance element can be selected as Disabled or PP Loops.

\( Z1\text{Fwd} \): Zone 1 forward reach in percentage. It is recommended to set zone 1 forward reach to 75% of transformer impedance.

\( Z1\text{Rev} \): Zone 1 reverse reach in percentage. It is recommended to set zone 1 reverse reach same as \( Z1\text{Fwd} \).

\( tZ1 \): Zone 1 trip time delay in seconds.

**Zone 2**

Zone 2 in ZGVPDIS function has offset mho characteristic and it can evaluate three phase-to-phase impedance measuring loops or Enhanced reach loop.

\( \text{OpModeZ2} \): Zone 2 distance element can be selected as Disabled, PP Loops or EnhancedReach.

\( Z2\text{Fwd} \): Zone 2 forward reach in percentage. It is recommended to set zone 2 forward reach to 125% of transformer impedance.

\( Z2\text{Rev} \): Zone 2 reverse reach in percentage. It is recommended to give limited reverse reach to ensure operation for close in fault and to minimize area covered in R-X plane. A setting of 8% is recommended.

\( tZ2 \): Zone 2 trip time delay in seconds. Time delay should be provided in order to coordinate with zone 1 element provided for the outgoing line.

**Zone 3**

Zone 3 in ZGVPDIS function has offset mho characteristic and it can evaluate three phase-to-phase impedance measuring loops or EnhancedReach loop.
**OpModeZ3:** Zone 3 distance element can be selected as *Disabled, PP Loops or EnhancedReach.* It is recommended to select *EnhancedReach* setting.

**Z3Fwd:** Zone 3 forward reach in percentage. It is recommended to set zone 3 forward reach to coordinate with the longest time delay for the transmission line protection connected to the generating substation bus. Alternatively it can be set to 80% of the load impedance considering maximum short time over load of the generator.

**Z3Rev:** Zone 3 reverse reach in percentage. It is recommended to give limited reverse reach to ensure operation for close in faults and to minimize area covered in R-X plane. A setting of 8% is recommended.

**tZ3:** Zone 3 operates time delay in seconds. Time delay is provided in order to coordinate with slowest circuit backup protection or slowest local backup for faults within zone 3 reach. A safety margin of 100 ms should be considered.

### 8.9.3.2 Load encroachment

The settings involved in load encroachment feature are:

- **LdAngle:** Angle in degrees of load encroachment characteristics
- **RLd:** Positive sequence resistance in per unit

The procedure of calculating the settings for load encroachment consists basically of defining load angle *LdAngle* and resistive blinder *RLd.* The load encroachment logic can be enabled for zone 2 and zone 3 elements. For zone 2, the load encroachment can be enabled or disabled using the *LoadEnchModZ2* setting by selecting either *Enabled* or *Disabled.* Similarly for zone 3 load encroachment can be enabled or disabled using the *LoadEnchModZ3* setting by selecting either *Enabled* or *Disabled.*

The load angle *LdAngle* is same in forward and reverse direction, so it is suitable to begin the calculation of the parameter setting. The parameter is set to the maximum possible load angle at the maximum active load. A value larger than 20° must be used.

The blinder *RLd* can be calculated according to the equation 170

\[
RLd = \left( 0.8 \cdot \frac{V_{min}}{P_{exp\,max}} \right)
\]

(Equation 170)

Where,

- \(P_{exp\,max}\) is the maximum exporting active power
- \(V_{min}\) is the minimum voltage for which \(P_{exp\,max}\) occurs
- 0.8 is the security factor to ensure that the setting of \(RLd\) can be lesser than the calculated minimal resistive load
8.9.3.3 Under voltage seal-in

Settings involved in under voltage seal-in are:

*OpMode27pickup*: Under voltage seal-in feature is enabled using this setting and can be selected as *Disabled* or *Z2pick up* or *Z3pick up*. If the under voltage seal-in has to be triggered with zone 2 pickup, *Z2pick up* enumeration has to be selected. If zone 3 select *Z3pick up* enumeration.

*27_COMP*: The pickup value of the under voltage seal-in feature can be set using *27_COMP*. This is provided in percentage of *VBase*. Recommended setting is 70%.

*timeDelay27*: The operate time delay in seconds for the under voltage seal-in. The recommended time delay is to provide the same trip delay setting as the selected zone that is, either zone 2 or zone 3.

8.10 Rotor ground fault protection (64R) using CVGAPC

The field winding, including the rotor winding and the non-rotating excitation equipment, is always insulated from the metallic parts of the rotor. The insulation resistance is high if the rotor is cooled by air or by hydrogen. The insulation resistance is much lower if the rotor winding is cooled by water. This is true even if the insulation is intact. A fault in the insulation of the field circuit will result in a conducting path from the field winding to ground. This means that the fault has caused a field ground fault.
The field circuit of a synchronous generator is normally ungrounded. Therefore, a single ground fault on the field winding will cause only a very small fault current. Thus the ground fault does not produce any damage in the generator. Furthermore, it will not affect the operation of a generating unit in any way. However, the existence of a single ground fault increases the electric stress at other points in the field circuit. This means that the risk for a second ground fault at another point on the field winding has increased considerably. A second ground fault will cause a field short-circuit with severe consequences.

The rotor ground fault protection is based on injection of an AC voltage to the isolated field circuit. In non-faulted conditions there will be no current flow associated to this injected voltage. If a rotor ground fault occurs, this condition will be detected by the rotor ground fault protection. Depending on the generator owner philosophy this operational state will be alarmed and/or the generator will be tripped. An injection unit RXTTE4 and an optional protective resistor on plate are required for correct rotor ground fault protection operation.

Rotor ground fault protection can be integrated in the IED among all other protection functions typically required for generator protection. How this is achieved by using COMBIFLEX injection unit RXTTE4 is described in Instruction 1MRG001910.
Section 9  Current protection

9.1  Instantaneous phase overcurrent protection PHPIOC (50)

9.1.1  Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Instantaneous phase overcurrent protection</td>
<td>PHPIOC</td>
<td>3I&gt;&gt;</td>
<td>50</td>
</tr>
</tbody>
</table>

9.1.2  Application

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

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

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

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

The instantaneous phase overcurrent protection PHPIOC (50) can operate in 10 ms for faults characterized by very high currents.

9.1.3  Setting guidelines

The parameters for instantaneous phase overcurrent protection PHPIOC (50) are set via the local HMI or PCM600.
This protection function must operate only in a selective way. So check all system and transient conditions that could cause its unwanted operation.

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

Also study transients that could cause a high increase of the line current for short times. A typical example is a transmission line with a power transformer at the remote end, which can cause high inrush current when connected to the network and can thus also cause the operation of the built-in, instantaneous, overcurrent protection.

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

**GlobalBaseSel**: This is used to select GBASVAL function for reference of base values.

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

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

**Pickup**: Set operate current in % of IB.

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

**MultPU**: The set operate current can be changed by activation of the binary input MULTPU to the set factor MultPU.

### 9.1.3.1 Meshed network without parallel line

The following fault calculations have to be done for three-phase, single-phase-to-ground and two-phase-to-ground faults. With reference to Figure 169, apply a fault in B and then calculate the current through-fault phase current I_fB. The calculation should be done using the minimum source impedance values for Z_A and the maximum source impedance values for Z_B in order to get the maximum through fault current from A to B.
Fault

Figure 169: Through fault current from A to B: $I_{FB}$

Then a fault in A has to be applied and the through fault current $I_{FA}$ has to be calculated, Figure 170. In order to get the maximum through fault current, the minimum value for $Z_B$ and the maximum value for $Z_A$ have to be considered.

Fault

Figure 170: Through fault current from B to A: $I_{FA}$

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

\[ I_{min} \geq \text{MAX}(I_{FA}, I_{FB}) \]

(Equation 171)

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

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

\[ I_s \geq 1.3 \cdot I_{min} \]

(Equation 172)
The protection function can be used for the specific application only if this setting value is equal to or less than the maximum fault current that the IED has to clear, $I_F$ in Figure 171.

![Diagram of a power system with a fault](ANSI09000024-1-en.vsd)

**Figure 171: Fault current: $I_F$**

The IED setting value *Pickup* is given in percentage of the primary base current value, $IBase$. The value for *Pickup* is given from this formula:

$$
Pickup = \frac{Is}{IBase} \cdot 100
$$

(Equation 173)

### 9.1.3.2 Meshed network with parallel line

In case of parallel lines, the influence of the induced current from the parallel line to the protected line has to be considered. One example is given in Figure 172, where the two lines are connected to the same busbars. In this case the influence of the induced fault current from the faulty line (line 1) to the healthy line (line 2) is considered together with the two through fault currents $I_{fA}$ and $I_{fB}$ mentioned previously. The maximal influence from the parallel line for the IED in Figure 172 will be with a fault at the C point with the C breaker open.

A fault in C has to be applied, and then the maximum current seen from the IED ($I_M$) on the healthy line (this applies for single-phase-to-ground and two-phase-to-ground faults) is calculated.
The minimum theoretical current setting for the overcurrent protection function ($I_{\text{min}}$) will be:

$$I_{\text{min}} \geq \text{MAX}(I_{A}, I_{B}, I_{M})$$  
(Equation 174)

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

$$I_{s} \geq 1.3 \times I_{\text{min}}$$  
(Equation 175)

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

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

$$\textit{Pickup} = \frac{I_{s}}{I_{\text{Base}}} \times 100$$  
(Equation 176)

### 9.2 Directional phase overcurrent protection, four steps

OC4PTOC(51_67)
9.2.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Directional phase overcurrent protection, four steps</td>
<td>OC4PTOC</td>
<td></td>
<td>51_67</td>
</tr>
</tbody>
</table>

9.2.2 Application

Directional phase overcurrent protection, four steps OC4PTOC (51_67) is used in several applications in the power system. Some applications are:

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

In many applications several steps with different current pickup levels and time delays are needed. OC4PTOC (51_67) can have up to four different, individually settable steps. The following options are possible:

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

If VT inputs are not available or not connected, the setting parameter DirModeSelx (x = step 1, 2, 3 or 4) shall be left to the default value Non-directional.

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

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

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

Power transformers can have a large inrush current, when being energized. This phenomenon is due to saturation of the transformer magnetic core during parts of the period. There is a risk that inrush current will reach levels above the pick-up current of the phase overcurrent protection. The inrush current has a large 2\textsuperscript{nd} harmonic content. This can be used to avoid unwanted operation of the protection function. Therefore, OC4PTOC (51/67) has a possibility of 2\textsuperscript{nd} harmonic restrain if the level of 2\textsuperscript{nd} harmonic current reaches a value above a set percent of the fundamental current.

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

### 9.2.3 Setting guidelines

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

The parameters for the directional phase overcurrent protection, four steps OC4PTOC (51/67) are set via the local HMI or PCM600.

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

- **GlobalBaseSel:** Selects the global base value group used by the function to define \( I_{Base} \), \( V_{Base} \) and \( S_{Base} \). Note that this function will only use \( I_{Base} \) value.

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

- **Operation:** The protection can be set to Enabled or Disabled.

- **AngleRCA:** Protection characteristic angle set in degrees. If the angle of the fault loop current has the angle RCA, the direction to the fault is forward.

- **AngleROA:** Angle value, given in degrees, to define the angle sector of the directional function, shown in Figure 173.

- **NumPhSel:** Number of phases, with high current, required for operation. The setting possibilities are: 1 out of 3, 2 out of 3 and 3 out of 3. The default setting is 1 out of 3.

- **PUMinOpPhSel:** Minimum current setting level for releasing the directional start signals in \% of \( I_{B} \). This setting should be less than the lowest step setting. The default setting is 7\% of \( I_{B} \).
2ndHarmonicStab: Operate level of 2nd harmonic current restrain set in % of the fundamental current. The setting range is 5 - 100% in steps of 1%. The default setting is 20%.

Figure 173: Directional function characteristic
1. RCA = Relay characteristic angle
2. ROA = Relay operating angle
3. Reverse
4. Forward

9.2.3.1 Settings for each step

\[ x \] means step 1, 2, 3 and 4.

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

Characteristx: Selection of time characteristic for step \( x \). Definite time delay and different types of inverse time characteristics are available according to Table 34.
Table 34: Inverse time characteristics

<table>
<thead>
<tr>
<th>Curve name</th>
</tr>
</thead>
<tbody>
<tr>
<td>ANSI Extremely Inverse</td>
</tr>
<tr>
<td>ANSI Very Inverse</td>
</tr>
<tr>
<td>ANSI Normal Inverse</td>
</tr>
<tr>
<td>ANSI Moderately Inverse</td>
</tr>
<tr>
<td>ANSI/IEEE Definite time</td>
</tr>
<tr>
<td>ANSI Long Time Extremely Inverse</td>
</tr>
<tr>
<td>ANSI Long Time Very Inverse</td>
</tr>
<tr>
<td>ANSI Long Time Inverse</td>
</tr>
<tr>
<td>IEC Normal Inverse</td>
</tr>
<tr>
<td>IEC Very Inverse</td>
</tr>
<tr>
<td>IEC Inverse</td>
</tr>
<tr>
<td>IEC Extremely Inverse</td>
</tr>
<tr>
<td>IEC Short Time Inverse</td>
</tr>
<tr>
<td>IEC Long Time Inverse</td>
</tr>
<tr>
<td>IEC Definite Time</td>
</tr>
<tr>
<td>User Programmable</td>
</tr>
<tr>
<td>ASEA RI</td>
</tr>
<tr>
<td>RXIDG or RD (logarithmic)</td>
</tr>
</tbody>
</table>

The different characteristics are described in *Technical manual.*

*Pickupx:* Operate phase current level for step $x$ given in % of $IB$.

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

*tx:* Definite time delay for step $x$. The definite time $tx$ is added to the inverse time when inverse time characteristic is selected. Note that the value set is the time between activation of the start and the trip outputs.

*TDx:* Time multiplier for inverse time delay for step $x$.

*IMinx:* Minimum operate current in % of $IB$ for all inverse time characteristics, below which no operation takes place.

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

*txMin:* Minimum trip time for all inverse time characteristics. At high currents the inverse time characteristic might give a very short operation time. By setting this parameter the operation time of the step can never be shorter than the setting. Setting range: 0.000 - 60.000s in steps of 0.001s.
**MultPUx**: Multiplier for scaling of the current setting value. If a binary input signal ENMULTx (enableMultiplier) is activated the current operation level is increased by this setting constant. Setting range: 1.0-10.0

![Graph showing trip time and pickup current](image)

**Figure 174: Minimum pickup current and trip time for inverse time characteristics**

In order to fully comply with the definition of the curve, the setting parameter $txMin$ shall be set to a value equal to the operating time of the selected inverse curve for twenty times the set current pickup value. Note that the operating time is dependent on the selected time multiplier setting $kx$.

**ResetTypeCrvx**: The reset of the delay timer can be made as shown in Table 35.

<table>
<thead>
<tr>
<th>Curve name</th>
<th>Curve index no.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Instantaneous</td>
<td>1</td>
</tr>
<tr>
<td>IEC Reset (constant time)</td>
<td>2</td>
</tr>
<tr>
<td>ANSI Reset (inverse time)</td>
<td>3</td>
</tr>
</tbody>
</table>

The delay characteristics are described in *Technical manual*. There are some restrictions regarding the choice of the reset delay.

For the definite time delay characteristics, the possible delay time setting instantaneous (1) and IEC (2 = set constant time reset).

For ANSI inverse time characteristics, all three types of reset time characteristics are available: instantaneous (1), IEC (2 = set constant time reset) and ANSI (3 = current dependent reset time).

For IEC inverse time characteristics, the possible delay time settings are instantaneous (1) and IEC (2 = set constant time reset).
For the customer tailor-made inverse time delay characteristics (type 17), all three types of reset time characteristics are available: instantaneous (1), IEC (2 = set constant time reset) and ANSI (3 = current dependent reset time). If the current-dependent type is used, settings \( pr \), \( tr \) and \( cr \) must be given.

\( tResetx \): Constant reset time delay in seconds for step \( x \).

\( tPCrvx, tACrvx, tBCrvx, tCCrvx \): These parameters are used by the customer to create the inverse time characteristic curve. See equation 177 for the time characteristic equation. For more information, refer to Technical manual.

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

(Equation 177)

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

\( \text{HarmRestrainx} \): Enables the block of step \( x \) from the harmonic restrain function (2nd harmonic). This function should be used when there is a risk of an unwanted trip caused by power transformer inrush currents. It can be set to Disabled/Enabled.

### 9.2.3.2 Setting example

Directional phase overcurrent protection, four steps can be used in different ways, depending on the application where the protection is used. A general description is given below.

The pickup current setting of the inverse time protection, or the lowest current step of the definite time protection, must be defined so that the highest possible load current does not cause protection operation. The protection reset current must also be considered so that a short peak of overcurrent does not cause the operation of a protection even when the overcurrent has ceased. This phenomenon is described in Figure 175.
Figure 175: Pickup and reset current for an overcurrent protection

The lowest setting value can be written according to Equation 178.

\[ I_{pu} \geq 1.2 \cdot \frac{I_{max}}{k} \]

(Equation 178)

where:
- 1.2 is a safety factor
- \( k \) is the reset ratio of the protection
- \( I_{max} \) is the maximum load current

The load current up to the present situation can be found from operation statistics. The current setting must remain valid for several years. In most cases, the setting values are updated once every five years or less often. Investigate the maximum load current that the equipment on the line can withstand. Study components, such as line conductors, current transformers, circuit breakers, and disconnectors. The manufacturer of the equipment normally gives the maximum thermal load current of the equipment.

The maximum load current on the line has to be estimated. There is also a demand that all faults within the zone that the protection shall cover must be detected by the phase overcurrent protection. The minimum fault current \( I_{scmin} \) to be detected by the protection must be calculated. Taking this value as a base, the highest pickup current setting can be written according to Equation 179.
Ipu ≤ 0.7 · Isc min

(Equation 179)

where:

0.7 is a safety factor
Iscmin is the smallest fault current to be detected by the overcurrent protection.

As a summary, the pickup current shall be chosen within the interval stated in Equation 180.

\[
1.2 \cdot \frac{I_{\text{max}}}{k} \leq I_{\text{pu}} \leq 0.7 \cdot \text{Isc min}
\]

(Equation 180)

The high current function of the overcurrent protection, which only has a short-delay trip time, must be given a current setting so that the protection is selective to other protection functions in the power system. It is desirable to have rapid tripping of faults within a large part of the power system to be protected by the protection (primary protected zone). A fault current calculation gives the largest current of faults, Iscmax, at the most remote part of the primary protected zone. The risk of transient overreach must be considered, due to a possible DC component of the short circuit current. The lowest current setting of the fastest stage can be written according to

\[
I_{\text{high}} \geq 1.2 \cdot k_t \cdot I_{\text{sc max}}
\]

(Equation 181)

where:

1.2 is a safety factor
k_t is a factor that takes care of the transient overreach due to the DC component of the fault current and can be considered to be less than 1.05
Iscmax is the largest fault current at a fault at the most remote point of the primary protection zone.

The operate time of the phase overcurrent protection has to be chosen so that the fault time is short enough that the protected equipment will not be destroyed due to thermal overload while, at the same time, selectivity is assured. For overcurrent protection in a radial fed network, the time setting can be chosen in a graphical way. This is mostly used in the case of inverse time overcurrent protection. Figure 176 shows how the time-versus-current curves are plotted in a diagram. The time setting is chosen to get the shortest fault time with maintained selectivity. Selectivity is assured if the time difference between the curves is larger than a critical time difference.
The operation time can be set individually for each overcurrent protection.

To assure selectivity between different protection functions in the radial network, there has to be a minimum time difference $\Delta t$ between the time delays of two protections. To determine the shortest possible time difference, the operation time of the protection, the breaker opening time and the protection resetting time must be known. These time delays can vary significantly between different protective equipment. The following time delays can be estimated:

- Protection operation time: 15-60 ms
- Protection resetting time: 15-60 ms
- Breaker opening time: 20-120 ms

**Example for time coordination**

Assume two substations A and B directly connected to each other via one line, as shown in the Figure 177. Consider a fault located at another line from the station B. The fault current to the overcurrent protection of IED B1 has a magnitude so that the overcurrent protection will start and subsequently trip, and the overcurrent protection of IED A1 must have a delayed operation in order to avoid maloperation. The sequence of events during the fault can be described using a time axis shown in Figure 177.
Figure 177: Sequence of events during fault

where:

\( t=0 \) is when the fault occurs
\( t=t_1 \) is when protection IED B1 and protection IED A1 start
\( t=t_2 \) is when the trip signal from the overcurrent protection at IED B1 is sent to the circuit breaker.
\( t=t_3 \) is when the circuit breaker at IED B1 opens. The circuit breaker opening time is \( t_3 - t_2 \)
\( t=t_4 \) is when the overcurrent protection at IED A1 resets. The protection resetting time is \( t_4 - t_3 \).

To ensure that the overcurrent protection at IED A1 is selective to the overcurrent protection at IED B1, the minimum time difference must be larger than the time \( t_3 \). There are uncertainties in the values of protection operation time, breaker opening time and protection resetting time. Therefore a safety margin has to be included. With normal values the needed time difference can be calculated according to Equation 182.

\[
\Delta t \geq 40\, ms + 100\, ms + 40\, ms + 40\, ms = 220\, ms
\]

(Equation 182)

where it is considered that:

- the operate time of overcurrent protection B1 is 40 ms
- the breaker open time is 100 ms
- the resetting time of protection A1 is 40 ms and
- the additional margin is 40 ms
9.3 Instantaneous residual overcurrent protection EFPIOC (50N)

9.3.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Instantaneous residual overcurrent protection</td>
<td>EFPIOC</td>
<td></td>
<td>50N</td>
</tr>
</tbody>
</table>

9.3.2 Application

In many applications, when fault current is limited to a defined value by the object impedance, an instantaneous ground-fault protection can provide fast and selective tripping.

The Instantaneous residual overcurrent EFPIOC (50N), which can operate in 15 ms (50 Hz nominal system frequency) for faults characterized by very high currents, is included in the IED.

9.3.3 Setting guidelines

The parameters for the Instantaneous residual overcurrent protection EFPIOC (50N) are set via the local HMI or PCM600.

Some guidelines for the choice of setting parameter for EFPIOC (50N) is given.

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

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

The basic requirement is to assure selectivity, that is EFPIOC (50N) shall not be allowed to operate for faults at other objects than the protected object (line).

For a normal line in a meshed system single phase-to-ground faults and phase-to-phase-to-ground faults shall be calculated as shown in Figure 178 and Figure 179. The residual currents (3I₀) to the protection are calculated. For a fault at the remote line end this fault current is I_B. In this calculation the operational state with high source impedance Z_A and low source impedance Z_B should be used. For the fault at the home busbar this fault current is I_A. In this calculation the operational state with low source impedance Z_A and high source impedance Z_B should be used.
Figure 178: Through fault current from A to B: $I_{fB}$

Figure 179: Through fault current from B to A: $I_{fA}$

The function shall not operate for any of the calculated currents to the protection. The minimum theoretical current setting ($I_{min}$) will be:

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

(Equation 183)

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

The minimum primary current setting ($I_s$) is:

$$I_s = 1.3 \times I_{min}$$

(Equation 184)

In case of parallel lines with zero sequence mutual coupling a fault on the parallel line, as shown in Figure 180, should be calculated.
Figure 180: Two parallel lines. Influence from parallel line to the through fault current: \( I_M \)

The minimum theoretical current setting (\( I_{\text{min}} \)) will in this case be:

\[
I_{\text{min}} \geq \text{MAX}(I_A, I_B, I_M)
\]

(Equation 185)

Where:

\( I_A \) and \( I_B \) have been described for the single line case.

Considering the safety margins mentioned previously, the minimum setting (\( I_s \)) is:

\[
I_s = 1.3 \times I_{\text{min}}
\]

(Equation 186)

The IED setting value \( IN>>> \) is given in percent of the primary base current value, \( I_{\text{Base}} \). The value for \( IN>>> \) is given by the formula:

\[
IN>>> = \left( \frac{I_s}{I_{\text{Base}}} \right) \times 100
\]

(Equation 187)

Transformer inrush current shall be considered.

The setting of the protection is set as a percentage of the base current (\( I_{\text{Base}} \)).

Operation: set the protection to Enabled or Disabled.

Pickup: Set operate current in % of \( I_B \).

\( IN>>>\text{Max} \) and \( IN>>>\text{Min} \) should only be changed if remote setting of operation current level, \( IN>>> \), is used. The limits are used for decreasing the used range of the \( IN>>> \) setting. If \( IN>>> \) is set outside \( IN>>>\text{Max} \) and \( IN>>>\text{Min} \), the closest of the limits to \( IN>>> \) is used by the function. If \( IN>>>\text{Max} \) is smaller than \( IN>>>\text{Min} \), the limits are swapped.
MultPU: The set operate current can be changed by activation of the binary input MULTPU to the set factor MultPU.

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

9.4.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Directional residual overcurrent protection, four steps</td>
<td>EF4PTOC</td>
<td></td>
<td>51N_67N</td>
</tr>
</tbody>
</table>

9.4.2 Application

The directional residual overcurrent protection, four steps EF4PTOC (51N_67N) is used in several applications in the power system. Some applications are:

- Ground-fault protection of feeders in effectively grounded distribution and subtransmission systems. Normally these feeders have radial structure.
- Back-up ground-fault protection of transmission lines.
- Sensitive ground-fault protection of transmission lines. EF4PTOC (51N_67N) can have better sensitivity to detect resistive phase-to-ground-faults compared to distance protection.
- Back-up ground-fault protection of power transformers.
- Ground-fault protection of different kinds of equipment connected to the power system such as shunt capacitor banks, shunt reactors and others.

In many applications, several steps with different current pickup levels and time delays are needed. EF4PTOC (51N_67N) can have up to four, individual settable steps. The flexibility of each step of EF4PTOC (51N_67N) is great. The following options are possible:

Non-directional/Directional function: In some applications the non-directional functionality is used. This is mostly the case when no fault current can be fed from the protected object itself. In order to achieve both selectivity and fast fault clearance, the directional function can be necessary. This can be the case for ground-fault protection in meshed and effectively grounded transmission systems. The directional residual overcurrent protection is also well suited to operate in teleprotection communication schemes, which enables fast clearance of ground faults on transmission lines. The directional function uses the polarizing quantity as decided by setting. Voltage polarizing is the most commonly used, but alternatively current polarizing where currents in transformer neutrals providing the neutral source (ZN) is used to polarize (IN · ZN) the function. Dual polarizing, where the sum of both voltage and current components is allowed to polarize can also be selected.

Choice of time characteristics: There are several types of time characteristics available such as definite time delay and different types of inverse time characteristics. The selectivity between
different overcurrent protections is normally enabled by co-ordination between the operate time of the different protections. To enable optimal co-ordination all overcurrent protections, to be co-ordinated against each other, should have the same time characteristic. Therefore a wide range of standardized inverse time characteristics are available for IEC and ANSI.

<table>
<thead>
<tr>
<th>Curve name</th>
</tr>
</thead>
<tbody>
<tr>
<td>ANSI Extremely Inverse</td>
</tr>
<tr>
<td>ANSI Very Inverse</td>
</tr>
<tr>
<td>ANSI Normal Inverse</td>
</tr>
<tr>
<td>ANSI Moderately Inverse</td>
</tr>
<tr>
<td>ANSI/IEEE Definite time</td>
</tr>
<tr>
<td>ANSI Long Time Extremely Inverse</td>
</tr>
<tr>
<td>ANSI Long Time Very Inverse</td>
</tr>
<tr>
<td>ANSI Long Time Inverse</td>
</tr>
<tr>
<td>IEC Normal Inverse</td>
</tr>
<tr>
<td>IEC Very Inverse</td>
</tr>
<tr>
<td>IEC Inverse</td>
</tr>
<tr>
<td>IEC Extremely Inverse</td>
</tr>
<tr>
<td>IEC Short Time Inverse</td>
</tr>
<tr>
<td>IEC Long Time Inverse</td>
</tr>
<tr>
<td>IEC Definite Time</td>
</tr>
<tr>
<td>User Programmable</td>
</tr>
<tr>
<td>ASEA RI</td>
</tr>
<tr>
<td>RXIDG or RD (logarithmic)</td>
</tr>
</tbody>
</table>

It is also possible to tailor make the inverse time characteristic.

Normally it is required that EF4PTOC (51N_67N) shall reset as fast as possible when the current level gets lower than the operation level. In some cases some sort of delayed reset is required. Therefore different kinds of reset characteristics can be used.

For some protection applications, there can be a need to change the current pickup level for some time. Therefore, there is a possibility to give a setting of a multiplication factor \( \text{INxMult} \) to the residual current pick-up level. This multiplication factor is activated from a binary input signal MULTPUx to the function.

Power transformers can have a large inrush current, when being energized. This inrush current can produce residual current component. The phenomenon is due to saturation of the transformer magnetic core during parts of the cycle. There is a risk that inrush current will give a residual current that reaches level above the pickup current of the residual overcurrent protection. The inrush current has a large second harmonic content. This can be used to avoid unwanted operation of the protection. Therefore, EF4PTOC (51N_67N) has a possibility of second harmonic restrain if the level of 2\(^{nd}\) harmonic current reaches a value above a set percent of the fundamental current.
9.4.3 Setting guidelines

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

The parameters for the four step residual overcurrent protection are set via the local HMI or PCM600. The following settings can be done for the function.

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

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

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

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

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

9.4.3.1 Common settings for all steps

AngleRCA: Relay characteristic angle given in degree. This angle is defined as shown in Figure 181. The angle is defined positive when the residual current lags the reference voltage (Vpol = 3V₀ or V₂)

![Diagram of relay characteristic angle given in degree](en.0500135-ansi.vsd)

Figure 181: Relay characteristic angle given in degree
In a normal transmission network a normal value of RCA is about 65°. The setting range is -180° to +180°.

**polMethod:** Defines if the directional polarization is from

- **Voltage** \((3V_0\text{ or } V_2)\)
- **Current** \((3I_0 \cdot ZNpol\text{ or } 3I_2 \cdot ZNpol)\) where ZNpol is RNpol + jXNpol, or
- both currents and voltage, **Dual** \((3V_0 + 3I_0 \cdot ZNpol)\text{ or } (V_2 + I_2 \cdot ZNpol)\))

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

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

**RNPol, XNPol:** The zero-sequence source is set in primary ohms as base for the current polarizing. The polarizing voltage is then achieved as \(3I_0 \cdot ZNpol\). The ZNpol can be defined as \((ZS_1 - ZS_0)/3\), that is the ground return impedance of the source behind the protection. The maximum ground-fault current at the local source can be used to calculate the value of ZN as \(V/(\sqrt{3} \cdot 3I_0)\) Typically, the minimum ZNPol \((3 \cdot \text{zero sequence source})\) is set. The setting is in primary ohms.

When the dual polarizing method is used, it is important that the setting \(Pickupx\) or the product \(3I_0 \cdot ZNpol\) is not greater than \(3V_0\). If so, there is a risk for incorrect operation for faults in the reverse direction.

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

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

**IDirPU:** Operate residual current release level in % of \(IB\) for directional comparison scheme. The setting is given in % of \(IB\) and must be set below the lowest \(INx>\) setting, set for the directional measurement. The output signals, PUFW and PUREV can be used in a teleprotection scheme. The appropriate signal should be configured to the communication scheme block.

### 9.4.3.2 2nd harmonic restrain

If a power transformer is energized there is a risk that the current transformer core will saturate during part of the period, resulting in a transformer inrush current. This will give a declining residual current in the network, as the inrush current is deviating between the phases. There is a risk that the residual overcurrent function will give an unwanted trip. The inrush current has a relatively large ratio of 2nd harmonic component. This component can be used to create a restrain signal to prevent this unwanted function.

At current transformer saturation a false residual current can be measured by the protection. Here the 2\(^{nd}\) harmonic restrain can prevent unwanted operation as well.

**2ndHarmStab:** The rate of 2nd harmonic current content for activation of the 2nd harmonic restrain signal. The setting is given in % of the fundamental frequency residual current.
9.4.3.3 Parallel transformer inrush current logic

In case of parallel transformers there is a risk of sympathetic inrush current. If one of the transformers is in operation, and the parallel transformer is switched in, the asymmetric inrush current of the switched-in transformer will cause partial saturation of the transformer already in service. This is called transferred saturation. The 2\textsuperscript{nd} harmonic of the inrush currents of the two transformers will be in phase opposition. The summation of the two currents will thus give a small 2\textsuperscript{nd} harmonic current. The residual fundamental current will however be significant. The inrush current of the transformer in service before the parallel transformer energizing, will be a little delayed compared to the first transformer. Therefore, we will have high 2\textsuperscript{nd} harmonic current initially. After a short period this current will however be small and the normal 2\textsuperscript{nd} harmonic blocking will reset.

![Figure 182: Application for parallel transformer inrush current logic](en05000136_ansi.vsd)

If the $BlkParTransf$ function is activated, the 2\textsuperscript{nd} harmonic restrain signal will latch as long as the residual current measured by the relay is larger than a selected step current level. Assume that step 4 is chosen to be the most sensitive step of the four step residual overcurrent protection function EF4PTOC (51N_67N). The harmonic restrain blocking is enabled for this step. Also the same current setting as this step is chosen for the blocking at parallel transformer energizing.

The settings for the parallel transformer logic are described below.

$BlkParTransf$: This is used to Enable blocking at energising of parallel transformers.

$Use\_PUValue$: Gives which current level should be used for the activation of the blocking signal. This is given as one of the settings of the steps: Step 1/2/3/4. Normally, the step having the lowest operation current level should be set.

9.4.3.4 Switch onto fault logic

In case of energizing a faulty object there is a risk of having a long fault clearance time, if the fault current is too small to give fast operation of the protection. The switch on to fault function can be activated from auxiliary signals from the circuit breaker, either the close command or the open/close position (change of position).

This logic can be used to issue a fast trip if one breaker pole does not close properly at a manual or automatic closing.

SOTF and under time are similar functions to achieve fast clearance at asymmetrical closing based on requirements from different utilities.
The function is divided into two parts. The SOTF function will give operation from step 2 or 3 during a set time after change in the position of the circuit breaker. The SOTF function has a set time delay. The under time function, which has 2nd harmonic restrain blocking, will give operation from step 4. The 2nd harmonic restrain will prevent unwanted function in case of transformer inrush current. The under time function has a set time delay.

Below the settings for switch on to fault logics are described.

**SOTF**: This parameter can be set: *Disabled/SOTF/Under Time/SOTF+Under Time.*

**SOTFSel**: This setting will select the signal to activate SOTF function; *CB position open/CB position closed/CB close command.*

**StepForSOTF**: If this parameter is set on step 3, the step 3 pickup signal will be used as current set level. If set on step 2, the step 2 pickup signal will be used as current set level.

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

**tSOTF**: Time delay for operation of the SOTF function. The setting range is 0.000 - 60.000 s in step of 0.001 s. The default setting is 0.100 s

**t4U**: Time interval when the SOTF function is active after breaker closing. The setting range is 0.000 - 60.000 s in step of 0.001 s. The default setting is 1.000 s.

**ActUndrTimeSel**: Describes the mode to activate the sensitive undertime function. The function can be activated by Circuit breaker position (change) or Circuit breaker command.

**tUnderTime**: Time delay for operation of the sensitive undertime function. The setting range is 0.000 - 60.000 s in step of 0.001 s. The default setting is 0.300 s

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

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

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

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

Inverse time characteristic enables fast fault clearance of high current faults at the same time as selectivity to other inverse time phase overcurrent protections can be assured. This is mainly used in radial fed networks but can also be used in meshed networks. In meshed networks, the settings must be based on network fault calculations.

To assure selectivity between different protections, in the radial network, there has to be a minimum time difference $\Delta t$ between the time delays of two protections. To determine the shortest possible time difference, the operation time of protections, breaker opening time and protection resetting time must be known. These time delays can vary significantly between different protective equipment. The following time delays can be estimated:

- Protection trip time: 15-60 ms
- Protection resetting time: 15-60 ms
- Breaker opening time: 20-120 ms
The different characteristics are described in the technical reference manual.

**tx**: Definite time delay for step x. The definite time *tx* is added to the inverse time when inverse time characteristic is selected. Note that the value set is the time between activation of the start and the trip outputs.

**Pickup"x"**: Operate residual current level for step x given in % of *IB*.

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

**kx**: Time multiplier for the dependent (inverse) characteristic for step x.

**IMinx**: Minimum pickup current for step x in % of *IB*. Set *IMinx* below *Pickupx* for every step to achieve ANSI reset characteristic according to standard. If *IMinx* is set above for any step, signal will reset at current equals to zero.

**txMin**: Minimum operating time for inverse time characteristics. At high currents, the inverse time characteristic might give a very short operation time. By setting this parameter, the operation time of the step can never be shorter than the setting.

![Diagram](ANSI10000058-1-en.vsdx)

**Figure 183: Minimum pickup current and trip time for inverse time characteristics**

In order to fully comply with the curves definition, the setting parameter *txMin* shall be set to the value which is equal to the operate time of the selected IEC inverse curve for measured current of twenty times the set current pickup value. Note that the operate time value is dependent on the selected setting value for time multiplier *kx*.

**INxMult**: Multiplier for scaling of the current setting value. If a binary input signal (MULTPUx) is activated, the current operation level is increased by this setting constant.
ResetTypeCrvx: The reset of the delay timer can be made in different ways. The possibilities are described in the technical reference manual.

tResetx: Constant reset time delay in s for step x.

HarmBlockx: This is used to enable block of step x from 2\textsuperscript{nd} harmonic restrain function.

tPCrvx, tACrvx, tBCrvx, tCCrvx: Parameters for user programmable of inverse time characteristic curve. The time characteristic equation is according to equation 188:

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

(Equation 188)

Further description can be found in the technical reference manual.

tPRCrvx, tTRCrvx, tCRCrvx: Parameters for user programmable of inverse reset time characteristic curve. Further description can be found in the technical reference manual.

### 9.4.3.6 Transformer application example

Two main cases are of interest when residual overcurrent protection is used for a power transformer, namely if residual current can be fed from the protected transformer winding or not.

The protected winding will feed ground-fault (residual) current to ground faults in the connected power system. The residual current fed from the transformer at external phase-to-ground faults is highly dependent on the total positive and zero-sequence source impedances. It is also dependent on the residual current distribution between the network zero-sequence impedance and the transformer zero-sequence impedance. An example of this application is shown in Figure 184.
Figure 184: Residual overcurrent protection application on a directly grounded transformer winding

In this case the protection has two different tasks:

- Detection of ground faults on the transformer winding.
- Detection of ground faults in the power system.

It can be suitable to use a residual overcurrent protection with at least two steps. Step 1 shall have a short definite time delay and a relatively high current setting, in order to detect and clear high current ground faults in the transformer winding or in the power system close to the transformer. Step 2 shall have a longer time delay (definite or inverse time delay) and a lower current operation level. Step 2 shall detect and clear transformer winding ground faults with low ground-fault current, that is, faults close to the transformer winding neutral point. If the current setting gap between step 1 and step 2 is large another step can be introduced with a current and time delay setting between the two described steps.

The transformer inrush current will have a large residual current component. To prevent unwanted function of the ground-fault overcurrent protection, the 2nd harmonic restrain blocking should be used, at least for the sensitive step 2.

If the protected winding will not feed ground-fault (residual) current to ground faults in the connected power system, the application is as shown in Figure 185.
Figure 185: Residual overcurrent protection application on an isolated transformer winding

In the calculation of the fault current fed to the protection, at different ground faults, are highly dependent on the positive and zero sequence source impedances, as well as the division of residual current in the network. Ground-fault current calculations are necessary for the setting.

**Setting of step 1**

One requirement is that ground faults at the busbar, where the transformer winding is connected, shall be detected. Therefore a fault calculation as shown in Figure 186 is made.

Figure 186: Step 1 fault calculation 1
This calculation gives the current fed to the protection: $3I_{\text{ofault1}}$.

To assure that step 1, selectivity to other ground-fault protections in the network a short delay is selected. Normally, a delay in the range 0.3 – 0.4 s is appropriate. To assure selectivity to line faults, tripped after a delay (typically distance protection zone 2) of about 0.5 s the current setting must be set so high so that such faults does not cause unwanted step 1 trip. Therefore, a fault calculation as shown in Figure 187 is made.

![Diagram of fault calculation](ANSI05000493_3_en.vsd)

**Figure 187: Step 1 fault calculation 1**

The fault is located at the borderline between instantaneous and delayed operation of the line protection, such as Distance protection or line residual overcurrent protection. This calculation gives the current fed to the protection: $3I_{\text{ofault2}}$

The setting of step 1 can be chosen within the interval shown in equation 189.

$$3I_{\text{ofault2}} \cdot \text{lowmar} < I_{\text{step1}} < 3I_{\text{ofault1}} \cdot \text{highmar}$$

(Equation 189)

Where:
- lowmar is a margin to assure selectivity (typical 1.2) and
- highmar is a margin to assure fast fault clearance of busbar fault (typical 1.2).
Setting of step 2
The setting of the sensitive step 2 is dependent of the chosen time delay. Often a relatively long
definite time delay or inverse time delay is chosen. The current setting can be chosen very low. As
it is required to detect ground faults in the transformer winding, close to the neutral point, values
down to the minimum setting possibilities can be chosen. However, one must consider zero-
sequence currents that can occur during normal operation of the power system. Such currents can
be due to un-transposed lines.

In case to protection of transformer windings not feeding residual current at external ground
faults, a fast low current step can be acceptable.

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

9.5.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Four step negative sequence overcurrent protection</td>
<td>NS4PTOC</td>
<td>46I2</td>
<td></td>
</tr>
</tbody>
</table>

9.5.2 Application

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

- Ground-fault and phase-phase short circuit protection of feeders in effectively grounded
distribution and subtransmission systems. Normally these feeders have radial structure.
- Back-up ground-fault and phase-phase short circuit protection of transmission lines.
- Sensitive ground-fault protection of transmission lines. NS4PTOC (46I2) can have better
sensitivity to detect resistive phase-to-ground-faults compared to distance protection.
- Back-up ground-fault and phase-phase short circuit protection of power transformers.
- Ground-fault and phase-phase short circuit protection of different kinds of equipment
connected to the power system such as shunt capacitor banks, shunt reactors and others.

In many applications several steps with different current pickup levels and time delays are needed.
NS4PTOC (46I2) can have up to four, individual settable steps. The flexibility of each step of
NS4PTOC (46I2) function is great. The following options are possible:

Non-directional/Directional function: In some applications the non-directional functionality is
used. This is mostly the case when no fault current can be fed from the protected object itself. In
order to achieve both selectivity and fast fault clearance, the directional function can be
necessary. This can be the case for unsymmetrical fault protection in meshed and effectively
grounded transmission systems. The directional negative sequence overcurrent protection is also
well suited to operate in teleprotection communication schemes, which enables fast clearance of
unsymmetrical faults on transmission lines. The directional function uses the voltage polarizing quantity.

Choice of time characteristics: There are several types of time characteristics available such as definite time delay and different types of inverse time characteristics. The selectivity between different overcurrent protections is normally enabled by co-ordination between the operating time of the different protections. To enable optimal co-ordination all overcurrent relays, to be co-ordinated against each other, should have the same time characteristic. Therefore a wide range of standardized inverse time characteristics are available: IEC and ANSI.

Table 37: Inverse time characteristics

<table>
<thead>
<tr>
<th>Curve name</th>
</tr>
</thead>
<tbody>
<tr>
<td>ANSI Extremely Inverse</td>
</tr>
<tr>
<td>ANSI Very Inverse</td>
</tr>
<tr>
<td>ANSI Normal Inverse</td>
</tr>
<tr>
<td>ANSI Moderately Inverse</td>
</tr>
<tr>
<td>ANSI/IEEE Definite time</td>
</tr>
<tr>
<td>ANSI Long Time Extremely Inverse</td>
</tr>
<tr>
<td>ANSI Long Time Very Inverse</td>
</tr>
<tr>
<td>ANSI Long Time Inverse</td>
</tr>
<tr>
<td>IEC Normal Inverse</td>
</tr>
<tr>
<td>IEC Very Inverse</td>
</tr>
<tr>
<td>IEC Inverse</td>
</tr>
<tr>
<td>IEC Extremely Inverse</td>
</tr>
<tr>
<td>IEC Short Time Inverse</td>
</tr>
<tr>
<td>IEC Long Time Inverse</td>
</tr>
<tr>
<td>IEC Definite Time</td>
</tr>
<tr>
<td>User Programmable</td>
</tr>
<tr>
<td>ASEA RI</td>
</tr>
<tr>
<td>RXIDG (logarithmic)</td>
</tr>
</tbody>
</table>

There is also a user programmable inverse time characteristic.

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

For some protection applications there can be a need to change the current pickup level for some time. Therefore there is a possibility to give a setting of a multiplication factor $MultPUx$ to the negative sequence current pick-up level. This multiplication factor is activated from a binary input signal MULTPUx to the function.

### 9.5.3 Setting guidelines

The parameters for Four step negative sequence overcurrent protection NS4PTOC (46I2) are set via the local HMI or Protection and Control Manager (PCM600).
The following settings can be done for the four step negative sequence overcurrent protection:

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

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

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

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

### 9.5.3.1 Settings for each step

*x* means step 1, 2, 3 and 4.

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

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

<table>
<thead>
<tr>
<th>Curve name</th>
</tr>
</thead>
<tbody>
<tr>
<td>ANSI Extremely Inverse</td>
</tr>
<tr>
<td>ANSI Very Inverse</td>
</tr>
<tr>
<td>ANSI Normal Inverse</td>
</tr>
<tr>
<td>ANSI Moderately Inverse</td>
</tr>
<tr>
<td>ANSI/IEEE Definite time</td>
</tr>
<tr>
<td>ANSI Long Time Extremely Inverse</td>
</tr>
<tr>
<td>ANSI Long Time Very Inverse</td>
</tr>
<tr>
<td>ANSI Long Time Inverse</td>
</tr>
<tr>
<td>IEC Normal Inverse</td>
</tr>
<tr>
<td>IEC Very Inverse</td>
</tr>
<tr>
<td>IEC Inverse</td>
</tr>
<tr>
<td>IEC Extremely Inverse</td>
</tr>
<tr>
<td>IEC Short Time Inverse</td>
</tr>
<tr>
<td>IEC Long Time Inverse</td>
</tr>
<tr>
<td>IEC Definite Time</td>
</tr>
</tbody>
</table>

Table continues on next page
The different characteristics are described in the Technical Reference Manual (TRM).

*Pickupx:* Operation negative sequence current level for step x given in % of $I_{\text{Base}}$.

*tx:* Definite time delay for step x. The definite time $tx$ is added to the inverse time when inverse time characteristic is selected. Note that the value set is the time between activation of the start and the trip outputs.

*TDx:* Time multiplier for the dependent (inverse) characteristic.

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

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

*txMin:* Minimum operation time for inverse time characteristics. At high currents the inverse time characteristic might give a very short operation time. By setting this parameter the operation time of the step can never be shorter than the setting.

*Figure 188:* Minimum operate current and operation time for inverse time characteristics

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

<table>
<thead>
<tr>
<th>Curve name</th>
</tr>
</thead>
<tbody>
<tr>
<td>Instantaneous</td>
</tr>
<tr>
<td>IEC Reset (constant time)</td>
</tr>
<tr>
<td>ANSI Reset (inverse time)</td>
</tr>
</tbody>
</table>
The different reset characteristics are described in the Technical Reference Manual (TRM). There are some restrictions regarding the choice of reset delay.

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

For ANSI inverse time delay characteristics all three types of reset time characteristics are available; instantaneous (1), IEC (2 = set constant time reset) and ANSI (3 = current dependent reset time).

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

For the programmable inverse time delay characteristics all three types of reset time characteristics are available; instantaneous (1), IEC (2 = set constant time reset) and ANSI (3 = current dependent reset time). If the current dependent type is used settings pr, tr and cr must be given.

tPCrvx, tACrvx, tBCrvx, tCCrvx: Parameters for programmable inverse time characteristic curve. The time characteristic equation is according to equation 190:

\[
t[s] = \left( \frac{A}{\left( \frac{i}{ipickup} \right)^p} + B \right) \cdot TD
\]

(Equation 190)

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

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

### 9.5.3.2 Common settings for all steps

\( x \) means step 1, 2, 3 and 4.

\( \text{AngleRCA} \): Relay characteristic angle given in degrees. This angle is defined as shown in figure 189. The angle is defined positive when the residual current lags the reference voltage (Vpol = -)
Figure 189: Relay characteristic angle given in degree
In a transmission network a normal value of RCA is about 80°.

$V_{PolMin}$: Minimum polarization (reference) voltage % of $V_{Base}$.

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

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

### 9.6.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sensitive directional residual over current and power protection</td>
<td>SDEPSDE</td>
<td>-</td>
<td>67N</td>
</tr>
</tbody>
</table>
9.6.2 Application

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

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

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

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

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

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

In resistance grounded networks or in Petersen coil grounded, with a parallel resistor, the active residual current component (in phase with the residual voltage) should be used for the ground fault detection. In such networks, the characteristic angle is chosen to \(0^\circ\).

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

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

- Sensitive directional residual overcurrent protection gives possibility for better sensitivity. The setting possibilities of this function are down to 0.25 % of \(I_{\text{Base}}\), 1 A or 5 A. This sensitivity is in most cases sufficient in high impedance network applications, if the measuring CT ratio is not too high.

- Sensitive directional residual power protection gives possibility to use inverse time characteristics. This is applicable in large high impedance grounded networks, with large capacitive ground fault currents. In such networks, the active fault current would be small and by using sensitive directional residual power protection, the operating quantity is elevated. Therefore, better possibility to detect ground faults. In addition, in low impedance grounded networks, the inverse time characteristic gives better time-selectivity in case of high zero-resistive fault currents.
Overcurrent functionality uses true $3I_0$, i.e. sum of GRPxA, GRPxB and GRPxC. For $3I_0$ to be calculated, connection is needed to all three phase inputs.

Directional and power functionality uses IN and VN. If a connection is made to GRPxFN this signal is used, else if connection is made to all inputs GRPxA, GRPxB and GRPxC the internally calculated sum of these inputs ($3I_0$ and $3V_0$) will be used.

### 9.6.3 Setting guidelines

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

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

In the setting of ground-fault protection, in a high impedance grounded system, the neutral point voltage (zero sequence voltage) and the ground-fault current will be calculated at the desired sensitivity (fault resistance). The complex neutral point voltage (zero sequence) can be calculated as:
\[ V_0 = \frac{V_{\text{phase}}}{1 + \frac{3 \cdot R_f}{Z_0}} \]

(Equation 191)

Where
- \( V_{\text{phase}} \) is the phase voltage in the fault point before the fault,
- \( R_f \) is the resistance to ground in the fault point and
- \( Z_0 \) is the system zero sequence impedance to ground

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

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

(Equation 192)

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

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

(Equation 193)

Where
- \( I_j \) is the capacitive ground fault current at a non-resistive phase-to-ground fault
- \( X_c \) is the capacitive reactance to ground

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

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

(Equation 194)

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

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

(Equation 195)

Where

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

Now consider a system with an grounding via a resistor giving higher ground fault current than the high impedance grounding. The series impedances in the system can no longer be neglected. The system with a single phase to ground fault can be described as in Figure 191.

![Figure 191: Equivalent of power system for calculation of setting](en06000654_ansi.vsd)

The residual fault current can be written:
\[ 3I_0 = \frac{3V_{\text{phase}}}{2 \cdot Z_1 + Z_0 + 3 \cdot R_f} \]

(Equation 196)

Where

- \( V_{\text{phase}} \) is the phase voltage in the fault point before the fault
- \( Z_1 \) is the total positive sequence impedance to the fault point. \( Z_1 = Z_{sc} + Z_{T,1} + Z_{\text{lineAB,1}} + Z_{\text{lineBC,1}} \)
- \( Z_0 \) is the total zero sequence impedance to the fault point. \( Z_0 = Z_{T,0} + 3R_N + Z_{\text{lineAB,0}} + Z_{\text{lineBC,0}} \)
- \( R_f \) is the fault resistance.

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

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

(Equation 197)

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

(Equation 198)

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

\[ S_{0A} = 3V_{0A} \cdot 3I_0 \]

(Equation 199)

\[ S_{0B} = 3V_{0B} \cdot 3I_0 \]

(Equation 200)

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

\[ S_{0A,\text{prot}} = 3V_{0A} \cdot 3I_0 \cdot \cos \phi_A \]

(Equation 201)

\[ S_{0B,\text{prot}} = 3V_{0B} \cdot 3I_0 \cdot \cos \phi_B \]

(Equation 202)

The angles \( \phi_A \) and \( \phi_B \) are the phase angles between the residual current and the residual voltage in the station compensated with the characteristic angle \( RCA \).
The protection will use the power components in the characteristic angle direction for measurement, and as base for the inverse time delay.

The inverse time delay is defined as:

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

(Equation 203)

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

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

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

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

With **OpModeSel** set to \(3I_0\cos fi\) the current component in the direction equal to the characteristic angle \(RCADir\) has the maximum sensitivity. The characteristic for \(RCADir\) is equal to 0° is shown in Figure 192.

![Figure 192: Characteristic for RCADir equal to 0°](en06000648_ansi.vsd)

The characteristic is for \(RCADir\) equal to -90° is shown in Figure 193.
When $\text{OpModeSel}$ is set to $3I03V0\cos\phi$ the apparent residual power component in the direction is measured.

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

The characteristic for this $\text{OpModeSel}$ when $\text{RCADir} = 0^\circ$ and $\text{ROADir} = 80^\circ$ is shown in figure 194.
DirMode is set *Forward* or *Reverse* to set the direction of the operation for the directional function selected by the OpModeSel.

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

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

\[ t\text{Def} \] is the definite time delay, given in s, for the directional residual current protection.

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

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

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

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

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

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

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

\[
\begin{align*}
\text{t}_{\text{inv}} &= \frac{\text{TDSN} \cdot \text{SRef}}{3I_0 \cdot 3V_0 \cdot \cos \varphi(\text{measured})} \\
\end{align*}
\]

(Equation 204)

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

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

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

<table>
<thead>
<tr>
<th>Curve name</th>
</tr>
</thead>
<tbody>
<tr>
<td>ANSI Extremely Inverse</td>
</tr>
<tr>
<td>ANSI Very Inverse</td>
</tr>
<tr>
<td>ANSI Normal Inverse</td>
</tr>
<tr>
<td>ANSI Moderately Inverse</td>
</tr>
<tr>
<td>ANSI/IEEE Definite time</td>
</tr>
<tr>
<td>ANSI Long Time Extremely Inverse</td>
</tr>
<tr>
<td>ANSI Long Time Very Inverse</td>
</tr>
<tr>
<td>ANSI Long Time Inverse</td>
</tr>
<tr>
<td>IEC Normal Inverse</td>
</tr>
<tr>
<td>IEC Very Inverse</td>
</tr>
<tr>
<td>IEC Inverse</td>
</tr>
<tr>
<td>IEC Extremely Inverse</td>
</tr>
<tr>
<td>IEC Short Time Inverse</td>
</tr>
<tr>
<td>IEC Long Time Inverse</td>
</tr>
<tr>
<td>IEC Definite Time</td>
</tr>
<tr>
<td>User Programmable</td>
</tr>
<tr>
<td>ASEA RI</td>
</tr>
<tr>
<td>RXIDG (logarithmic)</td>
</tr>
</tbody>
</table>

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

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

\[ t[s] = \left( \frac{A}{i \cdot \text{Pickup} \cdot N} \right)^\nu - C \cdot \text{InMult} \]

(Equation 205)
$t\text{INNonDir}$ is the definite time delay for the non directional ground fault current protection, given in s.

$Op\text{VN}$ is set Enabled to activate the trip function of the residual over voltage protection.

$t\text{VN}$ is the definite time delay for the trip function of the residual voltage protection, given in s.

### 9.7 Thermal overload protection, two time constants TRPTTR (49)

#### 9.7.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermal overload protection, two time constants</td>
<td>TRPTTR</td>
<td></td>
<td>49</td>
</tr>
</tbody>
</table>

#### 9.7.2 Application

Transformers in the power system are designed for a certain maximum load current (power) level. If the current exceeds this level the losses will be higher than expected. As a consequence the temperature of the transformer will increase. If the temperature of the transformer reaches too high a value, the equipment might be damaged;

- The insulation within the transformer experiences forced ageing. As a consequence of this, the risk of internal phase-to-phase or phase-to-ground faults increases.
- There might be hot spots within the transformer, which degrades the paper insulation. It might also cause bubbling in the transformer oil.

In stressed situations in the power system it can be required to overload transformers for a limited time. This should be done without the above mentioned risks. The thermal overload protection provides information and makes temporary overloading of transformers possible.

The permissible load level of a power transformer is highly dependent on the cooling system of the transformer. There are two main principles:

- OA: The air is naturally circulated to the coolers without fans and the oil is naturally circulated without pumps.
- FOA: The coolers have fans to force air for cooling and pumps to force the circulation of the transformer oil.

The protection can have two sets of parameters, one for non-forced cooling and one for forced cooling. Both the permissive steady state loading level as well as the thermal time constant is influenced by the cooling system of the transformer. The two parameters sets can be activated by
the binary input signal COOLING. This can be used for transformers where forced cooling can be taken out of operation, for example at fan or pump faults.

The thermal overload protection estimates the internal heat content of the transformer (temperature) continuously. This estimation is made by using a thermal model of the transformer which is based on current measurement.

If the heat content of the protected transformer reaches a set alarm level a signal can be given to the operator. Two alarm levels are available. This enables preventive actions in the power system to be taken before dangerous temperatures are reached. If the temperature continues to increase to the trip value, the protection initiates a trip of the protected transformer.

After tripping by the thermal overload protection, the transformer will cool down over time. There will be a time gap before the heat content (temperature) reaches such a level so that the transformer can be taken into service again. Therefore, the function will continue to estimate the heat content using a set cooling time constant. Energizing of the transformer can be blocked until the heat content has reached a set level.

### 9.7.3 Setting guideline

The parameters for the thermal overload protection, two time constants (TRPTTR, 49) are set via the local HMI or Protection and Control IED Manager (PCM600).

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

**Operation: Disabled/Enabled**

**Operation:** Sets the mode of operation. **Disabled** switches off the complete function.

**GlobalBaseSel:** Selects the global base value group used by the function to define \( I_{Base} \), \( V_{Base} \) and \( S_{Base} \). Note that this function will only use \( I_{Base} \) value.

**\( I_{Ref} \):** Reference level of the current given in %. When the current is equal to \( I_{Ref} \) the final (steady state) heat content is equal to 1. It is suggested to give a setting corresponding to the rated current of the transformer winding.

**\( I_{RefMult} \):** If a binary input ENMULT is activated the reference current value can be multiplied by the factor \( I_{RefMult} \). The activation could be used in case of deviating ambient temperature from the reference value. In the standard for loading of a transformer an ambient temperature of 20°C is used. For lower ambient temperatures the load ability is increased and vice versa. \( I_{RefMult} \) can be set within a range: 0.01 - 10.00.

**\( I_{Base1} \):** Base current for setting given as percentage of \( I_{Base} \). This setting shall be related to the status with no COOLING input. It is suggested to give a setting corresponding to the rated current of the transformer with natural cooling (OA).

**\( I_{Base2} \):** Base current for setting given as percentage of \( I_{Base} \). This setting shall be related to the status with activated COOLING input. It is suggested to give a setting corresponding to the rated current of the transformer with forced cooling (FOA). If the transformer has no forced cooling \( I_{Base2} \) can be set equal to \( I_{Base1} \).

**\( \tau_{1} \):** The thermal time constant of the protected transformer, related to \( I_{Base1} \) (no cooling) given in minutes.

**\( \tau_{2} \):** The thermal time constant of the protected transformer, related to \( I_{Base2} \) (with cooling) given in minutes.
The thermal time constant should be obtained from the transformer manufacturers manuals. The thermal time constant is dependent on the cooling and the amount of oil. Normal time constants for medium and large transformers (according to IEC 60076-7) are about 2.5 hours for naturally cooled transformers and 1.5 hours for forced cooled transformers.

The time constant can be estimated from measurements of the oil temperature during a cooling sequence (described in IEC 60076-7). It is assumed that the transformer is operated at a certain load level with a constant oil temperature (steady state operation). The oil temperature above the ambient temperature is \( \Delta \theta_{o0} \). Then the transformer is disconnected from the grid (no load). After a time \( t \) of at least 30 minutes the temperature of the oil is measured again. Now the oil temperature above the ambient temperature is \( \Delta \theta_{ot} \). The thermal time constant can now be estimated as:

\[
\tau = \frac{t}{\ln \Delta \theta_{o0} - \ln \Delta \theta_{ot}}
\]

(Equation 206)

If the transformer has forced cooling (FOA) the measurement should be made both with and without the forced cooling in operation, giving \( \tau_{2} \) and \( \tau_{1} \).

The time constants can be changed if the current is higher than a set value or lower than a set value. If the current is high it is assumed that the forced cooling is activated while it is deactivated at low current. The setting of the parameters below enables automatic adjustment of the time constant.

\( \tau_{1High} \): Multiplication factor to adjust the time constant \( \tau_{1} \) if the current is higher than the set value \( I_{High \tau_{1}} \). \( I_{High \tau_{1}} \) is set in % of \( I_{Base_{1}} \).

\( \tau_{1Low} \): Multiplication factor to adjust the time constant \( \tau_{1} \) if the current is lower than the set value \( I_{Low \tau_{1}} \). \( I_{Low \tau_{1}} \) is set in % of \( I_{Base_{1}} \).

\( \tau_{2High} \): Multiplication factor to adjust the time constant \( \tau_{2} \) if the current is higher than the set value \( I_{High \tau_{2}} \). \( I_{High \tau_{2}} \) is set in % of \( I_{Base_{2}} \).

\( \tau_{2Low} \): Multiplication factor to adjust the time constant \( \tau_{2} \) if the current is lower than the set value \( I_{Low \tau_{2}} \). \( I_{Low \tau_{2}} \) is set in % of \( I_{Base_{2}} \).

The possibility to change time constant with the current value as the base can be useful in different applications. Below some examples are given:

• In case a total interruption (low current) of the protected transformer all cooling possibilities will be inactive. This can result in a changed value of the time constant.

• If other components (motors) are included in the thermal protection, there is a risk of overheating of that equipment in case of very high current. The thermal time constant is often smaller for a motor than for the transformer.

\( I_{Trip} \): The steady state current that the transformer can withstand. The setting is given in % of \( I_{Base_{1}} \) or \( I_{Base_{2}} \).

\( Alarm_{1} \): Heat content level for activation of the signal ALARM1. ALARM1 is set in % of the trip heat content level.

\( Alarm_{2} \): Heat content level for activation of the output signal ALARM2. ALARM2 is set in % of the trip heat content level.
**LockoutReset**: Lockout release level of heat content to release the lockout signal. When the thermal overload protection trips a lock-out signal is activated. This signal is intended to block switching on of the protected circuit transformer as long as the transformer temperature is high. The signal is released when the estimated heat content is below the set value. This temperature value should be chosen below the alarm temperature. **LockoutReset** is set in % of the trip heat content level.

**ThetaInit**: Heat content before activation of the function. This setting can be set a little below the alarm level. If the transformer is loaded before the activation of the protection function, its temperature can be higher than the ambient temperature. The start point given in the setting will prevent risk of no trip at overtemperature during the first moments after activation. **ThetaInit**: is set in % of the trip heat content level.

**Warning**: If the calculated time to trip factor is below the setting **Warning** a warning signal is activated. The setting is given in minutes.

### 9.7.3.1 Setting example

Calculation of the operate time with the available current is performed only if the calculated final temperature is greater than the operate level temperature.

where:

- \( t_{\text{operate}} \) is the time to operate
- \( \tau \) is the time constant

\[
\theta_{\text{final}} = \left( \frac{I}{I_{\text{ref}}} \right)^2
\]

- \( I \) is the largest phase load current
- \( I_{\text{ref}} \) is the given reference load current

\[
\theta_{\text{operate}} = \left( I_{\text{Base}} \times I_{\text{ref}} \times I_{\text{trip}} \right)^2
\]

- \( I_{\text{Base}} \) is the selected base current based cooling system \( \text{ON/OFF} \)
- \( I_{\text{ref}} \) is the operate level load current
- \( \theta_n \) is the current heat content

Consider that the given system has \( I_{\text{Base}} \) of 1000 A and the cooling system is \( \text{ON} \). The following settings are used to calculate the operate time:

- \( I_{\text{Ref}} \) 110%
- \( I_{\text{Base}1} \) 110% of IB
- \( I_{\text{Base}2} \) 120% of IB
- \( \tau_{1} \) 150 min
- \( \tau_{2} \) 90 min
- \( I_{\text{High}\tau_{1}} \) 110% of IB
As the cooling system is ON, \( I_{\text{Base2}} \) is selected as the base current and \( Tau2 \) setting is selected as the time constant.

For example, the largest phase load current is taken as 1800 A, then:

\[
\theta_{\text{final}} = \left( \frac{1800}{1.1} \right)^2 = 2677685.95
\]

\[
\theta_{\text{operate}} = (1.2 \times 1000 \times 1.1 \times 1.2)^2 = 2509056
\]

Here

\[
\Theta_{\text{final}} > \Theta_{n}
\]

At \( t=0 \)

\[
\theta_n = \theta_{\text{init}} = \Theta_{\text{Final}} \times \theta_{\text{operate}} = 0.5 \times 2509056 = 1254528
\]

At next execution, \( \theta_{n-1}=1254528 \) and \( \theta_n=1254555.04 \).

Therefore, \( t_{\text{operate}} = -90 \times \ln((2677685.95 - 2509056) / (2677685.95 - 1254555.04)) = 192 \text{ min} \)

After the trip, a lockout is released to inhibit reconnecting the tripped circuit. The output lockout signal LOCKOUT is activated when the temperature of the object is greater than the set lockout release temperature setting \( ResLo \).

\[
t_{\text{lockout\_release}} = -\tau \cdot \ln \left( \frac{\Theta_{\text{final}} - \Theta_{\text{lockout\_release}}}{\Theta_{\text{final}} - \Theta_n} \right)
\]

(Equation 208)

where:

\( t_{\text{lockout\_release}} \) is the time to lockout release

\( \Theta_{\text{lockout\_release}} \) is the lockout release level heat content = \( ResLo \times \theta_{\text{operate}} \)
Consider that the current heat content $\theta_n$ is 2700000 and the cooling system is still ON, then:

$$\theta_{\text{lockout, release}} = 0.6 \times 2509056 = 1505433.6$$

$$t_{\text{lockout, release}} = -90 \times \ln((2677685.95 - 1505433.6) / (2677685.95 - 2700000)) = 244 \text{ min}$$

9.8 Breaker failure protection CCRBRF(50BF)

9.8.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Breaker failure protection, 3-phase activation and output</td>
<td>CCRBRF</td>
<td></td>
<td>50BF</td>
</tr>
</tbody>
</table>

9.8.2 Application

In the design of the fault clearance system the N-1 criterion is often used. This means that a fault needs to be cleared even if any component in the fault clearance system is faulty. One necessary component in the fault clearance system is the circuit breaker.

It is from practical and economical reason not feasible to duplicate the circuit breaker for the protected object. Instead a breaker failure protection is used.

Breaker failure protection CCRBRF (50BF) will issue a backup trip command to adjacent circuit breakers in case of failure to trip of the “normal” circuit breaker for the protected object. The detection of failure to break the current through the breaker is made either by means of current measurement or as detection of closed status using auxiliary contact.

CCRBRF (50BF) can also give a retrip command. This means that a second trip signal is sent to the protected object circuit breaker. The retrip function can be used to increase the probability of operation of the breaker, or it can be used to avoid backup trip of many breakers in case of mistakes during relay maintenance and testing.

9.8.3 Setting guidelines

The parameters for Breaker failure protection CCRBRF (50BF) are set via the local HMI or PCM600.

The following settings can be done for the breaker failure protection.

*GlobalBaseSel:* Selects the global base value group used by the function to define $I_{\text{Base}}, V_{\text{Base}}$ and $S_{\text{Base}}$. Note that this function will only use $I_{\text{Base}}$ value.

*Operation:* *Disabled/Enabled* to enable/disable the complete function.
**FunctionMode**: It defines the way the detection of failure of the breaker is performed. In the [Current mode](#), the current measurement is used for the detection. In the [CB Pos mode](#), the CB auxiliary contact status is used as an indicator of the failure of the breaker. The mode [Current or CB Pos](#) means that both ways of detections can be activated. The [CB Pos mode](#) is used in applications where the fault current through the circuit breaker is small. This can be the case for some generator protection application (for example, reverse power protection) or in the case of line ends with weak end infeed.

**StartMode**: By this setting it is possible to select how $t_1$ and $t_2$ timers are run and consequently how output commands are given from the function:

- **Option 1 - LatchedStart**: “By external start signals which is internally latched”. When function is once started by external START signal, the timers $t_1$ and $t_2$ will always elapse and then measurement criterion defined by parameter FunctionMode will be always checked in order to verify if the appropriate command shall be given out from the function. Timers cannot be stopped by removing the external START signal. Function can be started again only when all of the following three timers $t_1$, $t_2$ and fixed timer of 150ms in function internal design has expired and the measurement criterion defined by parameter FunctionMode has deactivated, see [Figure 195](#). Note that this option corresponds to the function behavior in previous versions of the 670 Series from version 1.0 up to and including version 2.1.

- **Option 2 - FollowStart**: “Follow the external start signal only”. The timers $t_1$ and $t_2$ will run while external START signal is present. If they elapse then measurement criterion defined by parameter FunctionMode will be checked in order to verify if the appropriate command shall be given out from the function. Timers can be always stopped by resetting the external START signal, see [Figure 196](#).

- **Option 3- FollowStart&Mode**: “Follow external start signal and selected FunctionMode”. The timers $t_1$ and $t_2$ will run while external START signal is present and in the same time the measurement criterion defined by parameter FunctionMode is active. If they elapse then the appropriate command will be given out from the function. Timers can be stopped by resetting the external START signal or if the measurement criterion de-activates, see [Figure 197](#).

When one of the two “follow modes” is used, there is a settable timer $t_{StartTimeout}$ which will block the external START input signal when it times-out. This will automatically also reset the $t_1$ and $t_2$ timers and consequently prevent any backup trip command. At the same time the STALARM output from the function will have logical value one. To reset this signal external START signal shall be removed. This is done in order to prevent unwanted operation of the breaker failure function for cases where a permanent START signal is given by mistake (e.g. due to a fault in the station battery system). Note that any backup trip command will inhibit running of $t_{StartTimeout}$ timer.
RetripMode: This setting defines how the retrip function shall operate. Refer to Table 40 for more details.
Table 40: Dependencies between parameters RetripMode and FunctionMode

<table>
<thead>
<tr>
<th>RetripMode</th>
<th>FunctionMode</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Off</td>
<td>N/A</td>
<td>The retrip function is disabled</td>
</tr>
<tr>
<td>UseFunctionMode</td>
<td>Current</td>
<td>A phase current should be larger than the set operate level to allow retrip once the t1 timer elapses</td>
</tr>
<tr>
<td></td>
<td>CB Pos</td>
<td>retrip is done when the breaker position indicates that breaker is still closed after retrip time has elapsed</td>
</tr>
<tr>
<td></td>
<td>Current or CB Pos</td>
<td>Both the methods are used</td>
</tr>
<tr>
<td>Always</td>
<td>N/A</td>
<td>retrip is always given when t1 elapses without any further checks</td>
</tr>
</tbody>
</table>

**BuTripMode**: Defines how many current criterias to be fulfilled in order to detect failure of the breaker. For **Current** operation *2 out of 4* means that at least two currents, of the three-phase currents and the residual current, shall be high to indicate breaker failure. *1 out of 3* means that at least one current of the three-phase currents shall be high to indicate breaker failure. *1 out of 4* means that at least one current of the three phase currents or the residual current shall be high to indicate breaker failure. In most applications *1 out of 3* is sufficient. For **CB Pos** operation *1 out of 3* is always used.

**Pickup_PH**: Current level for detection of breaker failure, set in % of IBase. This parameter should be set so that faults with small fault current can be detected. The setting can be chosen in accordance with the most sensitive protection function to start the breaker failure protection. Default setting is 10% of IBase. Note that this setting shall not be set lower than 4% of Ir, where Ir is rated current of the IED CT input where the function is connected. In principle Ir is either 1A or 5A depending on the ordered IED.

**Pickup>BlkCBPos**: If the FunctionMode is set to **Current or CB pos** breaker failure for high current faults are safely detected by the current measurement function. To increase security for low currents the contact based function will be enabled only if the current at the moment of starting is below this set level. The setting can be given within the range 5 – 200% of IBase. It is strongly recommended to set this level above IPPU set level.

**Pickup_N**: Residual current level for detection of breaker failure set in % of IBase. In high impedance earthed systems the residual current at phase- to-ground faults are normally much smaller than the short circuit currents. In order to detect breaker failure at single phase-to-ground faults in such systems it is necessary to measure the residual current separately. The **BuTripMode** shall be set *1 out of 4* in such systems The current setting should be chosen in accordance to the setting of the sensitive ground-fault protection. The setting can be given within the range 2 – 200% of IBase.

**t1**: Time delay of the retrip. The setting can be given within the range 0 – 60s in steps of 0.001 s. Typical setting is within range 0 – 50ms.

**t2**: Time delay of the backup trip. The choice of this setting is made as short as possible at the same time as unwanted operation must be avoided. Typical setting is within range 90 – 200ms (also dependent of retrip timer).

Timer t2 is used when function is started in one phase only (i.e. for single-phase to ground fault on an OHL (Over Head Lines) when single-pole auto-reclosing is used).
The minimum time delay for the backup trip can be estimated as:

\[ t_2 \geq t_1 + t_{\text{CB\_open}} + t_{\text{BFP\_reset}} + t_{\text{margin}} \]

(Equation 209)

where:
- \( t_{\text{CB\_open}} \) is the maximum opening time for the circuit breaker
- \( t_{\text{BFP\_reset}} \) is the maximum time for breaker failure protection to detect correct breaker function (the current criteria reset)
- \( t_{\text{margin}} \) is a safety margin

It is often required that the total fault clearance time shall be less than a given critical time. This time is often dependent of the ability of the power system to maintain transient stability in case of a fault close to a power plant.

**Figure 198: Time sequence**

\( t_{2\text{MPh}} \): Time delay of the backup trip at multi-phase initiate. The critical fault clearance time is often shorter in case of multi-phase faults, compared to single phase-to-ground faults. Therefore there is a possibility to reduce the backup trip delay for multi-phase faults. Typical setting is 90 – 150 ms.

Note that for a protected object which are always tripped three-phase (e.g. transformers, generators, reactors, cables, etc.) this timer shall always be set to the same value as \( t_2 \) timer.

\( t_3 \): Additional time delay to \( t_2 \) for a second backup trip TRBU2. In some applications there might be a requirement to have separated backup trip functions, tripping different backup circuit breakers.
**tCBAAlarm**: Time delay for alarm in case of indication of faulty circuit breaker. There is a binary input 52FAIL from the circuit breaker. This signal is activated when internal supervision in the circuit breaker detect that the circuit breaker is unable to clear fault. This could be the case when gas pressure is low in a SF6 circuit breaker, of others. After the set time an alarm is given, so that actions can be done to repair the circuit breaker. Note that the time delay for backup trip \( t2 \) is bypassed when the 52FAIL is active. Typical setting is 2.0 seconds..

**tPulse**: Trip pulse duration. This setting must be larger than the opening time of circuit breakers to be tripped from the breaker failure protection. Typical setting is 200 ms.

**tStartTimeout**: When one of the two “Follow Modes” is used, there is a settable timer \( t \text{StartTimeout} \) which will block the external \( \text{START} \) input signal when it times-out. This will automatically also reset the \( t1 \) and \( t2 \) timers and consequently prevent any backup trip command. At the same time the STALARM output from the function will have logical value one. To reset that condition external \( \text{START} \) signal shall be removed. This is done in order to prevent unwanted operation of the breaker failure function for cases where a permanent \( \text{START} \) signal is given by mistake (e.g. due to a fault in the station battery system). Note that any backup trip command will inhibit running of \( t \text{StartTimeout} \) timer.

---

**Table 41: Setting summary for FunctionMode, StartMode, RetripMode and BuTripMode**

<table>
<thead>
<tr>
<th>No.</th>
<th>StartMode</th>
<th>RetripMode</th>
<th>( t1 ) and ( t2 ) initiated with</th>
<th>When ( t1 ) has elapsed, TRRET will</th>
<th>When ( t2 ) or ( t2\text{MPh} ) has elapsed, TRBU will be given if</th>
<th>( t1 ) and ( t2 ) and ( t2\text{MPh} ) will be stopped (reset) if</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>LatchedStart</td>
<td>Off</td>
<td>external START</td>
<td>never be given</td>
<td>current is above set level ( * )</td>
<td>( t1 ) and (( t2 ) or ( t2\text{MPh} ) and 150ms expires and current is below set level ( * ))</td>
</tr>
<tr>
<td>2</td>
<td>LatchedStart</td>
<td>UseFunctionMode</td>
<td>external START</td>
<td>be given if current is above set level of ( \text{IPh} )</td>
<td>current is above set level ( * )</td>
<td>( t1 ) and (( t2 ) or ( t2\text{MPh} ) and 150ms expires and current is below set level ( * ))</td>
</tr>
<tr>
<td>3</td>
<td>LatchedStart</td>
<td>Always</td>
<td>external START</td>
<td>always be given</td>
<td>current is above set level ( * )</td>
<td>( t1 ) and (( t2 ) or ( t2\text{MPh} ) and 150ms expires and current is below set level ( * ))</td>
</tr>
<tr>
<td>4</td>
<td>FollowStart</td>
<td>Off</td>
<td>external START</td>
<td>never be given</td>
<td>current is above set level ( * )</td>
<td>external START disappears</td>
</tr>
<tr>
<td>5</td>
<td>FollowStart</td>
<td>UseFunctionMode</td>
<td>external START</td>
<td>be given if current is above set level of ( \text{IPh} )</td>
<td>current is above set level ( * )</td>
<td>external START disappears</td>
</tr>
<tr>
<td>6</td>
<td>FollowStart</td>
<td>Always</td>
<td>external START</td>
<td>be given if external ( \text{START} ) is present</td>
<td>current is above set level ( * )</td>
<td>external START disappears</td>
</tr>
<tr>
<td>7</td>
<td>FollowStart&amp; Mode</td>
<td>Off</td>
<td>external START and current above set level</td>
<td>never be given</td>
<td>current is above set level ( * ) and external ( \text{START} ) present</td>
<td>current is below set level ( * ) or external ( \text{START} ) disappears</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>No.</th>
<th>StartMode</th>
<th>RetripMode</th>
<th>t1 and t2 initiated with</th>
<th>When t1 has elapsed, TRRET will</th>
<th>When t2 or t2MPh has elapsed, TRBU will be given if</th>
<th>t1 and t2 and t2MPh will be stopped (reset) if</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>FollowStart&amp;</td>
<td>UseFunctionMode</td>
<td>external START and current above set level</td>
<td>be given if current is above set level of IPh&gt; and external START is present</td>
<td>current is above set level *) and external START present</td>
<td>current is below set level *) or external START disappears</td>
</tr>
<tr>
<td>9</td>
<td>FollowStart&amp;</td>
<td>Always</td>
<td>external START and current above set level</td>
<td>be given if external START is present</td>
<td>current is above set level *) and external START present</td>
<td>current is below set level *) or external START disappears</td>
</tr>
</tbody>
</table>

*) Set level depends on selected BuTripMode, that is, set level can be either IPh> or IN> or both.

<table>
<thead>
<tr>
<th>No.</th>
<th>StartMode</th>
<th>RetripMode</th>
<th>t1 and t2 initiated with</th>
<th>When t1 has elapsed, TRRET will</th>
<th>When t2 or t2MPh has elapsed, TRBU will be given if</th>
<th>t1 and t2 and t2MPh will be stopped (reset) if</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>LatchedStart</td>
<td>Off</td>
<td>external START</td>
<td>never be given</td>
<td>CBCCLDLx input has logical value one</td>
<td>t1 and (t2 or t2MPh) and 150ms expires and CBCCLDLx input has logical value zero</td>
</tr>
<tr>
<td>11</td>
<td>LatchedStart</td>
<td>UseFunctionMode</td>
<td>external START</td>
<td>be given if CBCCLDLx input has logical value one</td>
<td>CBCCLDLx input has logical value one</td>
<td>t1 and (t2 or t2MPh) and 150ms expires and CBCCLDLx input has logical value zero</td>
</tr>
<tr>
<td>12</td>
<td>LatchedStart</td>
<td>Always</td>
<td>external START</td>
<td>always be given</td>
<td>CBCCLDLx input has logical value one</td>
<td>t1 and (t2 or t2MPh) and 150ms expires and CBCCLDLx input has logical value zero</td>
</tr>
<tr>
<td>13</td>
<td>FollowStart</td>
<td>Off</td>
<td>external START</td>
<td>never be given</td>
<td>CBCCLDLx input has logical value one</td>
<td>external START disappears</td>
</tr>
<tr>
<td>14</td>
<td>FollowStart</td>
<td>UseFunctionMode</td>
<td>external START</td>
<td>be given if CBCCLDLx input has logical value one</td>
<td>CBCCLDLx input has logical value one</td>
<td>external START disappears</td>
</tr>
<tr>
<td>15</td>
<td>FollowStart</td>
<td>Always</td>
<td>external START</td>
<td>if external START is present</td>
<td>CBCCLDLx input has logical value one</td>
<td>external START disappears</td>
</tr>
<tr>
<td>16</td>
<td>FollowStart&amp;</td>
<td>Off</td>
<td>external START and CBCCLDLx input has logical value one</td>
<td>never be given</td>
<td>be given if CBCCLDLx input has logical value one and external START is present</td>
<td>CBCCLDLx input has logical value zero or external START disappears</td>
</tr>
<tr>
<td>17</td>
<td>FollowStart&amp;</td>
<td>UseFunctionMode</td>
<td>external START and CBCCLDLx input has logical value one</td>
<td>be given if CBCCLDLx input has logical value one and external START is present</td>
<td>be given if CBCCLDLx input has logical value one and external START is present</td>
<td>CBCCLDLx input has logical value zero or external START disappears</td>
</tr>
<tr>
<td>18</td>
<td>FollowStart&amp;</td>
<td>Always</td>
<td>external START and CBCCLDLx input has logical value one</td>
<td>be given if external START is present</td>
<td>be given if CBCCLDLx input has logical value one and external START is present</td>
<td>CBCCLDLx input has logical value zero or external START disappears</td>
</tr>
<tr>
<td>No.</td>
<td>StartMode</td>
<td>RetripMode</td>
<td>t1 and t2 initiated with</td>
<td>When t1 has elapsed, TRRET will</td>
<td>When t2 or t2MPh has elapsed, TRBU will be given if</td>
<td>t1 and t2 and t2MPh will be stopped (reset) if</td>
</tr>
<tr>
<td>-----</td>
<td>------------</td>
<td>------------</td>
<td>--------------------------</td>
<td>---------------------------------</td>
<td>--------------------------------------------------</td>
<td>------------------------------------------------</td>
</tr>
<tr>
<td>19</td>
<td>LatchedStart</td>
<td>Off</td>
<td>external START</td>
<td>never be given</td>
<td>current is above set level *) and higher than I&gt;BlkCBPos or CBCLDLx input has logical value one when current is smaller than I&gt;BlkCBPos</td>
<td>t1 and (t2 or t2MPh) and 150ms expires and current is below set level *) or CBCLDLx input has logical value zero</td>
</tr>
<tr>
<td>20</td>
<td>LatchedStart</td>
<td>UseFunctionMode</td>
<td>external START</td>
<td>be given if current is above set level *) and higher than I&gt;BlkCBPos or CBCLDLx input has logical value one when current is smaller than I&gt;BlkCBPos</td>
<td>current is above set level *) and higher than I&gt;BlkCBPos or CBCLDLx input has logical value one when current is smaller than I&gt;BlkCBPos</td>
<td>t1 and (t2 or t2MPh) and 150ms expires and current is below set level *) or CBCLDLx input has logical value zero</td>
</tr>
<tr>
<td>21</td>
<td>LatchedStart</td>
<td>Always</td>
<td>external START</td>
<td>always be given</td>
<td>current is above set level *) and higher than I&gt;BlkCBPos or CBCLDLx input has logical value one when current is smaller than I&gt;BlkCBPos</td>
<td>t1 and (t2 or t2MPh) and 150ms expires and current is below set level *) or CBCLDLx input has logical value zero</td>
</tr>
<tr>
<td>22</td>
<td>FollowStart</td>
<td>Off</td>
<td>external START</td>
<td>never be given</td>
<td>current is above set level *) and higher than I&gt;BlkCBPos or CBCLDLx input has logical value one when current is smaller than I&gt;BlkCBPos</td>
<td>external START disappears</td>
</tr>
<tr>
<td>23</td>
<td>FollowStart</td>
<td>UseFunctionMode</td>
<td>external START</td>
<td>be given if current is above set level *) and higher than I&gt;BlkCBPos or CBCLDLx input has logical value one when current is smaller than I&gt;BlkCBPos</td>
<td>current is above set level *) and higher than I&gt;BlkCBPos or CBCLDLx input has logical value one when current is smaller than I&gt;BlkCBPos</td>
<td>external START disappears</td>
</tr>
<tr>
<td>24</td>
<td>FollowStart</td>
<td>Always</td>
<td>external START</td>
<td>be given if external START is present</td>
<td>current is above set level *) and higher than I&gt;BlkCBPos or CBCLDLx input has logical value one when current is smaller than I&gt;BlkCBPos</td>
<td>external START disappears</td>
</tr>
</tbody>
</table>

Table continues on next page
### 9.9 Pole discrepancy protection CCPDSC(52PD)

#### 9.9.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pole discrepancy protection</td>
<td>CCPDSC</td>
<td></td>
<td>52PD</td>
</tr>
</tbody>
</table>

#### 9.9.2 Application

There is a risk that a circuit breaker will get discrepancy between the poles at circuit breaker operation: closing or opening. One pole can be open and the other two closed, or two poles can be open and one closed. Pole discrepancy of a circuit breaker will cause unsymmetrical currents in the power system. The consequence of this can be:
Negative sequence currents that will give stress on rotating machines.
Zero sequence currents that might give unwanted operation of sensitive ground-fault protections in the power system.

It is therefore important to detect situations with pole discrepancy of circuit breakers. When this is detected the breaker should be tripped directly.

Pole discordance protection CCPDSC (52PD) will detect situation with deviating positions of the poles of the protected circuit breaker. The protection has two different options to make this detection:

- By connecting the auxiliary contacts in the circuit breaker so that logic is created, a signal can be sent to the protection, indicating pole discrepancy. This logic can also be realized within the protection itself, by using opened and close signals for each circuit breaker pole, connected to the protection.
- Each phase current through the circuit breaker is measured. If the difference between the phase currents is larger than a $\text{CurrUnsymPU}$ this is an indication of pole discrepancy, and the protection will operate.

9.9.3 Setting guidelines

The parameters for the Pole discordance protection CCPDSC (52PD) are set via the local HMI or PCM600.

The following settings can be done for the pole discrepancy protection.

*GlobalBaseSel:* Selects the global base value group used by the function to define $I_{\text{Base}}$, $V_{\text{Base}}$ and $S_{\text{Base}}$. Note that this function will only use $I_{\text{Base}}$ value.

*Operation:* Disabled or Enabled

*tTrip:* Time delay of the operation.

*ContactSel:* Operation of the contact based pole discrepancy protection. Can be set: Disabled/ PD signal from CB. If PD signal from CB is chosen the logic to detect pole discrepancy is made in the vicinity to the breaker auxiliary contacts and only one signal is connected to the pole discrepancy function. If the Pole pos aux cont. alternative is chosen each open close signal is connected to the IED and the logic to detect pole discrepancy is realized within the function itself.

*CurrentSel:* Operation of the current based pole discrepancy protection. Can be set: Disabled/ CB oper monitor/ Continuous monitor. In the alternative CB oper monitor the function is activated only directly in connection to breaker open or close command (during 200 ms). In the alternative Continuous monitor function is continuously activated.

*CurrUnsymPU:* Unsymmetrical magnitude of lowest phase current compared to the highest, set in % of the highest phase current. Natural difference between phase currents in breaker-and-a-half installations must be considered. For circuit breakers in breaker-and-a-half configured switch yards there might be natural unbalance currents through the breaker. This is due to the existence of low impedance current paths in the switch yard. This phenomenon must be considered in the setting of the parameter.

*CurrRelPU:* Current magnitude for release of the function in % of $I_{\text{Base}}$. 
9.10 Directional underpower protection GUPPDUP (37)

9.10.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Directional underpower protection</td>
<td>GUPPDUP</td>
<td></td>
<td>37</td>
</tr>
</tbody>
</table>

9.10.2 Application

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

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

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

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

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

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

The critical time to overheating a steam turbine varies from about 0.5 to 30 minutes depending on the type of turbine. A high-pressure turbine with small and thin blades will become overheated more easily than a low-pressure turbine with long and heavy blades. The conditions vary from turbine to turbine and it is necessary to ask the turbine manufacturer in each case.
Power to the power plant auxiliaries may come from a station service transformer connected to the secondary side of the step-up transformer. Power may also come from a start-up service transformer connected to the external network. One has to design the reverse power protection so that it can detect reverse power independent of the flow of power to the power plant auxiliaries.

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

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

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

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

Gas turbines usually do not require reverse power protection.

Figure 199 illustrates the reverse power protection with underpower protection and with overpower protection. The underpower protection gives a higher margin and should provide better dependability. On the other hand, the risk for unwanted operation immediately after synchronization may be higher. One should set the underpower protection (reference angle set to 0) to trip if the active power from the generator is less than about 2%. One should set the overpower protection (reference angle set to 180) to trip if the power flow from the network to the generator is higher than 1%.

**Figure 199: Reverse power protection with underpower or overpower protection**
### 9.10.3 Setting guidelines

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

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

*Mode:* The voltage and current used for the power measurement. The setting possibilities are shown in table 42.

#### Table 42: Complex power calculation

<table>
<thead>
<tr>
<th>Set value Mode</th>
<th>Formula used for complex power calculation</th>
</tr>
</thead>
<tbody>
<tr>
<td>A, B, C</td>
<td>$\bar{S} = \bar{V}_A \cdot \bar{I}_A^* + \bar{V}_B \cdot \bar{I}_B^* + \bar{V}_C \cdot \bar{I}_C^*$ (Equation 211)</td>
</tr>
<tr>
<td>Arone</td>
<td>$\bar{S} = \bar{V}_{AB} \cdot \bar{I}<em>A^* - \bar{V}</em>{BC} \cdot \bar{I}_C^*$ (Equation 212)</td>
</tr>
<tr>
<td>PosSeq</td>
<td>$\bar{S} = 3 \cdot \bar{V}<em>{PosSeq} \cdot \bar{I}</em>{PosSeq}^*$ (Equation 213)</td>
</tr>
<tr>
<td>AB</td>
<td>$\bar{S} = \bar{V}_{AB} \cdot (\bar{I}_A^* - \bar{I}_B^*)$ (Equation 214)</td>
</tr>
<tr>
<td>BC</td>
<td>$\bar{S} = \bar{V}_{BC} \cdot (\bar{I}_B^* - \bar{I}_C^*)$ (Equation 215)</td>
</tr>
<tr>
<td>CA</td>
<td>$\bar{S} = \bar{V}_{CA} \cdot (\bar{I}_C^* - \bar{I}_A^*)$ (Equation 216)</td>
</tr>
<tr>
<td>A</td>
<td>$\bar{S} = 3 \cdot \bar{V}_A \cdot \bar{I}_A^*$ (Equation 217)</td>
</tr>
<tr>
<td>B</td>
<td>$\bar{S} = 3 \cdot \bar{V}_B \cdot \bar{I}_B^*$ (Equation 218)</td>
</tr>
<tr>
<td>C</td>
<td>$\bar{S} = 3 \cdot \bar{V}_C \cdot \bar{I}_C^*$ (Equation 219)</td>
</tr>
</tbody>
</table>

The function has two stages that can be set independently.

With the parameter *OpMode1(2)* the function can be set *Enabled/Disabled*. 
The function gives trip if the power component in the direction defined by the setting \textit{Angle1(2)} is smaller than the set pick up power value \textit{Power1(2)}

\textit{Figure 200: Underpower mode}

The setting \textit{Power1(2)} gives the power component pick up value in the \textit{Angle1(2)} direction. The setting is given in p.u. of the generator rated power, see equation (220).

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

\[
S_N = \sqrt{3} \cdot V_{\text{Base}} \cdot I_{\text{Base}}
\]

(Equation 220)

The setting \textit{Angle1(2)} gives the characteristic angle giving maximum sensitivity of the power protection function. The setting is given in degrees. For active power the set angle should be 0° or 180°. 0° should be used for generator low forward active power protection.
Figure 201: For low forward power the set angle should be 0° in the underpower function. 

TripDelay\(1(2)\) is set in seconds to give the time delay for trip of the stage after pick up.

Hysteresis\(1(2)\) is given in p.u. of generator rated power according to equation 221.

\[
S_N = \sqrt{3} \cdot V_{\text{Base}} \cdot I_{\text{Base}}
\]  

(Equation 221)

The drop out power will be Power\(1(2) + \text{Hysteresis}1(2)\).

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

\[
S = TD \cdot S_{\text{Old}} + (1 - TD) \cdot S_{\text{Calculated}}
\]  

(Equation 222)

Where

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

The value of \(k=0.92\) is recommended in generator applications as the trip delay is normally quite long.
The calibration factors for current and voltage measurement errors are set % of rated current/voltage:

$IMagComp5$, $IMagComp30$, $IMagComp100$

$VMagComp5$, $VMagComp30$, $VMagComp100$

$IMagComp5$, $IMagComp30$, $IMagComp100$

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

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

9.11 Directional overpower protection GOPPDOP (32)

9.11.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Directional overpower protection</td>
<td>GOPPDOP</td>
<td></td>
<td>32</td>
</tr>
</tbody>
</table>

9.11.2 Application

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

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

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

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

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

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

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

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

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

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

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

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

Gas turbines usually do not require reverse power protection.

Figure 202 illustrates the reverse power protection with underpower IED and with overpower IED. The underpower IED gives a higher margin and should provide better dependability. On the other hand, the risk for unwanted operation immediately after synchronization may be higher. One should set the underpower IED to trip if the active power from the generator is less than about 2%. One should set the overpower IED to trip if the power flow from the network to the generator is higher than 1%.
9.11.3 Setting guidelines

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

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

Mode: The voltage and current used for the power measurement. The setting possibilities are shown in table 43.

Table 43: Complex power calculation

<table>
<thead>
<tr>
<th>Set value Mode</th>
<th>Formula used for complex power calculation</th>
</tr>
</thead>
<tbody>
<tr>
<td>A,B,C</td>
<td>[ \bar{S} = \bar{V}_A \cdot \bar{I}_A^* + \bar{V}_B \cdot \bar{I}_B^* + \bar{V}_C \cdot \bar{I}_C^* ] (Equation 224)</td>
</tr>
<tr>
<td>Arone</td>
<td>[ \bar{S} = \bar{V}_{AB} \cdot \bar{I}<em>A^* - \bar{V}</em>{BC} \cdot \bar{I}_C^* ] (Equation 225)</td>
</tr>
<tr>
<td>PosSeq</td>
<td>[ \bar{S} = 3 \cdot \bar{V}<em>{PosSeq} \cdot \bar{I}</em>{PosSeq}^* ] (Equation 226)</td>
</tr>
<tr>
<td>A,B</td>
<td>[ \bar{S} = \bar{V}_{AB} \cdot (\bar{I}_A^* - \bar{I}_B^*) ] (Equation 227)</td>
</tr>
<tr>
<td>B,C</td>
<td>[ \bar{S} = \bar{V}_{BC} \cdot (\bar{I}_B^* - \bar{I}_C^*) ] (Equation 228)</td>
</tr>
<tr>
<td>C,A</td>
<td>[ \bar{S} = \bar{V}_{CA} \cdot (\bar{I}_C^* - \bar{I}_A^*) ] (Equation 229)</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Set value Mode</th>
<th>Formula used for complex power calculation</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>( \bar{S} = 3 \cdot \bar{V}_A \cdot \bar{I}_A^* ) \hspace{1cm} (Equation 230)</td>
</tr>
<tr>
<td>B</td>
<td>( \bar{S} = 3 \cdot \bar{V}_B \cdot \bar{I}_B^* ) \hspace{1cm} (Equation 231)</td>
</tr>
<tr>
<td>C</td>
<td>( \bar{S} = 3 \cdot \bar{V}_C \cdot \bar{I}_C^* ) \hspace{1cm} (Equation 232)</td>
</tr>
</tbody>
</table>

The function has two stages that can be set independently.

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

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

Figure 203: Overpower mode

The setting *Power1(2)* gives the power component pick up value in the *Angle1(2)* direction. The setting is given in p.u. of the generator rated power, see equation 233.

Minimum recommended setting is 0.2% of \( S_N \) when metering class CT inputs into the IED are used.
The setting $\text{Angle1}(2)$ gives the characteristic angle giving maximum sensitivity of the power protection function. The setting is given in degrees. For active power the set angle should be 0° or 180°. 180° should be used for generator reverse power protection.

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

(Equation 233)

Figure 204: For reverse power the set angle should be 180° in the overpower function

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

$\text{Hysteresis1}(2)$ is given in p.u. of generator rated power according to equation 234.

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

(Equation 234)

The drop out power will be $\text{Power1}(2) - \text{Hysteresis1}(2)$.

The possibility to have low pass filtering of the measured power can be made as shown in the formula:
\[ S = TD \cdot S_{\text{Old}} + (1 - TD) \cdot S_{\text{Calculated}} \]

(Equation 235)

Where

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

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

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

- \( IM_{\text{MagComp5}}, IM_{\text{MagComp30}}, IM_{\text{MagComp100}} \)
- \( VM_{\text{MagComp5}}, VM_{\text{MagComp30}}, VM_{\text{MagComp100}} \)
- \( IA_{\text{AngComp5}}, IA_{\text{AngComp30}}, IA_{\text{AngComp100}} \)

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

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

### 9.12 Negativ sequence time overcurrent protection for machines NS2PTOC (46I2)

#### 9.12.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Negative sequence time overcurrent protection for machines</td>
<td>NS2PTOC</td>
<td>2I2&gt;</td>
<td>46I2</td>
</tr>
</tbody>
</table>

#### 9.12.2 Application

Negative sequence overcurrent protection for machines NS2PTOC (46I2) is intended primarily for the protection of generators against possible overheating of the rotor caused by negative sequence component in the stator current.

The negative sequence currents in a generator may, among others, be caused by:
- Unbalanced loads
- Line to line faults
- Line to ground faults
- Broken conductors
- Malfunction of one or more poles of a circuit breaker or a disconnector

NS2PTOC (46I2) can also be used as a backup protection, that is, to protect the generator in the event line protections or circuit breakers fail to perform for unbalanced system faults.

To provide an effective protection for the generator for external unbalanced conditions, NS2PTOC (46I2) is able to directly measure the negative sequence current. NS2PTOC (46I2) also have a time delay characteristic which matches the heating characteristic of the generator $I_2^2t = K$ as defined in standard.

where:

\[
I_2 \quad \text{is negative sequence current expressed in per unit of the rated generator current}
\]

\[
t \quad \text{is operating time in seconds}
\]

\[
K \quad \text{is a constant which depends of the generators size and design}
\]

A wide range of $I_2^2t$ settings is available, which provide the sensitivity and capability necessary to detect and trip for negative sequence currents down to the continuous capability of a generator.

A separate output is available as an alarm feature to warn the operator of a potentially dangerous situation.

### 9.12.2.1 Features

Negative-sequence time overcurrent protection NS2PTOC (46I2) is designed to provide a reliable protection for generators of all types and sizes against the effect of unbalanced system conditions.

The following features are available:

- Two steps, independently adjustable, with separate tripping outputs.
- Sensitive protection, capable of detecting and tripping for negative sequence currents down to 3% of rated generator current with high accuracy.
- Two time delay characteristics:
  - Definite time delay
  - Inverse time delay
- The inverse time overcurrent characteristic matches $I_2^2t = K$ capability curve of the generators.
- Wide range of settings for generator capability constant $K$ is provided, from 1 to 99 seconds, as this constant may vary greatly with the type of generator.
- Minimum trip time delay for inverse time characteristic, freely settable. This setting assures appropriate coordination with, for example, line protections.
• Maximum trip time delay for inverse time characteristic, freely settable.
• Inverse reset characteristic which approximates generator rotor cooling rates and provides reduced operate time if an unbalance reoccurs before the protection resets.
• Service value that is, measured negative sequence current value, in primary Amperes, is available through the local HMI.

9.12.2.2 Generator continuous unbalance current capability

During unbalanced loading, negative sequence current flows in the stator winding. Negative sequence current in the stator winding will induce double frequency current in the rotor surface and cause heating in almost all parts of the generator rotor.

When the negative sequence current increases beyond the generator’s continuous unbalance current capability, the rotor temperature will increase. If the generator is not tripped, a rotor failure may occur. Therefore, industry standards has been established that determine generator continuous and short-time unbalanced current capabilities in terms of negative sequence current \( I_2 \) and rotor heating criteria \( I_2^2 t \).

Typical short-time capability (referred to as unbalanced fault capability) expressed in terms of rotor heating criterion \( I_2^2 t = K \) is shown below in Table 44.

<table>
<thead>
<tr>
<th>Types of Synchronous Machine</th>
<th>Permissible ( I_2^2 t = K [s] )</th>
</tr>
</thead>
<tbody>
<tr>
<td>Salient pole generator</td>
<td>40</td>
</tr>
<tr>
<td>Synchronous condenser</td>
<td>30</td>
</tr>
<tr>
<td>Cylindrical rotor generators:</td>
<td>Indirectly cooled</td>
</tr>
<tr>
<td></td>
<td>Directly cooled (0 – 800 MVA)</td>
</tr>
<tr>
<td></td>
<td>30</td>
</tr>
<tr>
<td></td>
<td>Directly cooled (801 – 1600 MVA)</td>
</tr>
<tr>
<td></td>
<td>10</td>
</tr>
<tr>
<td></td>
<td>Directly cooled (801 – 1600 MVA)</td>
</tr>
<tr>
<td></td>
<td>See Figure 205</td>
</tr>
</tbody>
</table>

Fig 205 shows a graphical representation of the relationship between generator \( I_2^2 t \) capability and generator MVA rating for directly cooled (conductor cooled) generators. For example, a 500 MVA generator would have \( K = 10 \) seconds and a 1600 MVA generator would have \( K = 5 \) seconds. Unbalanced short-time negative sequence current \( I_2 \) is expressed in per unit of rated generator current and time \( t \) in seconds.
Continuous \( I_2 \)-capability of generators is also covered by the standard. Table 45 below (from IEEE standard C50.13: 2014) contains the suggested capability:

<table>
<thead>
<tr>
<th>Type of generator</th>
<th>Permissible ( I_2 ) (in percent of rated generator current)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Salient Pole:</td>
<td></td>
</tr>
<tr>
<td>with damper winding</td>
<td>10</td>
</tr>
<tr>
<td>without damper winding</td>
<td>5</td>
</tr>
<tr>
<td>Cylindrical Rotor</td>
<td></td>
</tr>
<tr>
<td>Indirectly cooled</td>
<td></td>
</tr>
<tr>
<td>Directly cooled</td>
<td></td>
</tr>
<tr>
<td>to 350 MVA</td>
<td>10</td>
</tr>
<tr>
<td>351 to 1250 MVA</td>
<td>8</td>
</tr>
<tr>
<td>1251 to 1600 MVA</td>
<td>8–(MVA-350)/300</td>
</tr>
<tr>
<td>Above 1600 MVA</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td>By agreement</td>
</tr>
</tbody>
</table>

As it is described in the table above that the continuous negative sequence current capability of the generator is in range of 5% to 10% of the rated generator current. During an open conductor or open generator breaker pole condition, the negative sequence current can be in the range of 10% to 30% of the rated generator current. Other generator or system protections will not usually detect this condition and the only protection is the negative sequence overcurrent protection.

Negative sequence currents in a generator may be caused by:

- Unbalanced loads such as
  - Single phase railroad load
- Unbalanced system faults such as
• Line to ground faults
• Double line to ground faults
• Line to line faults
• Open conductors, includes
  • Broken line conductors
  • Malfunction of one pole of a circuit breaker

9.12.3 Setting guidelines

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

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

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

9.12.3.1 Operate time characteristic

Negative sequence time overcurrent protection for machines NS2PTOC (46I2) provides two operating time delay characteristics for step 1 and 2:

• Definite time delay characteristic
• Inverse time delay characteristic

The desired operate time delay characteristic is selected by setting CurveType1 as follows:

• CurveType1 = Definite
• CurveType1 = Inverse

Definite time delay\footnote{1} is independent of the magnitude of the negative sequence current once the pickup value is exceeded, while inverse time delay characteristic do depend on the magnitude of the negative sequence current.

This means that inverse time delay is long for a small overcurrent and becomes progressively shorter as the magnitude of the negative sequence current increases. Inverse time delay characteristic of the NS2PTOC (46I2) function is represented in the equation \( I_2 t = K \), where the \( K1 \) setting is adjustable over the range of 1 – 99 seconds. A typical inverse time overcurrent curve is shown in Figure 206.

\footnote{1} The definite time delay is described by the setting \( t1 \), which is the time between activation of pickup and trip outputs. 

The example in figure 206 indicates that the protection function has a set minimum trip time \( t_{\text{1Min}} \) of 5 sec. The setting \( t_{\text{1Min}} \) is freely settable and is used as a security measure. This minimum setting assures appropriate coordination with for example line protections. It is also possible to set the upper time limit, \( t_{\text{1Max}} \).

### 9.12.3.2 Pickup sensitivity

The trip pickup levels Current \( i_{2-1} > \) and \( i_{2-2} > \) of NS2PTOC (46i2) are freely settable over a range of 3 to 500 % of rated generator current \( i_{\text{Base}} \). The wide range of pickup setting is required in order to be able to protect generators of different types and sizes.

After pickup, a certain hysteresis is used before resetting pickup levels. For both steps the reset ratio is 0.97.

### 9.12.3.3 Alarm function

The alarm function is operated by PICKUP signal and used to warn the operator for an abnormal situation, for example, when generator continuous negative sequence current capability is exceeded, thereby allowing corrective action to be taken before removing the generator from service. A settable time delay \( t_{\text{Alarm}} \) is provided for the alarm function to avoid false alarms during short-time unbalanced conditions.
9.13 Accidental energizing protection for synchronous generator AEGPVOC (50AE)

9.13.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Accidental energizing protection for synchronous generator</td>
<td>AEGPVOC</td>
<td>U&lt;1&gt;</td>
<td>50AE</td>
</tr>
</tbody>
</table>

9.13.2 Application

Operating error, breaker head flashovers, control circuit malfunctions or a combination of these causes results in the generator being accidentally energized while offline. Three-phase energizing of a generator that is at standstill or on turning gears causes it to behave and accelerate similarly to an induction motor. The generator, at this point, essentially represent sub-transient reactance to the system and it can draw one to four per unit current depending upon the equivalent system impedance. This high current may thermally damage the generator in a few seconds.

Accidental energizing protection for synchronous generator AEGPVOC (50AE) monitors maximum phase current and maximum phase-to-phase voltage of the generator. In its basis it is “voltage supervised over current protection”. When generator voltage fails below preset level for longer than preset time delay an overcurrent protection stage is enabled. This overcurrent stage is intended to trip generator in case of an accidental energizing. When the generator voltage is high again this overcurrent stage is automatically disabled.

9.13.3 Setting guidelines

*IPickup*: Level of current trip level when the function is armed, that is, at generator standstill, given in % of *I*Base. This setting should be based on evaluation of the largest current that can occur during the accidental energizing: \( I_{\text{energisation}} \). This current can be calculated as:

\[
I_{\text{energisation}} = \frac{V_N}{X_d'' + X_T + Z_{\text{network}}} \left( \frac{\sqrt{3}}{3} \right)
\]

(Equation 236)

Where

- \( V_N \) is the rated voltage of the generator
- \( X_d'' \) is the subtransient reactance for the generator (Ω)
- \( X_T \) is the reactance of the step-up transformer (Ω)
- \( Z_{\text{network}} \) is the short circuit source impedance of the connected network recalculated to the generator voltage level (Ω)

The setting can be chosen:
\[ I > 0.8 \cdot I_{\text{energisation}} \]

(Equation 237)

\( t_{OC} \): Time delay for trip in case of high current detection due to accidental energizing of the generator. The default value 0.03s is recommended.

\( 27\_\text{pick\_up} \): Voltage level, given in % of \( V_{\text{Base}} \), for activation (arming) of the accidental energizing protection function. This voltage shall be lower than the lowest operation voltage. The default value 50% is recommended.

\( t_{Arm} \): Time delay of voltage under the level \( Arm< \) for activation. The time delay shall be longer than the longest fault time at short circuits or phase-ground faults in the network. The default value 5s is recommended.

\( 59\_\text{Drop\_out} \): Voltage level, given in % of \( V_{\text{Base}} \), for deactivation (dearming) of the accidental energizing protection function. This voltage shall be higher than the \( 27\_\text{pick\_up} \) level. This setting level shall also be lower than the lowest operation voltage. The default value 80% is recommended.

\( t_{Disarm} \): Time delay of voltage over the level \( 59\_\text{Drop\_out} \) for deactivation. The time delay shall be longer than \( t_{OC} \). The default value 0.5s is recommended.

### 9.14 Voltage-restrained time overcurrent protection VRPVOC (51V)

#### 9.14.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage-restrained time overcurrent protection</td>
<td>VRPVOC</td>
<td>I/&gt;!/U&lt;</td>
<td>51V</td>
</tr>
</tbody>
</table>

#### 9.14.2 Application

A breakdown of the insulation between phase conductors or a phase conductor and ground results in a short-circuit or a ground fault. Such faults can result in large fault currents and may cause severe damage to the power system primary equipment.

A typical application of the voltage-restrained time overcurrent protection is in the generator protection system, where it is used as backup protection. If a phase-to-phase fault affects a generator, the fault current amplitude is a function of time, and it depends on generator characteristic (reactances and time constants), its load conditions (immediately before the fault) and excitation system performance and characteristic. So the fault current amplitude may decay with time. A voltage-restrained overcurrent relay can be set in order to remain in the picked-up state in spite of the current decay, and perform a backup trip in case of failure of the main protection.

The IED can be provided with a voltage-restrained time overcurrent protection (VRPVOC, 51V). The VRPVOC (51V) function is always connected to three-phase current and three-phase voltage input in the configuration tool, but it will always measure the maximum phase current and the minimum phase-to-phase voltage.
VRPVOC (51V) function module has two independent protection each consisting of:

- One overcurrent step with the following built-in features:
  - Selectable definite time delay or Inverse Time IDMT characteristic
  - Voltage restrained/controlled feature is available in order to modify the pick-up level of the overcurrent stage in proportion to the magnitude of the measured voltage
- One undervoltage step with the following built-in feature:
  - Definite time delay

The undervoltage function can be enabled or disabled. Sometimes in order to obtain the desired application functionality it is necessary to provide interaction between the two protection elements within the VRPVOC (51V) function by appropriate IED configuration (for example, overcurrent protection with under-voltage seal-in). Sometimes in order to obtain the desired application functionality it is necessary to provide interaction between the two protection elements within the D2PTOC(51V) function by appropriate IED configuration (for example, overcurrent protection with under-voltage seal-in).

### 9.14.2.1 Base quantities

*GlobalBaseSel* defines the particular Global Base Values Group where the base quantities of the function are set. In that Global Base Values Group:

- *IBase* shall be entered as rated phase current of the protected object in primary amperes.
- *VBase* shall be entered as rated phase-to-phase voltage of the protected object in primary kV.

### 9.14.2.2 Application possibilities

VRPVOC (51V) function can be used in one of the following applications:

- voltage controlled over-current
- voltage restrained over-current

In both applications a seal-in of the overcurrent function at under-voltage can be included by configuration.

### 9.14.2.3 Undervoltage seal-in

In the case of a generator with a static excitation system, which receives its power from the generator terminals, the magnitude of a sustained phase short-circuit current depends on the generator terminal voltage. In case of a nearby multi-phase fault, the generator terminal voltage may drop to quite low level, for example, less than 25%, and the generator fault current may consequently fall below the pickup level of the overcurrent protection. The short-circuit current may drop below the generator rated current after 0.5...1 s. Also, for generators with an excitation system not fed from the generator terminals, a fault can occur when the automatic voltage regulator is out of service. In such cases, to ensure tripping under such conditions, overcurrent protection with undervoltage seal-in can be used.

To apply the VRPVOC(51V) function, the configuration is done according to figure 207. As seen in the figure, the pickup of the overcurrent stage will enable the undervoltage stage. Once enabled, the undervoltage stage will start a timer, which causes function tripping, if the voltage does not
recover above the set value. To ensure a proper reset, the function is blocked two seconds after the trip signal is issued.

Figure 207: Undervoltage seal-in of current pickup

9.14.3 Setting guidelines

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

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

9.14.3.1 Explanation of the setting parameters

Operation: Set to On in order to activate the function; set to Off to switch off the complete function.

Pickup_Curr: Operation phase current level given in % of IBase.

Characterist: Selection of time characteristic: Definite time delay and different types of inverse time characteristics are available; see Technical Manual for details.

tDef_OC: Definite time delay. It is used if definite time characteristic is chosen; it shall be set to 0 s if the inverse time characteristic is chosen and no additional delay shall be added. Note that the value set is the time between activation of the start and the trip outputs.

k: Time multiplier for inverse time delay.

tMin: Minimum operation time for all inverse time characteristics. At high currents the inverse time characteristic might give a very short operation time. By setting this parameter the operation time of the step can never be shorter than the setting.

Operation_UV: it sets On/Off the operation of the under-voltage stage.
**PickUp_Volt:** Operation phase-to-phase voltage level given in % of \( V_{Base} \) for the under-voltage stage. Typical setting may be, for example, in the range from 70% to 80% of the rated voltage of the generator.

**tDef_UV:** Definite time delay. Since it is related to a backup protection function, a long time delay (for example 0.5 s or more) is typically used. Note that the value set is the time between activation of the start and the trip outputs.

**EnBlkLowV:** This parameter enables the internal block of the undervoltage stage for low voltage condition; the voltage level is defined by the parameter \( BlkLowVolt \).

**BlkLowVolt:** Voltage level under which the internal blocking of the undervoltage stage is activated; it is set in % of \( V_{Base} \). This setting must be lower than the setting \( StartVolt \). The setting can be very low, for example, lower than 10%.

**VDepMode:** Selection of the characteristic of the start level of the overcurrent stage as a function of the phase-to-phase voltage; two options are available: Slope and Step. See Technical Manual for details about the characteristics.

**VDepFact:** Slope mode: it is the pickup level of the overcurrent stage given in % of \( Pickup_{Curr} \) when the voltage is lower than 25% of \( V_{Base} \), so it defines the first point of the characteristic \( (VDepFact \times Pickup_{Curr}/100 \times I_{Base}; 0.25 \times V_{Base}) \).

**Step mode:** it is the pickup level of the overcurrent stage given in % of \( Pickup_{Curr} \) when the voltage is lower than \( V_{HighLimit}/100 \times V_{Base} \).

**VHighLimit:** when the measured phase-to-phase voltage is higher than \( V_{HighLimit}/100 \times V_{Base} \), the pickup level of the overcurrent stage is \( Pickup_{Curr}/100 \times I_{Base} \). In particular, in Slope mode it define the second point of the characteristic \( (Pickup_{Curr}/100 \times I_{Base}; V_{HighLimit}/100 \times V_{Base}) \).

### 9.14.3.2 Voltage-restrained overcurrent protection for generator and step-up transformer

An example of how to use VRPVOC (51V) function to provide voltage restrained overcurrent protection for a generator is given below. Let us assume that the time coordination study gives the following required settings:

- Inverse Time Over Current IDMT curve: IEC very inverse, with multiplier \( k=1 \)
- Pickup current of 185% of generator rated current at rated generator voltage
- Pickup current 25% of the original pickup current value for generator voltages below 25% of rated voltage

To ensure proper operation of the function:

1. Set **Operation** to **Enabled**
2. Set **GlobalBaseSel** to the right value in order to select the Global Base Values Group with \( V_{Base} \) and \( I_{Base} \) equal to the rated phase-to-phase voltage and the rated phase current of the generator.
3. Connect three-phase generator currents and voltages to VRPVOC (51V) in the application configuration.
4. Select **Characterist** to match the type of overcurrent curves used in the network \( IEC \) Very inv.
5. Set the multiplier \( k=1 \) (default value).
6. Set \( t_{Def_{OC}} = 0.00 \) s, in order to add no additional delay to the trip time defined by the inverse time characteristic.
7. If required, set the minimum operating time for this curve by using the parameter \( t_{\text{MinTripDelay}} \) (default value 0.05 s).
8. Set \( \text{PickupCurr} \) to the value 185%.
9. Set \( \text{VDepMode} \) to \( \text{Slope} \) (default value).
10. Set \( \text{VDepFact} \) to the value 25% (default value).
11. Set \( \text{VHighLimit} \) to the value 100% (default value).

All other settings can be left at the default values.

### 9.14.3.3 General settings

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

Common base IED values for primary current (\( I_{\text{Base}} \)), primary voltage (\( V_{\text{Base}} \)) and primary power (\( S_{\text{Base}} \)) are set in Global base values for settings function GBASVAL. Setting **GlobalBaseSel** is used to select a GBASVAL function for reference of base values.

**\( I_{\text{Base}} \):** The parameter \( I_{\text{Base}} \) is set to the generator rated current according to equation 238.

\[
I_{\text{Base}} = \frac{S_N}{\sqrt{3} \cdot U_N}
\]

(Equation 238)

\[
I_{\text{Base}} = \frac{S_N}{\sqrt{3} \cdot V_N}
\]

(Equation 238)

**\( V_{\text{Base}} \):** The parameter \( V_{\text{Base}} \) is set to the generator rated Voltage (phase-phase) in kV.

### 9.14.3.4 Overcurrent protection with undervoltage seal-in

To obtain this functionality, the IED application configuration shall include a logic in accordance to figure 207 and, of course, the relevant three-phase generator currents and voltages shall be connected to VRPVOC. Let us assume that, taking into account the characteristic of the generator, the excitation system and the short circuit study, the following settings are required:

- Pickup current of the overcurrent stage: 150% of generator rated current at rated generator voltage;
- Pickup voltage of the undervoltage stage: 70% of generator rated voltage;
- Trip time: 3.0 s.

The overcurrent stage and the undervoltage stage shall be set in the following way:

1. Set **Operation** to **Enabled**.
2. Set **GlobalBaseSel** to the right value in order to select the Global Base Values Group with \( V_{\text{Base}} \) and \( I_{\text{Base}} \) equal to the rated phase-to-phase voltage and the rated phase current of the generator.
3. Set **StartCurr** to the value 150%.
4. Set **Characteristic** to **IEC Def. Time**.
5. Set **tDef_OC** to 6000.00 s, if no trip of the overcurrent stage is required.
6. Set \( V\text{DepFact} \) to the value 100\% in order to ensure that the pickup value of the overcurrent stage is constant, irrespective of the magnitude of the generator voltage.

7. Set \( \text{Operation\_UV} \) to \text{Enabled} to activate the undervoltage stage.

8. Set \( \text{StartVolt} \) to the values 70\%.

9. Set \( t\text{Def\_UV} \) to 3.0\ s.

10. Set \( \text{EnBlkLowV} \) to \text{Disabled} (default value) to disable the cut-off level for low-voltage of the undervoltage stage.

The other parameters may be left at their default value.

9.15 Generator stator overload protection GSPTTR (49S)

9.15.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator stator overload protection</td>
<td>GSPTTR</td>
<td></td>
<td>49S</td>
</tr>
</tbody>
</table>

9.15.2 Application

Overload protection for stator, GSPTTR(49S).

The overload protection GSPTTR(49S) is intended to prevent thermal damage. A generator may suffer thermal damage as a result of overloads. Damage is the result when one or more internal generator components exceeds its design temperature limit. Damage to generator insulation can range from minor loss of life to complete failure, depending on the severity and duration of the temperature excursion. Excess temperature can also cause mechanical damage due to thermal expansion. Temperature rise with in a generator for these conditions is primarily a function of \( I^2R \) copper losses. Because temperature increases with current, it is logical to apply overcurrent elements with inverse time-current characteristics. The generator overcurrent applications are complicated by the complexity of generator thermal characteristics and the time-varying nature of current experienced during starting and when the generator drives a time-varying load.

The generator stator overload function GSPTTR(49S) protects stator windings against excessive temperature rise as result of overcurrents.

9.16 Generator rotor overload protection GRPTTR (49R)
9.16.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator rotor overload protection</td>
<td>GRPTTR</td>
<td>$\Phi&lt;1$</td>
<td>49R</td>
</tr>
</tbody>
</table>

9.16.2 Application

The overload GRPTTR (49R) protection is intended to prevent thermal damage. A generator may suffer thermal damage as a result of overloads. Damage is the result when one or more internal generator components exceeds its design temperature limit. Damage to generator insulation can range from minor loss of life to complete failure, depending on the severity and duration of the temperature excursion. Excess temperature can also cause mechanical damage due to thermal expansion. Rotor components such as bars and end rings are vulnerable to this damage. Temperature rise within a generator for these conditions is primarily a function of $I^2R$ copper losses. Because temperature increases with current, it is logical to apply overcurrent elements with inverse time-current characteristics. The generator overcurrent applications are complicated by the complexity of generator thermal characteristics and the time-varying nature of current experienced during starting and when the generator drives a time-varying load.

The generator rotor overload function GRPTTR (49R) protects rotor windings against excessive temperature rise as result of overcurrents.

9.16.3 Setting guideline

Two setting examples will be given for two applications as shown in Figure 208.
Figure 208: Two application examples

First example (shown in a) is for a 100MVA machine and the second example (shown in b) is for a 315MVA machine.

It is important to know which CT (that is, on HV or LV side of the excitation transformer) is used. Make sure that appropriate CT ratio (for example, 100/1 or 1000/5) is set on these three analogue inputs.

All settings will be given in a table format for both applications.

Table 46: 100MVA machine application when LV side 1000/5 CT is used

<table>
<thead>
<tr>
<th>Parameter name</th>
<th>Selected value</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>MeasurCurrent</td>
<td>DC</td>
<td>In order to measure directly rotor winding DC current</td>
</tr>
<tr>
<td>iBase</td>
<td>810</td>
<td>Rated current of the field winding (i.e. field current required to produce rated output from the stator)</td>
</tr>
<tr>
<td>CT_Location</td>
<td>LV_winding</td>
<td>LV side 1000/5 CT used for measurement</td>
</tr>
<tr>
<td>VrLV</td>
<td>400.0</td>
<td>Rated LV side AC voltage (in Volts)</td>
</tr>
<tr>
<td>VrHV</td>
<td>18.00</td>
<td>Rated HV side AC voltage in kV</td>
</tr>
<tr>
<td>PhAngleShift</td>
<td>150</td>
<td>5°*30= 150 degree, this provides 150 degrees clock-wise phase angle shift across the excitation transformer</td>
</tr>
</tbody>
</table>
Note that last three parameters from the table above have no direct influence on function operation (that is, LV side CT is used) but are anyhow set to the correct values.

Table 47: 315MVA machine application when HV side 100/5 CT is used

<table>
<thead>
<tr>
<th>Parameter name</th>
<th>Selected value</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>MeasurCurrent</td>
<td>DC</td>
<td>In order to measure directly rotor winding DC current</td>
</tr>
<tr>
<td>IBase</td>
<td>1520</td>
<td>Rated current of the field winding (i.e. field current required to produce rated output from the stator)</td>
</tr>
<tr>
<td>CT_Location</td>
<td>HV_winding</td>
<td>HV side 100/5 CT used for measurement</td>
</tr>
<tr>
<td>VrLV</td>
<td>550.0</td>
<td>Rated LV side AC voltage (in Volts)</td>
</tr>
<tr>
<td>VrHV</td>
<td>11.00</td>
<td>Rated HV side AC voltage in kV</td>
</tr>
<tr>
<td>PhAngleShift</td>
<td>-30</td>
<td>11*30-360=-30 degree, this provides 30 degrees anti-clock-wise phase angle shift across the excitation transformer</td>
</tr>
</tbody>
</table>

Note that last three parameters from the table above must be properly set in order to have proper operation of the rotor overload function.

The rest of the parameters can be set with the default values, if the generator is fabricated according to IEEE-C50.13. The parameters have to be changed according to the specifications, if different standards are applicable.

The parameters for the Generator rotor overload protection GRPTTR (49R) are set via the local HMI or PCM600.
Section 10  Voltage protection

10.1  Two step undervoltage protection UV2PTUV (27)

10.1.1  Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Two step undervoltage protection</td>
<td>UV2PTUV</td>
<td></td>
<td>3U&lt;</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>27</td>
</tr>
</tbody>
</table>

10.1.2  Application

Two-step undervoltage protection function (UV2PTUV,27) is applied to power system elements, such as generators, transformers, motors and power lines in order to detect low voltage conditions. It is used as a supervision and fault detection function for other protection functions as well, to increase the security of a complete protection system. Low voltage conditions are caused by abnormal operation or faults in the power system, such as:

- Malfunctioning of a voltage regulator or wrong settings under manual control (symmetrical voltage decrease)
- Overload (symmetrical voltage decrease)
- Short circuits, often as phase-to-ground faults (unsymmetrical voltage decrease)

UV2PTUV (27) is used in combination with overcurrent protections, either as restraint or in logic "and gates" of the trip signals issued by the two functions. It can also be used to:

- Detect no voltage conditions, for example, before the energization of a HV line or for automatic breaker trip in case of a blackout
- Initiate voltage correction measures, like insertion of shunt capacitor banks to compensate for reactive load and thereby increasing the voltage
- Disconnect apparatuses, like electric motors, which will be damaged when subject to service under low voltage conditions.

The function has a high measuring accuracy and a settable hysteresis to allow applications to control reactive load.

In many cases, UV2PTUV (27) is a useful function in circuits for local or remote automation processes in the power system.
10.1.3 Setting guidelines

All the voltage conditions in the system where UV2PTUV (27) performs its functions should be considered. The same also applies to the associated equipment, its voltage and time characteristic.

There is a very wide application area where general undervoltage functions are used. All voltage-related settings are made as a percentage of the global base value $V_{\text{Base}}$, which normally is set to the primary rated voltage level (phase-to-phase) of the power system or the high voltage equipment under consideration.

The trip time setting for UV2PTUV (27) is normally not critical, since there must be enough time available for the main protection to clear short circuits and ground faults.

Some applications and related setting guidelines for the voltage level are described in the following sections.

10.1.3.1 Equipment protection, such as for motors and generators

The setting must be below the lowest occurring “normal” voltage and above the lowest acceptable voltage for the equipment.

10.1.3.2 Disconnected equipment detection

The setting must be below the lowest occurring “normal” voltage and above the highest occurring voltage, caused by inductive or capacitive coupling, when the equipment is disconnected.

10.1.3.3 Power supply quality

The setting must be below the lowest occurring “normal” voltage and above the lowest acceptable voltage, due to regulation, good practice or other agreements.

10.1.3.4 Voltage instability mitigation

This setting is very much dependent on the power system characteristics, and thorough studies have to be made to find the suitable levels.

10.1.3.5 Backup protection for power system faults

The setting must be below the lowest occurring “normal” voltage and above the highest occurring voltage during the fault conditions under consideration.

10.1.3.6 Settings for two step undervoltage protection

The following settings can be done for Two step undervoltage protection UV2PTUV (27):

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

- **Operation**: Disabled or Enabled.
**VBase** (given in **GlobalBaseSel**): Base voltage phase-to-phase in primary kV. This voltage is used as reference for voltage setting. UV2PTUV (27) will operate if the voltage becomes lower than the set percentage of \( V_{Base} \). This setting is used when **ConnType** is set to *PhPh DFT* or *PhPh RMS*. Therefore, always set \( V_{Base} \) as rated primary phase-to-phase voltage of the protected object. For more information, refer to the Technical manual.

The setting parameters described below are identical for the two steps (\( n = 1 \) or 2). Therefore, the setting parameters are described only once.

**Characteristic**: This parameter gives the type of time delay to be used. The setting can be *Definite time, Inverse Curve A, Inverse Curve B, Prog. inv. curve*. The selection is dependent on the protection application.

**OpMode**: This parameter describes how many of the three measured voltages should be below the set level to give operation for step \( n \). The setting can be *1 out of 3, 2 out of 3 or 3 out of 3*. In most applications, it is sufficient that one phase voltage is low to give operation. If UV2PTUV (27) shall be insensitive for single phase-to-ground faults, *2 out of 3* can be chosen. In subtransmission and transmission networks the undervoltage function is mainly a system supervision function and *3 out of 3* is selected.

**Pickup**: Set pickup undervoltage operation value for step \( n \), given as % of the parameter \( V_{Base} \). The setting is highly dependent on the protection application. It is essential to consider the minimum voltage at non-faulted situations. Normally, this non-faulted voltage is larger than 90% of the nominal voltage.

**\( t_n \)**: time delay of step \( n \), given in s. This setting is dependent on the protection application. In many applications the protection function shall not directly trip when there is a short circuit or ground faults in the system. The time delay must be coordinated to the other short circuit protections.

**\( t_{Reset_n} \)**: Reset time for step \( n \) if definite time delay is used, given in s. The default value is 25 ms.

**\( t_{nMin} \)**: Minimum operation time for inverse time characteristic for step \( n \), given in s. When using inverse time characteristic for the undervoltage function during very low voltages can give a short operation time. This might lead to unselective tripping. By setting \( t_{nMin} \) longer than the operation time for other protections, such unselective tripping can be avoided.

**ResetTypeCrvn**: This parameter for inverse time characteristic can be set to *Instantaneous, Frozen time, Linearly decreased*. The default setting is *Instantaneous*.

**\( t_{IReset_n} \)**: Reset time for step \( n \) if inverse time delay is used, given in s. The default value is 25 ms.

**\( T_{Dn} \)**: Time multiplier for inverse time characteristic. This parameter is used for coordination between different inverse time delayed undervoltage protections.

**ACrvn, BCrvn, CCrvn, DCrvn, PCrvn**: Parameters to create a programmable under voltage inverse time characteristic. Description of this can be found in the Technical manual.

**CrvSatn**: Tuning parameter that is used to compensate for the undesired discontinuity created when the denominator in the equation for the customer programmable curve is equal to zero. For more information, see the Technical manual.

**IntBlkSel**: This parameter can be set to *Disabled, Block of trip, Block all*. In case of a low voltage the undervoltage function can be blocked. This function can be used to prevent function when the protected object is switched off. If the parameter is set *Block of trip or Block all* unwanted trip is prevented.
\textit{IntBlkStValn}. Voltage level under which the blocking is activated set in \% of \textit{VBase}. This setting must be lower than the setting \textit{Pickupn}. As switch of shall be detected the setting can be very low, that is, about 10\%.

\textit{tBlkUVn}. Time delay to block the undervoltage step \( n \) when the voltage level is below \textit{IntBlkStValn}, given in s. It is important that this delay is shorter than the trip time delay of the undervoltage protection step.

### 10.2 Two step overvoltage protection OV2PTOV (59)

#### 10.2.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Two step overvoltage protection</td>
<td>OV2PTOV</td>
<td></td>
<td>59</td>
</tr>
</tbody>
</table>

#### 10.2.2 Application

Two step overvoltage protection OV2PTOV (59) is applicable in all situations, where reliable detection of high voltage is necessary. OV2PTOV (59) is used for supervision and detection of abnormal conditions, which, in combination with other protection functions, increase the security of a complete protection system.

High overvoltage conditions are caused by abnormal situations in the power system. OV2PTOV (59) is applied to power system elements, such as generators, transformers, motors and power lines in order to detect high voltage conditions. OV2PTOV (59) is used in combination with low current signals, to identify a transmission line, open in the remote end. In addition to that, OV2PTOV (59) is also used to initiate voltage correction measures, like insertion of shunt reactors, to compensate for low load, and thereby decreasing the voltage. The function has a high measuring accuracy and hysteresis setting to allow applications to control reactive load.

OV2PTOV (59) is used to disconnect apparatuses, like electric motors, which will be damaged when subject to service under high voltage conditions. It deals with high voltage conditions at power system frequency, which can be caused by:

1. Different kinds of faults, where a too high voltage appears in a certain power system, like metallic connection to a higher voltage level (broken conductor falling down to a crossing overhead line, transformer flash over fault from the high voltage winding to the low voltage winding and so on).
2. Malfunctioning of a voltage regulator or wrong settings under manual control (symmetrical voltage decrease).
3. Low load compared to the reactive power generation (symmetrical voltage decrease).
4. Ground-faults in high impedance grounded systems causes, beside the high voltage in the neutral, high voltages in the two non-faulted phases, (unsymmetrical voltage increase).
OV2PTOV (59) prevents sensitive equipment from running under conditions that could cause their overheating or stress of insulation material, and, thus, shorten their life time expectancy. In many cases, it is a useful function in circuits for local or remote automation processes in the power system.

10.2.3 Setting guidelines

The parameters for Two step overvoltage protection (OV2PTOV) are set via the local HMI or PCM600.

All the voltage conditions in the system where OV2PTOV (59) performs its functions should be considered. The same also applies to the associated equipment, its voltage and time characteristic.

There are wide applications where general overvoltage functions are used. All voltage related settings are made as a percentage of a settable base primary voltage, which is normally set to the nominal voltage level (phase-to-phase) of the power system or the high voltage equipment under consideration.

The time delay for the OV2PTOV (59) can sometimes be critical and related to the size of the overvoltage - a power system or a high voltage component can withstand smaller overvoltages for some time, but in case of large overvoltages the related equipment should be disconnected more rapidly.

Some applications and related setting guidelines for the voltage level are given below:

The hysteresis is for overvoltage functions very important to prevent that a transient voltage over set level is not “sealed-in” due to a high hysteresis. Typical values should be ≤ 0.5%.

10.2.3.1 Equipment protection, such as for motors, generators, reactors and transformers

High voltage will cause overexcitation of the core and deteriorate the winding insulation. The setting has to be well above the highest occurring "normal" voltage and well below the highest acceptable voltage for the equipment.

10.2.3.2 Equipment protection, capacitors

High voltage will deteriorate the dielectricum and the insulation. The setting has to be well above the highest occurring "normal" voltage and well below the highest acceptable voltage for the capacitor.

10.2.3.3 Power supply quality

The setting has to be well above the highest occurring "normal" voltage and below the highest acceptable voltage, due to regulation, good practice or other agreements.

10.2.3.4 High impedance grounded systems

In high impedance grounded systems, ground-faults cause a voltage increase in the non-faulty phases. Two step overvoltage protection (OV2PTOV, 59) is used to detect such faults. The setting must be above the highest occurring "normal" voltage and below the lowest occurring voltage
during faults. A metallic single-phase ground-fault causes the non-faulted phase voltages to increase a factor of \(\sqrt{3}\).

### 10.2.3.5 The following settings can be done for the two step overvoltage protection

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

**Operation:** Disabled/Enabled.

**VBase** (given in GlobalBaseSel): Base voltage phase to phase in primary kV. This voltage is used as reference for voltage setting. OV2PTOV (59) measures selectively phase-to-ground voltages, or phase-to-phase voltage chosen by the setting ConnType. The function will operate if the voltage gets lower than the set percentage of VBase. When ConnType is set to PhN DFT or PhN RMS then the IED automatically divides set value for VBase by \(\sqrt{3}\). When ConnType is set to PhPh DFT or PhPh RMS then set value for VBase is used. Therefore, always set VBase as rated primary phase-to-phase ground voltage of the protected object. If phase to neutral (PhN) measurement is selected as setting, the operation of phase-to-ground over voltage is automatically divided by sqrt3. This means operation for phase-to-ground voltage over:

\[
V > (\%) \cdot \frac{V_{Base}(kV)}{\sqrt{3}}
\]

(Equation 239)

and operation for phase-to-phase voltage over:

\[
V_{\text{pickup}} > (\%) \cdot V_{Base}(kV)
\]

(Equation 240)

The below described setting parameters are identical for the two steps \((n = 1 \text{ or } 2)\). Therefore the setting parameters are described only once.

**Characteristic**: This parameter gives the type of time delay to be used. The setting can be Definite time, Inverse Curve A, Inverse Curve B, Inverse Curve C or I/Prog. inv. curve. The choice is highly dependent of the protection application.

**OpModen**: This parameter describes how many of the three measured voltages that should be above the set level to give operation. The setting can be 1 out of 3, 2 out of 3, 3 out of 3. In most applications it is sufficient that one phase voltage is high to give operation. If the function shall be insensitive for single phase-to-ground faults 1 out of 3 can be chosen, because the voltage will normally rise in the non-faulted phases at single phase-to-ground faults. In subtransmission and transmission networks the UV function is mainly a system supervision function and 3 out of 3 is selected.

**Pickupn**: Set pickup overvoltage operation value for step \(n\), given as % of VBase. The setting is highly dependent of the protection application. Here it is essential to consider the maximum voltage at non-faulted situations. Normally this voltage is less than 110% of nominal voltage.

**tn**: time delay of step \(n\), given in s. The setting is highly dependent of the protection application. In many applications the protection function is used to prevent damages to the protected object. The speed might be important for example in case of protection of transformer that might be overexcited. The time delay must be co-ordinated with other automated actions in the system.

**tResetn**: Reset time for step \(n\) if definite time delay is used, given in s. The default value is 25 ms.
**tnMin**: Minimum operation time for inverse time characteristic for step \( n \), given in s. For very high voltages the overvoltage function, using inverse time characteristic, can give very short operation time. This might lead to unselective trip. By setting \( t1\text{Min} \) longer than the operation time for other protections such unselective tripping can be avoided.

**ResetTypeCrvn**: This parameter for inverse time characteristic can be set: *Instantaneous, Frozen time, Linearly decreased*. The default setting is *Instantaneous*.

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

**TDn**: Time multiplier for inverse time characteristic. This parameter is used for co-ordination between different inverse time delayed undervoltage protections.

**ACrvn, BCrvn, CCrvn, DCrvn, PCrvn**: Parameters to set to create programmable under voltage inverse time characteristic. Description of this can be found in the technical reference manual.

**CrvSatn**: When the denominator in the expression of the programmable curve is equal to zero the time delay will be infinity. There will be an undesired discontinuity. Therefore a tuning parameter \( \text{CrvSatn} \) is set to compensate for this phenomenon. In the voltage interval \( \text{Pickup} \cdot (1.0 + \text{CrvSatn}/100) \) the used voltage will be: \( \text{Pickup} \cdot (1.0 + \text{CrvSatn}/100) \). If the programmable curve is used, this parameter must be calculated so that:

\[
B \cdot \frac{\text{CrvSatn}}{100} - C > 0
\]

(Equation 241)

**HystAbsn**: Absolute hysteresis set in % of \( V\text{Base} \). The setting of this parameter is highly dependent of the application. If the function is used as control for automatic switching of reactive compensation devices the hysteresis must be set smaller than the voltage change after switching of the compensation device.

### 10.3 Two step residual overvoltage protection ROV2PTOV (59N)

#### 10.3.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Two step residual overvoltage protection</td>
<td>ROV2PTOV</td>
<td></td>
<td>59N</td>
</tr>
</tbody>
</table>

Two step residual overvoltage protection ROV2PTOV (59N) is primarily used in high impedance grounded distribution networks, mainly as a backup for the primary ground fault protection of the feeders and the transformer. To increase the security for different ground fault related functions, the residual overvoltage signal can be used as a release signal. The residual voltage can be
measured either at the transformer neutral or from a voltage transformer open delta connection. The residual voltage can also be calculated internally, based on the measurement of the three phase-to-ground voltages.

In high impedance grounded systems the residual voltage will increase in case of any fault connected to ground. Depending on the type of fault and fault resistance the residual voltage will reach different values. The highest residual voltage, equal to three times the phase-to-ground voltage, is achieved for a single phase-to-ground fault. The residual voltage increases approximately to the same level in the whole system and does not provide any guidance in finding the faulted component. Therefore, ROV2PTOV (59N) is often used as a backup protection or as a release signal for the feeder ground fault protection.

10.3.3 Setting guidelines

All the voltage conditions in the system where ROV2PTOV (59N) performs its functions should be considered. The same also applies to the associated equipment, its voltage withstand capability and time characteristic.

All voltage-related settings are made as a percentage of a settable base voltage, which shall be set to the primary nominal voltage (phase-phase) level of the power system or the high-voltage equipment under consideration.

The time delay for ROV2PTOV (59N) is seldom critical, since residual voltage is related to ground faults in a high-impedance grounded system, and enough time must normally be given for the primary protection to clear the fault. In some more specific situations, where the residual overvoltage protection is used to protect some specific equipment, the time delay is shorter.

Some applications and related setting guidelines for the residual voltage level are given below.

10.3.3.1 Equipment protection, such as for motors, generators, reactors and transformers

Equipment protection for transformers

High residual voltage indicates ground fault in the system, perhaps in the component to which two step residual overvoltage protection (ROV2PTOV, 59N) is connected. For selectivity reasons to the primary protection for the faulted device, ROV2PTOV (59N) must trip the component with some time delay. The setting must be above the highest occurring "normal" residual voltage and below the highest acceptable residual voltage for the equipment.

10.3.3.2 Equipment protection, capacitors

High voltage will deteriorate the dielectric and the insulation. Two step residual overvoltage protection (ROV2PTOV, 59N) has to be connected to a neutral or open delta winding. The setting must be above the highest occurring "normal" residual voltage and below the highest acceptable residual voltage for the capacitor.

10.3.3.3 Stator ground-fault protection based on residual voltage measurement

Accidental contact between the stator winding in the slots and the stator core is the most common electrical fault in generators. The fault is normally initiated by mechanical or thermal damage to the insulating material or the anti-corona paint on a stator coil. Turn-to-turn faults, which normally are difficult to detect, quickly develop into an ground fault and are tripped by the stator ground-fault protection. Common practice in most countries is to ground the generator
neutral through a resistor, which limits the maximum ground-fault current to 5-10 A primary. Tuned reactors, which limits the ground-fault current to less than 1 A, are also used. In both cases, the transient voltages in the stator system during intermittent ground-faults are kept within acceptable limits, and ground-faults, which are tripped within a second from fault inception, only cause negligible damage to the laminations of the stator core.

A residual overvoltage function used for such protection can be connected to different voltage transformers.

1. voltage (or distribution) transformer connected between the generator neutral point and ground.
2. three-phase-to-ground-connected voltage transformers on the generator HV terminal side (in this case the residual voltage is internally calculated by the IED).
3. broken delta winding of three-phase-to-ground voltage transformers connected on the generator HV terminal side.

These three connection options are shown in Figure 209. Depending on pickup setting and fault resistance, such function can typically protect 80-95 percent of the stator winding. Thus, the function is normally set to operate for faults located at 5 percent or more from the stator neutral point with a time delay setting of 0.5 seconds. Thus such function protects approximately 95 percent of the stator winding. The function also covers the generator bus, the low-voltage winding of the unit transformer and the high-voltage winding of the auxiliary transformer of the unit. The function can be set so low because the generator-grounding resistor normally limits the neutral voltage transmitted from the high-voltage side of the unit transformer in case of an ground fault on the high-voltage side to a maximum of 2-3 percent.

Units with a generator breaker between the transformer and the generator should also have a three-phase voltage transformer connected to the bus between the low-voltage winding of the unit transformer and the generator circuit breaker (function 3 in Figure 209). The open delta secondary VT winding is connected to a residual overvoltage function, normally set to 20-30 percent, which provides ground-fault protection for the transformer low-voltage winding and the section of the bus connected to it when the generator breaker is open.

The two-stage residual overvoltage function ROV2PTOV (59N) can be used for all three applications. The residual overvoltage function measures and operates only on the fundamental frequency voltage component. It has an excellent rejection of the third harmonic voltage component commonly present in such generator installations.
Figure 209: Voltage-based stator ground-fault protection

**ROV2PTOV (59N) application #1**

ROV2PTOV (59N) is here connected to a voltage (or distribution) transformer located at generator star point.

1. Due to such connection, ROV2PTOV (59N) measures the Uo voltage at the generator star point. Due to such connection, ROV2PTOV (59N) measures the Vo voltage at the generator star point. The maximum Vo voltage is present for a single phase-to-ground fault at the generator HV terminal and it has the maximum primary value:
2. One VT input is to be used in the IED. The VT ratio should be set according to the neutral point transformer ratio. For this application, the correct primary and secondary rating values are 6.35 kV and 110 V respectively.
3. For the base value, a generator-rated phase-to-phase voltage is to be set. Thus for this application \( V_{\text{Base}} = 11 \text{ kV} \).
4. ROV2PTOV (59N) divides internally the set voltage base value with \( \sqrt{3} \). Thus, the internally used base is equal to the maximum \( V_o \) value. Therefore, if wanted pickup is 5 percent from the neutral point, the ROV2PTOV (59N) pickup value is set to \( \text{Pickup1} \geq 5\% \).
5. The definite time delay is set to 0.5 seconds.

**ROV2PTOV (59N) application #2**

ROV2PTOV (59N) is here connected to a three-phase voltage transformer set located at generator HV terminal side.

1. Due to such connection, ROV2PTOV (59N) function calculates internally the 3\( V_o \) voltage (that is, \( 3V_o = V_A + V_B + V_C \)) at the HV terminals of the generator. Maximum 3\( V_o \) voltage is present for a single phase-to-ground fault at the HV terminal of the generator and it has the maximum primary value \( 3V_{o,\text{Max}} \):

\[
3V_{o,\text{Max}} = \sqrt{3} \cdot V_{o,\text{Max}} = \sqrt{3} \cdot 11 \text{ kV} = 19.05 \text{ kV}
\]  
(Equation 243)
2. Three VT inputs are to be used in the IED. The VT ratio should be set according to the VT ratio. For this application, the correct primary and secondary VT rating values are 11 kV and 110 V respectively.
3. For the base value, a generator-rated phase-to-phase voltage is to be set. Thus for this application \( V_{\text{Base}} = 11 \text{ kV} \). This base voltage value is not set directly under the function but it is instead selected by the Global Base Value parameter.
4. ROV2PTOV (59N) divides internally the set voltage base value with \( \sqrt{3} \). Thus internally used base voltage value is 6.35 kV. This is three times smaller than the maximum 3\( V_o \) voltage. Therefore, if the wanted start is 5 percent from the neutral point the ROV2PTOV (59N) pickup value is set to \( \text{Pickup1} = 3 \cdot 5\% = 15\% \)(that is, three times the desired coverage).
5. The definite time delay is set to 0.5 seconds.

**ROV2PTOV (59N) application #3**

ROV2PTOV (59N) is here connected to an open delta winding of the VT located at the HV terminal side of the generator or the LV side of the unit transformer.

1. Due to such connection, ROV2PTOV (59N) measures the 3\( V_o \) voltage at generator HV terminals. Maximum 3\( V_o \) voltage is present for a single phase-to-ground fault at the HV terminal of the generator and it has the primary maximum value \( 3V_{o,\text{Max}} \):

\[
V_o = \frac{V_{\text{Max}}}{\sqrt{3}} = \frac{11 \text{ kV}}{\sqrt{3}} = 6.35 \text{ kV}
\]  
(Equation 242)
2. One VT input is to be used in the IED. The VT ratio is to be set according to the open delta winding ratio. For this application correct primary and secondary rating values are 19.05 kV and 110 V respectively.

3. For the base value, a generator-rated phase-to-phase voltage is to be set. Thus for this application $V_{\text{Base}} = 11\,\text{kV}$. This base voltage value is not set directly under the function but it is instead selected by the Global Base Value parameter.

4. ROV2PTOV (59N) internally divides the set voltage base value with $\sqrt{3}$. Thus, the internally used base voltage value is 6.35 kV. This is three times smaller than maximum $3U_0$ voltage. Therefore, if the wanted pickup is 5 percent from the neutral point the ROV2PTOV (59N) pickup value is set to $\text{Pickup}_1 = 3\cdot 5\% = 15\%$ (that is, three times the desired coverage).

5. The definite time delay is set to 0.5 seconds.

### 10.3.3.4 Power supply quality

The setting must be above the highest occurring "normal" residual voltage and below the highest acceptable residual voltage, due to regulation, good practice or other agreements.

### 10.3.3.5 High impedance grounded systems

In high impedance grounded systems, ground faults cause a neutral voltage in the feeding transformer neutral. Two step residual overvoltage protection ROV2PTOV (59N) is used to trip the transformer, as a backup protection for the feeder ground fault protection, and as a backup for the transformer primary ground fault protection. The setting must be above the highest occurring "normal" residual voltage, and below the lowest occurring residual voltage during the faults under consideration. A metallic single-phase ground fault causes a transformer neutral to reach a voltage equal to the nominal phase-to-ground voltage.

The voltage transformers measuring the phase-to-ground voltages measure zero voltage in the faulty phase. The two healthy phases will measure full phase-to-phase voltage, as the faulty phase will be connected to ground. The residual overvoltage will be three times the phase-to-ground voltage. See figure 210.
### 10.3.3.6 Direct grounded system

In direct grounded systems, a ground fault on one phase is indicated by voltage collapse in that phase. The other healthy phase will still have normal phase-to-ground voltage. The residual sum will have the same value as the remaining phase-to-ground voltage, which is shown in Figure 211.

### 10.3.3.7 Settings for two step residual overvoltage protection

*Operation: Disabled or Enabled*
*VBase* (given in *GlobalBaseSel*) is used as voltage reference for the set pickup values. The voltage can be fed to the IED in different ways:

1. The IED is fed from a normal voltage transformer group where the residual voltage is calculated internally from the phase-to-ground voltages within the protection. The setting of the analogue input is given as \( V_{\text{Base}} = V_{\text{ph-ph}} \).
2. The IED is fed from a broken delta connection normal voltage transformer group. In an open delta connection the protection is fed by the voltage \( 3V_0 \) (single input). Section *Analog inputs* in the Application manual explains how the analog input needs to be set.
3. The IED is fed from a single voltage transformer connected to the neutral point of a power transformer in the power system. In this connection the protection is fed by the voltage \( V_N = V_0 \) (single input). Section *Analog inputs* in the Application manual explains how the analog input needs to be set.

ROV2PTOV (59N) will measure the residual voltage corresponding to the nominal phase-to-ground voltage for a high-impedance grounded system. The measurement will be based on the neutral voltage displacement.

The setting parameters described below are identical for the two steps \((n = \text{step 1 and 2})\). Therefore the setting parameters are described only once.

*OperationStep* \( n \): This is to enable/disable operation of step \( n \).

*Characteristic* \( n \): Selected inverse time characteristic for step \( n \). This parameter gives the type of time delay to be used. The setting can be, *Definite time* or *Inverse curve A* or *Inverse curve B* or *Inverse curve C* or *Prog. inv. curve*. The choice is highly dependent of the protection application.

*Pickup* \( n \): Set operate overvoltage operation value for step \( n \), given as % of residual voltage corresponding to *VBase*:

\[
V > \left(\%\right) \cdot V_{\text{Base}} (kV) / \sqrt{3}
\]

(Equation 245)

The setting depends on the required sensitivity of the protection and the type of system grounding. In non-effectively grounded systems, the residual voltage cannot be higher than three times the rated phase-to-ground voltage, which should correspond to 100%.

In effectively grounded systems, this value depends on the ratio \( Z_0/Z_1 \). The required setting to detect high resistive ground faults must be based on network calculations.

*\( t_n \)*: time delay of step \( n \), given in s. The setting is highly dependent on the protection application. In many applications, the protection function has the task to prevent damage to the protected object. The speed might be important, for example, in the case of the protection of a transformer that might be overexcited. The time delay must be co-ordinated with other automated actions in the system.

*\( t_{\text{Reset}} n \)*: Reset time for step \( n \) if definite time delay is used, given in s. The default value is 25 ms.

*\( t_{\text{Min}} n \)*: Minimum operation time for inverse time characteristic for step \( n \), given in s. For very high voltages the overvoltage function, using inverse time characteristic, can give very short operation time. This might lead to unselective trip. By setting \( t_{\text{Min}} n \) longer than the operation time for other protections such unselective tripping can be avoided.

*ResetTypeCrv* \( n \): Set reset type curve for step \( n \). This parameter can be set: *Instantaneous*, *Frozen time*, *Linearly decreased*. The default setting is *Instantaneous*. 
**tiResetn**: Reset time for step \( n \) if inverse time delay is used, given in s. The default value is 25 ms.

**TDn**: Time multiplier for inverse time characteristic. This parameter is used for co-ordination between different inverse time delayed undervoltage protections.

**ACrvn, BCrvn, CCrvn, DCrvn, PCrvn**: Parameters for step \( n \), to set to create programmable undervoltage inverse time characteristic. Description of this can be found in the technical reference manual.

**CrvSatn**: Set tuning parameter for step \( n \). When the denominator in the expression of the programmable curve is equal to zero, the time delay will be infinite. There will be an undesired discontinuity. Therefore, a tuning parameter \( CrvSatn \) is set to compensate for this phenomenon. In the voltage interval \( Pickup > \) up to \( Pickup > \cdot (1.0 + CrvSatn/100) \) the used voltage will be: \( Pickup > \cdot (1.0 + CrvSatn/100) \). If the programmable curve is used this parameter must be calculated so that:

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

(Equation 246)

**HystAbsn**: Absolute hysteresis for step \( n \), set in % of \( VBase \). The setting of this parameter is highly dependent of the application. The hysteresis is used to avoid oscillations of the PICKUP output signal. This signal resets when the measured voltage drops below the setting level and leaves the hysteresis area. Make sure that the set value for parameter \( HystABSn \) is somewhat smaller than the set pickup value. Otherwise there is a risk that step \( n \) will not reset properly.

### 10.4 Overexcitation protection OEXPVPH (24)

#### 10.4.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overexcitation protection</td>
<td>OEXPVPH</td>
<td></td>
<td>24</td>
</tr>
</tbody>
</table>

#### 10.4.2 Application

When the laminated core of a power transformer is subjected to a magnetic flux density beyond its design limits, stray flux will flow into non-laminated components not designed to carry flux and cause eddy currents to flow. The eddy currents can cause excessive heating and severe damage to insulation and adjacent parts in a relatively short time.

Overvoltage, or underfrequency, or a combination of both, will result in an excessive flux density level, which is denominated overfluxing or over-excitation.

The greatest risk for overexcitation exists in a thermal power station when the generator-transformer block is disconnected from the rest of the network, or in network "islands" occurring at disturbance where high voltages and/or low frequencies can occur. Overexcitation can occur...
during start-up and shut-down of the generator if the field current is not properly adjusted. Loss-of-load or load-shedding can also result in overexcitation if the voltage control and frequency governor is not functioning properly. Loss of load or load-shedding at a transformer substation can result in overexcitation if the voltage control function is insufficient or out of order. Low frequency in a system isolated from the main network can result in overexcitation if the voltage regulating system maintains normal voltage.

According to the IEC standards, the power transformers shall be capable of delivering rated load current continuously at an applied voltage of 105% of rated value (at rated frequency). For special cases, the purchaser may specify that the transformer shall be capable of operating continuously at an applied voltage 110% of rated value at no load, reduced to 105% at rated secondary load current.

According to ANSI/IEEE standards, the transformers shall be capable of delivering rated load current continuously at an output voltage of 105% of rated value (at rated frequency) and operate continuously with output voltage equal to 110% of rated value at no load.

The capability of a transformer (or generator) to withstand overexcitation can be illustrated in the form of a thermal capability curve, that is, a diagram which shows the permissible time as a function of the level of over-excitation. When the transformer is loaded, the induced voltage and hence the flux density in the core can not be read off directly from the transformer terminal voltage. Normally, the leakage reactance of each separate winding is not known and the flux density in the transformer core can then not be calculated. In two-winding transformers, the low voltage winding is normally located close to the core and the voltage across this winding reflects the flux density in the core. However, depending on the design, the flux flowing in the yoke may be critical for the ability of the transformer to handle excess flux.

The Overexcitation protection (OEXPVPH, 24) has current inputs to allow calculation of the load influence on the induced voltage. This gives a more exact measurement of the magnetizing flow. For power transformers with unidirectional load flow, the voltage to OEXPVPH (24) should therefore be taken from the feeder side.

Heat accumulated in critical parts during a period of overexcitation will be reduced gradually when the excitation returns to the normal value. If a new period of overexcitation occurs after a short time interval, the heating will start from a higher level, therefore, OEXPVPH (24) must have thermal memory. A fixed cooling time constant is settable within a wide range.

The general experience is that the overexcitation characteristics for a number of power transformers are not in accordance with standard inverse time curves. In order to make optimal settings possible, a transformer adapted characteristic is available in the IED. The operate characteristic of the protection function can be set to correspond quite well with any characteristic by setting the operate time for six different figures of overexcitation in the range from 100% to 180% of rated V/Hz.

When configured to a single phase-to-phase voltage input, a corresponding phase-to-phase current is calculated which has the same phase angle relative the phase-to-phase voltage as the phase currents have relative the phase voltages in a symmetrical system. The function should preferably be configured to use a three-phase voltage input if available. It then uses the positive sequence quantities of voltages and currents.

Analog measurements shall not be taken from any winding where a load tap changer is located.

Some different connection alternatives are shown in figure 212.
10.4.3 Setting guidelines

10.4.3.1 Recommendations for input and output signals

Recommendations for Input signals
Please see the default factory configuration.

**BLOCK**: The input will block the operation of the Overexcitation protection OEXPVPH (24), for example, the block input can be used to block the operation for a limited time during special service conditions.

**RESET**: OEXPVPH (24) has a thermal memory, which can take a long time to reset. Activation of the RESET input will reset the function instantaneously.

Recommendations for Output signals
Please see the default factory configuration for examples of configuration.

**ERROR**: The output indicates a measuring error. The reason, for example, can be configuration problems where analogue signals are missing.

**BFI**: The BFI output indicates that the level Pickup1> has been reached. It can be used to initiate time measurement.

**TRIP**: The TRIP output is activated after the operate time for the V/f level has expired. TRIP signal is used to trip the circuit breaker(s).

**ALARM**: The output is activated when the alarm level has been reached and the alarm timer has elapsed. When the system voltage is high this output sends an alarm to the operator.
10.4.3.2 Settings

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

*Operation:* The operation of the Overexcitation protection OEXPVPH (24) can be set to *Enabled/Disabled*.

*MeasuredV:* The phases involved in the measurement are set here. Normally the three phase measurement measuring the positive sequence voltage should be used but when only individual VT's are used a single phase-to-phase can be used.

*MeasuredI:* The phases involved in the measurement are set here. *MeasuredI:* must be in accordance with *MeasuredV*.

*Pickup1:* Operating level for the inverse characteristic, IEEE or tailor made. The operation is based on the relation between rated voltage and rated frequency and set as a percentage factor. Normal setting is around 108-110% depending of the capability curve for the transformer/generator.

*Pickup2:* Operating level for the *t_MinTripDelay* definite time delay used at high overvoltages. The operation is based on the relation between rated voltage and rated frequency and set as a percentage factor. Normal setting is around 110-180% depending of the capability curve of the transformer/generator. Setting should be above the knee-point when the characteristic starts to be straight on the high side.

Lower V/Hz limit is always set value V/Hz> in %. Upper V/Hz limit for the inverse time characteristic is taken as greater value among the following two values in %:

- 1.10 x V/Hz>
- V/Hz>>

The reason behind this is to prevent loss of accuracy of the inverse time characteristic when the difference between V/Hz> and V/Hz>> set values is too small.

*XLLeakage:* The transformer leakage reactance on which the compensation of voltage measurement with load current is based. The setting shall be the transformer leak reactance in primary ohms. If no current compensation is used (mostly the case) the setting is not used.

*t_TripPulse:* The length of the trip pulse. Normally the final trip pulse is decided by the trip function block. A typical pulse length can be 50 ms.

*CurveType:* Selection of the curve type for the inverse delay. The IEEE curves or tailor made curve can be selected depending of which one matches the capability curve best.

*TDforIEEECurve:* The time constant for the inverse characteristic. Select the one giving the best match to the transformer capability.

*t_CoolingK:* The cooling time constant giving the reset time when voltages drops below the set value. Shall be set above the cooling time constant of the transformer. The default value is recommended to be used if the constant is not known.

*t_MinTripDelay:* The operating times at voltages higher than the set *Pickup2*. The setting shall match capabilities on these high voltages. Typical setting can be 1-10 second.
**t\textsubscript{MaxTripDelay}:** For overvoltages close to the set value times can be extremely long if a high K time constant is used. A maximum time can then be set to cut the longest times. Typical settings are 1800-3600 seconds (30-60 minutes)

**AlarmPickup:** Setting of the alarm level in percentage of the set trip level. The alarm level is normally set at around 98% of the trip level.

**t\textsubscript{Alarm}:** Setting of the time to alarm is given from when the alarm level has been reached. Typical setting is 5 seconds.

### 10.4.3.3 Service value report

A number of internal parameters are available as service values for use at commissioning and during service. Remaining time to trip (in seconds) TMTOTRIP, flux density VPERHZ, internal thermal content in percentage of trip value THERMSTA. The values are available at local HMI, Substation SAasytem and PCM600.

### 10.4.3.4 Setting example

Sufficient information about the overexcitation capability of the protected object(s) must be available when making the settings. The most complete information is given in an overexcitation capability diagram as shown in figure 213.

The settings *Pickup2 and Pickup1* are made in per unit of the rated voltage of the transformer winding at rated frequency.

Set the transformer adapted curve for a transformer with overexcitation characteristics in according to figure 213.

*Pickup1* for the protection is set equal to the permissible continuous overexcitation according to figure 213 = 105%. When the overexcitation is equal to *Pickup1*, tripping is obtained after a time equal to the setting of t1.

This is the case when \( V\text{Base} \) is equal to the transformer rated voltages. For other values, the percentage settings need to be adjusted accordingly.

When the overexcitation is equal to the set value of *Pickup2*, tripping is obtained after a time equal to the setting of t6. A suitable setting would be *Pickup2* = 140% and t6 = 4 s.

The interval between *Pickup2 and Pickup1* is automatically divided up in five equal steps, and the time delays t2 to t5 will be allocated to these values of overexcitation. In this example, each step will be (140-105) /5 = 7%. The setting of time delays t1 to t6 are listed in table 48.

<table>
<thead>
<tr>
<th>V/f op (%)</th>
<th>Timer</th>
<th>Time set (s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>105</td>
<td>t1</td>
<td>7200 (max)</td>
</tr>
<tr>
<td>112</td>
<td>t2</td>
<td>600</td>
</tr>
<tr>
<td>119</td>
<td>t3</td>
<td>60</td>
</tr>
<tr>
<td>126</td>
<td>t4</td>
<td>20</td>
</tr>
<tr>
<td>133</td>
<td>t5</td>
<td>8</td>
</tr>
<tr>
<td>140</td>
<td>t6</td>
<td>4</td>
</tr>
</tbody>
</table>

Table 48: Settings
Information on the cooling time constant $T_{cool}$ should be retrieved from the power transformer manufacturer.

![Diagram showing transformer capability curve and V/Hz protection settings for power transformer](employee000377.vsd)

*Figure 213: Example on overexcitation capability curve and V/Hz protection settings for power transformer*

### 10.5 Voltage differential protection VDCPTOV (60)

#### 10.5.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage differential protection</td>
<td>VDCPTOV</td>
<td>-</td>
<td>60</td>
</tr>
</tbody>
</table>

#### 10.5.2 Application

The Voltage differential protection VDCPTOV (60) functions can be used in some different applications.

- Voltage unbalance protection for capacitor banks. The voltage on the bus is supervised with the voltage in the capacitor bank, phase-by-phase. Difference indicates a fault, either short-circuited or open element in the capacitor bank. It is mainly used on elements with external fuses but can also be used on elements with internal fuses instead of a current unbalance protection measuring the current between the neutrals of two half’s of the capacitor bank.
The function requires voltage transformers in all phases of the capacitor bank. Figure 214 shows some different alternative connections of this function.

![Diagram showing single grounded wye and double wye connections.]

**Figure 214: Connection of voltage differential protection VDCPTOV (60) function to detect unbalance in capacitor banks (one phase only is shown)**

VDCPTOV (60) function has a block input (BLOCK) where a fuse failure supervision (or MCB tripped) can be connected to prevent problems if one fuse in the capacitor bank voltage transformer set has opened and not the other (capacitor voltage is connected to input V2). It will also ensure that a fuse failure alarm is given instead of a Undervoltage or Differential voltage alarm and/or tripping.

Fuse failure supervision (SDDRFUF) function for voltage transformers. In many application the voltages of two fuse groups of the same voltage transformer or fuse groups of two separate voltage transformers measuring the same voltage can be supervised with this function. It will be an alternative for example, generator units where often two voltage transformers are supplied for measurement and excitation equipment.

The application to supervise the voltage on two voltage transformers in the generator circuit is shown in figure 215.
10.5.3 Setting guidelines

The parameters for the voltage differential function are set via the local HMI or PCM600.

The following settings are done for the voltage differential function.

*Operation: Off/On*

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

*BlkDiffAtVLow:* The setting is to block the function when the voltages in the phases are low.

*RFLx:* Is the setting of the voltage ratio compensation factor where possible differences between the voltages is compensated for. The differences can be due to different voltage transformer ratios, different voltage levels e.g. the voltage measurement inside the capacitor bank can have a different voltage level but the difference can also e.g. be used by voltage drop in the secondary circuits. The setting is normally done at site by evaluating the differential voltage achieved as a service value for each phase. The factor is defined as \( V_2 \cdot RFLx \) and shall be equal to the \( V_1 \) voltage. Each phase has its own ratio factor.

*VDTrip:* The voltage differential level required for tripping is set with this parameter. For application on capacitor banks the setting will depend of the capacitor bank voltage and the number of elements per phase in series and parallel. Capacitor banks must be tripped before excessive voltage occurs on the healthy capacitor elements. The setting values required are normally given by the capacitor bank supplier. For other applications it has to be decided case by case. For fuse supervision normally only the alarm level is used.

*tTrip:* The time delay for tripping is set by this parameter. Normally, the delay does not need to be so short in capacitor bank applications as there is no fault requiring urgent tripping.
tReset: The time delay for reset of tripping level element is set by this parameter. Normally, it can be set to a short delay as faults are permanent when they occur.

For the advanced users following parameters are also available for setting. Default values are here expected to be acceptable.

V1Low: The setting of the undervoltage level for the first voltage input is decided by this parameter. The proposed default setting is 70%.

V2Low: The setting of the undervoltage level for the second voltage input is decided by this parameter. The proposed default setting is 70%.

tBlock: The time delay for blocking of the function at detected undervoltages is set by this parameter.

VDAlarm: The voltage differential level required for alarm is set with this parameter. For application on capacitor banks the setting will depend of the capacitor bank voltage and the number of elements per phase in series and parallel. Normally values required are given by capacitor bank supplier.

For fuse supervision normally only this alarm level is used and a suitable voltage level is 3-5% if the ratio correction factor has been properly evaluated during commissioning.

For other applications it has to be decided case by case.

tAlarm: The time delay for alarm is set by this parameter. Normally, few seconds delay can be used on capacitor banks alarm. For fuse failure supervision (SDDRFUF) the alarm delay can be set to zero.

10.6 100% Stator ground fault protection, 3rd harmonic based STEFPHIZ (59THD)

10.6.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>100% Stator ground fault protection, 3rd harmonic based</td>
<td>STEFPHIZ</td>
<td>-</td>
<td>59THD</td>
</tr>
</tbody>
</table>

10.6.2 Application

The stator ground-fault protection of medium and large generators connected to their power transformers should preferably be able of detecting small ground current leakages (with equivalent resistances of the order of several kΩ) occurring even in the vicinity of the generator neutral. A high resistance ground fault close to the neutral is not critical itself, but must anyway be detected in order to prevent a double ground fault when another grounding fault occurs, for example near the generator terminals. Such a double fault can be disastrous.

Short-circuit between the stator winding in the slots and stator core is the most common type of electrical fault in generators. Medium and large generators normally have high impedance ground, that is, grounding via a neutral point resistor. This resistor is dimensioned to give an ground fault...
current in the range 3 – 15 A at a solid ground-fault directly at the generator high voltage terminal. The relatively small ground fault currents (of just one ground fault) give much less thermal and mechanical stress on the generator, compared, for example to short circuit between phases. Anyhow, the ground faults in the generator have to be detected and the generator has to be tripped, even if longer fault time, compared to short circuits, can be allowed.

The relation between the magnitude of the generator ground fault current and the fault time, with defined consequence, is shown in figure 216.

![Figure 216: Relation between the magnitude of the generator ground fault current and the fault time](en00000316.vsd)

As mentioned earlier, for medium and large generators, the common practice is to have high impedance grounding of generating units. The most common grounding system is to use a neutral point resistor, giving an ground fault current in the range 3 – 15 A at a non-resistive ground-fault at the high voltage side of the generator. One version of this kind of grounding is a single-phase distribution transformer, the high voltage side of which is connected between the neutral point and ground, and with an equivalent resistor on the low voltage side of the transformer. Other types of system grounding of generator units, such as direct grounding and isolated neutral, are used but are quite rare.

In normal non-faulted operation of the generating unit the neutral point voltage is close to zero, and there is no zero sequence current flow in the generator. When a phase-to-ground fault occurs the fundamental frequency neutral point voltage will increase and there will be a fundamental frequency current flow through the neutral point resistor.
To detect a ground-fault on the windings of a generating unit one may use a neutral point overvoltage protection, a neutral point overcurrent protection, a zero sequence overvoltage protection or a residual differential protection. These protection schemes are simple and have served well during many years. However, at best these schemes protect only 95% of the stator winding. They leave 5% at the neutral end unprotected. Under unfavorable conditions the blind zone may extend to 20% from the neutral. Some different ground fault protection solutions are shown in figure 217 and figure 218.

![Figure 217: Broken delta voltage transformer measurement of $3V_0$ voltage](ANSI06000317_3_en.vsd)

![Figure 218: Neutral point voltage transformer measurement of neutral point voltage (that is $V_0$ voltage)](ANSI06000318_3_en.vsd)

Alternatively zero sequence current can be measured as shown in fig 219.

In some applications the neutral point resistor is connected to the low voltage side of a single-phase distribution transformer, connected to the generator neutral point. In such a case the voltage measurement can be made directly across the secondary resistor.
Figure 219: Neutral point current measurement

In some power plants the connection of the neutral point resistor is made to the generator unit transformer neutral point. This is often done if several generators are connected to the same bus. The detection of ground-fault can be made by current measurement as shown in figure 220.

Figure 220: Residual current measurement

One difficulty with this solution is that the current transformer ratio is normally so large so that the secondary residual current will be very small. The false residual current, due to difference between the three phase current transformers, can be in the same range as the secondary ground fault current. Thus if physically possible, cable CT is recommended for such applications in order to measure $3I_0$ correct.

As indicated above, there will be very small neutral voltage or residual current if the stator ground fault is situated close to the generator neutral. The probability for this fault is quite small but not zero. For small generators the risk of not detecting the stator ground fault, close to the neutral, can be accepted. For medium and large generator it is however often a requirement that also these faults have to be detected. Therefore, a special neutral end ground fault protection
STEFPHIZ (59THD) is required. STEFPHIZ (59THD) can be realized in different ways. The two main principles are:

- 3\textsuperscript{rd} harmonic voltage detection
- Neutral point voltage injection

The 3\textsuperscript{rd} harmonic voltage detection is based on the fact that the generator generates some degree of 3\textsuperscript{rd} harmonic voltages. These voltages have the same phase angle in the three phases. This means that there will be a harmonic voltage in the generator neutral during normal operation. This component is used for detection of ground faults in the generator, close to the neutral.

If the 3\textsuperscript{rd} harmonic voltage generated in the generator is less than 0.8 V RMS secondary, the 3\textsuperscript{rd} harmonic based protection cannot be used.

In this protection function, a 3\textsuperscript{rd} harmonic voltage differential principle is used.

### 10.6.3 Setting guidelines

The 100% Stator ground fault protection, 3rd harmonic based (STEFPHIZ, 59THD) protection is using the 3\textsuperscript{rd} harmonic voltage generated by the generator itself. To assure reliable function of the protection it is necessary that the 3\textsuperscript{rd} harmonic voltage generation is at least 1\% of the generator rated voltage.

Adaptive frequency tracking must be properly configured and set for the Signal Matrix for analog inputs (SMAI) preprocessing blocks in order to ensure proper operation of the generator differential protection function during varying frequency conditions.

**Operation:** The parameter *Operation* is used to set the function */EnabledDisabled*.

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

*TVoltType:* STEFPHIZ (59THD) function is fed from a voltage transformer in the generator neutral. *TVoltType* defines how the protection function is fed from voltage transformers at the high voltage side of the generator. The setting alternatives are:

- *NoVoltage* is used when no voltage transformers are connected to the generator terminals. In this case the protection will operate as a 3\textsuperscript{rd} harmonic undervoltage protection.
- *ResidualVoltage 3V0* is used if the protection is fed from a broken delta connected three-phase group of voltage transformers connected to the generator terminals. This is the recommended alternative.
- *AllThreePhases* is used when the protection is fed from the three phase voltage transformers. The third harmonic residual voltage is derived internally from the phase voltages.
- *PhaseA, PhaseB or PhaseC*, are used when there is only one phase voltage transformer available at the generator terminals.

The setting *Beta* gives the proportion of the 3\textsuperscript{rd} harmonic voltage in the neutral point of the generator to be used as restrain quantity. *Beta* must be set so that there is no risk of trip during normal, non-faulted, operation of the generator. On the other hand, if *Beta* is set high, this will
limit the portion of the stator winding covered by the protection. The default setting 3.0 will in most cases give acceptable sensitivity for ground fault near to the neutral point of the stator winding. One possibility to assure best performance is to make measurements during normal operation of the generator. The protective function itself makes the required information available:

- VT3, the 3rd harmonic voltage at the generator terminal side
- VN3, the 3rd harmonic voltage at the generator neutral side
- E3, the induced harmonic voltage
- ANGLE, the phase angle between voltage phasors VT3 and VN3
- DV3, the differential voltage between VT3 and VN3; |VT3 + VN3|
- BV3, the bias voltage (Beta x VN3)

For different operation points (P and Q) of the generator the differential voltage DV3 can be compared to the bias BV3, and a suitable factor Beta can be chosen to assure security.

CBexists: CBexists is set to Yes if there is a generator breaker (between the generator and the block transformer).

FactorCBopen: The setting FactorCBopen gives a constant to be multiplied to Beta if the generator circuit breaker is open, input 52a is not active and CBexists is set to Yes.

VN3rdHPU: The setting VN3rdHPU gives the undervoltage operation level if TVoltType is set to NoVoltage. In all other connection alternatives this setting is not active and operation is instead based on comparison of the differential voltage DV3 with the bias voltage BV3. The setting is given as % of the rated phase-to-ground voltage. The setting should be based on neutral point 3rd harmonic voltage measurement at normal operation.

VNFundPU: VNFundPU gives the operation level for the fundamental frequency residual voltage stator ground fault protection. The setting is given as % of the rated phase-to-ground voltage. A normal setting is in the range 5 – 10%.

VT3BlkLevel: VT3BlkLevel gives a voltage level for the 3rd harmonic voltage level at the terminal side. If this level is lower than the setting the function is blocked. The setting is given as % of the rated phase-to-ground voltage. The setting is typically 1 %.

t3rdH: t3rdH gives the trip delay of the 3rd harmonic stator ground fault protection. The setting is given in seconds. Normally, a relatively long delay (about 10 s) is acceptable as the ground fault current is small.

tVNFund: tVNFund gives the trip delay of the fundamental frequency residual voltage stator ground fault protection. The setting is given in s. A delay in the range 0.5 – 2 seconds is acceptable.
Section 11 Frequency protection

11.1 Underfrequency protection SAPTUF (81)

11.1.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Underfrequency protection</td>
<td>SAPTUF</td>
<td></td>
<td>81</td>
</tr>
</tbody>
</table>

11.1.2 Application

Underfrequency protection SAPTUF (81) is applicable in all situations, where reliable detection of low fundamental power system frequency is needed. The power system frequency, and the rate of change of frequency, is a measure of the unbalance between the actual generation and the load demand. Low fundamental frequency in a power system indicates that the available generation is too low to fully supply the power demanded by the load connected to the power grid. SAPTUF (81) detects such situations and provides an output signal, suitable for load shedding, generator boosting, HVDC-set-point change, gas turbine start up and so on. Sometimes shunt reactors are automatically switched in due to low frequency, in order to reduce the power system voltage and hence also reduce the voltage dependent part of the load.

SAPTUF (81) is very sensitive and accurate and is used to alert operators that frequency has slightly deviated from the set-point, and that manual actions might be enough. The underfrequency signal is also used for overexcitation detection. This is especially important for generator step-up transformers, which might be connected to the generator but disconnected from the grid, during a roll-out sequence. If the generator is still energized, the system will experience overexcitation, due to the low frequency.

11.1.3 Setting guidelines

All the frequency and voltage magnitude conditions in the system where SAPTUF (81) performs its functions should be considered. The same also applies to the associated equipment, its frequency and time characteristic.

There are two specific application areas for SAPTUF (81):

1. to protect equipment against damage due to low frequency, such as generators, transformers, and motors. Overexcitation is also related to low frequency
2. to protect a power system, or a part of a power system, against breakdown, by shedding load, in generation deficit situations.
The under frequency pickup value is set in Hz. All voltage magnitude related settings are made as a percentage of a global base voltage parameter. The UBase value should be set as a primary phase-to-phase value.

Some applications and related setting guidelines for the frequency level are given below:

**Equipment protection, such as for motors and generators**

The setting has to be well below the lowest occurring "normal" frequency and well above the lowest acceptable frequency for the equipment.

**Power system protection, by load shedding**

The setting has to be below the lowest occurring "normal" frequency and well above the lowest acceptable frequency for power stations, or sensitive loads. The setting level, the number of levels and the distance between two levels (in time and/or in frequency) depends very much on the characteristics of the power system under consideration. The size of the "largest loss of production" compared to "the size of the power system" is a critical parameter. In large systems, the load shedding can be set at a fairly high frequency level, and the time delay is normally not critical. In smaller systems the frequency pickup level has to be set at a lower value, and the time delay must be rather short.

The voltage related time delay is used for load shedding. The settings of SAPTUF (81) could be the same all over the power system. The load shedding is then performed firstly in areas with low voltage magnitude, which normally are the most problematic areas, where the load shedding also is most efficient.

### 11.2 Overfrequency protection SAPTOF (81)

#### 11.2.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overfrequency protection</td>
<td>SAPTOF</td>
<td></td>
<td>81</td>
</tr>
</tbody>
</table>

#### 11.2.2 Application

Overfrequency protection function SAPTOF (81) is applicable in all situations, where reliable detection of high fundamental power system frequency is needed. The power system frequency, and rate of change of frequency, is a measure of the unbalance between the actual generation and the load demand. High fundamental frequency in a power system indicates that the available generation is too large compared to the power demanded by the load connected to the power grid. SAPTOF (81) detects such situations and provides an output signal, suitable for generator shedding, HVDC-set-point change and so on. SAPTOF (81) is very sensitive and accurate and can also be used to alert operators that frequency has slightly deviated from the set-point, and that manual actions might be enough.
11.2.3 Setting guidelines

All the frequency and voltage magnitude conditions in the system where SAPTOF (81) performs its functions must be considered. The same also applies to the associated equipment, its frequency and time characteristic.

There are two application areas for SAPTOF (81):

1. to protect equipment against damage due to high frequency, such as generators, and motors
2. to protect a power system, or a part of a power system, against breakdown, by shedding generation, in over production situations.

The overfrequency pickup value is set in Hz. All voltage magnitude related settings are made as a percentage of a settable global base voltage parameter $V_{base}$. The $U_{base}$ value should be set as a primary phase-to-phase value.

Some applications and related setting guidelines for the frequency level are given below:

**Equipment protection, such as for motors and generators**

The setting has to be well above the highest occurring "normal" frequency and well below the highest acceptable frequency for the equipment.

**Power system protection, by generator shedding**

The setting must be above the highest occurring "normal" frequency and below the highest acceptable frequency for power stations, or sensitive loads. The setting level, the number of levels and the distance between two levels (in time and/or in frequency) depend very much on the characteristics of the power system under consideration. The size of the "largest loss of load" compared to "the size of the power system" is a critical parameter. In large systems, the generator shedding can be set at a fairly low frequency level, and the time delay is normally not critical. In smaller systems the frequency PICKUP level has to be set at a higher value, and the time delay must be rather short.

11.3 Rate-of-change of frequency protection SAPFRC (81)

11.3.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rate-of-change of frequency protection</td>
<td>SAPFRC</td>
<td></td>
<td>81</td>
</tr>
</tbody>
</table>

11.3.2 Application

Rate-of-change of frequency protection (SAPFRC, 81) is applicable in all situations, where reliable detection of change of the fundamental power system voltage frequency is needed. SAPFRC (81)
can be used both for increasing frequency and for decreasing frequency. SAPFRC (81) provides an output signal, suitable for load shedding or generator shedding, generator boosting, HVDC-setpoint change, gas turbine start up and so on. Very often SAPFRC (81) is used in combination with a low frequency signal, especially in smaller power systems, where loss of a fairly large generator will require quick remedial actions to secure the power system integrity. In such situations load shedding actions are required at a rather high frequency level, but in combination with a large negative rate-of-change of frequency the underfrequency protection can be used at a rather high setting.

### 11.3.3 Setting guidelines

The parameters for Rate-of-change frequency protection SAPFRC (81) are set via the local HMI or through the Protection and Control Manager (PCM600).

All the frequency and voltage magnitude conditions in the system where SAPFRC (81) performs its functions should be considered. The same also applies to the associated equipment, its frequency and time characteristic.

There are two application areas for SAPFRC (81):

1. to protect equipment against damage due to high or too low frequency, such as generators, transformers, and motors
2. to protect a power system, or a part of a power system, against breakdown by shedding load or generation, in situations where load and generation are not in balance.

SAPFRC (81) is normally used together with an overfrequency or underfrequency function, in small power systems, where a single event can cause a large imbalance between load and generation. In such situations load or generation shedding has to take place very quickly, and there might not be enough time to wait until the frequency signal has reached an abnormal value. Actions are therefore taken at a frequency level closer to the primary nominal level, if the rate-of-change frequency is large (with respect to sign).

The pickup value for SAPFRC (81) is set in Hz/s. All voltage magnitude related settings are made as a percentage of a settable base voltage, which normally is set to the primary nominal voltage level (phase-phase) of the power system or the high voltage equipment under consideration.

SAPFRC (81) is not instantaneous, since the function needs some time to supply a stable value. It is recommended to have a time delay long enough to take care of signal noise. However, the time, rate-of-change frequency and frequency steps between different actions might be critical, and sometimes a rather short operation time is required, for example, down to 70 ms.

Smaller industrial systems might experience rate-of-change frequency as large as 5 Hz/s, due to a single event. Even large power systems may form small islands with a large imbalance between load and generation, when severe faults (or combinations of faults) are cleared - up to 3 Hz/s has been experienced when a small island was isolated from a large system. For more "normal" severe disturbances in large power systems, rate-of-change of frequency is much less, most often just a fraction of 1.0 Hz/s.
11.4 Frequency time accumulation protection function
FTAQFVR (81A)

11.4.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE identification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency time accumulation protection</td>
<td>FTAQFVR</td>
<td>f&lt;&gt;</td>
<td>81A</td>
</tr>
</tbody>
</table>

11.4.2 Application

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

The turbine blade is designed with its natural frequency adequately far from the rated speed or multiples of the rated speed of the turbine. This design avoids the mechanical resonant condition, which can lead to an increased mechanical stress on turbine blade. If the ratio between the turbine resonant frequencies to the system operating frequency is nearly equal to 1, mechanical stress on the blades is approximately 300 times the nonresonant operating condition stress values. The stress magnification factor is shown in the typical resonance curve in Figure 221.
Each turbine manufactured for different design of blades has various time restriction limits for various frequency bands. The time limits depend on the natural frequencies of the blades inside the turbine, corrosion and erosion of the blade edges and additional loss of blade lifetime during the abnormal operating conditions.

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

However, the IEEE/ANSI C37.106-2003 standard “Guide for Abnormal Frequency Protection for Power Generating Plants” provides some examples where the time accumulated within each frequency range is as shown in Figure 222.
Another application for the FTAQFVR (81A) protection function is to supervise variations from rated voltage-frequency. Generators are designed to accommodate the IEC 60034-3:1996 requirement of continuous operation within the confines of their capability curves over the ranges of +/-5% in voltage and +/-2% in frequency. Operation of the machine at rated power outside these voltage-frequency limits lead to increased temperatures and reduction of insulation life.

### 11.4.3 Setting guidelines

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

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

### Setting procedure on the IED

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

Common base IED values for primary current $I_{Base}$ and primary voltage $V_{Base}$ are set in the global base values for settings function GBASVAL. The $GlobalBaseSel$ is used to select GBASVAL for the reference of base values.
FTAQFVR (81A) used to protect a turbine:

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

\textit{EnaVoltCheck} set to \textit{Disable}.

\textit{tCont}: to be coordinated to the grid requirements.

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

FTAQFVR (81A) used to protect a generator:

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

\textit{PickupCurrentLevel} set to \textit{Disable}.

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

\textit{tCont}: to be coordinated to the grid requirements.

\textit{tAccLimit}, \textit{FreqHighLimit} and \textit{FreqLowLimit} setting is derived from the generator manufacturer's operating requirements.
Section 12  Multipurpose protection

12.1 General current and voltage protection CVGAPC

12.1.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>General current and voltage protection</td>
<td>CVGAPC</td>
<td>2(I&gt;/U&lt;)</td>
<td>-</td>
</tr>
</tbody>
</table>

12.1.2 Application

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

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

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

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

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

2. Two undercurrent steps with the following built-in features:
   • Definite time delay for both steps

3. Two overvoltage steps with the following built-in features
   • Definite time delay or Inverse Time Overcurrent TOC/IDMT delay for both steps

4. Two undervoltage steps with the following built-in features
   • Definite time delay or Inverse Time Overcurrent TOC/IDMT delay for both steps

All these four protection elements within one general protection function works independently from each other and they can be individually enabled or disabled. However, note that all these four protection elements measure one selected current quantity and one selected voltage quantity (see table 49 and table 50). It is possible to simultaneously use all four protection elements and their individual stages. Sometimes, it is necessary to provide interaction between two or more protection elements/stages within one CVGAPC function by appropriate IED configuration to obtain desired application functionality.

12.1.2.1 Current and voltage selection for CVGAPC function

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

The user can select a current input, by a setting parameter CurrentInput, to measure one of the current quantities shown in table 49.

Table 49: Available selection for current quantity within CVGAPC function

<table>
<thead>
<tr>
<th>Set value for parameter &quot;CurrentInput&quot;</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 PhaseA</td>
<td>CVGAPC function will measure the phase A current phasor</td>
</tr>
<tr>
<td>2 PhaseB</td>
<td>CVGAPC function will measure the phase B current phasor</td>
</tr>
<tr>
<td>3 PhaseC</td>
<td>CVGAPC function will measure the phase C current phasor</td>
</tr>
<tr>
<td>4 PosSeq</td>
<td>CVGAPC function will measure internally calculated positive sequence current phasor</td>
</tr>
<tr>
<td>5 NegSeq</td>
<td>CVGAPC function will measure internally calculated negative sequence current phasor</td>
</tr>
<tr>
<td>6 3 · ZeroSeq</td>
<td>CVGAPC function will measure internally calculated zero sequence current phasor multiplied by factor 3</td>
</tr>
</tbody>
</table>

Table continues on next page
### Set value for parameter “CurrentInput”

<table>
<thead>
<tr>
<th>Set value for parameter “CurrentInput”</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>7 MaxPh</td>
<td>CVGAPC function will measure current phasor of the phase with maximum magnitude</td>
</tr>
<tr>
<td>8 MinPh</td>
<td>CVGAPC function will measure current phasor of the phase with minimum magnitude</td>
</tr>
<tr>
<td>9 UnbalancePh</td>
<td>CVGAPC function will measure magnitude of unbalance current, which is internally calculated as the algebraic magnitude difference between the current phasor of the phase with maximum magnitude and current phasor of the phase with minimum magnitude. Phase angle will be set to 0° all the time</td>
</tr>
<tr>
<td>10 PhaseA-PhaseB</td>
<td>CVGAPC function will measure the current phasor internally calculated as the vector difference between the phase A current phasor and phase B current phasor (VA-VB)</td>
</tr>
<tr>
<td>11 PhaseB-PhaseC</td>
<td>CVGAPC function will measure the current phasor internally calculated as the vector difference between the phase B current phasor and phase C current phasor (VB-VC)</td>
</tr>
<tr>
<td>12 PhaseC-PhaseA</td>
<td>CVGAPC function will measure the current phasor internally calculated as the vector difference between the phase C current phasor and phase A current phasor (VC-VA)</td>
</tr>
<tr>
<td>13 MaxPh-Ph</td>
<td>CVGAPC function will measure ph-ph current phasor with the maximum magnitude</td>
</tr>
<tr>
<td>14 MinPh-Ph</td>
<td>CVGAPC function will measure ph-ph current phasor with the minimum magnitude</td>
</tr>
<tr>
<td>15 UnbalancePh-Ph</td>
<td>CVGAPC function will measure magnitude of unbalance current, which is internally calculated as the algebraic magnitude difference between the ph-ph current phasor with maximum magnitude and ph-ph current phasor with minimum magnitude. Phase angle will be set to 0° all the time</td>
</tr>
</tbody>
</table>

The user can select a voltage input, by a setting parameter VoltageInput, to measure one of the voltage quantities shown in table 50.

Table 50: Available selection for voltage quantity within CVGAPC function

<table>
<thead>
<tr>
<th>Set value for parameter “VoltageInput”</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 PhaseA</td>
<td>CVGAPC function will measure the phase A voltage phasor</td>
</tr>
<tr>
<td>2 PhaseB</td>
<td>CVGAPC function will measure the phase B voltage phasor</td>
</tr>
<tr>
<td>3 PhaseC</td>
<td>CVGAPC function will measure the phase C voltage phasor</td>
</tr>
<tr>
<td>4 PosSeq</td>
<td>CVGAPC function will measure internally calculated positive sequence voltage phasor</td>
</tr>
<tr>
<td>5 -NegSeq</td>
<td>CVGAPC function will measure internally calculated negative sequence voltage phasor. This voltage phasor will be intentionally rotated for 180° in order to enable easier settings for the directional feature when used.</td>
</tr>
<tr>
<td>6 -3*ZeroSeq</td>
<td>CVGAPC function will measure internally calculated zero sequence voltage phasor multiplied by factor 3. This voltage phasor will be intentionally rotated for 180° in order to enable easier settings for the directional feature when used.</td>
</tr>
<tr>
<td>7 MaxPh</td>
<td>CVGAPC function will measure voltage phasor of the phase with maximum magnitude</td>
</tr>
<tr>
<td>8 MinPh</td>
<td>CVGAPC function will measure voltage phasor of the phase with minimum magnitude</td>
</tr>
</tbody>
</table>

Table continues on next page
Set value for parameter "VoltageInput" | Comment
--- | ---
9 | *UnbalancePh* | CVGAPC function will measure magnitude of unbalance voltage, which is internally calculated as the algebraic magnitude difference between the voltage phasor of the phase with maximum magnitude and voltage phasor of the phase with minimum magnitude. Phase angle will be set to 0° all the time.
10 | *PhaseA-PhaseB* | CVGAPC function will measure the voltage phasor internally calculated as the vector difference between the phase A voltage phasor and phase B voltage phasor (VA-VB).
11 | *PhaseB-PhaseC* | CVGAPC function will measure the voltage phasor internally calculated as the vector difference between the phase B voltage phasor and phase C voltage phasor (VB-VC).
12 | *PhaseC-PhaseC* | CVGAPC function will measure the voltage phasor internally calculated as the vector difference between the phase C voltage phasor and phase A voltage phasor (VC-VA).
13 | *MaxPh-Ph* | CVGAPC function will measure ph-ph voltage phasor with the maximum magnitude.
14 | *MinPh-Ph* | CVGAPC function will measure ph-ph voltage phasor with the minimum magnitude.
15 | *UnbalancePh-Ph* | CVGAPC function will measure magnitude of unbalance voltage, which is internally calculated as the algebraic magnitude difference between the ph-ph voltage phasor with maximum magnitude and ph-ph voltage phasor with minimum magnitude. Phase angle will be set to 0° all the time.

Note that the voltage selection from table 50 is always applicable regardless the actual external VT connections. The three-phase VT inputs can be connected to IED as either three phase-to-ground voltages, VA, VB and VC or three phase-to-phase voltages $V_{AB}$, $V_{BC}$ and $V_{CA}$. This information about actual VT connection is entered as a setting parameter for the pre-processing block, which will then be taken care automatically.

### 12.1.2.2 Base quantities for CVGAPC function

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

Base current shall be entered as:

1. rated phase-to-earth current of the protected object in primary amperes, when the measured Current Quantity is selected from 1 to 9, as shown in table 49.
2. rated phase current of the protected object in primary amperes multiplied by $\sqrt{3}$ (1.732 x Iphase), when the measured Current Quantity is selected from 10 to 15, as shown in table 49.

Base voltage shall be entered as:

1. rated phase-to-ground voltage of the protected object in primary kV, when the measured Voltage Quantity is selected from 1 to 9, as shown in table 50.
2. rated phase-to-phase voltage of the protected object in primary kV, when the measured Voltage Quantity is selected from 10 to 15, as shown in table 50.
12.1.2.3 Application possibilities

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

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

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

12.1.2.4 Inadvertent generator energization

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

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

Since a generator behaves similarly to an induction motor, high currents will develop in the rotor during the period it is accelerating. Although the rotor may be thermally damaged from excessive high currents, the time to damage will be on the order of a few seconds. Of more critical concern, however, is the bearing, which can be damaged in a fraction of a second due to low oil pressure. Therefore, it is essential that high speed tripping is provided. This tripping should be almost instantaneous (< 100 ms).

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

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

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

### 12.1.3 Setting guidelines

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

The parameters for the general current and voltage protection function (CVGAPC) are set via the local HMI or Protection and Control Manager (PCM600).

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

**GlobalBaseSel**: Selects the global base value group used by the function to define \(I_{Base}\), \(V_{Base}\) and \(S_{Base}\). Note that this function will only use \(I_{Base}\) value.

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

The function has default setting of operate values and timers according to the typical application as a power system back up protection. These settings should be modified according to the system back up protection strategy of individual utility. The recommended minimum time delay setting of function should be greater than 0.05s when used in process bus 9-2 application.
### 12.1.3.1 Directional negative sequence overcurrent protection

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

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

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

1. Connect three-phase power line currents and three-phase power line voltages to one CVGAPC instance (for example, GF04)
2. Set CurrentInput to NegSeq (please note that CVGAPC function measures I2 current and NOT 3I2 current; this is essential for proper OC pickup level setting)
3. Set VoltageInput to -NegSeq (please note that the negative sequence voltage phasor is intentionally inverted in order to simplify directionality)
4. Set base current IBase value equal to the rated primary current of power line CTs
5. Set base voltage UBase value equal to the rated power line phase-to-phase voltage in kV
6. Set RCADir to value +65 degrees (NegSeq current typically lags the inverted NegSeq voltage for this angle during the fault)
7. Set ROADir to value 90 degree
8. Set LowVolt_VM to value 2% (NegSeq voltage level above which the directional element will be enabled)
9. Enable one overcurrent stage (for example, OC1)
10. By parameter CurveType_OC1 select appropriate TOC/IDMT or definite time delayed curve in accordance with your network protection philosophy
11. Set PickupCurr_OC1 to value between 3-10% (typical values)
12. Set tDef_OC1 or parameter "TD" when TOC/IDMT curves are used to insure proper time coordination with other ground-fault protections installed in the vicinity of this power line
13. Set DirMode_OC1 to Forward
14. Set DirPrinc_OC1 to IcosPhi&U
15. Set ActLowVolt_1_VM to Block

   • In order to insure proper restraining of this element for CT saturations during three-phase faults it is possible to use current restraint feature and enable this element to operate only when NegSeq current is bigger than a certain percentage (10% is typical value) of measured PosSeq current in the power line. To do this the following settings within the same function shall be done:

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

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

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

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

**12.1.3.2 Negative sequence overcurrent protection**

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

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

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

(Equation 247)

where:
- \( t_{op} \) is the operating time in seconds of the negative sequence overcurrent IED
- \( TD \) is the generator capability constant in seconds
- \( I_{NS} \) is the measured negative sequence current
- \( I_r \) is the generator rated current

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

\[
x = 7\% = 0.07\ pu
\]

(Equation 248)

Equation 247 can be re-written in the following way without changing the value for the operate time of the negative sequence inverse overcurrent IED:
In order to achieve such protection functionality with one CVGAPC functions the following must be done:

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

\[
T_{op} = \frac{TD \cdot \frac{1}{x^2}}{\left(\frac{I_{NS}}{x \cdot I_t}\right)^2}
\]

(Equation 249)

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

When the equation 247 is compared with the equation 249 for the inverse time characteristic of the OC1 it is obvious that if the following rules are followed:

1. set TD equal to the generator negative sequence capability value
2. set \(A_{OC1}\) equal to the value \(1/x^2\)
3. set \(B_{OC1} = 0.0, C_{OC1} = 0.0\) and \(P_{OC1} = 2.0\)
4. set PickupCurr_OC1 equal to the value \(x\)

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

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

1. select negative sequence current as measuring quantity for this CVGAPC function
2. make sure that the base current value for the CVGAPC function is equal to the generator rated current
3. set \(TD_{OC1} = 20\)
4. set \(A_{OC1} = 1/0.07^2 = 204.0816\)
5. set \(B_{OC1} = 0.0, C_{OC1} = 0.0\) and \(P_{OC1} = 2.0\)
6. set PickupCurr_{OC1} = 7%
Proper timing of the CVGAPC function made in this way can easily be verified by secondary injection. All other settings can be left at the default values. If required delayed time reset for OC1 step can be set in order to ensure proper function operation in case of repetitive unbalance conditions.

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

### 12.1.3.3 Generator stator overload protection in accordance with IEC or ANSI standards

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

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

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

(Equation 251)

where:
- \(t_{op}\) is the operating time of the generator stator overload IED
- \(TD\) is the generator capability constant in accordance with the relevant standard (TD = 37.5 for the IEC standard or TD = 41.4 for the ANSI standard)
- \(I_m\) is the magnitude of the measured current
- \(I_r\) is the generator rated current

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

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

\[
x = 116\% = 1.16 \text{ pu}
\]

(Equation 252)

formula 3.5 can be re-written in the following way without changing the value for the operate time of the generator stator overload IED:
In order to achieve such protection functionality with one CVGAPC function the following must be done:

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

\[ t_{op} = \frac{TD \cdot \frac{1}{X^2}}{\left( \frac{I_m}{X \cdot I_r} \right)^2 - \frac{1}{X^2}} \]

(Equation 253)

where:

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

When the equation 253 is compared with the equation 254 for the inverse time characteristic of the OC1 step it is obvious that if the following rules are followed:

1. set TD equal to the IEC or ANSI standard generator capability value
2. set parameter A_OC1 equal to the value 1/x2
3. set parameter C_OC1 equal to the value 1/x2
4. set parameters B_OC1 = 0.0 and P_OC1=2.0
5. set PickupCurr_OC1 equal to the value x

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

1. select positive sequence current as measuring quantity for this CVGAPC function
2. make sure that the base current value for CVGAPC function is equal to the generator rated current
3. set TD = 37.5 for the IEC standard or TD = 41.4 for the ANSI standard
4. set A_OC1= 1/1.162 = 0.7432
5. set C_OC1= 1/1.162 = 0.7432
6. set B_OC1 = 0.0 and P_OC1=2.0
7. set PickupCurr_OC1 = 116%
Proper timing of CVGAPC function made in this way can easily be verified by secondary injection. All other settings can be left at the default values. If required delayed time reset for OC1 step can be set in order to insure proper function operation in case of repetitive overload conditions.

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

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

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

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

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

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

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

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

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

- Inverse Time Over Current TOC/IDMT curve: ANSI very inverse
- Pickup current of 185% of generator rated current at rated generator voltage
- Pickup current 25% of the original pickup current value for generator voltages below 25% of rated voltage
This functionality can be achieved by using one CVGAPC function. The following shall be done in order to ensure proper operation of the function:

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

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

**12.1.3.6 Loss of excitation protection for a generator**

Example will be given how by using positive sequence directional overcurrent protection element within a CVGAPC function, loss of excitation protection for a generator can be achieved. Let us assume that from rated generator data the following values are calculated:

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

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

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

Proper operation of the CVGAPC function made in this way can easily be verified by secondary injection. All other settings can be left at the default values. However it shall be noted that set values for RCA & ROA angles will be applicable for OC2 step if directional feature is enabled for this step as well. Figure 223 shows overall protection characteristic.

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

![Operating Region](en05000535_ansl.vsd)

*Figure 223: Loss of excitation*

### 12.1.3.7 Inadvertent generator energization

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

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

Since a generator behaves similarly to an induction motor, high currents will develop in the rotor during the period it is accelerating. Although the rotor may be thermally damaged from excessive high currents, the time to damage will be on the order of a few seconds. Of more critical concern, however, is the bearing, which can be damaged in a fraction of a second due to low oil pressure. Therefore, it is essential that high speed tripping is provided. This tripping should be almost instantaneous (< 100 ms).
There is a risk that the current into the generator at inadvertent energization will be limited so that the "normal" overcurrent or underimpedance protection will not detect the dangerous situation. The delay of these protection functions might be too long. The reverse power protection might detect the situation but the operation time of this protection is normally too long.

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

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

The inadvertent energization function is realized by means of the general current and voltage protection function (CVGAPC). The function is configured as shown in figure 224.

![Diagram of the inadvertent energization function](ANSI10000028-1-en.vsd)

*Figure 224: Configuration of the inadvertent energization function*

The setting of the function in the inadvertent energization application is done as described below. It is assumed that the instance is used only for the inadvertent energization application. It is however possible to extend the use of the instance by using OC2, UC1, UC2, OV2, UV2 for other protection applications.
12.1.3.8 Undercurrent protection for capacitor bank

Following example explains how an undercurrent protection within CVGAPC function can be used for the disconnection of shunt capacitor bank (SCB) in case of very low voltages at the busbar.

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

1. Connect three-phase terminal currents to CVGAPC function and no need of voltage input, that is, connect GRP_OFF from FXDSIGN to U3P of CVGAPC.
2. Set operation = On, select CurrentInput = MaxPh and set VoltageInput to default value
3. Set Operation_UC1 = On
4. Set EnBlkLowI_UC1 = On
5. Set BlkLowCurr_UC1 = 10.0 %IB
6. Set StartCurr_UC1 = 70.0 %IB
7. Set tDef_UC1 = 5.00 s
8. Set tResetDef_UC1 = 0.0 s
9. Set HarmRestr_UC1 = Off

12.1.3.9 General settings of the instance

Operation: With the parameter Operation the function can be set EnabledOn/OffDisabled.

CurrentInput: The current used for the inadvertent energization application is set by the parameter CurrentInput. Here the setting MaxPh is chosen.

GlobalBaseSel: Selects the global base value group used by the function to define (IBase), (UBase) and (SBase).

VoltageInput: The Voltage used for the inadvertent energization application is set by the parameter VoltageInput. Here the setting MaxPh-Ph is chosen.

OperHarmRestr: No 2nd harmonic restrain is used in this application: OperHarmRestr is set Disabled. It can be set Enabled if the instance is used also for other protection functions.

EnRestrainCurr: The restrain current function is not used in this application: EnRestrainCurr is set Disabled. It can be set Enabled if the instance is used also for other protection functions.

12.1.3.10 Settings for OC1

Operation_OC1: The parameter Operation_OC1 is set Enabled to activate this function.

PickupCurr_OC1: The operate current level for OC1 is set by the parameter PickupCurr_OC1. The setting is made in % of IBase. The setting should be made so that the protection picks up at all situations when the generator is switched on to the grid at stand still situations. The generator current in such situations is dependent of the short circuit capacity of the external grid. It is however assumed that a setting of 50% of the generator rated current will detect all situations of inadvertent energization of the generator.

CurveType_OC1: The time delay of OC1 should be of type definite time and this is set in the parameter CurveType_OC1 where ANSI Def. Time is chosen.
The time delay is set in the parameter `tDef_OC1` and is set to a short time. 0.05 s is recommended. Note that the value set is the time between activation of the start and the trip outputs.

Voltage control mode for OC1: `VCntrlMode_OC1` is set *Disabled*.

Harmonic restrain for OC1: `HarmRestr_OC1` is set *Disabled*.

Direction mode for OC1: `DirMode_OC1` is set *Disabled*.

**12.1.3.11 Setting for OC2**

`Operation_OC2`: `Operation_OC2` is set *Disabled* if the function is not used for other protection function.

**12.1.3.12 Setting for UC1**

`Operation_UC1`: `Operation_UC1` is set *Disabled* if the function is not used for other protection function.

**12.1.3.13 Setting for UC2**

`Operation_UC2`: `Operation_UC2` is set *Disabled* if the function is not used for other protection function.

**12.1.3.14 Settings for OV1**

`Operation_OV1`: The parameter `Operation_OV1` is set *Enabled* to activate this function.

`PickupVolt_OV1`: The operate voltage level for OV1 is set by the parameter `PickupVolt_OV1`. The setting is made in % of `VBase`. The setting should be made so that the protection blocks the function at all situation of normal operation. The setting is done as the lowest operate voltage level of the generator with an added margin. The setting 85% can be used in most cases.

`CurveType_OV1`: The time delay of OV1 should be of type definite time and this is set in the parameter `CurveType_OV1` where *Definite time* is chosen.

`ResCrvType_OV1`: The reset time delay of OV1 should be instantaneous and this is set in the parameter `ResCrvType_OV1` where *Instantaneous* chosen.

`tDef_OV1`: The time delay is set in the parameter `tDef_OV1` and is set so that the inadvertent energizing function is active a short time after energizing the generator. 1.0 s is recommended.

**12.1.3.15 Setting for OV2**

`Operation_OV2`: `Operation_OV2` is set *Disabled* if the function is not used for other protection function.

**12.1.3.16 Settings for UV1**

`Operation_UV1`: The parameter `Operation_UV1` is set *Enabled* to activate this function.
**PickupVolt_UV1**: The operate voltage level for UV1 is set by the parameter *PickupVolt_UV1*. The setting is made in % of *VBase*. The setting shall be done so that all situations with disconnected generator are detected. The setting 70% can be used in most cases.

**CurveType_UV1**: The time delay of UV1 should be of type definite time and this is set in the parameter *CurveType_UV1* where *Definite time* is chosen.

**ResCrvType_UV1**: The reset time delay of UV1 should be delayed a short time so that the function is not blocked before operation of OC1 in case of inadvertent energizing of the generator. The parameter *ResCrvType_UV1* is set to *Frozen timer*.

**tDef_UV1**: The time delay is set in the parameter *tDef_UV1* and is set so that the inadvertent energizing function is activated after some time when the generator is disconnected from the grid. 10.0 s is recommended.

**tResetDef_UV1**: The reset time of UV1 is set by the parameter *tResetDef_UV1*. The setting 1.0 s is recommended.

### 12.1.3.17 Setting for UV2

*Operation_UV2*: *Operation_UV2* is set *Disabled* if the function is not used for other protection function.
Section 13    System protection and control

13.1    Multipurpose filter SMAIHPAC

13.1.1    Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Multipurpose filter</td>
<td>SMAIHPAC</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

13.1.2    Application

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

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

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

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

The filter output can also be connected to the measurement function blocks such as CVMMXN (Measurements), CMMXU (Phase current measurement), VMMXU (Phase-phase voltage measurement), etc. in order to report the extracted phasor values to the supervisory system (e.g. MicroSCADA).
It is recommended that the trip time delay of under voltage or under current functions is set longer than the SMAIHPAC FilterLength to allow time for the SAMIHPAC outputs to stabilize at startup.

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

![Figure 225: Required ACT configuration](IEC13000179-1-en.vsd)

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

### 13.1.3 Setting guidelines

#### 13.1.3.1 Setting example

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

\[
    t_{op} = T_{01} + \frac{K}{I_S}
\]

(Equation 255)

Where:

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

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

Solution:
First the IED configuration shall be arranged as shown in Figure 225. Then the settings for SMAI HPAC filter and multipurpose function shall be derived from existing relay settings in the following way:

The subsynchronous current frequency is calculated as follows:

\[ f_s = 50\, \text{Hz} - 18.5\, \text{Hz} = 31.5\, \text{Hz} \]  

\[ \text{(Equation 256)} \]

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

<table>
<thead>
<tr>
<th>Table 51: Proposed settings for SMAIHPAC</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>I_HPAC_31_5Hz: SMAIHPAC:1</strong></td>
</tr>
<tr>
<td>ConnectionType</td>
</tr>
<tr>
<td>SetFrequency</td>
</tr>
<tr>
<td>FreqBandWidth</td>
</tr>
<tr>
<td>FilterLength</td>
</tr>
<tr>
<td>OverLap</td>
</tr>
<tr>
<td>Operation</td>
</tr>
</tbody>
</table>

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

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

\[ \text{ (Equation 257) } \]

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

\[ i[x] = \left( \frac{K}{\frac{i_s}{I_{so}}} + T_0 \right) \cdot 1 \]  

\[ \text{ (Equation 258) } \]

Thus if the following rules are followed when multi-purpose overcurrent stage one is set:
\[ A = \frac{K}{I_{so}} = \frac{35566}{300} = 118.55 \]
\[ B = T_{01} = 0.64 \]
\[ C = 0.0 \]
\[ p = 1.0 \]
\[ k = 1.0 \]

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

<table>
<thead>
<tr>
<th>Setting Group1</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Operation</td>
<td>On</td>
</tr>
<tr>
<td>CurrentInput</td>
<td>MaxPh</td>
</tr>
<tr>
<td>IBase</td>
<td>1000</td>
</tr>
<tr>
<td>VoltageInput</td>
<td>MaxPh</td>
</tr>
<tr>
<td>UBase</td>
<td>20.50</td>
</tr>
<tr>
<td>OPerHarmRestr</td>
<td>Off</td>
</tr>
<tr>
<td>I_2ndI_fund</td>
<td>20.0</td>
</tr>
<tr>
<td>BlkLevel2nd</td>
<td>5000</td>
</tr>
<tr>
<td>EnRestrainCurr</td>
<td>Off</td>
</tr>
<tr>
<td>RestrCurrInput</td>
<td>PosSeq</td>
</tr>
<tr>
<td>RestrCurrCoeff</td>
<td>0.00</td>
</tr>
<tr>
<td>RCADir</td>
<td>-75</td>
</tr>
<tr>
<td>ROADir</td>
<td>75</td>
</tr>
<tr>
<td>LowVolt_VM</td>
<td>0.5</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>OC1</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Setting Group1</td>
<td></td>
</tr>
<tr>
<td>Operation_OC1</td>
<td>On</td>
</tr>
<tr>
<td>StartCurr_OC1</td>
<td>30.0</td>
</tr>
<tr>
<td>CurrMult_OC1</td>
<td>2.0</td>
</tr>
<tr>
<td>CurveType_OC1</td>
<td>Programmable</td>
</tr>
<tr>
<td>tDef_OC1</td>
<td>0.00</td>
</tr>
<tr>
<td>k_OC1</td>
<td>1.00</td>
</tr>
<tr>
<td>tMin1</td>
<td>30</td>
</tr>
<tr>
<td>tMin_OC1</td>
<td>1.40</td>
</tr>
<tr>
<td>ResCrVType_OC1</td>
<td>Instantaneous</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>tResetDef_OC1</td>
<td>0.00</td>
</tr>
<tr>
<td>P_OC1</td>
<td>1.000</td>
</tr>
<tr>
<td>A_OC1</td>
<td>118.55</td>
</tr>
<tr>
<td>B_OC1</td>
<td>0.640</td>
</tr>
<tr>
<td>C_OC1</td>
<td>0.000</td>
</tr>
</tbody>
</table>
Section 14  Secondary system supervision

14.1  Current circuit supervision (87)

14.1.1  Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current circuit supervision</td>
<td>CCSPVC</td>
<td>-</td>
<td>87</td>
</tr>
</tbody>
</table>

14.1.2  Application

Open or short circuited current transformer cores can cause unwanted operation of many protection functions such as differential, ground-fault current and negative-sequence current functions. When currents from two independent three-phase sets of CTs, or CT cores, measuring the same primary currents are available, reliable current circuit supervision can be arranged by comparing the currents from the two sets. If an error in any CT circuit is detected, the protection functions concerned can be blocked and an alarm given.

In case of large currents, unequal transient saturation of CT cores with different remanence or different saturation factor may result in differences in the secondary currents from the two CT sets. Unwanted blocking of protection functions during the transient stage must then be avoided.

Current circuit supervision CCSPVC (87) must be sensitive and have short operate time in order to prevent unwanted tripping from fast-acting, sensitive numerical protections in case of faulty CT secondary circuits.

Open CT circuits creates extremely high voltages in the circuits which is extremely dangerous for the personnel. It can also damage the insulation and cause new problems. The application shall, thus, be done with this in consideration, especially if the protection functions are blocked.

14.1.3  Setting guidelines

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

Current circuit supervision CCSPVC (87) compares the residual current from a three-phase set of current transformer cores with the neutral point current on a separate input taken from another set of cores on the same current transformer.

*IMinOp:* It must be set as a minimum to twice the residual current in the supervised CT circuits under normal service conditions and rated primary current.
**Pickup Block:** It is normally set at 150% to block the function during transient conditions.

The FAIL output is connected to the blocking input of the protection function to be blocked at faulty CT secondary circuits.

### 14.2 Fuse failure supervision FUFSPVC

#### 14.2.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuse failure supervision</td>
<td>FUFSPVC</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

#### 14.2.2 Application

Different protection functions within the protection IED, operates on the basis of the measured voltage in the relay point. Examples are:

- impedance protection functions
- undervoltage function
- energizing check function and voltage check for the weak infeed logic

These functions can operate unintentionally if a fault occurs in the secondary circuits between the voltage instrument transformers and the IED.

It is possible to use different measures to prevent such unwanted operations. Miniature circuit breakers in the voltage measuring circuits should be located as close as possible to the voltage instrument transformers, and shall be equipped with auxiliary contacts that are wired to the IEDs. Separate fuse-failure monitoring IEDs or elements within the protection and monitoring devices are another possibilities. These solutions are combined to get the best possible effect in the fuse failure supervision function (FUFSFPC).

FUFSFPC function built into the IED products can operate on the basis of external binary signals from the miniature circuit breaker or from the line disconnector. The first case influences the operation of all voltage-dependent functions while the second one does not affect the impedance measuring functions.

The negative sequence detection algorithm, based on the negative-sequence measuring quantities is recommended for use in isolated or high-impedance grounded networks: a high value of voltage $3V_2$ without the presence of the negative-sequence current $3I_2$ is a condition that is related to a fuse failure event.

The zero sequence detection algorithm, based on the zero sequence measuring quantities is recommended for use in directly or low impedance grounded networks: a high value of voltage $3V_0$ without the presence of the residual current $3I_0$ is a condition that is related to a fuse failure event. In cases where the line can have a weak-infeed of zero sequence current this function shall be avoided.
A criterion based on delta current and delta voltage measurements can be added to the fuse failure supervision function in order to detect a three phase fuse failure. This is beneficial for example during three phase transformer switching.

14.2.3 Setting guidelines

14.2.3.1 General

The negative and zero sequence voltages and currents always exist due to different non-symmetries in the primary system and differences in the current and voltage instrument transformers. The minimum value for the operation of the current and voltage measuring elements must always be set with a safety margin of 10 to 20%, depending on the system operating conditions.

Pay special attention to the dissymmetry of the measuring quantities when the function is used on long untransposed lines, on multicircuit lines and so on.

The settings of negative sequence, zero sequence and delta algorithm are in percent of the base voltage and base current for the function. Common base IED values for primary current ($I_{Base}$), primary voltage ($V_{Base}$) and primary power ($S_{Base}$) are set in Global Base Values $GBASVAL$. The setting $GlobalBaseSel$ is used to select a particular $GBASVAL$ and used its base values.

14.2.3.2 Setting of common parameters

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

The voltage threshold $V_{PPU}$ is used to identify low voltage condition in the system. Set $V_{PPU}$ below the minimum operating voltage that might occur during emergency conditions. We propose a setting of approximately 70% of $V_{Base}$.

The drop off time of 200 ms for dead phase detection makes it recommended to always set $SealIn$ to $Enabled$ since this will secure a fuse failure indication at persistent fuse fail when closing the local breaker when the line is already energized from the other end. When the remote breaker closes the voltage will return except in the phase that has a persistent fuse fail. Since the local breaker is open there is no current and the dead phase indication will persist in the phase with the blown fuse. When the local breaker closes the current will start to flow and the function detects the fuse failure situation. But due to the 200 ms drop off timer the output BLKZ will not be activated until after 200 ms. This means that distance functions are not blocked and due to the “no voltage but current” situation might issue a trip.

The operation mode selector $OpModeSel$ has been introduced for better adaptation to system requirements. The mode selector enables selecting interactions between the negative sequence and zero sequence algorithm. In normal applications, the $OpModeSel$ is set to either $V2I2$ for selecting negative sequence algorithm or $V0I0$ for zero sequence based algorithm. If system studies or field experiences shows that there is a risk that the fuse failure function will not be activated due to the system conditions, the dependability of the fuse failure function can be increased if the $OpModeSel$ is set to $V0I0 OR V2I2$ or $OptimZsNs$. In mode $V0I0 OR V2I2$ both negative and zero sequence algorithms are activated and working in an OR-condition. Also in mode $OptimZsNs$ both negative and zero sequence algorithms are activated and the one that has the highest magnitude of measured negative or zero sequence current will operate. If there is a requirement to increase the security of the fuse failure function $OpModeSel$ can be selected to $V0I0 AND V2I2$ which gives that both negative and zero sequence algorithms are activated and
working in an AND-condition, that is, both algorithms must give condition for block in order to activate the output signals BLKV or BLKZ.

14.2.3.3 Negative sequence based

The relay setting value $3V_{2PU}$ is given in percentage of the base voltage $V_{Base}$ and should not be set lower than the value that is calculated according to equation 259.

$$3V_{2PU} = \frac{V_{2}}{V_{Base}/\sqrt{3}} \cdot 100$$

(Equation 259)

where:
- $V_{2PU}$ is the maximal negative sequence voltage during normal operation conditions, plus a margin of 10...20%
- $V_{Base}$ is the base voltage for the function according to the setting $GlobalBaseSel$

The setting of the current limit $3I_{2PU}$ is in percentage of parameter $I_{Base}$. The setting of $3I_{2PU}$ must be higher than the normal unbalance current that might exist in the system and can be calculated according to equation 260.

$$3I_{2PU} = \frac{I_{2}}{I_{Base}} \cdot 100$$

(Equation 260)

where:
- $I_{2}$ is the maximal negative sequence current during normal operating conditions, plus a margin of 10...20%
- $I_{Base}$ is the base current for the function according to the setting $GlobalBaseSel$

14.2.3.4 Zero sequence based

The IED setting value $3V_{0PU}$ is given in percentage of the base voltage $V_{Base}$. The setting of $3V_{0PU}$ should not be set lower than the value that is calculated according to equation 261.

$$3V_{0PU} = \frac{3V_{0}}{V_{Base}/\sqrt{3}} \cdot 100$$

(Equation 261)

where:
- $3V_{0}$ is the maximal zero sequence voltage during normal operation conditions, plus a margin of 10...20%
- $V_{Base}$ is the base voltage for the function according to the setting $GlobalBaseSel$

The setting of the current limit $3I_{0PU}$ is done in percentage of $I_{Base}$. The setting of pickup must be higher than the normal unbalance current that might exist in the system. The setting can be calculated according to equation 262.
\[ 3I_{OPU} = \frac{3I_{0}}{I_{Base}} \cdot 100 \]

(Equation 262)

where:

- \(3I_{OPU}\) is the maximal zero sequence current during normal operating conditions, plus a margin of 10...20%
- \(I_{Base}\) is the base current for the function according to the setting \textit{GlobalBaseSel}

### 14.2.3.5 Delta V and delta I

Set the operation mode selector \textit{OpDVDI} to \textit{Enabled} if the delta function shall be in operation.

The setting of \(DV_{PU}\) should be set high (approximately 60\% of \(V_{Base}\)) and the current threshold \(DI_{PU}\)low (approximately 10\% of \(I_{Base}\)) to avoid unwanted operation due to normal switching conditions in the network. The delta current and delta voltage function shall always be used together with either the negative or zero sequence algorithm. If \(V_{Set_{prim}}\) is the primary voltage for operation of \(dU/dt\) and \(I_{Set_{prim}}\) the primary current for operation of \(dI/dt\), the setting of \(DV_{PU}\) and \(DI_{PU}\) will be given according to equation 263 and equation 264.

- \(DV_{PU} = \frac{V_{Set_{prim}}}{V_{Base}} \cdot 100\)

(Equation 263)

- \(DI_{PU} = \frac{I_{Set_{prim}}}{I_{Base}} \cdot 100\)

(Equation 264)

The voltage thresholds \(V_{PPU}\) is used to identify low voltage condition in the system. Set \(V_{PPU}\) below the minimum operating voltage that might occur during emergency conditions. A setting of approximately 70\% of \(V_{Base}\) is recommended.

The current threshold \(S0_{P}\) shall be set lower than the \(I_{MinOp}\) for the distance protection function. A 5...10\% lower value is recommended.

### 14.2.3.6 Dead line detection

The condition for operation of the dead line detection is set by the parameters \(ID_{LDPU}\) for the current threshold and \(UD_{LD}<\) for the voltage threshold.

Set the \(ID_{LDPU}\) with a sufficient margin below the minimum expected load current. A safety margin of at least 15-20\% is recommended. The operate value must however exceed the maximum charging current of an overhead line, when only one phase is disconnected (mutual coupling to the other phases).

Set the \(VD_{LDPU}\) with a sufficient margin below the minimum expected operating voltage. A safety margin of at least 15\% is recommended.
14.3  Fuse failure supervision VDSPVC (60)

14.3.1  Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuse failure supervision</td>
<td>VDSPVC</td>
<td>VTS</td>
<td>60</td>
</tr>
</tbody>
</table>

14.3.2  Application

Some protection functions operate on the basis of measured voltage at the relay point. Examples of such protection functions are distance protection function, undervoltage function and energisation-check function. These functions might mal-operate if there is an incorrect measured voltage due to fuse failure or other kind of faults in voltage measurement circuit.

VDSPVC is designed to detect fuse failures or faults in voltage measurement circuit based on comparison of the voltages of the main and pilot fused circuits phase wise. VDSPVC output can be configured to block voltage dependent protection functions such as high-speed distance protection, undervoltage relays, underimpedance relays and so on.
14.3.3 Setting guidelines

The parameters for Fuse failure supervision VDSPVC are set via the local HMI or PCM600.

The voltage input type (phase-to-phase or phase-to-neutral) is selected using *ConTypeMain* and *ConTypePilot* parameters, for main and pilot fuse groups respectively.

The connection type for the main and the pilot fuse groups must be consistent.

The settings *Vdif Main block*, *Vdif Pilot alarm* and *VSealIn* are in percentage of the base voltage, *VBase*. Set *VBase* to the primary rated phase-to-phase voltage of the potential voltage transformer. *VBase* is available in the Global Base Value groups; the particular Global Base Value group, that is used by VDSPVC (60), is set by the setting parameter *GlobalBaseSel*. 
The settings \textit{Vdif Main block} and \textit{Vdif Pilot alarm} should be set low (approximately 30\% of \textit{VBase}) so that they are sensitive to the fault on the voltage measurement circuit, since the voltage on both sides are equal in the healthy condition. If \( V_{SetPrim} \) is the desired pick up primary phase-to-phase voltage of measured fuse group, the setting of \textit{Vdif Main block} and \textit{Vdif Pilot alarm} will be given according to equation \ref{eq:265}.

\[
\text{Vdif Main block or Vdif Pilot alarm} = \frac{V_{SetPrim}}{V_{Base}} \times 100
\]

(Equation 265)

\( V_{SetPrim} \) is defined as phase to neutral or phase to phase voltage dependent of the selected \textit{ConTypeMain} and \textit{ConTypePilot}. If \textit{ConTypeMain} and \textit{ConTypePilot} are set to \textit{Ph-N} than the function performs internally the rescaling of \( V_{SetPrim} \).

When \textit{SealIn} is set to \textit{On} and the fuse failure has last for more than 5 seconds, the blocked protection functions will remain blocked until normal voltage conditions are restored above the \( V_{SealIn} \) setting. The fuse failure outputs are deactivated when the normal voltage conditions are restored.

14.4 Voltage based delta supervision DELVSPVC(78V)

14.4.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage based delta supervision</td>
<td>DELVSPVC</td>
<td>–</td>
<td>7V_78V</td>
</tr>
</tbody>
</table>

14.4.2 Application

In a weak grid networks, fault detection and operation of other protection functions is reliably done by delta supervision functionality. In this type of network, a delta based release criteria is used to release the trip signal. The measurement of delta differs from country to country between magnitude, vector or sample based detection.

In this function, a voltage based delta supervision is implemented in a phase segregated design. The delta function has the following features:

- Instantaneous sample based delta detection
- True RMS value based delta detection
- DFT magnitude based delta detection
- Vector shift protection

The Delta detection mode is selected on the basis of application requirements. For example, instantaneous sample based delta supervision is very fast; the delta is detected in less than a cycle typically. Hence, instantaneous sample based delta supervision can be used for functions that are used as protection enablers or fault detectors.

All the other supervision modes like RMS/DFT Mag or Angle requires minimum one cycle for delta detection and can be used for time delay functions.
Angle shift mode

Use of distributed generation (DG) units is increasing due to liberalized markets (deregulation) and the global trend to use more renewable sources of energy. They generate power in the range of 10 kW to 10 MW and most of them are interconnected to the distribution network. They can supply power into the network as well as to the local loads. It is not common to connect generators directly to the distribution networks and thus the distributed generation can cause some challenges for the protection of distribution networks. From the protection point of view, one of the most challenging issue is islanding.

Islanding is defined as a condition in which a distributed generation unit continues to supply power to a certain part of the distribution network when power from the larger utility main grid is no longer available after opening of a circuit-breaker.

Islanding is also referred as Loss of Mains (LOM) or Loss of Grid (LOG). When LOM occurs, neither the voltage nor the frequency is controlled by the utility supply. Also, these distributed generators are not equipped with voltage and frequency control; therefore, the voltage magnitude of an islanded network may not be kept within the desired limits resulting into undefined voltage magnitudes during islanding situations and frequency instability. Further, uncontrolled frequency represents a high risk for drives and other machines.

Islanding can occur as a consequence of:

- a fault in the network
- circuit-breaker maloperation
- circuit-breaker opening during maintenance

If the distributed generator continues its operation after the utility supply is disconnected, faults do not clear under certain conditions as the arc is charged by the distributed generators. Moreover, the distributed generators are incompatible with the current reclosing practices. During the reclosing sequence dead time, the generators in the network usually tend to drift out of synchronism with the grid and, reconnecting them without synchronizing may damage the generators introducing high currents and voltages in the neighbouring network.

Due to the technical difficulties mentioned above, protection should be provided, which disconnects the distributed generation once it is electrically isolated from the main grid supply. Various techniques are used for detecting Loss of Mains. However, the present feature of voltage supervision focuses on voltage vector shift.

For islanding based on vector shift protection, the logic shown in Figure 227 should be used to trip the breaker. With this logic, reliable tripping can be ensured as angle shift has been detected in all the three phase voltages.
The vector shift detection guarantees fast and reliable detection of mains failure in almost all operational conditions when a distributed generation unit is running in parallel with the mains supply, but in certain cases this may fail.

If the active and reactive power generated by the distributed generation units is nearly balanced (for example, if the power mismatch or unbalance is less than 5...10%) with the active and reactive power consumed by loads, a large enough voltage phase shift may not occur which can be detected by the vector shift algorithm. This means that the vector shift algorithm has a small non-detection zone (NDZ) which is also dependent on the type of generators, loads, network and start or operate value of the vector shift algorithm.

Other network events like capacitor switching, switching of very large loads in weak network or connection of parallel transformer at HV/MV substation, in which the voltage magnitude is not changed considerably (unlike in faults) can potentially cause maloperation of vector shift algorithm, if very sensitive settings are used.

The vector shift detection also protects synchronous generators from damaging due to islanding or loss-of-mains.

### 14.4.3 Setting guidelines

**Operation**: This setting is used to enable/disable the delta supervision function.

**Umin**: The minimum start level setting should be set as % of $U_{Base}$. This setting enables the function to start detecting delta. Typical setting is 10% of $U_{Base}$. If the MeasMode setting is set as *phase to ground*, this setting is taken as 50% of the set value.

**MeasMode**: This setting is used to detect the mode of measurement; *phase to phase* or *phase to ground*.

**OpMode**: This setting is used to select the mode of operation. For protection applications, this should be set to *Instantaneous 1 cycle old*. Load supervision can be done using vector shift mode or DFT mag mode.

**DelU>**: This setting is used to detect the start value for instantaneous sample, RMS, DFT mag based delta detection. Set a typical value of 50% of $U_{Base}$ to use this function as fault detection.
DelUang: This setting is used for angle based delta detection. This setting could be used to detect islanding condition. A typical setting of 8-10 deg. is good to detect a major islanding condition.

DeltaT: This setting defines the number of old cycles data to be used for delta calculation in RMS/DFT Mag and angle mode. Typical value is 2 cycles. This value is not used if OpMode is chosen as instantaneous 1 cycle or instantaneous 2 cycle.

tHold: This setting defines the pulse length for supervision start signal. Typical value is 100 ms.

14.5 Current based delta supervision DELISPVC(7I)

14.5.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current based delta supervision</td>
<td>DELISPVC</td>
<td>–</td>
<td>7I &lt;&gt;</td>
</tr>
</tbody>
</table>

14.5.2 Application

In power system networks, fault detection and operation of other protection functions is reliably done by delta supervision functionality. Single phase networks are an important application of delta supervision. In this type of network, a delta based release criteria is used to release the protection function. The measurement of delta differs from country to country between magnitude, vector or sample based detection.

In this function, a current based delta supervision is implemented in a phase segregated design. The delta function has the following features:

- Instantaneous sample based delta detection (vectorial delta)
- True RMS value based delta detection
- DFT magnitude based delta detection
- 2nd harmonic blocking of delta function
- 3rd harmonic based adaption of starting value

Instantaneous sample based delta supervision is very fast; the delta is detected in less than a cycle typically. This mode can be used for high impedance earth fault detection. All the other supervision modes like RMS/DFT Mag requires minimum one cycle for delta detection.

Therefore, the choice of delta detection mode should be based on the application requirement. Instantaneous sample based delta supervision can be used for functions that are used as protection enabler or fault detector. For time delayed functions, other modes can be used. Current based function can be used for load supervision also in DFT Mag based delta mode.

14.5.3 Setting guidelines

Operation: This setting is used to enable/disable the delta supervision function.
*Imin*: The minimum pickup level setting should be set as % of *IBase*. This setting enables the function to start detecting delta. Typical setting is 10% of *IBase*.

*MeasMode*: This setting is used to detect the mode of measurement; *phase to phase* or *phase to ground*.

*OpMode*: This setting is used to select the mode of operation. For protection applications, this should be set to *Instantaneous 1 cycle old*. Load supervision can be done using DFT mag mode.

*DelI>*: This setting is used to detect the pickup value for instantaneous sample, RMS, DFT mag based delta detection. Set a typical value of 200% of *IBase* to use this function as fault detection.

*DeltaT*: This setting defines the number of old cycles data to be used for delta calculation in RMS/DFT Mag mode. Typical value is 2 cycles.

*tHold*: This setting defines the pulse length for supervision pickup signal. Typical value is 100 ms.

*EnaHarm2Blk*: This setting should be set to ON, to enable blocking for heavy inrush currents or other sources of 2nd harmonic injections.

*Harm2BlkLev*: This is the blocking level of 2nd harmonic with respect to the fundamental signal. Typical setting is 15% of fundamental signal.

*EnStValAdap*: This setting should be set to ENABLE in special networks where settings in the network are adapted with respect to 3rd harmonic level.

*Harm3Level*: This is the set level of 3rd harmonic with respect to fundamental signal at which the *DelI>* should be modified. Typical setting is 15% of fundamental signal.

*StValGrad*: This setting is used to modify the *DelI>* based on 3rd harmonic level. Typical setting is 10% to modify the *DelI>*.

### 14.6 Delta supervision of real input DELSPVC

#### 14.6.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Delta supervision of real input DELSPVC</td>
<td>DELSPVC</td>
<td>–</td>
<td>–</td>
</tr>
</tbody>
</table>

#### 14.6.2 Application

Delta supervision of real input DELSPVC is a general processed input delta supervision. It is used to configure any processed inputs such as:

- Power (S)
- Active power (P)
- Reactive power (P)
- Thermal heat content (\(\theta\))
- Energy
The change over time of these quantities with respect to the old value can be supervised with this function.

### 14.6.3 Setting guidelines

*Operation*: This setting is used to enable/disable the delta supervision function.

*MinStVal*: The minimum start level of the function. If the input is below this level, the function will be blocked. It should be set depending on the input connected.

*DelSt>:* This setting is used to set the start value for delta detection.

*DeltaT*: This setting defines the number of execution cycles of old data to be used for delta calculation. That is, if *DeltaT* setting is set as 6 for a 3 ms function, an 18 ms old value will be used to compare the change against.

*tHold*: This setting defines the pulse length for the start signal. A typical value of this setting is 100 ms.
Section 15  Control

15.1  Synchronism check, energizing check, and synchronizing SESRSYN (25)

15.1.1  Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Synchrocheck, energizing check, and synchronizing</td>
<td>SESRSYN</td>
<td></td>
<td>25</td>
</tr>
</tbody>
</table>

15.1.2  Application

15.1.2.1  Synchronizing

To allow closing of breakers between asynchronous networks, a synchronizing feature is provided. The breaker close command is issued at the optimum time when conditions across the breaker are satisfied in order to avoid stress on the network and its components.

The systems are defined as asynchronous when the frequency difference between bus and line is larger than an adjustable parameter. If the frequency difference is less than this threshold value the system is defined to have a parallel circuit and the synchronism check function is used.

The synchronizing function measures the difference between the V-Line and the V-Bus. It operates and enables a closing command to the circuit breaker when the calculated closing angle is equal to the measured phase angle and the following conditions are simultaneously fulfilled:

- The voltages V-Line and V-Bus are higher than the set values for $V_{HighBusSynch}$ and $V_{HighLineSynch}$ of the respective base voltages $GlbBaseSelBus$ and $GlbBaseSelLine$.
- The difference in the voltage is smaller than the set value of $V_{DiffSynch}$.
- The difference in frequency is less than the set value of $FreqDiffMax$ and larger than the set value of $FreqDiffMin$. If the frequency is less than $FreqDiffMin$ the synchronism check is used and the value of $FreqDiffMin$ must thus be identical to the value $FreqDiffM$ resp $FreqDiffA$ for synchronism check function. The bus and line frequencies must also be within a range of ±5 Hz from the rated frequency. When the synchronizing option is included also for autoreclose there is no reason to have different frequency setting for the manual and automatic reclosing and the frequency difference values for synchronism check should be kept low.
- The frequency rate of change is less than set value for both V-Bus and V-Line.
- The difference in the phase angle is smaller than the set value of $CloseAngleMax$.
- The closing angle is decided by the calculation of slip frequency and required pre-closing time.
The synchronizing function compensates for the measured slip frequency as well as the circuit breaker closing delay. The phase angle advance is calculated continuously. The calculation of the operation pulse sent in advance is using the measured SlipFrequency and the set tBreaker time. To prevent incorrect closing pulses, a maximum closing angle between bus and line is set with CloseAngleMax. Table 52 below shows the maximum settable value for tBreaker when CloseAngleMax is set to 15 or 30 degrees, at different allowed slip frequencies for synchronizing. To minimize the moment stress when synchronizing near a power station, a narrower limit for the CloseAngleMax needs to be used.

Table 52: Dependencies between tBreaker and SlipFrequency with different CloseAngleMax values

<table>
<thead>
<tr>
<th>tBreaker [s] (max settable value) with CloseAngleMax = 15 degrees [default value]</th>
<th>tBreaker [s] (max settable value) with CloseAngleMax = 30 degrees [max value]</th>
<th>SlipFrequency [Hz] (BusFrequency - LineFrequency)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.040</td>
<td>0.080</td>
<td>1.000</td>
</tr>
<tr>
<td>0.050</td>
<td>0.100</td>
<td>0.800</td>
</tr>
<tr>
<td>0.080</td>
<td>0.160</td>
<td>0.500</td>
</tr>
<tr>
<td>0.200</td>
<td>0.400</td>
<td>0.200</td>
</tr>
<tr>
<td>0.400</td>
<td>0.810</td>
<td>0.100</td>
</tr>
<tr>
<td>1.000</td>
<td></td>
<td>0.080</td>
</tr>
<tr>
<td>0.800</td>
<td></td>
<td>0.050</td>
</tr>
<tr>
<td>1.000</td>
<td></td>
<td>0.040</td>
</tr>
</tbody>
</table>

The reference voltage can be phase-neutral A, B, C or phase-phase A-B, B-C, C-A or positive sequence (Require a three phase voltage, that is VA, VB and VC). By setting the phases used for SESRSYN, with the settings SelPhaseBus1, SelPhaseBus2, SelPhaseLine2 and SelPhaseLine2, a compensation is made automatically for the voltage amplitude difference and the phase angle difference caused if different setting values are selected for the two sides of the breaker. If needed an additional phase angle adjustment can be done for selected line voltage with the PhaseShift setting.

### 15.1.2.2 Synchronism check

The main purpose of the synchronism check function is to provide control over the closing of circuit breakers in power networks in order to prevent closing if conditions for synchronism are not detected. It is also used to prevent the re-connection of two systems, which are divided after islanding and after a three pole reclosing.

Single pole auto-reclosing does not require any synchronism check since the system is tied together by two phases.

SESRSYN (25) function block includes both the synchronism check function and the energizing function to allow closing when one side of the breaker is dead. SESRSYN (25) function also includes a built in voltage selection scheme which allows adoption to various busbar arrangements.
Figure 228: Two interconnected power systems

Figure 228 shows two interconnected power systems. The cloud means that the interconnection can be further away, that is, a weak connection through other stations. The need for a check of synchronization increases if the meshed system decreases since the risk of the two networks being out of synchronization at manual or automatic closing is greater.

The synchronism check function measures the conditions across the circuit breaker and compares them to set limits. Output is generated only when all measured conditions are within their set limits simultaneously. The check consists of:

- Live line and live bus.
- Voltage level difference.
- Frequency difference (slip). The bus and line frequency must also be within a range of ±5 Hz from rated frequency.
- Phase angle difference.

A time delay is available to ensure that the conditions are fulfilled for a minimum period of time.

In very stable power systems the frequency difference is insignificant or zero for manually initiated closing or closing by automatic restoration. In steady conditions a bigger phase angle difference can be allowed as this is sometimes the case in a long and loaded parallel power line. For this application we accept a synchronism check with a long operation time and high sensitivity regarding the frequency difference. The phase angle difference setting can be set for steady state conditions.

Another example is the operation of a power network that is disturbed by a fault event: after the fault clearance a highspeed auto-reclosing takes place. This can cause a power swing in the net and the phase angle difference may begin to oscillate. Generally, the frequency difference is the time derivative of the phase angle difference and will, typically oscillate between positive and negative values. When the circuit breaker needs to be closed by auto-reclosing after fault-clearance some frequency difference should be tolerated, to a greater extent than in the steady condition mentioned in the case above. But if a big phase angle difference is allowed at the same time, there is some risk that auto-reclosing will take place when the phase angle difference is big and increasing. In this case it should be safer to close when the phase angle difference is smaller.

To fulfill the above requirements the synchronism check function is provided with duplicate settings, one for steady (Manual) conditions and one for operation under disturbed conditions (Auto).
15.1.2.3 Energizing check

The main purpose of the energizing check function is to facilitate the controlled re-connection of disconnected lines and buses to energized buses and lines.

The energizing check function measures the bus and line voltages and compares them to both high and low threshold values. The output is given only when the actual measured conditions match the set conditions. Figure 230 shows two substations, where one (1) is energized and the other (2) is not energized. The line between CB A and CB B is energized (DLLB) from substation 1 via the circuit breaker A and energization of station 2 is done by CB B energization check device for that breaker DBLL. (or Both).

Figure 229: Principle for the synchronism check function

Figure 230: Principle for the energizing check function
The energizing operation can operate in the dead line live bus (DLLB) direction, dead bus live line (DBLL) direction, or in both directions over the circuit breaker. Energizing from different directions can be different for automatic reclosing and manual closing of the circuit breaker. For manual closing it is also possible to allow closing when both sides of the breaker are dead, Dead Bus Dead Line (DBDL).

The equipment is considered energized (Live) if the voltage is above the set value for \( V_{\text{LiveBusEnerg}} \) or \( V_{\text{LiveLineEnerg}} \) of the base voltages \( G_{\text{BaseSelBus}} \) and \( G_{\text{BaseSelLine}} \), which are defined in the Global Base Value groups, according to the setting of \( G_{\text{BaseSelBus}} \) and \( G_{\text{BaseSelLine}} \); in a similar way, the equipment is considered non-energized (Dead) if the voltage is below the set value for \( V_{\text{DeadBusEnerg}} \) or \( V_{\text{DeadLineEnerg}} \) of the respective Global Base Value groups. A disconnected line can have a considerable potential due to factors such as induction from a line running in parallel, or feeding via extinguishing capacitors in the circuit breakers. This voltage can be as high as 50% or more of the base voltage of the line. Normally, for breakers with single breaking elements (<330 kV) the level is well below 30%.

When the energizing direction corresponds to the settings, the situation has to remain constant for a certain period of time before the close signal is permitted. The purpose of the delayed operate time is to ensure that the dead side remains de-energized and that the condition is not due to temporary interference.

### 15.1.2.4 Voltage selection

The voltage selection function is used for the connection of appropriate voltages to the synchronism check, synchronizing and energizing check functions. For example, when the IED is used in a double bus arrangement, the voltage that should be selected depends on the status of the breakers and/or disconnectors. By checking the status of the disconnectors auxiliary contacts, the right voltages for the synchronism check and energizing check functions can be selected.

Available voltage selection types are for single circuit breaker with double busbars and the breaker-and-a-half arrangement. A double circuit breaker arrangement and single circuit breaker with a single busbar do not need any voltage selection function. Neither does a single circuit breaker with double busbars using external voltage selection need any internal voltage selection.

Manual energization of a completely open diameter in breaker-and-a-half switchgear is allowed by internal logic.

The voltages from busbars and lines must be physically connected to the voltage inputs in the IED and connected, using the PCM software, to each of the SESRSYN (25) functions available in the IED.

### 15.1.2.5 External fuse failure

Either external fuse-failure signals or signals from a tripped fuse (or miniature circuit breaker) are connected to HW binary inputs of the IED; these signals are connected to inputs of SESRSYN function in the application configuration tool of PCM600. The internal fuse failure supervision function can also be used if a three phase voltage is present. The signal BLKV, from the internal fuse failure supervision function, is then used and connected to the fuse supervision inputs of the SESRSYN function block. In case of a fuse failure, the SESRSYN energizing (25) function is blocked.

The VB1OK/VB2OK and VB1FF/VB2FF inputs are related to the busbar voltage and the VL1OK/ VL2OK and VL1FF/VL2FF inputs are related to the line voltage.
**External selection of energizing direction**

The energizing can be selected by use of the available logic function blocks. Below is an example where the choice of mode is done from a symbol, created in the Graphical Design Editor (GDE) tool on the local HMI, through selector switch function block, but alternatively there can for example, be a physical selector switch on the front of the panel which is connected to a binary to integer function block (B16I).

If the PSTO input is used, connected to the Local-Remote switch on the local HMI, the choice can also be from the station HMI system, typically ABB Microscada through IEC 61850–8–1 communication.

The connection example for selection of the manual energizing mode is shown in figure 231. Selected names are just examples but note that the symbol on the local HMI can only show the active position of the virtual selector.

![Diagram showing selection of energizing direction](ANSIO9000171_v1_en.vsd)

*Figure 231: Selection of the energizing direction from a local HMI symbol through a selector switch function block.*

### 15.1.3 Application examples

The synchronism check function block can also be used in some switchyard arrangements, but with different parameter settings. Below are some examples of how different arrangements are connected to the IED analog inputs and to the function block SESRSYN, 25. One function block is used per circuit breaker.

- The input used below in example are typical and can be changed by use of configuration and signal matrix tools.

- The SESRSYN and connected SMAI function block instances must have the same cycle time in the application configuration.
15.1.3.1  Single circuit breaker with single busbar

Figure 232: Connection of SESRSYN (25) function block in a single busbar arrangement

Figure 232 illustrates connection principles for a single busbar. For the SESRSYN (25) function there is one voltage transformer on each side of the circuit breaker. The voltage transformer circuit connections are straightforward; no special voltage selection is necessary.

The voltage from busbar VT is connected to V3PB1 and the voltage from the line VT is connected to V3PL1. The conditions of the VT fuses shall also be connected as shown above. The voltage selection parameter \( CBCConfig \) is set to \( No \ voltage \ sel. \)
15.1.3.2 Single circuit breaker with double busbar, external voltage selection

Figure 233: Connection of SESRSYN (25) function block in a single breaker, double busbar arrangement with external voltage selection

In this type of arrangement no internal voltage selection is required. The voltage selection is made by external relays typically connected according to figure 233. Suitable voltage and VT fuse failure supervision from the two busbars are selected based on the position of the busbar disconnectors. This means that the connections to the function block will be the same as for the single busbar arrangement. The voltage selection parameter CBConfig is set to No voltage sel.
15.1.3.3 Single circuit breaker with double busbar, internal voltage selection

When internal voltage selection is needed, the voltage transformer circuit connections are made according to figure 234. The voltage from the busbar 1 VT is connected to V3PB1 and the voltage from busbar 2 is connected to V3PB2. The voltage from the line VT is connected to V3PL1. The positions of the disconnectors and VT fuses shall be connected as shown in figure 234. The voltage selection parameter CBConfig is set to Double bus.

Figure 234: Connection of the SESRSYN function block in a single breaker, double busbar arrangement with internal voltage selection
Figure 235: Connections of the SESRSYN (25) function block in a double breaker arrangement

A double breaker arrangement requires two function blocks, one for breaker WA1_QA1 and one for breaker WA2_QA1. No voltage selection is necessary, because the voltage from busbar 1 VT is connected to V3PB1 on SESRSYN for WA1_QA1 and the voltage from busbar 2 VT is connected to V3PB1 on SESRSYN for WA2_QA1. The voltage from the line VT is connected to V3PL1 on both function blocks. The condition of VT fuses shall also be connected as shown in figure 234. The voltage selection parameter CBConfig is set to No voltage sel. for both function blocks.
15.1.3.5 Breaker-and-a-half

Figure 236 describes a breaker-and-a-half arrangement with three SESRSYN functions in the same IED, each of them handling voltage selection for WA1_QA1, TIE_QA1 and WA2_QA1 breakers respectively. The voltage from busbar 1 VT is connected to V3PB1 on all three function blocks and the voltage from busbar 2 VT is connected to V3PB2 on all three function blocks. The voltage from line1 VT is connected to V3PL1 on all three function blocks and the voltage from line2 VT is connected to V3PL2 on all three function blocks. The positions of the disconnectors and VT fuses shall be connected as shown in Figure 236.
Figure 236: Connections of the SESRSYN (25) function block in a breaker-and-a-half arrangement with internal voltage selection

The connections are similar in all SESRSYN functions, apart from the breaker position indications. The physical analog connections of voltages and the connection to the IED and SESRSYN (25) function blocks must be carefully checked in PCM600. In all SESRSYN functions the connections...
and configurations must abide by the following rules: Normally apparatus position is connected with contacts showing both open (b-type) and closed positions (a-type).

### WA1_QA1:

- BUS1_OP/CL = Position of TIE_QA1 breaker and belonging disconnectors
- BUS2_OP/CL = Position of WA2_QA1 breaker and belonging disconnectors
- LINE1_OP/CL = Position of LINE1_QB9 disconnector
- LINE2_OP/CL = Position of LINE2_QB9 disconnector
- VB1OK/FF = Supervision of WA1_MCB fuse
- VB2OK/FF = Supervision of WA2_MCB fuse
- VL1OK/FF = Supervision of LINE1_MCB fuse
- VL2OK/FF = Supervision of LINE2_MCB fuse
- Setting CBConfig = 1 1/2 bus CB

### TIE_QA1:

- BUS1_OP/CL = Position of WA1_QA1 breaker and belonging disconnectors
- BUS2_OP/CL = Position of WA2_QA1 breaker and belonging disconnectors
- LINE1_OP/CL = Position of LINE1_QB9 disconnector
- LINE2_OP/CL = Position of LINE2_QB9 disconnector
- VB1OK/FF = Supervision of WA1_MCB fuse
- VB2OK/FF = Supervision of WA2_MCB fuse
- VL1OK/FF = Supervision of LINE1_MCB fuse
- VL2OK/FF = Supervision of LINE2_MCB fuse
- Setting CBConfig = Tie CB

### WA2_QA1:

- BUS1_OP/CL = Position of WA1_QA1 breaker and belonging disconnectors
- BUS2_OP/CL = Position of TIE_QA1 breaker and belonging disconnectors
- LINE1_OP/CL = Position of LINE1_QB9 disconnector
- LINE2_OP/CL = Position of LINE2_QB9 disconnector
- VB1OK/FF = Supervision of WA1_MCB fuse
- VB2OK/FF = Supervision of WA2_MCB fuse
- VL1OK/FF = Supervision of LINE1_MCB fuse
- VL2OK/FF = Supervision of LINE2_MCB fuse
- Setting CBConfig = 1 1/2 bus alt. CB

If only two SESRSYN functions are provided in the same IED, the connections and settings are according to the SESRSYN functions for WA1_QA1 and TIE_QA1.

## 15.1.4 Setting guidelines

The setting parameters for the Synchronizing, synchronism check and energizing check function SESRSYN (25) are set via the local HMI (LHMI) or PCM600.

This setting guidelines describes the settings of the SESRSYN (25) function via the LHMI.

Common base IED value for primary voltage (VBase) is set in a Global base value function, GBASVAL, found under **Main menu/Configuration/Power system/GlobalBaseValue/GBASVAL_X/VBase**. The SESRSYN (25) function has one setting for the bus reference voltage (GblBaseSelBus) and one setting for the line reference voltage (GblBaseSelLine) which independently of each other can be set to select one of the twelve GBASVAL functions used for
reference of base values. This means that the reference voltage of bus and line can be set to different values. The settings for the SESRSYN (25) function are found under Main menu/Settings/IED Settings/Control/Synchronizing(25,SC/VC)/SESRSYN(25,SC/VC):X has been divided into four different setting groups: General, Synchronizing, Synchrocheck and Energizingcheck.

**General settings**

*Operation:* The operation mode can be set *Enabled* or *Disabled*. The setting *Disabled* disables the whole function.

*GblBaseSelBus* and *GblBaseSelLine*

These configuration settings are used for selecting one of twelve GBASVAL functions, which then is used as base value reference voltage, for bus and line respectively.

*SelPhaseBus1* and *SelPhaseBus2*

Configuration parameters for selecting the measuring phase of the voltage for busbar 1 and 2 respectively, which can be a single-phase (phase-neutral), two-phase (phase-phase) or a positive sequence voltage.

*SelPhaseLine1* and *SelPhaseLine2*

Configuration parameters for selecting the measuring phase of the voltage for line 1 and 2 respectively, which can be a single-phase (phase-neutral), two-phase (phase-phase) or a positive sequence voltage.

*CBConfig*

This configuration setting is used to define type of voltage selection. Type of voltage selection can be selected as:

- no voltage selection, *No voltage sel.*
- single circuit breaker with double bus, *Double bus*
- breaker-and-a-half arrangement with the breaker connected to busbar 1, *1 1/2 bus CB*
- breaker-and-a-half arrangement with the breaker connected to busbar 2, *1 1/2 bus alt. CB*
- breaker-and-a-half arrangement with the breaker connected to line 1 and 2, *Tie CB*

*PhaseShift*

This setting is used to compensate the phase shift between the measured bus voltage and line voltage when:

- different phase-neutral voltages are selected (for example UL1 for bus and UL2 for line);
- one available voltage is phase-phase and the other one is phase-neutral (for example UL1L2 for bus and UL1 for line).

The set value is added to the measured line phase angle. The bus voltage is reference voltage.

**Synchronizing settings**

*OperationSynch*

The setting *Off* disables the Synchronizing function. With the setting *On*, the function is in the service mode and the output signal depends on the input conditions.
**VHighBusSynch and VHighLineSynch**

The voltage level settings shall be chosen in relation to the bus/line network voltage. The threshold voltages *VHighBusSynch* and *VHighLineSynch* have to be set lower than the value where the network is expected to be synchronized. A typical value is 80% of the rated voltage.

**VDiffSynch**

Setting of the voltage difference between the line voltage and the bus voltage. The difference is set depending on the network configuration and expected voltages in the two networks running asynchronously. A normal setting is 0.10-0.15 p.u.

**FreqDiffMin**

The setting *FreqDiffMin* is the minimum frequency difference where the systems are defined to be asynchronous. For frequency differences lower than this value, the systems are considered to be in parallel. A typical value for *FreqDiffMin* is 10 mHz. Generally, the value should be low if both synchronizing and synchrocheck functions are provided, and it is better to let the synchronizing function close, as it will close at exactly the right instance if the networks run with a frequency difference.

To avoid overlapping of the synchronizing function and the synchrocheck function the setting *FreqDiffMin* must be set to a higher value than used setting *FreqDiffM*, respective *FreqDiffA* used for synchrocheck.

**FreqDiffMax**

The setting *FreqDiffMax* is the maximum slip frequency at which synchronizing is accepted. 1/ *FreqDiffMax* shows the time for the vector to move 360 degrees, one turn on the synchronoscope, and is called Beat time. A typical value for *FreqDiffMax* is 200-250 mHz, which gives beat times on 4-5 seconds. Higher values should be avoided as the two networks normally are regulated to nominal frequency independent of each other, so the frequency difference shall be small.

**FreqRateChange**

The maximum allowed rate of change for the frequency.

**CloseAngleMax**

The setting *CloseAngleMax* is the maximum closing angle between bus and line at which synchronizing is accepted. To minimize the moment stress when synchronizing near a power station, a narrower limit should be used. A typical value is 15 degrees.

**tBreaker**

The *tBreaker* shall be set to match the closing time for the circuit breaker and should also include the possible auxiliary relays in the closing circuit. It is important to check that no slow logic components are used in the configuration of the IED as there then can be big variations in closing time due to those components. Typical setting is 80-150 ms depending on the breaker closing time.

**tClosePulse**

The setting for the duration of the breaker close pulse.
tMaxSynch

The setting \textit{tMaxSynch} is set to reset the operation of the synchronizing function if the operation does not take place within this time. The setting must allow for the setting of \textit{FreqDiffMin}, which will decide how long it will take maximum to reach phase equality. At the setting of 10 mHz, the beat time is 100 seconds and the setting would thus need to be at least \textit{tMinSynch} plus 100 seconds. If the network frequencies are expected to be outside the limits from the start, a margin needs to be added. A typical setting is 600 seconds.

tMinSynch

The setting \textit{tMinSynch} is set to limit the minimum time at which the synchronizing closing attempt is given. The synchronizing function will not give a closing command within this time, from when the synchronizing is started, even if a synchronizing condition is fulfilled. A typical setting is 200 ms.

**Synchrocheck settings**

\textit{OperationSC}

The \textit{OperationSC} setting \textit{Off} disables the synchrocheck function and sets the outputs AUTOSYOK, MANSYOK, TSTAUTSY and TSTMANSY to low. With the setting \textit{On}, the function is in the service mode and the output signal depends on the input conditions.

\textit{VHighBusSC} and \textit{VHighLineSC}

The voltage level settings must be chosen in relation to the bus or line network voltage. The threshold voltages \textit{VHighBusSC} and \textit{VHighLineSC} have to be set lower than the value at which the breaker is expected to close with the synchronism check. A typical value can be 80\% of the base voltages.

\textit{VDiffSC}

The setting for voltage difference between line and bus in p.u. This setting in p.u. is defined as \((V_{Bus}/GblBaseSelBus) - (V_{Line}/GblBaseSelLine)\). A normal setting is 0,10-0,15 p.u.

\textit{FreqDiffM} and \textit{FreqDiffA}

The frequency difference level settings, \textit{FreqDiffM} and \textit{FreqDiffA}, shall be chosen depending on the condition in the network. At steady conditions a low frequency difference setting is needed, where the \textit{FreqDiffM} setting is used. For autoreclosing a bigger frequency difference setting is preferable, where the \textit{FreqDiffA} setting is used. A typical value for \textit{FreqDiffM} can be 10 mHz, and a typical value for \textit{FreqDiffA} can be 100-200 mHz.

\textit{PhaseDiffM} and \textit{PhaseDiffA}

The phase angle difference level settings, \textit{PhaseDiffM} and \textit{PhaseDiffA}, shall also be chosen depending on conditions in the network. The phase angle setting must be chosen to allow closing under maximum load condition. A typical maximum value in heavy-loaded networks can be 45 degrees, whereas in most networks the maximum occurring angle is below 25 degrees. The \textit{PhaseDiffM} setting is a limitation to \textit{PhaseDiffA} setting. Fluctuations occurring at high speed autoreclosing limit \textit{PhaseDiffA} setting.

\textit{tSCM} and \textit{tSCA}

The purpose of the timer delay settings, \textit{tSCM} and \textit{tSCA}, is to ensure that the synchrocheck conditions remains constant and that the situation is not due to a temporary interference. Should
the conditions not persist for the specified time, the delay timer is reset and the procedure is restarted when the conditions are fulfilled again. Circuit breaker closing is thus not permitted until the synchrocheck situation has remained constant throughout the set delay setting time. Manual closing is normally under more stable conditions and a longer operation time delay setting is needed, where the \( t_{SCM} \) setting is used. During auto-reclosing, a shorter operation time delay setting is preferable, where the \( t_{SCA} \) setting is used. A typical value for \( t_{SCM} \) can be 1 second and a typical value for \( t_{SCA} \) can be 0.1 seconds.

**Energizingcheck settings**

*AutoEnerg and ManEnerg*

Two different settings can be used for automatic and manual closing of the circuit breaker. The settings for each of them are:

- **Disabled**, the energizing function is disabled.
- **DLLB**, Dead Line Live Bus, the line voltage is below set value of \( V_{DeadLineEnerg} \) and the bus voltage is above set value of \( V_{LiveBusEnerg} \).
- **DBLL**, Dead Bus Live Line, the bus voltage is below set value of \( V_{DeadBusEnerg} \) and the line voltage is above set value of \( V_{LiveLineEnerg} \).
- **Both**, energizing can be done in both directions, DLLB or DBLL.

*ManEnergDBDL*

If the parameter is set to **Enabled**, manual closing is also enabled when both line voltage and bus voltage are below \( V_{DeadLineEnerg} \) and \( V_{DeadBusEnerg} \) respectively, and ManEnerg is set to DLLB, DBLL or Both.

*\( V_{LiveBusEnerg} \) and \( V_{LiveLineEnerg} \)*

The voltage level settings must be chosen in relation to the bus or line network voltage. The threshold voltages \( V_{LiveBusEnerg} \) and \( V_{LiveLineEnerg} \) have to be set lower than the value at which the network is considered to be energized. A typical value can be 80% of the base voltages.

*\( V_{DeadBusEnerg} \) and \( V_{DeadLineEnerg} \)*

The threshold voltages \( V_{DeadBusEnerg} \) and \( V_{DeadLineEnerg} \), have to be set to a value greater than the value where the network is considered not to be energized. A typical value can be 40% of the base voltages.

A disconnected line can have a considerable potential due to, for instance, induction from a line running in parallel, or by being fed via the extinguishing capacitors in the circuit breakers. This voltage can be as high as 30% or more of the base line voltage.

Because the setting ranges of the threshold voltages \( V_{LiveBusEnerg} \) / \( V_{LiveLineEnerg} \) and \( V_{DeadBusEnerg} \) / \( V_{DeadLineEnerg} \) partly overlap each other, the setting conditions may be such that the setting of the non-energized threshold value is higher than that of the energized threshold value. The parameters must therefore be set carefully to avoid overlapping.

*\( V_{MaxEnerg} \)*

This setting is used to block the closing when the voltage on the live side is above the set value of \( V_{MaxEnerg} \).
**tAutoEnerg and tManEnerg**

The purpose of the timer delay settings, *tAutoEnerg* and *tManEnerg*, is to ensure that the dead side remains de-energized and that the condition is not due to a temporary interference. Should the conditions not persist for the specified time, the delay timer is reset and the procedure is restarted when the conditions are fulfilled again. Circuit breaker closing is thus not permitted until the energizing condition has remained constant throughout the set delay setting time.

**15.2 Apparatus control**

**15.2.1 Application**

The apparatus control is a functionality for control and supervising of circuit breakers, disconnectors, and grounding switches within a bay. Permission to operate is given after evaluation of conditions from other functions such as interlocking, synchronism check, operator place selection and external or internal blockings.

The complete apparatus control function is not included in this product, and the information below is included for understanding of the principle for the use of QCBAY, LOCREM, LOCREMCTRL, SCILO, SCSWI, SXCBR.

Figure 237 shows from which places the apparatus control function receives commands. The commands to an apparatus can be initiated from the Control Centre (CC), the station HMI or the local HMI on the IED front.

![Figure 237: Overview of the apparatus control functions](ANSI08000227.vsd)

Features in the apparatus control function:

- Operation of primary apparatuses
- Select-Execute principle to give high security
- Selection and reservation function to prevent simultaneous operation
- Selection and supervision of operator place
• Command supervision
• Block/deblock of operation
• Block/deblock of updating of position indications
• Substitution of position indications
• Overriding of interlocking functions
• Overriding of synchronism check
• Pole discrepancy supervision
• Operation counter
• Suppression of mid position

The apparatus control function is realized by means of a number of function blocks designated:

• Switch controller SCSWI
• Circuit breaker SXCBR
• Circuit switch SXSWI
• Bay control QCBAY
• Bay reserve QCRSV
• Reservation input RESIN
• Local remote LOCREM
• Local remote control LOCREMCTRL

The signal flow between the function blocks is shown in Figure 238. To realize the reservation function, the function blocks Reservation input (RESIN) and Bay reserve (QCRSV) also are included in the apparatus control function. The application description for all these functions can be found below. The function SCILO in the Figure below is the logical node for interlocking.

When the circuit breaker or switch is located in a breaker IED, two more functions are added:

• GOOSE receive for switching device GOOSEXLNRCV
• Proxy for signals from switching device via GOOSE XLNPROXY

The extension of the signal flow and the usage of the GOOSE communication are shown in Figure 239.
Figure 238: Signal flow between apparatus control function blocks when all functions are situated within the IED
Control operation can be performed from the local IED HMI. If users are defined in the IED, then the local/remote switch is under authority control, otherwise the default user can perform control operations from the local IED HMI without logging in. The default position of the local/remote switch is on remote.
Accepted originator categories for PSTO

If the requested command is accepted by the authority control, the value will change. Otherwise the attribute `blocked-by-switching-hierarchy` is set in the `cause` signal. If the PSTO value is changed during a command, then the command is aborted.

The accepted originator categories for each PSTO value are shown in Table 53.

Table 53: Accepted originator categories for each PSTO

<table>
<thead>
<tr>
<th>Permitted Source To Operate</th>
<th>Originator (orCat)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0 = Off</td>
<td>4,5,6</td>
</tr>
<tr>
<td>1 = Local</td>
<td>1,4,5,6</td>
</tr>
<tr>
<td>2 = Remote</td>
<td>2,3,4,5,6</td>
</tr>
<tr>
<td>3 = Faulty</td>
<td>4,5,6</td>
</tr>
<tr>
<td>4 = Not in use</td>
<td>4,5,6</td>
</tr>
<tr>
<td>5 = All</td>
<td>1,2,3,4,5,6</td>
</tr>
<tr>
<td>6 = Station</td>
<td>2,4,5,6</td>
</tr>
<tr>
<td>7 = Remote</td>
<td>3,4,5,6</td>
</tr>
</tbody>
</table>

PSTO = All, then it is no priority between operator places. All operator places are allowed to operate.

According to IEC 61850 standard the `orCat` attribute in originator category are defined in Table 54

Table 54: orCat attribute according to IEC 61850

<table>
<thead>
<tr>
<th>Value</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>not-supported</td>
</tr>
<tr>
<td>1</td>
<td>bay-control</td>
</tr>
<tr>
<td>2</td>
<td>station-control</td>
</tr>
<tr>
<td>3</td>
<td>remote-control</td>
</tr>
<tr>
<td>4</td>
<td>automatic-bay</td>
</tr>
<tr>
<td>5</td>
<td>automatic-station</td>
</tr>
<tr>
<td>6</td>
<td>automatic-remote</td>
</tr>
<tr>
<td>7</td>
<td>maintenance</td>
</tr>
<tr>
<td>8</td>
<td>process</td>
</tr>
</tbody>
</table>

15.2.2 Bay control QCBAY

The Bay control (QCBAY) is used to handle the selection of the operator place per bay. The function gives permission to operate from two main types of locations either from Remote (for example, control centre or station HMI) or from Local (local HMI on the IED) or from all (Local and Remote). The Local/Remote switch position can also be set to Off, which means no operator place selected that is, operation is not possible either from local or from remote.
For IEC 61850-8-1 communication, the Bay Control function can be set to discriminate between commands with orCat station and remote (2 and 3). The selection is then done through the IEC 61850-8-1 edition 2 command LocSta.

QCBAY also provides blocking functions that can be distributed to different apparatuses within the bay. There are two different blocking alternatives:

- Blocking of update of positions
- Blocking of commands

![Diagram of APC - Local remote function block](image)

**Figure 240: APC - Local remote function block**

### 15.2.3 Switch controller SCSWI

SCSWI may handle and operate on one three-phase device or three one-phase switching devices.

After the selection of an apparatus and before the execution, the switch controller performs the following checks and actions:
• A request initiates to reserve other bays to prevent simultaneous operation.
• Actual position inputs for interlocking information are read and evaluated if the operation is permitted.
• The synchronism check/synchronizing conditions are read and checked, and performs operation upon positive response.
• The blocking conditions are evaluated
• The position indications are evaluated according to given command and its requested direction (open or closed).

The command sequence is supervised regarding the time between:

• Select and execute.
• Select and until the reservation is granted.
• Execute and the final end position of the apparatus.
• Execute and valid close conditions from the synchronism check.

At error the command sequence is cancelled.

In the case when there are three one-phase switches (SXCBR) connected to the switch controller function, the switch controller will "merge" the position of the three switches to the resulting three-phase position. In case of a pole discrepancy situation, that is, the positions of the one-phase switches are not equal for a time longer than a settable time; an error signal will be given.

The switch controller is not dependent on the type of switching device SXCBR or SXSWI. The switch controller represents the content of the SCSWI logical node (according to IEC 61850) with mandatory functionality.

15.2.4 **Switches SXCBR/SXSWI**

Switches are functions used to close and interrupt an ac power circuit under normal conditions, or to interrupt the circuit under fault, or emergency conditions. The intention with these functions is to represent the lowest level of a power-switching device with or without short circuit breaking capability, for example, circuit breakers, disconnectors, grounding switches etc.

The purpose of these functions is to provide the actual status of positions and to perform the control operations, that is, pass all the commands to the primary apparatus via output boards and to supervise the switching operation and position.

Switches have the following functionalities:

• Local/Remote switch intended for the switchyard
• Block/deblock for open/close command respectively
• Update block/deblock of position indication
• Substitution of position indication
• Supervision timer that the primary device starts moving after a command
• Supervision of allowed time for intermediate position
• Definition of pulse duration for open/close command respectively

The realizations of these functions are done with SXCBR representing a circuit breaker and with SXSWI representing a circuit switch that is, a disconnector or an grounding switch.

Circuit breaker (SXCBR) can be realized either as three one-phase switches or as one three-phase switch.
The content of this function is represented by the IEC 61850 definitions for the logical nodes Circuit breaker (SXCBR) and Circuit switch (SXSWI) with mandatory functionality.

15.2.5 **Proxy for signals from switching device via GOOSE XLNPROXY**

The purpose of the proxy for signals from switching device via GOOSE (XLNPROXY) is to give the same internal representation of the position status and control response for a switch modeled in a breaker IED as if represented by a SXCBR or SXSWI function.

The command response functionality is dependent on the connection of the execution information, XIN, from the SCSWI function controlling the represented switch. Otherwise, the function only reflects the current status of the switch, such as blocking, selection, position, operating capability and operation counter.

Since different switches are represented differently on IEC 61850, the data that is mandatory to model in IEC 61850 is mandatory inputs and the other useful data for the command and status following is optional. To make it easy to choose which data to use for the XLNPROXY function, their usage is controlled by the connection of each data’s signal input and valid input. These connections are usually from the GOOSEXLNRCV function (see Figure 241 and Figure 242).

![Configuration with XLNPROXY and GOOSEXLNRCV where all the IEC 61850 modelled data is used, including selection](IEC16000071-1-EN.psd)
Figure 242: Configuration with XLNPROXY and GOOSEXLNRCV where only the mandatory data in the IEC 61850 modelling is used

All the information from the XLNPROXY to the SCSWI about command following status, causes for failed command and selection status is transferred in the output XPOS. The other outputs may be used by other functions in the same way as the corresponding outputs of the SXCBR and SXSWI function.

When a command has been issued from the connected SCSWI function, the XLNPROXY function awaits the response on it from the represented switch through the inputs POSVAL and OPOK. While waiting for the switch to start moving, it checks if the switch is blocked for the operation. When the switch has started moving and no blocking condition has been detected, XLNPROXY issues a response to the SCSWI function that the command has started. If OPOK is used, this response is given when XLNPROXY receives the signal.

If no movement of the switch is registered within the limit $t_{StartMove}$, the command is considered failed, and the cause of the failure is evaluated. In the evaluation, the function checks if the state of the represented switch is indicating that the command is blocked in any way during the command, and gives the appropriate cause to the SCSWI function. This cause is also shown on the output L_CAUSE as indicated in the following table:

Table 55: Possible cause values from XLNPROXY

<table>
<thead>
<tr>
<th>Cause No</th>
<th>Cause Description</th>
<th>Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>Blocked-by-Mode</td>
<td>The BEH input is 5.</td>
</tr>
<tr>
<td>2</td>
<td>Blocked-by-switching-hierarchy</td>
<td>The LOC input indicates that only local commands are allowed for the breaker IED function.</td>
</tr>
<tr>
<td>-24</td>
<td>Blocked-for-open-cmd</td>
<td>The BLKOPN is active indicating that the switch is blocked for open commands.</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Cause No</th>
<th>Cause Description</th>
<th>Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>-25</td>
<td>Blocked-for-close-cmd</td>
<td>The BLKCLS is active indicating that the switch is blocked for close commands.</td>
</tr>
<tr>
<td>9</td>
<td>Blocked-by-process</td>
<td>If the Blk input is connected and active indicating that the switch is dynamically blocked. Or if the OPCAP input is connected, it indicates that the operation capability of the switch is not enough to perform the command.</td>
</tr>
<tr>
<td>5</td>
<td>Position-reached</td>
<td>Switch is already in the intended position.</td>
</tr>
<tr>
<td>-31</td>
<td>Switch-not-start-moving</td>
<td>Switch did not start moving within tStartMove.</td>
</tr>
<tr>
<td>-32</td>
<td>Persistent-intermediate-state</td>
<td>The switch stopped in intermediate state for longer than tIntermediate.</td>
</tr>
<tr>
<td>-33</td>
<td>Switch-returned-to-init-pos</td>
<td>Switch returned to the initial position.</td>
</tr>
<tr>
<td>-34</td>
<td>Switch-in-bad-state</td>
<td>Switch is in a bad position.</td>
</tr>
<tr>
<td>-35</td>
<td>Not-expected-final-position</td>
<td>Switch did not reach the expected final position.</td>
</tr>
</tbody>
</table>

The OPCAP input and output are used for the CBOpCap data of a XCBR respectively SwOpCap for a XSWI. The interpretation for the command following is controlled through the setting Switch Type.

### 15.2.6 Reservation function (QCRSV and RESIN)

The purpose of the reservation function is primarily to transfer interlocking information between IEDs in a safe way and to prevent double operation in a bay, switchyard part, or complete substation.

For interlocking evaluation in a substation, the position information from switching devices, such as circuit breakers, disconnectors and grounding switches can be required from the same bay or from several other bays. When information is needed from other bays, it is exchanged over the station bus between the distributed IEDs. The problem that arises, even at a high speed of communication, is a space of time during which the information about the position of the switching devices are uncertain. The interlocking function uses this information for evaluation, which means that also the interlocking conditions are uncertain.

To ensure that the interlocking information is correct at the time of operation, a unique reservation method is available in the IEDs. With this reservation method, the bay that wants the reservation sends a reservation request to other bays and then waits for a reservation granted signal from the other bays. Actual position indications from these bays are then transferred over the station bus for evaluation in the IED. After the evaluation the operation can be executed with high security.

This functionality is realized over the station bus by means of the function blocks QCRSV and RESIN. The application principle is shown in Figure 243.

The function block QCRSV handles the reservation. It sends out either the reservation request to other bays or the acknowledgement if the bay has received a request from another bay.

The other function block RESIN receives the reservation information from other bays. The number of instances is the same as the number of involved bays (up to 60 instances are available). The received signals are either the request for reservation from another bay or the acknowledgment...
Figure 243: Application principles for reservation over the station bus
The reservation can also be realized with external wiring according to the application example in Figure 244. This solution is realized with external auxiliary relays and extra binary inputs and outputs in each IED, but without use of function blocks QCRSV and RESIN.

Figure 244: Application principles for reservation with external wiring
The solution in Figure 244 can also be realized over the station bus according to the application example in Figure 244. The solutions in Figure 244 and Figure 245 do not have the same high security compared to the solution in Figure 243, but instead have a higher availability, since no acknowledgment is required.
15.2.7 Interaction between modules

A typical bay with apparatus control function consists of a combination of logical nodes or functions that are described here:

- The Switch controller (SCSWI) initializes all operations for one apparatus. It is the command interface of the apparatus. It includes the position reporting as well as the control of the position.
- The Circuit breaker (SXCBR) is the process interface to the circuit breaker for the apparatus control function.
- The Circuit switch (SXSWI) is the process interface to the disconnector or the grounding switch for the apparatus control function.
- The Bay control (QCBAY) fulfils the bay-level functions for the apparatuses, such as operator place selection and blockings for the complete bay.
- The Reservation (QCRSV) deals with the reservation function.
- The Protection trip logic (SMPPTRC, 94) connects the "trip" outputs of one or more protection functions to a common "trip" to be transmitted to SXCBR.
- The Autorecloser (SMBRREC, 79) consists of the facilities to automatically close a tripped breaker with respect to a number of configurable conditions.
- The logical node Interlocking (SCILO, 3) provides the information to SCSWI whether it is permitted to operate due to the switchyard topology. The interlocking conditions are evaluated with separate logic and connected to SCILO (3).
- The Synchronism, energizing check, and synchronizing (SESRSYN, 25) calculates and compares the voltage phasor difference from both sides of an open breaker with predefined switching conditions (synchronism check). Also the case that one side is dead (energizing-check) is included.
- The Generic Automatic Process Control function, GAPC, handles generic commands from the operator to the system.

The overview of the interaction between these functions is shown in Figure 246 below.
15.2.8 Setting guidelines

The setting parameters for the apparatus control function are set via the local HMI or PCM600.

15.2.8.1 Bay control (QCBAY)

If the parameter AllPSTOValid is set to No priority, all originators from local and remote are accepted without any priority.
If the parameter `RemoteIncStation` is set to `Yes`, commands from IEC 61850-8-1 clients at both station and remote level are accepted, when the QCBAAY function is in Remote. If set to `No`, the command LocSta controls which operator place is accepted when QCBAAY is in Remote. If LocSta is true, only commands from station level are accepted, otherwise only commands from remote level are accepted.

The parameter `RemoteIncStation` has only effect on the IEC 61850-8-1 communication. Further, when using IEC 61850 edition 1 communication, the parameter should be set to `Yes`, since the command LocSta is not defined in IEC 61850-8-1 edition 1.

### 15.2.8.2 Switch controller (SCSWI)

The parameter `CtlModel` specifies the type of control model according to IEC 61850. The default for control of circuit breakers, disconnectors and grounding switches the control model is set to `SBO Enh` (Select-Before-Operate) with enhanced security.

When the operation shall be performed in one step, and no monitoring of the result of the command is desired, the model direct control with normal security is used.

At control with enhanced security there is an additional supervision of the status value by the control object, which means that each command sequence must be terminated by a termination command.

The parameter `PosDependent` gives permission to operate depending on the position indication, that is, at `Always permitted` it is always permitted to operate independent of the value of the position. At `Not perm at 00/11` it is not permitted to operate if the position is in bad or intermediate state.

`tSelect` is the maximum allowed time between the select and the execute command signal, that is, the time the operator has to perform the command execution after the selection of the object to operate. When the time has expired, the selected output signal is set to false and a cause-code is given.

The time parameter `tResResponse` is the allowed time from reservation request to the feedback reservation granted from all bays involved in the reservation function. When the time has expired, the control function is reset, and a cause-code is given.

`tSynchrocheck` is the allowed time for the synchronism check function to fulfill the close conditions. When the time has expired, the function tries to start the synchronizing function. If `tSynchrocheck` is set to 0, no synchrocheck is done, before starting the synchronizing function.

The timer `tSynchronizing` supervises that the signal synchronizing in progress is obtained in SCSWI after start of the synchronizing function. The start signal for the synchronizing is set if the synchronism check conditions are not fulfilled. When the time has expired, the control function is reset, and a cause-code is given. If no synchronizing function is included, the time is set to 0, which means no start of the synchronizing function is done, and when `tSynchrocheck` has expired, the control function is reset and a cause-code is given.

`tExecutionFB` is the maximum time between the execute command signal and the command termination. When the time has expired, the control function is reset and a cause-code is given.
**tPoleDiscord** is the allowed time to have discrepancy between the poles at control of three single-phase breakers. At discrepancy an output signal is activated to be used for trip or alarm, and during a command, the control function is reset, and a cause-code is given.

*SuppressMidPos* when *On* suppresses the mid-position during the time *tIntermediate* of the connected switches.

The parameter *InterlockCheck* decides if interlock check should be done at both select and operate, Sel & Op phase, or only at operate, Op phase.

### 15.2.8.3 Switch (SXCBR/SXSWI)

**tStartMove** is the supervision time for the apparatus to start moving after a command execution is done from the SCSWI function. When the time has expired, the command supervision is reset, and a cause-code is given.

During the *tIntermediate* time, the position indication is allowed to be in an intermediate (00) state. When the time has expired, the command supervision is reset, and a cause-code is given. The indication of the mid-position at SCSWI is suppressed during this time period when the position changes from open to close or vice-versa if the parameter *SuppressMidPos* is set to *On* in the SCSWI function.

If the parameter *AdaptivePulse* is set to *Adaptive* the command output pulse resets when a new correct end position is reached. If the parameter is set to *Not adaptive* the command output pulse remains active until the timer *tOpenPulseClosePulse* has elapsed.

**tOpenPulse** is the output pulse length for an open command. If *AdaptivePulse* is set to *Adaptive*, it is the maximum length of the output pulse for an open command. The default length is set to 200 ms for a circuit breaker (SXCBR) and 500 ms for a disconnector (SXSWI).

**tClosePulse** is the output pulse length for a close command. If *AdaptivePulse* is set to *Adaptive*, it is the maximum length of the output pulse for an open command. The default length is set to 200 ms for a circuit breaker (SXCBR) and 500 ms for a disconnector (SXSWI).

### 15.2.8.4 Proxy for signals from switching device via GOOSE XLNPROXY

The *SwitchType* setting controls the evaluation of the operating capability. If *SwitchType* is set to *Circuit Breaker*, the input OPCAP is interpreted as a breaker operating capability, otherwise it is interpreted as a switch operating capability.

<table>
<thead>
<tr>
<th>Value</th>
<th>Breaker operating capability, CbOpCap</th>
<th>Switch operating capability, SwOpCap</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>2</td>
<td>Open</td>
<td>Open</td>
</tr>
<tr>
<td>3</td>
<td>Close – Open</td>
<td>Close</td>
</tr>
<tr>
<td>4</td>
<td>Open – Close – Open</td>
<td>Close and Open</td>
</tr>
<tr>
<td>5</td>
<td>Close – Open – Close – Open</td>
<td>Larger values handled as 4, both Close and Open</td>
</tr>
<tr>
<td>6</td>
<td>Open – Close – Open – Close – Open</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>more</td>
<td></td>
</tr>
</tbody>
</table>
**tStartMove** is the supervision time for the apparatus to start moving after a command execution is done from the SCSWI function. When the time has expired, the command supervision is reset, and a cause-code is given.

During the *tIntermediate* time, the position indication is allowed to be in an intermediate (00) state. When the time has expired, the command supervision is reset, and a cause-code is given. The indication of the mid-position at SCSWI is suppressed during this time period when the position changes from open to close or vice-versa if the parameter *SuppressMidPos* is set to *On* in the SCSWI function.

In most cases, the same value can be used for both *tStartMove* and *tIntermediate* as in the source function. However, *tStartMove* may need to be increased to accommodate for the communication delays, mainly when representing a circuit breaker.

**15.2.8.5 Bay Reserve (QCRSV)**

The timer *tCancelRes* defines the supervision time for canceling the reservation, when this cannot be done by requesting bay due to for example communication failure.

When the parameter *ParamRequestx* (*x*=1-8) is set to *Only own bay res.* individually for each apparatus (*x*) in the bay, only the own bay is reserved, that is, the output for reservation request of other bays (RES_BAYS) will not be activated at selection of apparatus *x*.

**15.2.8.6 Reservation input (RESIN)**

With the *FutureUse* parameter set to *Bay future use* the function can handle bays not yet installed in the SA system.

**15.3 Interlocking (3)**

The main purpose of switchgear interlocking is:

- To avoid the dangerous or damaging operation of switchgear
- To enforce restrictions on the operation of the substation for other reasons for example, load configuration. Examples of the latter are to limit the number of parallel transformers to a maximum of two or to ensure that energizing is always from one side, for example, the high voltage side of a transformer.

This section only deals with the first point, and only with restrictions caused by switching devices other than the one to be controlled. This means that switch interlock, because of device alarms, is not included in this section.

Disconnectors and grounding switches have a limited switching capacity. Disconnectors may therefore only operate:

- With basically zero current. The circuit is open on one side and has a small extension. The capacitive current is small (for example, < 5A) and power transformers with inrush current are not allowed.
- To connect or disconnect a parallel circuit carrying load current. The switching voltage across the open contacts is thus virtually zero, thanks to the parallel circuit (for example, < 1% of rated voltage). Paralleling of power transformers is not allowed.
Grounding switches are allowed to connect and disconnect grounding of isolated points. Due to capacitive or inductive coupling there may be some voltage (for example < 40% of rated voltage) before grounding and some current (for example < 100A) after grounding of a line.

Circuit breakers are usually not interlocked. Closing is only interlocked against running disconnectors in the same bay, and the bus-coupler opening is interlocked during a busbar transfer.

The positions of all switching devices in a bay and from some other bays determine the conditions for operational interlocking. Conditions from other stations are usually not available. Therefore, a line grounding switch is usually not fully interlocked. The operator must be convinced that the line is not energized from the other side before closing the grounding switch. As an option, a voltage indication can be used for interlocking. Take care to avoid a dangerous enable condition at the loss of a VT secondary voltage, for example, because of a blown fuse.

The switch positions used by the operational interlocking logic are obtained from auxiliary contacts or position sensors. For each end position (open or closed) a true indication is needed - thus forming a double indication. The apparatus control function continuously checks its consistency. If neither condition is high (1 or TRUE), the switch may be in an intermediate position, for example, moving. This dynamic state may continue for some time, which in the case of disconnectors may be up to 10 seconds. Should both indications stay low for a longer period, the position indication will be interpreted as unknown. If both indications stay high, something is wrong, and the state is again treated as unknown.

In both cases an alarm is sent to the operator. Indications from position sensors shall be self-checked and system faults indicated by a fault signal. In the interlocking logic, the signals are used to avoid dangerous enable or release conditions. When the switching state of a switching device cannot be determined operation is not permitted.

For switches with an individual operation gear per phase, the evaluation must consider possible phase discrepancies. This is done with the aid of an AND-function for all three phases in each apparatus for both open and close indications. Phase discrepancies will result in an unknown double indication state.

15.3.1 Configuration guidelines

The following sections describe how the interlocking for a certain switchgear configuration can be realized in the IED by using standard interlocking modules and their interconnections. They also describe the configuration settings. The inputs for delivery specific conditions (Qx_EXy) are set to 1=TRUE if they are not used, except in the following cases:

- 989_EX2 and 989_EX4 in modules BH_LINE_A and BH_LINE_B
- 152_EX3 in module AB_TRAFO

when they are set to 0=FALSE.

15.3.2 Interlocking for line bay ABC_LINE (3)

15.3.2.1 Application

The interlocking for line bay (ABC_LINE, 3) function is used for a line connected to a double busbar arrangement with a transfer busbar according to figure 247. The function can also be used for a
double busbar arrangement without transfer busbar or a single busbar arrangement with/without transfer busbar.

![Diagram of busbar arrangement](en04000478_ansl.vsd)

*Figure 247: Switchyard layout ABC_LINE (3)*

The signals from other bays connected to the module ABC_LINE (3) are described below.

### 15.3.2.2 Signals from bypass busbar

To derive the signals:

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>BB7_D_OP</td>
<td>All line disconnectors on bypass WA7 except in the own bay are open.</td>
</tr>
<tr>
<td>VP_BB7_D</td>
<td>The switch status of disconnectors on bypass busbar WA7 are valid.</td>
</tr>
<tr>
<td>EXDU_BPB</td>
<td>No transmission error from any bay containing disconnectors on bypass busbar WA7</td>
</tr>
</tbody>
</table>

These signals from each line bay (ABC_LINE, 3) except that of the own bay are needed:

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>789OPTR</td>
<td>789 is open</td>
</tr>
<tr>
<td>VP789TR</td>
<td>The switch status for 789 is valid.</td>
</tr>
<tr>
<td>EXDU_BPB</td>
<td>No transmission error from the bay that contains the above information.</td>
</tr>
</tbody>
</table>

For bay n, these conditions are valid:
15.3.2.3 Signals from bus-coupler

If the busbar is divided by bus-section disconnectors into bus sections, the busbar-busbar connection could exist via the bus-section disconnector and bus-coupler within the other bus section.

To derive the signals:

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>BC_12_CL</td>
<td>A bus-coupler connection exists between busbar WA1 and WA2.</td>
</tr>
<tr>
<td>BC_17_OP</td>
<td>No bus-coupler connection between busbar WA1 and WA7.</td>
</tr>
<tr>
<td>BC_17_CL</td>
<td>A bus-coupler connection exists between busbar WA1 and WA7.</td>
</tr>
<tr>
<td>BC_27_OP</td>
<td>No bus-coupler connection between busbar WA2 and WA7.</td>
</tr>
<tr>
<td>BC_27_CL</td>
<td>A bus-coupler connection exists between busbar WA2 and WA7.</td>
</tr>
<tr>
<td>VP_BC_12</td>
<td>The switch status of BC_12 is valid.</td>
</tr>
</tbody>
</table>

Table continues on next page
These signals from each bus-coupler bay (ABC_BC) are needed:

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>VP_BC_17</td>
<td>The switch status of BC_17 is valid.</td>
</tr>
<tr>
<td>VP_BC_27</td>
<td>The switch status of BC_27 is valid.</td>
</tr>
<tr>
<td>EXDU_BC</td>
<td>No transmission error from any bus-coupler bay (BC).</td>
</tr>
</tbody>
</table>

These signals from each bus-section disconnector bay (A1A2_DC) are also needed. For B1B2_DC, corresponding signals from busbar B are used. The same type of module (A1A2_DC) is used for different busbars, that is, for both bus-section disconnector A1A2_DC and B1B2_DC.

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>DCOPTR</td>
<td>The bus-section disconnector is open.</td>
</tr>
<tr>
<td>DCCLTR</td>
<td>The bus-section disconnector is closed.</td>
</tr>
<tr>
<td>VPDCCTR</td>
<td>The switch status of bus-section disconnector DC is valid.</td>
</tr>
<tr>
<td>EXDU_DC</td>
<td>No transmission error from the bay that contains the above information.</td>
</tr>
</tbody>
</table>

If the busbar is divided by bus-section circuit breakers, the signals from the bus-section coupler bay (A1A2_BS), rather than the bus-section disconnector bay (A1A2_DC) must be used. For B1B2_BS, corresponding signals from busbar B are used. The same type of module (A1A2_BS) is used for different busbars, that is, for both bus-section circuit breakers A1A2_BS and B1B2_BS.

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1S2OPTR</td>
<td>No bus-section coupler connection between bus-sections 1 and 2.</td>
</tr>
<tr>
<td>S1S2CLTR</td>
<td>A bus-section coupler connection exists between bus-sections 1 and 2.</td>
</tr>
<tr>
<td>VPS1S2TR</td>
<td>The switch status of bus-section coupler BS is valid.</td>
</tr>
<tr>
<td>EXDU_BS</td>
<td>No transmission error from the bay that contains the above information.</td>
</tr>
</tbody>
</table>
For a line bay in section 1, these conditions are valid:

**BC12CLTR (sect.1)**
- DCCLTR (A1A2)
- DCCLTR (B1B2)
- BC12CLTR (sect.2)

**OR**

**BC12CLTR (sect.2)**

**DCCLTR (A1A2)**

**DCCLTR (B1B2)**

**VPBC12TR (sect.1)**
- VPDCTR (A1A2)
- VPDCTR (B1B2)
- VPBC12TR (sect.2)

**OR**

**VPBC12TR (sect.2)**

**BC17OPTR (sect.1)**
- DCOPTR (A1A2)
- BC17OPTR (sect.2)

**BC17CLTR (sect.1)**
- DCCLTR (A1A2)
- BC17CLTR (sect.2)

**OR**

**BC17CLTR (sect.2)**

**VPBC17TR (sect.1)**
- VPDCTR (A1A2)
- VPBC17TR (sect.2)

**BC27OPTR (sect.1)**
- DCOPTR (B1B2)
- BC27OPTR (sect.2)

**BC27CLTR (sect.1)**
- DCCLTR (B1B2)
- BC27CLTR (sect.2)

**OR**

**BC27CLTR (sect.2)**

**VPBC27TR (sect.1)**
- VPDCTR (B1B2)
- VPBC27TR (sect.2)

**BC12CL**

**VP_BC_12**

**BC_17_OP**

**BC_17_CL**

**BC_27_OP**

**BC_27_CL**

**VP_BC_17**

**EXDU_BC**

**Figure 250: Signals to a line bay in section 1 from the bus-coupler bays in each section**

For a line bay in section 2, the same conditions as above are valid by changing section 1 to section 2 and vice versa.
15.3.2.4 Configuration setting

If there is no bypass busbar and therefore no 789 disconnector, then the interlocking for 789 is not used. The states for 789, 7189G, BB7_D, BC_17, BC_27 are set to open by setting the appropriate module inputs as follows. In the functional block diagram, 0 and 1 are designated 0=FALSE and 1=TRUE:

- 789_OP = 1
- 789_CL = 0
- 7189G_OP = 1
- 7189G_CL = 0
- BB7_D_OP = 1
- BC_17_OP = 1
- BC_17_CL = 0
- BC_27_OP = 1
- BC_27_CL = 0
- EXDU_BPB = 1
- VP_BB7_D = 1
- VP_BC_17 = 1
- VP_BC_27 = 1

If there is no second busbar WA2 and therefore no 289 disconnector, then the interlocking for 289 is not used. The state for 289, 2189G, BC_12, BC_27 are set to open by setting the appropriate module inputs as follows. In the functional block diagram, 0 and 1 are designated 0=FALSE and 1=TRUE:

- 289_OP = 1
- 289_CL = 0
- 2189G_OP = 1
- 2189G_CL = 0
- BC_12_CL = 0
- BC_27_OP = 1
- BC_27_CL = 0
- VP_BC_12 = 1

15.3.3 Interlocking for bus-coupler bay ABC_BC (3)
15.3.3.1 Application

The interlocking for bus-coupler bay (ABC_BC, 3) function is used for a bus-coupler bay connected to a double busbar arrangement according to figure 251. The function can also be used for a single busbar arrangement with transfer busbar or double busbar arrangement without transfer busbar.

![Switchyard layout ABC_BC (3)](en04000514_ansi.vsd)

Figure 251: Switchyard layout ABC_BC (3)

15.3.3.2 Configuration

The signals from the other bays connected to the bus-coupler module ABC_BC are described below.

15.3.3.3 Signals from all feeders

To derive the signals:

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>BBTR_OP</td>
<td>No busbar transfer is in progress concerning this bus-coupler.</td>
</tr>
<tr>
<td>VP_BBTR</td>
<td>The switch status is valid for all apparatuses involved in the busbar transfer.</td>
</tr>
<tr>
<td>EXDU_12</td>
<td>No transmission error from any bay connected to the WA1/WA2 busbars.</td>
</tr>
</tbody>
</table>

These signals from each line bay (ABC_LINE), each transformer bay (AB_TRAFO), and bus-coupler bay (ABC_BC), except the own bus-coupler bay are needed:

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q1289OPTR</td>
<td>189 or 289 or both are open.</td>
</tr>
<tr>
<td>VP1289TR</td>
<td>The switch status of 189 and 289 are valid.</td>
</tr>
<tr>
<td>EXDU_12</td>
<td>No transmission error from the bay that contains the above information.</td>
</tr>
</tbody>
</table>

For bus-coupler bay n, these conditions are valid:
Figure 252: Signals from any bays in bus-coupler bay n

If the busbar is divided by bus-section disconnectors into bus-sections, the signals BBTR are connected in parallel - if both bus-section disconnectors are closed. So for the basic project-specific logic for BBTR above, add this logic:

Figure 253: Busbars divided by bus-section disconnectors (circuit breakers)

The following signals from each bus-section disconnector bay (A1A2_DC) are needed. For B1B2_DC, corresponding signals from busbar B are used. The same type of module (A1A2_DC) is used for different busbars, that is, for both bus-section disconnector A1A2_DC and B1B2_DC.

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>DCOPTR</td>
<td>The bus-section disconnector is open.</td>
</tr>
<tr>
<td>VPDCTR</td>
<td>The switch status of bus-section disconnector DC is valid.</td>
</tr>
<tr>
<td>EXDU_DC</td>
<td>No transmission error from the bay that contains the above information.</td>
</tr>
</tbody>
</table>

If the busbar is divided by bus-section circuit breakers, the signals from the bus-section coupler bay (A1A2_BS), rather than the bus-section disconnector bay (A1A2_DC), have to be used. For B1B2_BS, corresponding signals from busbar B are used. The same type of module (A1A2_BS) is used for different busbars, that is, for both bus-section circuit breakers A1A2_BS and B1B2_BS.
For a bus-coupler bay in section 1, these conditions are valid:

- **BBTR_OP (sect.1)**
- **DCOPTR (A1A2)**
- **DCOPTR (B1B2)**
- **BBTR_OP (sect.2)**

For a bus-coupler bay in section 2, the same conditions as above are valid by changing section 1 to section 2 and vice versa.

### 15.3.3.4 Signals from bus-coupler

If the busbar is divided by bus-section disconnectors into bus-sections, the signals BC_12 from the busbar coupler of the other busbar section must be transmitted to the own busbar coupler if both disconnectors are closed.

*Figure 255: Busbars divided by bus-section disconnectors (circuit breakers)*

To derive the signals:
Another bus-coupler connection exists between busbar WA1 and WA2.

The switch status of BC_12 is valid.

No transmission error from any bus-coupler bay (BC).

These signals from each bus-coupler bay (ABC_BC), except the own bay, are needed:

- **Signal**
  - **BC12CLTR**: A bus-coupler connection through the own bus-coupler exists between busbar WA1 and WA2.
  - **VPBC12TR**: The switch status of BC_12 is valid.
  - **EXDU_BC**: No transmission error from the bay that contains the above information.

These signals from each bus-section disconnector bay (A1A2_DC) are also needed. For B1B2_DC, corresponding signals from busbar B are used. The same type of module (A1A2_DC) is used for different busbars, that is, for both bus-section disconnector A1A2_DC and B1B2_DC.

- **Signal**
  - **DCCLTR**: The bus-section disconnector is closed.
  - **VPDCTR**: The switch status of bus-section disconnector DC is valid.
  - **EXDU_DC**: No transmission error from the bay that contains the above information.

If the busbar is divided by bus-section circuit breakers, the signals from the bus-section coupler bay (A1A2_BS), rather than the bus-section disconnector bay (A1A2_DC), must be used. For B1B2_BS, corresponding signals from busbar B are used. The same type of module (A1A2_BS) is used for different busbars, that is, for both bus-section circuit breakers A1A2_BS and B1B2_BS.

- **Signal**
  - **S1S2CLTR**: A bus-section coupler connection exists between bus sections 1 and 2.
  - **VPS1S2TR**: The switch status of bus-section coupler BS is valid.
  - **EXDU_BS**: No transmission error from the bay containing the above information.

For a bus-coupler bay in section 1, these conditions are valid:
Figure 256: Signals to a bus-coupler bay in section 1 from a bus-coupler bay in another section

For a bus-coupler bay in section 2, the same conditions as above are valid by changing section 1 to section 2 and vice versa.

15.3.3.5 Configuration setting

If there is no bypass busbar and therefore no 289 and 789 disconnectors, then the interlocking for 289 and 789 is not used. The states for 289, 789, 7189G are set to open by setting the appropriate module inputs as follows. In the functional block diagram, 0 and 1 are designated 0=FALSE and 1=TRUE:

- 289_OP = 1
- 289_CL = 0
- 789_OP = 1
- 789_CL = 0
- 7189G_OP = 1
- 7189G_CL = 0

If there is no second busbar B and therefore no 289 and 2089 disconnectors, then the interlocking for 289 and 2089 are not used. The states for 289, 2089, 2189G, BC_12, BBTR are set to open by setting the appropriate module inputs as follows. In the functional block diagram, 0 and 1 are designated 0=FALSE and 1=TRUE:

- 289_OP = 1
- 289_CL = 0
- 2089_OP = 1
- 2089_CL = 0
- 2189G_OP = 1
- 2189G_CL = 0
- BC_12_CL = 0
- VP_BC_12 = 1
15.3.4 Interlocking for transformer bay AB_TRAFO (3)

15.3.4.1 Application

The interlocking for transformer bay (AB_TRAFO, 3) function is used for a transformer bay connected to a double busbar arrangement according to figure 257. The function is used when there is no disconnector between circuit breaker and transformer. Otherwise, the interlocking for line bay (ABC_LINE, 3) function can be used. This function can also be used in single busbar arrangements.

![Interlocking schematic](en04000515_ansi.vsd)

*Figure 257: Switchyard layout AB_TRAFO (3)*

The signals from other bays connected to the module AB_TRAFO are described below.

15.3.4.2 Signals from bus-coupler

If the busbar is divided by bus-section disconnectors into bus-sections, the busbar-busbar connection could exist via the bus-section disconnector and bus-coupler within the other bus-section.
Figure 258: Busbars divided by bus-section disconnectors (circuit breakers)

The project-specific logic for input signals concerning bus-coupler are the same as the specific logic for the line bay (ABC_LINE):

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>BC_12_CL</td>
<td>A bus-coupler connection exists between busbar WA1 and WA2.</td>
</tr>
<tr>
<td>VP_BC_12</td>
<td>The switch status of BC_12 is valid.</td>
</tr>
<tr>
<td>EXDU_BC</td>
<td>No transmission error from bus-coupler bay (BC).</td>
</tr>
</tbody>
</table>

The logic is identical to the double busbar configuration “Signals from bus-coupler”.

15.3.4.3 Configuration setting

If there are no second busbar B and therefore no 289 disconnector, then the interlocking for 289 is not used. The state for 289, 2189G, BC_12 are set to open by setting the appropriate module inputs as follows. In the functional block diagram, 0 and 1 are designated 0=FALSE and 1=TRUE:

- 289_OP = 1
- 289QB2_CL = 0

- 2189G_OP = 1
- 2189G_CL = 0

- BC_12_CL = 0
- VP_BC_12 = 1

If there is no second busbar B at the other side of the transformer and therefore no 489 disconnector, then the state for 489 is set to open by setting the appropriate module inputs as follows:

- 489_OP = 1
- 489_CL = 0
15.3.5 Interlocking for bus-section breaker A1A2_BS (3)

15.3.5.1 Application

The interlocking for bus-section breaker (A1A2_BS,3) function is used for one bus-section circuit breaker between section 1 and 2 according to figure 259. The function can be used for different busbars, which includes a bus-section circuit breaker.

![Interlocking schematic](en04000516_ansi.vsd)

*Figure 259: Switchyard layout A1A2_BS (3)*

The signals from other bays connected to the module A1A2_BS are described below.

15.3.5.2 Signals from all feeders

If the busbar is divided by bus-section circuit breakers into bus-sections and both circuit breakers are closed, the opening of the circuit breaker must be blocked if a bus-coupler connection exists between busbars on one bus-section side and if on the other bus-section side a busbar transfer is in progress:

![Busbar schematic](en04000489_ansi.vsd)

*Figure 260: Busbars divided by bus-section circuit breakers*

To derive the signals:
<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>BBTR_OP</td>
<td>No busbar transfer is in progress concerning this bus-section.</td>
</tr>
<tr>
<td>VP_BBTR</td>
<td>The switch status of BBTR is valid.</td>
</tr>
<tr>
<td>EXDU_12</td>
<td>No transmission error from any bay connected to busbar 1(A) and 2(B).</td>
</tr>
</tbody>
</table>

These signals from each line bay (ABC_LINE), each transformer bay (AB_TRAFO), and bus-coupler bay (ABC_BC) are needed:

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1289OPTR</td>
<td>189 or 289 or both are open.</td>
</tr>
<tr>
<td>VP1289TR</td>
<td>The switch status of 189 and 289 are valid.</td>
</tr>
<tr>
<td>EXDU_12</td>
<td>No transmission error from the bay that contains the above information.</td>
</tr>
</tbody>
</table>

These signals from each bus-coupler bay (ABC_BC) are needed:

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>BC12OPTR</td>
<td>No bus-coupler connection through the own bus-coupler between busbar WA1 and WA2.</td>
</tr>
<tr>
<td>VPBC12TR</td>
<td>The switch status of BC_12 is valid.</td>
</tr>
<tr>
<td>EXDU_BC</td>
<td>No transmission error from the bay that contains the above information.</td>
</tr>
</tbody>
</table>

These signals from the bus-section circuit breaker bay (A1A2_BS, B1B2_BS) are needed:

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1S2OPTR</td>
<td>No bus-section coupler connection between bus-sections 1 and 2.</td>
</tr>
<tr>
<td>VPS1S2TR</td>
<td>The switch status of bus-section coupler BS is valid.</td>
</tr>
<tr>
<td>EXDU_BS</td>
<td>No transmission error from the bay that contains the above information.</td>
</tr>
</tbody>
</table>

For a bus-section circuit breaker between A1 and A2 section busbars, these conditions are valid:
Figure 261: Signals from any bays for a bus-section circuit breaker between sections A1 and A2

For a bus-section circuit breaker between B1 and B2 section busbars, these conditions are valid:
**Figure 262: Signals from any bays for a bus-section circuit breaker between sections B1 and B2**

### 15.3.5.3 Configuration setting

If there is no other busbar via the busbar loops that are possible, then either the interlocking for the 152 open circuit breaker is not used or the state for BBTR is set to open. That is, no busbar transfer is in progress in this bus-section:

- BBTR_OP = 1
- VP_BBTR = 1

### 15.3.6 Interlocking for bus-section disconnector A1A2_DC (3)
15.3.6.1 Application

The interlocking for bus-section disconnector (A1A2_DC, 3) function is used for one bus-section disconnector between section 1 and 2 according to figure 263. A1A2_DC (3) function can be used for different busbars, which includes a bus-section disconnector.

![Figure 263: Switchyard layout A1A2_DC (3)](en04000492_ansi.vsd)

The signals from other bays connected to the module A1A2_DC are described below.

15.3.6.2 Signals in single breaker arrangement

If the busbar is divided by bus-section disconnectors, the condition no other disconnector connected to the bus-section must be made by a project-specific logic.

The same type of module (A1A2_DC) is used for different busbars, that is, for both bus-section disconnector A1A2_DC and B1B2_DC. But for B1B2_DC, corresponding signals from busbar B are used.

![Figure 264: Busbars divided by bus-section disconnectors (circuit breakers)](en04000493_ansi.vsd)

To derive the signals:

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1DC_OP</td>
<td>All disconnectors on bus-section 1 are open.</td>
</tr>
<tr>
<td>S2DC_OP</td>
<td>All disconnectors on bus-section 2 are open.</td>
</tr>
<tr>
<td>VPS1_DC</td>
<td>The switch status of disconnectors on bus-section 1 is valid.</td>
</tr>
<tr>
<td>VPS2_DC</td>
<td>The switch status of disconnectors on bus-section 2 is valid.</td>
</tr>
<tr>
<td>EXDU_BB</td>
<td>No transmission error from any bay that contains the above information.</td>
</tr>
</tbody>
</table>

These signals from each line bay (ABC_LINE), each transformer bay (AB_TRAFO), and each bus-coupler bay (ABC_BC) are needed:
If there is an additional bus-section disconnector, the signal from the bus-section disconnector bay (A1A2_DC) must be used:

<table>
<thead>
<tr>
<th>Signal</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>DCOPTR</td>
<td>The bus-section disconnector is open.</td>
</tr>
<tr>
<td>VPDCTR</td>
<td>The switch status of bus-section disconnector DC is valid.</td>
</tr>
<tr>
<td>EXDU_DC</td>
<td>No transmission error from the bay that contains the above information.</td>
</tr>
</tbody>
</table>

If there is an additional bus-section circuit breaker rather than an additional bus-section disconnector the signals from the bus-section, circuit-breaker bay (A1A2_BS) rather than the bus-section disconnector bay (A1A2_DC) must be used:

<table>
<thead>
<tr>
<th>Signal</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>189OPTR</td>
<td>189 is open.</td>
</tr>
<tr>
<td>289OPTR</td>
<td>289 is open.</td>
</tr>
<tr>
<td>VP189TR</td>
<td>The switch status of 189 is valid.</td>
</tr>
<tr>
<td>VP289TR</td>
<td>The switch status of 289 is valid.</td>
</tr>
<tr>
<td>EXDU_BS</td>
<td>No transmission error from the bay BS (bus-section coupler bay) that contains the above information.</td>
</tr>
</tbody>
</table>

For a bus-section disconnector, these conditions from the A1 busbar section are valid:

- $189\text{OPTR} (\text{bay } 1/\text{sect.A1})$ AND $S1\text{DC\_OP}$
- $189\text{OPTR} (\text{bay } n/\text{sect.A1})$
- $VP189\text{TR} (\text{bay } 1/\text{sect.A1})$ AND $VPS1\text{\_DC}$
- $VP189\text{TR} (\text{bay } n/\text{sect.A1})$
- $EXDU\text{\_BB} (\text{bay } 1/\text{sect.A1})$ AND $EXDU\text{\_BB}$
- $EXDU\text{\_BB} (\text{bay } n/\text{sect.A1})$

*Figure 265: Signals from any bays in section A1 to a bus-section disconnector*
For a bus-section disconnector, these conditions from the A2 busbar section are valid:

![Diagram of conditions for A2 busbar section](en04000495_ansi.vsd)

**Figure 266: Signals from any bays in section A2 to a bus-section disconnector**

For a bus-section disconnector, these conditions from the B1 busbar section are valid:

![Diagram of conditions for B1 busbar section](en04000496_ansi.vsd)

**Figure 267: Signals from any bays in section B1 to a bus-section disconnector**

For a bus-section disconnector, these conditions from the B2 busbar section are valid:
15.3.6.3 Signals in double-breaker arrangement

If the busbar is divided by bus-section disconnectors, the condition for the busbar disconnector bay no other disconnector connected to the bus-section must be made by a project-specific logic.

The same type of module (A1A2_DC) is used for different busbars, that is, for both bus-section disconnector A1A2_DC and B1B2_DC. But for B1B2_DC, corresponding signals from busbar B are used.

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1DC_OP</td>
<td>All disconnectors on bus-section 1 are open.</td>
</tr>
<tr>
<td>S2DC_OP</td>
<td>All disconnectors on bus-section 2 are open.</td>
</tr>
<tr>
<td>VPS1_DC</td>
<td>The switch status of all disconnectors on bus-section 1 is valid.</td>
</tr>
<tr>
<td>VPS2_DC</td>
<td>The switch status of all disconnectors on bus-section 2 is valid.</td>
</tr>
<tr>
<td>EXDU_BB</td>
<td>No transmission error from double-breaker bay (DB) that contains the above information.</td>
</tr>
</tbody>
</table>
These signals from each double-breaker bay (DB_BUS) are needed:

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>189OPTR</td>
<td>189 is open.</td>
</tr>
<tr>
<td>289OPTR</td>
<td>289 is open.</td>
</tr>
<tr>
<td>VP189TR</td>
<td>The switch status of 189 is valid.</td>
</tr>
<tr>
<td>VP289TR</td>
<td>The switch status of 289 is valid.</td>
</tr>
<tr>
<td>EXDU_DB</td>
<td>No transmission error from the bay that contains the above information.</td>
</tr>
</tbody>
</table>

The logic is identical to the double busbar configuration “Signals in single breaker arrangement”.

For a bus-section disconnector, these conditions from the A1 busbar section are valid:

189OPTR (bay 1/sect.A1) AND S1DC_OP
189OPTR (bay n/sect.A1)

VP189TR (bay 1/sect.A1) AND VPS1_DC
VP189TR (bay n/sect.A1)

EXDU_DB (bay 1/sect.A1) AND EXDU_BB
EXDU_DB (bay n/sect.A1)

*Figure 270: Signals from double-breaker bays in section A1 to a bus-section disconnector*

For a bus-section disconnector, these conditions from the A2 busbar section are valid:

189OPTR (bay 1/sect.A2) AND S2DC_OP
189OPTR (bay n/sect.A2)

VP189TR (bay 1/sect.A2) AND VPS2_DC
VP189TR (bay n/sect.A2)

EXDU_DB (bay 1/sect.A2) AND EXDU_BB
EXDU_DB (bay n/sect.A2)

*Figure 271: Signals from double-breaker bays in section A2 to a bus-section disconnector*

For a bus-section disconnector, these conditions from the B1 busbar section are valid:
Figure 272: Signals from double-breaker bays in section B1 to a bus-section disconnector

For a bus-section disconnector, these conditions from the B2 busbar section are valid:

Figure 273: Signals from double-breaker bays in section B2 to a bus-section disconnector

15.3.6.4 Signals in breaker and a half arrangement

If the busbar is divided by bus-section disconnectors, the condition for the busbar disconnector bay no other disconnector connected to the bus-section must be made by a project-specific logic.

The same type of module (A1A2_DC) is used for different busbars, that is, for both bus-section disconnector A1A2_DC and B1B2_DC. But for B1B2_DC, corresponding signals from busbar B are used.

Figure 274: Busbars divided by bus-section disconnectors (circuit breakers)
The project-specific logic is the same as for the logic for the double-breaker configuration.

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1DC_OP</td>
<td>All disconnectors on bus-section 1 are open.</td>
</tr>
<tr>
<td>S2DC_OP</td>
<td>All disconnectors on bus-section 2 are open.</td>
</tr>
<tr>
<td>VPS1_DC</td>
<td>The switch status of disconnectors on bus-section 1 is valid.</td>
</tr>
<tr>
<td>VPS2_DC</td>
<td>The switch status of disconnectors on bus-section 2 is valid.</td>
</tr>
<tr>
<td>EXDU_BB</td>
<td>No transmission error from breaker and a half (BH) that contains the above information.</td>
</tr>
</tbody>
</table>

### 15.3.7 Interlocking for busbar grounding switch BB_ES (3)

#### 15.3.7.1 Application

The interlocking for busbar grounding switch (BB_ES, 3) function is used for one busbar grounding switch on any busbar parts according to figure 275.

![Figure 275: Switchyard layout BB_ES (3)](en04000504.vsd)

The signals from other bays connected to the module BB_ES are described below.

#### 15.3.7.2 Signals in single breaker arrangement

The busbar grounding switch is only allowed to operate if all disconnectors of the bus-section are open.

![Figure 276: Busbars divided by bus-section disconnectors (circuit breakers)](en04000505_ansi.vsd)

To derive the signals:
These signals from each line bay (ABC_LINE), each transformer bay (AB_TRAFO), and each bus-coupler bay (ABC_BC) are needed:

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>BB_DC_OP</td>
<td>All disconnectors on this part of the busbar are open.</td>
</tr>
<tr>
<td>VP_BB_DC</td>
<td>The switch status of all disconnector on this part of the busbar is valid.</td>
</tr>
<tr>
<td>EXDU_BB</td>
<td>No transmission error from any bay containing the above information.</td>
</tr>
</tbody>
</table>

These signals from each bus-section disconnector bay (A1A2_DC) are also needed. For B1B2_DC, corresponding signals from busbar B are used. The same type of module (A1A2_DC) is used for different busbars, that is, for both bus-section disconnectors A1A2_DC and B1B2_DC.

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>DCOPTR</td>
<td>The bus-section disconnector is open.</td>
</tr>
<tr>
<td>VPDCTR</td>
<td>The switch status of bus-section disconnector DC is valid.</td>
</tr>
<tr>
<td>EXDU_DC</td>
<td>No transmission error from the bay that contains the above information.</td>
</tr>
</tbody>
</table>

If no bus-section disconnector exists, the signal DCOPTR, VPDCTR and EXDU_DC are set to 1 (TRUE).

If the busbar is divided by bus-section circuit breakers, the signals from the bus-section coupler bay (A1A2_BS) rather than the bus-section disconnector bay (A1A2_DC) must be used. For B1B2_BS, corresponding signals from busbar B are used. The same type of module (A1A2_BS) is used for different busbars, that is, for both bus-section circuit breakers A1A2_BS and B1B2_BS.

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>189OPTR</td>
<td>189 is open.</td>
</tr>
<tr>
<td>289OPTR</td>
<td>289 is open. (AB_TRAFO, ABC_LINE)</td>
</tr>
<tr>
<td>22089OTR</td>
<td>289 and 2089 are open (ABC_BC)</td>
</tr>
<tr>
<td>789OPTR</td>
<td>789 is open.</td>
</tr>
<tr>
<td>VP189TR</td>
<td>The switch status of 189 is valid.</td>
</tr>
<tr>
<td>VP289TR</td>
<td>The switch status of 289 is valid.</td>
</tr>
<tr>
<td>V22089TR</td>
<td>The switch status of 289 and 2089 is valid.</td>
</tr>
<tr>
<td>VP789TR</td>
<td>The switch status of 789 is valid.</td>
</tr>
<tr>
<td>EXDU_BS</td>
<td>No transmission error from the bay BS (bus-section coupler bay) that contains the above information.</td>
</tr>
</tbody>
</table>
For a busbar grounding switch, these conditions from the A1 busbar section are valid:

\[
\begin{align*}
189\text{OPTR (bay 1/sect.A1)} & & \text{AND} & & \text{BB\_DC\_OP} \\
\ldots & & \ldots & & \ldots \\
189\text{OPTR (bay n/sect.A1)} & & \text{DCOPTR (A1/A2)} & & \ldots \\
\ldots & & \ldots & & \ldots \\
\text{VP189TR (bay 1/sect.A1)} & & \text{AND} & & \text{VP\_BB\_DC} \\
\ldots & & \ldots & & \ldots \\
\text{VP189TR (bay n/sect.A1)} & & \text{VPDCTR (A1/A2)} & & \ldots \\
\ldots & & \ldots & & \ldots \\
\text{EXDU\_BB (bay 1/sect.A1)} & & \text{AND} & & \text{EXDU\_BB} \\
\ldots & & \ldots & & \ldots \\
\text{EXDU\_BB (bay n/sect.A1)} & & \text{EXDU\_DC (A1/A2)} & & \ldots \\
\ldots & & \ldots & & \ldots
\end{align*}
\]

**Figure 277: Signals from any bays in section A1 to a busbar grounding switch in the same section**

For a busbar grounding switch, these conditions from the A2 busbar section are valid:

\[
\begin{align*}
189\text{OPTR (bay 1/sect.A2)} & & \text{AND} & & \text{BB\_DC\_OP} \\
\ldots & & \ldots & & \ldots \\
189\text{OPTR (bay n/sect.A2)} & & \text{DCOPTR (A1/A2)} & & \ldots \\
\ldots & & \ldots & & \ldots \\
\text{VP189TR (bay 1/sect.A2)} & & \text{AND} & & \text{VP\_BB\_DC} \\
\ldots & & \ldots & & \ldots \\
\text{VP189TR (bay n/sect.A2)} & & \text{VPDCTR (A1/A2)} & & \ldots \\
\ldots & & \ldots & & \ldots \\
\text{EXDU\_BB (bay 1/sect.A2)} & & \text{AND} & & \text{EXDU\_BB} \\
\ldots & & \ldots & & \ldots \\
\text{EXDU\_BB (bay n/sect.A2)} & & \text{EXDU\_DC (A1/A2)} & & \ldots \\
\ldots & & \ldots & & \ldots
\end{align*}
\]

**Figure 278: Signals from any bays in section A2 to a busbar grounding switch in the same section**

For a busbar grounding switch, these conditions from the B1 busbar section are valid:
Figure 279: Signals from any bays in section B1 to a busbar grounding switch in the same section

For a busbar grounding switch, these conditions from the B2 busbar section are valid:

Figure 280: Signals from any bays in section B2 to a busbar grounding switch in the same section

For a busbar grounding switch on bypass busbar C, these conditions are valid:
15.3.7.3 Signals in double-breaker arrangement

The busbar grounding switch is only allowed to operate if all disconnectors of the bus section are open.

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>BB_DC_OP</td>
<td>All disconnectors of this part of the busbar are open.</td>
</tr>
<tr>
<td>VP_BB_DC</td>
<td>The switch status of all disconnectors on this part of the busbar are valid.</td>
</tr>
<tr>
<td>EXDU_BB</td>
<td>No transmission error from any bay that contains the above information.</td>
</tr>
</tbody>
</table>

These signals from each double-breaker bay (DB_BUS) are needed:

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>189OPTR</td>
<td>189 is open.</td>
</tr>
<tr>
<td>289OPTR</td>
<td>289 is open.</td>
</tr>
<tr>
<td>VP189TR</td>
<td>The switch status of 189 is valid.</td>
</tr>
<tr>
<td>VP289TR</td>
<td>The switch status of 289 is valid.</td>
</tr>
<tr>
<td>EXDU_DB</td>
<td>No transmission error from the bay that contains the above information.</td>
</tr>
</tbody>
</table>

Figure 281: Signals from bypass busbar to busbar grounding switch

Figure 282: Busbars divided by bus-section disconnectors (circuit breakers)
These signals from each bus-section disconnector bay (A1A2_DC) are also needed. For B1B2_DC, corresponding signals from busbar B are used. The same type of module (A1A2_DC) is used for different busbars, that is, for both bus-section disconnectors A1A2_DC and B1B2_DC.

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>DCOPTR</td>
<td>The bus-section disconnector is open.</td>
</tr>
<tr>
<td>VPDCTR</td>
<td>The switch status of bus-section disconnector DC is valid.</td>
</tr>
<tr>
<td>EXDU_DC</td>
<td>No transmission error from the bay that contains the above information.</td>
</tr>
</tbody>
</table>

The logic is identical to the double busbar configuration described in section “Signals in single breaker arrangement”.

### 15.3.7.4 Signals in breaker and a half arrangement

The busbar grounding switch is only allowed to operate if all disconnectors of the bus-section are open.

![Figure 283: Busbars divided by bus-section disconnectors (circuit breakers)](en04000512_ansi.vsd)

The project-specific logic are the same as for the logic for the double busbar configuration described in section “Signals in single breaker arrangement”.

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>BB_DC_OP</td>
<td>All disconnectors on this part of the busbar are open.</td>
</tr>
<tr>
<td>VP_BB_DC</td>
<td>The switch status of all disconnectors on this part of the busbar is valid.</td>
</tr>
<tr>
<td>EXDU_BB</td>
<td>No transmission error from any bay that contains the above information.</td>
</tr>
</tbody>
</table>

### 15.3.8 Interlocking for double CB bay DB (3)

#### 15.3.8.1 Application

The interlocking for a double busbar double circuit breaker bay including DB_BUS_A (3), DB_BUS_B (3) and DB_LINE (3) functions are used for a line connected to a double busbar arrangement according to figure 284.
Figure 284: Switchyard layout double circuit breaker

Three types of interlocking modules per double circuit breaker bay are defined. DB_BUS_A (3) handles the circuit breaker QA1 that is connected to busbar WA1 and the disconnectors and grounding switches of this section. DB_BUS_B (3) handles the circuit breaker QA2 that is connected to busbar WA2 and the disconnectors and grounding switches of this section.

For a double circuit-breaker bay, the modules DB_BUS_A, DB_LINE and DB_BUS_B must be used.

15.3.8.2 Configuration setting

For application without 989 and 989G, just set the appropriate inputs to open state and disregard the outputs. In the functional block diagram, 0 and 1 are designated 0=FALSE and 1=TRUE:

- 989_OP = 1
- 989_CL = 0
- 989G_OP = 1
- 989G_CL = 0

If, in this case, line voltage supervision is added, then rather than setting 989 to open state, specify the state of the voltage supervision:

- 989_OP = VOLT_OFF
- 989_CL = VOLT_ON

If there is no voltage supervision, then set the corresponding inputs as follows:

- VOLT_OFF = 1
- VOLT_ON = 0
15.3.9 Interlocking for breaker-and-a-half diameter BH (3)

15.3.9.1 Application

The interlocking for breaker-and-a-half diameter (BH_CONN(3), BH_LINE_A(3), BH_LINE_B(3)) functions are used for lines connected to a breaker-and-a-half diameter according to figure 285.

![Figure 285: Switchyard layout breaker-and-a-half](en04000513_ansi.vsd)

*Figure 285: Switchyard layout breaker-and-a-half*

Three types of interlocking modules per diameter are defined. BH_LINE_A (3) and BH_LINE_B (3) are the connections from a line to a busbar. BH_CONN (3) is the connection between the two lines of the diameter in the breaker-and-a-half switchyard layout.

For a breaker-and-a-half arrangement, the modules BH_LINE_A, BH_CONN and BH_LINE_B must be used.

15.3.9.2 Configuration setting

For application without 989 and 989G, just set the appropriate inputs to open state and disregard the outputs. In the functional block diagram, 0 and 1 are designated 0=FALSE and 1=TRUE:

- 989_OP = 1
- 989_CL = 0
If, in this case, line voltage supervision is added, then rather than setting 989 to open state, specify the state of the voltage supervision:

- 989_OP = VOLT_OFF
- 989_CL = VOLT_ON

If there is no voltage supervision, then set the corresponding inputs as follows:

- VOLT_OFF = 1
- VOLT_ON = 0

## 15.4 Voltage control

### 15.4.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tap changer control and supervision, 6 binary inputs</td>
<td>TCMYLTC</td>
<td>-</td>
<td>84</td>
</tr>
<tr>
<td>Tap changer control and supervision, 32 binary inputs</td>
<td>TCLYLTC</td>
<td>-</td>
<td>84</td>
</tr>
</tbody>
</table>

### 15.4.2 Application

When the load in a power network is increased the voltage will decrease and vice versa. To maintain the network voltage at a constant level, power transformers are usually equipped with on-load tap-changer. This alters the power transformer ratio in a number of predefined steps and in that way changes the voltage. Each step usually represents a change in voltage of approximately 0.5-1.7%.

The voltage control function is intended for control of power transformers with a motor driven on-load tap-changer. The function is designed to regulate the voltage at the secondary side of the power transformer. The control method is based on a step-by-step principle which means that a control pulse, one at a time, will be issued to the tap changer mechanism to move it one position up or down. The length of the control pulse can be set within a wide range to accommodate different types of tap changer mechanisms. The pulse is generated whenever the measured voltage, for a given time, deviates from the set reference value by more than the preset deadband (degree of insensitivity).

The voltage can be controlled at the point of voltage measurement, as well as at a load point located out in the network. In the latter case, the load point voltage is calculated based on the measured load current and the known impedance from the voltage measuring point to the load point.
The automatic voltage control can be either for a single transformer, or for parallel transformers. Parallel control of power transformers can be made in three alternative ways:

- With the master-follower method
- With the reverse reactance method
- With the circulating current method

Of these alternatives, the first and the last require communication between the function control blocks of the different transformers, whereas the middle alternative does not require any communication.

The voltage control includes many extra features such as possibility to avoid simultaneous tapping of parallel transformers, hot stand by regulation of a transformer within a parallel group, with a LV CB open, compensation for a possible capacitor bank on the LV side bay of a transformer, extensive tap changer monitoring including contact wear and hunting detection, monitoring of the power flow in the transformer so that for example, the voltage control can be blocked if the power reverses and so on.

The voltage control function is built up by two function blocks which both are logical nodes in IEC 61850-8-1:

- Automatic voltage control for tap changer, TR1ATCC (90) for single control and TR8ATCC (90) for parallel control.
- Tap changer control and supervision, 6 binary inputs, TCMYLTC (84) and 32 binary inputs, TCLYLTC (84)

Automatic voltage control for tap changer, TR1ATCC (90) or TR8ATCC (90) is a function designed to automatically maintain the voltage at the LV-side side of a power transformer within given limits around a set target voltage. A raise or lower command is generated whenever the measured voltage, for a given period of time, deviates from the set target value by more than the preset deadband value (degree of insensitivity). A time delay (inverse or definite time) is set to avoid unnecessary operation during shorter voltage deviations from the target value, and in order to coordinate with other automatic voltage controllers in the system.

TCMYLTC and TCLYLTC (84) are an interface between the Automatic voltage control for tap changer, TR1ATCC (90) or TR8ATCC (90) and the transformer load tap changer itself. More specifically this means that it gives command-pulses to a power transformer motor driven load tap changer and that it receives information from the load tap changer regarding tap position, progress of given commands, and so on.

TCMYLTC and TCLYLTC (84) also serve the purpose of giving information about tap position to the transformer differential protection.

**Control location local/remote**

The tap changer can be operated from the front of the IED or from a remote place alternatively. On the IED front there is a local remote switch that can be used to select the operator place. For this functionality the Apparatus control function blocks Bay control (QCBAY), Local remote (LOCREM) and Local remote control (LOCREMCTRL) are used.

Information about the control location is given to TR1ATCC (90) or TR8ATCC (90) function through connection of the Permitted Source to Operate (PSTO) output of the QCBAY function block to the input PSTO of the TR1ATCC (90) or TR8ATCC (90) function block.
**Control Mode**
The control mode of the automatic voltage control for tap changer function, TR1ATCC (90) for single control and TR8ATCC (90) for parallel control can be:

- Manual
- Automatic

The control mode can be changed from the local location via the command menu on the local HMI under **Main menu/Control/Commands/TransformerVoltageControl(ATCC,90)/TR1ATCC:x/TR8ATCC:x**, or changed from a remote location via binary signals connected to the MANCTRL, AUTOCTRL inputs on TR1ATCC (90) or TR8ATCC (90) function block.

**Measured Quantities**
In normal applications, the LV side of the transformer is used as the voltage measuring point. If necessary, the LV side current is used as load current to calculate the line-voltage drop to the regulation point.

Automatic voltage control for tap changer, TR1ATCC (90) for single control and TR8ATCC (90) for parallel control function block has three inputs I3P1, I3P2 and V3P2 corresponding to HV-current, LV-current and LV-voltage respectively. These analog quantities are fed to the IED via the transformer input module, the Analog to Digital Converter and thereafter a Pre-Processing Block. In the Pre-Processing Block, a great number of quantities for example, phase-to-phase analog values, sequence values, max value in a three phase group etc., are derived. The different function blocks in the IED are then “subscribing” on selected quantities from the pre-processing blocks. In case of TR1ATCC (90) or TR8ATCC (90), there are the following possibilities:

- I3P1 represents a three-phase group of phase current with the highest current in any of the three phases considered. As only the highest of the phase current is considered, it is also possible to use one single-phase current as well as two-phase currents. In these cases, the currents that are not used will be zero.
- For I3P2 and V3P2 the setting alternatives are: any individual phase current/voltage, as well as any combination of phase-phase current/voltage or the positive sequence current/voltage. Thus, single-phase as well as, phase-phase or three-phase feeding on the LV-side is possible but it is commonly selected for current and voltage.
On the HV side, the three-phase current is normally required in order to feed the three-phase over current protection that blocks the load tap changer in case of over-current above harmful levels.

The voltage measurement on the LV-side can be made single phase-ground. However, it shall be remembered that this can only be used in solidly grounded systems, as the measured phase-ground voltage can increase with as much as a factor $\sqrt{3}$ in case of ground faults in a non-solidly grounded system.

The analog input signals are normally common with other functions in the IED for example, protection functions.

The LV-busbar voltage is designated $V_B$, the load current $I_L$ and load point voltage $V_L$.

**Automatic voltage control for a single transformer**

Automatic voltage control for tap changer, single control TR1ATCC (90) measures the magnitude of the busbar voltage $V_B$. If no other additional features are enabled (line voltage drop compensation), this voltage is further used for voltage regulation.
TR1ATCC (90) then compares this voltage with the set voltage, $V_{Set}$ and decides which action should be taken. To avoid unnecessary switching around the setpoint, a deadband (degree of insensitivity) is introduced. The deadband is symmetrical around $V_{Set}$, see figure 287, and it is arranged in such a way that there is an outer and an inner deadband. Measured voltages outside the outer deadband start the timer to initiate tap commands, whilst the sequence resets when the measured voltage is once again back inside the inner deadband. One half of the outer deadband is denoted $\Delta V$. The setting of $\Delta V$, setting $V_{deadband}$ should be set to a value near to the power transformer’s tap changer voltage step (typically 75–125% of the tap changer step).

![Figure 287: Control actions on a voltage scale](ANSI06000489-2-en.vsd)

**Figure 287: Control actions on a voltage scale**

During normal operating conditions the busbar voltage $V_B$ stays within the outer deadband (interval between $V_1$ and $V_2$ in figure 287). In that case no actions will be taken by TR1ATCC (90). However, if $V_B$ becomes smaller than $V_1$, or greater than $V_2$, an appropriate raise or lower timer will start. The timer will run as long as the measured voltage stays outside the inner deadband. If this condition persists longer than the preset time delay, TR1ATCC (90) will initiate that the appropriate VLOWER or VRAISE command will be sent from TCMYLTC or TCLYLTC function block to the transformer tap changer. If necessary, the procedure will be repeated until the magnitude of the busbar voltage again falls within the inner deadband. One half of the inner deadband is denoted $\Delta V_{in}$. The inner deadband $\Delta V_{in}$, setting $V_{DeadbandInner}$ should be set to a value smaller than $\Delta V$. It is recommended to set the inner deadband to 25-70% of the $\Delta V$ value.

This way of working is used by TR1ATCC (90) while the busbar voltage is within the security range defined by settings $V_{min}$ and $V_{max}$.

A situation where $V_B$ falls outside this range will be regarded as an abnormal situation.

When $V_B$ falls below setting $V_{block}$, or alternatively, falls below setting $V_{min}$ but still above $V_{block}$, or rises above $V_{max}$, actions will be taken in accordance with settings for blocking conditions (refer to table 60).

If the busbar voltage rises above $V_{max}$, TR1ATCC (90) can initiate one or more fast step down commands (VLOWER commands) in order to bring the voltage back into the security range (settings $V_{min}$, and $V_{max}$). The fast step down function operation can be set in one of the following three ways: off /auto/auto and manual, according to the setting $FSDMode$. The VLOWER command, in fast step down mode, is issued with the settable time delay $t_{FSD}$.

The measured RMS magnitude of the busbar voltage $V_B$ is shown on the local HMI as value BUSVOLT under Main menu/Test/Function status/Control/TransformerVoltageControl(ATCC,90)/TR1ATCC:x/TR8ATCC:x.

**Time characteristic**

The time characteristic defines the time that elapses between the moment when measured voltage exceeds the deadband interval until the appropriate VRAISE or VLOWER command is initiated.
The purpose of the time delay is to prevent unnecessary load tap changer operations caused by temporary voltage fluctuations and to coordinate load tap changer operations in radial networks in order to limit the number of load tap changer operations. This can be done by setting a longer time delay closer to the consumer and shorter time delays higher up in the system.

The first time delay, $t_1$, is used as a time delay (usually long delay) for the first command in one direction. It can have a definite or inverse time characteristic, according to the setting $t1Use$ (Constant/Inverse). For inverse time characteristics larger voltage deviations from the $VSet$ value will result in shorter time delays, limited by the shortest time delay equal to the $tMin$ setting. This setting should be coordinated with the tap changer mechanism operation time.

Constant (definite) time delay is independent of the voltage deviation.

The inverse time characteristic for the first time delay follows the formulas:

$$DA = |VB - VSet|$$

(Equation 266)

$$D = \frac{DA}{\Delta V}$$

(Equation 267)

$$tMin = \frac{t_1}{D}$$

(Equation 268)

Where:
- $DA$: absolute voltage deviation from the set point
- $D$: relative voltage deviation in respect to set deadband value

For the last equation, the condition $t_1 > tMin$ shall also be fulfilled. This practically means that $tMin$ will be equal to the set $t1$ value when absolute voltage deviation $DA$ is equal to $\Delta V$ (relative voltage deviation $D$ is equal to 1). For other values see figure 288. It should be noted that operating times, shown in the figure 288 are for 30, 60, 90, 120, 150 & 180 seconds settings for $t1$ and 10 seconds for $tMin$. 
The second time delay, $t_2$, will be used for consecutive commands (commands in the same direction as the first command). It can have a definite or inverse time characteristic according to the setting $t2Use$ (Constant/Inverse). Inverse time characteristic for the second time delay follows the similar formulas as for the first time delay, but the $t_2$ setting is used instead of $t_1$.

**Line voltage drop**

The purpose with the line voltage drop compensation is to control the voltage, not at the power transformer low voltage side, but at a point closer to the load point.

Figure 289 shows the vector diagram for a line modelled as a series impedance with the voltage $V_B$ at the LV busbar and voltage $V_L$ at the load center. The load current on the line is $I_L$, the line resistance and reactance from the station busbar to the load point are $R_L$ and $X_L$. The angle between the busbar voltage and the current, is $\phi$. If all these parameters are known $V_L$ can be obtained by simple vector calculation.

Values for $R_L$ and $X_L$ are given as settings in primary system ohms. If more than one line is connected to the LV busbar, an equivalent impedance should be calculated and given as a parameter setting.

The line voltage drop compensation function can be turned Enabled/Disabled by the setting parameter OperationLDC. When it is enabled, the voltage $V_L$ will be used by the Automatic voltage control for tap changer function, TR1ATCC (90) for single control and TR8ATCC (90) for parallel control for voltage regulation instead of $V_B$. However, TR1ATCC (90) or TR8ATCC (90) will still perform the following two checks:

1. The magnitude of the measured busbar voltage $V_B$, shall be within the security range, (setting $V_{min}$ and $V_{max}$). If the busbar voltage falls-out of this range the line voltage drop compensation calculations will be temporarily stopped until the voltage $V_B$ comes back within the range.
2. The magnitude of the calculated voltage $V_L$ at the load point, can be limited such that it is only allowed to be equal to or smaller than the magnitude of $V_B$, otherwise $V_B$ will be used. However, a situation where $V_L > V_B$ can be caused by a capacitive load condition, and if the wish...
is to allow for a situation like that, the limitation can be removed by setting the parameter OperCapaLDC to Enabled.

Figure 289: Vector diagram for line voltage drop compensation

The calculated load voltage $V_L$ is shown on the local HMI as value $ULOAD$ under Main menu/Test/Function status/Control/TransformerVoltageControl(ATCC,90)/TR1ATCC:x/TR8ATCC:x.

Load voltage adjustment
Due to the fact that most loads are proportional to the square of the voltage, it is possible to provide a way to shed part of the load by decreasing the supply voltage a couple of percent. During high load conditions, the voltage drop might be considerable and there might be reasons to increase the supply voltage to keep up the power quality and customer satisfaction.

It is possible to do this voltage adjustment in two different ways in Automatic voltage control for tap changer, single control TR1ATCC (90) and parallel control TR8ATCC (90):

1. Automatic load voltage adjustment, proportional to the load current.
2. Constant load voltage adjustment with four different preset values.

In the first case the voltage adjustment is dependent on the load and maximum voltage adjustment should be obtained at rated load of the transformer.

In the second case, a voltage adjustment of the set point voltage can be made in four discrete steps (positive or negative) activated with binary signals connected to TR1ATCC (90) or TR8ATCC (90) function block inputs LVA1, LVA2, LVA3 and LVA4. The corresponding voltage adjustment factors are given as setting parameters $LVAConst1$, $LVAConst2$, $LVAConst3$ and $LVAConst4$. The inputs are activated with a pulse, and the latest activation of anyone of the four inputs is valid. Activation of the input LVARESET in TR1ATCC (90) or TR8ATCC (90) block, brings the voltage setpoint back to $Vset$.

With these factors, TR1ATCC (90) or TR8ATCC (90) adjusts the value of the set voltage $Vset$ according to the following formula:

$$Vset_{adjust} = Vset + S_v \cdot \frac{I_L}{I_{2Base}} + S_o$$

(Equation 269)
<table>
<thead>
<tr>
<th>$V_{\text{set, adjust}}$</th>
<th>Adjusted set voltage in per unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>$V_{\text{Set}}$</td>
<td>Original set voltage: Base quality is $V_{n2}$</td>
</tr>
<tr>
<td>$S_a$</td>
<td>Automatic load voltage adjustment factor, setting $V_{\text{RAuto}}$</td>
</tr>
<tr>
<td>$I_L$</td>
<td>Load current</td>
</tr>
<tr>
<td>$I_{2\text{Base}}$</td>
<td>Rated current, LV winding</td>
</tr>
<tr>
<td>$S_{\text{CI}}$</td>
<td>Constant load voltage adjust. factor for active input $i$ (corresponding to $LVA_{\text{Const}1}$, $LVA_{\text{Const}2}$, $LVA_{\text{Const}3}$ and $LVA_{\text{Const}4}$)</td>
</tr>
</tbody>
</table>

It shall be noted that the adjustment factor is negative in order to decrease the load voltage and positive in order to increase the load voltage. After this calculation $V_{\text{set, adjust}}$ will be used by TR1ATCC (90) or TR8ATCC (90) for voltage regulation instead of the original value $V_{\text{set}}$. The calculated set point voltage $V_{\text{set, adjust}}$ is shown on the local HMI as a service value under **Main menu/Test/Function status/Control/TransformerVoltageControl(ATCC,90)/TR1ATCC:x/TR8ATCC:x**.

**Automatic control of parallel transformers**

Control of parallel transformers means control of two or more power transformers connected to the same busbar on the LV side and in most cases also on the HV side. Special measures must be taken in order to avoid a runaway situation where the tap changers on the parallel transformers gradually diverge and end up in opposite end positions.

Three alternative methods can be used for parallel control with the Automatic voltage control for tap changer, single/parallel control TR8ATCC (90):

- master-follower method
- reverse reactance method
- circulating current method

In order to realize the need for special measures to be taken when controlling transformers in parallel, consider first two parallel transformers which are supposed to be equal with similar tap changers. If they would each be in automatic voltage control for single transformer that is, each of them regulating the voltage on the LV busbar individually without any further measures taken, then the following could happen. Assuming for instance that they start out on the same tap position and that the LV busbar voltage $V_B$ is within $V_{\text{set}} \pm \Delta V$, then a gradual increase or decrease in the load would at some stage make $V_B$ fall outside $V_{\text{set}} \pm \Delta V$ and a raise or lower command would be initiated. However, the rate of change of voltage would normally be slow, which would make one tap changer act before the other. This is unavoidable and is due to small inequalities in measurement and so on. The one tap changer that responds first on a low voltage condition with a raise command will be prone to always do so, and vice versa. The situation could thus develop such that, for example T1 responds first to a low busbar voltage with a raise command and thereby restores the voltage. When the busbar voltage thereafter at a later stage gets high, T2 could respond with a lower command and thereby again restore the busbar voltage to be within the inner deadband. However, this has now caused the load tap changer for the two transformers to be 2 tap positions apart, which in turn causes an increasing circulating current. This course of events will then repeat with T1 initiating raise commands and T2 initiating lower commands in order to keep the busbar voltage within $V_{\text{set}} \pm \Delta V$, but at the same time it will drive the two tap changers to their opposite end positions. High circulating currents and loss of control would be the result of this runaway tap situation.
Parallel control with the master-follower method

In the master-follower method, one of the transformers is selected to be master, and will regulate the voltage in accordance with the principles for Automatic voltage control. Selection of the master is made by activating the binary input FORCMAST in TR8ATCC (90) function block for one of the transformers in the group.

The followers can act in two alternative ways depending on the setting of the parameter MFMode. When this setting is Follow Cmd, raise and lower commands (VRAISE and VLOWER) generated by the master, will initiate the corresponding command in all follower TR8ATCCs (90) simultaneously, and consequently they will blindly follow the master irrespective of their individual tap positions. Effectively this means that if the tap positions of the followers were harmonized with the master from the beginning, they would stay like that as long as all transformers in the parallel group continue to participate in the parallel control. On the other hand for example, one transformer is disconnected from the group and misses a one tap step operation, and thereafter is reconnected to the group again, it will thereafter participate in the regulation but with a one tap position offset.

If the parameter MFMode is set to Follow Tap, then the followers will read the tap position of the master and adopt to the same tap position or to a tap position with an offset relative to the master, and given by setting parameter TapPosOffs (positive or negative integer value). The setting parameter tAutoMSF introduces a time delay on VRAISE/VLOWER commands individually for each follower when setting MFMode has the value Follow Tap.

Selecting a master is made by activating the input FORCMAST in TR8ATCC (90) function block. Deselecting a master is made by activating the input RSTMAST. These two inputs are pulse activated, and the most recent activation is valid that is, an activation of any of these two inputs overrides previous activations. If none of these inputs has been activated, the default is that the transformer acts as a follower (given of course that the settings are parallel control with the master follower method).

When the selection of master or follower in parallel control, or automatic control in single mode, is made with a three position switch in the substation, an arrangement as in figure 290 below is arranged with application configuration.

Figure 290: Principle for a three-position switch Master/Follower/Single

Parallel control with the reverse reactance method

Consider Figure 291 with two parallel transformers with equal rated data and similar tap changers. The tap positions will diverge and finally end up in a runaway tap situation if no measures to avoid this are taken.
Figure 291: Parallel transformers with equal rated data.

In the reverse reactance method, the line voltage drop compensation is used. The original of the line voltage drop compensation function purpose is to control the voltage at a load point further out in the network. The very same function can also be used here to control the voltage at a load point inside the transformer, by choosing a negative value of the parameter $X_{\text{line}}$.

Figure 292, shows a vector diagram where the principle of reverse reactance has been introduced for the transformers in figure 291. The transformers are here supposed to be on the same tap position, and the busbar voltage is supposed to give a calculated compensated value $V_L$ that coincides with the target voltage $V_{\text{Set}}$.

Figure 292: Vector diagram for two transformers regulated exactly on target voltage.

A comparison with figure 289 gives that the line voltage drop compensation for the purpose of reverse reactance control is made with a value with opposite sign on $X_L$, hence the designation “reverse reactance” or “negative reactance”. Effectively this means that, whereas the line voltage drop compensation in figure 289 gave a voltage drop along a line from the busbar voltage $V_B$ to a load point voltage $V_L$, the line voltage drop compensation in figure 292 gives a voltage increase (actually, by adjusting the ratio $X_L/R_L$ with respect to the power factor, the length of the vector $V_L$...
will be approximately equal to the length of \( V_B \) from \( V_B \) up towards the transformer itself. Thus in principal the difference between the vector diagrams in figure 289 and figure 292 is the sign of the setting parameter \( X_L \).

If now the tap position between the transformers will differ, a circulating current will appear, and the transformer with the highest tap (highest no load voltage) will be the source of this circulating current. Figure 293 below shows this situation with T1 being on a higher tap than T2.

**Figure 293: Circulating current caused by T1 on a higher tap than T2.**

The circulating current \( I_{cc} \) is predominantly reactive due to the reactive nature of the transformers. The impact of \( I_{cc} \) on the individual transformer currents is that it increases the current in T1 (the transformer that is driving \( I_{cc} \)) and decreases it in T2 at the same time as it introduces contradictory phase shifts, as can be seen in figure 293. The result is thus, that the line voltage drop compensation calculated voltage \( V_L \) for T1 will be higher than the line voltage drop compensation calculated voltage \( V_L \) for T2, or in other words, the transformer with the higher tap position will have the higher \( V_L \) value and the transformer with the lower tap position will have the lower \( V_L \) value. Consequently, when the busbar voltage increases, T1 will be the one to tap down, and when the busbar voltage decreases, T2 will be the one to tap up. The overall performance will then be that the runaway tap situation will be avoided and that the circulating current will be minimized.

**Parallel control with the circulating current method**

Two transformers with different turns ratio, connected to the same busbar on the HV-side, will apparently show different LV-side voltage. If they are now connected to the same LV busbar but remain unloaded, this difference in no-load voltage will cause a circulating current to flow through the transformers. When load is put on the transformers, the circulating current will remain the same, but now it will be superimposed on the load current in each transformer. Voltage control of parallel transformers with the circulating current method means minimizing of the circulating current at a given voltage target value, thereby achieving:
1. that the busbar or load voltage is regulated to a preset target value
2. that the load is shared between parallel transformers in proportion to their ohmic short circuit reactance

If the transformers have equal percentage impedance given in the respective transformer MVA base, the load will be divided in direct proportion to the rated power of the transformers when the circulating current is minimized.

This method requires extensive exchange of data between the TR8ATCC (90) function blocks (one TR8ATCC (90) function for each transformer in the parallel group). TR8ATCC (90) function block can either be located in the same IED, where they are configured in PCM600 to co-operate, or in different IEDs. If the functions are located in different IEDs they must communicate via GOOSE interbay communication on the IEC 61850 communication protocol. Complete exchange of TR8ATCC (90) data, analog as well as binary, via GOOSE is made cyclically every 300 ms.

The busbar voltage $V_B$ is measured individually for each transformer in the parallel group by its associated TR8ATCC (90) function. These measured values will then be exchanged between the transformers, and in each TR8ATCC (90) block, the mean value of all $V_B$ values will be calculated. The resulting value $V_B^{\text{mean}}$ will then be used in each IED instead of $V_B$ for the voltage regulation, thus assuring that the same value is used by all TR8ATCC functions, and thereby avoiding that one erroneous measurement in one transformer could upset the voltage regulation. At the same time, supervision of the VT mismatch is also performed. This works such that, if a measured voltage $V_B$, differs from $V_B^{\text{mean}}$ with more than a preset value (setting parameter $VTmismatch$) and for more than a pre set time (setting parameter $tVTmismatch$) an alarm signal $VTALARM$ will be generated.

The calculated mean busbar voltage $V_B^{\text{mean}}$ is shown on the local HMI as a service value BusVolt under **Main menu/Test/Function status/Control/TransformerVoltageControl(ATCC,90)/TR8ATCC:x**.

Measured current values for the individual transformers must be communicated between the participating TR8ATCC (90) functions, in order to calculate the circulating current.

The calculated circulating current $I_{cc,i}$ for transformer “$i$” is shown on the HMI as a service value $ICIRCUL$ under **Main menu/Test/Function status/Control/TransformerVoltageControl(ATCC,90)/TR8ATCC:x**.

When the circulating current is known, it is possible to calculate a no-load voltage for each transformer in the parallel group. To do that the magnitude of the circulating current in each bay, is first converted to a voltage deviation, $V_{di}$, with equation **270**:

$$V_{di} = C_i \cdot I_{cc,i} \cdot X_i$$

(Equation 270)

where $X_i$ is the short-circuit reactance for transformer $i$ and $C_i$ is a setting parameter named $Comp$ which serves the purpose of alternatively increasing or decreasing the impact of the circulating current in TR8ATCC control calculations. It should be noted that $V_{di}$ will have positive values for transformers that produce circulating currents and negative values for transformers that receive circulating currents.

Now the magnitude of the no-load voltage for each transformer can be approximated with:
\[ V_i = V_{Bmean} + V_{di} \] (Equation 271)

This value for the no-load voltage is then simply put into the voltage control function for single transformer. There it is treated as the measured busbar voltage, and further control actions are taken as described previously in section "Automatic voltage control for a single transformer". By doing this, the overall control strategy can be summarized as follows.

For the transformer producing/receiving the circulating current, the calculated no-load voltage will be greater/smaller than the measured voltage \( V_{Bmean} \). The calculated no-load voltage will then be compared with the set voltage \( V_{Set} \). A steady deviation which is outside the outer deadband will result in VLOWER or VRAISE being initiated alternatively. In this way the overall control action will always be correct since the position of a tap changer is directly proportional to the transformer no-load voltage. The sequence resets when \( V_{Bmean} \) is inside the inner deadband at the same time as the calculated no-load voltages for all transformers in the parallel group are inside the outer deadband.

In parallel operation with the circulating current method, different \( V_{Set} \) values for individual transformers can cause the voltage regulation to be unstable. For this reason, the mean value of \( V_{Set} \) for parallel operating transformers can be automatically calculated and used for the voltage regulation. This is set Enabled/ Disabled by setting parameter OperUsetPar. The calculated mean \( V_{Set} \) value is shown on the local HMI as a service value USETPAR under Main menu/Test/Function status/Control/TransformerVoltageControl(ATCC,90)/TR8ATCC:x.

The use of mean \( V_{Set} \) is recommended for parallel operation with the circulating current method, especially in cases when Load Voltage Adjustment is also used.

**Line voltage drop compensation for parallel control**

The line voltage drop compensation for a single transformer is described in section "Line voltage drop". The same principle is used for parallel control with the circulating current method and with the master – follower method, except that the total load current, \( I_L \), is used in the calculation instead of the individual transformer current. (See figure 289 for details). The same values for the parameters \( R_{line} \) and \( X_{line} \) shall be set in all IEDs in the same parallel group. There is no automatic change of these parameters due to changes in the substation topology, thus they should be changed manually if needed.

**Avoidance of simultaneous tapping**

Avoidance of simultaneous tapping (operation with the circulating current method)

For some types of tap changers, especially older designs, an unexpected interruption of the auxiliary voltage in the middle of a tap manoeuvre, can jam the tap changer. In order not to expose more than one tap changer at a time, simultaneous tapping of parallel transformers (regulated with the circulating current method) can be avoided. This is done by setting parameter OperSimTap to On. Simultaneous tapping is then avoided at the same time as tapping actions (in the long term) are distributed evenly amongst the parallel transformers.

The algorithm in Automatic voltage control for tap changer, parallel control TR8ATCC (90) will select the transformer with the greatest voltage deviation \( V_{di} \) to tap first. That transformer will then start timing, and after time delay \( t_1 \) the appropriate VRAISE or VLOWER command will be initiated. If now further tapping is required to bring the busbar voltage inside \( V_{Deadbandinner} \), the process will be repeated, and the transformer with the then greatest value of \( V_{di} \) amongst the remaining transformers in the group will tap after a further time delay \( t_2 \), and so on. This is made possible as the calculation of \( I_{cc} \) is cyclically updated with the most recent measured values. If two
transformers have equal magnitude of $V_{di}$ then there is a predetermined order governing which one is going to tap first.

Avoidance of simultaneous tapping (operation with the master follower method)
A time delay for the follower in relation to the command given from the master can be set when the setting MFMode is Follow Tap that is, when the follower follows the tap position (with or without an offset) of the master. The setting parameter tAutoMSF then introduces a time delay on VRAISE/VLOWER commands individually for each follower, and effectively this can be used to avoid simultaneous tapping.

**Homing**

Homing (operation with the circulating current method)
This function can be used with parallel operation of power transformers using the circulating current method. It makes possible to keep a transformer energized from the HV side, but open on the LV side (hot stand-by), to follow the voltage regulation of loaded parallel transformers, and thus be on a proper tap position when the LV circuit breaker closes.

For this function, it is needed to have the LV VTs for each transformer on the cable (tail) side (not the busbar side) of the CB, and to have the LV CB position hardwired to the IED.

In TR8ATCC block for one transformer, the state “Homing” will be defined as the situation when the transformer has information that it belongs to a parallel group (for example, information on T1INCLD=1 or T2INCLD=1 ... and so on), at the same time as the binary input DISC on TR8ATCC block is activated by open LV CB. If now the setting parameter OperHoming = Enabled for that transformer, TR8ATCC will act in the following way:

- The algorithm calculates the “true” busbar voltage, by averaging the voltage measurements of the other transformers included in the parallel group (voltage measurement of the “disconnected transformer” itself is not considered in the calculation).
- The value of this true busbar voltage is used in the same way as $V_{set}$ for control of a single transformer. The “disconnected transformer” will then automatically initiate VRAISE or VLOWER commands (with appropriate $t_1$ or $t_2$ time delay) in order to keep the LV side of the transformer within the deadband of the busbar voltage.

Homing (operation with the master follower method)
If one (or more) follower has its LV circuit breaker open and its HV circuit breaker closed, and if OperHoming = Enabled, this follower continues to follow the master just as it would have made with the LV circuit breaker closed. On the other hand, if the LV circuit breaker of the master opens, automatic control will be blocked and TR8ATCC function output MFERR will be activated as the system will not have a master.

**Adapt mode, manual control of a parallel group**

Adapt mode (operation with the circulating current method)
When the circulating current method is used, it is also possible to manually control the transformers as a group. To achieve this, the setting OperationAdapt must be set Enabled, then the control mode for one TR8ATCC (90) shall be set to “Manual” via the binary input MANCTRL or the local HMI under Main menu/Control/Commands/TransformerVoltageControl(ATCC,90)/TR8ATCC:x whereas the other TR8ATCCs (90) are left in “Automatic”. TR8ATCCs (90) in automatic mode will then observe that one transformer in the parallel group is in manual mode and will then automatically be set in adapt mode. As the name indicates they will adapt to the manual tapping of the transformer that has been put in manual mode.
TR8ATCC (90) in adapt mode will continue the calculation of $V_{di}$, but instead of adding $V_{di}$ to the measured busbar voltage, it will compare it with the deadband $\Delta V$. The following control rules are used:

1. If $V_{di}$ is positive and its modulus is greater than $\Delta V$, then initiate an VLOWER command. Tapping will then take place after appropriate $t_1/t_2$ timing.
2. If $V_{di}$ is negative and its modulus is greater than $\Delta V$, then initiate a VRAISE command. Tapping will then take place after appropriate $t_1/t_2$ timing.
3. If $V_{di}$ modulus is smaller than $\Delta V$, then do nothing.

The binary output signal ADAPT on the TR8ATCC (90) function block will be activated to indicate that this TR8ATCC (90) is adapting to another TR8ATCC (90) in the parallel group.

It shall be noted that control with adapt mode works as described under the condition that only one transformer in the parallel group is set to manual mode via the binary input MANCTRL or, the local HMI Main menu/Control/Commands/TransformerVoltageControl(ATCC,90)/TR8ATCC:x.

In order to operate each tap changer individually when the circulating current method is used, the operator must set each TR8ATCC (90) in the parallel group, in manual.

Adapt mode (operation with the master follower method)

When in master follower mode, the adapt situation occurs when the setting OperationAdapt is Enabled, and the master is put in manual control with the followers still in parallel master-follower control. In this situation the followers will continue to follow the master the same way as when it is in automatic control.

If one follower in a master follower parallel group is put in manual mode, still with the setting OperationAdaptEnabled, the rest of the group will continue in automatic master follower control. The follower in manual mode will of course disregard any possible tapping of the master. However, as one transformer in the parallel group is now exempted from the parallel control, the binary output signal ADAPT on TR8ATCC (90) function block will be activated for the rest of the parallel group.

Plant with capacitive shunt compensation (for operation with the circulating current method)

If significant capacitive shunt generation is connected in a substation and it is not symmetrically connected to all transformers in a parallel group, the situation may require compensation of the capacitive current to the ATCC.

An asymmetric connection will exist if for example, the capacitor is situated on the LV-side of a transformer, between the CT measuring point and the power transformer or at a tertiary winding of the power transformer, see figure 294. In a situation like this, the capacitive current will interact in opposite way in the different ATCCs with regard to the calculation of circulating currents. The capacitive current is part of the imaginary load current and therefore essential in the calculation. The calculated circulating current and the real circulating currents will in this case not be the same, and they will not reach a minimum at the same time. This might result in a situation when minimizing of the calculated circulating current will not regulate the tap changers to the same tap positions even if the power transformers are equal.

However if the capacitive current is also considered in the calculation of the circulating current, then the influence can be compensated for.
From figure 294 it is obvious that the two different connections of the capacitor banks are completely the same regarding the currents in the primary network. However the CT measured currents for the transformers would be different. The capacitor bank current may flow entirely to the load on the LV side, or it may be divided between the LV and the HV side. In the latter case, the part of $I_C$ that goes to the HV side will divide between the two transformers and it will be measured with opposite direction for $T2$ and $T1$. This in turn would be misinterpreted as a circulating current, and would upset a correct calculation of $I_{cc}$. Thus, if the actual connection is as in the left figure the capacitive current $I_C$ needs to be compensated for regardless of the operating conditions and in ATCC this is made numerically. The reactive power of the capacitor bank is given as a setting $Q1$, which makes it possible to calculate the reactive capacitance:

$$X_C = \frac{V^2}{Q1}$$

(Equation 272)

Thereafter the current $I_C$ at the actual measured voltage $V_B$ can be calculated as:
\[ I_c = \frac{V_b}{\sqrt{3} \cdot X_c} \]

(Equation 273)

In this way the measured LV currents can be adjusted so that the capacitor bank current will not influence the calculation of the circulating current.

Three independent capacitor bank values Q1, Q2 and Q3 can be set for each transformer in order to make possible switching of three steps in a capacitor bank in one bay.

**Power monitoring**

The level (with sign) of active and reactive power flow through the transformer, can be monitored. This function can be utilized for different purposes for example, to block the voltage control function when active power is flowing from the LV side to the HV side or to initiate switching of reactive power compensation plant, and so on.

There are four setting parameters \( P_>, P_<, Q_> \) and \( Q_< \) with associated outputs in TR8ATCC (90) and TR1ATCC (90) function blocks PGTFWD, PLTREV, QGTFWD and QLTREV. When passing the pre-set value, the associated output will be activated after the common time delay setting \( t_{Power} \).

The definition of direction of the power is such that the active power \( P \) is forward when power flows from the HV-side to the LV-side as shown in figure 295. The reactive power \( Q \) is forward when the total load on the LV side is inductive (reactance) as shown in figure 295.

[Figure 295: Power direction references]

With the four outputs in the function block available, it is possible to do more than just supervise a level of power flow in one direction. By combining the outputs with logical elements in application configuration, it is also possible to cover for example, intervals as well as areas in the P-Q plane.

**Busbar topology logic**

Information of the busbar topology that is, position of circuit breakers and isolators, yielding which transformers that are connected to which busbar and which busbars that are connected to each other, is vital for the Automatic voltage control for tap changer, parallel control function TR8ATCC (90) when the circulating current or the master-follower method is used. This information tells each TR8ATCC (90), which transformers that it has to consider in the parallel control.
In a simple case, when only the switchgear in the transformer bays needs to be considered, there is a built-in function in TR8ATCC (90) block that can provide information on whether a transformer is connected to the parallel group or not. This is made by connecting the transformer CB auxiliary contact status to TR8ATCC (90) function block input DISC, which can be made via a binary input, or via GOOSE from another IED in the substation. When the transformer CB is open, this activates that input which in turn will make a corresponding signal DISC=1 in TR8ATCC (90) data set. This data set is the same data package as the package that contains all TR8ATCC (90) data transmitted to the other transformers in the parallel group (see section "Exchange of information between TR8ATCC functions" for more details). Figure 296 shows an example where T3 is disconnected which will lead to T3 sending the DISC=1 signal to the other two parallel TR8ATCC (90) modules (T1 and T2) in the group. Also see table 59.

![Figure 296: Disconnection of one transformer in a parallel group](99000952.VSD)

When the busbar arrangement is more complicated with more buses and bus couplers/bus sections, it is necessary to engineer a specific station topology logic. This logic can be built in the application configuration in PCM600 and will keep record on which transformers that are in parallel (in one or more parallel groups). In each TR8ATCC (90) function block there are eight binary inputs (T1INCLD,..., T8INCLD) that will be activated from the logic depending on which transformers that are in parallel with the transformer to whom the TR8ATCC (90) function block belongs.

TR8ATCC (90) function block is also fitted with eight outputs (T1PG,..., T8PG) for indication of the actual composition of the parallel group that it itself is part of. If parallel operation mode has been selected in the IED with setting TrfId = Tx, then the TxPG signal will always be set to 1. The parallel function will consider communication messages only from the voltage control functions working in parallel (according to the current station configuration). When the parallel voltage control function detects that no other transformers work in parallel it will behave as a single voltage control function in automatic mode.

**Exchange of information between TR8ATCC functions**

Each transformer in a parallel group needs an Automatic voltage control for tap changer, parallel control TR8ATCC (90) function block of its own for the parallel voltage control. Communication between these TR8ATCCs (90) is made either on the GOOSE interbay communication on the IEC 61850 protocol if TR8ATCC (90) functions reside in different IEDs, or alternatively configured internally in one IED if multiple instances of TR8ATCC (90) reside in the same IED. Complete exchange of TR8ATCC (90) data, analog as well as binary, on GOOSE is made cyclically every 300 ms.

TR8ATCC (90) function block has an output ATCCOUT. This output contains two sets of signals. One is the data set that needs to be transmitted to other TR8ATCC (90) blocks in the same parallel
group, and the other is the data set that is transferred to the TCMLTC or TCLYLTC (84) function block for the same transformer as TR8ATCC (90) block belongs to.

There are 10 binary signals and 6 analog signals in the data set that is transmitted from one TR8ATCC (90) block to the other TR8ATCC (90) blocks in the same parallel group:

**Table 57: Binary signals**

<table>
<thead>
<tr>
<th>Signal</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>TimerOn</td>
<td>This signal is activated by the transformer that has started its timer and is going to tap when the set time has expired.</td>
</tr>
<tr>
<td>automaticCTRL</td>
<td>Activated when the transformer is set in automatic control</td>
</tr>
<tr>
<td>mutualBlock</td>
<td>Activated when the automatic control is blocked</td>
</tr>
<tr>
<td>disc</td>
<td>Activated when the transformer is disconnected from the busbar</td>
</tr>
<tr>
<td>receiveStat</td>
<td>Signal used for the horizontal communication</td>
</tr>
<tr>
<td>TermisForcedMast er</td>
<td>Activated when the transformer is selected Master in the master-follower parallel control mode</td>
</tr>
<tr>
<td>TermisMaster</td>
<td>Activated for the transformer that is master in the master-follower parallel control mode</td>
</tr>
<tr>
<td>termReadyForMSF</td>
<td>Activated when the transformer is ready for master-follower parallel control mode</td>
</tr>
<tr>
<td>raiseVoltageOut</td>
<td>Order from the master to the followers to tap up</td>
</tr>
<tr>
<td>lowerVoltageOut</td>
<td>Order from the master to the followers to tap down</td>
</tr>
</tbody>
</table>

**Table 58: Analog signals**

<table>
<thead>
<tr>
<th>Signal</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>voltageBusbar</td>
<td>Measured busbar voltage for this transformer</td>
</tr>
<tr>
<td>ownLoadCurrim</td>
<td>Measured load current imaginary part for this transformer</td>
</tr>
<tr>
<td>ownLoadCurre</td>
<td>Measured load current real part for this transformer</td>
</tr>
<tr>
<td>reacSec</td>
<td>Transformer reactance in primary ohms referred to the LV side</td>
</tr>
<tr>
<td>relativePosition</td>
<td>The transformer’s actual tap position</td>
</tr>
<tr>
<td>voltage Setpoint</td>
<td>The transformer’s set voltage (VSet) for automatic control</td>
</tr>
</tbody>
</table>

Manual configuration of VCTR GOOSE data set is required. Note that both data value attributes and quality attributes have to be mapped. The following data objects must be configured:

- BusV
- LodAlm
- LodAre
- PosRel
- SetV
- VCTRStatus
- X2

The transformers controlled in parallel with the circulating current method or the master-follower method must be assigned unique identities. These identities are entered as a setting in each
TR8ATCC (90), and they are predefined as T1, T2, T3,..., T8 (transformers 1 to 8). In figure 296 there are three transformers with the parameter TrfId set to T1, T2 and T3, respectively.

For parallel control with the circulating current method or the master-follower method alternatively, the same type of data set as described above, must be exchanged between two TR8ATCC (90). To achieve this, each TR8ATCC (90) is transmitting its own data set on the output ATCCOUT as previously mentioned. To receive data from the other transformers in the parallel group, the output ATCCOUT from each transformer must be connected (via GOOSE or internally in the application configuration) to the inputs HORIZx (x = identifier for the other transformers in the parallel group) on TR8ATCC (90) function block. Apart from this, there is also a setting in each TR8ATCC =/=,..., =/T1RXOP=Off/On,..., T8RXOP=Off/On. This setting determines from which of the other transformer individuals that data shall be received. Settings in the three TR8ATCC blocks for the transformers in figure 296, would then be according to the table 59:

<table>
<thead>
<tr>
<th>TrfId</th>
<th>T1RXOP</th>
<th>T2RXOP</th>
<th>T3RXOP</th>
<th>T4RXOP</th>
<th>T5RXOP</th>
<th>T6RXOP</th>
<th>T7RXOP</th>
<th>T8RXOP</th>
</tr>
</thead>
<tbody>
<tr>
<td>T1</td>
<td>Off</td>
<td>On</td>
<td>On</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
</tr>
<tr>
<td>T2</td>
<td>On</td>
<td>Off</td>
<td>On</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
</tr>
<tr>
<td>T3</td>
<td>On</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
<td>Off</td>
</tr>
</tbody>
</table>

Observe that this parameter must be set to Disabled for the “own” transformer. (for transformer with identity T1 parameter T1RXOP must be set to Disabled, and so on.

**Blocking**

Blocking conditions
The purpose of blocking is to prevent the tap changer from operating under conditions that can damage it, or otherwise when the conditions are such that power system related limits would be exceeded or when, for example the conditions for automatic control are not met.

For the Automatic voltage control for tap changer function, TR1ATCC (90) for single control and TR8ATCC (90) for parallel control, three types of blocking are used:

**Partial Block:** Prevents operation of the tap changer only in one direction (only VRAISE or VLOWER command is blocked) in manual and automatic control mode.

**Auto Block:** Prevents automatic voltage regulation, but the tap changer can still be controlled manually.

**Total Block:** Prevents any tap changer operation independently of the control mode (automatic as well as manual).

Setting parameters for blocking that can be set in TR1ATCC (90) or TR8ATCC (90) under general settings in PST/local HMI are listed in table 60.
<table>
<thead>
<tr>
<th>Setting</th>
<th>Values (Range)</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>OCBk</td>
<td>Alarm</td>
<td>When any one of the three HV currents exceeds the preset value $I_{Block}$, TR1ATCC (90) or TR8ATCC (90) will be temporarily totally blocked. The outputs IBLK and TOTBLK or AUTOBLK will be activated depending on the actual parameter setting.</td>
</tr>
<tr>
<td></td>
<td>Auto Block</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Auto&amp;Man Block</td>
<td></td>
</tr>
<tr>
<td>OVPartBk</td>
<td>Alarm</td>
<td>If the busbar voltage $V_B$ (not the compensated load point voltage $V_{UL}$) exceeds $V_{max}$ (see figure 287), an alarm will be initiated or further $V_{RAISE}$ commands will be blocked. If permitted by setting in PST configuration, Fast Step Down (FSD) of the tap changer will be initiated in order to re-enter the voltage into the range $V_{min} &lt; V_B &lt; V_{max}$. The FSD function is blocked when the lowest voltage tap position is reached. The time delay for the FSD function is separately set. The output $V_{HIGH}$ will be activated as long as the voltage is above $V_{max}$.</td>
</tr>
<tr>
<td></td>
<td>Auto&amp;Man Block</td>
<td></td>
</tr>
<tr>
<td>UVPartBk</td>
<td>Alarm</td>
<td>If the busbar voltage $V_B$ (not the compensated load point voltage $V_L$) is between $V_{block}$ and $V_{min}$ (see figure 287), an alarm will be initiated or further $V_{LOWER}$ commands will be blocked. The output $V_{LOW}$ will be activated.</td>
</tr>
<tr>
<td></td>
<td>Auto&amp;Man Block</td>
<td></td>
</tr>
<tr>
<td>UVBk</td>
<td>Alarm</td>
<td>If the busbar voltage $V_B$ falls below $V_{block}$ this blocking condition is active. It is recommended to block automatic control in this situation and allow manual control. This is because the situation normally would correspond to a disconnected transformer and then it should be allowed to operate the tap changer before reconnecting the transformer. The outputs VBLK and TOTBLK or AUTOBLK will be activated depending on the actual parameter setting.</td>
</tr>
<tr>
<td></td>
<td>Auto Block</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Auto&amp;Man Block</td>
<td></td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Setting</th>
<th>Values (Range)</th>
<th>Description</th>
</tr>
</thead>
</table>
| RevActPartBk (automatically reset) | Alarm  Auto Block | The risk of voltage instability increases as transmission lines become more heavily loaded in an attempt to maximize the efficient use of existing generation and transmission facilities. In the same time lack of reactive power may move the operation point of the power network to the lower part of the P-V-curve (unstable part). Under these conditions, when the voltage starts to drop, it might happen that an VRAISE command can give reversed result that is, a lower busbar voltage. Tap changer operation under voltage instability conditions makes it more difficult for the power system to recover. Therefore, it might be desirable to block TR1ATCC (90) or TR8ATCC (90) temporarily. Requirements for this blocking are:  
  • The load current must exceed the set value RevActLim  
  • After an VRAISE command, the measured busbar voltage shall have a lower value than its previous value  
  • The second requirement has to be fulfilled for two consecutive VRAISE commands  
  If all three requirements are fulfilled, TR1ATCC (90) or TR8ATCC (90) automatic control will be blocked for raise commands for a period of time given by the setting parameter tRevAct and the output signal REVACBLK will be set. The reversed action feature can be turned off/on with the setting parameter OperationRA. |
| CmdErrBk  (manually reset) | Alarm  Auto Block  Auto&Man Block | Typical operating time for a tap changer mechanism is around 3-8 seconds. Therefore, the function should wait for a position change before a new command is issued. The command error signal, CMDERRAL on the TCMLYT or TCLLYLT (84) function block, will be set if the tap changer position does not change one step in the correct direction within the time given by the setting tTCTimeout in TCMLYT or TCLLYLT (84) function block. The tap changer module TCMLYT or TCLLYLT (84) will then indicate the error until a successful command has been carried out or it has been reset by changing control mode of TRIATCC (90) or TRBATCC (90) function to Manual and then back to Automatic. The outputs CMDERRAL on TCMLYT or TCLLYLT (84) and TOTBLK or AUTOBLK on TRIATCC (90) or TR8ATCC (90) will be activated depending on the actual parameter setting.  
  This error condition can be reset by the input RESETERR on TCMLYT (84) function block, or alternatively by changing control mode of TRIATCC (90) or TR8ATCC (90) function to Manual and then back to Automatic.  
  Table continues on next page |
<table>
<thead>
<tr>
<th>Setting</th>
<th>Values (Range)</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>TapChgBk</td>
<td>Alarm Auto Block</td>
<td>If the input TCINPROG of TCMYLTC or TCLYLTC (84) function block is connected to the tap changer mechanism, then this blocking condition will be active if the TCINPROG input has not reset when the tTCTimeout timer has timed out. The output TCERRAL will be activated depending on the actual parameter setting. In correct operation the TCINPROG shall appear during the VRAISE/VLOWER output pulse and disappear before the tTCTimeout time has elapsed. This error condition can be reset by the input RESETERR on TCMYLTC (84) function block, or alternatively by changing control mode of TR1ATCC (90) or TR8ATCC (90) function to Manual and then back to Automatic.</td>
</tr>
<tr>
<td>(manually reset)</td>
<td>Auto&amp;Man Block</td>
<td></td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Setting</th>
<th>Values (Range)</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>TapPosBk</td>
<td>Alarm</td>
<td>This blocking/alarm is activated by either:</td>
</tr>
<tr>
<td></td>
<td>Auto Block</td>
<td>1. The tap changer reaching an end position i.e. one of the extreme positions according to the setting parameters LowVoltTap and HighVoltTap. When the tap changer reaches one of these two positions further commands in the corresponding direction will be blocked. Effectively this will then be a partial block if Auto Block or Auto&amp;Man Block is set. The outputs POSERRAL and LOPOSAL or HIPOSAL will be activated.</td>
</tr>
<tr>
<td></td>
<td>Auto&amp;Man Block</td>
<td>2. Tap Position Error which in turn can be caused by one of the following conditions:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Tap position is out of range that is, the indicated position is above or below the end positions.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• The tap changer indicates that it has changed more than one position on a single raise or lower command.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• The tap position reading shows a BCD code error (unaccepted combination) or a parity fault.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• The reading of tap position shows a mA value that is out of the mA-range. Supervision of the input signal for MIM is made by setting the MIM parameters I_Max and I_Min to desired values, for example, I_Max = 20mA and I_Min = 4mA.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Very low or negative mA-values.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Indication of hardware fault on BIM or MIM module. Supervision of the input hardware module is provided by connecting the corresponding error signal to the INERR input (input module error) or BIERR on TCMYLTC or TCLYLT (84) function block.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Interruption of communication with the tap changer.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>The outputs POSERRAL and AUTOBLK or TOTBLK will be set. This error condition can be reset by the input RESETERR on TCMYLTC (84) function block, or alternatively by changing control mode of TRIATCC (90) or TR8ATCC (90) function to Manual and then back to Automatic.</td>
</tr>
<tr>
<td>CircCurrBk</td>
<td>Alarm</td>
<td>When the magnitude of the circulating current exceeds the preset value (setting parameter CircCurrLimit) for longer time than the set time delay (setting parameter tCircCurr) it will cause this blocking condition to be fulfilled provided that the setting parameter OperCCBlock is Enabled. The signal resets automatically when the circulating current decreases below the preset value. Usually this can be achieved by manual control of the tap changers. TRIATCC (90) or TR8ATCC (90) outputs ICIRC and TOTBLK or AUTOBLK will be activated depending on the actual parameter setting.</td>
</tr>
<tr>
<td></td>
<td>Auto Block</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Auto&amp;Man Block</td>
<td></td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Setting</th>
<th>Value (Range)</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>MFPosDiffBk (manually reset)</td>
<td>Alarm Auto Block</td>
<td>In the master-follower mode, if the tap difference between a follower and the master is greater than the set value (setting parameter MFPosDiffLim) then this blocking condition is fulfilled and the outputs AUTOFPOS and AUTOBLK (alternatively an alarm) will be set.</td>
</tr>
</tbody>
</table>

Setting parameters for blocking that can be set in TRIATCC (90) or TR8ATCC (90) under setting group Nx in PST/ local HMI are listed in table 61.

Table 61: Blocking settings

<table>
<thead>
<tr>
<th>Setting</th>
<th>Value (Range)</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>TotalBlock (manually reset)</td>
<td>Enabled/Disabled</td>
<td>TRIATCC (90) or TR8ATCC (90) function can be totally blocked via the setting parameter TotalBlock, which can be set Enabled/Disabled from the local HMI or PST. The output TOTBLK will be activated.</td>
</tr>
<tr>
<td>AutoBlock (manually reset)</td>
<td>Enabled/Disabled</td>
<td>TRIATCC (90) or TR8ATCC (90) function can be blocked for automatic control via the setting parameter AutoBlock, which can be set Enabled/Disabled from the local HMI or PST. The output AUTOBLK will be set.</td>
</tr>
</tbody>
</table>

TRIATCC (90) or TR8ATCC (90) blockings that can be made via input signals in the function block are listed in table 62.

Table 62: Blocking via binary inputs

<table>
<thead>
<tr>
<th>Input name</th>
<th>Activation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>BLOCK (manually reset)</td>
<td>Enabled/Disabled</td>
<td>The voltage control function can be totally blocked via the binary input BLOCK on TRIATCC (90) or TR8ATCC (90) function block. The output TOTBLK will be activated.</td>
</tr>
<tr>
<td>EAUTOBLK (manually reset)</td>
<td>Enabled/Disabled</td>
<td>The voltage control function can be blocked for automatic control via the binary input EAUTOBLK on TRIATCC (90) or TR8ATCC (90) function block. The output AUTOBLK will be activated. Deblocking is made via the input DEBLKAUT.</td>
</tr>
</tbody>
</table>

Blockings activated by the operating conditions, without setting or separate external activation possibilities, are listed in table 63.
Table 63: Blockings without setting possibilities

<table>
<thead>
<tr>
<th>Activation</th>
<th>Type of blocking</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Disconnected transformer (automatically reset)</td>
<td>Auto Block</td>
<td>Automatic control is blocked for a transformer when parallel control with the circulating current method is used, and that transformer is disconnected from the LV-busbar. (This is under the condition that the setting OperHoming is selected Off for the disconnected transformer. Otherwise the transformer will get into the state Homing). The binary input signal DISC in TR1ATCC (90) or TR8ATCC (90) function shall be used to supervise if the transformer LV circuit breaker is closed or not. The outputs TRFDISC and AUTOBLK will be activated. Blocking will be removed when the transformer is reconnected (input signal DISC set back to zero).</td>
</tr>
<tr>
<td>No Master/More than one Master (automatically reset)</td>
<td>Auto Block</td>
<td>Automatic control is blocked when parallel control with the master-follower method is used, and the master is disconnected from the LV-busbar. Also if there for some reason should be a situation with more than one master in the system, the same blocking will occur. The binary input signal DISC in TR1ATCC (90) or TR8ATCC (90) function shall be used to supervise if the transformer LV circuit breaker is closed or not. The outputs TRFDISC, MFERR and AUTOBLK will be activated. The followers will also be blocked by mutual blocking in this situation. Blocking will be removed when the transformer is reconnected (input signal DISC set back to zero).</td>
</tr>
<tr>
<td>One transformer in a parallel group switched to manual control (automatically reset)</td>
<td>Auto Block</td>
<td>When the setting OperationAdapt is “Disabled”, automatic control will be blocked when parallel control with the master-follower or the circulating current method is used, and one of the transformers in the group is switched from auto to manual. The output AUTOBLK will be activated.</td>
</tr>
<tr>
<td>Communication error (COMMERR) (automatic deblocking)</td>
<td>Auto block</td>
<td>If the horizontal communication (GOOSE) for any one of TR8ATCCs (90) in the group fails it will cause blocking of automatic control in all TR8ATCC (90) functions, which belong to that parallel group. This error condition will be reset automatically when the communication is re-established. The outputs COMMERR and AUTOBLK will be set.</td>
</tr>
</tbody>
</table>

Circulating current method

**Mutual blocking**

When one parallel instance of voltage control TR8ATCC (90) blocks its operation, all other TR8ATCCs (90) working in parallel with that module, shall block their operation as well. To achieve this, the affected TR8ATCC (90) function broadcasts a mutual block to the other group members via the horizontal communication. When mutual block is received from any of the group members, automatic operation is blocked in the receiving TR8ATCCs (90) that is, all units of the parallel group.

The following conditions in any one of TR8ATCCs (90) in the group will cause mutual blocking when the circulating current method is used:
• Over-Current
• Total block via settings
• Total block via configuration
• Analog input error
• Automatic block via settings
• Automatic block via configuration
• Under-Voltage
• Command error
• Position indication error
• Tap changer error
• Reversed Action
• Circulating current
• Communication error

Master-follower method

When the master is blocked, the followers will not tap by themselves and there is consequently no need for further mutual blocking. On the other hand, when a follower is blocked there is a need to send a mutual blocking signal to the master. This will prevent a situation where the rest of the group otherwise would be able to tap away from the blocked individual, and that way cause high circulating currents.

Thus, when a follower is blocked, it broadcasts a mutual block on the horizontal communication. The master picks up this message, and blocks its automatic operation as well.

Besides the conditions listed above for mutual blocking with the circulating current method, the following blocking conditions in any of the followers will also cause mutual blocking:

• Master-follower out of position
• Master-follower error (No master/More than one master)

General

It should be noted that partial blocking will not cause mutual blocking.

TR8ATCC (90), which is the “source” of the mutual blocking will set its AUTOBLK output as well as the output which corresponds to the actual blocking condition for example, IBLK for over-current blocking. The other TR8ATCCs (90) that receive a mutual block signal will only set its AUTOBLK output.

The mutual blocking remains until TR8ATCC (90) that dispatched the mutual block signal is de-blocked. Another way to release the mutual blocking is to force TR8ATCC (90), which caused mutual blocking to Single mode operation. This is done by activating the binary input SNGLMODE on TR8ATCC (90) function block or by setting the parameter OperationPAR to Off from the built-in local HMI or PST.

TR8ATCC (90) function can be forced to single mode at any time. It will then behave exactly the same way as described in section "Automatic voltage control for a single transformer", except that horizontal communication messages are still sent and received, but the received messages are ignored. TR8ATCC (90) is at the same time also automatically excluded from the parallel group.

Disabling of blockings in special situations

When the Automatic voltage control for tap changer TR1ATCC (90) for single control and TR8ATCC (90) for parallel control, function block is connected to read back information (tap position value and tap changer in progress signal) it may sometimes be difficult to find timing data to be set in TR1ATCC (90) or TR8ATCC (90) for proper operation. Especially at commissioning of for example,
older transformers the sensors can be worn and the contacts maybe bouncing etc. Before the right timing data is set it may then happen that TR1ATCC (90) or TR8ATCC (90) becomes totally blocked or blocked in auto mode because of incorrect settings. In this situation, it is recommended to temporarily set these types of blockings to alarm instead until the commissioning of all main items are working as expected.

**Tap Changer position measurement and monitoring**

**Tap changer extreme positions**  
This feature supervises the extreme positions of the tap changer according to the settings LowVoltTap and HighVoltTap. When the tap changer reaches its lowest/highest position, the corresponding VLOWER/VRAISE command is prevented in both automatic and manual mode.

**Monitoring of tap changer operation**  
The Tap changer control and supervision, 6 binary inputs TCMYLTC (84) or 32 binary inputs TCLYLTC (84) output signal VRAISE or VLOWER is set high when TR1ATCC (90) or TR8ATCC (90) function has reached a decision to operate the tap changer. These outputs from TCMYLTC (84) and TCLYLTC (84) function blocks shall be connected to a binary output module, BOM in order to give the commands to the tap changer mechanism. The length of the output pulse can be set via TCMYLTC (84) or TCLYLTC (84) setting parameter tPulseDur. When an VRAISE/VLOWER command is given, a timer (set by setting tTCTimeout) (settable in PST/local HMI) is also started, and the idea is then that this timer shall have a setting that covers, with some margin, a normal tap changer operation.

Usually the tap changer mechanism can give a signal, “Tap change in progress”, during the time that it is carrying through an operation. This signal from the tap changer mechanism can be connected via a BIM module to TCMYLTC (84) or TCLYLTC (84) input TCINPROG, and it can then be used by TCMYLTC (84) or TCLYLTC (84) function in three ways, which is explained below with the help of figure 297.
### Figure 297: Timing of pulses for tap changer operation monitoring

<table>
<thead>
<tr>
<th>pos</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>a</td>
<td>Safety margin to avoid that TCINPROG is not set high without the simultaneous presence of an VRAISE or VLOWER command.</td>
</tr>
<tr>
<td>b</td>
<td>Time setting tPulseDur.</td>
</tr>
<tr>
<td>c</td>
<td>Fixed extension 4 sec. of tPulseDur, made internally in TCMYLTC (84) or TCLYLTC (84) function.</td>
</tr>
<tr>
<td>d</td>
<td>Time setting tStable</td>
</tr>
<tr>
<td>e</td>
<td>New tap position reached, making the signal “tap change in progress” disappear from the tap changer, and a new position reported.</td>
</tr>
<tr>
<td>f</td>
<td>The new tap position available in TCMYLTC (84) or TCLYLTC (84).</td>
</tr>
<tr>
<td>g</td>
<td>Fixed extension 2 sec. of TCINPROG, made internally in TCMYLTC (84) or TCLYLTC (84) function.</td>
</tr>
<tr>
<td>h</td>
<td>Safety margin to avoid that TCINPROG extends beyond tTCTimeout.</td>
</tr>
</tbody>
</table>

The first use is to reset the Automatic voltage control for tap changer function TR1ATCC (90) for single control and TR8ATCC (90) for parallel control as soon as the signal TCINPROG disappears. If the TCINPROG signal is not fed back from the tap changer mechanism, TR1ATCC (90) or TR8ATCC (90) will not reset until tTCTimeout has timed out. The advantage with monitoring the TCINPROG signal in this case is thus that resetting of TR1ATCC (90) or TR8ATCC (90) can sometimes be made faster, which in turn makes the system ready for consecutive commands in a shorter time.

The second use is to detect a jammed tap changer. If the timer tTCTimeout times out before the TCINPROG signal is set back to zero, the output signal TCERRAL is set high and TR1ATCC (90) or TR8ATCC (90) function is blocked.

The third use is to check the proper operation of the tap changer mechanism. As soon as the input signal TCINPROG is set back to zero TCMYLTC (84) or TCLYLTC (84) function expects to read a new and correct value for the tap position. If this does not happen the output signal CMDERRAL is set high and TR1ATCC (90) or TR8ATCC (90) function is blocked. The fixed extension (g) 2 sec. of TCINPROG, is made to prevent a situation where this could happen despite no real malfunction.

In figure 297, it can be noted that the fixed extension (c) 4 sec. of tPulseDur, is made to prevent a situation with TCINPROG set high without the simultaneous presence of an VRAISE or VLOWER command. If this would happen, TCMYLTC (84) or TCLYLTC (84) would see this as a spontaneous TCINPROG signal without an accompanying VRAISE or VLOWER command, and this would then...
lead to the output signal TCERRAL being set high and TR1ATCC (90) or TR8ATCC (90) function being blocked. Effectively this is then also a supervision of a run-away tap situation.

**Hunting detection**

Hunting detection is provided in order to generate an alarm when the voltage control gives an abnormal number of commands or abnormal sequence of commands within a pre-defined period of time.

There are three hunting functions:

1. The Automatic voltage control for tap changer function, TR1ATCC (90) for single control and TR8ATCC (90) for parallel control will activate the output signal DAYHUNT when the number of tap changer operations exceed the number given by the setting DayHuntDetect during the last 24 hours (sliding window). Active as well in manual as in automatic mode.
2. TR1ATCC (90) or TR8ATCC (90) function will activate the output signal HOURHUNT when the number of tap changer operations exceed the number given by the setting HourHuntDetect during the last hour (sliding window). Active as well in manual as in automatic mode.
3. TR1ATCC (90) or TR8ATCC (90) function will activate the output signal HUNTING when the total number of contradictory tap changer operations (RAISE, LOWER, RAISE, LOWER, and so on) exceeds the pre-set value given by the setting NoOpWindow within the time sliding window specified via the setting parameter tWindowHunt. Only active in automatic mode.

Hunting can be the result of a narrow deadband setting or some other abnormalities in the control system.

**Wearing of the tap changer contacts**

Two counters, ContactLife and NoOfOperations are available within the Tap changer control and supervision function, 6 binary inputs TCMYLTC or 32 binary inputs TCLYLTC (84). They can be used as a guide for maintenance of the tap changer mechanism. The ContactLife counter represents the remaining number of operations (decremental counter) at rated load.

\[
\text{ContactLife}_{n+1} = \text{ContactLife}_n - \alpha \left( \frac{I_{load}}{I_{rated}} \right) \\
\text{(Equation 274)}
\]

where \(n\) is the number of operations and \(\alpha\) is an adjustable setting parameter, CLFactor, with default value is set to 2. With this default setting an operation at rated load (current measured on HV-side) decrements the ContactLife counter with 1.

The NoOfOperations counter simply counts the total number of operations (incremental counter).

Both counters are stored in a non-volatile memory as well as, the times and dates of their last reset. These dates are stored automatically when the command to reset the counter is issued. It is therefore necessary to check that the IED internal time is correct before these counters are reset. The counter value can be reset on the local HMI under **Main menu/Reset/Reset counters/TransformerTapControl(YLTC,84)/TCMYLTC:1 or TCLYLTC:1/Reset Counter and ResetCLCounter**

Both counters and their last reset dates are shown on the local HMI as service values under **Main menu/Test/Function status/Control/TransformerTapControl(YLTC,84)/TCMYLTC:x/TCLYLTC:x/CLCNT_VAL and Main menu/Test/Function status/Control/TransformerTapControl(YLTC,84)/TCMYLTC:x/TCLYLTC:x/CNT_VAL**
15.4.3 Setting guidelines

15.4.3.1 TCMYLTC and TCLYLTC (84) general settings

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

\(\text{GlobalBaseSel}\): Selects the global base value group used by the function to define \(I_{\text{Base}}\), \(V_{\text{Base}}\) and \(S_{\text{Base}}\). Note that this function will only use \(I_{\text{Base}}\) value.

\(\text{LowVoltTap}\): This gives the tap position for the lowest LV-voltage.

\(\text{HighVoltTap}\): This gives the tap position for the highest LV-voltage.

\(m_{\text{ALow}}\): The mA value that corresponds to the lowest tap position. Applicable when reading of the tap position is made via a mA signal.

\(m_{\text{AHigh}}\): The mA value that corresponds to the highest tap position. Applicable when reading of the tap position is made via a mA signal.

\(\text{CodeType}\): This setting gives the method of tap position reading.

\(\text{UseParity}\): Sets the parity check \(\text{Enabled/Disabled}\) for tap position reading when this is made by Binary, BCD, or Gray code.

\(t_{\text{Stable}}\): This is the time that needs to elapse after a new tap position has been reported to TCMYLTC until it is accepted.

\(CLFactor\): This is the factor designated “a” in \ref{equation}”. When a tap changer operates at nominal load current (current measured on the HV-side), the ContactLife counter decrements with 1, irrespective of the setting of \(CLFactor\). The setting of this factor gives the weighting of the deviation with respect to the load current.

\(\text{InitCLCounter}\): The ContactLife counter monitors the remaining number of operations (decremental counter). The setting \(\text{InitCLCounter}\) then gives the start value for the counter that is, the total number of operations at rated load that the tap changer is designed for.

\(\text{EnabTapCmd}\): This setting enables/disables the lower and raise commands to the tap changer. It shall be \(\text{Enabled}\) for voltage control, and \(\text{Disabled}\) for tap position feedback to the transformer differential protection T2WPDIFF (87T) or T3WPDIFF (87T).

TCMYLTC and TCLYLTC (84) Setting group

General

\(\text{Operation}\): Switching the TCMYLTC or TCLYLTC (84) function \(\text{Enabled/Disabled}\).

\(I_{\text{Base}}\): Base current in primary Ampere for the HV-side of the transformer.

\(t_{\text{TCTimeout}}\): This setting gives the maximum time interval for a raise or lower command to be completed.

\(t_{\text{PulseDur}}\): Length of the command pulse (VRAISE/VLOWER) to the tap changer. It shall be noticed that this pulse has a fixed extension of 4 seconds that adds to the setting value of \(t_{\text{PulseDur}}\).
15.5 Logic rotating switch for function selection and LHMI presentation SLGAPC

15.5.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Logic rotating switch for function selection and LHMI presentation</td>
<td>SLGAPC</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

15.5.2 Application

The logic rotating switch for function selection and LHMI presentation function (SLGAPC) (or the selector switch function block, as it is also known) is used to get a selector switch functionality similar with the one provided by a hardware multi-position selector switch. Hardware selector switches are used extensively by utilities, in order to have different functions operating on pre-set values. Hardware switches are however sources for maintenance issues, lower system reliability and extended purchase portfolio. The virtual selector switches eliminate all these problems.

SLGAPC function block has two operating inputs (UP and DOWN), one blocking input (BLOCK) and one operator position input (PSTO).

SLGAPC can be activated both from the local HMI and from external sources (switches) via the IED binary inputs. It also allows the operation from remote (like the station computer). SWPOSN is an integer value output, giving the actual output number. Since the number of positions of the switch can be established by settings (see below), one must be careful in coordinating the settings with the configuration (if one sets the number of positions to x in settings – for example, there will be only the first x outputs available from the block in the configuration). Also the frequency of the (UP or DOWN) pulses should be lower than the setting $t_{\text{Pulse}}$.

From the local HMI, the selector switch can be operated from Single-line diagram (SLD).

15.5.3 Setting guidelines

The following settings are available for the Logic rotating switch for function selection and LHMI presentation (SLGAPC) function:

- **Operation**: Sets the operation of the function *Enabled* or *Disabled*.
- **NrPos**: Sets the number of positions in the switch (max. 32).
- **OutType**: Steady or Pulsed.
- **$t_{\text{Pulse}}$**: In case of a pulsed output, it gives the length of the pulse (in seconds).
- **$t_{\text{Delay}}$**: The delay between the UP or DOWN activation signal positive front and the output activation.
StopAtExtremes: Sets the behavior of the switch at the end positions – if set to Disabled, when pressing UP while on first position, the switch will jump to the last position; when pressing DOWN at the last position, the switch will jump to the first position; when set to Enabled, no jump will be allowed.

15.6 Selector mini switch VSGAPC

15.6.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Selector mini switch</td>
<td>VSGAPC</td>
<td>-</td>
<td>43</td>
</tr>
</tbody>
</table>

15.6.2 Application

Selector mini switch (VSGAPC) function is a multipurpose function used in the configuration tool in PCM600 for a variety of applications, as a general purpose switch. VSGAPC can be used for both acquiring an external switch position (through the IPOS1 and the IPOS2 inputs) and represent it through the single line diagram symbols (or use it in the configuration through the outputs POS1 and POS2) as well as, a command function (controlled by the PSTO input), giving switching commands through the CMDPOS12 and CMDPOS21 outputs.

The output POSITION is an integer output, showing the actual position as an integer number 0 – 3, where 0 = MidPos, 1 = Open, 2 = Closed and 3 = Error.

An example where VSGAPC is configured to switch Autorecloser enabled–disabled from a button symbol on the local HMI is shown in figure 298. The Close and Open buttons on the local HMI are normally used for enable–disable operations of the circuit breaker.

![Figure 298: Control of Autorecloser from local HMI through Selector mini switch](ANSI07000112-3-en.vsd)

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

Selector mini switch (VSGAPC) function can generate pulsed or steady commands (by setting the Mode parameter). When pulsed commands are generated, the length of the pulse can be set using the tPulse parameter. Also, being accessible on the single line diagram (SLD), this function block has two control modes (settable through CtlModel): Dir Norm and SBO Enh.

15.7 Generic communication function for Double Point indication DPGAPC

15.7.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generic communication function for Double Point indication</td>
<td>DPGAPC</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

15.7.2 Application

Generic communication function for Double Point indication (DPGAPC) function block is used to send double point position indication to other systems, equipment or functions in the substation through IEC 61850-8-1 or other communication protocols. It is especially intended to be used in the interlocking station-wide logics. To be able to get the signals into other systems, equipment or functions, one must use other tools, described in the Engineering manual, and define which function block in which systems, equipment or functions should receive this information.

More specifically, DPGAPC function reports a combined double point position indication output POSITION, by evaluating the value and the timestamp attributes of the inputs OPEN and CLOSE, together with the logical input signal VALID.

When the input signal VALID is active, the values of the OPEN and CLOSE inputs determine the two-bit integer value of the output POSITION. The timestamp of the output POSITION will have the latest updated timestamp of the inputs OPEN and CLOSE.

When the input signal VALID is inactive, DPGAPC function forces the position to intermediated state.

When the value of the input signal VALID changes, the timestamp of the output POSITION will be updated as the time when DPGAPC function detects the change.

Refer to Table 64 for the description of the input-output relationship in terms of the value and the quality attributes.
Table 64: Description of the input-output relationship

<table>
<thead>
<tr>
<th>VALID</th>
<th>OPEN</th>
<th>CLOSE</th>
<th>POSITION</th>
<th>Value</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>-</td>
<td>-</td>
<td>0</td>
<td>0</td>
<td>Intermediate</td>
</tr>
<tr>
<td>1</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>Intermediate</td>
</tr>
<tr>
<td>1</td>
<td>1</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>Open</td>
</tr>
<tr>
<td>1</td>
<td>0</td>
<td>1</td>
<td>2</td>
<td>2</td>
<td>Closed</td>
</tr>
<tr>
<td>1</td>
<td>1</td>
<td>1</td>
<td>3</td>
<td>3</td>
<td>Bad State</td>
</tr>
</tbody>
</table>

15.7.3 Setting guidelines

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

15.8 Single point generic control 8 signals SPC8GAPC

15.8.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Single point generic control 8 signals SPC8GAPC</td>
<td>SPC8GAPC</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

15.8.2 Application

The Single point generic control 8 signals (SPC8GAPC) function block is a collection of 8 single point commands that can be used for direct commands for example reset of LED’s or putting IED in “ChangeLock” state from remote. In this way, simple commands can be sent directly to the IED outputs, without confirmation. Confirmation (status) of the result of the commands is supposed to be achieved by other means, such as binary inputs and SPGAPC function blocks.

PSTO is the universal operator place selector for all control functions. Even if PSTO can be configured to allow LOCAL or ALL operator positions, the only functional position usable with the SPC8GAPC function block is REMOTE.

15.8.3 Setting guidelines

The parameters for the single point generic control 8 signals (SPC8GAPC) function are set via the local HMI or PCM600.

*Operation:* turning the function operation *Enabled/Disabled.*

There are two settings for every command output (totally 8):
PulseModex: decides if the command signal for output \( x \) is *Latched* (steady) or *Pulsed*.

tPulsex: if PulseModex is set to Pulsed, then \( tPulsex \) will set the length of the pulse (in seconds).

## 15.9 AutomationBits, command function for DNP3.0
### 15.9.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>AutomationBits, command function for DNP3</td>
<td>AUTOBITS</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

## 15.9.2 Application

Automation bits, command function for DNP3 (AUTOBITS) is used within PCM600 in order to get into the configuration the commands coming through the DNP3.0 protocol. The AUTOBITS function plays the same role as functions GOOSEINRCV (for IEC 61850) and MULTICMDRCV (for LON). AUTOBITS function block have 32 individual outputs which each can be mapped as a Binary Output point in DNP3. The output is operated by a "Object 12" in DNP3. This object contains parameters for control-code, count, on-time and off-time. To operate an AUTOBITS output point, send a control-code of latch-On, latch-Off, pulse-On, pulse-Off, Trip or Close. The remaining parameters are regarded as appropriate. For example, pulse-On, on-time=100, off-time=300, count=5 would give 5 positive 100 ms pulses, 300 ms apart.

For description of the DNP3 protocol implementation, refer to the Communication manual.

## 15.9.3 Setting guidelines

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

## 15.10 Single command, 16 signals SINGLECMD

### 15.10.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Single command, 16 signals</td>
<td>SINGLECMD</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>
15.10.2 Application

Single command, 16 signals (SINGLECMD) is a common function and always included in the IED.

The IEDs may be provided with a function to receive commands either from a substation automation system or from the local HMI. That receiving function block has outputs that can be used, for example, to control high voltage apparatuses in switchyards. For local control functions, the local HMI can also be used. Together with the configuration logic circuits, the user can govern pulses or steady output signals for control purposes within the IED or via binary outputs.

Figure 299 shows an application example of how the user can connect SINGLECMD via configuration logic circuit to control a high-voltage apparatus. This type of command control is normally carried out by sending a pulse to the binary outputs of the IED. Figure 299 shows a close operation. An open breaker operation is performed in a similar way but without the synchro-check condition.

![Diagram of single command function](en04000206_ansi.vsd)

Figure 299: Application example showing a logic diagram for control of a circuit breaker via configuration logic circuits

Figure 300 and figure 301 show other ways to control functions, which require steady Enabled/ Disabled signals. Here, the output is used to control built-in functions or external devices.
15.10.3 Setting guidelines

The parameters for Single command, 16 signals (SINGLECMD) are set via the local HMI or PCM600.

Parameters to be set are MODE, common for the whole block, and CMDOUTy which includes the user defined name for each output signal. The MODE input sets the outputs to be one of the types Disabled, Steady, or Pulse.
• Disabled, sets all outputs to 0, independent of the values sent from the station level, that is, the operator station or remote-control gateway.
• Steady, sets the outputs to a steady signal 0 or 1, depending on the values sent from the station level.
• Pulse, gives a pulse with 100 ms duration, if a value sent from the station level is changed from 0 to 1. That means the configured logic connected to the command function block may not have a cycle time longer than the cycle time for the command function block.
Section 16 Logic

16.1 Tripping logic SMPPTRC (94)

16.1.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tripping logic</td>
<td>SMPPTRC</td>
<td></td>
<td>1 -&gt; 0</td>
</tr>
</tbody>
</table>

16.1.2 Application

All trip signals from the different protection functions shall be routed through the trip logic. All start signals and directional information can be routed through the trip logic as well. In its simplest form, the trip logic will only link the TRIP signal to a binary output and make sure that the pulse time is long enough.

Tripping logic SMPPTRC (94) offers three different operating modes:

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

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

If the OHL is connected to the substation via more than one breaker, one SMPPTRC (94) function block should be used for each breaker. For example when single-pole tripping and autoreclosing is used on the line, both breakers are normally set up for 1/3-pole tripping and 1/3-phase autoreclosing. Alternatively, the breaker chosen as master can have single-pole tripping, while the slave breaker could have three-pole tripping and autoreclosing. In the case of a permanent fault, only one of the breakers has to be operated when the fault is energized a second time. In the event of a transient fault the slave breaker performs a three-pole reclosing onto the non-faulted line.

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

To prevent closing of a circuit breaker after a trip, the function offers a lockout function.
16.1.2.1 Three-pole tripping

Connect the inputs from the protection functions to the input TRINP_3P. The TMGAPC function block is used to combine up to 32 inputs into one output. Connect the output TRIP to the binary outputs on the IO board.

This signal can also be used for other purposes internally in the IED. An example could be the starting of breaker failure protection. The three outputs TR_A, TR_B, TR_C will always be activated at every trip and can be utilized on individual trip outputs if single-pole operating devices are available on the circuit breaker even when a three-pole tripping scheme is selected.

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

The typical connection is shown below in figure 302.

![Figure 302: Tripping logic SMPPTRC (94) is used for a simple three-pole tripping application](image)

16.1.2.2 Single- and/or three-pole tripping

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

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

The inputs 1PTRZ and 1PTRGF are used for single-pole tripping from functions which do not have built-in pole selection logic:

- 1PTRZ can be connected to the carrier aided trip signal from the distance protection scheme (it means that another distance protection function has seen or detected the fault)
- 1PTRGF can be connected to an earth fault function such as EF4PTOC or a carrier aided trip signal from the earth fault protection scheme

These two inputs are combined with the external phase selection logic. Phase selection signals from the external phase selector must be connected to the inputs PS_A, PS_B and PS_C to achieve the tripping on the respective single-pole trip outputs TR_A, TR_B and TR_C. The output TRIP is a general trip and is always activated independent of which phase is involved. Depending on which phases are involved the outputs TR1P, TR2P and TR3P will be activated as well.
When single-pole tripping schemes are used, a single-phase autoreclosing attempt is expected to follow. For cases where the autoreclosing is not in service or will not follow for some reason, the input prepare three-pole trip P3PTR must be activated. This input is normally connected to the output PREP3P on the autorecloser function SMBRREC (79) but can also be connected to other signals, for example, an external logic signal. If two circuit breakers are involved, one SMPPTRC block instance and one SMBRREC (79) instance are used for each circuit breaker. This will ensure correct operation and behavior of each circuit breaker.

The output TR3P must be connected to the input TR3P on the SMBRREC (79) function in order to switch SMBRREC (79) to perform a three-pole reclosing. If this signal is not activated, SMBRREC will use single-pole dead time.

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

Other back-up functions are connected to the input TRINP_3P as described above for three-pole tripping. A typical connection for a single-pole tripping scheme is shown in figure 303.

**Figure 303:** The trip logic function SMPPTRC (94) used for single-pole tripping application
16.1.2.3 Single-, two- or three-pole tripping

The single-/two-/three-pole tripping mode provides single-pole tripping for single-phase faults, two-pole tripping for two-phase faults and three-pole tripping for three-phase faults. The operating mode is always used together with an autoreclosing scheme with setting \( ARMode = 1/2/3 \ ph \) or \( ARMode = 1/2 \ Ph \).

The functionality is very similar to the single-phase scheme described above. However, in addition to the connections for single phase SMBRREC (79) must also be informed that the trip is two phases by connecting the output TR2P to the input TR2P in the SMBRREC (79) function.

16.1.2.4 Lock-out

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

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

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

16.1.2.5 Example of directional data

An example how to connect the directional data from different application functions to the trip function is given below, see Figure 304:
Figure 304: Example of the connection of directional start logic

The Start Matrix (SMAGAPC) merges start and directional output signals from different application functions and creates a common directional output signal (CND) to be connected to the Trip function (SMPPTRC). Protection functions connect their directional data via the STARTCOMB function to SMAGAPC and then to the SMPPTRC, or directly to SMAGAPC and then to the SMPPTRC.

The trip function (SMPPTRC) splits up the directional data as general output data for BFI_3P, BFI_A, BFI_B, BFI_C, STN, FW and REV.
All start and directional outputs are mapped to the logical node data model of the trip function and provided via the IEC 61850 attributes dirGeneral, DIRL1, DIRL2, DIRL3 and DIRN.

### 16.1.2.6 Blocking of the function block

Total block of the trip function is done by activating the input BLOCK and can be used to disable the outputs of the trip logic in the event of internal failures. Block of lock-out output is achieved by activating the input BLKLKOUT.

### 16.1.3 Setting guidelines

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

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

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

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

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

- **tTripMin**: Sets the required minimum duration of the trip pulse. It should be set to ensure that the circuit breaker is opened correctly. The normal setting is 0.150s.

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

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

### 16.2 Trip matrix logic TMAGAPC

#### 16.2.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Trip matrix logic</td>
<td>TMAGAPC</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

#### 16.2.2 Application

The trip matrix logic (TMAGAPC) function is used to route trip signals and other logical output signals to different output contacts on the IED.
The trip matrix logic function has 3 output signals and these outputs can be connected to physical tripping outputs according to the specific application needs for settable pulse or steady output.

### 16.2.3 Setting guidelines

**Operation**: Operation of function *Enabled*/*Disabled*.

**PulseTime**: Defines the pulse time when in *Pulsed* mode. When used for direct tripping of circuit breaker(s) the pulse time delay shall be set to approximately 0.150 seconds in order to obtain satisfactory minimum duration of the trip pulse to the circuit breaker trip coils.

**OnDelay**: Used to prevent output signals to be given for spurious inputs. Normally set to 0 or a low value.

**OffDelay**: Defines a delay of the reset of the outputs after the activation conditions no longer are fulfilled. It is only used in *Steady* mode. When used for direct tripping of circuit breaker(s) the off delay time shall be set to at least 0.150 seconds in order to obtain a satisfactory minimum duration of the trip pulse to the circuit breaker trip coils.

**ModeOutputx**: Defines if output signal *OUTPUTx* (where x=1-3) is *Steady* or *Pulsed*.

### 16.3 Logic for group alarm ALMCALH

#### 16.3.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Logic for group alarm</td>
<td>ALMCALH</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

#### 16.3.2 Application

Group alarm logic function ALMCALH is used to route alarm signals to different LEDs and/or output contacts on the IED.

ALMCALH output signal and the physical outputs allows the user to adapt the alarm signal to physical tripping outputs according to the specific application needs.

#### 16.3.3 Setting guidelines

**Operation**: *Enabled* or *Disabled*

### 16.4 Logic for group alarm WRNCALH

#### 16.4.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Logic for group warning</td>
<td>WRNCALH</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>
16.4.1.1 Application

Group warning logic function WRNCALH is used to route warning signals to LEDs and/or output contacts on the IED.

WRNCALH output signal WARNING and the physical outputs allows the user to adapt the warning signal to physical tripping outputs according to the specific application needs.

16.4.1.2 Setting guidelines

Operation: Enabled or Disabled

16.5 Logic for group indication INDCALH

16.5.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Logic for group indication</td>
<td>INDCALH</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

16.5.1.1 Application

Group indication logic function INDCALH is used to route indication signals to different LEDs and/or output contacts on the IED.

INDCALH output signal IND and the physical outputs allows the user to adapt the indication signal to physical outputs according to the specific application needs.

16.5.1.2 Setting guidelines

Operation: Enabled or Disabled

16.6 Configurable logic blocks

The configurable logic blocks are available in two categories:

- Configurable logic blocks that do not propagate the time stamp and the quality of signals. They do not have the suffix QT at the end of their function block name, for example, SRMEMORY. These logic blocks are also available as part of an extension logic package with the same number of instances.
- Configurable logic blocks that propagate the time stamp and the quality of signals. They have the suffix QT at the end of their function block name, for example, SRMEMORYQT.

16.6.1 Application

A set of standard logic blocks, like AND, OR etc, and timers are available for adapting the IED configuration to the specific application needs. Additional logic blocks that, beside the normal
logical function, have the capability to propagate timestamp and quality are also available. Those blocks have a designation including the letters QT, like ANDQT, ORQT etc.

### 16.6.2 Setting guidelines

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

For normal On/Off delay and pulse timers the time delays and pulse lengths are set from the local HMI or via the PST tool.

Both timers in the same logic block (the one delayed on pick-up and the one delayed on drop-out) always have a common setting value.

For controllable gates, settable timers and SR flip-flops with memory, the setting parameters are accessible via the local HMI or via the PST tool.

### 16.6.2.1 Configuration

Logic is configured using the ACT configuration tool in PCM600.

Execution of functions as defined by the configurable logic blocks runs according to a fixed sequence with different cycle times.

For each cycle time, the function block is given an serial execution number. This is shown when using the ACT configuration tool with the designation of the function block and the cycle time, see example below.

![Function Block Instance](IEC09000695_2_en.vsd)

*Figure 305: Example designation, serial execution number and cycle time for logic function*
The execution of different function blocks within the same cycle is determined by the order of their serial execution numbers. Always remember this when connecting two or more logical function blocks in series.

Always be careful when connecting function blocks with a fast cycle time to function blocks with a slow cycle time.

Remember to design the logic circuits carefully and always check the execution sequence for different functions. In other cases, additional time delays must be introduced into the logic schemes to prevent errors, for example, race between functions.

### 16.7 Fixed signal function block FXDSIGN

#### 16.7.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 Identification</th>
<th>IEC 60617 Identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed signals</td>
<td>FXDSIGN</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

#### 16.7.2 Application

The Fixed signals function (FXDSIGN) has nine pre-set (fixed) signals that can be used in the configuration of an IED, either for forcing the unused inputs in other function blocks to a certain level/value, or for creating certain logic. Boolean, integer, floating point, string types of signals are available.

One FXDSIGN function block is included in all IEDs.

**Example for use of GRP_OFF signal in FXDSIGN**

The Restricted earth fault function (REFPDIF) (87N) can be used both for auto-transformers and normal transformers.
When used for auto-transformers, information from both windings parts, together with the neutral point current, needs to be available to the function. This means that three inputs are needed.

![Figure 307: REFPDIF (87N) function inputs for autotransformer application](image1)

For normal transformers only one winding and the neutral point is available. This means that only two inputs are used. Since all group connections are mandatory to be connected, the third input needs to be connected to something, which is the GRP_OFF signal in FXDSIGN function block.

![Figure 308: REFPDIF (87N) function inputs for normal transformer application](image2)

### 16.8 Boolean 16 to Integer conversion B16I

#### 16.8.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boolean 16 to integer conversion</td>
<td>B16I</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>
16.8.2 Application

Boolean 16 to integer conversion function B16I is used to transform a set of 16 binary (logical) signals into an integer. It can be used – for example, to connect logical output signals from a function (like distance protection) to integer inputs from another function (like line differential protection). B16I does not have a logical node mapping.

The Boolean 16 to integer conversion function (B16I) will transfer a combination of up to 16 binary inputs INx where 1≤x≤16 to an integer. Each INx represents a value according to the table below from 0 to 32768. This follows the general formula: \( \text{INx} = 2^{x-1} \) where 1≤x≤16. The sum of all the values on the activated INx will be available on the output OUT as a sum of the values of all the inputs INx that are activated. OUT is an integer. When all INx where 1≤x≤16 are activated that is = Boolean 1 it corresponds to that integer 65535 is available on the output OUT. B16I function is designed for receiving up to 16 booleans input locally. If the BLOCK input is activated, it will freeze the output at the last value.

Values of each of the different OUTx from function block B16I for 1≤x≤16.

The sum of the value on each INx corresponds to the integer presented on the output OUT on the function block B16I.

<table>
<thead>
<tr>
<th>Name of Input</th>
<th>Type</th>
<th>Default</th>
<th>Description</th>
<th>Value when activated</th>
<th>Value when deactivated</th>
</tr>
</thead>
<tbody>
<tr>
<td>IN1</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 1</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>IN2</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 2</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td>IN3</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 3</td>
<td>4</td>
<td>0</td>
</tr>
<tr>
<td>IN4</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 4</td>
<td>8</td>
<td>0</td>
</tr>
<tr>
<td>IN5</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 5</td>
<td>16</td>
<td>0</td>
</tr>
<tr>
<td>IN6</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 6</td>
<td>32</td>
<td>0</td>
</tr>
<tr>
<td>IN7</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 7</td>
<td>64</td>
<td>0</td>
</tr>
<tr>
<td>IN8</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 8</td>
<td>128</td>
<td>0</td>
</tr>
<tr>
<td>IN9</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 9</td>
<td>256</td>
<td>0</td>
</tr>
<tr>
<td>IN10</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 10</td>
<td>512</td>
<td>0</td>
</tr>
<tr>
<td>IN11</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 11</td>
<td>1024</td>
<td>0</td>
</tr>
<tr>
<td>IN12</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 12</td>
<td>2048</td>
<td>0</td>
</tr>
<tr>
<td>IN13</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 13</td>
<td>4096</td>
<td>0</td>
</tr>
<tr>
<td>IN14</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 14</td>
<td>8192</td>
<td>0</td>
</tr>
<tr>
<td>IN15</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 15</td>
<td>16384</td>
<td>0</td>
</tr>
<tr>
<td>IN16</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 16</td>
<td>32768</td>
<td>0</td>
</tr>
</tbody>
</table>

The sum of the numbers in column “Value when activated” when all INx (where 1≤x≤16) are active that is=1; is 65535. 65535 is the highest boolean value that can be converted to an integer by the B16I function block.
16.9 Boolean to integer conversion with logical node representation, 16 bit BTIGAPC

16.9.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boolean to integer conversion with logical node representation, 16 bit</td>
<td>BTIGAPC</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

16.9.2 Application

Boolean to integer conversion with logical node representation, 16 bit (BTIGAPC) is used to transform a set of 16 binary (logical) signals into an integer. BTIGAPC has a logical node mapping in IEC 61850.

The BTIGAPC function will transfer a combination of up to 16 binary inputs INx where 1≤x≤16 to an integer. Each INx represents a value according to the table below from 0 to 32768. This follows the general formula: $INx = 2^{x-1}$ where 1≤x≤16. The sum of all the values on the activated INx will be available on the output OUT as a sum of the values of all the inputs INx that are activated. OUT is an integer. When all INx where 1≤x≤16 are activated that is = Boolean 1 it corresponds to that integer 65535 is available on the output OUT. BTIGAPC function is designed for receiving up to 16 booleans input locally. If the BLOCK input is activated, it will freeze the output at the last value.

Values of each of the different OUTx from function block BTIGAPC for 1≤x≤16.

The sum of the value on each INx corresponds to the integer presented on the output OUT on the function block BTIGAPC.

<table>
<thead>
<tr>
<th>Name of input</th>
<th>Type</th>
<th>Default</th>
<th>Description</th>
<th>Value when activated</th>
<th>Value when deactivated</th>
</tr>
</thead>
<tbody>
<tr>
<td>IN1</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 1</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>IN2</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 2</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td>IN3</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 3</td>
<td>4</td>
<td>0</td>
</tr>
<tr>
<td>IN4</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 4</td>
<td>8</td>
<td>0</td>
</tr>
<tr>
<td>IN5</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 5</td>
<td>16</td>
<td>0</td>
</tr>
<tr>
<td>IN6</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 6</td>
<td>32</td>
<td>0</td>
</tr>
<tr>
<td>IN7</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 7</td>
<td>64</td>
<td>0</td>
</tr>
<tr>
<td>IN8</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 8</td>
<td>128</td>
<td>0</td>
</tr>
<tr>
<td>IN9</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 9</td>
<td>256</td>
<td>0</td>
</tr>
<tr>
<td>IN10</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 10</td>
<td>512</td>
<td>0</td>
</tr>
<tr>
<td>IN11</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 11</td>
<td>1024</td>
<td>0</td>
</tr>
<tr>
<td>IN12</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 12</td>
<td>2048</td>
<td>0</td>
</tr>
<tr>
<td>IN13</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 13</td>
<td>4096</td>
<td>0</td>
</tr>
</tbody>
</table>

Table continues on next page
Name of input | Type | Default | Description | Value when activated | Value when deactivated
--- | --- | --- | --- | --- | ---
IN14 | BOOLEAN | 0 | Input 14 | 8192 | 0
IN15 | BOOLEAN | 0 | Input 15 | 16384 | 0
IN16 | BOOLEAN | 0 | Input 16 | 32768 | 0

The sum of the numbers in column “Value when activated” when all INx (where 1≤x≤16) are active that is =1, is 65535. 65535 is the highest boolean value that can be converted to an integer by the BTIGAPC function block.

16.10 **Integer to Boolean 16 conversion IB16**

16.10.1 **Identification**

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Integer to boolean 16 conversion</td>
<td>IB16</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

16.10.2 **Application**

Integer to boolean 16 conversion function (IB16) is used to transform an integer into a set of 16 binary (logical) signals. It can be used – for example, to connect integer output signals from one function to binary (logical) inputs to another function. IB16 function does not have a logical node mapping.

The Boolean 16 to integer conversion function (IB16) will transfer a combination of up to 16 binary inputs INx where 1≤x≤16 to an integer. Each INx represents a value according to the table below from 0 to 32768. This follows the general formula: INx = 2^{x-1} where 1≤x≤16. The sum of all the values on the activated INx will be available on the output OUT as a sum of the values of all the inputs INx that are activated. OUT is an integer. When all INx where 1≤x≤16 are activated that is = Boolean 1 it corresponds to that integer 65535 is available on the output OUT. IB16 function is designed for receiving up to 16 booleans input locally. If the BLOCK input is activated, it will freeze the output at the last value.

Values of each of the different OUTx from function block IB16 for 1≤x≤16.

<table>
<thead>
<tr>
<th>Name of input</th>
<th>Type</th>
<th>Default</th>
<th>Description</th>
<th>Value when activated</th>
<th>Value when deactivated</th>
</tr>
</thead>
<tbody>
<tr>
<td>IN1</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 1</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>IN2</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 2</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td>IN3</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 3</td>
<td>4</td>
<td>0</td>
</tr>
<tr>
<td>IN4</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 4</td>
<td>8</td>
<td>0</td>
</tr>
</tbody>
</table>

The sum of the value on each INx corresponds to the integer presented on the output OUT on the function block IB16.
<table>
<thead>
<tr>
<th>Name of input</th>
<th>Type</th>
<th>Default</th>
<th>Description</th>
<th>Value when activated</th>
<th>Value when deactivated</th>
</tr>
</thead>
<tbody>
<tr>
<td>IN5</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 5</td>
<td>16</td>
<td>0</td>
</tr>
<tr>
<td>IN6</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 6</td>
<td>32</td>
<td>0</td>
</tr>
<tr>
<td>IN7</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 7</td>
<td>64</td>
<td>0</td>
</tr>
<tr>
<td>IN8</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 8</td>
<td>128</td>
<td>0</td>
</tr>
<tr>
<td>IN9</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 9</td>
<td>256</td>
<td>0</td>
</tr>
<tr>
<td>IN10</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 10</td>
<td>512</td>
<td>0</td>
</tr>
<tr>
<td>IN11</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 11</td>
<td>1024</td>
<td>0</td>
</tr>
<tr>
<td>IN12</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 12</td>
<td>2048</td>
<td>0</td>
</tr>
<tr>
<td>IN13</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 13</td>
<td>4096</td>
<td>0</td>
</tr>
<tr>
<td>IN14</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 14</td>
<td>8192</td>
<td>0</td>
</tr>
<tr>
<td>IN15</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 15</td>
<td>16384</td>
<td>0</td>
</tr>
<tr>
<td>IN16</td>
<td>BOOLEAN</td>
<td>0</td>
<td>Input 16</td>
<td>32768</td>
<td>0</td>
</tr>
</tbody>
</table>

The sum of the numbers in column “Value when activated” when all INx (where 1≤x≤16) are active that is=1, is 65535. 65535 is the highest boolean value that can be converted to an integer by the IB16 function block.

### 16.11 Integer to Boolean 16 conversion with logic node representation ITBGAPC

#### 16.11.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Integer to boolean 16 conversion with logic node representation</td>
<td>ITBGAPC</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

#### 16.11.2 Application

Integer to boolean 16 conversion with logic node representation function (ITBGAPC) is used to transform an integer into a set of 16 boolean signals. ITBGAPC function can receive an integer from a station computer – for example, over IEC 61850–8–1. This function is very useful when the user wants to generate logical commands (for selector switches or voltage controllers) by inputting an integer number. ITBGAPC function has a logical node mapping in IEC 61850.

The Integer to Boolean 16 conversion with logic node representation function (ITBGAPC) will transfer an integer with a value between 0 to 65535 communicated via IEC 61850 and connected to the ITBGAPC function block to a combination of activated outputs OUTx where 1≤x≤16.

The values of the different OUTx are according to the Table 65.
If the BLOCK input is activated, it freezes the logical outputs at the last value.

Table 65: Output signals

<table>
<thead>
<tr>
<th>Name of OUTx</th>
<th>Type</th>
<th>Description</th>
<th>Value when activated</th>
<th>Value when deactivated</th>
</tr>
</thead>
<tbody>
<tr>
<td>OUT1</td>
<td>BOOLEAN</td>
<td>Output 1</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>OUT2</td>
<td>BOOLEAN</td>
<td>Output 2</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td>OUT3</td>
<td>BOOLEAN</td>
<td>Output 3</td>
<td>4</td>
<td>0</td>
</tr>
<tr>
<td>OUT4</td>
<td>BOOLEAN</td>
<td>Output 4</td>
<td>8</td>
<td>0</td>
</tr>
<tr>
<td>OUT5</td>
<td>BOOLEAN</td>
<td>Output 5</td>
<td>16</td>
<td>0</td>
</tr>
<tr>
<td>OUT6</td>
<td>BOOLEAN</td>
<td>Output 6</td>
<td>32</td>
<td>0</td>
</tr>
<tr>
<td>OUT7</td>
<td>BOOLEAN</td>
<td>Output 7</td>
<td>64</td>
<td>0</td>
</tr>
<tr>
<td>OUT8</td>
<td>BOOLEAN</td>
<td>Output 8</td>
<td>128</td>
<td>0</td>
</tr>
<tr>
<td>OUT9</td>
<td>BOOLEAN</td>
<td>Output 9</td>
<td>256</td>
<td>0</td>
</tr>
<tr>
<td>OUT10</td>
<td>BOOLEAN</td>
<td>Output 10</td>
<td>512</td>
<td>0</td>
</tr>
<tr>
<td>OUT11</td>
<td>BOOLEAN</td>
<td>Output 11</td>
<td>1024</td>
<td>0</td>
</tr>
<tr>
<td>OUT12</td>
<td>BOOLEAN</td>
<td>Output 12</td>
<td>2048</td>
<td>0</td>
</tr>
<tr>
<td>OUT13</td>
<td>BOOLEAN</td>
<td>Output 13</td>
<td>4096</td>
<td>0</td>
</tr>
<tr>
<td>OUT14</td>
<td>BOOLEAN</td>
<td>Output 14</td>
<td>8192</td>
<td>0</td>
</tr>
<tr>
<td>OUT15</td>
<td>BOOLEAN</td>
<td>Output 15</td>
<td>16384</td>
<td>0</td>
</tr>
<tr>
<td>OUT16</td>
<td>BOOLEAN</td>
<td>Output 16</td>
<td>32768</td>
<td>0</td>
</tr>
</tbody>
</table>

The sum of the numbers in column “Value when activated” when all OUTx (1≤x≤16) are active equals 65535. This is the highest integer that can be converted by the ITBGAPC function block.

16.12 Pulse integrator TIGAPC

16.12.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pulse integrator</td>
<td>TIGAPC</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

16.12.2 Application

The pulse integrator function TIGAPC is intended for applications where there is a need for a integration of a pulsed signal. For example, the pulses from the pickup output of certain functions, like reverse power, loss of excitation and pole slip. Some applications may require the integration of the pickup output of those functions to perform the trip.
16.12.3 Setting guidelines

The pulse integrator function provides settings for time delay to operate and time delay to reset. The time delay to operate setting is evaluated for activation of the output and there will be no output until the integration of the input pulses equals this setting. The output will be deactivated when the input signal is deactivated and the time delay to reset has elapsed.

16.13 Elapsed time integrator with limit transgression and overflow supervision TEIGAPC

16.13.1 Identification

<table>
<thead>
<tr>
<th>Function Description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Elapsed time integrator</td>
<td>TEIGAPC</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

16.13.2 Application

The function TEIGAPC is used for user-defined logics and it can also be used for different purposes internally in the IED. An application example is the integration of elapsed time during the measurement of neutral point voltage or neutral current at earth-fault conditions.

Settable time limits for warning and alarm are provided. The time limit for overflow indication is fixed to 999999.9 seconds.

16.13.3 Setting guidelines

The settings $t_{\text{Alarm}}$ and $t_{\text{Warning}}$ are user settable limits defined in seconds. The achievable resolution of the settings depends on the level of the values defined.

A resolution of 10 ms can be achieved when the settings are defined within the range

\[
1.00 \text{ second} \leq t_{\text{Alarm}} \leq 99 999.99 \text{ seconds}
\]

\[
1.00 \text{ second} \leq t_{\text{Warning}} \leq 99 999.99 \text{ seconds}.
\]

If the values are above this range, the resolution becomes lower due to the 32 bit float representation

\[
99 999.99 \text{ seconds} < t_{\text{Alarm}} \leq 999 999.0 \text{ seconds}
\]

\[
99 999.99 \text{ seconds} < t_{\text{Warning}} \leq 999 999.0 \text{ seconds}
\]

Note that $t_{\text{Alarm}}$ and $t_{\text{Warning}}$ are independent settings, that is, there is no check if $t_{\text{Alarm}} > t_{\text{Warning}}$.

The limit for the overflow supervision is fixed at 999999.9 seconds.
16.14 Comparator for integer inputs - INTCOMP

16.14.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Comparison of integer values</td>
<td>INTCOMP</td>
<td>int&lt;=</td>
<td></td>
</tr>
</tbody>
</table>

16.14.2 Application

The function gives the possibility to monitor the level of integer values in the system relative to each other or to a fixed value. It is a basic arithmetic function that can be used for monitoring, supervision, interlocking and other logics.

16.14.3 Setting guidelines

For proper operation of comparison the set value should be set within the range of $\pm 2 \times 10^9$.

Setting procedure on the IED:

*EnaAbs*: This setting is used to select the comparison type between signed and absolute values.

- *Absolute*: Comparison is performed on absolute values of input and reference values
- *Signed*: Comparison is performed on signed values of input and reference values.

*RefSource*: This setting is used to select the reference source between input and setting for comparison.

- *Input REF*: The function will take reference value from input REF
- *Set Value*: The function will take reference value from setting SetValue

*SetValue*: This setting is used to set the reference value for comparison when setting *RefSource* is selected as *SetValue*.

16.14.4 Setting example

For absolute comparison between inputs:

Set the *EnaAbs* = *Absolute*

Set the *RefSource* = *Input REF*

Similarly for Signed comparison between inputs

Set the *EnaAbs* = *Signed*

Set the *RefSource* = *Input REF*
For absolute comparison between input and setting
Set the EnaAbs = Absolute
Set the RefSource = Set Value
SetValue shall be set between -2000000000 to 2000000000

Similarly for signed comparison between input and setting
Set the EnaAbs = Signed
Set the RefSource = Set Value
SetValue shall be set between -2000000000 to 2000000000

16.15 Comparator for real inputs - REALCOMP

16.15.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Comparator for real inputs</td>
<td>REALCOMP</td>
<td>Real&lt;==&gt;</td>
<td></td>
</tr>
</tbody>
</table>

16.15.2 Application

The function gives the possibility to monitor the level of real values in the system relative to each other or to a fixed value. It is a basic arithmetic function that can be used for monitoring, supervision, interlocking and other logics.

16.15.3 Setting guidelines

Setting procedure on the IED:

EnaAbs: This setting is used to select the comparison type between signed and absolute values.
- Absolute: Comparison is performed with absolute values of input and reference.
- Signed: Comparison is performed with signed values of input and reference.

RefSource: This setting is used to select the reference source between input and setting for comparison.
- Input REF: The function will take reference value from input REF
- Set Value: The function will take reference value from setting SetValue

SetValue: This setting is used to set the reference value for comparison when setting RefSource is selected as Set Value. If this setting value is less than 0.2% of the set unit then the output INLOW will never pickup.
**RefPrefix**: This setting is used to set the unit of the reference value for comparison when setting **RefSource** is selected as **SetValue**. It has 5 unit selections and they are Milli, Unity, Kilo, Mega and Giga.

**EqualBandHigh**: This setting is used to set the equal condition high band limit in % of reference value. This high band limit will act as reset limit for INHIGH output when INHIGH.

**EqualBandLow**: This setting is used to set the equal condition low band limit in % of reference value. This low band limit will act as reset limit for INLOW output when INLOW.

### 16.15.4 Setting example

Let us consider a comparison is to be done between current magnitudes in the range of 90 to 110 with nominal rating is 100 and the order is kA.

For the above condition the comparator can be designed with settings as follows,

**EnaAbs = Absolute**

**RefSource = Set Value**

**SetValue = 100**

**RefPrefix = Kilo**

**EqualBandHigh = 5.0 % of reference value**

**EqualBandLow = 5.0 % of reference value**

**Operation**

The function will set the outputs for the following conditions,

INEQUAL will set when the INPUT is between the ranges of 95 to 105 kA.

INHIGH will set when the INPUT crosses above 105 kA.

INLOW will set when the INPUT crosses below 95 kA.

If the comparison should be done between two current magnitudes then those current signals need to be connected to function inputs, INPUT and REF. Then the settings should be adjusted as below,

**EnaAbs = Absolute**

**RefSource = Input REF**

**EqualBandHigh = 5.0 % of reference value**

**EqualBandLow = 5.0 % of reference value.**
**Section 17 Monitoring**

### 17.1 Measurement

#### 17.1.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power system measurements</td>
<td>CVMMXN</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Phase current measurement</td>
<td>CMMXU</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Phase-phase voltage measurement</td>
<td>VMMXU</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Current sequence component measurement</td>
<td>CMSQI</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Voltage sequence component measurement</td>
<td>VMSQI</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Phase-neutral voltage measurement</td>
<td>VNMMXU</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- **Function description**: Power system measurements, Phase current measurement, Phase-phase voltage measurement, Current sequence component measurement, Voltage sequence component measurement, Phase-neutral voltage measurement
- **IEC 61850 identification**: CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU
- **IEC 60617 identification**: P, Q, I, U, f
- **ANSI/IEEE C37.2 device number**: -

#### 17.1.2 Application

Measurement functions are used for power system measurement, supervision and reporting to the local HMI, monitoring tool within PCM600 or to station level for example, via IEC 61850. The possibility to continuously monitor measured values of active power, reactive power, currents, voltages, frequency, power factor etc. is vital for efficient production, transmission and distribution of electrical energy. It provides to the system operator fast and easy overview of the present status of the power system. Additionally, it can be used during testing and commissioning of protection and control IEDs in order to verify proper operation and connection of instrument transformers (CTs and VTs). During normal service by periodic comparison of the measured value...
from the IED with other independent meters the proper operation of the IED analog measurement chain can be verified. Finally, it can be used to verify proper direction orientation for distance or directional overcurrent protection function.

The available measured values from an IED are depending on the actual hardware (TRM) and the logic configuration made in PCM600.

All measured values can be supervised with four settable limits that is, low-low limit, low limit, high limit and high-high limit. A zero clamping reduction is also supported, that is, the measured value below a settable limit is forced to zero which reduces the impact of noise in the inputs.

Dead-band supervision can be used to report measured signal value to station level when change in measured value is above set threshold limit or time integral of all changes since the last time value updating exceeds the threshold limit. Measure value can also be based on periodic reporting.

Main menu/Measurement/Monitoring/Service values/CVMMXN

The measurement function, CVMMXN, provides the following power system quantities:

- P, Q and S: three phase active, reactive and apparent power
- PF: power factor
- V: phase-to-phase voltage magnitude
- I: phase current magnitude
- F: power system frequency

The measuring functions CMMXU, VMMXU and VNMMXU provide physical quantities:

- I: phase currents (magnitude and angle) (CMMXU)
- V: voltages (phase-to-ground and phase-to-phase voltage, magnitude and angle) (VMMXU, VNMMXU)

The CVMMXN function calculates three-phase power quantities by using fundamental frequency phasors (DFT values) of the measured current and voltage signals. The measured power quantities are available either, as instantaneously calculated quantities or, averaged values over a period of time (low pass filtered) depending on the selected settings.

It is possible to calibrate the measuring function above to get better then class 0.5 presentation. This is accomplished by angle and magnitude compensation at 5, 30 and 100% of rated current and at 100% of rated voltage.

The power system quantities provided, depends on the actual hardware, (TRM) and the logic configuration made in PCM600.

The measuring functions CMSQI and VMSQI provide sequence component quantities:

- I: sequence currents (positive, zero, negative sequence, magnitude and angle)
- V: sequence voltages (positive, zero and negative sequence, magnitude and angle).
17.1.3 Zero clamping

Measuring functions CVMMXN, CMMXU, VMMXU and VNMMXU have no interconnections regarding any settings or parameters.

Zero clamping is also handled entirely by ZeroDb separately for each function's every output signal. For example, zero clamping of U12 is handled by UL12ZeroDb in VMMXU, zero clamping of I1 is handled by IL1ZeroDb in CMMXU, and so on.

Example of CVMMXN operation

Outputs seen on the local HMI under Main menu/Measurements/Monitoring/Servicevalues(P_Q)/CVMMXN(P_Q):

- **S**: Apparent three-phase power
- **P**: Active three-phase power
- **Q**: Reactive three-phase power
- **PF**: Power factor
- **ILAG**: I lagging U
- **ILEAD**: I leading U
- **U**: System mean voltage, calculated according to selected mode
- **I**: System mean current, calculated according to selected mode
- **F**: Frequency

Relevant settings and their values on the local HMI under Main menu/Settings/IED settings/Monitoring/Servicevalues(P_Q)/CVMMXN(P_Q):

- When system voltage falls below UGenZeroDB, values for S, P, Q, PF, ILAG, ILEAD, U and F are forced to zero.
- When system current falls below IGenZeroDB, values for S, P, Q, PF, ILAG, ILEAD, U and F are forced to zero.
- When the value of a single signal falls below its set deadband, the value is forced to zero. For example, if the apparent three-phase power falls below SZeroDb, the value for S is forced to zero.

17.1.4 Setting guidelines

The available setting parameters of the measurement function CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU are depending on the actual hardware (TRM) and the logic configuration made in PCM600.

The parameters for the Measurement functions CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU are set via the local HMI or PCM600.

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

**Operation**: Disabled/Enabled. Every function instance (CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU) can be taken in operation (Enabled) or out of operation (Disabled).
The following general settings can be set for the Measurement function (CVMMXN).

**PowMagFact:** Magnitude factor to scale power calculations.

**PowAngComp:** Angle compensation for phase shift between measured I & V.

**Mode:** Selection of measured current and voltage. There are 9 different ways of calculating monitored three-phase values depending on the available VT inputs connected to the IED. See parameter group setting table.

**k:** Low pass filter coefficient for power measurement, V and I.

**VGenZeroDb:** Minimum level of voltage in % of VBase, used as indication of zero voltage (zero point clamping). If measured value is below VGenZeroDb calculated S, P, Q and PF will be zero.

**IGenZeroDb:** Minimum level of current in % of IBase, used as indication of zero current (zero point clamping). If measured value is below IGenZeroDb calculated S, P, Q and PF will be zero.

**VMagCompY:** Magnitude compensation to calibrate voltage measurements at Y% of Vn, where Y is equal to 5, 30 or 100.

**IMagCompY:** Magnitude compensation to calibrate current measurements at Y% of In, where Y is equal to 5, 30 or 100.

**IAngCompY:** Angle compensation to calibrate angle measurements at Y% of In, where Y is equal to 5, 30 or 100.

The following general settings can be set for the Phase current measurement (CMMXU).

**IMagCompY:** Magnitude compensation to calibrate current measurements at Y% of In, where Y is equal to 5, 30 or 100.

**IAngCompY:** Angle compensation to calibrate angle measurements at Y% of In, where Y is equal to 5, 30 or 100.

The following general settings can be set for the Phase-phase voltage measurement (VMMXU).

**VMagCompY:** Amplitude compensation to calibrate voltage measurements at Y% of Vn, where Y is equal to 5, 30 or 100.

**VAngCompY:** Angle compensation to calibrate angle measurements at Y% of Vn, where Y is equal to 5, 30 or 100.

The following general settings can be set for all monitored quantities included in the functions (CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU) X in setting names below equals S, P, Q, PF, V, I, F, IA,IB,IC, VA, VB, VCVAB, VBC, VCA, I1, I2, 3I0, V1, V2 or 3V0.

**Xmin:** Minimum value for analog signal X set directly in applicable measuring unit. This forms the minimum limit of the range.

**Xmax:** Maximum value for analog signal X. This forms the maximum limit of the range.

**XZeroDb:** Zero point clamping. A signal value less than XZeroDb is forced to zero.

Observe the related zero point clamping settings in Setting group N for CVMMXN (VGenZeroDb and IGenZeroDb). If measured value is below VGenZeroDb and/or IGenZeroDb calculated S, P, Q and PF will be zero and these settings will override XZeroDb.
**XRepTyp**: Reporting type. Cyclic (*Cyclic*), magnitude deadband (*Dead band*), integral deadband (*Int deadband*) or Deadband and xx sec cyclic (xx: 5 sec, 30 sec, 1 min). The reporting interval is controlled by the parameter **XDbReplint**.

**XDbReplint**: This setting handles all the reporting types. If setting is deadband in XRepTyp, XDbReplint defines the deadband in m% of the measuring range. For cyclic reporting type (**XRepTyp**: cyclic), the setting value reporting interval is in seconds. Magnitude deadband is the setting value in m% of measuring range. Integral deadband setting is the integral area, that is, measured value in m% of measuring range multiplied by the time between two measured values.

**XHiHiLim**: High-high limit. Set as % of **YBase** (**Y** is **SBase** for S,P,Q **UBase** for Voltage measurement and **IBase** for current measurement).

**XHiLim**: High limit. Set as % of **YBase** (**Y** is **SBase** for S,P,Q **UBase** for Voltage measurement and **IBase** for current measurement).

**XLowLim**: Low limit. Set as % of **YBase** (**Y** is **SBase** for S,P,Q **UBase** for Voltage measurement and **IBase** for current measurement).

**XLowLowLim**: Low-low limit. Set as % of **YBase** (**Y** is **SBase** for S,P,Q **UBase** for Voltage measurement and **IBase** for current measurement).

**XLimHyst**: Hysteresis value in % of range and is common for all limits.

All phase angles are presented in relation to defined reference channel. The parameter **PhaseAngleRef** defines the reference.

**Calibration curves**

It is possible to calibrate the functions (CVMMXN, CMMXU, VMMXU and VNMMXU) to get class 0.5 presentations of currents, voltages and powers. This is accomplished by magnitude and angle compensation at 5, 30 and 100% of rated current and voltage. The compensation curve will have the characteristic for magnitude and angle compensation of currents as shown in figure 309 (example). The first phase will be used as reference channel and compared with the curve for calculation of factors. The factors will then be used for all related channels.
17.1.4.1 Setting examples

Three setting examples, in connection to Measurement function (CVMMXN), are provided:

- Measurement function (CVMMXN) application for a OHL
- Measurement function (CVMMXN) application on the secondary side of a transformer
- Measurement function (CVMMXN) application for a generator

For each of them detail explanation and final list of selected setting parameters values will be provided.

The available measured values of an IED are depending on the actual hardware (TRM) and the logic configuration made in PCM600.

**Measurement function application for a 380kV OHL**

Single line diagram for this application is given in figure 310:
Figure 310: Single line diagram for 380kV OHL application

In order to monitor, supervise and calibrate the active and reactive power as indicated in figure 310 it is necessary to do the following:

1. Set correctly CT and VT data and phase angle reference channel PhaseAngleRef using PCM600 for analog input channels
2. Connect, in PCM600, measurement function to three-phase CT and VT inputs
3. Set under General settings parameters for the Measurement function:
   - general settings as shown in table 66.
   - level supervision of active power as shown in table 67.
   - calibration parameters as shown in table 68.

Table 66: General settings parameters for the Measurement function

<table>
<thead>
<tr>
<th>Setting</th>
<th>Short Description</th>
<th>Selected value</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operation</td>
<td>Operation Off/On</td>
<td>On</td>
<td>Function must be On</td>
</tr>
<tr>
<td>PowAmpFact</td>
<td>Amplitude factor to scale power calculations</td>
<td>1.000</td>
<td>It can be used during commissioning to achieve higher measurement accuracy. Typically no scaling is required</td>
</tr>
<tr>
<td>PowAngComp</td>
<td>Angle compensation for phase shift between measured I &amp; U</td>
<td>0.0</td>
<td>It can be used during commissioning to achieve higher measurement accuracy. Typically no angle compensation is required. As well here required direction of P &amp; Q measurement is towards protected object (as per IED internal default direction)</td>
</tr>
<tr>
<td>Mode</td>
<td>Selection of measured current and voltage</td>
<td>L1, L2, L3</td>
<td>All three phase-to-ground VT inputs are available</td>
</tr>
<tr>
<td>k</td>
<td>Low pass filter coefficient for power measurement, V and I</td>
<td>0.00</td>
<td>Typically no additional filtering is required</td>
</tr>
<tr>
<td>VGenZeroDb</td>
<td>Zero point clamping in % of Ubase</td>
<td>25</td>
<td>Set minimum voltage level to 25%. Voltage below 25% will force S, P and Q to zero.</td>
</tr>
<tr>
<td>IGenZeroDb</td>
<td>Zero point clamping in % of Ibase</td>
<td>3</td>
<td>Set minimum current level to 3%. Current below 3% will force S, P and Q to zero.</td>
</tr>
</tbody>
</table>

Table continues on next page
### Table 67: Settings parameters for level supervision

<table>
<thead>
<tr>
<th>Setting</th>
<th>Short Description</th>
<th>Selected value</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>VBase (set in Global base)</td>
<td>Base setting for voltage level in kV</td>
<td>400.00</td>
<td>Set rated OHL phase-to-phase voltage</td>
</tr>
<tr>
<td>IBase (set in Global base)</td>
<td>Base setting for current level in A</td>
<td>1000</td>
<td>Set rated primary CT current used for OHL</td>
</tr>
<tr>
<td>SBase (set in Global base)</td>
<td>Base Setting for power base in MVA</td>
<td>1000</td>
<td>Set based on rated Power</td>
</tr>
<tr>
<td>PMin</td>
<td>Minimum value</td>
<td>-100</td>
<td>Minimum expected load</td>
</tr>
<tr>
<td>PMax</td>
<td>Minimum value</td>
<td>100</td>
<td>Maximum expected load</td>
</tr>
<tr>
<td>PZeroDb</td>
<td>Zero point clamping in 0.001% of range</td>
<td>3000</td>
<td>Set zero point clamping to 60 MW that is, 3% of 200 MW</td>
</tr>
<tr>
<td>PrepTyp</td>
<td>Reporting type</td>
<td>db</td>
<td>Select magnitude deadband supervision</td>
</tr>
<tr>
<td>PDbRepInt</td>
<td>Cycl: Report interval (s), Db: In 0.001% of range, Int Db: In 0.001%</td>
<td>2000</td>
<td>Set ±Δdb=40 MW that is, 2% (larger changes than 40 MW will be reported)</td>
</tr>
<tr>
<td>PHIHiLim</td>
<td>High High limit (physical value), % of SBase</td>
<td>60</td>
<td>High alarm limit that is, extreme overload alarm, hence it will be 415 MW.</td>
</tr>
<tr>
<td>PHILim</td>
<td>High limit (physical value), in % of SBase</td>
<td>50</td>
<td>High warning limit that is, overload warning, hence it will be 371 MW.</td>
</tr>
<tr>
<td>PLowLim</td>
<td>Low limit (physical value), in % of SBase</td>
<td>-50</td>
<td>Low warning limit -500 MW</td>
</tr>
<tr>
<td>PLowLowLim</td>
<td>Low Low limit (physical value), in % of SBase</td>
<td>-60</td>
<td>Low alarm limit -600 MW</td>
</tr>
<tr>
<td>PLimHyst</td>
<td>Hysteresis value in % of range (common for all limits)</td>
<td>1</td>
<td>Set ±Δ Hysteresis 20 MW that is, 1% of range (2000 MW)</td>
</tr>
</tbody>
</table>

### Table 68: Settings for calibration parameters

<table>
<thead>
<tr>
<th>Setting</th>
<th>Short Description</th>
<th>Selected value</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>IMagComp5</td>
<td>Magnitude factor to calibrate current at 5% of In</td>
<td>0.00</td>
<td></td>
</tr>
<tr>
<td>IMagComp30</td>
<td>Magnitude factor to calibrate current at 30% of In</td>
<td>0.00</td>
<td></td>
</tr>
<tr>
<td>IMagComp100</td>
<td>Magnitude factor to calibrate current at 100% of In</td>
<td>0.00</td>
<td></td>
</tr>
<tr>
<td>VAmpComp5</td>
<td>Magnitude factor to calibrate voltage at 5% of Vn</td>
<td>0.00</td>
<td></td>
</tr>
<tr>
<td>VMagComp30</td>
<td>Magnitude factor to calibrate voltage at 30% of Vn</td>
<td>0.00</td>
<td></td>
</tr>
<tr>
<td>VMagComp100</td>
<td>Magnitude factor to calibrate voltage at 100% of Vn</td>
<td>0.00</td>
<td></td>
</tr>
</tbody>
</table>

Table continues on next page
Measurement function application for a power transformer

Single line diagram for this application is given in figure 311.

Figure 311: Single line diagram for transformer application

In order to measure the active and reactive power as indicated in figure 311, it is necessary to do the following:

1. Set correctly all CT and VT and phase angle reference channel PhaseAngleRef data using PCM600 for analog input channels
2. Connect, in PCM600, measurement function to LV side CT & VT inputs
3. Set the setting parameters for relevant Measurement function as shown in the following table:

<table>
<thead>
<tr>
<th>Setting</th>
<th>Short Description</th>
<th>Selected value</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>IAngComp5</td>
<td>Angle calibration for current at 5% of In</td>
<td>0.00</td>
<td></td>
</tr>
<tr>
<td>IAngComp30</td>
<td>Angle pre-calibration for current at 30% of In</td>
<td>0.00</td>
<td></td>
</tr>
<tr>
<td>IAngComp100</td>
<td>Angle pre-calibration for current at 100% of In</td>
<td>0.00</td>
<td></td>
</tr>
</tbody>
</table>
**Table 69: General settings parameters for the Measurement function**

<table>
<thead>
<tr>
<th>Setting</th>
<th>Short description</th>
<th>Selected value</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operation</td>
<td>Operation Disabled/Enabled</td>
<td>Enabled</td>
<td>Function must be Enabled</td>
</tr>
<tr>
<td>PowAmpFact</td>
<td>Magnitude factor to scale power calculations</td>
<td>1.000</td>
<td>Typically no scaling is required</td>
</tr>
<tr>
<td>PowAngComp</td>
<td>Angle compensation for phase shift between measured I &amp; V</td>
<td>180.0</td>
<td>Typically no angle compensation is required. However here the required direction of P &amp; Q measurement is towards busbar (Not per IED internal default direction). Therefore angle compensation have to be used in order to get measurements in alinment with the required direction.</td>
</tr>
<tr>
<td>Mode</td>
<td>Selection of measured current and voltage</td>
<td>L1L2</td>
<td>Only UL1L2 phase-to-phase voltage is available</td>
</tr>
<tr>
<td>k</td>
<td>Low pass filter coefficient for power measurement, V and I</td>
<td>0.00</td>
<td>Typically no additional filtering is required</td>
</tr>
<tr>
<td>VGenZeroDb</td>
<td>Zero point clamping in % of Vbase</td>
<td>25</td>
<td>Set minimum voltage level to 25%</td>
</tr>
<tr>
<td>IGenZeroDb</td>
<td>Zero point clamping in % of Ibase</td>
<td>3</td>
<td>Set minimum current level to 3%</td>
</tr>
<tr>
<td>VBase (set in Global base)</td>
<td>Base setting for voltage level in kV</td>
<td>35.00</td>
<td>Set LV side rated phase-to-phase voltage</td>
</tr>
<tr>
<td>IBase (set in Global base)</td>
<td>Base setting for current level in A</td>
<td>495</td>
<td>Set transformer LV winding rated current</td>
</tr>
<tr>
<td>SBase (set in Global base)</td>
<td>Base setting for power in MVA</td>
<td>31.5</td>
<td>Set based on rated power</td>
</tr>
</tbody>
</table>

**Measurement function application for a generator**

Single line diagram for this application is given in figure 312.
In order to measure the active and reactive power as indicated in figure 312, it is necessary to do the following:

1. Set correctly all CT and VT data and phase angle reference channel PhaseAngleRef using PCM600 for analog input channels
2. Connect, in PCM600, measurement function to the generator CT & VT inputs
3. Set the setting parameters for relevant Measurement function as shown in the following table:

Table 70: General settings parameters for the Measurement function

<table>
<thead>
<tr>
<th>Setting</th>
<th>Short description</th>
<th>Selected value</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operation</td>
<td>Operation Off/On</td>
<td>Off</td>
<td>Function must be Off</td>
</tr>
<tr>
<td>PowAmpFact</td>
<td>Amplitude factor to scale power calculations</td>
<td>1.000</td>
<td>Typically no scaling is required</td>
</tr>
<tr>
<td>PowAngComp</td>
<td>Angle compensation for phase shift between measured I &amp; V</td>
<td>0.0</td>
<td>Typically no angle compensation is required. As well here required direction of P &amp; Q measurement is towards protected object (as per IED internal default direction)</td>
</tr>
<tr>
<td>Mode</td>
<td>Selection of measured current and voltage</td>
<td>Arone</td>
<td>Generator VTs are connected between phases (V-connected)</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Setting</th>
<th>Short description</th>
<th>Selected value</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>k</td>
<td>Low pass filter coefficient for power measurement, V and I</td>
<td>0.00</td>
<td>Typically no additional filtering is required</td>
</tr>
<tr>
<td>VGenZeroDb</td>
<td>Zero point clamping in % of Vbase</td>
<td>25%</td>
<td>Set minimum voltage level to 25%</td>
</tr>
<tr>
<td>IGenZeroDb</td>
<td>Zero point clamping in % of Ibase</td>
<td>3</td>
<td>Set minimum current level to 3%</td>
</tr>
<tr>
<td>VBase (set in Global base)</td>
<td>Base setting for voltage level in kV</td>
<td>15.65</td>
<td>Set generator rated phase-to-phase voltage</td>
</tr>
<tr>
<td>IBase (set in Global base)</td>
<td>Base setting for current level in A</td>
<td>3690</td>
<td>Set generator rated current</td>
</tr>
</tbody>
</table>

### 17.2 Gas medium supervision SSIMG (63)

#### 17.2.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Insulation gas monitoring function</td>
<td>SSIMG</td>
<td>-</td>
<td>63</td>
</tr>
</tbody>
</table>

#### 17.2.2 Application

Gas medium supervision (SSIMG, 63) is used for monitoring the circuit breaker condition. Proper arc extinction by the compressed gas in the circuit breaker is very important. When the pressure becomes too low compared to the required value, the circuit breaker operation shall be blocked to minimize the risk of internal failure. Binary information based on the gas pressure in the circuit breaker is used as an input signal to the function. The function generates alarms based on the received information.

#### 17.2.3 Setting guidelines

The parameters for Gas medium supervision SSIMG can be set via local HMI or Protection and Control Manager PCM600.

**Operation:** This is used to disable/enable the operation of gas medium supervision i.e. Off/On.

**PresAlmLimit:** This is used to set the limit for a pressure alarm condition in the circuit breaker.

**PresLOLimit:** This is used to set the limit for a pressure lockout condition in the circuit breaker.

**TempAlarmLimit:** This is used to set the limit for a temperature alarm condition in the circuit breaker.

**TempLOLimit:** This is used to set the limit for a temperature lockout condition in the circuit breaker.

**tPressureAlarm:** This is used to set the time delay for a pressure alarm indication, given in s.
**17.3 Liquid medium supervision SSIML (71)**

### 17.3.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Insulation liquid monitoring function</td>
<td>SSIML</td>
<td>-</td>
<td>71</td>
</tr>
</tbody>
</table>

### 17.3.2 Application

Liquid medium supervision (SSIML ,71) is used for monitoring the oil insulated device condition. For example, transformers, shunt reactors, and so on. When the level becomes too low compared to the required value, the operation is blocked to minimize the risk of internal failures. Binary information based on the oil level in the oil insulated devices are used as input signals to the function. In addition, the function generates alarms based on the received information.

### 17.3.3 Setting guidelines

The parameters for Liquid medium supervision SSIML can be set via local HMI or Protection and Control Manager PCM600.

*Operation*: This is used to disable/enable the operation of liquid medium supervision i.e. **Off/On**.

*LevelAlmLimit*: This is used to set the limit for a level alarm condition in the oil insulated device.

*LevelLOLimit*: This is used to set the limit for a level lockout condition in the oil insulated device.

*TempAlarmLimit*: This is used to set the limit for a temperature alarm condition in the oil insulated device.

*TempLOLimit*: This is used to set the limit for a temperature lockout condition in the oil insulated device.

*tLevelAlarm*: This is used to set the time delay for a level alarm indication, given in s.
**tLevelLockOut**: This is used to set the time delay for a level lockout indication, given in s.

**tTempAlarm**: This is used to set the time delay for a temperature alarm indication, given in s.

**tTempLockOut**: This is used to set the time delay for a temperature lockout indication, given in s.

**tResetLevelAlm**: This is used for the level alarm indication to reset after a set time delay in s.

**tResetLevelLO**: This is used for the level lockout indication to reset after a set time delay in s.

**tResetTempLO**: This is used for the temperature lockout indication to reset after a set time delay in s.

**tResetTempAlm**: This is used for the temperature alarm indication to reset after a set time delay in s.

### 17.4 Breaker monitoring SSCBR

#### 17.4.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Breaker monitoring</td>
<td>SSCBR</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

#### 17.4.2 Application

The circuit breaker maintenance is usually based on regular time intervals or the number of operations performed. This has some disadvantages because there could be a number of abnormal operations or few operations with high-level currents within the predetermined maintenance interval. Hence, condition-based maintenance scheduling is an optimum solution in assessing the condition of circuit breakers.

**Circuit breaker contact travel time**

Auxiliary contacts provide information about the mechanical operation, opening time and closing time of a breaker. Detecting an excessive traveling time is essential to indicate the need for maintenance of the circuit breaker mechanism. The excessive travel time can be due to problems in the driving mechanism or failures of the contacts.

**Circuit breaker status**

Monitoring the breaker status ensures proper functioning of the features within the protection relay such as breaker control, breaker failure and autoreclosing. The breaker status is monitored using breaker auxiliary contacts. The breaker status is indicated by the binary outputs. These signals indicate whether the circuit breaker is in an open, closed or error state.

**Remaining life of circuit breaker**

Every time the breaker operates, the circuit breaker life reduces due to wear. The wear in a breaker depends on the interrupted current. For breaker maintenance or replacement at the right time, the remaining life of the breaker must be estimated. The remaining life of a breaker can be estimated using the maintenance curve provided by the circuit breaker manufacturer.
Circuit breaker manufacturers provide the number of make-break operations possible at various interrupted currents. An example is shown in figure 313.

**Figure 313: An example for estimating the remaining life of a circuit breaker**

**Calculation for estimating the remaining life**

The graph shows that there are 10000 possible operations at the rated operating current and 900 operations at 10 kA and 50 operations at rated fault current. Therefore, if the interrupted current is 10 kA, one operation is equivalent to 10000/900 = 11 operations at the rated current. It is assumed that prior to tripping, the remaining life of a breaker is 10000 operations. Remaining life calculation for three different interrupted current conditions is explained below.

- Breaker interrupts at and below the rated operating current, that is, 2 kA, the remaining life of the CB is decreased by 1 operation and therefore, 9999 operations remaining at the rated operating current.
- Breaker interrupts between rated operating current and rated fault current, that is, 10 kA, one operation at 10kA is equivalent to 10000/900 = 11 operations at the rated current. The remaining life of the CB would be (10000 − 10) = 9989 at the rated operating current after one operation at 10 kA.
- Breaker interrupts at and above rated fault current, that is, 50 kA, one operation at 50 kA is equivalent to 10000/50 = 200 operations at the rated operating current. The remaining life of
the CB would become \((10000 - 200) = 9800\) operations at the rated operating current after one operation at 50 kA.

**Accumulated energy**

Monitoring the contact erosion and interrupter wear has a direct influence on the required maintenance frequency. Therefore, it is necessary to accurately estimate the erosion of the contacts and condition of interrupters using cumulative summation of \(I^y\). The factor “\(y\)” depends on the type of circuit breaker. The energy values were accumulated using the current value and exponent factor for CB contact opening duration. When the next CB opening operation is started, the energy is accumulated from the previous value. The accumulated energy value can be reset to initial accumulation energy value by using the Reset accumulating energy input, \(RSTIPOW\).

**Circuit breaker operation cycles**

Routine breaker maintenance like lubricating breaker mechanism is based on the number of operations. A suitable threshold setting helps in preventive maintenance. This can also be used to indicate the requirement for oil sampling for dielectric testing in case of an oil circuit breaker.

**Circuit breaker operation monitoring**

By monitoring the activity of the number of operations, it is possible to calculate the number of days the breaker has been inactive. Long periods of inactivity degrade the reliability for the protection system.

**Circuit breaker spring charge monitoring**

For normal circuit breaker operation, the circuit breaker spring should be charged within a specified time. Detecting a long spring charging time indicates the time for circuit breaker maintenance. The last value of the spring charging time can be given as a service value.

**Circuit breaker gas pressure indication**

For proper arc extinction by the compressed gas in the circuit breaker, the pressure of the gas must be adequate. Binary input available from the pressure sensor is based on the pressure levels inside the arc chamber. When the pressure becomes too low compared to the required value, the circuit breaker operation is blocked.

**17.4.3 Setting guidelines**

The breaker monitoring function is used to monitor different parameters of the circuit breaker. The breaker requires maintenance when the number of operations has reached a predefined value. For proper functioning of the circuit breaker, it is also essential to monitor the circuit breaker operation, spring charge indication or breaker wear, travel time, number of operation cycles and accumulated energy during arc extinction.
Since there is no current measurement in SAM600-IO, evaluation of the following parameters are not possible in the circuit breaker condition monitoring function (SSCBR):

- Circuit breaker status
- Remaining life of the circuit breaker
- Contact erosion estimation
- Circuit breaker contact travel time

Ensure that OPENPOS, CLOSEPOS, INVDPOS, CBLIFEAL, IPOWALPH, IPOWLOPH, TRVTOPAL and TRVTCLAL signals are not used in SAM600–IO.

17.4.3.1 Setting procedure on the IED

The parameters for breaker monitoring (SSCBR) can be set via the local HMI or Protection and Control Manager (PCM600).

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

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

**Operation:** Enabled or Disabled.

\(I_{Base}\): Base phase current in primary A. This current is used as reference for current settings.

**OpenTimeCorr:** Correction factor for circuit breaker opening travel time.

**CloseTimeCorr:** Correction factor for circuit breaker closing travel time.

\(tTrOpenAlm\): Setting of alarm level for opening travel time.

\(tTrCloseAlm\): Setting of alarm level for closing travel time.

**OperAlmLevel:** Alarm limit for number of mechanical operations.

**OperLOLevel:** Lockout limit for number of mechanical operations.

**CurrExponent:** Current exponent setting for energy calculation. It varies for different types of circuit breakers. This factor ranges from 0.5 to 3.0.

**AccStopCurr:** RMS current setting below which calculation of energy accumulation stops. It is given as a percentage of \(I_{Base}\).

**ContTrCorr:** Correction factor for time difference in auxiliary and main contacts' opening time.

**AlmAccCurrPwr:** Setting of alarm level for accumulated energy.

**LOAccCurrPwr:** Lockout limit setting for accumulated energy.

**SpChAlmTime:** Time delay for spring charging time alarm.

**tDGasPresAlm:** Time delay for gas pressure alarm.

**tDGasPresLO:** Time delay for gas pressure lockout.
DirCoef: Directional coefficient for circuit breaker life calculation.

RatedOperCurr: Rated operating current of the circuit breaker.

RatedFltCurr: Rated fault current of the circuit breaker.

OperNoRated: Number of operations possible at rated current.

OperNoFault: Number of operations possible at rated fault current.

CBLifeAlmLevel: Alarm level for circuit breaker remaining life.

AccSelCal: Selection between the method of calculation of accumulated energy.

OperTimeDelay: Time delay between change of status of trip output and start of main contact separation.

17.5 Event function EVENT

17.5.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Event function</td>
<td>EVENT</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

17.5.2 Application

When using a Substation Automation system with LON or SPA communication, time-tagged events can be sent at change or cyclically from the IED to the station level. These events are created from any available signal in the IED that is connected to the Event function (EVENT). The EVENT function block is used for remote communication.

Analog, integer and double indication values are also transferred through the EVENT function.

17.5.3 Setting guidelines

The input parameters for the Event function (EVENT) can be set individually via the local HMI (Main Menu/Settings / IED Settings / Monitoring / Event Function) or via the Parameter Setting Tool (PST).

EventMask (Ch_1 - 16)
The inputs can be set individually as:
- \textit{NoEvents}
- \textit{OnSet}, at pick-up of the signal
- \textit{OnReset}, at drop-out of the signal
- \textit{OnChange}, at both pick-up and drop-out of the signal
- \textit{AutoDetect}, the EVENT function makes the reporting decision (reporting criteria for integers have no semantic, prefer to be set by the user)

\textbf{LONChannelMask or SPAChannelMask}

Definition of which part of the event function block that shall generate events:

- \textit{Disabled}
- \textit{Channel 1-8}
- \textit{Channel 9-16}
- \textit{Channel 1-16}

\textit{MinRepIntVal (1 - 16)}

A time interval between cyclic events can be set individually for each input channel. This can be set between 0 s to 3600 s in steps of 1 s. It should normally be set to 0, that is, no cyclic communication.

\begin{itemize}
  \item It is important to set the time interval for cyclic events in an optimized way to minimize the load on the station bus.
\end{itemize}

\textbf{17.6 Disturbance report DRPRDRE}

\subsection{17.6.1 Identification}

\begin{table}
\begin{tabular}{|c|c|c|c|}
\hline
Function description & IEC 61850 identification & IEC 60617 identification & ANSI/IEEE C37.2 device number \\
\hline
Disturbance report & DRPRDRE & - & - \\
Disturbance report & A1RADR - A4RADR & - & - \\
Disturbance report & B1RBDR - B22RBDR & - & - \\
\hline
\end{tabular}
\end{table}

\subsection{17.6.2 Application}

To get fast, complete and reliable information about disturbances in the primary and/or in the secondary system it is very important to gather information on fault currents, voltages and events. It is also important having a continuous event-logging to be able to monitor in an overview perspective. These tasks are accomplished by the disturbance report function DRPRDRE and facilitate a better understanding of the power system behavior and related primary and secondary equipment during and after a disturbance. An analysis of the recorded data provides valuable information that can be used to explain a disturbance, basis for change of IED setting plan, improve existing equipment, and so on. This information can also be used in a longer perspective
when planning for and designing new installations, that is, a disturbance recording could be a part of Functional Analysis (FA).

Disturbance report DRPRDRE, always included in the IED, acquires sampled data of all selected analog and binary signals connected to the function blocks that is,

- Maximum 30 external analog signals,
- 10 internal derived analog signals, and
- 352 binary signals

Disturbance report function is a common name for several functions; Indications (IND), Event recorder (ER), Sequential of events (SOE), Trip value recorder (TVR), Disturbance recorder (DR).

Disturbance report function is characterized by great flexibility as far as configuration, starting conditions, recording times, and storage capacity are concerned. Thus, disturbance report is not dependent on the operation of protective functions, and it can record disturbances that were not discovered by protective functions for one reason or another. Disturbance report can be used as an advanced stand-alone disturbance recorder.

Every disturbance report recording is saved in the IED. The same applies to all events, which are continuously saved in a ring-buffer. Local HMI can be used to get information about the recordings, and the disturbance report files may be uploaded in the PCM600 using the Disturbance handling tool, for report reading or further analysis (using WaveWin, that can be found on the PCM600 installation CD). The user can also upload disturbance report files using FTP or MMS (over 61850–8–1) clients.

If the IED is connected to a station bus (IEC 61850-8-1), the disturbance recorder (record made and fault number) and the fault locator information are available. The same information is obtainable if IEC 60870-5-103 is used.

### 17.6.3 Setting guidelines

The setting parameters for the Disturbance report function DRPRDRE are set via the local HMI or PCM600.

It is possible to handle up to 40 analog and 352 binary signals, either internal signals or signals coming from external inputs. The binary signals are identical in all functions that is, Disturbance recorder (DR), Event recorder (ER), Indication (IND), Trip value recorder (TVR) and Sequential of events (SOE) function.

User-defined names of binary and analog input signals are set using PCM600. The analog and binary signals appear with their user-defined names. The name is used in all related functions (Disturbance recorder (DR), Event recorder (ER), Indication (IND), Trip value recorder (TVR) and Sequential of events (SOE)).

Figure 314 shows the relations between Disturbance report, included functions and function blocks. Sequential of events (SOE), Event recorder (ER) and Indication (IND) uses information from the binary input function blocks (BxRBDR). Trip value recorder (TVR) uses analog information from the analog input function blocks (AxRADR). Disturbance report function acquires information from both AxRADR and BxRBDR.
Figure 314: Disturbance report functions and related function blocks

For Disturbance report function there are a number of settings which also influences the sub-functions.

Three LED indications placed above the LCD screen makes it possible to get quick status information about the IED.

Green LED:
- Steady light: In Service
- Flashing light: Internal failure
- Dark: No power supply

Yellow LED:
- Steady light: Triggered on binary signal N with SetLEDx = Start (or Start and Trip)
- Flashing light: The IED is in test mode

Red LED:
- Steady light: Triggered on binary signal N with SetLEDx = Trip (or Start and Trip)
- Flashing: The IED is in configuration mode
**Operation**
The operation of Disturbance report function DRPRDRE has to be set *Enabled* or *Disabled*. If *Disabled* is selected, note that no disturbance report is registered, and none sub-function will operate (the only general parameter that influences Sequential of events (SOE)).

*Operation = Disabled:*
- Disturbance reports are not stored.
- LED information (yellow - pickup, red - trip) is not stored or changed.

*Operation = Enabled:*
- Disturbance reports are stored, disturbance data can be read from the local HMI and from a PC for example using PCM600.
- LED information (yellow - pickup, red - trip) is stored.

Every recording will get a number (0 to 999) which is used as identifier (local HMI, disturbance handling tool and IEC 61850). An alternative recording identification is date, time and sequence number. The sequence number is automatically increased by one for each new recording and is reset to zero at midnight. The maximum number of recordings stored in the IED is 100. The oldest recording will be overwritten when a new recording arrives (FIFO).

To be able to delete disturbance records, *Operation* parameter has to be *Enabled*.

The maximum number of recordings depend on each recordings total recording time. Long recording time will reduce the number of recordings to less than 100.

The IED flash disk should NOT be used to store any user files. This might cause disturbance recordings to be deleted due to lack of disk space.

**17.6.3.1 Recording times**

Prefault recording time (*PreFaultRecT*) is the recording time before the starting point of the disturbance. The setting should be at least 0.1 s to ensure enough samples for the estimation of pre-fault values in the Trip value recorder (TVR) function.

Postfault recording time (*PostFaultRecT*) is the maximum recording time after the disappearance of the trig-signal (does not influence the Trip value recorder (TVR) function).

Recording time limit (*TimeLimit*) is the maximum recording time after trig. The parameter limits the recording time if some trigging condition (fault-time) is very long or permanently set (does not influence the Trip value recorder (TVR) function).

**Operation in test mode**
If the IED is in test mode and *OpModeTest = Disabled*. Disturbance report function does not save any recordings and no LED information is displayed.
If the IED is in test mode and $\text{OpModeTest} = \text{Enabled}$, Disturbance report function works in normal mode and the status is indicated in the saved recording.

**Post Retrigger**
Disturbance report function does not automatically respond to any new trig condition during a recording, after all signals set as trigger signals have been reset. However, under certain circumstances the fault condition may reoccur during the post-fault recording, for instance by automatic reclosing to a still faulty power line.

In order to capture the new disturbance it is possible to allow retriggering ($\text{PostRetrig} = \text{Enabled}$) during the post-fault time. In this case a new, complete recording will pickup and, during a period, run in parallel with the initial recording.

When the retrig parameter is disabled ($\text{PostRetrig} = \text{Disabled}$), a new recording will not pickup until the post-fault ($\text{PostFaultrecT}$ or $\text{TimeLimit}$) period is terminated. If a new trig occurs during the post-fault period and lasts longer than the proceeding recording a new complete recording will be started.

Disturbance report function can handle a maximum of 3 simultaneous disturbance recordings.

### 17.6.3.2 Binary input signals

Up to 352 binary signals can be selected among internal logical and binary input signals. The configuration tool is used to configure the signals.

For each of the 352 signals, it is also possible to select if the signal is to be used as a trigger for the start of the Disturbance report and if the trigger should be activated on positive (1) or negative (0) slope.

$\text{TrigDRN}$: Disturbance report may trig for binary input N ($\text{Enabled}$) or not ($\text{Disabled}$).

$\text{TrigLevelN}$: Trig on positive ($\text{Trig on 1}$) or negative ($\text{Trig on 0}$) slope for binary input N.

$\text{Func103N}$: Function type number (0-255) for binary input N according to IEC-60870-5-103, that is, 128: Distance protection, 160: overcurrent protection, 176: transformer differential protection and 192: line differential protection.

$\text{Info103N}$: Information number (0-255) for binary input N according to IEC-60870-5-103, that is, 69-71: Trip L1-L3, 78-83: Zone 1-6.

See also description in the chapter IEC 60870-5-103.

### 17.6.3.3 Analog input signals

Up to 40 analog signals can be selected among internal analog and analog input signals. PCM600 is used to configure the signals.

For retrieving remote data from LDCM module, the Disturbance report function should be connected to a 8 ms SMAI function block if this is the only intended use for the remote data.

The analog trigger of Disturbance report is not affected if analog input M is to be included in the disturbance recording or not ($\text{OperationM} = \text{Enabled}/\text{Disabled}$).
If \( \text{OperationM} = \text{Disabled} \), no waveform (samples) will be recorded and reported in graph. However, Trip value, pre-fault and fault value will be recorded and reported. The input channel can still be used to trig the disturbance recorder.

If \( \text{OperationM} = \text{Enabled} \), waveform (samples) will also be recorded and reported in graph.

\( \text{NomValueM} \): Nominal value for input M.

\( \text{OverTrigOpM}, \text{UnderTrigOpM} \): Over or Under trig operation, Disturbance report may trig for high/low level of analog input M (\text{Enabled}) or not (\text{Disabled}).

\( \text{OverTrigLeM}, \text{UnderTrigLeM} \): Over or under trig level, Trig high/low level relative nominal value for analog input M in percent of nominal value.

### 17.6.3.4 Sub-function parameters

All functions are in operation as long as Disturbance report is in operation.

**Indications**

\( \text{IndicationMaN} \): Indication mask for binary input N. If set (Show), a status change of that particular input, will be fetched and shown in the disturbance summary on local HMI. If not set (Hide), status change will not be indicated.

\( \text{SetLEDN} \): Set red LED on local HMI in front of the IED if binary input N changes status.

**Disturbance recorder**

\( \text{OperationM} \): Analog channel M is to be recorded by the disturbance recorder (\text{Enabled}) or not (\text{Disabled}).

If \( \text{OperationM} = \text{Disabled} \), no waveform (samples) will be recorded and reported in graph. However, Trip value, pre-fault and fault value will be recorded and reported. The input channel can still be used to trig the disturbance recorder.

If \( \text{OperationM} = \text{Enabled} \), waveform (samples) will also be recorded and reported in graph.

**Setting information**

\( \text{SetInfoInDrep} \): Parameter used to enable or disable the settings information in disturbance header.

**Event recorder**

Event recorder (ER) function has no dedicated parameters.

**Trip value recorder**

\( \text{ZeroAngleRef} \): The parameter defines which analog signal that will be used as phase angle reference for all other analog input signals. This signal will also be used for frequency measurement and the measured frequency is used when calculating trip values. It is suggested to point out a sampled voltage input signal, for example, a line or busbar phase voltage (channel 1-30).

**Sequential of events**

function has no dedicated parameters.
17.6.3.5 Consideration

The density of recording equipment in power systems is increasing, since the number of modern IEDs, where recorders are included, is increasing. This leads to a vast number of recordings at every single disturbance and a lot of information has to be handled if the recording functions do not have proper settings. The goal is to optimize the settings in each IED to be able to capture just valuable disturbances and to maximize the number that is possible to save in the IED.

The recording time should not be longer than necessary (*PostFaultrecT* and *TimeLimit*).

- Should the function record faults only for the protected object or cover more?
- How long is the longest expected fault clearing time?
- Is it necessary to include reclosure in the recording or should a persistent fault generate a second recording (*PostRetrig*)?

Minimize the number of recordings:

- Binary signals: Use only relevant signals to start the recording that is, protection trip, carrier receive and/or pickup signals.
- Analog signals: The level triggering should be used with great care, since unfortunate settings will cause enormously number of recordings. If nevertheless analog input triggering is used, chose settings by a sufficient margin from normal operation values. Phase voltages are not recommended for triggering.

![Warning](image)

There is a risk of flash wear out if the disturbance report triggers too often.

Remember that values of parameters set elsewhere are linked to the information on a report. Such parameters are, for example, station and object identifiers, CT and VT ratios.

17.7 Logical signal status report BINSTATREP

17.7.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Logical signal status report</td>
<td>BINSTATREP</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

17.7.2 Application

The Logical signal status report (BINSTATREP) function makes it possible to poll signals from various other function blocks.

BINSTATREP has 16 inputs and 16 outputs. The output status follows the inputs and can be read from the local HMI or via SPA communication.
When an input is set, the respective output is set for a user defined time. If the input signal remains set for a longer period, the output will remain set until the input signal resets.

![BINSTATREP logical diagram](IEC09000732-1-en.vsd)

**Figure 315: BINSTATREP logical diagram**

### 17.7.3 Setting guidelines

The pulse time $t$ is the only setting for the Logical signal status report (BINSTATREP). Each output can be set or reset individually, but the pulse time will be the same for all outputs in the entire BINSTATREP function.

### 17.8 Limit counter L4UFCNT

#### 17.8.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Limit counter</td>
<td>L4UFCNT</td>
<td></td>
<td>-</td>
</tr>
</tbody>
</table>

#### 17.8.2 Application

Limit counter (L4UFCNT) is intended for applications where positive and/or negative sides on a binary signal need to be counted.

The limit counter provides four independent limits to be checked against the accumulated counted value. The four limit reach indication outputs can be utilized to initiate proceeding actions. The output indicators remain high until the reset of the function.

It is also possible to initiate the counter from a non-zero value by resetting the function to the wanted initial value provided as a setting.

If applicable, the counter can be set to stop or rollover to zero and continue counting after reaching the maximum count value. The steady overflow output flag indicates the next count after reaching the maximum count value. It is also possible to set the counter to rollover and indicate the overflow as a pulse, which lasts up to the first count after rolling over to zero. In this case, periodic pulses will be generated at multiple overflow of the function.
17.8.3 Setting guidelines

The parameters for Limit counter L4UFCNT are set via the local HMI or PCM600.

17.9 Running hour-meter TEILGAPC

17.9.1 Identification

<table>
<thead>
<tr>
<th>Function Description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Running hour-meter</td>
<td>TEILGAPC</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

17.9.2 Application

The function is used for user-defined logics and it can also be used for different purposes internally in the IED. An application example is to accumulate the total running/energized time of the generator, transformer, reactor, capacitor bank or even line.

Settable time limits for warning and alarm are provided. The time limit for overflow indication is fixed to 99999.9 hours. At overflow the accumulated time resets and the accumulation starts from zero again.

17.9.3 Setting guidelines

The settings $t_{\text{Alarm}}$ and $t_{\text{Warning}}$ are user settable limits defined in hours. The achievable resolution of the settings is 0.1 hours (6 minutes).

$t_{\text{Alarm}}$ and $t_{\text{Warning}}$ are independent settings, that is, there is no check if $t_{\text{Alarm}} > t_{\text{Warning}}$.

The limit for the overflow supervision is fixed at 99999.9 hours.

The setting $t_{\text{AddToTime}}$ is a user settable time parameter in hours.

17.10 Estimation of transformer insulation life LOLSPTR (26/49HS)

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Estimation of transformer winding insulation life</td>
<td>LOLSPTR</td>
<td>3Ihp$&gt;T$</td>
<td>26/49HS</td>
</tr>
</tbody>
</table>
17.10.1 Application

A typical power transformer is composed of:

- Laminated steel core with copper or aluminium windings
- Solid refined paper insulation
- Highly refined mineral oil as insulating and cooling medium for the entire transformer

The oil is cooled by a separate cooling system using air or water. The core, windings and insulation have specific thermal capabilities.

Losses in the winding and core can cause temperature rises in the transformer, which is transferred to the insulating oil. Failure to limit these temperature rises to the thermal capability of the insulation and core materials can cause premature failure of the transformer.

A transformer is rated at the power output. It can continuously deliver at rated voltage and frequency without exceeding the specified temperature limit. This temperature rise is based on thermal limitations of the core, winding and insulation. Therefore, transformer MVA rating is based on maximum allowable temperature of the insulation. Design standards express temperature limits for transformers exceeds ambient temperature. Use of ambient temperature as a base ensures that a transformer has adequate thermal capacity and independent of daily environmental conditions.

Transformers in the power system are designed to withstand certain overload conditions. The permissible transformer load level is highly depends on the transformer cooling system. Both IEEE and IEC standards have established transformer thermal model for all cooling system types and described formulae for transformer temperature calculation.

Table 71: Different cooling systems used in transformers

<table>
<thead>
<tr>
<th>Cooling system</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>OF (non-directed oil flow)</td>
<td>Pumped oil from the radiators or heat exchangers flows freely inside the tank and not forced to flow through the windings.</td>
</tr>
<tr>
<td>ON (non-directed oil flow)</td>
<td>Oil from the radiators or heat exchangers flows freely inside the tank and not forced to flow through the windings.</td>
</tr>
<tr>
<td>OD (non-directed oil flow)</td>
<td>Part of pumped oil from the radiators or heat exchangers is forced to flow through the windings.</td>
</tr>
</tbody>
</table>

In addition to types of cooling system used, size of the transformer also determines transformer loading beyond the nameplate rating. Leakage flux density, short circuit force and high electric stress on the insulation increases once size of the transformer increases. Hence, determination of hot spot temperature becomes more complex. Therefore, large transformers are more vulnerable than the smaller ones. Consequences of transformer failures are more severe for larger sizes than for smaller ones.

As per IEC 60076 guidelines, reasonable risk degree for the expected duties are categorized into three types:
- **Distribution transformers**: Only hot spot temperature in the windings and thermal deterioration are considered.
- **Medium power transformers**: Hot spot temperature in the windings, thermal deterioration and variations in the cooling modes are considered.
- **Large power transformer**: Hot spot temperature in the windings, thermal deterioration, variations in the cooling modes and effects of stray leakage flux are considered.

Conductors on top of the winding experience the maximum leakage field and the highest transformer oil temperature. It would be natural to consider that conductors at the top have the hottest spot. However, measurements have shown that the hottest spot might be moved to conductors in the lower part of the winding. Therefore, direct hot spot temperature measurement is difficult. Hence, it should be calculated using the empirical formulae given by relevant standards. The hot spot temperature shall be monitored continuously so that it will not exceed the transformer oil flashover value.

Figure 316 shows the complex transformer temperature distribution. The assumptions made are:

- Oil temperature increases linearly from bottom to top irrespective of the cooling system.
- Winding temperature rise is parallel to the oil temperature rise with constant difference ‘g’ (average winding to average oil temperature gradient).
- The hot spot temperature rise is higher than the top winding temperature rise with the factor called Hot Spot Factor (H).

![Figure 316: Thermal diagram](IEC15000440-1-en.vsdx)

Winding hot spot temperature depends on the oil temperature inside the winding, load losses in the winding, cooling type and ambient temperature. For most transformers in service, oil temperature inside a winding is difficult to measure. On the other hand, top oil temperature at the top of the tank is well known, either by measurement or calculation.
In addition to loading of the transformer, oil temperature rise depends also on reduced oil flow inside the winding and malfunctioning/failure of the cooling system (water or air circulation). Therefore, hot spot temperature can be measured by sensing top oil temperature without separately considering the effects of oil flow blockage and malfunction of cooler groups.

Normal life expected of the transformer is a conventional reference based on the designed operating condition and ambient temperature. If the transformer load exceeds its rated condition, ageing will accelerate. Consequences of excessive transformer loading leads to unacceptable temperature rise in windings, leads, insulation and oil. When temperature changes, moisture and gas content in the insulation and oil will change.

IEEE C57.91-1995 standard has developed four different loading conditions beyond nameplate to explain the risk involved in the higher operating temperatures, see Figure 317. The four types of loading are:

- Normal life expectancy
  - Normal life expectancy loading: The transformer loading is continuous at rated output when operated under usual conditions.

- Sacrifice of life expectancy
  - Planned loading beyond nameplate: Restricted to transformers that do not carry a continuous steady load and it is a normal, planned repetitive load.
  - Long time emergency loading: Loading results from the prolonged outage of some system element. This is not a normal operating condition, but may persist for some time.
  - Short time emergency loading: Unusually heavy loading for short time due to occurrence of one or more unwanted events that disturb the normal system loading seriously.
Figure 317: Typical load cycles for example

Impact of the increased currents and temperature leads to premature transformer failure and this may have an immediate short term effect or a cumulative long term effect.

- **Short-term effect**: Reduction in dielectric strength due to the possible presence of gas bubbles which leads to super saturation of the oil and reduction in short circuit strength.
- **Long-term effect**: Continuous deterioration of the conductor reduces the transformer life.

Deterioration of insulation reduces mechanical strength and dielectric strength. Heating from heavy overload or large electromagnetic force resulting from short circuit causes expansion and unusual movement of conductors and it leads to turn-to-turn fault.

Insulation aging or deterioration is a time function of temperature, moisture content, and oxygen content. With modern oil preservation systems, the moisture and oxygen contributions to insulation deterioration can be minimized, leaving insulation temperature as the controlling parameter.

Temperature distribution is not uniform in transformers, the part that is operating at the highest temperature normally undergoes the greatest deterioration. Therefore, in aging studies it is usual to consider the aging effects produced by the highest (hottest-spot) temperature. Since many factors influences the cumulative effect of temperature over time which causes transformer
insulation deterioration, it is difficult to predict the useful life of the insulation in a transformer with great degree of accuracy. However, this function will help in reducing the accelerated aging of power transformers during overload conditions and thus maximize the transformer operating life.

17.10.2 Setting guidelines

The parameters for the estimation of transformer insulation life function LOLSPTR (26/49HS) are set via the local HMI or PCM600.

Minimum information about the transformer parameters which are required to decide the transformer insulation life are:

1. Top oil temperature rise over ambient temperature at rated load
2. Average conductor temperature rise over ambient temperature at rated load
3. Winding hot spot temperature rise over ambient temperature
4. Load losses at rated load
5. No-Load (core) loss
6. Oil flow design (Directed or non-directed)
7. Weight of core and coil assembly
8. Weight of tank and fittings
9. Weight of oil in the tank and cooling equipment (excluding load tap changer, oil expansion tanks)

For information about 1 to 5, the conditions (load, ambient temperature, tap, etc.) under which the measurements are made should be known. In order to have more precise calculations, load loss at rated and tap extremes or all possible tap connection combinations are required.

Operation: Disabled or Enabled.

TrafoRating: Rated transformer power in MVA.

TrafoType: This setting is used to set the number of phases in the transformer. The options are:

- Three Phase Trafo: The function considers the given transformer as three phase transformer.
- Single Phase Trafo: The function considers the given transformer as single phase transformer.

Based on the settings TrafoRating and TrafoType, transformer parameters are selected for temperature calculations. Both IEEE and IEC standards defines the transformer parameters based on three categories of transformer rating.

In the case of three phase transformers:

- If the transformer rating is less than 2.5 MVA, the function considers this as a distribution transformer.
- If the transformer rating is less than 100 MVA, it is considered as a medium power transformer.
- If the transformer rating is above 100 MVA, it is considered as a larger power transformer.

In the case of single phase transformers:
• If the transformer rating is less than 0.833 MVA, the function considers this as a distribution transformer.
• If the transformer rating is less than 33.3 MVA, it is considered as a medium power transformer.
• If the transformer rating is above 33.3 MVA, it is considered as a larger power transformer.

**NoOfWindings**: This setting is used to set the number of windings in the transformer. The options are:

- **Three winding**: The function considers the given transformer as three winding transformer.
- **Two winding**: The function considers the given transformer as two winding transformer.

Based on the setting **NoOfWindings**, hot spot temperature of the winding 3 is either calculated or assigned as zero.

**ConstSelection**: This setting is used to select the transformer parameters taken either from IEC 60076-7 standard or IEEE C57.96-1995 standard. The options are:

- **IEC**: Transformer parameters like constants, winding and oil exponents will be taken from IEC 60076-7 standard for temperature calculations.
- **IEEE**: Transformer parameters like constants, winding and oil exponents will be taken from IEEE C57.96-1995 standard for temperature calculations.

**CurrSelectMode**: This setting is used to select the current determining method which is used for the load factor calculation. The function takes phase currents of each winding as input. From each winding, only one phase current is considered for load factor calculation. The options are:

- **Average**: The average of all phase currents of winding is considered for calculation.
- **Maximum**: The maximum current out of the all phase currents is considered for calculation.

**TempeUnitMode**: This setting is used to select the temperature unit to be used for the function interface. The options are:

- **°F**: The temperature unit will be selected as °F. Since all calculation formulae needs temperature values in °C, the temperature inputs are converted into °C for calculation. Once the calculations are done, the outputs in °C are converted into °F.
- **°C**: The temperature unit will be selected as °C. All temperature inputs will be taken as they are and the output is given in °C.

LOLSPTR (26/49HS) can work with (n-1) winding CT availability, that is, if the given transformer has three windings and it has CTs only in two windings, then the function will calculate the missing winding current based on voltage transformation ratio. Following settings are required to calculate the winding current with available CT input:

**AvailableCT**: Availability of CT connection can be set by this setting. The options are:

- **Winding 1**: Only winding 1 CT is available. This option can be selected when two winding transformer is considered.
- **Winding 2**: Only winding 2 CT is available. This option can be selected when two winding transformer is considered.
- **Winding 1&2**: Only winding 1 and winding 2 CTs are available. This option can be selected when three winding transformer is considered.
• **Winding 1&3**: Only winding 1 and winding 3 CTs are available. This option can be selected when three winding transformer is considered.
• **Winding 2&3**: Only winding 2 and winding 3 CTs are available. This option can be selected when three winding transformer is considered.
• **All windings**: All windings CTs are available. This option can be selected for both two and three winding transformer.

**RatedVoltW1**: This setting is used to set the rated voltage of winding 1 in kV.

**RatedVoltW2**: This setting is used to set the rated voltage of winding 2 in kV.

**RatedVoltW3**: This setting is used to set the rated voltage of winding 3 in kV.

**UPerTap**: This setting is used to set the voltage increment/decrement between two successive tap positions (ΔV) in kV.

Time required for the top oil temperature in relation to ambient temperature to reach its ultimate value is a function of the thermal oil time constant. The function has the following settings related to oil time constant.

**OilTmConstMode**: This setting is used to select the oil time constant mode of input to the function. It has three options:

• **Standard**: Oil time constant is taken from the IEEE or IEC standard as selected for the temperature calculations.
• **User defined**: Oil time constant is provided by the user through setting. The value may be given by the transformer manufacturer.
• **Calculated**: Oil time constant is calculated by the function based on the transformer parameters given by the user.

**OilTimeConst**: This setting is used to get the oil time constant from the user and this will be used when **OilTmConstMode** setting is selected as **User defined**. Likely it is between 1 and 3 hours.

**AvgOilTmpRise**: The top oil temperature is based on the average temperature rise of the lumped mass. In the case of transformer, this would be the average oil temperature. This setting is used to set the average oil temperature rise above ambient temperature in K (Kelvin). This value should be obtained from the manufacturer based on certified heat run test reports conducted at maximum rating given in the name plate.

**CoilCoreMass**: This setting is used to set the transformer coil and core assembly mass. This mass consists of all winding mass, core mass and paper mass of the transformer.

**OilMass**: This setting is used to set the transformer oil mass. This mass consists of free oil mass and oil insulation mass of the transformer.

**TankMass**: This setting is used to set the transformer tank mass. This mass is only the tank and fittings that are in contact with heated oil.

**LoadLoss**: This setting is used to set the transformer load loss at rated condition.

**TTLTloadLoss**: This setting is used to set the transformer load loss arrived from type test.

**NoloadLoss**: This setting is used to set the transformer no-load loss.

**TTNoloadLoss**: This setting is used to set the transformer no-load loss arrived from type test.
Winding time constant is the time for winding temperature to rise over the oil temperature to reach 63.2% of the difference between the final rise and initial rise during a load change. The winding time constant may be estimated from the resistance cooling curve during thermal tests or calculated by the manufacturer using mass of the conductor material. The function has the following settings related to winding time constant.

**WdgTmConstMode**: This setting is used to select the winding time constant mode of input to the function. It has three options:

- **Standard**: Winding time constant is taken from the IEEE or IEC standard as selected for the temperature calculations.
- **User defined**: Winding time constant is provided by the user through setting. The value may be given by the transformer manufacturer.
- **Calculated**: Winding time constant is calculated by the function based on the transformer parameters given by the user.

**WdgTimeConst1**: This setting is used to get the winding time constant for winding 1. This is used when the WdgTmConstMode setting is selected as User defined.

**WdgTimeConst2**: This setting is used to get the winding time constant for winding 2. This is used when the WdgTmConstMode setting is selected as User defined.

**WdgTimeConst3**: This setting is used to get the winding time constant for winding 3. This is used when the WdgTmConstMode setting is selected as User defined.

The winding time constant is likely to be in the order of 5 to 20 minutes.

**ConductorType**: This setting is used to select the winding material between copper and aluminum. This setting is useful when setting WdgTmConstMode is selected for calculation. This setting has two options:

- **Copper**: Winding material is selected as copper.
- **Aluminum**: Winding material is selected as aluminum.

Winding to oil temperature gradient differs from winding to winding depending on current density in the winding, physical dimensions, cooling system etc., This value can be between 10 to 20 °C for both distribution and power transformers. For low current density winding it can be 10 °C and for high current density winding it can be 20 °C. The settings given below are also used for the calculation of winding time constant.

**WdgToOilGrad1**: Winding to oil temperature gradient for the winding 1 at rated load.

**WdgToOilGrad2**: Winding to oil temperature gradient for the winding 2 at rated load.

**WdgToOilGrad3**: Winding to oil temperature gradient for the winding 3 at rated load.

**CuLossW1**: This setting is used to set the winding loss at rated load for the winding 1.

**CuLossW2**: This setting is used to set the winding loss at rated load for the winding 2.

**CuLossW3**: This setting is used to set the winding loss at rated load for the winding 3.

**MassW1**: This setting is used to set the mass of the winding 1.

**MassW2**: This setting is used to set the mass of the winding 2.
MassW3: This setting is used to set the mass of the winding 3.

Loss ratios at different tap positions are required for the calculation of top oil temperature, especially when the transformer is using online tap changer. This loss ratio is the ratio between load losses to no-load loss. It may vary from 6-7 for distribution transformer and 4-8 for power transformer. Normally it varies from 3 to 11. The function has the following settings related to loss ratio calculation.

RLRated: This setting is used to set the ratio of load losses to no-load loss at principal tapping position.

RLHighRated: This setting is used to set the ratio of load losses to no-load loss at principal tapping +1 position.

RLMaxTap: This setting is used to set the ratio of load losses to no-load loss at maximum tap position where maximum voltage is possible.

RLMinTap: This setting is used to set the ratio of load losses to no-load loss at minimum tap position where minimum voltage is possible.

RatedVoltTap: This setting is used to set the position number of tap changer at rated voltage.

HighVoltTap: This setting is used to set the position number of tap changer at possible maximum voltage.

LowVoltTap: This setting is used to set the position number of tap changer at possible minimum voltage.

The following settings are required to perform the calculation of top oil temperature using monthly model of ambient temperature when AMBVALID is low:

JanAmbTmp: This setting is used to set the January month average ambient temperature.

FebAmbTmp: This setting is used to set the February month average ambient temperature.

MarchAmbTmp: This setting is used to set the March month average ambient temperature.

AprilAmbTmp: This setting is used to set the April month average ambient temperature.

MayAmbTmp: This setting is used to set the May month average ambient temperature.

JuneAmbTmp: This setting is used to set the June month average ambient temperature.

JulyAmbTmp: This setting is used to set the July month average ambient temperature.

AugAmbTmp: This setting is used to set the August month average ambient temperature.

SepAmbTmp: This setting is used to set the September month average ambient temperature.

OctAmbTmp: This setting is used to set the October month average ambient temperature.

NovAmbTmp: This setting is used to set the November month average ambient temperature.

DecAmbTmp: This setting is used to set the December month average ambient temperature.

The hot spot temperature calculation is done by estimating the temperature rise between the hot spot and the top oil. This difference is due to stray losses, local oil flows and additional paper on
conductor. The function has the following settings related to hot spot to top oil temperature gradient calculation.

*HPTmpRiseW1:* This setting is used to set the hot spot temperature rise of winding 1 above ambient temperature in K (Kelvin).

*HPTmpRiseW2:* This setting is used to set the hot spot temperature rise of winding 2 above ambient temperature in K (Kelvin).

*HPTmpRiseW3:* This setting is used to set the hot spot temperature rise of winding 3 above ambient temperature in K (Kelvin).

*TopOilTmpRise:* This setting is used to set the top oil temperature rise above ambient temperature in K (Kelvin).

The above setting values (*HPTmpRiseWX* and *TopOilTmpRise*) should be obtained from the manufacturer based on certified heat run test reports conducted at maximum rating given in the name plate. The IEEE C57.91-1995 also recommends assuming a value of 80 °C for a 65 °C average winding rise and a value of 65 °C for a 55 °C average winding rise on its nameplate, respectively.

*RatedCurrW1:* This setting is used to set the rated RMS current of winding 1 in A.

*RatedCurrW2:* This setting is used to set the rated RMS current of winding 2 in A.

*RatedCurrW3:* This setting is used to set the rated RMS current of winding 3 in A.

*CurrTypeTestW1:* This setting is used to set the RMS value of the current which is applied during the type test in A for winding 1.

*CurrTypeTestW2:* This setting is used to set the RMS value of the current which is applied during the type test in A for winding 2.

*CurrTypeTestW3:* This setting is used to set the RMS value of the current which is applied during the type test in A for winding 3.

The following settings are required to perform the insulation loss of life calculation:

*EnaAgeCalc:* This setting is used to enable or disable the transformer insulation loss of life calculation. It has the following options:
  - *Enable:* Transformer insulation age calculation is enabled.
  - *Disable:* Transformer insulation age calculation is disabled. The function only calculates up to hot spot temperature and age calculation will not take place.

*InitialLife:* This setting is used to set the transformer initial insulation loss of life. This should be set before implementing the function in service. If it is a newly installed transformer, this setting should be set as zero hours and if it is previously installed transformer then, the user should pre-determine the transformer insulation life consumed in hours and set it. If the transformer insulation loss of life value will start from this value and at any time the insulation loss of life value can be reset with this value by activating LOLRST from local HMI reset menu.

*ExpectedLife:* The transformer expected insulation life in hours can be set by this setting. As per IEEE C57.91-1995 the normal life expectancy at a continuous hot spot temperature of 110 °C is 180,000 Hours.
**AgeingRateMeth:** This setting is used to select the method to be used for transformer insulation relative ageing rate calculation between IEC standard method and IEEE standard method. It has the following options:

- **IEC:** Transformer insulation age calculation based on IEC standard method.
- **IEEE:** Transformer insulation age calculation based on IEEE standard method.

**ThermalUpgrade:** This setting is used to select the transformer insulation paper type between thermally upgraded insulation and normal insulation. It has the following options:

- **Upgraded:** The function considers the given transformer has thermally upgraded paper insulation.
- **Normal:** The function considers the given transformer has normal insulation.

**TimeToUpdate:** This setting is used to set the time interval for updating the transformer insulation loss of life calculation outputs LOLINDAY and LOLINYRS. It can be selected as 1 hour/2 hour/4 hour/8 hour/12 hour/24 hour depending on user requirement.

Two settable warning levels are available for hot spot temperature with separate outputs. If warning level exceeds for the set time, an alarm is generated.

IEEE C57.96-1995 has suggested maximum temperature limits for the four types of loading, see table 72.

**Table 72: Suggested maximum temperature limits**

<table>
<thead>
<tr>
<th>Type of temperature</th>
<th>Normal life expectancy loading</th>
<th>Planned loading beyond nameplate rating</th>
<th>Long term loading</th>
<th>Short term loading</th>
</tr>
</thead>
<tbody>
<tr>
<td>Insulated winding hot spot temperature in °C</td>
<td>120</td>
<td>130</td>
<td>140</td>
<td>180</td>
</tr>
<tr>
<td>Top oil temperature in °C</td>
<td>105</td>
<td>110</td>
<td>110</td>
<td>110</td>
</tr>
</tbody>
</table>

IEEE standard has also suggested the limits of temperature and load for loads higher than transformer nameplate.

- For distribution transformers with 65°C hot spot temperature rise:
  - Top oil temperature = 120°C
  - Hot spot winding temperature = 200°C
  - Short-time loading (1/2 h or less) = 300%
- For power transformer with 65°C hot spot temperature rise:
  - Top oil temperature = 110°C
  - Hot spot winding temperature = 180°C
  - Maximum loading = 200%

Settings related to warning and alarm are:

**WrnHPTmpLev1:** This setting is used to set the level 1 value for hot spot temperature warning.
**WrnHPTmpLev2**: This setting is used to set the level 2 value for hot spot temperature warning. This should be more than the *WrnHPTmpLev1* setting.

**tDelayToAlarm1**: This setting is used to set the time delay for the level 1 hot spot temperature alarm. This time setting can be less than the winding time constant. For example if the winding time constant is 420 sec, this setting can be 400 sec.

**tDelayToAlarm2**: This setting is used to set the time delay for the level 2 hot spot temperature alarm. This should be less than time setting in *tDelayToAlarm1*.

### 17.10.3 Setting example

#### 17.10.3.1 Transformer Rated Data

**Table 73: Transformer Rated Data**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Note</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency</td>
<td>50 Hz</td>
<td></td>
</tr>
<tr>
<td>Rated Power</td>
<td>500 MVA / 500 MVA / 20 MVA</td>
<td></td>
</tr>
<tr>
<td>Voltage ratio</td>
<td>415 kV / 230 kV / 20 kV</td>
<td></td>
</tr>
<tr>
<td>Tap changer</td>
<td>+9</td>
<td>1.67% of 230 kV</td>
</tr>
<tr>
<td>Winding 1 rated current</td>
<td>696 A</td>
<td></td>
</tr>
<tr>
<td>Winding 2 rated current</td>
<td>1255 A</td>
<td></td>
</tr>
<tr>
<td>Winding 3 rated current</td>
<td>577 A</td>
<td></td>
</tr>
<tr>
<td>Connection Type</td>
<td>YNyn0d1</td>
<td></td>
</tr>
<tr>
<td>Cooling</td>
<td>ONAF</td>
<td></td>
</tr>
<tr>
<td>p.u. Impedance</td>
<td>0.120</td>
<td></td>
</tr>
<tr>
<td>At Base</td>
<td>500 MVA</td>
<td></td>
</tr>
<tr>
<td>CT ratio Winding 1</td>
<td>1000/1 A</td>
<td></td>
</tr>
<tr>
<td>CT ratio Winding 2</td>
<td>2000/1 A</td>
<td></td>
</tr>
<tr>
<td>CT ratio Winding 3</td>
<td>1000/1 A</td>
<td></td>
</tr>
</tbody>
</table>

#### 17.10.3.2 Setting parameters for insulation loss of life calculation function (LOL1)

**Table 74: Setting parameters for insulation loss of life calculation function (LOL1)**

<table>
<thead>
<tr>
<th>Setting</th>
<th>Short Description</th>
<th>Selected value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operation</td>
<td>Activation of transformer insulation loss of life calculation function</td>
<td>Enabled</td>
</tr>
<tr>
<td>TrafoRating</td>
<td>Set the transformer rated power of the function on which the parameters are selected</td>
<td>500 MVA</td>
</tr>
<tr>
<td>TrafoType</td>
<td>Select the transformer number of phases</td>
<td>Three phase</td>
</tr>
<tr>
<td>NoOfWindings</td>
<td>Select the transformer number of windings</td>
<td>Three winding</td>
</tr>
<tr>
<td>Setting</td>
<td>Short Description</td>
<td>Selected value</td>
</tr>
<tr>
<td>------------------</td>
<td>------------------------------------------------------------------------------------</td>
<td>----------------------------------</td>
</tr>
<tr>
<td>ConstSelection</td>
<td>Select the standard from which the transformer parameters should be taken</td>
<td>IEC</td>
</tr>
<tr>
<td>CurrSelectMode</td>
<td>Select the method for the determination of current on which the load factor needs to be calculated</td>
<td>Maximum</td>
</tr>
<tr>
<td>TempeUnitMode</td>
<td>Select the unit of temperature should be used in the function</td>
<td>°C</td>
</tr>
<tr>
<td>AvailableCT</td>
<td>Select the available CT connections on the windings</td>
<td>All windings</td>
</tr>
<tr>
<td>RatedVoltageW1</td>
<td>Set the winding 1 rated nominal voltage</td>
<td>415.0 kV</td>
</tr>
<tr>
<td>RatedVoltageW2</td>
<td>Set the winding 2 rated nominal voltage</td>
<td>230.0 kV</td>
</tr>
<tr>
<td>RatedVoltageW3</td>
<td>Set the winding 3 rated nominal voltage</td>
<td>20.0 kV</td>
</tr>
<tr>
<td>UPerTap</td>
<td>Set the voltage increment or decrement between two successive tap positions</td>
<td>3.84 kV</td>
</tr>
<tr>
<td>OilTmConstMode</td>
<td>Select the transformer oil time constant mode of input to the function</td>
<td>Standard</td>
</tr>
<tr>
<td>OilTimeConst</td>
<td>Set the transformer oil time constant when the oil time constant mode is selected as User defined</td>
<td>9000.0 sec</td>
</tr>
<tr>
<td>AvgOilTmpRise</td>
<td>Set the transformer average oil temperature rise for the calculation of oil time constant</td>
<td>45° C</td>
</tr>
<tr>
<td>CoilCoreMass</td>
<td>Set the transformer coil and core assembly mass for the calculation of oil time constant</td>
<td>65.0 t</td>
</tr>
<tr>
<td>OilMass</td>
<td>Set the transformer oil mass for the calculation of oil time constant</td>
<td>35.0 t</td>
</tr>
<tr>
<td>TankMass</td>
<td>Set the transformer tank mass which is having direct contact with heated oil for the calculation of oil time constant</td>
<td>15.0 t</td>
</tr>
<tr>
<td>LoadLoss</td>
<td>Set the rated load loss of the transformer for the calculation of oil time constant</td>
<td>10.0 MW</td>
</tr>
<tr>
<td>TTLoadLoss</td>
<td>Set the load loss of the transformer arrived from the type test for the calculation of oil time constant</td>
<td>10.0 MW</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Setting</th>
<th>Short Description</th>
<th>Selected value</th>
</tr>
</thead>
<tbody>
<tr>
<td>NoLoadLoss</td>
<td>Set the rated no-load loss of the transformer for the calculation of oil time constant</td>
<td>2.0 MW</td>
</tr>
<tr>
<td>TTNoloadLoss</td>
<td>Set the no-load loss of the transformer arrived from the type test for the calculation of oil time constant</td>
<td>2.0 MW</td>
</tr>
<tr>
<td>WdgTmConstMode</td>
<td>Select the transformer winding time constant mode of input to the function</td>
<td>Standard</td>
</tr>
<tr>
<td>WdgTimeConst1</td>
<td>Set the transformer winding time constant for the winding 1 when the winding time constant mode is selected as User defined</td>
<td>420.0 sec</td>
</tr>
<tr>
<td>WdgTimeConst2</td>
<td>Set the transformer winding time constant for the winding 2 when the winding time constant mode is selected as User defined</td>
<td>420.0 sec</td>
</tr>
<tr>
<td>WdgTimeConst3</td>
<td>Set the transformer winding time constant for the winding 3 when the winding time constant mode is selected as User defined</td>
<td>420.0 sec</td>
</tr>
<tr>
<td>ConductorType</td>
<td>Select the transformer winding material for the winding time constant</td>
<td>Copper</td>
</tr>
<tr>
<td>WdgToOilGrad1</td>
<td>Set the transformer winding to oil temperature gradient for the winding 1 when the winding time constant mode is selected as Calculated</td>
<td>20° C</td>
</tr>
<tr>
<td>WdgToOilGrad2</td>
<td>Set the transformer winding to oil temperature gradient for the winding 2 when the winding time constant mode is selected as Calculated</td>
<td>20° C</td>
</tr>
<tr>
<td>WdgToOilGrad3</td>
<td>Set the transformer winding to oil temperature gradient for the winding 3 when the winding time constant mode is selected as Calculated</td>
<td>20° C</td>
</tr>
<tr>
<td>CuLossW1</td>
<td>Set the transformer winding loss for the winding 1 when the winding time constant mode is selected as Calculated</td>
<td>2.0 MW</td>
</tr>
<tr>
<td>CuLossW2</td>
<td>Set the transformer winding loss for the winding 2 when the winding time constant mode is selected as Calculated</td>
<td>4.0 MW</td>
</tr>
<tr>
<td>CuLossW3</td>
<td>Set the transformer winding loss for the winding 3 when the winding time constant mode is selected as Calculated</td>
<td>1.0 MW</td>
</tr>
<tr>
<td>MassW1</td>
<td>Set the mass of transformer winding 1 when the winding time constant mode is selected as Calculated</td>
<td>10.0 t</td>
</tr>
<tr>
<td>MassW2</td>
<td>Set the mass of transformer winding 2 when the winding time constant mode is selected as Calculated</td>
<td>10.0 t</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Setting</th>
<th>Short Description</th>
<th>Selected value</th>
</tr>
</thead>
<tbody>
<tr>
<td>MassW3</td>
<td>Set the mass of transformer winding 3 when the winding time constant mode is selected as Calculated</td>
<td>10.0 t</td>
</tr>
<tr>
<td>RLRated</td>
<td>Set the loss ratio at principal tapping position for the calculation of ratio loss at the given tap position</td>
<td>3.0</td>
</tr>
<tr>
<td>RLHighRated</td>
<td>Set the loss ratio at principal tapping +1 position for the calculation of ratio loss at the given tap position</td>
<td>5.0</td>
</tr>
<tr>
<td>RLMaxTap</td>
<td>Set the loss ratio at maximum tapping position where maximum voltage is possible for the calculation of ratio loss at the given tap position</td>
<td>8.0</td>
</tr>
<tr>
<td>RLMinTap</td>
<td>Set the loss ratio at minimum tapping position where minimum voltage is possible for the calculation of ratio loss at the given tap position</td>
<td>11.0</td>
</tr>
<tr>
<td>RatedVoltTap</td>
<td>Set the rated voltage tap position number</td>
<td>10</td>
</tr>
<tr>
<td>HighVoltTap</td>
<td>Set the tap position number where maximum voltage is possible</td>
<td>19</td>
</tr>
<tr>
<td>LowVoltTap</td>
<td>Set the tap position number where minimum voltage is possible</td>
<td>1</td>
</tr>
<tr>
<td>JanAmbTmp</td>
<td>Set the January month average ambient temperature for the calculation of top oil temperature when ambient temperature sensor failure/absence</td>
<td>30° C</td>
</tr>
<tr>
<td>FebAmbTmp</td>
<td>Set the February month average ambient temperature for the calculation of top oil temperature when ambient temperature sensor failure/absence</td>
<td>30° C</td>
</tr>
<tr>
<td>MarchAmbTmp</td>
<td>Set the March month average ambient temperature for the calculation of top oil temperature when ambient temperature sensor failure/absence</td>
<td>30° C</td>
</tr>
<tr>
<td>AprilAmbTmp</td>
<td>Set the April month average ambient temperature for the calculation of top oil temperature when ambient temperature sensor failure/absence</td>
<td>30° C</td>
</tr>
<tr>
<td>MayAmbTmp</td>
<td>Set the May month average ambient temperature for the calculation of top oil temperature when ambient temperature sensor failure/absence</td>
<td>30° C</td>
</tr>
<tr>
<td>JuneAmbTmp</td>
<td>Set the June month average ambient temperature for the calculation of top oil temperature when ambient temperature sensor failure/absence</td>
<td>30° C</td>
</tr>
<tr>
<td>JulyAmbTmp</td>
<td>Set the July month average ambient temperature for the calculation of top oil temperature when ambient temperature sensor failure/absence</td>
<td>30° C</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Setting</th>
<th>Short Description</th>
<th>Selected value</th>
</tr>
</thead>
<tbody>
<tr>
<td>AugAmbTmp</td>
<td>Set the August month average ambient temperature for the calculation of top oil temperature when ambient temperature sensor failure/absence</td>
<td>30° C</td>
</tr>
<tr>
<td>SepAmbTmp</td>
<td>Set the September month average ambient temperature for the calculation of top oil temperature when ambient temperature sensor failure/absence</td>
<td>30° C</td>
</tr>
<tr>
<td>OctAmbTmp</td>
<td>Set the October month average ambient temperature for the calculation of top oil temperature when ambient temperature sensor failure/absence</td>
<td>30° C</td>
</tr>
<tr>
<td>NovAmbTmp</td>
<td>Set the November month average ambient temperature for the calculation of top oil temperature when ambient temperature sensor failure/absence</td>
<td>30° C</td>
</tr>
<tr>
<td>DecAmbTmp</td>
<td>Set the December month average ambient temperature for the calculation of top oil temperature when ambient temperature sensor failure/absence</td>
<td>30° C</td>
</tr>
<tr>
<td>HPTmpRiseW1</td>
<td>Set the hot spot temperature rise of winding 1 for the calculation of hot spot to top oil temperature gradient</td>
<td>65° C</td>
</tr>
<tr>
<td>HPTmpRiseW2</td>
<td>Set the hot spot temperature rise of winding 2 for the calculation of hot spot to top oil temperature gradient</td>
<td>65° C</td>
</tr>
<tr>
<td>HPTmpRiseW3</td>
<td>Set the hot spot temperature rise of winding 3 for the calculation of hot spot to top oil temperature gradient</td>
<td>65° C</td>
</tr>
<tr>
<td>TopOilTmpRise</td>
<td>Set the top oil temperature rise for the calculation of hot spot to top oil temperature gradient</td>
<td>55° C</td>
</tr>
<tr>
<td>RatedCurrW1</td>
<td>Set the rated current of the winding 1</td>
<td>696.0 A</td>
</tr>
<tr>
<td>RatedCurrW2</td>
<td>Set the rated current of the winding 2</td>
<td>1255.0 A</td>
</tr>
<tr>
<td>RatedCurrW3</td>
<td>Set the rated current of the winding 3</td>
<td>577.0 A</td>
</tr>
<tr>
<td>CurrTypeTestW1</td>
<td>Set the current applied to the winding 1 during type test</td>
<td>696.0 A</td>
</tr>
<tr>
<td>CurrTypeTestW2</td>
<td>Set the current applied to the winding 2 during type test</td>
<td>1255.0 A</td>
</tr>
<tr>
<td>CurrTypeTestW3</td>
<td>Set the current applied to the winding 3 during type test</td>
<td>577.0 A</td>
</tr>
<tr>
<td>EnaAgeCalc</td>
<td>Enable the transformer insulation loss of life calculation</td>
<td>Enable</td>
</tr>
<tr>
<td>InitialLife</td>
<td>Set the initial loss of insulation life</td>
<td>0.0 Hours</td>
</tr>
<tr>
<td>ExpectedLife</td>
<td>Set the expected life of the transformer</td>
<td>1, 80,000 Hours</td>
</tr>
</tbody>
</table>
### Through fault monitoring PTRSTHR (51TF)

#### Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Through fault monitoring</td>
<td>PTRSTHR</td>
<td>-</td>
<td>51TF</td>
</tr>
</tbody>
</table>

#### Application

The through fault monitoring function PTRSTHR(51TF) is used to monitor the mechanical stress on a transformer and place it against its withstand capability. During through faults, the fault-current magnitude is higher as the allowed overload current range. At low fault current magnitudes which are below the overload capability of the transformer, mechanical effects are considered less important unless the frequency of fault occurrence is high. Since through fault current magnitudes are typically closer to the extreme design capabilities of the transformer, mechanical effects are more significant than thermal effects.

The point of transition between mechanical stress and thermal stress cannot be precisely defined. However, mechanical stresses tend to have a prominent role in larger kilovolt-amps ratings, since the currents are higher. It is important to identify all transformer through faults, capture the energy profile of each individual through fault, and ascertain the consequences of aggregate effects to the transformer.

According to IEEE C57.12.00-1993 standard, transformers rated over 10 MVA come under category IV. For these transformers, a single curve represents both thermal and mechanical damage considerations. The recommended duration limit is based upon the curve in Figure 318. The validity of these damage limit curves cannot be demonstrated by tests since the effects are cumulative over the transformers lifetime. They are based principally on informed engineering judgment and favorable, historical field experience as said in IEEE standard.
Figure 318: Transformer capability curve for category IV

Low values of 3.5 or fewer times normal base current may result from overloads rather than faults. For such cases, loading guides may indicate different allowable time durations, that is given in Figure 318. The short-circuit currents shown in Figure 318 is the balanced transformer winding currents. The line currents that relate to these winding currents depend upon the transformer connection and the type of fault present. The protection curves only apply to transformers described in the IEEE C57.12.00-1993 standard. For transformers built the prior to early 1970s, consult the manufacturer for short circuit withstand capabilities.

17.11.3 Setting guidelines

17.11.3.1 Setting procedure on the IED

Parameters for the PTRSTHR (51TF) function are set via the local HMI or PCM600.

17.11.3.2 Consideration of zero sequence currents

Transformer withstand capability against through faults are determined based on fault current flows through the windings. If the winding and CT connections are in wye, then CT measures the winding currents which can be used directly for calculations. However, if any one of the windings or the CT is delta connected, then the measured current cannot be used directly for the calculation. This is due to the fact that the zero sequence current cannot be measured if any one of the windings or CT is delta connected. It is important to consider zero sequence currents in order to calculate the $I^2t$ accurately.

Calculation of zero sequence current is difficult when more than one measured current does not have zero sequence current. The function is able to calculate zero sequence current for a winding
by knowing the zero sequence currents of other winding(s). The zero sequence current calculation is done numerically by setting ZSCurrCor = Disabled or Enabled and does not require any auxiliary transformers or zero sequence traps. However, it is necessary to consider zero sequence currents from every individual winding by proper setting of ZSCurrCor to Disabled or Enabled.

On the other hand, winding current transformers measure the winding currents directly so that there is no need to calculate winding currents. In these cases, the ZSCurrCor should be set as Disabled and ConnTypeWx should be set as WYE.

The following settings are related to the winding current calculation which is set under advanced settings.

Common base IED values for primary current (IBase) and primary voltage (UBase) for a particular winding are set in global base values for settings function GBASVAL. The settings GlobalBaseSelW1, GlobalBaseSelW2 and GlobalBaseSelW3 in the through fault monitoring function are used to select the corresponding GBASVAL function as a reference.

GlobalBaseSelW1: It defines the GBASVAL function instance for the reference of base values for winding 1. Similarly, GlobalBaseSelW2 and GlobalBaseSelW3 settings shall be used to define the GBASVAL function instance for winding 2 and winding 3 respectively.

NoOfWindings: It defines the number of windings in a transformer. It has two options to select between; Two windings and Three windings. When the value Two windings is selected, then the third winding related outputs are set to zero. General data in the through fault monitoring report will show zero for all outputs which is related to winding 3 for two-winding configuration.

ConnTypeW1: It defines the connection type of winding 1. It has two options to select between; WYE and Delta. Similarly, connection types shall be set for winding 2 and winding 3 in settings which designated with W2 and W3 in the settings name. In this case, if more than one winding connection type is Delta, then setting ZSCurrCor shall be set as Disabled.

ClockNumberW2: It defines the phase displacement between winding 1 and winding 2. It has the options to select the clock number between 0 to 11. Similarly, the phase displacement between winding 1 and winding 3 shall be set using setting ClockNumberW3.

17.11.3.3 On-line correction with on-load tap changer position

The PTRSTHR (51TF) function in the IED has a built-in logic to correct the calculated winding current according to the present tap position of an on-load tap changer. The following settings are related this correction feature which is set under advanced settings:

OLTCWinding: It defines where the OLTC’s (OLTC1, OLTC2) are physically located. It has 10 options to select between; Not Used / Winding 1 / Winding 2 / Winding 3 / Winding 1, Winding 2 / Winding 1, Winding 3 / Winding 2, Winding 1 / Winding 2, Winding 3 / Winding 1, Winding 3, Winding 1 / Winding 3, Winding 2.

- If the value Not Used is selected, then the function assumes that both OLTC1 and OLTC2 do not exist and it disregards all other settings related to OLTC’s.
- If either one of the Winding 1 / Winding 2 / Winding 3 values is selected, then the function assumes that only one OLTC has existed and it discards settings related to second OLTC.
- If any values other than the above-mentioned options are selected, then the function assumes that the OLTC1 is located in first mentioned winding and OLTC 2 is located in secondly mentioned winding. For example, if the value Winding 1, Winding 3 is selected, then the function assumes OLTC1 is located in winding 1 and OLTC2 is located in winding 3.
**LowTapOLTC1**: It defines the tap position number at which minimum voltage is possible for OLTC1.

**RatedTapOLTC1**: It defines the tap position number at which rated current and voltage of that winding for OLTC1.

**HighTapPsOLTC1**: It defines the tap position number at which maximum voltage is possible for OLTC1.

**StepSizeOLTC1**: It defines the change per OLTC1 step (for example, 1.5% of the rated voltage of that winding).

The above settings are defined for OLTC1. Similar settings shall be set for second on-load tap changer designated with OLTC2 in the setting names, for three winding configurations.

### 17.11.3.4 Through fault detection

The transformer is subjected to electrical and mechanical stress when a fault current flows through it, which is more than the transformer overload current. In general, stress reduces the transformer life and it becomes even worse when stress occurs due to through faults. The function checks the measured RMS currents against the set pickup level for through fault detection. If the measured RMS current is above the set threshold limit and sustains even after the set time delay, then through fault is detected. This time delay is used to ignore inadvertent detection of faults. Also, for resetting through fault detection, a hysteresis has been considered to avoid oscillations in boundary conditions.

The following settings are related to through fault detection which are set under basic settings:

**W1 I pickup**: It defines the current pickup value for through fault detection in percentage of winding 1 Ib. This setting shall be set higher than the overload capacity of the transformer. This is because currents below 3.5 times the rated current may generate due to overloads. Similarly, current pickup values shall be set for winding 2 and winding 3 using settings which designated with W2 and W3 in the settings name.

**t_MinTripDelay**: It defines the minimum duration of fault to start any calculations. It is used to ignore accidental detection and calculations if the fault current drops below the lower threshold level within a short time.

The function monitors the time between last two subsequent through fault detections and it gives a warning signal when the time difference is below the set time. This indicates that the transformer has faults very frequently and it may undergo heavy electrical and mechanical stress. Thereby, the utility can take prior attention and undertake preventive actions to avoid serious consequences. This warning signal resets if no more faults occurred within the same set time.

**tMultiThroFlt**: It defines the time window to detect multi through faults. This setting shall be set based on the maximum allowed number of through fault per time period, which may be indicated by the transformer manufacturer.

### 17.11.3.5 Through fault $F\tau$ alarms

Through fault $F\tau$ calculations are done for all windings and phase-wise, and when this integration exceeds the set limit in any one phase, an alarm is raised. The $F\tau$ limit shall be set winding-wise.
and once the alarm is raised, then control actions can be taken such as changing auto-reclosing settings.

MaxI2tW1: It defines the $I^2t$ threshold limit for an individual event or fault per phase. This setting shall be set based on the withstand capability of each winding with respect to corresponding rated current. Similarly, the threshold limit for winding 2 and winding 3 shall be set using MaxI2tW2 and MaxI2tW3 settings.

Even though transformer damages caused by through faults are cumulative by nature, individual through fault events also require attention. This is because the impact of several small through faults can be less compared to one heavy through fault.

The PTRSTHR (51TF) function monitors each through fault events and accumulates the calculated $I^2t$ values for each fault to determine the cumulative effect. This cumulative $I^2t$ is calculated for all windings phase-wise and when this value exceeds the cumulative $I^2t$ set limit, an alarm is raised.

MaxI2tCmlW1: It defines the cumulative $I^2t$ threshold limit for all fault events in winding 1, per phase. Similarly, the cumulative threshold limit for winding 2 and winding 3 shall be set using MaxI2tCmlW2 and MaxI2tCmlW3 settings.

The alarm signal due to individual event $I^2t$ will be reset either after the ongoing fault is cleared or the set minimum time delay, whichever is longer. The alarm signal due to cumulative $I^2t$ is set high continuously until the cumulative $I^2t$ values are reset to a lower value than the set limit.

tPulse: It defines the pulse duration for an individual event $I^2t$ alarm.

Consider all the calculations based on through fault not as a precise indicator of transformer health. These values indicate that the transformer should be inspected, they do not indicate a strict necessity to shut-down the transformer.

### 17.11.3.6 Initial values for cumulative $I^2t$ and number of through faults

The calculated cumulative $I^2t$ values for each phase of windings and number of through faults counts can be reset with preset values using command inputs under the clear menu or via binary inputs. The following parameters which are set under advanced parameters are related to the initial values of cumulative $I^2t$ and number of through faults.

InitCl2tW1L1: It defines the initial cumulative $I^2t$ value for winding 1 and phase A. Similarly, initial cumulative $I^2t$ value for B and C phase shall be set using parameters which are designated with B and C in the parameters name. For other windings, the initial cumulative $I^2t$ values shall be set using the parameters which are designated with W2 and W3 in the parameters name.

InitTFCntW1L1: It defines the initial fault counter value of winding 1 and phase A. Similarly, the initial fault counter value for other phases B and C shall be set using parameters which are designated with B and C in the parameters name. Also, for other windings the initial fault counter value shall be set using the parameters which are designated with W2 and W3 in the parameters name.

InitCmlTFCnt: It defines the initial overall fault counter value for the transformer.
17.11.4 Setting examples

In order to correctly apply transformer through fault monitoring with proper zero sequence current, correction is needed for:

- Power transformer phase shift (phase shift compensation)
- Zero sequence current (zero sequence current consideration)

The through fault monitoring is suitable for all standard three-phase power transformers without any interposing CTs. It is designed with the assumption that all main CTs are wye connected. For such applications, it is only necessary to enter CT rated data and power transformer data directly as they are given on the power transformer nameplate. The zero sequence current is then calculated and included in the winding currents itself unless there is more than one delta winding configuration.

However, the IED can also be used in applications where some of the main CTs are connected in delta. In such cases, the ratio for the main CT connected in delta shall be intentionally set to \( \sqrt{3} = 1.732 \) times smaller than the actual ratio of individual phase CTs (for example, set 462/5 instead of 800/5). In case the ratio is 800/2.88A, often designed for such typical delta connections, set the ratio as 800/5 in the IED.

At the same time, the power transformer phase shift shall be set as \( YyO \) since the IED shall not internally provide any phase angle shift compensation. The necessary phase angle shift compensation will be provided externally by delta connected main CT. All other settings should have the same values irrespective of main CT connections.

Irrespective of the main CT connections (wye or delta), online reading and automatic correction for actual load tap changer position can be used in the IED.

17.11.4.1 Typical main CT connections for transformer

Three most typical main CT connections used for transformers are shown in Figure 319. It is assumed that the primary phase sequence is A-B-C.

![Diagram of main CT connections for transformers](ANSI18000079-1-en.vsd)

Figure 319: Main CT connections for transformers
For wye connected main CTs, secondary currents fed to the IED:

- Are directly proportional to the measured primary currents
- Are in phase with the measured primary currents
- Contains all sequence components including zero sequence current component

For wye connected main CTs, the main CT ratio shall be set as it is in the actual application. The StarPoint parameter, for the particular wye connection shown in Figure 319, shall be set as ToObject. If wye connected main CTs have their wye point away from the protected transformer, this parameter shall be set as FromObject.

For delta DAC connected main CTs, secondary currents fed to the IED:

- Are increased √3 times (1.732 times) in comparison with wye connected CTs
- Lag by 30° the primary winding currents (this CT connection rotates currents by 30° in clockwise direction)
- Does not contain zero sequence current component and consequently winding currents are not properly measured for all types of faults

For DAC delta connected main CTs, the ratio shall be set for √3 times smaller than the actual ratio of individual phase CTs. The StarPoint parameter, for the particular wye connection shall be set as ToObject.

The delta DAC connected main CTs must be connected exactly as shown in Figure 319.

For delta DAB connected main CTs, secondary currents fed to the IED:

- Are increased √3 times (1.732 times) in comparison with wye connected CTs
- Lead by 30° the primary winding currents (this CT connection rotates currents by 30° in anti-clockwise direction)
- Does not contain zero sequence current component and consequently winding currents are not properly measured for all types of faults

For DAB delta connected, main CT ratio shall be set √3 times smaller than the actual ratio of individual phase CTs. The StarPoint parameter for this particular connection shall be set as ToObject.

The delta DAB connected main CTs must be connected exactly as shown in Figure 319.

For more detailed information regarding CT data settings, refer to Section Application examples.

It is strongly recommended to use wye connected main CTs on all sides of the monitored power transformer.

17.11.4.2  Application examples for power transformers

Three application examples are presented here and each one has the following solutions:
• Solution 1: with all main CTs wye connected
• Solution 2: with delta connected main CT on Y (i.e., wye) connected sides of the protected power transformer

The following settings are given for each solution:

• Input CT channels on the transformer input modules
• General settings for the transformer through fault monitoring where specific data about monitored power transformer is entered.

Example 1: Wye-delta connected power transformer without on-load tap changer
Single line diagrams for two possible solutions for such type of power transformer with all relevant application data is given in Figure 320.

Figure 320: Wye-delta connected power transformer solutions
For this particular power transformer, the 69 kV side phase-to-ground no-load voltages lead the 12.5 kV side phase-to-ground no-load voltages by 30 degrees. Thus, ensure that the HV currents are rotated by 30° in the clockwise direction when external phase angle shift compensation is done by connecting main HV CTs in delta (as shown in Figure 320, right-hand side). Therefore, the DAC delta CT connection must be used for 69 kV CTs in order to put 69 kV & 12.5 kV currents in phase.

In order to ensure proper application of the IED for this power transformer, proceed as follows:
1. Ensure that HV & LV CTs are connected to 5 A CT inputs in the IED.
2. For the second solution, make sure that HV delta connected CTs are DAC connected.
3. For wye connected CTs, make sure how they are wye-connected (i.e., grounded) to/from the protected transformer.
4. Enter the settings for all three CT input channels used for the LV side CTs as shown in Table 75.

Table 75: LV side CTs input channels

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Selected value for both solutions</th>
</tr>
</thead>
<tbody>
<tr>
<td>CTprim</td>
<td>800</td>
</tr>
<tr>
<td>CTsec</td>
<td>5</td>
</tr>
<tr>
<td>CTStarPoint</td>
<td>ToObject</td>
</tr>
</tbody>
</table>

5. Enter the settings for all three CT input channels used for the HV side CTs as shown in Table 76.

Table 76: HV side CTs input channels

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Selected value for solution 1 (wye connected CT)</th>
<th>Selected value for solution 2 (delta connected CT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CTprim</td>
<td>300</td>
<td>300 (\frac{300}{\sqrt{3}} = 173) (\text{(To compensate for delta connected CTs)})</td>
</tr>
<tr>
<td>CTsec</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>CTStarPoint</td>
<td>FromObject</td>
<td>ToObject</td>
</tr>
</tbody>
</table>

6. Enter the values for the general settings of the PTRSTHR (51TF) function as shown in Table 77.

Table 77: Through fault monitoring function general settings

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Select value for solution 1 (wye connected CT)</th>
<th>Select value for solution 2 (delta connected CT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ConnTypeW1</td>
<td>WYE (Y)</td>
<td>WYE (Y)</td>
</tr>
<tr>
<td>ConnTypeW2</td>
<td>Delta</td>
<td>WYE (Y)(^1)</td>
</tr>
<tr>
<td>ClockNumberW2</td>
<td>1 [30 deg lag]</td>
<td>0 (\text{[0 deg]})(^2)</td>
</tr>
<tr>
<td>ZSCurrCor</td>
<td>Enabled</td>
<td>Disabled(^2)</td>
</tr>
<tr>
<td>OLTCWinding</td>
<td>Not in use</td>
<td>Not in use</td>
</tr>
</tbody>
</table>

1) To compensate for delta connected CTs
2) Zero-sequence current is removed by connecting main CTs in delta

Example 2: Delta-wye connected power transformer without tap charger
Single line diagrams for two possible solutions for such type of power transformer with all relevant application data is given in Figure 321.
Figure 321: Delta-wye connected power transformer solutions

For this particular power transformer, the 115 kV side phase-to-ground no-load voltages lead the 24.9 kV side phase-to-ground no-load voltages by 30 degrees. Thus, ensure that the 24.9 kV currents are rotated by 30° in the anti-clockwise direction when external phase angle shift compensation is done by connecting main 24.9 kV CTs in delta (as shown in Figure 321, right-hand side). Therefore, the DAB CT connection must be used for 24.9 kV CTs in order to put 115 kV & 24.9 kV currents in phase.

In order to ensure proper application of the IED for this power transformer, proceed as follows:

1. Ensure that HV & LV CTs are connected to 5 A CT inputs in the IED.
2. For the second solution, make sure that LV delta connected CTs are DAB connected.
3. For wye connected CTs, make sure how they are wye connected (i.e., grounded) to/from the protected transformer.
4. Enter the settings for all three CT input channels used for the HV side CTs as shown in Table 78.

**Table 78: HV side CTs input channels**

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Selected value for both solutions</th>
</tr>
</thead>
<tbody>
<tr>
<td>CTprim</td>
<td>400</td>
</tr>
<tr>
<td>CTsec</td>
<td>5</td>
</tr>
<tr>
<td>CTStarPoint</td>
<td>ToObject</td>
</tr>
</tbody>
</table>
5. Enter the settings for all three CT input channels used for the LV side CTs as shown in Table 79.

Table 79: LV side CTs input channels

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Selected value for solution 1 (wye connected CT)</th>
<th>Selected value for solution 2 (delta connected CT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CTprim</td>
<td>1500</td>
<td>$\frac{1500}{\sqrt{3}} = 866$ (To compensate for delta connected CTs)</td>
</tr>
<tr>
<td>CTsec</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>CTStarPoint</td>
<td>ToObject</td>
<td>ToObject</td>
</tr>
</tbody>
</table>

6. Enter the values for the general settings of the PTRSTHR (51TF) function as shown in Table 80.

Table 80: Through fault monitoring function general settings

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Select value for solution 1 (wye connected CT)</th>
<th>Select value for solution 2 (delta connected CT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ConnTypeW1</td>
<td>Delta</td>
<td>WYE (Y)</td>
</tr>
<tr>
<td>ConnTypeW2</td>
<td>WYE (Y)</td>
<td>WYE (Y)$^1$</td>
</tr>
<tr>
<td>ClockNumberW2</td>
<td>1 [30 deg lag]</td>
<td>0 [0 deg]$^1$</td>
</tr>
<tr>
<td>ZSCurrCor</td>
<td>Enabled</td>
<td>Disabled$^2$</td>
</tr>
<tr>
<td>OLTCWinding</td>
<td>Not in use</td>
<td>Not in use</td>
</tr>
</tbody>
</table>

$^1$ To compensate for delta connected CTs
$^2$ Zero-sequence current is removed by connecting main CTs in delta, so winding current with zero sequence current is not possible

Example 3: Wye-wye connected power transformer with load tap changer and tertiary not loaded delta winding

Single line diagrams for two possible solutions for such type of power transformer with all relevant application data is given in Figure 322.

This example is also applicable for autotransformer not loaded with tertiary delta.
Figure 322: Wye-wye connected power transformer solutions

For this particular power transformer, the 110 kV side phase-to-ground no-load voltages are exactly in phase with the 36.75 kV side phase-to-ground no-load voltages. Thus, when external phase angle shift compensation is done by connecting main CTs in delta, both set of CTs must be identically connected (i.e., either both DAC or both DAB as shown in the right-hand side in Figure 322) in order to put 110 kV & 36.75 kV currents in phase.

In order to ensure proper application of the IED for this power transformer, proceed as follows:

1. Ensure that HV & LV CTs are connected to 1 A CT inputs in the IED.
2. Check that LV CTs are connected to 5 A CT inputs in the IED.
3. Make sure that both CT sets are identically connected (i.e., either both side DAC or both side DAB) when delta connected CTs are used.
4. For wye connected CTs, make sure how they are wye connected (i.e., grounded) towards or away from the protected transformer.
5. Enter the settings for all three CT input channels used for the HV side CTs as shown in Figure 322.

Table 81: HV side CTs input channels

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Selected value for solution 1 (wye connected CT)</th>
<th>Selected value for solution 2 (delta connected CT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CTprim</td>
<td>200</td>
<td>200 $\frac{200}{\sqrt{3}} = 115$ (To compensate for delta connected CTs)</td>
</tr>
<tr>
<td>CTsec</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>CTStarPoint</td>
<td>FromObject</td>
<td>ToObject</td>
</tr>
</tbody>
</table>
6. Enter the settings for all three CT input channels used for the LV side CTs as shown in Table 81.

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Selected value for solution 1 (wye connected CT)</th>
<th>Selected value for solution 2 (delta connected CT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CTprim</td>
<td>500</td>
<td>500 (\frac{289}{\sqrt{3}}) = 289</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(To compensate for delta connected CTs)</td>
</tr>
<tr>
<td>CTsec</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>CTStarPoint</td>
<td>ToObject</td>
<td>ToObject</td>
</tr>
</tbody>
</table>

7. Enter the values for the general settings of the PTRSTHR (51TF) function as shown in Table 83.

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Select value for solution 1 (wye connected CT)</th>
<th>Select value for solution 2 (delta connected CT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ConnTypeW1</td>
<td>WYE (Y)</td>
<td>WYE (Y)</td>
</tr>
<tr>
<td>ConnTypeW2</td>
<td>WYE (Y)</td>
<td>WYE (Y)</td>
</tr>
<tr>
<td>ClockNumberW2</td>
<td>0 [0 deg]</td>
<td>0 [0 deg]</td>
</tr>
<tr>
<td>ZSCurrCor</td>
<td>Disabled</td>
<td>Disabled(^1)</td>
</tr>
<tr>
<td>OLTCWinding</td>
<td>Winding 1 (W1)</td>
<td>Winding 1 (W1)</td>
</tr>
<tr>
<td>LowTapOLTC1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>RatedTapOLTC1</td>
<td>12</td>
<td>12</td>
</tr>
<tr>
<td>HighTapOLTC1</td>
<td>23</td>
<td>23</td>
</tr>
<tr>
<td>StepSizeOLTC1</td>
<td>1.5%</td>
<td>1.5%</td>
</tr>
</tbody>
</table>

\(^1\) Zero-sequence current is removed by connecting main CTs in delta, so winding current with zero sequence current is not possible

Summary and conclusions
The IED can be used for through fault monitoring of transformers with main CTs are either wye or delta connected. However, the IED is designed with an assumption that all main CTs are wye connected. The IED can be used in applications where the main CTs are delta connected. For such applications, consider the following:

- The ratio for delta connected CTs shall be set \(\sqrt{3} = 1.732\) times smaller than the actual individual phase CT ratio.
- The power transformer phase shift shall typically be set as Yy0 since the compensation for power transformer the actual phase shift is provided by the external delta CT connection.
- The zero sequence current is removed by the main CT delta connections. Therefore, when wye winding sides, the CTs are connected in delta the zero sequence current correction shall be set to *Disabled* in the IED.
Table below summarizes the most commonly used wye-delta phase shifts around the world and provides information about the required type of main CT delta connection on the wye side of the transformer.

<table>
<thead>
<tr>
<th>IEC phase shift</th>
<th>ANSI designation</th>
<th>Positive sequence no-load voltage phasor diagram</th>
<th>Required delta CT connection type on wye side of the protected power transformer and internal phase shift setting in the IED</th>
</tr>
</thead>
<tbody>
<tr>
<td>YNd1</td>
<td>YD_{AC}</td>
<td><img src="image1.png" alt="YD AC Diagram" /></td>
<td>DAC/Yy0</td>
</tr>
<tr>
<td>Dyn1</td>
<td>D_{AB}Y</td>
<td><img src="image2.png" alt="DAB Y Diagram" /></td>
<td>DAB/Yy0</td>
</tr>
<tr>
<td>YNd11</td>
<td>YD_{AB}</td>
<td><img src="image3.png" alt="YD AB Diagram" /></td>
<td>DAB/Yy0</td>
</tr>
<tr>
<td>Dyn11</td>
<td>D_{AC}Y</td>
<td><img src="image4.png" alt="DAC Y Diagram" /></td>
<td>DAC/Yy0</td>
</tr>
<tr>
<td>YNd5</td>
<td>YD150</td>
<td><img src="image5.png" alt="YD 150 Diagram" /></td>
<td>DAB/Yy6</td>
</tr>
<tr>
<td>Dyn5</td>
<td>DY150</td>
<td><img src="image6.png" alt="DY 150 Diagram" /></td>
<td>DAC/Yy6</td>
</tr>
</tbody>
</table>
Settings for transformer withstand capability calculation

Four different protection curves are given in the IEEE C57.109.1993 standard for different categories of transformer which are covered by IEEE C57.12.00-1993 standard. These curves are based on the historical evolution of the short circuit withstand requirements and these should be applicable to transformers built beginning in the early 1970s.

For transformers built prior to the early 1970s, consult the manufacturer for short circuit withstand capabilities as a precaution.

According to IEEE C57.109.1993 standard, single phase transformers above 10 MVA and three phase transformers above 30 MVA come under category IV transformers. The recommended protection curve for category IV transformer is given in Figure 318. This curve should be applied as a protection curve for all faults, frequent and in-frequent. The curve is dependents upon the transformer short circuit impedance for fault currents above 50% of the maximum possible and it leads to worst case mechanical duty with maximum fault current for 2s. The damage intensity from through faults depends on the current magnitude, fault duration, and the total number of fault occurrences. Refer to Table 84 for the through fault monitoring function settings values corresponding to the given transformer.

Table 84: Transformer nameplate data

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency</td>
<td>50 Hz</td>
</tr>
<tr>
<td>Rated Power</td>
<td>500 MVA / 500 MVA / 20 MVA</td>
</tr>
<tr>
<td>Voltage ratio</td>
<td>415 kV / 230 kV / 20 kV</td>
</tr>
<tr>
<td>Winding 1 rated current</td>
<td>696 A</td>
</tr>
<tr>
<td>Winding 2 rated current</td>
<td>1255 A</td>
</tr>
<tr>
<td>Winding 3 rated current</td>
<td>577 A</td>
</tr>
<tr>
<td>Tap changer</td>
<td>±9; 1.67% of 230 kV</td>
</tr>
<tr>
<td>Connection Type YNyn0d1</td>
<td>YNyn0d1</td>
</tr>
<tr>
<td>Cooling</td>
<td>ONAF</td>
</tr>
<tr>
<td>% Impedance</td>
<td>12 @ Base 500 MVA</td>
</tr>
</tbody>
</table>

According to the IEEE standard and Figure 318, the given transformer withstand capability can be calculated with respect to transformer % impedance 12. In this case, $I^2t$ limits are calculated based on the maximum allowable fault current 800 % of rated current for 2s duration. Also, if the transformer manufacturer indicates that 10 such through faults can be withstand over the life time of the transformer, then the cumulative $I^2t$ limits can be set accordingly.

Table 85: PTRSTHR (51TF) setting parameters

<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Select value</th>
</tr>
</thead>
<tbody>
<tr>
<td>W1 I pickup</td>
<td>350 % IBaseW1</td>
</tr>
<tr>
<td>W2 I pickup</td>
<td>350 % IBaseW2</td>
</tr>
<tr>
<td>W3 I pickup</td>
<td>350 % IBaseW3</td>
</tr>
<tr>
<td>t_MinTripDelay</td>
<td>0.2 s</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Setting parameter</th>
<th>Select value</th>
</tr>
</thead>
</table>
| MaxI<sup>2</sup>tW<sub>1</sub> | \[
\frac{(696 \times 8)^2}{1000000} \times 2 = 62.0 (kA)^2 \times s
\] |
| MaxI<sup>2</sup>tW<sub>2</sub> | \[
\frac{(1255 \times 8)^2}{1000000} \times 2 = 201.608 (kA)^2 \times s
\] |
| MaxI<sup>2</sup>tW<sub>3</sub> | \[
\frac{(577 \times 8)^2}{1000000} \times 2 = 45.615 (kA)^2 \times s
\] |
| MaxI<sup>2</sup>tCmlW<sub>1</sub> | \[
62.0 \times 10 = 620 (kA)^2 \times s
\] |
| MaxI<sup>2</sup>tCmlW<sub>2</sub> | \[
201.608 \times 10 = 2016.08 (kA)^2 \times s
\] |
| MaxI<sup>2</sup>tCmlW<sub>3</sub> | \[
42.615 \times 10 = 426.15 (kA)^2 \times s
\] |

### 17.11.4.3 Application example for OHL

Additionally, the PTRSTHR (51TF) function can be used to monitor faults on OHL. In such cases, the OHL current and voltage shall be connected to W1 inputs. In case of one-and-a-half breaker configuration, W1 and W2 currents shall be used.

For such applications, the PTRSTHR (51TF) function can be triggered either by the set phase current level or externally by the START or TRIP signal from the distance protection. As a result, a summary list that provides an overview about all through faults seen by the IED will be available on the local HMI.

### 17.12 Current harmonic monitoring CHMMHAI(ITHD)

#### 17.12.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current harmonic monitoring</td>
<td>CHMMHAI</td>
<td>ITHD</td>
<td>ITHD</td>
</tr>
</tbody>
</table>

#### 17.12.2 Application

In order to maintain the power quality for better supply, harmonics in the system must be monitored. Due to the nonlinear loads connected to the system, harmonics (apart from fundamental frequency component) are generated and thereby the system voltage is distorted. Voltage distortion appears to have a little effect on operation of nonlinear loads connected, either phase-to-phase or phase-to-neutral. Current distortion is limited at the point of common coupling PCC to control the harmonic current from the utility to the consumer. Thereby, the voltage distortion must be limited in order to prevent it from spreading to other facilities.
Voltage harmonic distortion levels can vary drastically, depending on the configuration of system. These voltage harmonics can damage the equipment as they are designed to operate for certain range of voltage inaccuracy.

Moreover, in four-wire distribution systems (three-phase and neutral), the currents in the three phases will return via the neutral conductor, a 120 degree phase shift between corresponding phase currents that causes the currents to cancel out in the neutral, under balanced loading conditions. When nonlinear loads are present, any 'Triplen' (3rd, 9th...) harmonics in the phase currents does not cancel out. However, they will be added cumulatively in the neutral conductor, which can carry up to 173% of phase current at a frequency of predominately 180 Hz (3rd harmonic).

In case of electric traction systems, it generates various power quality problems that have an important impact on its distribution network. DC traction loads, fed through AC/DC rectifiers, generates non-linear voltages and currents on the AC system, that will result in harmonic voltage distortion of the power supply system. Traction power supply system creates power quality problems to the corresponding grid, which can cause:

- Poor power quality
- Increase in operational cost due to less productivity
- Damage to sensitive equipment in nearby facilities.

Maintaining high power quality in traction system is very complex. The presence of non-linear loads reduces the capability of the existing harmonic mitigation techniques. However, it is essential to minimize the issues like harmonics, voltage sags and flicker to protect sensitive equipment affected by the aforementioned issues produced by traction systems.

Various practical conditions which have dynamic characteristics like the speed of locomotion, load and line condition will make this problem even worse. Harmonic current increases the heat dissipation due to hysteresis and eddy currents, which causes stress on insulation materials. Harmonic current increases transmission loss and the voltage drops.

In general, harmonics can cause reduced equipment life if a system is designed without considering the harmonics and if the equipment is not designed to withstand harmonics. Hence, it is important to measure and monitor harmonics in power systems. Harmonic voltage distortions on 161 kV power system and above is limited to 1.5% of total harmonic distortion (THD), in with each individual harmonic is limited to 1.0%.

Current harmonic limits vary based on the short circuit strength of the corresponding system they are injected into. Harmonic current limit defines the maximum amount of harmonic current that can be inject into the utility system. The difference between THD and TDD is used to calculate the harmonics level during light load conditions.

### 17.12.3 Setting guidelines

The recommended limits for total harmonic distortion and individual harmonic distortion are available in the IEEE 519 standard. The limits are based on measurements which are done at the point of common coupling. It should not be applied to either individual pieces of equipment or at locations within a user’s facility. In most cases, harmonic voltages and currents at these locations could be found to be significantly beyond recommended limits at the PCC due to the lack of diversity, cancellation, and other phenomena that tend to reduce the combined effects of multiple harmonic sources to levels below their algebraic summation.
17.12.3.1 Setting procedure on the IED

Parameters for CHMMHAI (ITHD) function are set via the local HMI or PCM600.

Common base IED values for primary current (IBase) is set in the global base values for settings function GBASVAL.

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

Minimum and maximum current limit is set as 5% of the IB and 300.0% of IB respectively. If the current is outside the above range, the calculation of total harmonic distortion, individual harmonic distortion, total demand distortion and crest factor are blocked and outputs are provided as zero.

MaxLoadCurr: Maximum demand load current at PCC for total demand distortion calculation. When the point of common coupling (PCC) is considered at the service entrance or utility metering point, IEEE 519 standard recommends that the maximum demand load current must be calculated as the average current of maximum demand for the preceding 12 months.

WrnLimitTDD: It defines the warning limit for the calculated total demand distortion. Harmonic current distortions on a power systems with ratio between the maximum short circuit current to the maximum demand load current is 20, limited to 5% of the total demand distortion (TDD).

tDelayAlmTDD: It defines the alarm delay time from warning for the calculated total demand distortion.

WrnLimitTHD: It defines the warning limit for the calculated total harmonic distortion.

tDelayAlmTHD: It defines the alarm delay time from warning for the calculated total harmonic distortion. This intimates the operator to take corrective operations immediately, otherwise the system will undergo thermal stress.

WrnLimit2ndHD: It defines the warning limit for the calculated second harmonic distortion.

tDelayAlm2ndHD: It defines the alarm delay time from warning for the calculated second harmonic distortion.

WrnLimit3rdHD: It defines the warning limit for the calculated third harmonic distortion.

tDelayAlm3rdHD: It defines the alarm delay time from warning for the calculated third harmonic distortion.

WrnLimit4thHD: It defines the warning limit for the calculated fourth harmonic distortion.

tDelayAlm4thHD: It defines the alarm delay time from warning for the calculated fourth harmonic distortion.

WrnLimit5thHD: It defines the warning limit for the calculated fifth harmonic distortion.

tDelayAlm5thHD: It defines the alarm delay time from warning for the calculated fifth harmonic distortion.
17.13 Voltage harmonic monitoring VHMMHAI(VTHD)

17.13.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage harmonic monitoring</td>
<td>VHMMHAI</td>
<td>UTHD</td>
<td>VTHD</td>
</tr>
</tbody>
</table>

17.13.2 Application

In order to maintain the power quality for better supply, harmonics in the system must be monitored. Due to the nonlinear loads connected to the system, harmonics (apart from fundamental frequency component) are generated and thereby the system voltage is distorted. Voltage distortion appears to have a little effect on operation of nonlinear loads connected, either phase-to-phase or phase-to-neutral. Current distortion is limited at the point of common coupling PCC to control the harmonic current from the utility to the consumer. Thereby, the voltage distortion must be limited in order to prevent it from spreading to other facilities.

Voltage harmonic distortion levels can vary drastically, depending on the configuration of system. These voltage harmonics can damage the equipment as they are designed to operate for certain range of voltage inaccuracy.

Moreover, in four-wire distribution systems (three-phase and neutral), the currents in the three phases will return via the neutral conductor, a 120 degree phase shift between corresponding phase currents that causes the currents to cancel out in the neutral, under balanced loading conditions. When nonlinear loads are present, any 'Triplen' (3rd, 9th ...) harmonics in the phase currents does not cancel out. However, they will be added cumulatively in the neutral conductor, which can carry up to 173% of phase current at a frequency of predominately 180 Hz (3rd harmonic).

In case of electric traction systems, it generates various power quality problems that have an important impact on its distribution network. DC traction loads, fed through AC/DC rectifiers, generates non-linear voltages and currents on the AC system, that will result in harmonic voltage distortion of the power supply system. Traction power supply system creates power quality problems to the corresponding grid, which can cause:

- Poor power quality
- Increase in operational cost due to less productivity
- Damage to sensitive equipment in nearby facilities.

In general, harmonics can cause reduced equipment life if a system is designed without considering the harmonics and if the equipment is not designed to withstand harmonics. Hence, it is important to measure and monitor harmonics in power systems. Harmonic voltage distortions on 161 kV power system and above is limited to 1.5% of total harmonic distortion (THD), in with each individual harmonic is limited to 1.0%.

17.13.3 Setting guidelines

The recommended limits for total harmonic distortion and individual harmonic distortion are available in the IEEE 519 standard. The limits are based on measurements which are done at the
point of common coupling. It should not be applied to either individual pieces of equipment or at locations within a user’s facility. In most cases, harmonic voltages and currents at these locations could be found to be significantly beyond recommended limits at the PCC due to the lack of diversity, cancellation, and other phenomena that tend to reduce the combined effects of multiple harmonic sources to levels below their algebraic summation.

17.13.3.1 Setting procedure on the IED

Parameters for VHMMHAI(VTHD) function are set via the local HMI or PCM600.

Common base IED values for primary voltage ($U_{Base}$) is set in the global base values for settings function GBASVAL.

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

Minimum and maximum voltage limit is set as 5% of the $U_B$ and 300.0% of $U_B$ respectively. If the voltage is outside the above range, the calculation of total harmonic distortion, individual harmonic distortion and crest factor are blocked and outputs are provided as zero.

$WrnLimitTHD$: It defines the warning limit for the calculated total harmonic distortion.

$tDelayAlmTHD$: It defines the alarm delay time from warning for the calculated total harmonic distortion. This intimates the operator to take corrective operations immediately, otherwise the system will undergo thermal stress.

$WrnLimit2ndHD$: It defines the warning limit for the calculated second harmonic distortion.

$tDelayAlm2ndHD$: It defines the alarm delay time from warning for the calculated second harmonic distortion.

$WrnLimit3rdHD$: It defines the warning limit for the calculated third harmonic distortion.

$tDelayAlm3rdHD$: It defines the alarm delay time from warning for the calculated third harmonic distortion.

$WrnLimit4thHD$: It defines the warning limit for the calculated fourth harmonic distortion.

$tDelayAlm4thHD$: It defines the alarm delay time from warning for the calculated fourth harmonic distortion.

$WrnLimit5thHD$: It defines the warning limit for the calculated fifth harmonic distortion.

$tDelayAlm5thHD$: It defines the alarm delay time from warning for the calculated fifth harmonic distortion.
Section 18  Metering

18.1  Pulse-counter logic PCFCNT

18.1.1  Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pulse-counter logic</td>
<td>PCFCNT</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

18.1.2  Application

Pulse-counter logic (PCFCNT) function counts externally generated binary pulses, for instance pulses coming from an external energy meter, for calculation of energy consumption values. The pulses are captured by the binary input module (BIM), and read by the PCFCNT function. The number of pulses in the counter is then reported via the station bus to the substation automation system or read via the station monitoring system as a service value. When using IEC 61850–8–1, a scaled service value is available over the station bus.

The normal use for this function is the counting of energy pulses from external energy meters. An optional number of inputs from an arbitrary input module in IED can be used for this purpose with a frequency of up to 40 Hz. The pulse-counter logic PCFCNT can also be used as a general purpose counter.

18.1.3  Setting guidelines

Parameters that can be set individually for each pulse counter from PCM600:

- **Operation**: Disabled/Enabled
- **tReporting**: 0-3600s
- **EventMask**: NoEvents/ReportEvents

Configuration of inputs and outputs of PCFCNT is made via PCM600.

On the Binary input module (BIM), the debounce filter default time is set to 1 ms, that is, the counter suppresses pulses with a pulse length less than 1 ms. The input oscillation blocking frequency is preset to 40 Hz meaning that the counter detects the input to oscillate if the input frequency is greater than 40 Hz. Oscillation suppression is released at 30 Hz. Block/release values for oscillation can be changed on the local HMI and PCM600 under **Main menu/Configuration/I/O modules**.
The setting is common for all input channels on BIM, that is, if limit changes are made for inputs not connected to the pulse counter, the setting also influences the inputs on the same board used for pulse counting.

### 18.2 Function for energy calculation and demand handling

**ETPMMTR**

#### 18.2.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Function for energy calculation and demand handling</td>
<td>ETPMMTR</td>
<td>W_Varh</td>
<td>-</td>
</tr>
</tbody>
</table>

#### 18.2.2 Application

Energy calculation and demand handling function (ETPMMTR) is intended for statistics of the forward and reverse active and reactive energy. It has a high accuracy basically given by the measurements function (CVMMXN). This function has a site calibration possibility to further increase the total accuracy.

The function is connected to the instantaneous outputs of (CVMMXN) as shown in figure 323.

---

**Figure 323:** Connection of energy calculation and demand handling function ETPMMTR to the measurements function (CVMMXN)

The energy values can be read through communication in MWh and MVArh in monitoring tool of PCM600 and/or alternatively the values can be presented on the local HMI. The local HMI graphical display is configured with PCM600 Graphical Display Editor tool (GDE) with a measuring value which is selected to the active and reactive component as preferred. Also all Accumulated Active Forward, Active Reverse, Reactive Forward and Reactive Reverse energy values can be presented.
Maximum demand values are presented in MWh or MVArh in the same way.

Alternatively, the energy values can be presented with use of the pulse counters function (PCGGIO). The output energy values are scaled with the pulse output setting values $E_A F_A c c P l s Q t y$, $E_A R Acc P l s Q t y$, $E_R F A cc P l s Q t y$ and $E_R V Acc P l s Q t y$ of the energy metering function and then the pulse counter can be set-up to present the correct values by scaling in this function. Pulse counter values can then be presented on the local HMI in the same way and/or sent to the SA (Substation Automation) system through communication where the total energy then is calculated by summation of the energy pulses. This principle is good for very high values of energy as the saturation of numbers else will limit energy integration to about one year with 50 kV and 3000 A. After that the accumulation will start on zero again.

18.2.3 Setting guidelines

The parameters are set via the local HMI or PCM600.

The following settings can be done for the energy calculation and demand handling function ETPMMTR:

*GlobalBaseSel:* Selects the global base value group used by the function to define $I_{Baseline}$, $V_{Baseline}$ and $S_{Baseline}$. Note that this function will only use $I_{Baseline}$ value.

*Operation: Disabled/Enabled*

*EnaAcc: Disabled/Enabled* is used to switch the accumulation of energy on and off.

*tEnergy: Time interval when energy is measured.*

*tEnergyOnPls: gives the pulse length ON time of the pulse. It should be at least 100 ms when connected to the Pulse counter function block. Typical value can be 100 ms.*

*tEnergyOffPls: gives the OFF time between pulses. Typical value can be 100 ms.*

*EAFAccPlsQty and EARAccPlsQty:* gives the MWh value in each pulse. It should be selected together with the setting of the Pulse counter (PCGGIO) settings to give the correct total pulse value.

*ERFAccPlsQty and ERVAccPlsQty:* gives the MVArh value in each pulse. It should be selected together with the setting of the Pulse counter (PCGGIO) settings to give the correct total pulse value.

For the advanced user there are a number of settings for direction, zero clamping, max limit, and so on. Normally, the default values are suitable for these parameters.
Section 19  Ethernet-based communication

19.1  Access point

19.1.1  Application

The access points are used to connect the IED to the communication buses (like the station bus) that use communication protocols. The access point can be used for single and redundant data communication. The access points are also used for communication with the merging units and for time synchronization using Precision Time Protocol (PTP).

19.1.2  Setting guidelines

The physical ports allocated to access points 2–6 have to be added in the hardware tool in PCM600 before the access points can be configured. The factory setting only includes the physical ports allocated to the front port and access point 1.

The settings for the access points are configured using the Ethernet configuration tool (ECT) in PCM600.

The access point is activated if the Operation checkbox is checked for the respective access point and a partial or common write to IED is performed.

To increase security, it is recommended to deactivate the access point when it is not in use.

Redundancy and PTP cannot be set for the front port (Access point 0) as redundant communication and PTP are only available for the rear optical Ethernet ports.

Subnetwork shows the SCL subnetwork to which the access point is connected. This column shows the SCL subnetworks available in the PCM600 project. SCL subnetworks can be created/deleted in the Subnetworks tab of IEC 61850 Configuration tool in PCM600.

When saving the ECT configuration after selecting a subnetwork, ECT creates the access point in the SCL model. Unselecting the subnetwork removes the access point from the SCL model. This column is editable for IEC61850 Ed2 IEDs and not editable for IEC61850 Ed1 IEDs because in IEC61850 Ed1 only one access point can be modelled in SCL.

The IP address can be set in IP address. ECT validates the value, the access points have to be on separate subnetworks.

The subnetwork mask can be set in Subnet mask. This field will be updated to the SCL model based on the Subnetwork selection.
To select which communication protocols can be run on the respective access points, check or uncheck the check box for the relevant protocol. The protocols are not activated/deactivated in ECT, only filtered for the specific access point. For information on how to activate the individual communication protocols, see the communication protocol chapters.

To increase security it is recommended to uncheck protocols that are not used on the access point.

The default gateway can be selected by entering the IP address in Default gateway. The default gateway is the router that is used to communicate with the devices in the other subnetwork. By default this is set to 0.0.0.0 which means that no default gateway is selected. ECT validates the entered value, but the default gateway has to be in the same subnet as the access point. The default gateway is the router that is being used as default, that is when no route has been set up for the destination. If communication with a device in another subnetwork is needed, a route has to be set up. For more information on routes, see the Routes chapter in the Technical manual and the Application manual.

DHCP can be activated for the front port from the LHMI in Main menu/Configuration/Communication/Ethernet configuration/Front port/DHCP:1

19.2 Redundant communication

19.2.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>IEC 62439-3 Parallel redundancy protocol</td>
<td>PRP</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>IEC 62439-3 High-availability seamless redundancy</td>
<td>HSR</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Access point diagnostic for redundant Ethernet ports</td>
<td>RCHLCCH</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

19.2.2 Application

Dynamic access point diagnostic (RCHLCCH) is used to supervise and assure redundant Ethernet communication over two channels. This will secure data transfer even though one communication channel might not be available for some reason.

Parallel Redundancy Protocol (PRP) and High-availability Seamless Redundancy (HSR) provides redundant communication over station bus running the available communication protocols. The redundant communication uses two Ethernet ports.
Figure 324: Parallel Redundancy Protocol (PRP)

Figure 325: High-availability Seamless Redundancy (HSR)
19.2.3 Setting guidelines

Redundant communication is configured with the Ethernet configuration tool in PCM600.

*Redundancy:* redundant communication is activated when the parameter is set to PRP-0, PRP-1 or HSR. The settings for the next access point will be hidden and PhyPortB will show the second port information. Redundant communication is activated after a common write to IED is done.

PRP-1 should be used primarily, PRP-0 is intended only for use in existing PRP-networks. PRP-1 and HSR can be combined in a mixed network.

If the access point is not taken into operation, the write option in Ethernet Configuration Tool can be used to activate the access point.

![Figure 326: ECT screen with Redundancy set to PRP-1 on Access point 1 and HSR Access point 3](image-url)

19.3 Merging unit

19.3.1 Application

The IEC/UCA 61850-9-2LE process bus communication protocol enables an IED to communicate with devices providing measured values in digital format, commonly known as Merging Units (MU). The rear access points are used for the communication.

The merging units (MU) are called so because they can gather analog values from one or more measuring transformers, sample the data and send the data over process bus to other clients (or subscribers) in the system. Some merging units are able to get data from classical measuring transformers, others from non-conventional measuring transducers and yet others can pick up data from both types.
19.3.2 Setting guidelines

For information on the merging unit setting guidelines, see section IEC/UCA 61850-9-2LE communication protocol.

19.4 Routes

19.4.1 Application

Setting up a route enables communication to a device that is located in another subnetwork. Routing is used when the destination device is not in the same subnetwork as the default gateway.

The route specifies that when a package is sent to the destination device it should be sent through the selected router. If no route is specified the source device will not find the destination device.

19.4.2 Setting guidelines

Routes are configured using the Ethernet configuration tool in PCM600.

Operation for the route can be set to On/Off by checking and unchecking the check-box in the operation column.

Gateway specifies the address of the gateway.

Destination specifies the destination.

Destination subnet mask specifies the subnetwork mask of the destination.
Section 20  Station communication

20.1  Communication protocols

Each IED is provided with several communication interfaces enabling it to connect to one or many substation level systems or equipment, either on the Substation Automation (SA) bus or Substation Monitoring (SM) bus.

Available communication protocols are:

- IEC 61850-8-1 communication protocol
- IEC/UCA 61850-9-2LE communication protocol
- LON communication protocol
- SPA communication protocol
- IEC 60870-5-103 communication protocol
- C37.118 communication protocol

Several protocols can be combined in the same IED.

20.2  IEC 61850-8-1 communication protocol

20.2.1  Application IEC 61850-8-1

IEC 61850-8-1 communication protocol allows vertical communication to HSI clients and allows horizontal communication between two or more intelligent electronic devices (IEDs) from one or several vendors to exchange information and to use it in the performance of their functions and for correct co-operation.

GOOSE (Generic Object Oriented Substation Event), which is a part of IEC 61850–8–1 standard, allows the IEDs to communicate state and control information amongst themselves, using a publish-subscribe mechanism. That is, upon detecting an event, the IED(s) use a multi-cast transmission to notify those devices that have registered to receive the data. An IED can, by publishing a GOOSE message, report its status. It can also request a control action to be directed at any device in the network.

Figure 328 shows the topology of an IEC 61850–8–1 configuration. IEC 61850–8–1 specifies only the interface to the substation LAN. The LAN itself is left to the system integrator.
Figure 328: SA system with IEC 61850–8–1

Figure 329 shows the GOOSE peer-to-peer communication.

Figure 329: Example of a broadcasted GOOSE message
20.2.2 Setting guidelines

There are two settings related to the IEC 61850–8–1 protocol:

Operation: User can set IEC 61850 communication to Enabled or Disabled.

GOOSEPortEd1: Selection of the Ethernet link where GOOSE traffic shall be sent and received. This is only valid for Edition 1 and can be ignored if Edition 2 is used. For Edition 2, the Ethernet link selection is done with the Ethernet Configuration Tool (ECT) in PCM600.

20.2.3 Horizontal communication via GOOSE

20.2.3.1 Sending data

In addition to the data object and data attributes of the logical nodes, it is possible to send the outputs of the function blocks using the generic communication blocks. The outputs of this function can be set in a dataset and be sent in a GOOSE Control Block to other subscriber IEDs. There are different function blocks for different type of sending data.

Generic communication function for Single Point indication SPGAPC, SP16GAPC

Application
Generic communication function for Single Point Value (SPGAPC) function is used to send one single logical output to other systems or equipment in the substation. SP16GAPC can be used to send up to 16 single point values from the application functions running in the same cycle time. SPGAPC has one visible input and SPGAPC16 has 16 visible inputs that should be connected in the ACT tool.

Setting guidelines
There are no settings available for the user for SPGAPC.

Generic communication function for Measured Value MVGAPC

Application
Generic communication function for measured values (MVGAPC) function is used to send the instantaneous value of an analog signal to other systems or equipment in the substation. It can also be used inside the same IED, to attach a RANGE aspect to an analog value and to permit measurement supervision on that value.

Setting guidelines
The settings available for Generic communication function for Measured Value (MVGAPC) function allows the user to choose a deadband and a zero deadband for the monitored signal. Values within the zero deadband are considered as zero.

The high and low limit settings provides limits for the high-high-, high, normal, low and low-low ranges of the measured value. The actual range of the measured value is shown on the range output of MVGAPC function block. When a Measured value expander block (RANGE_XP) is connected to the range output, the logical outputs of the RANGE_XP are changed accordingly.
20.2.3.2 Receiving data

The GOOSE data must be received at function blocks. There are different GOOSE receiving function blocks depending on the type of the received data. Refer to the Engineering manual for more information about how to configure GOOSE.

<table>
<thead>
<tr>
<th>Function block type</th>
<th>Data Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>GOOSEBINRCV</td>
<td>16 single point</td>
</tr>
<tr>
<td>GOOSEINTLKRCV</td>
<td>2 single points</td>
</tr>
<tr>
<td></td>
<td>16 double points</td>
</tr>
<tr>
<td>GOOSEEDPRCV</td>
<td>Double point</td>
</tr>
<tr>
<td>GOOSEINTRCV</td>
<td>Integer</td>
</tr>
<tr>
<td>GOOSEMVRRCV</td>
<td>Analog value</td>
</tr>
<tr>
<td>GOOSESPPRCV</td>
<td>Single point</td>
</tr>
<tr>
<td>GOOSEXLNRCV</td>
<td>Switch status</td>
</tr>
</tbody>
</table>

Application

The GOOSE receive function blocks are used to receive subscribed data from the GOOSE protocol. The validity of the data value is exposed as outputs of the function block as well as the validity of the communication. It is recommended to use these outputs to ensure that only valid data is handled on the subscriber IED. An example could be to control the external reservation before operating on a bay. In the figure below, the GOOSESPPRCV is used to receive the status of the bay reservation. The validity of the received data is used in additional logic to guarantee that the value has good quality before operation on that bay.

![Figure 330: GOOSESPPRCV and AND function blocks - checking the validity of the received data](image)

20.3 IEC/UCA 61850-9-2LE communication protocol

20.3.1 Introduction

Every IED can be provided with communication interfaces enabling it to connect to the process buses in order to get data from analog data acquisition units close to the process (primary apparatus), commonly known as Merging Units (MU). The protocol used in this case is the IEC/UCA 61850-9-2LE communication protocol.

The IEC/UCA 61850-9-2LE standard does not specify the quality of the sampled values. Thus, the accuracy of the current and voltage inputs to the merging unit and the inaccuracy added by the merging unit must be coordinated with the requirement for the actual type of protection function.
Factors influencing the accuracy of the sampled values from the merging unit are, for example, anti aliasing filters, frequency range, step response, truncating, A/D conversion inaccuracy, time tagging accuracy etc.

In principle, the accuracy of the current and voltage transformers, together with the merging unit, will have the same quality as the direct input of currents and voltages.

The process bus physical layout can be arranged in several ways, described in Annex B of the standard, depending on what are the needs for sampled data in a substation.

Figure 331: Example of a station configuration with separated process bus and station bus

The IED can get analog values simultaneously from a classical CT or VT and from a Merging Unit, like in this example:

The merging units (MU) are called so because they can gather analog values from one or more measuring transformers, sample the data and send the data over process bus to other clients (or subscribers) in the system. Some merging units are able to get data from classical measuring transformers, others from non-conventional measuring transducers and yet others can pick up data from both types. The electronic part of a non-conventional measuring transducer (like a Rogowski coil or a capacitive divider) can represent a MU by itself as long as it can send sampled data over process bus.
20.3.2 Faulty merging unit for bay in service

When a merging unit goes faulty while the bay is in service, the protection functions connected to that merging unit get blocked. Also, protection functions configured in a 1 1/2 circuit breaker applications, where two SV streams from different merging units are combined get blocked. Thus, this has no effect on protection functions in a 1 1/2 circuit breaker configuration.

This can be resolved by connecting external binary input signals to the BLOCK input on the respective SMAI function blocks with the use of ACT. When the BLOCK input on a SMAI function is
energized, the SMAI function delivers a magnitude of zero with good quality for all the channels. Thus, this has no effect on a busbar protection, nor protections in an 1 1/2 circuit breaker configuration.

SMAI function blocks exist in different cycle times, and all the SMAI blocks that receive SV streams from the merging units must have the block input signal configured in the same way to get the correct behavior.

---

**Figure 333:** Configuration of current inputs using SMAIs in a 1 1/2 circuit breaker application.

**Procedure to bring protections back into service and enable maintenance of a faulty merging unit**

1. Disconnect bay
2. Energize binary input, block of bay. Protections are now back in service.
3. Maintenance of the merging unit can start.

**Procedure to bring bay back into service after maintenance of a merging unit**

1. Energize merging unit.
2. De-energize binary input block of bay. Protections are now back in service.
3. Reconnect bay.

**20.3.3 Bay out of service for maintenance**

When a bay needs maintenance and has energized merging unit connected, it is always a risk to get unplanned interruptions in the auxiliary power supply which may lead to unwanted blocking of protections.

This can be resolved by using the same ACT configuration recommendations and procedures as described in section [Faulty merging unit for bay in service](#).
20.3.4 Setting guidelines

Merging Units (MUs) have several settings on local HMI under:

- **Main menu/Configuration/Analog modules/MUx:92xx**. The corresponding settings are also available in PST (PCM600).
- **Main menu/Configuration/Communication/Merging units configuration/MUx:92xx**. The corresponding settings are also available in ECT (PCM600).

XX can take value 01–12.

20.3.4.1 Specific settings related to the IEC/UCA 61850-9-2LE communication

The process bus communication IEC/UCA 61850-9-2LE has specific settings, similar to the analog inputs modules.

If there are more than one sample group involved, time synch is mandatory. If there is no time synchronization, the protection functions will be blocked due to condition blocking.

**CTStarPointx**: These parameters specify the direction to or from object. See also section "Setting of current channels".

**SyncLostMode**: If this parameter is set to *Block* and the IED hardware time synchronization is lost or the synchronization to the MU time is lost, the protection functions in the list "" will be blocked due to conditional blocking. If this parameter is set to *BlockOnLostUTC*, the protection functions in list "" are blocked if the IED hardware time synchronization is lost or the synchronization of the MU time is lost or the IED has lost global common synchronization (i.e. GPS, IRIG-B or PTP). *SYNCH* output will be set if IED hardware time synchronization is lost. *MUSYNCH* output will be set if either of MU or IED hardware time synchronization is lost.

Binary signals over LDCM are transmitted as valid and processed normally even when analog signals are transmitted as invalid due to loss of communication or loss of time synchronization.

Table 86: Blocked protection functions if IEC/UCA 61850-9-2LE communication is interrupted and functions are connected to specific MUs

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>Function description</th>
<th>IEC 61850 Identification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Accidental energizing protection for synchronous generator</td>
<td>AEGPVOC</td>
<td>Two step overvoltage protection</td>
<td>OV2PTOV</td>
</tr>
<tr>
<td>Broken conductor check</td>
<td>BRCPTOC</td>
<td>Four step single phase overcurrent protection</td>
<td>PH4SPTOC</td>
</tr>
<tr>
<td>Capacitor bank protection</td>
<td>CBPGAPC</td>
<td>Radial feeder protection</td>
<td>PAPGAPC</td>
</tr>
<tr>
<td>Pole discordance protection</td>
<td>CCPDSC</td>
<td>Instantaneous phase overcurrent protection</td>
<td>PHPIOC</td>
</tr>
<tr>
<td>Breaker failure protection</td>
<td>CCRBRF</td>
<td>PoleSlip/Out-of-step protection</td>
<td>PSSPPPAM</td>
</tr>
<tr>
<td>Breaker failure protection, single phase version</td>
<td>CCSRBRF</td>
<td>Restricted earth fault protection, low impedance</td>
<td>REFPDIF</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 Identification</th>
<th>Function description</th>
<th>IEC 61850 Identification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current circuit supervision</td>
<td>CCSSPVC</td>
<td>Two step residual overvoltage protection</td>
<td>ROV2PTOVP</td>
</tr>
<tr>
<td>Compensated over- and undervoltage protection</td>
<td>COUVGAPC</td>
<td>Rate-of-change frequency protection</td>
<td>SAPFRC</td>
</tr>
<tr>
<td>General current and voltage protection</td>
<td>CVGAPC</td>
<td>Overfrequency protection</td>
<td>SAPTOF</td>
</tr>
<tr>
<td>Current reversal and weakened infeed logic for residual overcurrent protection</td>
<td>ECRWPSCH</td>
<td>Underfrequency protection</td>
<td>SAPTUF</td>
</tr>
<tr>
<td>Four step residual overcurrent protection</td>
<td>EF4PTOC</td>
<td>Sudden change in current variation</td>
<td>SCCVPTOC</td>
</tr>
<tr>
<td>Instantaneous residual overcurrent protection</td>
<td>EFPIOC</td>
<td>Sensitive Directional residual over current and power protection</td>
<td>SDEPSDE</td>
</tr>
<tr>
<td>Phase selection, quadrilateral characteristic with fixed angle</td>
<td>FDPSPDIS</td>
<td>Synchrocheck, energizing check, and synchronizing</td>
<td>SESRSYN</td>
</tr>
<tr>
<td>Faulty phase identification with load encroachment</td>
<td>FMPSPDIS</td>
<td>Circuit breaker condition monitoring</td>
<td>SSCBR</td>
</tr>
<tr>
<td>Phase selection, quadrilateral characteristic with settable angle</td>
<td>FRPSPDIS</td>
<td>Insulation gas monitoring</td>
<td>SSIMG</td>
</tr>
<tr>
<td>Frequency time accumulation protection</td>
<td>FTAQFVR</td>
<td>Insulation liquid monitoring</td>
<td>SSIML</td>
</tr>
<tr>
<td>Fuse failure supervision</td>
<td>FUFSVPVC</td>
<td>Stub protection</td>
<td>STBPTOC</td>
</tr>
<tr>
<td>Generator differential protection</td>
<td>GENPDIF</td>
<td>Transformer differential protection, two winding</td>
<td>T2WPDIF</td>
</tr>
<tr>
<td>Directional Overpower protection</td>
<td>GOPPDOP</td>
<td>Transformer differential protection, three winding</td>
<td>T3WPDIF</td>
</tr>
<tr>
<td>Generator rotor overload protection</td>
<td>GRPTTR</td>
<td>Automatic voltage control for tapchanger, single control</td>
<td>TRIATCC</td>
</tr>
<tr>
<td>Generator stator overload protection</td>
<td>GSPTTR</td>
<td>Automatic voltage control for tapchanger, parallel control</td>
<td>TR8ATCC</td>
</tr>
<tr>
<td>Directional Underpower protection</td>
<td>GUPPDUP</td>
<td>Thermal overload protection, two time constants</td>
<td>TRPTTR</td>
</tr>
<tr>
<td>1Ph High impedance differential protection</td>
<td>HZPDIF</td>
<td>Two step undervoltage protection</td>
<td>UV2PTUUV</td>
</tr>
<tr>
<td>Line differential protection, 3 CT sets, 2-3 line ends</td>
<td>L3CPDIF</td>
<td>Voltage differential protection</td>
<td>VDCPTOVT</td>
</tr>
<tr>
<td>Line differential protection, 6 CT sets, 3-5 line ends</td>
<td>L6CPDIF</td>
<td>Fuse failure supervision</td>
<td>VDRFUF</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>Function description</th>
<th>IEC 61850 Identification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low active power and power factor protection</td>
<td>LAPPGAPC</td>
<td>Voltage-restrained time overcurrent protection</td>
<td>VRPVOCS</td>
</tr>
<tr>
<td>Negative sequence overcurrent protection</td>
<td>LCNSPTOC</td>
<td>Local acceleration logic</td>
<td>ZCLCPSCCH</td>
</tr>
<tr>
<td>Negative sequence overvoltage protection</td>
<td>LCNSPTOV</td>
<td>Scheme communication logic for distance or overcurrent protection</td>
<td>ZCPSCCH</td>
</tr>
<tr>
<td>Three phase overcurrent</td>
<td>LCP3PTOC</td>
<td>Current reversal and weak-end infeed logic for distance protection</td>
<td>ZCRWPSCH</td>
</tr>
<tr>
<td>Three phase undercurrent</td>
<td>LCP3PTUC</td>
<td>Automatic switch onto fault logic, voltage and current based</td>
<td>ZCVPSOF</td>
</tr>
<tr>
<td>Thermal overload protection, one time constant</td>
<td>LCPTTR</td>
<td>Under impedance protection for generator</td>
<td>ZGVPDIS</td>
</tr>
<tr>
<td>Zero sequence overcurrent protection</td>
<td>LCZSPTOC</td>
<td>Fast distance protection</td>
<td>ZMFCPDIS</td>
</tr>
<tr>
<td>Zero sequence overvoltage protection</td>
<td>LCZSPTOV</td>
<td>High speed distance protection</td>
<td>ZMFPPDIS</td>
</tr>
<tr>
<td>Line differential coordination</td>
<td>LDLPSCCH</td>
<td>Distance measuring zone, quadrilateral characteristic for series compensated lines</td>
<td>ZMCAPDIS</td>
</tr>
<tr>
<td>Additional security logic for differential protection</td>
<td>LDRGFC</td>
<td>Distance measuring zone, quadrilateral characteristic for series compensated lines</td>
<td>ZMCAPDIS</td>
</tr>
<tr>
<td>Loss of excitation</td>
<td>LEXPDIS</td>
<td>Fullscheme distance protection, mho characteristic</td>
<td>ZMHPDIS</td>
</tr>
<tr>
<td>Thermal overload protection, one time constant</td>
<td>LFPTTR</td>
<td>Fullscheme distance protection, quadrilateral for earth faults</td>
<td>ZMMAPDIS</td>
</tr>
<tr>
<td>Loss of voltage check</td>
<td>LOVPTUV</td>
<td>Fullscheme distance protection, quadrilateral for earth faults</td>
<td>ZMMPDIS</td>
</tr>
<tr>
<td>Line differential protection 3 CT sets, with inzone transformers, 2-3 line ends</td>
<td>LT3CPDIF</td>
<td>Distance protection zone, quadrilateral characteristic</td>
<td>ZMQAPDIS</td>
</tr>
<tr>
<td>Line differential protection 6 CT sets, with inzone transformers, 3-5 line ends</td>
<td>LT6CPDIF</td>
<td>Distance protection zone, quadrilateral characteristic</td>
<td>ZMQPDIS</td>
</tr>
<tr>
<td>Negativ sequence time overcurrent protection for machines</td>
<td>NS2PTOC</td>
<td>Distance protection zone, quadrilateral characteristic, separate settings</td>
<td>ZMRAPDIS</td>
</tr>
<tr>
<td>Four step directional negative phase sequence overcurrent protection</td>
<td>NS4PTOC</td>
<td>Distance protection zone, quadrilateral characteristic, separate settings</td>
<td>ZMRPDIS</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 Identification</th>
<th>Function description</th>
<th>IEC 61850 Identification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Four step phase overcurrent protection</td>
<td>OC4PTOC</td>
<td>Power swing detection</td>
<td>ZMRPSB</td>
</tr>
<tr>
<td>Overexcitation protection</td>
<td>OEXPVPH</td>
<td>Mho Impedance supervision logic</td>
<td>ZSMGAPC</td>
</tr>
<tr>
<td>Out-of-step protection</td>
<td>OOSPPAM</td>
<td>Transformer tank overcurrent protection</td>
<td>TPPIOC</td>
</tr>
<tr>
<td>Busbar differential protection, check zone</td>
<td>BCZPDIF</td>
<td>Busbar differential protection, bus interconnection xx</td>
<td>BICPTRC_x, (1≤x≤5)</td>
</tr>
<tr>
<td>Busbar differential protection, dynamic zone selection</td>
<td>BDZSGAPC</td>
<td>Busbar differential protection, zone 1</td>
<td>BZNPDIF_Zx, (1≤x≤6)</td>
</tr>
<tr>
<td>Busbar differential protection, single phase feeder xx</td>
<td>BFPRTRC_Fx, (1≤x≤24)</td>
<td>Through fault monitoring</td>
<td>PTRSTHR</td>
</tr>
<tr>
<td>Voltage delta supervision, 2 phase</td>
<td>DELVSPVC</td>
<td>Current delta supervision, 2 phase</td>
<td>DELISPVC</td>
</tr>
<tr>
<td></td>
<td>DELSPVVC</td>
<td>Current harmonic monitoring, 2 phase</td>
<td>CHMMHAN</td>
</tr>
</tbody>
</table>

### 20.3.4.2 Setting examples for IEC/UCA 61850-9-2LE and time synchronization

The IED and the Merging Units (MU) should use the same time reference especially if analog data is used from several sources, for example from an internal TRM and an MU, or if several physical MUs are used. Having the same time reference is important to correlate data so that channels from different sources refer to the correct phase angle.

When only one MU is used as an analog source, it is theoretically possible to do without time synchronization. However, this would mean that timestamps for analog and binary data/events become uncorrelated. If the IED has no time synchronization source configured, then the binary data/events will be synchronized with the merging unit. However, the global/complete time might not be correct. Disturbance recordings then appear incorrect since analog data is timestamped by MU, and binary events use the internal IED time. It is thus recommended to use time synchronization also when analog data emanate from only one MU.

An external time source can be used to synchronize both the IED and the MU. It is also possible to use the MU as a clock master to synchronize the IED from the MU. When using an external clock, it is possible to set the IED to be synchronized via PPS,IRIG-B or PTP. It is also possible to use an internal GPS receiver in the IED (if the external clock is using GPS).
Using PTP for synchronizing the MU

Figure 334: Setting example with PTP synchronization

Settings on the local HMI under Main menu/Configuration/Time/Synchronization/TIMESYNCHGEN:1/IEC61850-9-2:

1. **HwSyncSrc**: is not used as the SW-time and HW-time are connected with each other due to PTP
2. **SyncLostMode**: set to **Block** to block protection functions if time synchronization is lost or set to **BlockOnLostUTC** if the protection functions are to be blocked when global common synchronization is lost
3. **SyncAccLevel**: can be set to **1μs** since this corresponds to a maximum phase angle error of 0.018 degrees at 50Hz

Settings on the local HMI under Main menu/Configuration/Communication/Ethernet configuration/Access point/AP_X:

1. **Operation**: On
2. **PTP**: On

Two status monitoring signals can be:
• SYNCH signal on the MUx function block indicates that protection functions are blocked due to loss of internal time synchronization to the IED.
• MUSYNCH signal on the MUx function block monitors the synchronization flag \textit{smpSynch} in the datastream and IED hardware time synchronization.

**Using MU for time synchronization via PPS**

This example is not valid when GPS time is used for differential protection, when PTP is enabled or when the PMU report is used.

---

**Figure 335: Setting example when MU is the synchronizing source**

Settings on the local HMI under \textbf{Main menu/Configuration/Time/Synchronization/ TIMESYNCHGEN:1/IEC61850-9-2:}

• \textit{HwSyncSrc}: set to PPS as generated by the MU (ABB MU)
• \textit{SyncLostMode}: set to \textit{Block} to block protection functions if time synchronization is lost
• \textit{SyncAccLevel}: can be set to 4\(\mu\)s since this corresponds to a maximum phase angle error of 0.072 degrees at 50Hz

Settings on the local HMI under \textbf{Main menu/Configuration/Time/Synchronization/ TIMESYNCHGEN:1/General:}

• \textit{fineSyncSource} can be set to something different to correlate events and data to other IEDs in the station.

Two status monitoring signals can be:

• SYNCH signal on the MUx function block indicates that protection functions are blocked due to loss of internal time synchronization to the IED.
• MUSYNCH signal on the MUx function block monitors the synchronization flag \textit{smpSynch} in the datastream and IED hardware time synchronization.
SMPLLOST indicates that merging unit data are generated by internal substitution or one/more channel's Quality is not good or merging unit is in Testmode/detailed quality=Test, IED is not in test mode.

**Using external clock for time synchronization**

This example is not valid when GPS time is used for differential protection, when PTP is enabled or when the PMU report is used.

![Diagram of external clock synchronization](image)

**Figure 336: Setting example with external synchronization**

Settings on the local HMI under **Main menu/Configuration/Time/Synchronization/TIMESYNCHGEN:1/IEC61850-9-2:**

- **HwSyncSrc**: set to PPS/IRIG-B depending on available outputs on the clock.
- **SyncLostMode**: set to Block to block protection functions if time synchronization is lost.
- **SyncAccLevel**: can be set to 4μs since this corresponds to a maximum phase angle error of 0.072 degrees at 50Hz.
- **fineSyncSource**: should be set to IRIG-B if available from the clock. If PPS is used for HWSyncSrc, “full-time” has to be acquired from another source. If station clock is on the local area network (LAN) and has an sntp-server, this is one option.

Two status monitoring signals can be:

- **SYNCH** signal on the MUX function block indicates that protection functions are blocked due to loss of internal time synchronization to the IED (that is loss of the hardware synchSrc).
- **MUSYNCH** signal on the MUX function block monitors the synchronization flag smpSynch in the datastream and IED hardware time synchronization.

**No time synchronization**

This example is not valid when GPS time is used for differential protection, when PTP is enabled or when the PMU report is used.
Figure 337: Setting example without time synchronization

It is also possible to use IEC/UCA 61850-9-2LE communication without time synchronization.

Settings on the local HMI under **Main menu/Configuration/Time/Synchronization/TIMESYNCHGEN:1/IEC61850-9-2**:

- \( HwSyncSrc \) set to **Off**
- \( SyncLostMode \) set to **No block** to indicate that protection functions are not blocked
- \( SyncAccLevel \) set to **unspecified**

Two status monitoring signals with no time synchronization:

- SYCH signal on the MUx function block indicates that protection functions are blocked due to loss of internal time synchronization to the IED. Since \( SyncLostMode \) is set to **No block**, this signal is not set.
- MUSYNCH signal on the MUx function block is set if the datastream indicates time synchronization loss. However, protection functions are not blocked.

To get higher availability in protection functions, it is possible to avoid blocking during time synchronization loss if there is a single source of analog data. This means that if there is only one physical MU and no TRM, parameter \( SyncLostMode \) is set to **No block** but parameter \( HwSyncSrc \) is still set to **PPS**. This maintains analog and binary data correlation in disturbance recordings without blocking protection functions if PPS is lost.
20.4 LON communication protocol

20.4.1 Application

![Diagram of LON communication structure](IEC05000663-1-en.vsd)

**Figure 338: Example of LON communication structure for a substation automation system**

An optical network can be used within the substation automation system. This enables communication with the IEDs through the LON bus from the operator’s workplace, from the control center and also from other IEDs via bay-to-bay horizontal communication. For LON communication an SLM card should be ordered for the IEDs.

The fiber optic LON bus is implemented using either glass core or plastic core fiber optic cables.

**Table 87: Specification of the fiber optic connectors**

<table>
<thead>
<tr>
<th></th>
<th>Glass fiber</th>
<th>Plastic fiber</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cable connector</td>
<td>ST-connector</td>
<td>snap-in connector</td>
</tr>
<tr>
<td>Cable diameter</td>
<td>62.5/125 m</td>
<td>1 mm</td>
</tr>
<tr>
<td>Max. cable length</td>
<td>1000 m</td>
<td>10 m</td>
</tr>
<tr>
<td>Wavelength</td>
<td>820-900 nm</td>
<td>660 nm</td>
</tr>
<tr>
<td>Transmitted power</td>
<td>-13 dBm (HFBR-1414)</td>
<td>-13 dBm (HFBR-1521)</td>
</tr>
<tr>
<td>Receiver sensitivity</td>
<td>-24 dBm (HFBR-2412)</td>
<td>-20 dBm (HFBR-2521)</td>
</tr>
</tbody>
</table>

The LON Protocol

The LON protocol is specified in the LonTalkProtocol Specification Version 3 from Echelon Corporation. This protocol is designed for communication in control networks and is a peer-to-peer protocol where all the devices connected to the network can communicate with each other.
directly. For more information of the bay-to-bay communication, refer to the section Multiple command function.

**Hardware and software modules**
The hardware needed for applying LON communication depends on the application, but one very central unit needed is the LON Star Coupler and optical fibers connecting the star coupler to the IEDs. To interface the IEDs from the MicroSCADA with Classic Monitor, application library LIB520 is required.

The HV Control 670 software module is included in the LIB520 high-voltage process package, which is a part of the Application Software Library in MicroSCADA applications.

The HV Control 670 software module is used for control functions in the IEDs. The module contains a process picture, dialogues and a tool to generate a process database for the control application in MicroSCADA.

When using MicroSCADA Monitor Pro instead of the Classic Monitor, SA LIB is used together with 670 series Object Type files.

The HV Control 670 software module and 670 series Object Type files are used with both 650 and 670 series IEDs.

Use the LON Network Tool (LNT) to set the LON communication. This is a software tool applied as one node on the LON bus. To communicate via LON, the IEDs need to know:

- The node addresses of the other connected IEDs.
- The network variable selectors to be used.

This is organized by LNT.

The node address is transferred to LNT via the local HMI by setting the parameter ServicePinMsg = Yes. The node address is sent to LNT via the LON bus, or LNT can scan the network for new nodes.

The communication speed of the LON bus is set to the default of 1.25 Mbit/s. This can be changed by LNT.

### 20.4.2 MULTICMDRCV and MULTICMDSND

#### 20.4.2.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Multiple command and receive</td>
<td>MULTICMDRCV</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Multiple command and send</td>
<td>MULTICMDSND</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>
20.4.2.2 Application

The IED provides two function blocks enabling several IEDs to send and receive signals via the interbay bus. The sending function block, MULTICMDSEND, takes 16 binary inputs. LON enables these to be transmitted to the equivalent receiving function block, MULTICMDRCV, which has 16 binary outputs.

20.4.2.3 Setting guidelines

Settings

The parameters for the multiple command function are set via PCM600.

The Mode setting sets the outputs to either a Steady or Pulsed mode.

20.5 SPA communication protocol

20.5.1 Application

SPA communication protocol is an alternative to IEC 60870-5-103, and they use the same rear communication port.

When communicating with a PC connected to the utility substation LAN via WAN and the utility office LAN (see Figure 339), and when using the rear optical Ethernet port, the only hardware required for a station monitoring system is:

- Optical fibers from the IED to the utility substation LAN
- PC connected to the utility office LAN

Figure 339: SPA communication structure for a remote monitoring system via a substation LAN, WAN and utility LAN

SPA communication is mainly used for the Station Monitoring System. It can include different IEDs with remote communication possibilities. Connection to a PC can be made directly (if the PC is located in the substation), via a telephone modem through a telephone network with ITU (former CCITT) characteristics or via a LAN/WAN connection.
### Functionality
The SPA protocol V2.5 is an ASCII-based protocol for serial communication. The communication is based on a master-slave principle, where the IED is a slave and the PC is the master. Only one master can be applied on each fiber optic loop. A program is required in the master computer for interpretation of the SPA-bus codes and for translation of the data that should be sent to the IED.

For the specification of the SPA protocol V2.5, refer to SPA-bus Communication Protocol V2.5.

#### 20.5.2 Setting guidelines

SPA, IEC 60870-5-103 and DNP3 use the same rear communication port. This port can be set for SPA use on the local HMI under Main menu / Configuration / Communication / Station communication / Port configuration / SLM optical serial port / PROTOCOL: 1. When the communication protocol is selected, the IED is automatically restarted, and the port then operates as a SPA port.

The SPA communication setting parameters are set on the local HMI under Main menu / Configuration / Communication / Station communication / SPA / SPA: 1.

The most important SPA communication setting parameters are **SlaveAddress** and **BaudRate**. They are essential for all communication contact to the IED. **SlaveAddress** and **BaudRate** can be set only on the local HMI for rear and front channel communication.

**SlaveAddress** can be set to any value between 1–899 as long as the slave number is unique within the used SPA loop. **BaudRate** (communication speed) can be set between 300–38400 baud. **BaudRate** should be the same for the whole station although different communication speeds in a loop are possible. If different communication speeds are used in the same fiber optical loop or RS485 network, take this into account when making the communication setup in the communication master (the PC).

With local fiber optic communication, communication speed is usually set to 19200 or 38400 baud. With telephone communication, the speed setting depends on the quality of the connection and the type of modem used. Refer to technical data to determine the rated communication speed for the selected communication interfaces.

The IED does not adapt its speed to the actual communication conditions because the communication speed is set on the local HMI.
20.6 **IEC 60870-5-103 communication protocol**

### 20.6.1 Application

![Diagram](ANS105000680-4-en.vsd)

*Figure 340: Example of IEC 60870-5-103 communication structure for a substation automation system*

IEC 60870-5-103 communication protocol is mainly used when a protection IED communicates with a third party control or monitoring system. This system must have software that can interpret the IEC 60870-5-103 communication messages.

When communicating locally in the station using a Personal Computer (PC) or a Remote Terminal Unit (RTU) connected to the Communication and processing module, the only hardware needed is optical fibers and an opto/electrical converter for the PC/RTU, or a RS-485 connection depending on the used IED communication interface.

#### 20.6.1.1 Functionality

IEC 60870-5-103 is an unbalanced (master-slave) protocol for coded-bit serial communication exchanging information with a control system. In IEC terminology a primary station is a master and a secondary station is a slave. The communication is based on a point-to-point principle. The master must have software that can interpret the IEC 60870-5-103 communication messages. For detailed information about IEC 60870-5-103, refer to IEC 60870 standard part 5: Transmission protocols, and to the section 103, Companion standard for the informative interface of protection equipment.

#### 20.6.1.2 Design
General
The protocol implementation consists of the following functions:

- Event handling
- Report of analog service values (measurands)
- Fault location
- Command handling
  - Autorecloser ON/OFF
  - Teleprotection ON/OFF
  - Protection ON/OFF
  - LED reset
  - Characteristics 1 - 4 (Setting groups)
- File transfer (disturbance files)
- Time synchronization

Hardware
When communicating locally with a Personal Computer (PC) or a Remote Terminal Unit (RTU) in the station, using the SPA/IEC port, the only hardware needed is:
- Optical fibers, glass/plastic
- Opto/electrical converter for the PC/RTU
- PC/RTU

Commands
The commands defined in the IEC 60870-5-103 protocol are represented in dedicated function blocks. These blocks have output signals for all available commands according to the protocol. For more information, refer to the Communication protocol manual, IEC 60870-5-103.

- IED commands in control direction
  
  Function block with defined IED functions in control direction, I103IEDCMD. This block uses PARAMETR as FUNCTION TYPE, and INFORMATION NUMBER parameter is defined for each output signal.

- Function commands in control direction

  Function block with pre-defined functions in control direction, I103CMD. This block includes the FUNCTION TYPE parameter, and the INFORMATION NUMBER parameter is defined for each output signal.

- Function commands in control direction

  Function block with user defined functions in control direction, I103UserCMD. These function blocks include the FUNCTION TYPE parameter for each block in the private range, and the INFORMATION NUMBER parameter for each output signal.

Status
For more information on the function blocks below, refer to the Communication protocol manual, IEC 60870-5-103.

The events created in the IED available for the IEC 60870-5-103 protocol are based on the:

- IED status indication in monitor direction
Function block with defined IED functions in monitor direction, I103IED. This block uses PARAMETER as FUNCTION TYPE, and INFORMATION NUMBER parameter is defined for each input signal.

- Function status indication in monitor direction, user-defined
  
Function blocks with user defined input signals in monitor direction, I103UserDef. These function blocks include the FUNCTION TYPE parameter for each block in the private range, and the INFORMATION NUMBER parameter for each input signal.

- Supervision indications in monitor direction
  
Function block with defined functions for supervision indications in monitor direction, I103Superv. This block includes the FUNCTION TYPE parameter, and the INFORMATION NUMBER parameter is defined for each output signal.

- Ground fault indications in monitor direction
  
Function block with defined functions for ground fault indications in monitor direction, I103EF. This block includes the FUNCTION TYPE parameter, and the INFORMATION NUMBER parameter is defined for each output signal.

- Fault indications in monitor direction
  
Function block with defined functions for fault indications in monitor direction, I103FLTPROT. This block includes the FUNCTION TYPE parameter, and the INFORMATION NUMBER parameter is defined for each input signal.

This block is suitable for distance protection, line differential, transformer differential, overcurrent and ground-fault protection functions.

- Autorecloser indications in monitor direction
  
Function block with defined functions for autorecloser indications in monitor direction, I103AR. This block includes the FUNCTION TYPE parameter, and the INFORMATION NUMBER parameter is defined for each output signal.

**Measurands**

The measurands can be included as type 3.1, 3.2, 3.3, 3.4 and type 9 according to the standard.

- Measurands in public range
  
Function block that reports all valid measuring types depending on connected signals, I103Meas.

- Measurands in private range
  
Function blocks with user defined input measurands in monitor direction, I103MeasUsr. These function blocks include the FUNCTION TYPE parameter for each block in the private range, and the INFORMATION NUMBER parameter for each block.
Fault location
The fault location is expressed in reactive ohms. In relation to the line length in reactive ohms, it gives the distance to the fault in percent. The data is available and reported when the fault locator function is included in the IED.

Disturbance recordings
- The transfer functionality is based on the Disturbance recorder function. The analog and binary signals recorded will be reported to the master by polling. The eight last disturbances that are recorded are available for transfer to the master. A file that has been transferred and acknowledged by the master cannot be transferred again.
- The binary signals that are included in the disturbance recorder are those that are connected to the disturbance function blocks B1RBDR to B22RBDR. These function blocks include the function type and the information number for each signal. For more information on the description of the Disturbance report in the Technical reference manual. The analog channels, that are reported, are those connected to the disturbance function blocks A1RADR to A4RADR. The eight first ones belong to the public range and the remaining ones to the private range.

20.6.2 Settings

20.6.2.1 Settings for RS485 and optical serial communication

General settings
SPA, DNP and IEC 60870-5-103 can be configured to operate on the SLM optical serial port while DNP and IEC 60870-5-103 additionally can utilize the RS485 port. A single protocol can be active on a given physical port at any time.

Two different areas in the HMI are used to configure the IEC 60870-5-103 protocol.

1. The port specific IEC 60870-5-103 protocol parameters are configured under:
   Main menu/Configuration/Communication/Station Communication/IEC60870-5-103/
   - <config-selector>
   - SlaveAddress
   - BaudRate
   - RevPolarity (optical channel only)
   - CycMeasRepTime
   - MasterTimeDomain
   - TimeSyncMode
   - EvalTimeAccuracy
   - EventRepMode
   - CmdMode
   - RepIntermediatePos

   <config-selector> is:
   - “OPTICAL103:1” for the optical serial channel on the SLM
   - “RS485103:1” for the RS485 port

2. The protocol to activate on a physical port is selected under:
   Main menu/Configuration/Communication/Station Communication/Port configuration/
   - RS485 port
RS485PROT:1 (off, DNP, IEC103)
SLM optical serial port
PROTOCOL:1 (off, DNP, IEC103, SPA)

Figure 341: Settings for IEC 60870-5-103 communication

The general settings for IEC 60870-5-103 communication are the following:

- **SlaveAddress** and **BaudRate**: Settings for slave number and communication speed (baud rate). The slave number can be set to any value between 1 and 254. The communication speed can be set either to 9600 bits/s or 19200 bits/s.
- **RevPolarity**: Setting for inverting the light (or not). Standard IEC 60870-5-103 setting is **Enabled**.
- **CycMeasRepTime**: See I103MEAS function block for more information.
- **EventRepMode**: Defines the mode for how events are reported. The event buffer size is 1000 events.

### Event reporting mode

If **EventRepMode = SeqOfEvent**, all GI and spontaneous events will be delivered in the order they were generated by BSW. The most recent value is the latest value delivered. All GI data from a single block will come from the same cycle.

If **EventRepMode = HiPriSpont**, spontaneous events will be delivered prior to GI event. To prevent old GI data from being delivered after a new spontaneous event, the pending GI event is modified to contain the same value as the spontaneous event. As a result, the GI dataset is not time-correlated.

### Settings from PCM600

#### I103USEDEF

For each input of the I103USEDEF function there is a setting for the information number of the connected signal. The information number can be set to any value between 0 and 255. To get proper operation of the sequence of events the event masks in the event function is to be set to **ON_CHANGE**. For single-command signals, the event mask is to be set to **ON_SET**.

In addition there is a setting on each event block for function type. Refer to description of the Main Function type set on the local HMI.

#### Commands

As for the commands defined in the protocol there is a dedicated function block with eight output signals. Use PCM600 to configure these signals. To realize the BlockOfInformation command,
which is operated from the local HMI, the output BLKINFO on the IEC command function block ICOM has to be connected to an input on an event function block. This input must have the information number 20 (monitor direction blocked) according to the standard.

**Disturbance Recordings**

For each input of the Disturbance recorder function there is a setting for the information number of the connected signal. The function type and the information number can be set to any value between 0 and 255. To get INF and FUN for the recorded binary signals, there are parameters on the disturbance recorder for each input. The user must set these parameters to whatever he connects to the corresponding input.

Refer to description of Main Function type set on the local HMI.

Recorded analog channels are sent with ASDU26 and ASDU31. One information element in these ASDUs is called ACC, and it indicates the actual channel to be processed. The channels on disturbance recorder are sent with an ACC as shown in Table 88.

*Table 88: Channels on disturbance recorder sent with a given ACC*

<table>
<thead>
<tr>
<th>DRA#-Input</th>
<th>ACC</th>
<th>IEC103 meaning</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>IA</td>
</tr>
<tr>
<td>2</td>
<td>2</td>
<td>IB</td>
</tr>
<tr>
<td>3</td>
<td>3</td>
<td>IC</td>
</tr>
<tr>
<td>4</td>
<td>4</td>
<td>IG</td>
</tr>
<tr>
<td>5</td>
<td>5</td>
<td>VA</td>
</tr>
<tr>
<td>6</td>
<td>6</td>
<td>VB</td>
</tr>
<tr>
<td>7</td>
<td>7</td>
<td>VC</td>
</tr>
<tr>
<td>8</td>
<td>8</td>
<td>VG</td>
</tr>
<tr>
<td>9</td>
<td>64</td>
<td>Private range</td>
</tr>
<tr>
<td>10</td>
<td>65</td>
<td>Private range</td>
</tr>
<tr>
<td>11</td>
<td>66</td>
<td>Private range</td>
</tr>
<tr>
<td>12</td>
<td>67</td>
<td>Private range</td>
</tr>
<tr>
<td>13</td>
<td>68</td>
<td>Private range</td>
</tr>
<tr>
<td>14</td>
<td>69</td>
<td>Private range</td>
</tr>
<tr>
<td>15</td>
<td>70</td>
<td>Private range</td>
</tr>
<tr>
<td>16</td>
<td>71</td>
<td>Private range</td>
</tr>
<tr>
<td>17</td>
<td>72</td>
<td>Private range</td>
</tr>
<tr>
<td>18</td>
<td>73</td>
<td>Private range</td>
</tr>
<tr>
<td>19</td>
<td>74</td>
<td>Private range</td>
</tr>
<tr>
<td>20</td>
<td>75</td>
<td>Private range</td>
</tr>
<tr>
<td>21</td>
<td>76</td>
<td>Private range</td>
</tr>
<tr>
<td>22</td>
<td>77</td>
<td>Private range</td>
</tr>
<tr>
<td>23</td>
<td>78</td>
<td>Private range</td>
</tr>
<tr>
<td>24</td>
<td>79</td>
<td>Private range</td>
</tr>
<tr>
<td>25</td>
<td>80</td>
<td>Private range</td>
</tr>
<tr>
<td>26</td>
<td>81</td>
<td>Private range</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>DRA#-Input</th>
<th>ACC</th>
<th>IEC103 meaning</th>
</tr>
</thead>
<tbody>
<tr>
<td>27</td>
<td>82</td>
<td>Private range</td>
</tr>
<tr>
<td>28</td>
<td>83</td>
<td>Private range</td>
</tr>
<tr>
<td>29</td>
<td>84</td>
<td>Private range</td>
</tr>
<tr>
<td>30</td>
<td>85</td>
<td>Private range</td>
</tr>
<tr>
<td>31</td>
<td>86</td>
<td>Private range</td>
</tr>
<tr>
<td>32</td>
<td>87</td>
<td>Private range</td>
</tr>
<tr>
<td>33</td>
<td>88</td>
<td>Private range</td>
</tr>
<tr>
<td>34</td>
<td>89</td>
<td>Private range</td>
</tr>
<tr>
<td>35</td>
<td>90</td>
<td>Private range</td>
</tr>
<tr>
<td>36</td>
<td>91</td>
<td>Private range</td>
</tr>
<tr>
<td>37</td>
<td>92</td>
<td>Private range</td>
</tr>
<tr>
<td>38</td>
<td>93</td>
<td>Private range</td>
</tr>
<tr>
<td>39</td>
<td>94</td>
<td>Private range</td>
</tr>
<tr>
<td>40</td>
<td>95</td>
<td>Private range</td>
</tr>
</tbody>
</table>

### 20.6.3 Function and information types

Product type IEC103mainFunType value Comment:

- **REL 128** Compatible range
- **REC 242** Private range, use default
- **RED 192** Compatible range
- **RET 176** Compatible range
- **REB 207** Private range
- **REG 150** Private range
- **REQ 245** Private range
- **RER 152** Private range
- **RES 118** Private range

Refer to the tables in the Technical reference manual /Station communication, specifying the information types supported by the communication protocol IEC 60870-5-103.

To support the information, corresponding functions must be included in the protection IED.

There is no representation for the following parts:

- Generating events for test mode
- Cause of transmission: Info no 11, Local operation
Glass or plastic fiber should be used. BFOC/2.5 is the recommended interface to use (BFOC/2.5 is the same as ST connectors). ST connectors are used with the optical power as specified in standard.

For more information, refer to IEC standard IEC 60870-5-103.

**20.7 DNP3 Communication protocol**

**20.7.1 Application**

For more information on the application and setting guidelines for the DNP3 communication protocol refer to the DNP3 Communication protocol manual.
Section 21  Remote communication

21.1  Binary signal transfer

21.1.1  Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Binary signal transfer, receive</td>
<td>BinSignRec1_1</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>BinSignRec1_2</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>BinSignReceive2</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Binary signal transfer,</td>
<td>BinSigRec1_12M</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2Mbit receive</td>
<td>BinSigRec1_22M</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Binary signal transfer,</td>
<td>BinSignTrans1_1</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>transmit</td>
<td>BinSignTrans1_2</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>BinSignTransm2</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Binary signal transfer,</td>
<td>BinSigTran1_12M</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2Mbit transmit</td>
<td>BinSigTran1_22M</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

21.1.2  Application

The IEDs can be equipped with communication devices for line differential communication (not applicable for RER670) and/or communication of binary signals between IEDs. The same communication hardware is used for both purposes.

Sending of binary signals between two IEDs is used in teleprotection schemes and for direct transfer trips. In addition to this, there are application possibilities, for example, blocking/enabling functionality in the remote substation, changing setting group in the remote IED depending on the switching situation in the local substation and so on.

If equipped with a 64kbit/s LDCM module, the IED can be configured to send either 192 binary signals or 3 analog and 8 binary signals to a remote IED. If equipped with a 2Mbps LDCM module, the IED can send 9 analog channels and 192 binary channels to a remote IED.

Link forwarding
If it is not possible to have a communication link between each station, the solution has been to set the protection up in a slave-master-slave configuration. This means that in Figure 342, only IED-B has access to all currents and, therefore, this is the only place where the differential current is evaluated. If the evaluation results in a trip, the trip signal will be sent over the two communication links.
Figure 342: Three-end differential protection with two communication links

If the LDCM is in 2Mbit mode, you can send the three local currents as well as the three remote currents from the other links by configuring the transmitters in IED-B:

1. Ldcm312 transmitter sends the local currents and the three currents received by Ldcm313.
2. Ldcm313 transmitter sends the three local currents and the three currents received from Ldcm312.

As a result, six currents are received in IED-A and IED-C. These currents can be connected to the protection function together with the local three currents.

In order to forward the logic signals (for example, inter-trip or inter-block) between IED-A and IED-C, the setting LinkForwarded should be defined. In IED-B, it is set to LDCM313 for Ldcm312 and to LDCM312 for Ldcm313.

This setup results in a master-master-master configuration, but without the benefit of reverting to a slave-master-slave configuration in case of a communication link interruption. In case of a communication link interruption, all three IEDs would be blocked.

21.1.2.1 Communication hardware solutions

The LDCM (Line Data Communication Module) has an optical connection such that two IEDs can be connected over a direct fiber (multimode), as shown in figure 343. The protocol used is IEEE/ANSI C37.94. The distance with this solution is typical 110 km/68 miles.

Figure 343: Direct fiber optical connection between two IEDs with LDCM

The LDCM can also be used together with an external optical to galvanic G.703 converter or with an alternative external optical to galvanic X.21 as shown in figure 344. These solutions are aimed
for connections to a multiplexer, which in turn is connected to a telecommunications transmission network (for example PDH).

![Diagram of multiplexer and telecommunications network]

*) Converting optical to galvanic G.703

**Figure 344: LDCM with an external optical to galvanic converter and a multiplexer**

When an external modem G.703 or X.21 is used, the connection between LDCM and the modem is made with a multimode fiber of max. 3 km/2 mile length. The IEEE/ANSI C37.94 protocol is always used between LDCM and the modem.

Alternatively, a LDCM with X.21 built-in converter and micro D-sub 15-pole connector output can be used.

### 21.1.3 Setting guidelines

**64 kbit mode common settings**

*ChannelMode* defines how an IED discards the LDCM information when one of the IEDs in the system is out of service: it can either be done on the IED out of service by setting all local LDCMs to channel mode *OutOfService* or at the remote end by setting the corresponding LDCM to channel mode *Blocked*. If *OutOfService* is selected, the IED should have active communication to the remote end during the whole maintenance process, that is, no restart or removal of the fiber can be done.

This setting does not apply to two-end communication.

<table>
<thead>
<tr>
<th>Mode</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Blocked</td>
<td>IED does not use data from the LDCM</td>
</tr>
<tr>
<td>OutOfService</td>
<td>IED informs the remote end that it is out of service</td>
</tr>
</tbody>
</table>

*TerminalNo* is used to assign a unique address to each LDCM in all current differential IEDs. Up to 256 LDCMs can be assigned a unique number. For example, in a local IED with two LDCMs:
In multiterminal current differential applications, with 4 LDCMs in each IED, up to 20 unique addresses must be set.

A unique address is necessary to give high security against incorrect addressing in the communication system. If the same number is used for TerminalNo in some of the LDCMs, a loop-back test in the communication system can give an incorrect trip.

RemoteTermNo is used to assign a number to each related LDCM in the remote IED. For each LDCM, RemoteTermNo is set to a different value than TerminalNo, but equal to the TerminalNo of the remote end LDCM. In the remote IED, TerminalNo and RemoteTermNo are reversed as follows:

- LDCM for slot 305: set TerminalNo to 2 and RemoteTermNo to 1
- LDCM for slot 306: set TerminalNo to 4 and RemoteTermNo to 3

The redundant channel is always configured to the lower position, for example:
- Slot 305: main channel
- Slot 306: redundant channel

The same is applicable for slot 312-313 and slot 322-323.

DiffSync defines the method of time synchronization for the line differential function: Echo or GPS.

Using Echo in this case is safe only if there is no risk of varying transmission asymmetry.

GPSSyncErr: when GPS synchronization is lost, synchronization of the line differential function continues for 16 s based on the stability in the local IED clocks. After that, setting Block blocks the line differential function or setting Echo keeps it on by using the Echo synchronization method.

Using Echo in this case is safe only if there is no risk of varying transmission asymmetry.

CommSync defines the Master and Slave relation in the communication system, and should not be mistaken for the synchronization of line differential current samples. When direct fiber is used, one LDCM is set as Master and the other as Slave. When a modem and multiplexer is used, the IED is always set as Slave because the telecommunication system provides the clock master.

OptoPower has two settings: LowPower and HighPower.

Short-range LDCM: Use LowPower for fibers 0 – 1 km and HighPower for fibers greater than 1 km.

Medium-range LDCM: Typical distance 80 km for both LowPower and HighPower.
Long-range LDCM: Typical distance 120 km for both LowPower and HighPower.

An optical budget calculation should be made for the actual case. For medium range LDCM and long range LDCM the recommendation is to use the LowPower setting to minimize the power consumption and keep the heat dissipation at minimum.

The HighPower setting adds 3 dBm extra optical power and can be used to increase the margin at distances close to maximum.

**Table 89: Optical budgets with C37.94 protocol**

<table>
<thead>
<tr>
<th>Type of LDCM</th>
<th>Short range (SR)</th>
<th>Short range (SR)</th>
<th>Medium range (MR)</th>
<th>Long range (LR)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type of fibre</td>
<td>Multi-mode fiber glass 50/125 µm</td>
<td>Multi-mode fiber glass 62.5/125 µm</td>
<td>Single-mode fiber glass 9/125 µm</td>
<td>Single-mode fiber glass 9/125 µm</td>
</tr>
<tr>
<td>Modem type</td>
<td>1MRK0002122-AB</td>
<td>1MRK0002122-AB</td>
<td>1MRK002311-AA</td>
<td>1MRK002311-BA</td>
</tr>
<tr>
<td>Contact type</td>
<td>ST</td>
<td>ST</td>
<td>FC/PC</td>
<td>FC/PC</td>
</tr>
<tr>
<td>Minimum output power</td>
<td>–21 dBm</td>
<td>–13.7 dBm</td>
<td>–3.2 dBm</td>
<td>–1.3 dBm</td>
</tr>
<tr>
<td>Minimum receiver sensitivity</td>
<td>–32.5 dBm</td>
<td>–32.5 dBm</td>
<td>–30 dBm</td>
<td>–30 dBm</td>
</tr>
<tr>
<td>Optical link budget</td>
<td>11.5 dB</td>
<td>18.8 dB</td>
<td>26.8 dB</td>
<td>28.7 dB</td>
</tr>
</tbody>
</table>

1) Minimum output power is measured with 1 m of the selected fiber and the high power mode.
2) The optical budget includes a satisfactory margin for aging in transmitter and receiver during 20–30 years.

**Table 90: Example of input data for calculating the optical budget (maximum distance)**

<table>
<thead>
<tr>
<th>Type of LDCM</th>
<th>Short range (SR)</th>
<th>Short range (SR)</th>
<th>Medium range (MR)</th>
<th>Long range (LR)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type of fibre</td>
<td>Multi-mode fiber glass 50/125 µm</td>
<td>Multi-mode fiber glass 62.5/125 µm</td>
<td>Single-mode fiber glass 9/125 µm</td>
<td>Single-mode fiber glass 9/125 µm</td>
</tr>
<tr>
<td>Modem type</td>
<td>1MRK0002122-AB</td>
<td>1MRK0002122-AB</td>
<td>1MRK002311-AA</td>
<td>1MRK002311-BA</td>
</tr>
<tr>
<td>Typical attenuation in fibre-optic cables</td>
<td>3 dB/km</td>
<td>3 dB/km</td>
<td>0.32 dB/km</td>
<td>0.21 dB/km</td>
</tr>
<tr>
<td>Attenuation/Contact</td>
<td>1.5 dB/ST</td>
<td>1.5 dB/ST</td>
<td>0.3 dB/FC/PC</td>
<td>0.3 dB/FC/PC</td>
</tr>
<tr>
<td>Factory splice attenuation</td>
<td>0.5 dB/splice 0.3 splices/km</td>
<td>0.5 dB/splice 0.1 splices/km</td>
<td>0.08 dB/splice 0.1 splices/km</td>
<td>0.08 dB/splice 0.1 splices/km</td>
</tr>
<tr>
<td>Repair splices</td>
<td>0.25 dB/splice 0.1 splices/km</td>
<td>0.25 dB/splice 0.1 splices/km</td>
<td>0.1 dB/splice 0.05 splices/km</td>
<td>0.1 dB/splice 0.05 splices/km</td>
</tr>
<tr>
<td>Fiber margin for aging</td>
<td>0.1 dB/km</td>
<td>0.1 dB/km</td>
<td>0.01 dB/km</td>
<td>0.01 dB/km</td>
</tr>
</tbody>
</table>
Table 91: Example of calculating the optical budget (maximum distance)

<table>
<thead>
<tr>
<th>Type of LDCM</th>
<th>Short range (SR)</th>
<th>Short range (SR)</th>
<th>Medium range (MR)</th>
<th>Long range (LR)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type of fibre</td>
<td>Multi-mode fiber glass 50/125 μm</td>
<td>Multi-mode fiber glass 62.5/125 μm</td>
<td>Single-mode fiber glass 9/125 μm</td>
<td>Single-mode fiber glass 9/125 μm</td>
</tr>
<tr>
<td>Modem type</td>
<td>1MRK0002122-AB</td>
<td>1MRK0002122-AB</td>
<td>1MRK002311-AA</td>
<td>1MRK002311-BA</td>
</tr>
<tr>
<td>Maximum distance</td>
<td>2 km</td>
<td>3 km</td>
<td>80 km</td>
<td>120 km</td>
</tr>
<tr>
<td>Attenuation in fibre-optic cables</td>
<td>6 dB</td>
<td>9 dB</td>
<td>25.6 dB</td>
<td>25.2 dB</td>
</tr>
<tr>
<td>2 contacts</td>
<td>2 dB</td>
<td>3 dB</td>
<td>0.6 dB</td>
<td>0.6 dB</td>
</tr>
<tr>
<td>Factory splice attenuation</td>
<td>0.3 dB</td>
<td>0.45 dB</td>
<td>0.64 dB</td>
<td>0.96 dB</td>
</tr>
<tr>
<td>Repair splices</td>
<td>0.1 dB</td>
<td>0.3 dB</td>
<td>0.8 dB</td>
<td>1.2 dB</td>
</tr>
<tr>
<td>Fiber margin for aging</td>
<td>0.2 dB</td>
<td>0.3 dB</td>
<td>0.8 dB</td>
<td>1.2 dB</td>
</tr>
<tr>
<td>Total attenuation</td>
<td>8.6 dB</td>
<td>12.05 dB</td>
<td>26.04 dB</td>
<td>28.56 dB</td>
</tr>
<tr>
<td>Optical link budget</td>
<td>9 dB</td>
<td>13 dB</td>
<td>26.8 dB</td>
<td>28.7 dB</td>
</tr>
<tr>
<td>Link margin</td>
<td>0.4 dB</td>
<td>0.95 dB</td>
<td>0.76 dB</td>
<td>0.14 dB</td>
</tr>
</tbody>
</table>

ComAlarmDel defines the time delay for communication failure alarm. In communication systems, route switching can sometimes cause interruptions with a duration of up to 50 ms. Too short a time delay can thus cause nuisance alarms.

ComAlrmResDel defines the time delay for communication failure alarm reset.

RedChSwTime defines the time delay before switching over to a redundant channel in case of primary channel failure.

RedChRturnTime defines the time delay before switching back to the primary channel after channel failure.

AsymDelay denotes asymmetry which is defined as transmission delay minus receive delay. If fixed asymmetry is known, Echo synchronization method can be used, provided that AsymDelay is properly set. From the definition follows that asymmetry is always positive at one end and negative at the other end.

MaxTransmDelay indicates maximum transmission delay. Data for maximum 40 ms transmission delay can be buffered up. Delay times in the range of some ms are common. If data arrive in wrong order, the oldest data is disregarded.

MaxtDiffLeve indicates the maximum time difference allowed between internal clocks in respective line ends.

64 kbit mode specific settings

TransmCurr is used to select among the following:
- one of the two possible local currents is transmitted
- sum of the two local currents is transmitted
- channel is used as a redundant backup channel

breaker-and-a-half arrangement has two local currents, and the Current Transformer (CT) grounding for those can differ. CT-SUM transmits the sum of the two CT groups. CT-DIFF1 transmits CT group 1 minus CT group 2 and CT-DIFF2 transmits CT group 2 minus CT group 1.

CT-GRP1 and CT-GRP2 transmit the respective CT groups, and setting RedundantChannel determines that the channel is used as a redundant backup channel. The redundant channel takes the CT group setting of the main channel.

RemAinLatency corresponds to LocAinLatency set in the remote IED.

AnalogLatency specifies the time delay (number of samples) between actual sampling and the time the sample reaches LDCM. The value is set to 2 when transmitting analog data. When a merging unit according to IEC 61850-9-2 is used instead of the TRM, this parameter shall be set to 5.

CompRange value indicates the current peak value over which truncation is made. To set this value, knowledge of fault current levels is required. It is recommended to set the minimum range that will cover the expected fault current value. For example, if a 40kA fault level is expected on the network, the 0-50kA settings range should be chosen.
Section 22  Security

22.1  Authority status ATHSTAT

22.1.1  Application

Authority status (ATHSTAT) function is an indication function block, which informs about two events related to the IED and the user authorization:

- the fact that at least one user has tried to log on wrongly into the IED and it was blocked (the output USRBLKED)
- the fact that at least one user is logged on (the output LOGGEDON)

The two outputs of ATHSTAT function can be used in the configuration for different indication and alarming reasons, or can be sent to the station control for the same purpose.

22.2  Self supervision with internal event list INTERRSIG

22.2.1  Application

The protection and control IEDs have many functions included. The included self-supervision with internal event list function block provides good supervision of the IED. The fault signals make it easier to analyze and locate a fault.

Both hardware and software supervision is included and it is also possible to indicate possible faults through a hardware contact on the power supply module and/or through the communication.

Internal events are generated by the built-in supervisory functions. The supervisory functions supervise the status of the various modules in the IED and, in case of failure, a corresponding event is generated. Similarly, when the failure is corrected, a corresponding event is generated.

Apart from the built-in supervision of the various modules, events are also generated when the status changes for the:

- built-in real time clock (in operation/out of order).
- external time synchronization (in operation/out of order).

Events are also generated:

- whenever any setting in the IED is changed.

The internal events are time tagged with a resolution of 1 ms and stored in a list. The list can store up to 40 events. The list is based on the FIFO principle, that is, when it is full, the oldest event is overwritten. The list contents cannot be modified, but the whole list can be cleared using the Reset menu in the LHMI.
The list of internal events provides valuable information, which can be used during commissioning and fault tracing.

The information can, in addition to be viewed on the built in HMI, also be retrieved with the aid of a PC with PCM600 installed and by using the Event Monitoring Tool. The PC can either be connected to the front port, or to the port at the back of the IED.

22.3 Change lock CHNGLCK

22.3.1 Application

Change lock function CHNGLCK is used to block further changes to the IED configuration once the commissioning is complete. The purpose is to make it impossible to perform inadvertent IED configuration and setting changes.

However, when activated, CHNGLCK will still allow the following actions that does not involve reconfiguring of the IED:

- Monitoring
- Reading events
- Resetting events
- Reading disturbance data
- Clear disturbances
- Reset LEDs
- Reset counters and other runtime component states
- Control operations
- Set system time
- Enter and exit from test mode
- Change of active setting group

The binary input controlling the function is defined in ACT or SMT. The CHNGLCK function is configured using ACT.

LOCK Binary input signal that will activate/deactivate the function, defined in ACT or SMT.

When CHNGLCK has a logical one on its input, then all attempts to modify the IED configuration and setting will be denied and the message "Error: Changes blocked" will be displayed on the local HMI; in PCM600 the message will be "Operation denied by active ChangeLock". The CHNGLCK function should be configured so that it is controlled by a signal from a binary input card. This guarantees that by setting that signal to a logical zero, CHNGLCK is deactivated. If any logic is included in the signal path to the CHNGLCK input, that logic must be designed so that it cannot permanently issue a logical one to the CHNGLCK input. If such a situation would occur in spite of these precautions, then please contact the local ABB representative for remedial action.
22.4 Denial of service SCHLCCH/RCHLCCH

22.4.1 Application

The denial of service functionality is designed to limit the CPU load that can be produced by Ethernet network traffic on the IED. The communication facilities must not be allowed to compromise the primary functionality of the device. All inbound network traffic will be quota controlled so that too heavy network loads can be controlled. Heavy network load might for instance be the result of malfunctioning equipment connected to the network.

The functions Access point diagnostics function block measure the IED load from communication and, if necessary, limit it for not jeopardizing the IEDs control and protection functionality due to high CPU load. The function has the following denial of service related outputs:

- LINKSTS indicates the Ethernet link status for the rear ports (single communication)
- CHALISTS and CHBLISTS indicates the Ethernet link status for the rear ports channel A and B (redundant communication)
- LinkStatus indicates the Ethernet link status for the front port

22.4.2 Setting guidelines

The function does not have any parameters available in the local HMI or PCM600.
Section 23  Basic IED functions

23.1  IED identifiers TERMINALID

23.1.1  Application

IED identifiers (TERMINALID) function allows the user to identify the individual IED in the system, not only in the substation, but in a whole region or a country.

Use only characters A-Z, a-z and 0-9 in station, object and unit names.

23.2  Product information PRODINF

23.2.1  Application

Product information contains unchangeable data that uniquely identifies the IED.

Product information data is visible on the local HMI under Main menu/Diagnostics/IED status/Product identifiers and under Main menu/Diagnostics/IED Status/Identifiers:

Product information data is visible on the local HMI under Main menu/Diagnostics/IED status/Product identifiers and under Main menu/Diagnostics/IED Status/Identifiers.

- ProductVer
- ProductDef
- FirmwareVer
- SerialNo
- OrderingNo
- ProductionDate
- IEDProdType

Figure 345: IED summary

This information is very helpful when interacting with ABB product support (for example during repair and maintenance).

23.2.2  Factory defined settings

The factory defined settings are very useful for identifying a specific version and very helpful in the case of maintenance, repair, interchanging IEDs between different Substation Automation Systems and upgrading. The factory made settings can not be changed by the customer. They can only be viewed. The settings are found in the local HMI under Main menu/Diagnostics/IED status/Product identifiers

The following identifiers are available:
• IEDProdType
  • Describes the type of the IED. Example: REL670

• ProductDef
  • Describes the release number from the production. Example: 2.1.0

• FirmwareVer
  • Describes the firmware version.
  • The firmware version can be checked from **Main menu/Diagnostics/IED status/Product identifiers**
  • Firmware version numbers run independently from the release production numbers. For every release number there can be one or more firmware versions depending on the small issues corrected in between releases.

• ProductVer
  • Describes the product version. Example: 2.1.0
  
| 1 | is the Major version of the manufactured product this means, new platform of the product |
| 2 | is the Minor version of the manufactured product this means, new functions or new hardware added to the product |
| 3 | is the Major revision of the manufactured product this means, functions or hardware is either changed or enhanced in the product |

• IEDMainFunType
  • Main function type code according to IEC 60870-5-103. Example: 128 (meaning line protection).

• SerialNo
• OrderingNo
• ProductionDate

### 23.3 Measured value expander block RANGE_XP

#### 23.3.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Measured value expander block</td>
<td>RANGE_XP</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

#### 23.3.2 Application

The current and voltage measurements functions (CVMMXN, CMMXU, VMMXU and VNMMXU), current and voltage sequence measurement functions (CMSQI and VMSQI) and IEC 61850 generic communication I/O functions (MVGAPC) are provided with measurement supervision functionality. All measured values can be supervised with four settable limits, that is low-low limit, low limit, high limit and high-high limit. The measure value expander block (RANGE_XP) has been introduced to be able to translate the integer output signal from the measuring functions to 5 binary signals, that is below low-low limit, below low limit, normal, above high-high limit or above high limit. The output signals can be used as conditions in the configurable logic.
23.3.3 Setting guidelines

There are no settable parameters for the measured value expander block function.

23.4 Parameter setting groups

23.4.1 Application

Six sets of settings are available to optimize IED operation for different power system conditions. By creating and switching between fine tuned setting sets, either from the local HMI or configurable binary inputs, results in a highly adaptable IED that can cope with a variety of power system scenarios.

Different conditions in networks with different voltage levels require highly adaptable protection and control units to best provide for dependability, security and selectivity requirements. Protection units operate with a higher degree of availability, especially, if the setting values of their parameters are continuously optimized according to the conditions in the power system.

Operational departments can plan for different operating conditions in the primary equipment. The protection engineer can prepare the necessary optimized and pre-tested settings in advance for different protection functions. Six different groups of setting parameters are available in the IED. Any of them can be activated through the different programmable binary inputs by means of external or internal control signals.

A function block, SETGRPS, defines how many setting groups are used. Setting is done with parameter MAXSETGR and shall be set to the required value for each IED. Only the number of setting groups set will be available in the Parameter Setting tool for activation with the ActiveGroup function block.

23.4.2 Setting guidelines

The setting ActiveSetGrp, is used to select which parameter group to be active. The active group can also be selected with configured input to the function block SETGRPS.

The length of the pulse, sent out by the output signal GRP_CHGD when an active group has changed, is set with the parameter t.

The parameter MAXSETGR defines the maximum number of setting groups in use to switch between. Only the selected number of setting groups will be available in the Parameter Setting tool (PST) for activation with the ActiveGroup function block.

23.5 Rated system frequency PRIMVAL

23.5.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Primary system values</td>
<td>PRIMVAL</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>
23.5.2 Application

The rated system frequency and phase rotation direction are set under Main menu/Configuration/Power system/Primary Values in the local HMI and PCM600 parameter setting tree.

23.5.3 Setting guidelines

Set the system rated frequency. Refer to section "Signal matrix for analog inputs SMAI" for description on frequency tracking.

23.6 Summation block 3 phase 3PHSUM

23.6.1 Application

The analog summation block 3PHSUM function block is used in order to get the sum of two sets of 3 phase analog signals (of the same type) for those IED functions that might need it.

23.6.2 Setting guidelines

The summation block receives the three-phase signals from SMAI blocks. The summation block has several settings.

SummationType: Summation type (Group 1 + Group 2, Group 1 - Group 2, Group 2 - Group 1 or – (Group 1 + Group 2)).

DFTReference: The reference DFT block (InternalDFTRef, DFTRefGrp1 or External DFT ref).

DFTRefGrp1: This setting means use own internal adaptive DFT reference (this setting makes the SUM3PH self DFT adaptive, that is, it will use the measured frequency for the summation signal to adapt DFT).

InternalDFTRef: Gives fixed window DFT (to nominal system frequency).

ExternalDFTRef: This setting means that the DFT samples-per-cycle (adaptive DFT) will be controlled by SMAI1 SPFCOUT.

FreqMeasMinVal: The minimum value of the voltage for which the frequency is calculated, expressed as percent of VBase (base voltage setting (for each instance x).

GlobalBaseSel: Selects the global base value group used by the function to define (IBase), (VBase) and (SBase).

23.7 Global base values GBASVAL
23.7.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Global base values</td>
<td>GBASVAL</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

23.7.2 Application

Global base values function (GBASVAL) is used to provide global values, common for all applicable functions within the IED. One set of global values consists of values for current, voltage and apparent power and it is possible to have twelve different sets.

This is an advantage since all applicable functions in the IED use a single source of base values. This facilitates consistency throughout the IED and also facilitates a single point for updating values when necessary.

Each applicable function in the IED has a parameter, GlobalBaseSel, defining one out of the twelve sets of GBASVAL functions.

23.7.3 Setting guidelines

VBase: Phase-to-phase voltage value to be used as a base value for applicable functions throughout the IED.

IBase: Phase current value to be used as a base value for applicable functions throughout the IED.

SBase: Standard apparent power value to be used as a base value for applicable functions throughout the IED, typically SBase=√3·VBase·IBase.

23.8 Signal matrix for binary inputs SMBI

23.8.1 Application

The Signal matrix for binary inputs function SMBI is used within the Application Configuration tool in direct relation with the Signal Matrix tool. SMBI represents the way binary inputs are brought in for one IED configuration.

23.8.2 Setting guidelines

There are no setting parameters for the Signal matrix for binary inputs SMBI available to the user in Parameter Setting tool. However, the user shall give a name to SMBI instance and the SMBI inputs, directly in the Application Configuration tool. These names will define SMBI function in the Signal Matrix tool. The user defined name for the input or output signal will also appear on the respective output or input signal.
23.9 Signal matrix for binary outputs SMBO

23.9.1 Application

The Signal matrix for binary outputs function SMBO is used within the Application Configuration tool in direct relation with the Signal Matrix tool. SMBO represents the way binary outputs are sent from one IED configuration.

23.9.2 Setting guidelines

There are no setting parameters for the Signal matrix for binary outputs SMBO available to the user in Parameter Setting tool. However, the user must give a name to SMBO instance and SMBO outputs, directly in the Application Configuration tool. These names will define SMBO function in the Signal Matrix tool.

23.10 Signal matrix for mA inputs SMMI

23.10.1 Application

The Signal matrix for mA inputs function SMMI is used within the Application Configuration tool in direct relation with the Signal Matrix tool. SMMI represents the way milliamp (mA) inputs are brought in for one IED configuration.

23.10.2 Setting guidelines

There are no setting parameters for the Signal matrix for mA inputs SMMI available to the user in the Parameter Setting tool. However, the user must give a name to SMMI instance and SMMI inputs, directly in the Application Configuration tool.

23.11 Signal matrix for analog inputs SMAI

23.11.1 Application

Signal matrix for analog inputs (SMAI), also known as the preprocessor function block, analyses the connected four analog signals (three phases and neutral) and calculates all relevant information from them like the phasor magnitude, phase angle, frequency, true RMS value, harmonics, sequence components and so on. This information is then used by the respective functions connected to this SMAI block in ACT (for example protection, measurement or monitoring functions).
23.11.2 Frequency values

The SMAI function includes a functionality based on the level of positive sequence voltage, \( \text{MinValFreqMeas} \), to validate if the frequency measurement is valid or not. If the positive sequence voltage is lower than \( \text{MinValFreqMeas} \), the function freezes the frequency output value for 500 ms and after that the frequency output is set to the nominal value. A signal is available for the SMAI function to prevent operation due to non-valid frequency values. \( \text{MinValFreqMeas} \) is set as % of \( \frac{V_{\text{Base}}}{\sqrt{3}} \).

If SMAI setting \( \text{ConnectionType} \) is \( \text{Ph-Ph} \), at least two of the inputs \( \text{GRP}_x_\text{A}, \text{GRP}_x_\text{B} \), and \( \text{GRP}_x_\text{C} \), where \( 1 \leq x \leq 12 \), must be connected in order to calculate the positive sequence voltage. Note that phase to phase inputs shall always be connected as follows: A-B to \( \text{GRP}_x_\text{A}, \text{B-C} \) to \( \text{GRP}_x_\text{B} \), \( \text{C-A} \) to \( \text{GRP}_x_\text{C} \). If SMAI setting \( \text{ConnectionType} \) is \( \text{Ph-N} \), all three inputs \( \text{GRP}_x_\text{A}, \text{GRP}_x_\text{B} \), and \( \text{GRP}_x_\text{C} \) must be connected in order to calculate the positive sequence voltage.

If only one phase-phase voltage is available and SMAI setting \( \text{ConnectionType} \) is \( \text{Ph-Ph} \), the user is advised to connect two (not three) of the inputs \( \text{GRP}_x_\text{A}, \text{GRP}_x_\text{B} \) and \( \text{GRP}_x_\text{C} \) to the same voltage input as shown in figure 346 to make SMAI calculate a positive sequence voltage.

**Figure 346: Connection example**

The above described scenario does not work if SMAI setting \( \text{ConnectionType} \) is \( \text{Ph-N} \). If only one phase-ground voltage is available, the same type of connection can be used but the SMAI \( \text{ConnectionType} \) setting must still be \( \text{Ph-Ph} \) and this has to be accounted for when setting \( \text{MinValFreqMeas} \). If SMAI setting \( \text{ConnectionType} \) is \( \text{Ph-N} \) and the same voltage is connected to all three SMAI inputs, the positive sequence voltage will be zero and the frequency functions will not work properly.

The outputs from the above configured SMAI block shall only be used for Overfrequency protection (SAPTOF, 81), Underfrequency protection (SAPTUF, 81) and Rate-of-change frequency protection (SAPFRC, 81) due to that all other information except frequency and positive sequence voltage might be wrongly calculated.

The same phase-phase voltage connection principle shall be used for frequency tracking master SMAI block in pump-storage power plant applications when swapping of positive and negative sequence voltages happens during generator/motor mode of operation.
23.11.3 Setting guidelines

The parameters for the signal matrix for analog inputs (SMAI) functions are set via the local HMI or PCM600.

Every SMAI function block can receive four analog signals (three phases and one neutral value), either voltage or current. SMAI outputs give information about every aspect of the 3ph analog signals acquired (phase angle, RMS value, frequency and frequency derivates, and so on – 244 values in total). Besides the block “group name”, the analog inputs type (voltage or current) and the analog input names that can be set directly in ACT.

Application functions should be connected to a SMAI block with same task cycle as the application function, except for e.g. measurement functions that run in slow cycle tasks.

**DFTRefExtOut**: Parameter valid only for function block SMAI1.

Reference block for external output (SPFCOUT function output).

**DFTReference**: Reference DFT for the SMAI block use.

These DFT reference block settings decide DFT reference for DFT calculations. The setting `InternalDFTRef` will use fixed DFT reference based on set system frequency. `DFTRefGrp(n)` will use DFT reference from the selected group block, when own group is selected, an adaptive DFT reference will be used based on calculated signal frequency from own group. The setting `ExternalDFTRef` will use reference based on what is connected to input DFTSPFC.

The setting **ConnectionType**: Connection type for that specific instance (n) of the SMAI (if it is Ph-N or Ph-Ph). Depending on connection type setting the not connected Ph-N or Ph-Ph outputs will be calculated as long as they are possible to calculate. E.g. at Ph-Ph connection A, B and C will be calculated for use in symmetrical situations. If N component should be used respectively the phase component during faults \( I_N/V_N \) must be connected to input 4.

**Negation**: If the user wants to negate the 3ph signal, it is possible to choose to negate only the phase signals `Negate3Ph`, only the neutral signal `NegateN` or both `Negate3Ph+N`. negation means rotation with 180° of the vectors.

**GlobalBaseSel**: Selects the global base value group used by the function to define (iBase), (VBase) and (SBase).

**MinValFreqMeas**: The minimum value of the voltage for which the frequency is calculated, expressed as percent of VBase (for each instance n).

Settings `DFTRefExtOut` and `DFTReference` shall be set to default value `InternalDFTRef` if no VT inputs are available.

Even if the user sets the **AnalogInputType** of a SMAI block to “Current”, the **MinValFreqMeas** is still visible. However, using the current channel values as base for frequency measurement is not recommended for a number of reasons, not last among them being the low level of currents that one can have in normal operating conditions.

**Examples of adaptive frequency tracking**
Preprocessing block shall only be used to feed functions within the same execution cycles (e.g. use preprocessing block with cycle 1 to feed transformer differential protection). The only exceptions are measurement functions (CVMMXN, CMMXU, VMMXU, etc.) which shall be fed by preprocessing blocks with cycle 8.

When two or more preprocessing blocks are used to feed one protection function (e.g. over-power function GOPPDOP), it is of outmost importance that parameter setting DFTReference has the same set value for all of the preprocessing blocks involved.
**Figure 347:** Twelve SMAI instances are grouped within one task time. SMAI blocks are available in three different task times in the IED. Two pointed instances are used in the following examples.

The examples show a situation with adaptive frequency tracking with one reference selected for all instances. In practice each instance can be adapted to the needs of the actual application. The adaptive frequency tracking is needed in IEDs that belong to the protection system of synchronous machines and that are active during run-up and shout-down of the machine. In other application the usual setting of the parameter DFTReference of SMAI is InternalDFTRef.

**Example 1**
Figure 348: Configuration for using an instance in task time group 1 as DFT reference

Assume instance SMAI1:7 in task time group 1 has been selected in the configuration to control the frequency tracking. Observe that the selected reference instance (i.e. frequency tracking master) must be a voltage type. Observe that positive sequence voltage is used for the frequency tracking feature.

For task time group 1 this gives the following settings (see Figure 347 for numbering):

SMAI1:1: DFTRefExtOut = DFTRefGrp7 to route SMAI7:7 reference to the SPFCOUT output,
DFTReference = DFTRefGrp7 for SMAI1:1 to use SMAI7:7 as reference (see Figure 348)

For task time group 2 this gives the following settings:

SMAI1:13 – SMAI12:24: DFTReference = ExternalDFTRef to use DFTSPFC input of SMAI1:13 as reference (SMAI7:7)

For task time group 3 this gives the following settings:

SMAI1:25 – SMAI12:36: DFTReference = ExternalDFTRef to use DFTSPFC input as reference (SMAI7:7)

Example 2
Figure 349: Configuration for using an instance in task time group 2 as DFT reference.
Assume instance SMAI4:16 in task time group 2 has been selected in the configuration to control the frequency tracking for all instances. Observe that the selected reference instance (i.e. frequency tracking master) must be a voltage type. Observe that positive sequence voltage is used for the frequency tracking feature.

For task time group 1 this gives the following settings (see Figure 347 for numbering):

SMAI1:1 – SMAI12:12: DFTReference = ExternalDFTRef to use DFTSPFC input as reference (SMAI4:16)

For task time group 2 this gives the following settings:

SMAI1:13: DFTRefExtOut = DFTRefGrp4 to route SMAI4:16 reference to the SPFCOUT output, DFTReference = DFTRefGrp4 for SMAI1:13 to use SMAI4:16 as reference (see Figure 349) SMAI2:14 – SMAI12:24: DFTReference = DFTRefGrp4 to use SMAI4:16 as reference.

For task time group 3 this gives the following settings:

SMAI1:25 – SMAI12:36: DFTReference = ExternalDFTRef to use DFTSPFC input as reference (SMAI4:16)

23.12 Test mode functionality TESTMODE

23.12.1 Application

The protection and control IEDs may have a complex configuration with many included functions. To make the testing procedure easier, the IEDs include the feature that allows individual blocking of a single-, several-, or all functions.

This means that it is possible to see when a function is activated or trips. It also enables the user to follow the operation of several related functions to check correct functionality and to check parts of the configuration, and to check parts.
23.12.1.1 IEC 61850 protocol test mode

The function block TESTMODE has implemented the extended testing mode capabilities for IEC 61850 Ed2 systems. Operator commands sent to the function block TESTMODE determine the behavior of the functions. The command can be given remotely from an IEC 61850 client or from the LHMI under the Main menu/Test/Function test modes/Communication/Station Communication/IEC61850 LD0 LLN0/LD0LLN0:1. The possible values of the function block TESTMODE are described in Communication protocol manual, IEC 61850 Edition 1 and Edition 2.

There is no setting in PCM600 via PST for the TESTMODE function block.

To be able to set the function block TESTMODE remotely, the setting via path on LHMI and in PST: Main menu/Configuration/Communication/Station Communication/IEC61850-8-1/IEC61850-8-1:1 RemoteModControl may not be set to Off. The possible values of the parameter RemoteModControl are Off, Maintenance or All levels. The Off value denies all access to function block TESTMODE from remote, Maintenance requires that the category of the originator (orCat) is Maintenance and All levels allow any orCat.

The DataObject Mod of the Root LD.LLN0 can be set on the LHMI under Main menu/Test/Function test modes/Communication/Station communication/IEC61850 LD0 LLN0/LD0LLN0:1 to On, Off, TestBlocked, Test or Blocked.

When the setting of the DataObject Mod is changed at this level, all Logical Nodes inside the logical device update their own behavior according to IEC61850-7-4. The supported values of the function block TESTMODE are described in Communication protocol manual, IEC 61850 Edition 2. When the function block TESTMODE is in test mode the Start LED on the LHMI is turned on with steady light.

The parameter Mod of any specific function block can be configured under Main menu/Test/Function test modes/Communication/Station Communication

The parameter Mod can be set on the LHMI to the same values as for the DataObject Mod of the Root LD.LLN0 to On, Off, TestBlocked, Test or Blocked. For Example, Main menu/ Test/ Function test modes/ Differential protection/GeneratorDiff(87G,3Id/I>)/ GENPDIF(87G,3Id/I>):1.

It is possible that the behavior of the function block TESTMODE is also influenced by other sources as well, independent of the mode communicated via the IEC61850-8-1 station bus. For example the insertion of the test handle into the test switch with its auxiliary contact is connected to a BI on the IED and further inside the configuration to the input IED_TEST on the function block TESTMODE. Another example is when loss of Service Values appears, or as explained above the setting via the LHMI.

When setting via PST or LHMI the parameter Operation of any function in an IED is set to Off, the function is not executed and the behavior (beh) is set to Off and it is not possible to override it. When a behavior of a function is Off the function will not execute. The related Mod keeps its current state.

When IEC 61850 Mod of a function is set to Off or Blocked, the Start LED on the LHMI will be set to flashing to indicate the abnormal operation of the IED.
The IEC 61850-7-4 gives a detailed overview over all aspects of the test mode and other states of mode and behavior. The status of a function block behavior Beh is shown on the LHMI under the Main menu/Test/Function status/Function group/Function block descriptive name/LN name/Outputs.

- When the Beh of a function block is set to Test, the function block is not blocked and all control commands with a test bit are accepted.
- When the Beh of a function block is set to Test/Blocked, all control commands with a test bit are accepted. Outputs to the process via a non-IEC 61850 link data are blocked by the function block. Only process-related outputs on function blocks related to primary equipment are blocked. If there is an XCBR function block used, the outputs EXC_Open and EXC_Close are blocked.
- When the Beh of a function block is set to Blocked, all control commands with a test bit are accepted. Outputs to the process via a non-IEC 61850 link data are blocked by the function block. In addition, the function block can be blocked when their Beh is blocked. This can be done if the function block has a block input.

The block status of a component is shown on the LHMI as the Blk output under the same path as for Beh: Main menu/Test/Function status/Function group/Function block descriptive name/LN name/Outputs. If the Blk output is not shown, the component cannot be blocked.

23.12.2 Setting guidelines

Remember always that there are two possible ways to place the IED in the TestMode= Enabled state. If, the IED is set to normal operation (TestMode = Disabled), but the functions are still shown being in the test mode, the input signal IED_TEST on the TESTMODE function block is activated in the configuration.

Forcing of binary input and output signals is only possible when the IED is in IED test mode.

23.13 Time synchronization TIMESYNCHGEN

23.13.1 Application

Use time synchronization to achieve a common time base for the IEDs in a protection and control system. This makes it possible to compare events and disturbance data between all IEDs in the system. If a global common source (i.e. GPS) is used in different substations for the time synchronization, also comparisons and analysis between recordings made at different locations can be easily performed and a more accurate view of the actual sequence of events can be obtained.

Time-tagging of internal events and disturbances are an excellent help when evaluating faults. Without time synchronization, only the events within one IED can be compared with each other. With time synchronization, events and disturbances within the whole network, can be compared and evaluated.

In the IED, the internal time can be synchronized from the following sources:

- BIN (Binary Minute Pulse)
- DNP
- GPS
- IEC103
- SNTP
• IRIG-B
• SPA
• LON
• PPS
• IEEE 1588 (PTP)

For IEDs using PMU functionality, only PTP, GPS or IRIG-B or a combination of both GPS and IRIG-B is allowed.

For IEDs using IEC/UCA 61850-9-2LE in "mixed mode" a time synchronization from an external clock is recommended to the IED and all connected merging units. The time synchronization from the clock to the IED can be PTP, optical PPS or IRIG-B. For IEDs using IEC/UCA 61850-9-2LE from one single MU as analog data source, the MU and IED still need to be synchronized to each other. This could be done by letting the MU supply a PPS signal to the IED or by supplying a PPS signal from the IED to the MU, by using a GTM.

Out of these, LON and SPA contains two types of synchronization messages:

• Coarse time messages are sent every minute and contain complete date and time, that is year, month, day, hour, minute, second and millisecond.
• Fine time messages are sent every second and comprise only seconds and milliseconds.

The selection of the time source is done via the corresponding setting.

It is possible to select more than one time source, in which case one is backup for the other. The time synchronization source with the best calculated time-quality is automatically selected. For instance, if both GPS and IRIG-B are selected and both sources have the required accuracy, optical IRIG-B with IEEE1344 will be automatically selected as the time synchronization source. Or if GPS and SNTP are selected, when the GPS signal quality is bad, the IED will automatically choose SNTP as the time-source.

If PTP is activated, the device with the best accuracy within the synchronizing group will be selected as the source. For more information about PTP, see the Technical manual.

**IEEE 1588 (PTP)**

PTP according to IEEE 1588-2008 and specifically its profile IEC/IEEE 61850-9-3 for power utility automation is a synchronization method that can be used to maintain a common time within a station. This time can be synchronized to the global time using, for instance, a GPS receiver. If PTP is enabled on the IEDs and the switches that connect the station are compatible with IEEE 1588, the station will become synchronized to one common time with an accuracy of under 1us. Using an IED as a boundary clock between several networks will keep 1us accuracy on three levels or when using an HSR, 15 IEDs can be connected in a ring without losing a single microsecond in accuracy.

### 23.13.2 Setting guidelines

All the parameters related to time are divided into two categories: System time and Synchronization.

#### 23.13.2.1 System time

The time is set with years, month, day, hour, minute, second and millisecond.
23.13.2.2 Synchronization

The setting parameters for the real-time clock with external time synchronization are set via local HMI or PCM600. The path for Time Synchronization parameters on local HMI is Main menu/Configuration/Time/Synchronization. The parameters are categorized as Time Synchronization (TIMESYNCHGEN) and IRIG-B settings (IRIG-B:1) in case that IRIG-B is used as the external time synchronization source.

TimeSynch
When the source of the time synchronization is selected on the local HMI, the parameter is called TimeSynch. The time synchronization source can also be set from PCM600. The setting alternatives are:

FineSyncSource can have the following values:

- Disabled
- SPA
- LON
- BIN (Binary Minute Pulse)
- GPS
- GPS+SPA
- GPS+LON
- GPS+BIN
- SNTP
- GPS+SNTP
- IRIG-B
- GPS+IRIG-B
- PPS

CoarseSyncSrc which can have the following values:

- Disabled
- SPA
- LON
- DNP
- IEC 60870-5-103

The function input to be used for minute-pulse synchronization is called BININPUT. For a description of the BININPUT settings, see the Technical Manual.

The system time can be set manually, either via the local HMI or via any of the communication ports. The time synchronization fine tunes the clock (seconds and milliseconds).

The parameter SyncMaster defines if the IED is a master, or not a master for time synchronization within a Substation Automation System, for IEDs connected in a communication network (IEC 61850-8-1). The SyncMaster can have the following values:

- Disabled
- SNTP -Server
Set the course time synchronizing source (CoarseSyncSrc) to Disabled when GPS time synchronization of line differential function is used. Set the fine time synchronization source (FineSyncSource) to GPS. The GPS will thus provide the complete time synchronization. GPS alone shall synchronize the analogue values in such systems.

All protection functions will be blocked if the AppSynch parameter is set to Synch while there is no 9-2 synchronization source. For more information please refer to the "IEC/UCA 61850-9-2LE communication protocol" section.

**IEEE 1588 (PTP)**

Precision Time Protocol (PTP) is enabled/disabled using the Ethernet configuration tool (ECT) in PCM600.

PTP can be set to On, Off or Slave only. When set to Slave only the IED is connected to the PTP-group and will synchronize to the grandmaster but cannot function as the grandmaster.

A PTP-group is set up by connecting the IEDs to a network and enabling PTP. To set one IED as the grandmaster change Priority2 to 127 instead of the default 128.

*Figure 350: Enabling PTP in ECT*

The PTP VLAN tag must have the same value in station clock and in the IED. The default value is set to 0.

The PTP VLAN tag does not need to be the same on all access points in one IED. It is possible to mix as long as they are the same for all devices on each subnet.
Setting example

![Diagram](IEC16000167-1-en.vsdx)

**Figure 351: Example system**

Figure 351 describes an example system. The REC and REL are both using the 9-2 stream from the SAM600, and gets its synch from the GPS. Moreover, the REL and REC both acts as a boundary clock to provide synch to the SAM600. The REL contains a GTM card, which has a PPS output that is used to synchronize merging units that are not PTP compliant. As a side effect, the GTM contains a GPS receiver and the REL acts as a backup of the GPS on the station bus.

On all access points, the PTP parameter is "ON".

On the REL, the parameter FineSyncSource (under Configuration/Time/Synchronization/ TIMESYNCHGEN:1/General) is set to "GPS" if there is a GPS antenna attached.

If the GTM is used as a PPS output only, the FineSynchSource is not set.

### 23.13.2.3 Process bus IEC/UCA 61850-9-2LE synchronization

When process bus communication (IEC/UCA 61850-9-2LE protocol) is used, it is essential that the merging units are synchronized with the hardware time of the IED (see Technical manual, section Design of the time system (clock synchronization) ). To achieve this, PTP, PPS or IRIG-B can be used depending of the facilities of the merging unit.

If the merging unit supports PTP, use PTP. If PTP is used in the IED and the merging unit is not PTP capable, then synchronize the merging unit from the IED via a PPS out from the GTM. If PTP is used in the IED and the merging unit cannot be synchronized from the IED, then use GPS-based clocks to provide PTP synch as well as sync to the merging unit.

If synchronization of the IED and the merging unit is based on GPS, set the parameter SyncLostMode to BlockOnLostUTC in order to provide a block of protection functions whenever the global common time is lost.
If PTP is not used, use the same synchronization method for the HwSyncSrc as the merging unit provides. For instance, if the merging unit provides PPS as synchronization, use PPS as HwSyncSrc. If either PMU or LDCM in GPS-mode is used, that is, the hardware and software clocks are connected to each other, HwSyncSrc is not used and other means to synchronize the merging unit to the IED is required. Either FineSyncSource is set to the same source that the merging unit uses, or the PPS output from the GTM module is used to synchronize the merging unit. If the PPS output from the GTM module is used to synchronize the merging unit and PTP is not used, the IED does not know how the merging unit is synchronized and the parameter SyncLostMode must be set to NoBlock.

If the IED is used together with a merging unit and no time synchronization is available, for example, in the laboratory test, the IED will synchronize to the SV data stream. During the re-synchronization, the protection functions will be blocked once a second for about 45 ms, and this will continue for up to 10 minutes. To avoid this, configure PTP (IEEE 1588) to On for the access point where the merging unit is configured.
Section 24 Requirements

24.1 Current transformer requirements

The performance of a protection function will depend on the quality of the measured current signal. Saturation of the current transformers (CTs) will cause distortion of the current signals and can result in a failure to operate or cause unwanted operations of some functions. Consequently CT saturation can have an influence on both the dependability and the security of the protection. This protection IED has been designed to permit heavy CT saturation with maintained correct operation.

24.1.1 Current transformer basic classification and requirements

To guarantee correct operation, the current transformers (CTs) must be able to correctly reproduce the current for a minimum time before the CT will begin to saturate. To fulfill the requirement on a specified time to saturation the CTs must fulfill the requirements of a minimum secondary e.m.f. that is specified below.

CTs are specified according to many different classes and standards. In principle, there are three different types of protection CTs. These types are related to the design of the iron core and the presence of airgaps. Airgaps affects the properties of the remanent flux.

The following three different types of protection CTs have been specified:

- The High Remanence type with closed iron core and no specified limit of the remanent flux
- The Low Remanence type with small airgaps in the iron core and the remanent flux limit is specified to be maximum 10% of the saturation flux
- The Non Remanence type with big airgaps in the iron core and the remanent flux can be neglected

Even though no limit of the remanent flux is specified in the IEC standard for closed core CTs, it is a common opinion that the remanent flux is normally limited to maximum 75 - 80 % of the saturation flux.

Since approximately year 2000 some CT manufactures have introduced new core materials that gradually have increased the possible maximum levels of remanent flux even up to 95 % related to the hysteresis curve. Corresponding level of actual remanent flux is 90 % of the saturation flux ($\Psi_{sat}$). As the present CT standards have no limitation of the level of remanent flux, these CTs are also classified as for example, class TPX, P and PX according to IEC. The IEC TR 61869-100, Edition 1.0 2017-01, Instrument transformers – Guidance for application of current transformers in power system protection, is the first official document that highlighted this development. So far remanence factors of maximum 80% have been considered when CT requirements have been decided for ABB IEDs. Even in the future this level of remanent flux probably will be the maximum level that will be considered when decided the CT requirements. If higher remanence levels should be considered, it should often lead to unrealistic CT sizes.

Thus, now there is a need to limit the acceptable level of remanent flux. To be able to guarantee the performance of protection IEDs, we need to introduce the following classification of CTs:

There are many different standards and a lot of classes but fundamentally there are four different types of CTs:
- Very High Remanence type CT
- High Remanence type CT
- Low Remanence type CT
- Non Remanence type CT

**The Very High Remanence (VHR) type** is a CT with closed iron core (for example, protection classes TPX, P, PX according to IEC, class C, K according to ANSI/IEEE) and with an iron core material (new material, typically new alloy based magnetic materials) that gives a remanent flux higher than 80 % of the saturation flux.

**The High Remanence (HR) type** is a CT with closed iron core (for example, protection classes TPX, P, PX according to IEC, class C, K according to ANSI/IEEE) but with an iron core material (traditional material) that gives a remanent flux that is limited to maximum 80 % of the saturation flux.

**The Low Remanence (LR) type** is a CT with small airgaps in the iron core (for example, TPY, PR, PXR according to IEC) and the remanent flux limit is specified to be maximum 10% of the saturation flux.

**The Non Remanence (NR) type** is a CT with big airgaps in the core (for example, TPZ according to IEC) and the remanent flux can be neglected.

It is also possible that different CT classes of HR and LR type may be mixed.

CT type VHR (using new material) should not be used for protection CT cores. This means that it is important to specify that the remanence factor must not exceed 80 % when ordering for example, class P, PX or TPX CTs. If CT manufacturers are using new core material and are not able to fulfill this requirement, the CTs shall be specified with small airgaps and therefore will be CTs of LR type (for example, class PR, TPY or PXR). Very high remanence level in a protection core CT can cause the following problems for protection IEDs:

1. Unwanted operation of differential (i.e. unit) protections for external faults
2. Unacceptably delayed or even missing operation of all types of protections (for example, distance, differential, overcurrent, etc.) which can result in loosing protection selectivity in the network

No information is available about how frequent the use of the new iron core material is for protection CT cores, but it is known that some CT manufacturers are using the new material while other manufacturers continue to use the old traditional core material for protection CT cores. In a case where VHR type CTs have been already installed, the calculated values of $E_{al}$ for HR type CTs, for which the formulas are given in this document, must be multiplied by factor two-and-a-half in order for VHR type CTs (i.e. with new material) to be used together with ABB protection IEDs. However, this may result in unacceptably big CT cores, which can be difficult to manufacture and fit in available space.

Different standards and classes specify the saturation e.m.f. in different ways but it is possible to approximately compare values from different classes. The rated equivalent limiting secondary e.m.f. $E_{al}$ according to the IEC 61869–2 standard is used to specify the CT requirements for the IED. The requirements are also specified according to other standards.

### 24.1.2 Conditions
The requirements are a result of investigations performed in our network simulator. The current transformer models are representative for current transformers of high remanence and low remanence type. The results may not always be valid for non remanence type CTs (TPZ).

The performances of the protection functions have been checked in the range from symmetrical to fully asymmetrical fault currents. Primary time constants of at least 120 ms have been considered at the tests. The current requirements below are thus applicable both for symmetrical and asymmetrical fault currents.

Depending on the protection function phase-to-ground, phase-to-phase and three-phase faults have been tested for different relevant fault positions for example, close in forward and reverse faults, zone 1 reach faults, internal and external faults. The dependability and security of the protection was verified by checking for example, time delays, unwanted operations, directionality, overreach and stability.

The remanence in the current transformer core can cause unwanted operations or minor additional time delays for some protection functions. As unwanted operations are not acceptable at all maximum remanence has been considered for fault cases critical for the security, for example, faults in reverse direction and external faults. Because of the almost negligible risk of additional time delays and the non-existent risk of failure to operate the remanence have not been considered for the dependability cases. The requirements below are therefore fully valid for all normal applications.

It is difficult to give general recommendations for additional margins for remanence to avoid the minor risk of an additional time delay. They depend on the performance and economy requirements. When current transformers of low remanence type (for example, TPY, PR) are used, normally no additional margin is needed. For current transformers of high remanence type (for example, P, PX, TPX) the small probability of fully asymmetrical faults, together with high remanence in the same direction as the flux generated by the fault, has to be kept in mind at the decision of an additional margin. Fully asymmetrical fault current will be achieved when the fault occurs at approximately zero voltage (0°). Investigations have shown that 95% of the faults in the network will occur when the voltage is between 40° and 90°. In addition fully asymmetrical fault current will not exist in all phases at the same time.

### 24.1.3 Fault current

The current transformer requirements are based on the maximum fault current for faults in different positions. Maximum fault current will occur for three-phase faults or single phase-to-ground faults. The current for a single phase-to-ground fault will exceed the current for a three-phase fault when the zero sequence impedance in the total fault loop is less than the positive sequence impedance.

When calculating the current transformer requirements, maximum fault current for the relevant fault position should be used and therefore both fault types have to be considered.

### 24.1.4 Secondary wire resistance and additional load

The voltage at the current transformer secondary terminals directly affects the current transformer saturation. This voltage is developed in a loop containing the secondary wires and the burden of all relays in the circuit. For ground faults the loop includes the phase and neutral wire, normally twice the resistance of the single secondary wire. For three-phase faults the neutral current is zero and it is just necessary to consider the resistance up to the point where the phase wires are connected to the common neutral wire. The most common practice is to use four wires.
secondary cables so it normally is sufficient to consider just a single secondary wire for the three-phase case.

The conclusion is that the loop resistance, twice the resistance of the single secondary wire, must be used in the calculation for phase-to-ground faults and the phase resistance, the resistance of a single secondary wire, may normally be used in the calculation for three-phase faults.

As the burden can be considerable different for three-phase faults and phase-to-ground faults it is important to consider both cases. Even in a case where the phase-to-ground fault current is smaller than the three-phase fault current the phase-to-ground fault can be dimensioning for the CT depending on the higher burden.

In isolated or high impedance grounded systems the phase-to-ground fault is not the dimensioning case. Therefore, the resistance of the single secondary wire can always be used in the calculation for this kind of power systems.

24.1.5 General current transformer requirements

The current transformer ratio is mainly selected based on power system data for example, maximum load and/or maximum fault current. It should be verified that the current to the protection is higher than the minimum operating value for all faults that are to be detected with the selected CT ratio. It should also be verified that the maximum possible fault current is within the limits of the IED.

The current error of the current transformer can limit the possibility to use a very sensitive setting of a sensitive residual overcurrent protection. If a very sensitive setting of this function will be used it is recommended that the current transformer should have an accuracy class which have an current error at rated primary current that is less than ±1% (for example, 5P). If current transformers with less accuracy are used it is advisable to check the actual unwanted residual current during the commissioning.

24.1.6 Rated equivalent secondary e.m.f. requirements

With regard to saturation of the current transformer all current transformers of high remanence and low remanence type that fulfill the requirements on the rated equivalent limiting secondary e.m.f. $E_{al}$ below can be used. The characteristic of the non remanence type CT (TPZ) is not well defined as far as the phase angle error is concerned. If no explicit recommendation is given for a specific function we therefore recommend contacting ABB to confirm that the non remanence type can be used.

The CT requirements for the different functions below are specified as a rated equivalent limiting secondary e.m.f. $E_{al}$ according to the IEC 61869-2 standard. Requirements for CTs specified according to other classes and standards are given at the end of this section.

24.1.6.1 Guide for calculation of CT for generator differential protection

This section is an informative guide describing the practical procedure when dimensioning CTs for the generator differential protection IED. Two different cases are of interest. The first case describes how to verify that existing CTs fulfill the requirements in a specific application. The other case describes a method to provide CT manufacturers with necessary CT data for the application. Below is one example for each case.
In IED the generator differential and the transformer differential functions have the same CT requirements. According to the manual the CTs must have a rated equivalent limiting secondary e.m.f. $E_{al}$ that is larger than or equal to the maximum of the required rated equivalent limiting secondary e.m.f. $E_{alreqRat}$ and $E_{alreqExt}$ below:

$$E_{al} \geq E_{alreqRat} = 30 \cdot \frac{I_{NG}}{I_{pr}} \cdot I_{ss} \left( R_{ct} + R_{w} + R_{addbu} \right)$$  \hspace{1cm} (Equation 275)

$$E_{al} \geq E_{alreqExt} = 2 \cdot \frac{I_{tf}}{I_{pr}} \cdot I_{sr} \left( R_{ct} + R_{w} + R_{addbu} \right)$$  \hspace{1cm} (Equation 276)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$I_{NG}$</td>
<td>The rated primary current of the generator</td>
</tr>
<tr>
<td>$I_{tf}$</td>
<td>Maximum primary fault current through the CTs for external faults. Generally both three phase faults and phase to earth faults shall be considered. However, in most generator applications the system is high impedance earthed and the phase to earth fault current is small which means that the three phase fault will be the dimensioning case.</td>
</tr>
<tr>
<td>$I_{pr}$</td>
<td>CT rated primary current</td>
</tr>
<tr>
<td>$I_{sr}$</td>
<td>CT rated secondary current</td>
</tr>
<tr>
<td>$R_{ct}$</td>
<td>CT secondary winding resistance</td>
</tr>
<tr>
<td>$R_{w}$</td>
<td>The resistance of the secondary wire. For phase to earth faults the loop resistance containing the phase and neutral wires (double length) shall be used and for three phase faults the phase wire (single length) can be used.</td>
</tr>
<tr>
<td>$R_{addbu}$</td>
<td>The total additional burden from the differential relay and possible other relays</td>
</tr>
</tbody>
</table>

We assume that the secondary wire and additional burden are the same for the two examples. The resistance of the secondary wires can be calculated with the following expression:

$$R_{w} = \rho \cdot \frac{I}{A} \Omega$$  \hspace{1cm} (Equation 277)
In our example the single length of the secondary wire is 300 m both to CT1 and CT2. The cross-section area is 2.5 mm². The resistivity for copper at 75°C is 0.021 Ω m²/m.

With this value

\[ R_w = \rho \cdot \frac{I}{A} = 0.021 \cdot \frac{300}{2.5} = 2.5 \Omega \]

(Equation 278)

The total additional burden in our example is 0.3 Ω for both CTs.

**Calculation example 1**
Verify that the existing CTs fulfil the requirements for the REG670 generator differential protection in the following application.

![Diagram of generator protection system](IEC11000215-1-en.vsd)

**Figure 352:**

Generator data:
- Rated apparent power: 90 MVA
- Rated voltage: 16 kV
- Short circuit impedance: 25 %

The existing CTs (CT1 and CT2) have the following data:
- CT1: 4000/1 A, 5P10, 15 VA, the secondary winding resistance \( R_{ct} = 5 \Omega \) The rated burden:
  \[ R_b = \frac{15}{I_{sr}^2} = \frac{15}{1} = 15 \Omega \]
  (Equation 279)
- CT2: 4000/1 A, class PX, the rated knee point e.m.f. \( E_k = 200 \) V, \( R_{ct} = 5 \Omega \)

From the data the \( E_{al} \) can be calculated:
- CT1:
\[ E_{\text{al}} = \text{ALF} \cdot I_{\text{sr}} \cdot (R_{\text{ct}} + R_{\text{w}}) = 10 \cdot 1 \cdot (5 + 15) = 200 \text{ V} \]

(Equation 280)

where ALF is the CT accuracy limit factor.

• CT2:

\[ E_{\text{al}} = \frac{E_k}{0.8} = \frac{200}{0.8} = 250 \text{ V} \]

(Equation 281)

The rated current of the generator and the fault current for a three phase external short circuit must be calculated.

\[ I_{\text{NG}} = \frac{S_n}{\sqrt{3} \cdot U_n} = \frac{90}{\sqrt{3} \cdot 16} = 3.25 \text{ kA} \]

(Equation 282)

\[ I_{\text{f}} = \frac{I_{\text{NG}}}{X_g} = \frac{3.25}{0.25} = 13.0 \text{ kA} \]

(Equation 283)

We can now calculate the required secondary e.m.f. according to equation 275 and 276. As the 16 kV system is high impedance earthed the burden only needs to consider the single length of the secondary wire.

**Check of CT1 and CT2:**

The CTs must have a rated equivalent limiting secondary e.m.f. \( E_{\text{al}} \) that is larger than or equal to the maximum of the required rated equivalent limiting secondary e.m.f. \( E_{\text{alreqRat}} \) and \( E_{\text{alreqExt}} \) below:

\[ E_{\text{al}} \geq E_{\text{alreqRat}} = 30 \cdot \frac{I_{\text{NG}}}{I_{\text{pr}}} \cdot I_{\text{sr}} (R_{\text{ct}} + R_{\text{w}} + R_{\text{addbu}}) = 30 \cdot \frac{3250}{4000} \cdot 1 \cdot (5 + 2.5 + 0.3) = 190 \text{ V} \]

(Equation 284)

\[ E_{\text{al}} \geq E_{\text{alreqExt}} = 2 \cdot \frac{I_{\text{f}}}{I_{\text{pr}}} \cdot I_{\text{sr}} (R_{\text{ct}} + R_{\text{w}} + R_{\text{addbu}}) = 2 \cdot \frac{13000}{4000} \cdot 1 \cdot (5 + 2.5 + 0.3) = 51 \text{ V} \]

(Equation 285)

In this application we can see that the CTs must have a rated equivalent secondary e.m.f. \( E_{\text{al}} \) that is equal or larger than 190 V. As the existing CT1 has \( E_{\text{al}} = 200 \text{ V} \) and CT2 has \( E_{\text{al}} = 250 \text{ V} \) we can conclude that the CTs fulfil the requirements for the generator differential protection in REG670.

**Calculation example 2**

We are using the same example as before (Calculation example 1) but now the CT data is not known and we shall specify the CTs and provide CT manufacturers with necessary CT data.

The rated current of the generator and the fault current for a three phase external short circuit is calculated.
\[ I_{NG} = \frac{S_n}{\sqrt{3} \cdot U_n} = \frac{90}{\sqrt{3} \cdot 16} = 3.25 \text{ kA} \]  

(Equation 286)

\[ I_{fr} = \frac{I_{NG}}{X_g} = \frac{3.25}{0.25} = 13.0 \text{ kA} \]  

(Equation 287)

We decide that CT1 and CT2 shall be equal (not necessary according to the requirements). The CT ratio is decided to 4000/1 A and the burden is the same as in Example 1. So \( R_w = 2.5 \Omega \) (single length) and the total additional burden \( R_{addbu} = 0.3 \Omega \) for both CTs. As we do not know the CT secondary winding resistance \( R_{ct} \) we must assume a realistic value. The value can vary much depending on the design of the CT but a realistic range is between 20 to 80 % of the rated burden. Therefore we first must decide the rated burden of the CT.

Maximum burden for the CTs are:

\[ R_{b_{max}} = R_w + R_{addbu} = 2.5 + 0.3 = 2.8 \Omega \]  

(Equation 288)

It is often economical favorable to specify a low rated burden and a higher overcurrent factor instead of vice versa. In our case it can be suitable to decide the rated burden to \( R_b = 5 \Omega \) (5 VA). Now we can assume the CT secondary winding resistance to be 60 % of \( R_b, R_{ct} = 3 \Omega \).

We can now calculate the required secondary e.m.f. according to equation 275 and 276. As the 16 kV system is high impedance earthed the burden only needs to consider the single length of the secondary wire.

**Dimensioning of CT1 and CT2:**

The CTs must have a rated equivalent limiting secondary e.m.f. \( E_{al} \) that is larger than or equal to the maximum of the required rated equivalent limiting secondary e.m.f. \( E_{alreqRat} \) and \( E_{alreqExt} \) below:

\[ E_{al} \geq E_{alreqRat} = 30 \cdot \frac{I_{NG}}{I_{fr}} \cdot I_{fr} \cdot (R_{ct} + R_w + R_{addbu}) = 30 \cdot \frac{3250}{4000} \cdot 1 \cdot (3 + 2.5 + 0.3) = 142 \text{ V} \]  

(Equation 289)

\[ E_{al} \geq E_{alreqExt} = 2 \cdot \frac{I_{fr}}{I_{fr}} \cdot I_{fr} \cdot (R_{ct} + R_w + R_{addbu}) = 2 \cdot \frac{13000}{4000} \cdot 1 \cdot (3 + 2.5 + 0.3) = 38 \text{ V} \]  

(Equation 290)

The conclusion is that we need a CT with \( E_{al} > 142 \text{ V} \). For example a CT class 5P with the rated burden 5 VA and \( R_{CT} < 3 \Omega \) shall fulfil the following:

\[ E_{al} \geq 142 = \text{ALF} \cdot I_{fr} \cdot (R_{ct} + R_w) = \text{ALF} \cdot 1 \cdot (3 + 5) \]  

(Equation 291)

\[ \text{ALF} \geq \frac{142}{(3 + 5)} = 17.8 \]  

(Equation 292)
CTs with the following data will fulfil the requirements for the generator differential protection in this application:

- Class 5P2 (5P18), 5 VA and $R_{ct} < 3 \, \Omega$.

It shall be noted that even if the rated burden of this CT is specified to 5 VA it is not possible to have an actual burden more than 2.8 $\Omega$ and still fulfil the CT requirements.

It is of course also possible to specify the CT according to other classes. For example a CT with the following data will also fulfil the requirements:

- Class PX, $R_{ct} < 3 \, \Omega$ and the knee point e.m.f.

$$E_k \geq 0.8 \cdot E_{al} = 0.8 \cdot 142 = 114 \, V$$

(Equation 293)

As an alternative it can be suitable to provide the CT manufacturer with the data according to equation 294 as follows:

$$E_{al} \geq E_{alreq} = 30 \cdot \frac{L_{NG}}{I_{pr}} \cdot I_{sr} \left( R_{ct} + R_w + R_{addbu} \right) = 30 \cdot \frac{3250}{4000} \cdot 1 \cdot (R_{ct} + 2.8)$$

(Equation 294)

$$\frac{E_{al}}{R_{ct} + 2.8} \geq 30 \cdot \frac{3250}{4000} \cdot 1 = 24.4$$

(Equation 295)

This can give the CT manufacturer a possibility to optimize the relation between the resistance of the CT winding and the area of the iron core.

If the CT shall be specified as a class PX the following relation between the knee point e.m.f. $E_k$ and $R_{ct}$ shall be fulfilled:

$$\frac{E_k}{0.8 \cdot (R_{ct} + 2.8)} \geq 24.4 \quad \text{or} \quad \frac{E_k}{R_{ct} + 2.8} \geq 19.5$$

(Equation 296)

### 24.1.6.2 Transformer differential protection

The current transformers must have a rated equivalent limiting secondary e.m.f. $E_{al}$ that is larger than the maximum of the required rated equivalent limiting secondary e.m.f. $E_{alreq}$ below:

$$E_{al} \geq E_{alreq} = 30 \cdot \frac{I_n}{I_{pr}} \cdot \left( R_{ct} + R_L + \frac{S_R}{I_n} \right)$$

(Equation 297)
\[ E_{al} \geq E_{alreq} = 2 \cdot I_f \cdot \frac{I_{pa}}{I_{pn}} \left( R_{CT} + R_L + \frac{S_R}{I_n} \right) \]

(Equation 298)

where:
- \( I_{rt} \): The rated primary current of the power transformer (A)
- \( I_{tf} \): Maximum primary fundamental frequency current that passes two main CTs and the power transformer (A)
- \( I_{pr} \): The rated primary CT current (A)
- \( I_{sr} \): The rated secondary CT current (A)
- \( I_n \): The nominal current of the protection IED (A)
- \( R_{ct} \): The secondary resistance of the CT (Ω)
- \( R_L \): The resistance of the secondary wire and additional load (Ω). The loop resistance containing the phase and neutral wires must be used for faults in solidly grounded systems. The resistance of a single secondary wire should be used for faults in high impedance grounded systems.
- \( S_R \): The burden of an IED current input channel (VA). \( S_R = 0.020 \, \text{VA/channel for } I_r = 1 \, \text{A and } S_R = 0.150 \, \text{VA/channel for } I_r = 5 \, \text{A} \)

In substations with breaker-and-a-half or double-busbar double-breaker arrangement, the fault current may pass two main CTs for the transformer differential protection without passing the power transformer. In such cases and if both main CTs have equal ratios and magnetization characteristics the CTs must satisfy equation 297 and equation 299.

\[ E_{al} \geq E_{alreq} = I_f \cdot \frac{I_{pa}}{I_{pn}} \left( R_{CT} + R_L + \frac{S_R}{I_n} \right) \]

(Equation 299)

where:
- \( I_f \): Maximum primary fundamental frequency current that passes two main CTs without passing the power transformer (A)

### 24.1.6.3 Breaker failure protection

The CTs must have a rated equivalent limiting secondary e.m.f. \( E_{al} \) that is larger than or equal to the required rated equivalent limiting secondary e.m.f. \( E_{alreq} \) below:


\[ E_{al} \geq E_{al\text{req}} = 5 \cdot I_{op} \cdot \frac{I_{sr}}{I_{pr}} \left( R_{ct} + R_{L} + \frac{S_R}{I_{n}^2} \right) \]  

(Equation 300)

where:
- \( I_{op} \) The primary operate value (A)
- \( I_{pr} \) The rated primary CT current (A)
- \( I_{sr} \) The rated secondary CT current (A)
- \( I_{n} \) The nominal current of the protection IED (A)
- \( R_{ct} \) The secondary resistance of the CT (Ω)
- \( R_{L} \) The resistance of the secondary cable and additional load (Ω). The loop resistance containing the phase and neutral wires, must be used for faults in solidly grounded systems. The resistance of a single secondary wire should be used for faults in high impedance grounded systems.
- \( S_R \) The burden of an IED current input channel (VA). \( S_R = 0.020 \text{ VA/channel for } I_{r} = 1 \text{ A and } S_R = 0.150 \text{ VA/channel for } I_{r} = 5 \text{ A} \)

### 24.1.6.4 Restricted ground fault protection (low impedance differential)

The requirements are specified separately for solidly grounded and impedance grounded transformers. For impedance grounded transformers, the requirements for the phase CTs are depending whether it is three individual CTs connected in parallel or it is a cable CT enclosing all three phases.

**Neutral CTs and phase CTs for solidly ground transformers**

The neutral CT and the phase CTs must have a rated equivalent limiting secondary e.m.f. \( E_{al} \) that is larger than or equal to the maximum of the required rated equivalent limiting secondary e.m.f. \( E_{al\text{req}} \) below:

\[ E_{al} \geq E_{al\text{req}} = 30 \cdot I_{rt} \cdot \frac{I_{sr}}{I_{pr}} \left( R_{ct} + R_{L} + \frac{S_R}{I_{r}^2} \right) \]  

(Equation 301)

\[ E_{al} \geq E_{al\text{req}} = 2 \cdot I_{eff} \cdot \frac{I_{sr}}{I_{pr}} \left( R_{ct} + R_{L} + \frac{S_R}{I_{r}^2} \right) \]  

(Equation 302)

Where:
- \( I_{rt} \) The rated primary current of the power transformer (A)
- \( I_{eff} \) Maximum primary fundamental frequency phase-to-ground fault current that passes the CTs and the power transformer neutral (A)
- \( I_{pr} \) The rated primary CT current (A)
- \( I_{sr} \) The rated secondary CT current (A)

Table continues on next page
The rated current of the protection IED (A)

The secondary resistance of the CT (Ω)

The resistance of the secondary wire and additional load (Ω). The loop resistance containing the phase and neutral wires shall be used.

The burden of a REx670 current input channel (VA). \( S_R = 0.020 \text{ VA/channel for } I_r = 1 \text{ A and } S_R = 0.150 \text{ VA/channel for } I_r = 5 \text{ A} \)

In substations with breaker-and-a-half or double-busbar double-breaker arrangement, the fault current may pass two main phase CTs for the restricted ground fault protection without passing the power transformer. In such cases and if both main CTs have equal ratios and magnetization characteristics the CTs must satisfy Requirement 301 and the Requirement 302:

\[
E_{al} \geq E_{alreq} = I_{ef} \cdot \frac{I_{sr}}{I_{pr}} \cdot \left( R_{ct} + R_L + \frac{S_R}{I_r^2} \right) \]

(Equation 303)

Where:

- \( I_{ef} \) Maximum primary fundamental frequency phase-to-ground fault current that passes two main CTs without passing the power transformer neutral (A)

**Neutral CTs and phase CTs for impedance grounded transformers**

The neutral CT and phase CTs must have a rated equivalent limiting secondary e.m.f. \( E_{al} \) that is larger than or equal to the required rated equivalent limiting secondary e.m.f. \( E_{alreq} \) below:

\[
E_{al} \geq E_{alreq} = 3 \cdot I_{ef} \cdot \frac{I_{sr}}{I_{pr}} \cdot \left( R_{ct} + R_L + \frac{S_R}{I_r^2} \right) \]

(Equation 304)

Where:

- \( I_{ef} \) Maximum primary fundamental frequency phase-to-ground fault current that passes the CTs and the power transformer neutral (A)
- \( I_{pr} \) The rated primary CT current (A)
- \( I_{sr} \) The rated secondary CT current (A)
- \( I_r \) The rated current of the protection IED (A)
- \( R_{ct} \) The secondary resistance of the CT (Ω)
- \( R_L \) The resistance of the secondary wire and additional load (Ω). The loop resistance containing the phase and neutral wires shall be used.
- \( S_R \) The burden of a REx670 current input channel (VA). \( S_R = 0.020 \text{ VA/channel for } I_r = 1 \text{ A and } S_R = 0.150 \text{ VA/channel for } I_r = 5 \text{ A} \)

In case of three individual CTs connected in parallel (Holmgren connection) on the phase side the following additional requirements must also be fulfilled.
The three individual phase CTs must have a rated equivalent limiting secondary e.m.f. $E_{al}$ that is larger than or equal to the maximum of the required rated equivalent limiting secondary e.m.f. $E_{alreq}$ below:

$$E_{al} \geq E_{alreq} = 2 \cdot I_{f} \cdot \frac{I_{sr}}{I_{pr}} \left( R_{ct} + R_{Lsw} + \frac{S_{R}}{I_{r}^2} \right)$$

(Equation 305)

Where:
- $I_{f}$: Maximum primary fundamental frequency three-phase fault current that passes the CTs and the power transformer (A).
- $R_{Lsw}$: The resistance of the single secondary wire and additional load (Ω).

In impedance grounded systems the phase-to-ground fault currents often are relatively small and the requirements might result in small CTs. However, in applications where the zero sequence current from the phase side of the transformer is a summation of currents from more than one CT (cable CTs or groups of individual CTs in Holmgren connection) for example, in substations with breaker-and-a-half or double-busbar double-breaker arrangement or if the transformer has a T-connection to different busbars, there is a risk that the CTs can be exposed for higher fault currents than the considered phase-to-ground fault currents above. Examples of such cases can be cross-country faults or phase-to-phase faults with high fault currents and unsymmetrical distribution of the phase currents between the CTs. The zero sequence fault current level can differ much and is often difficult to calculate or estimate for different cases. To cover these cases, with summation of zero sequence currents from more than one CT, the phase side CTs must fulfill the Requirement 306 below:

$$E_{al} \geq E_{alreq} = I_{f} \cdot \frac{I_{sr}}{I_{pr}} \left( R_{ct} + R_{L} + \frac{S_{R}}{I_{r}^2} \right)$$

(Equation 306)

Where:
- $I_{f}$: Maximum primary fundamental frequency three-phase fault current that passes the CTs (A).
- $R_{L}$: The resistance of the secondary wire and additional load (Ω). The loop resistance containing the phase and neutral wires shall be used.

### 24.1.7 Current transformer requirements for CTs according to other standards

All kinds of conventional magnetic core CTs are possible to use with the IEDs if they fulfill the requirements corresponding to the above specified expressed as the rated equivalent limiting secondary e.m.f. $E_{al}$ according to the IEC 61869-2 standard. From different standards and available data for relaying applications it is possible to approximately calculate a secondary e.m.f. of the CT comparable with $E_{al}$. By comparing this with the required rated equivalent limiting secondary e.m.f. $E_{alreq}$ it is possible to judge if the CT fulfills the requirements. The requirements according to some other standards are specified below.
24.1.7.1 Current transformers according to IEC 61869-2, class P, PR

A CT according to IEC 61869-2 is specified by the secondary limiting e.m.f. $E_{\text{ALF}}$. The value of the $E_{\text{ALF}}$ is approximately equal to the corresponding $E_{\text{al}}$. Therefore, the CTs according to class P and PR must have a secondary limiting e.m.f. $E_{\text{ALF}}$ that fulfills the following:

$$E_{\text{ALF}} > \max E_{\text{alreq}}$$

(Equation 307)

24.1.7.2 Current transformers according to IEC 61869-2, class PX, PXR (and old IEC 60044-6, class TPS and old British Standard, class X)

CTs according to these classes are specified approximately in the same way by a rated knee point e.m.f. $E_{\text{knee}}$ ($E_{\text{k}}$ for class PX and PXR, $E_{\text{kneeBS}}$ for class X and the limiting secondary voltage $V_{\text{al}}$ for TPS). The value of the $E_{\text{knee}}$ is lower than the corresponding $E_{\text{al}}$ according to IEC 61869-2. It is not possible to give a general relation between the $E_{\text{knee}}$ and the $E_{\text{al}}$ but normally the $E_{\text{knee}}$ is approximately 80 % of the $E_{\text{al}}$. Therefore, the CTs according to class PX, PXR, X and TPS must have a rated knee point e.m.f. $E_{\text{knee}}$ that fulfills the following:

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

(Equation 308)

24.1.7.3 Current transformers according to ANSI/IEEE

Current transformers according to ANSI/IEEE are partly specified in different ways. A rated secondary terminal voltage $V_{\text{ANSI}}$ is specified for a CT of class C. $V_{\text{ANSI}}$ is the secondary terminal voltage the CT will deliver to a standard burden at 20 times rated secondary current without exceeding 10 % ratio correction. There are a number of standardized $V_{\text{ANSI}}$ values for example, $V_{\text{ANSI}}$ is 400 V for a C400 CT. A corresponding rated equivalent limiting secondary e.m.f. $E_{\text{alANSI}}$ can be estimated as follows:

$$E_{\text{alANSI}} = 20 \cdot I_{\text{SN}} \cdot R_{\text{CT}} + V_{\text{ANSI}} = 20 \cdot I_{\text{SN}} \cdot R_{\text{CT}} + 20 \cdot I_{\text{SN}} \cdot Z_{\text{bANSI}}$$

(Equation 309)

where:

$Z_{\text{bANSI}}$ The impedance (that is, with a complex quantity) of the standard ANSI burden for the specific C class ($\Omega$)

$V_{\text{ANSI}}$ The secondary terminal voltage for the specific C class (V)

The CTs according to class C must have a calculated rated equivalent limiting secondary e.m.f. $E_{\text{alANSI}}$ that fulfills the following:

$$E_{\text{alANSI}} > \max E_{\text{alreq}}$$

(Equation 310)
A CT according to ANSI/IEEE is also specified by the knee point voltage $V_{\text{kneeANSI}}$ that is graphically defined from an excitation curve. The knee point voltage $V_{\text{kneeANSI}}$ normally has a lower value than the knee-point e.m.f. according to IEC and BS. $V_{\text{kneeANSI}}$ can approximately be estimated to 75% of the corresponding $E_{\text{al}}$ according to IEC 61869-2. Therefore, the CTs according to ANSI/IEEE must have a knee point voltage $V_{\text{kneeANSI}}$ that fulfills the following:

$$V_{\text{kneeANSI}} > 0.75 \times (\text{maximum of } E_{\text{alreq}})$$

(Equation 311)

The following guide may also be referred for some more application aspects of ANSI class CTs: IEEE C37.110 (2007), IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes.

### 24.2 Voltage transformer requirements

The performance of a protection function will depend on the quality of the measured input signal. Transients caused by capacitive Coupled voltage transformers (CCVTs) can affect some protection functions.

Magnetic or capacitive voltage transformers can be used.

The capacitive voltage transformers (CCVTs) should fulfill the requirements according to the IEC 61869-5 standard regarding ferro-resonance and transients. The ferro-resonance requirements of the CCVTs are specified in chapter 6.502 of the standard.

The transient responses for three different standard transient response classes, T1, T2 and T3 are specified in chapter 6.503 of the standard. CCVTs according to all classes can be used.

The protection IED has effective filters for these transients, which gives secure and correct operation with CCVTs.

### 24.3 SNTP server requirements

The SNTP server to be used is connected to the local network, that is not more than 4-5 switches or routers away from the IED. The SNTP server is dedicated for its task, or at least equipped with a real-time operating system, that is not a PC with SNTP server software. The SNTP server should be stable, that is, either synchronized from a stable source like GPS, or local without synchronization. Using a local SNTP server without synchronization as primary or secondary server in a redundant configuration is not recommended.

### 24.4 PTP requirements

For PTP to perform properly, the Ethernet equipment that is used needs to be compliant with IEEE1588. The clocks used must follow the IEEE1588 standard BMC (Best Master Algorithm) and shall, for instance, not claim class 7 for a longer time than it can guarantee 1us absolute accuracy.
24.5 Sample specification of communication requirements for the protection and control terminals in digital telecommunication networks

The communication requirements are based on echo timing.

**Bit Error Rate (BER) according to ITU-T G.821, G.826 and G.828**

- $10^{-6}$ according to the standard for data and voice transfer

**Bit Error Rate (BER) for high availability of the differential protection**

- $10^{-8}$-$10^{-9}$ during normal operation
- $10^{-6}$ during disturbed operation

During disturbed conditions, the trip security function can cope with high bit error rates up to $10^{-5}$ or even up to $10^{-4}$. The trip security can be configured to be independent of COMFAIL from the differential protection communication supervision, or blocked when COMFAIL is issued after receive error $>100$ ms. (Default).

**Synchronization in SDH systems with G.703 E1 or IEEE C37.94**

The G.703 E1, 2 Mbit shall be set according to ITU-T G.803, G.810-13

- One master clock for the actual network
- The actual port Synchronized to the SDH system clock at 2048 kbit
- Synchronization; bit synchronized, synchronized mapping
- Maximum clock deviation $\pm 50$ ppm nominal, $\pm 100$ ppm operational
- Jitter and Wander according to ITU-T G.823 and G.825
- Buffer memory $<250$ μs, $<100$ μs asymmetric difference
- Format G.704 frame, structured etc.Format.
- No CRC-check

**Synchronization in PDH systems connected to SDH systems**

- Independent synchronization, asynchronous mapping
- The actual SDH port must be set to allow transmission of the master clock from the PDH-system via the SDH-system in transparent mode.
- Maximum clock deviation $\pm 50$ ppm nominal, $\pm 100$ ppm operational
- Jitter and Wander according to ITU-T G.823 and G.825
- Buffer memory $<100$ μs
- Format: Transparent
- Maximum channel delay
- Loop time $<40$ ms continuous (2 x 20 ms)

**IED with echo synchronization of differential clock (without GPS clock)**

- Both channels must have the same route with maximum asymmetry of 0,2-0,5 ms, depending on set sensitivity of the differential protection.
- A fixed asymmetry can be compensated (setting of asymmetric delay in built in HMI or the parameter setting tool PST).
IED with GPS clock

- Independent of asymmetry.

24.6 IEC/UCA 61850-9-2LE Merging unit requirements

The merging units that supply the IED with measured values via the process bus must fulfill the IEC/UCA 61850-9-2LE standard.

This part of the IEC 61850 is specifying “Communication Service Mapping (SCSM) – Sampled values over ISO/IEC 8802”, in other words – sampled data over Ethernet. The 9-2 part of the IEC 61850 protocol uses also definitions from 7-2, “Basic communication structure for substation and feeder equipment – Abstract communication service interface (ACSI)”. The set of functionality implemented in the IED (IEC/UCA 61850-9-2LE) is a subset of the IEC 61850-9-2. For example the IED covers the client part of the standard, not the server part.

The standard does not define the sample rate for data, but in the UCA users group recommendations there are indicated sample rates that are adopted, by consensus, in the industry.

There are two sample rates defined: 80 samples/cycle (4000 samples/sec. at 50Hz or 4800 samples/sec. at 60 Hz) for a merging unit “type1” and 256 samples/cycle for a merging unit “type2”. The IED can receive data rates of 80 samples/cycle.

Note that the IEC/UCA 61850-9-2LE standard does not specify the quality of the sampled values, only the transportation. Thus, the accuracy of the current and voltage inputs to the merging unit and the inaccuracy added by the merging unit must be coordinated with the requirement for actual type of protection function.

Factors influencing the accuracy of the sampled values from the merging unit are for example anti aliasing filters, frequency range, step response, truncating, A/D conversion inaccuracy, time tagging accuracy etc.

In principle the accuracy of the current and voltage transformers, together with the merging unit, shall have the same quality as direct input of currents and voltages.
### Glossary

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>AC</td>
<td>Alternating current</td>
</tr>
<tr>
<td>ACC</td>
<td>Actual channel</td>
</tr>
<tr>
<td>ACT</td>
<td>Application configuration tool within PCM600</td>
</tr>
<tr>
<td>A/D converter</td>
<td>Analog-to-digital converter</td>
</tr>
<tr>
<td>ADBS</td>
<td>Amplitude deadband supervision</td>
</tr>
<tr>
<td>ADM</td>
<td>Analog digital conversion module, with time synchronization</td>
</tr>
<tr>
<td>AI</td>
<td>Analog input</td>
</tr>
<tr>
<td>ANSI</td>
<td>American National Standards Institute</td>
</tr>
<tr>
<td>AR</td>
<td>Autoreclosing</td>
</tr>
<tr>
<td>ASCT</td>
<td>Auxiliary summation current transformer</td>
</tr>
<tr>
<td>ASD</td>
<td>Adaptive signal detection</td>
</tr>
<tr>
<td>ASDU</td>
<td>Application service data unit</td>
</tr>
<tr>
<td>AWG</td>
<td>American Wire Gauge standard</td>
</tr>
<tr>
<td>BBP</td>
<td>Busbar protection</td>
</tr>
<tr>
<td>BFOC/2,5</td>
<td>Bayonet fiber optic connector</td>
</tr>
<tr>
<td>BFP</td>
<td>Breaker failure protection</td>
</tr>
<tr>
<td>BI</td>
<td>Binary input</td>
</tr>
<tr>
<td>BIM</td>
<td>Binary input module</td>
</tr>
<tr>
<td>BOM</td>
<td>Binary output module</td>
</tr>
<tr>
<td>BOS</td>
<td>Binary outputs status</td>
</tr>
<tr>
<td>BR</td>
<td>External bistable relay</td>
</tr>
<tr>
<td>BS</td>
<td>British Standards</td>
</tr>
<tr>
<td>BSR</td>
<td>Binary signal transfer function, receiver blocks</td>
</tr>
<tr>
<td>BST</td>
<td>Binary signal transfer function, transmit blocks</td>
</tr>
<tr>
<td>C37.94</td>
<td>IEEE/ANSI protocol used when sending binary signals between IEDs</td>
</tr>
<tr>
<td>CAN</td>
<td>Controller Area Network. ISO standard (ISO 11898) for serial communication</td>
</tr>
<tr>
<td>CB</td>
<td>Circuit breaker</td>
</tr>
<tr>
<td>CBM</td>
<td>Combined backplane module</td>
</tr>
<tr>
<td>CCM</td>
<td>CAN carrier module</td>
</tr>
<tr>
<td>CCVT</td>
<td>Capacitive Coupled Voltage Transformer</td>
</tr>
</tbody>
</table>
Class C Protection Current Transformer class as per IEEE/ ANSI
CMPPS Combined megapulses per second
CMT Communication Management tool in PCM600
CO cycle Close-open cycle
Codirectional Way of transmitting G.703 over a balanced line. Involves two twisted pairs making it possible to transmit information in both directions
COM Command
COMTRADE Standard Common Format for Transient Data Exchange format for Disturbance recorder according to IEEE/ANSI C37.111, 1999 / IEC 60255-24
Contra-directional Way of transmitting G.703 over a balanced line. Involves four twisted pairs, two of which are used for transmitting data in both directions and two for transmitting clock signals
COT Cause of transmission
CPU Central processing unit
CR Carrier receive
CRC Cyclic redundancy check
CROB Control relay output block
CS Carrier send
CT Current transformer
CU Communication unit
CVT or CCVT Capacitive voltage transformer
DAR Delayed autoreclosing
DARPA Defense Advanced Research Projects Agency (The US developer of the TCP/IP protocol etc.)
DBDL Dead bus dead line
DBLL Dead bus live line
DC Direct current
DFC Data flow control
DFT Discrete Fourier transform
DHCP Dynamic Host Configuration Protocol
DIP-switch Small switch mounted on a printed circuit board
DI Digital input
DLLB Dead line live bus
DNP Distributed Network Protocol as per IEEE Std 1815-2012
DR Disturbance recorder
DRAM Dynamic random access memory
DRH Disturbance report handler
DSP Digital signal processor
DTT Direct transfer trip scheme
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>ECT</td>
<td>Ethernet configuration tool</td>
</tr>
<tr>
<td>EHV network</td>
<td>Extra high voltage network</td>
</tr>
<tr>
<td>EIA</td>
<td>Electronic Industries Association</td>
</tr>
<tr>
<td>EMC</td>
<td>Electromagnetic compatibility</td>
</tr>
<tr>
<td>EMF</td>
<td>Electromotive force</td>
</tr>
<tr>
<td>EMI</td>
<td>Electromagnetic interference</td>
</tr>
<tr>
<td>EnFP</td>
<td>End fault protection</td>
</tr>
<tr>
<td>EPA</td>
<td>Enhanced performance architecture</td>
</tr>
<tr>
<td>ESD</td>
<td>Electrostatic discharge</td>
</tr>
<tr>
<td>F-SMA</td>
<td>Type of optical fiber connector</td>
</tr>
<tr>
<td>FAN</td>
<td>Fault number</td>
</tr>
<tr>
<td>FCB</td>
<td>Flow control bit; Frame count bit</td>
</tr>
<tr>
<td>FOX 20</td>
<td>Modular 20 channel telecommunication system for speech, data and protection signals</td>
</tr>
<tr>
<td>FOX 512/515</td>
<td>Access multiplexer</td>
</tr>
<tr>
<td>FOX 6Plus</td>
<td>Compact time-division multiplexer for the transmission of up to seven duplex channels of digital data over optical fibers</td>
</tr>
<tr>
<td>FPN</td>
<td>Flexible product naming</td>
</tr>
<tr>
<td>FTP</td>
<td>File Transfer Protocol</td>
</tr>
<tr>
<td>FUN</td>
<td>Function type</td>
</tr>
<tr>
<td>G.703</td>
<td>Electrical and functional description for digital lines used by local telephone companies. Can be transported over balanced and unbalanced lines</td>
</tr>
<tr>
<td>GCM</td>
<td>Communication interface module with carrier of GPS receiver module</td>
</tr>
<tr>
<td>GDE</td>
<td>Graphical display editor within PCM600</td>
</tr>
<tr>
<td>GI</td>
<td>General interrogation command</td>
</tr>
<tr>
<td>GIS</td>
<td>Gas-insulated switchgear</td>
</tr>
<tr>
<td>GOOSE</td>
<td>Generic object-oriented substation event</td>
</tr>
<tr>
<td>GPS</td>
<td>Global positioning system</td>
</tr>
<tr>
<td>GSAL</td>
<td>Generic security application</td>
</tr>
<tr>
<td>GSE</td>
<td>Generic substation event</td>
</tr>
<tr>
<td>HDLC protocol</td>
<td>High-level data link control, protocol based on the HDLC standard</td>
</tr>
<tr>
<td>HFBR connector type</td>
<td>Plastic fiber connector</td>
</tr>
<tr>
<td>HLV circuit</td>
<td>Hazardous Live Voltage according to IEC60255-27</td>
</tr>
<tr>
<td>HMI</td>
<td>Human-machine interface</td>
</tr>
<tr>
<td>HSAR</td>
<td>High speed autoreclosing</td>
</tr>
<tr>
<td>HSR</td>
<td>High-availability Seamless Redundancy</td>
</tr>
<tr>
<td>HV</td>
<td>High-voltage</td>
</tr>
<tr>
<td>HVDC</td>
<td>High-voltage direct current</td>
</tr>
</tbody>
</table>
ICT  Installation and Commissioning Tool for injection based protection in REG670
IDBS  Integrating deadband supervision
IEC  International Electrical Committee
IEC 60044-6  IEC Standard, Instrument transformers – Part 6: Requirements for protective current transformers for transient performance
IEC 60870-5-103  Communication standard for protection equipment. A serial master/slave protocol for point-to-point communication
IEC 61850  Substation automation communication standard
IEC 61850–8–1  Communication protocol standard
IEEE  Institute of Electrical and Electronics Engineers
IEEE 802.12  A network technology standard that provides 100 Mbits/s on twisted-pair or optical fiber cable
IEEE P1386.1  PCI Mezzanine Card (PMC) standard for local bus modules. References the CMC (IEEE P1386, also known as Common Mezzanine Card) standard for the mechanics and the PCI specifications from the PCI SIG (Special Interest Group) for the electrical EMF (Electromotive force).
IEEE 1686  Standard for Substation Intelligent Electronic Devices (IEDs) Cyber Security Capabilities
IED  Intelligent electronic device
IET600  Integrated engineering tool
I-GIS  Intelligent gas-insulated switchgear
IOM  Binary input/output module
Instance  When several occurrences of the same function are available in the IED, they are referred to as instances of that function. One instance of a function is identical to another of the same kind but has a different number in the IED user interfaces. The word “instance” is sometimes defined as an item of information that is representative of a type. In the same way an instance of a function in the IED is representative of a type of function.
IP  1. Internet protocol. The network layer for the TCP/IP protocol suite widely used on Ethernet networks. IP is a connectionless, best-effort packet-switching protocol. It provides packet routing, fragmentation and reassembly through the data link layer.
2. Ingression protection, according to IEC 60529
IP 20  Ingression protection, according to IEC 60529, level IP20- Protected against solid foreign objects of 12.5mm diameter and greater.
IP 40  Ingression protection, according to IEC 60529, level IP40-Protected against solid foreign objects of 1mm diameter and greater.
IP 54  Ingression protection, according to IEC 60529, level IP54-Dust-protected, protected against splashing water.
IRF  Internal failure signal
IRIG-B:  InterRange Instrumentation Group Time code format B, standard 200
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>ITU</td>
<td>International Telecommunications Union</td>
</tr>
<tr>
<td>LAN</td>
<td>Local area network</td>
</tr>
<tr>
<td>LIB 520</td>
<td>High-voltage software module</td>
</tr>
<tr>
<td>LCD</td>
<td>Liquid crystal display</td>
</tr>
<tr>
<td>LDCM</td>
<td>Line data communication module</td>
</tr>
<tr>
<td>LDD</td>
<td>Local detection device</td>
</tr>
<tr>
<td>LED</td>
<td>Light-emitting diode</td>
</tr>
<tr>
<td>LNT</td>
<td>LON network tool</td>
</tr>
<tr>
<td>LON</td>
<td>Local operating network</td>
</tr>
<tr>
<td>MCB</td>
<td>Miniature circuit breaker</td>
</tr>
<tr>
<td>MCM</td>
<td>Mezzanine carrier module</td>
</tr>
<tr>
<td>MIM</td>
<td>Milli-ampere module</td>
</tr>
<tr>
<td>MPM</td>
<td>Main processing module</td>
</tr>
<tr>
<td>MVAL</td>
<td>Value of measurement</td>
</tr>
<tr>
<td>MVB</td>
<td>Multifunction vehicle bus. Standardized serial bus originally developed for use in trains.</td>
</tr>
<tr>
<td>NCC</td>
<td>National Control Centre</td>
</tr>
<tr>
<td>NOF</td>
<td>Number of grid faults</td>
</tr>
<tr>
<td>NUM</td>
<td>Numerical module</td>
</tr>
<tr>
<td>OCO cycle</td>
<td>Open-close-open cycle</td>
</tr>
<tr>
<td>OCP</td>
<td>Overcurrent protection</td>
</tr>
<tr>
<td>OEM</td>
<td>Optical Ethernet module</td>
</tr>
<tr>
<td>OLTC</td>
<td>On-load tap changer</td>
</tr>
<tr>
<td>OTEV</td>
<td>Disturbance data recording initiated by other event than start/pick-up</td>
</tr>
<tr>
<td>OV</td>
<td>Overvoltage</td>
</tr>
<tr>
<td>Overreach</td>
<td>A term used to describe how the relay behaves during a fault condition. For example, a distance relay is overreaching when the impedance presented to it is smaller than the apparent impedance to the fault applied to the balance point, that is, the set reach. The relay “sees” the fault but perhaps it should not have seen it.</td>
</tr>
<tr>
<td>PCI</td>
<td>Peripheral component interconnect, a local data bus</td>
</tr>
<tr>
<td>PCM</td>
<td>Pulse code modulation</td>
</tr>
<tr>
<td>PCM600</td>
<td>Protection and control IED manager</td>
</tr>
<tr>
<td>PC-MIP</td>
<td>Mezzanine card standard</td>
</tr>
<tr>
<td>PELV circuit</td>
<td>Protected Extra-Low Voltage circuit type according to IEC60255-27</td>
</tr>
<tr>
<td>PMC</td>
<td>PCI Mezzanine card</td>
</tr>
<tr>
<td>POR</td>
<td>Permissive overreach</td>
</tr>
<tr>
<td>POTT</td>
<td>Permissive overreach transfer trip</td>
</tr>
</tbody>
</table>
**Process bus**  Bus or LAN used at the process level, that is, in near proximity to the measured and/or controlled components

**PRP**  Parallel redundancy protocol

**PSM**  Power supply module

**PST**  Parameter setting tool within PCM600

**PTP**  Precision time protocol

**PT ratio**  Potential transformer or voltage transformer ratio

**PUTT**  Permissive underreach transfer trip

**RASC**  Synchrocheck relay, COMBIFLEX

**RCA**  Relay characteristic angle

**RISC**  Reduced instruction set computer

**RMS value**  Root mean square value

**RS422**  A balanced serial interface for the transmission of digital data in point-to-point connections

**RS485**  Serial link according to EIA standard RS485

**RTC**  Real-time clock

**RTU**  Remote terminal unit

**SA**  Substation Automation

**SBO**  Select-before-operate

**SC**  Switch or push button to close

**SCL**  Short circuit location

**SCS**  Station control system

**SCADA**  Supervision, control and data acquisition

**SCT**  System configuration tool according to standard IEC 61850

**SDU**  Service data unit

**SELV circuit**  Safety Extra-Low Voltage circuit type according to IEC60255-27

**SFP**  Small form-factor pluggable (abbreviation)

Optical Ethernet port (explanation)

**SLM**  Serial communication module.

**SMA connector**  Subminiature version A, A threaded connector with constant impedance.

**SMT**  Signal matrix tool within PCM600

**SMS**  Station monitoring system

**SNTP**  Simple network time protocol – is used to synchronize computer clocks on local area networks. This reduces the requirement to have accurate hardware clocks in every embedded system in a network. Each embedded node can instead synchronize with a remote clock, providing the required accuracy.

**SOF**  Status of fault
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>SPA</td>
<td>Strömberg Protection Acquisition (SPA), a serial master/slave protocol for point-to-point and ring communication.</td>
</tr>
<tr>
<td>SRY</td>
<td>Switch for CB ready condition</td>
</tr>
<tr>
<td>ST</td>
<td>Switch or push button to trip</td>
</tr>
<tr>
<td>Starpoint</td>
<td>Neutral/Wye point of transformer or generator</td>
</tr>
<tr>
<td>SVC</td>
<td>Static VAr compensation</td>
</tr>
<tr>
<td>TC</td>
<td>Trip coil</td>
</tr>
<tr>
<td>TCS</td>
<td>Trip circuit supervision</td>
</tr>
<tr>
<td>TCP</td>
<td>Transmission control protocol. The most common transport layer protocol used on Ethernet and the Internet.</td>
</tr>
<tr>
<td>TCP/IP</td>
<td>Transmission control protocol over Internet Protocol. The de facto standard Ethernet protocols incorporated into 4.2BSD Unix. TCP/IP was developed by DARPA for Internet working and encompasses both network layer and transport layer protocols. While TCP and IP specify two protocols at specific protocol layers, TCP/IP is often used to refer to the entire US Department of Defense protocol suite based upon these, including Telnet, FTP, UDP and RDP.</td>
</tr>
<tr>
<td>TEF</td>
<td>Time delayed ground-fault protection function</td>
</tr>
<tr>
<td>TLS</td>
<td>Transport Layer Security</td>
</tr>
<tr>
<td>TM</td>
<td>Transmit (disturbance data)</td>
</tr>
<tr>
<td>TNC connector</td>
<td>Threaded Neill-Concelman, a threaded constant impedance version of a BNC connector</td>
</tr>
<tr>
<td>TP</td>
<td>Trip (recorded fault)</td>
</tr>
<tr>
<td>TPZ, TPY, TPX, TPS</td>
<td>Current transformer class according to IEC</td>
</tr>
<tr>
<td>TRM</td>
<td>Transformer Module. This module transforms currents and voltages taken from the process into levels suitable for further signal processing.</td>
</tr>
<tr>
<td>TYP</td>
<td>Type identification</td>
</tr>
<tr>
<td>UMT</td>
<td>User management tool</td>
</tr>
<tr>
<td>Underreach</td>
<td>A term used to describe how the relay behaves during a fault condition. For example, a distance relay is underreaching when the impedance presented to it is greater than the apparent impedance to the fault applied to the balance point, that is, the set reach. The relay does not “see” the fault but perhaps it should have seen it. See also Overreach.</td>
</tr>
<tr>
<td>UTC</td>
<td>Coordinated Universal Time. A coordinated time scale, maintained by the Bureau International des Poids et Mesures (BIPM), which forms the basis of a coordinated dissemination of standard frequencies and time signals. UTC is derived from International Atomic Time (TAI) by the addition of a whole number of “leap seconds” to synchronize it with Universal Time 1 (UT1), thus allowing for the eccentricity of the Earth’s orbit, the rotational axis tilt (23.5 degrees), but still showing the Earth’s irregular rotation, on which UT1 is based. The Coordinated Universal Time is expressed using a 24-hour clock, and uses the Gregorian calendar. It is used for aeroplane and ship navigation, where it is also sometimes known by the military name, “Zulu time.” “Zulu” in the phonetic alphabet stands for “Z”, which stands for longitude zero.</td>
</tr>
<tr>
<td>UV</td>
<td>Undervoltage</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
</tr>
<tr>
<td>--------------</td>
<td>-------------</td>
</tr>
<tr>
<td><strong>WEI</strong></td>
<td>Weak end infeed logic</td>
</tr>
<tr>
<td><strong>VT</strong></td>
<td>Voltage transformer</td>
</tr>
<tr>
<td><strong>X.21</strong></td>
<td>A digital signalling interface primarily used for telecom equipment</td>
</tr>
<tr>
<td><strong>3I₀</strong></td>
<td>Three times zero-sequence current. Often referred to as the residual or the ground-fault current</td>
</tr>
<tr>
<td><strong>3V₀</strong></td>
<td>Three times the zero sequence voltage. Often referred to as the residual voltage or the neutral point voltage</td>
</tr>
</tbody>
</table>