Relion® 670 series

Busbar protection REB670 2.0 IEC
Application manual
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This product complies with the directive of the Council of the European Communities on the approximation of the laws of the Member States relating to electromagnetic compatibility (EMC Directive 2004/108/EC) and concerning electrical equipment for use within specified voltage limits (Low-voltage directive 2006/95/EC). This conformity is the result of tests conducted by ABB in accordance with the product standard EN 60255-26 for the EMC directive, and with the product standards EN 60255-1 and EN 60255-27 for the low voltage directive. The product is designed in accordance with the international standards of the IEC 60255 series.
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Section 1  Introduction

1.1  This manual

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

1.2  Intended audience

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

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

1.3.1  Product documentation set

![Diagram showing the intended use of manuals throughout the product lifecycle](IEC07000220-4-en.vsd)

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, LHMI functions as well as communication engineering for IEC 60870-5-103, IEC 61850 and DNP3.

The installation manual contains instructions on how to install the IED. The manual provides procedures for mechanical and electrical installation. The chapters are organized in 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 application and functionality descriptions and lists function blocks, logic diagrams, input and output signals, setting parameters and technical data, sorted per function. The manual can be used as a technical reference during the engineering phase, installation and commissioning phase, and during normal service.

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

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

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

1.3.2 Dokumentenänderungsverzeichnis

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<th>Dokument geändert / am</th>
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1.3.3 Related documents

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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.
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 ![button](image) and ![button](image).
- 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 ![button](image).
- 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.
- Logic diagrams describe the signal logic inside the function block and are bordered by dashed lines.
- Signals in frames with a shaded area on their right hand side represent setting parameter signals that are only settable via the PST or LHMI.
- If an internal signal path cannot be drawn with a continuous line, the suffix -int is added to the signal name to indicate where the signal starts and continues.
- Signal paths that extend beyond the logic diagram and continue in another diagram have the suffix ”-cont.”

Illustrations are used as an example and might show other products than the one the manual describes. The example that is illustrated is still valid.

### 1.4.3 IEC 61850 edition 1 / edition 2 mapping

**Table 1: IEC 61850 edition 1 / edition 2 mapping**

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Section 2 Application

2.1 General IED application

REB670 is designed for the selective, reliable and fast differential protection of busbars, T-connections and meshed corners. REB670 can be used for protection of single and double busbar with or without transfer bus, double circuit breaker or one-and-half circuit breaker stations. The IED is applicable for the protection of medium voltage (MV), high voltage (HV) and extra high voltage (EHV) installations at a power system frequency of 50Hz or 60Hz. The IED can detect all types of internal phase-to-phase and phase-to-earth faults in solidly earthed or low impedance earthed power systems, as well as all internal multi-phase faults in isolated or high-impedance earthed power systems.

Ordering of VT inputs inside of the busbar protection IED will allow integration of voltage related functionality like under-voltage release, residual over-voltage, power functions, metering and voltage recording during the faults. However attention shall be given to the fact that inclusion of VT inputs will reduce number of available CT inputs (in total 24 analogue inputs are the product limit). Consequently when VT inputs are ordered the busbar protection IED will be applicable for buses with a fewer number of bays. Practically the number of available CT inputs will limit the size of the station which can be protected.

REB670 has very low requirements on the main current transformers (that is, CTs) and no interposing current transformers are necessary. For all applications, it is possible to include and mix main CTs with 1A and 5A rated secondary current within the same protection zone. Typically, CTs with up to 10:1 ratio difference can be used within the same differential protection zone. Adjustment for different main CT ratios is achieved numerically by a parameter setting.

The numerical, low-impedance differential protection function is designed for fast and selective protection for faults within protected zone. All connected CT inputs are provided with a restraint feature. The minimum pick-up value for the differential current is set to give a suitable sensitivity for all internal faults. For busbar protection applications typical setting value for the minimum differential operating current is from 50% to 150% of the biggest CT. This setting is made directly in primary amperes. The operating slope for the differential operating characteristic is fixed to 53% in the algorithm.

The fast tripping time (shortest trip time is 5ms) of the low-impedance differential protection function is especially advantageous for power system networks with high fault levels or where fast fault clearance is required for power system stability.
All CT inputs are provided with a restraint feature. The operation is based on the well-proven RADSS percentage restraint stabilization principle, with an extra stabilization feature to stabilize for very heavy CT saturation. Stability for external faults is guaranteed if a CT is not saturated for at least two milliseconds during each power system cycle.

The advanced open CT detection algorithm detects instantly the open CT secondary circuits and prevents differential protection operation without any need for additional check zone.

Differential protection zones in REB670 include a sensitive operational level. This sensitive operational level is designed to be able to detect internal busbar earth faults in low impedance earthed power systems (that is, power systems where the earth-fault current is limited to a certain level, typically between 300A and 2000A primary by a neutral point reactor or resistor). Alternatively this sensitive level can be used when high sensitivity is required from busbar differential protection (that is, energizing of the bus via long line).

Overall operating characteristic of the differential function in REB670 is shown in figure 2.

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**Figure 2: REB670 operating characteristic**

Integrated overall check zone feature, independent from any disconnector position, is available. It can be used in double busbar stations to secure stability of the busbar differential protection in case of entirely wrong status indication of busbar disconnector in any of the feeder bays.

Flexible, software based dynamic Zone Selection enables easy and fast adaptation to the most common substation arrangements such as single busbar with or without transfer bus, double busbar with or without transfer bus, one-and-a-half breaker
stations, double busbar-double breaker stations, ring busbars, and so on. The software based dynamic Zone Selections ensures:

- Dynamic linking of measured CT currents to the appropriate differential protection zone as required by substation topology
- Efficient merging of the two differential zones when required by substation topology (that is load-transfer)
- Selective operation of busbar differential protection ensures tripping only of circuit breakers connected to the faulty zone
- Correct marshaling of backup-trip commands from internally integrated or external circuit breaker failure protections to all surrounding circuit breakers
- Easy incorporation of bus-section and/or bus-coupler bays (that is, tie-breakers) with one or two sets of CTs into the protection scheme
- Disconnector and/or circuit breaker status supervision

Advanced Zone Selection logic accompanied by optionally available end-fault and/or circuit breaker failure protections ensure minimum possible tripping time and selectivity for faults within the blind spot or the end zone between bay CT and bay circuit breaker. Therefore REB670 offers best possible coverage for such faults in feeder and bus-section/bus-coupler bays.

Optionally available circuit breaker failure protection, one for every CT input into REB670, offers secure local back-up protection for the circuit breakers in the station.

Optionally available four-stage, non-directional overcurrent protections, one for every CT input into REB670, provide remote backup functionality for connected feeders and remote-end stations.

Optionally available voltage and frequency protection functions open possibility to include voltage release criterion for busbar protection or to integrate independent over-, under-voltage protection for the bus in the busbar protection IED.

Optionally available over-current, thermal overload and capacitor bank protection functions open possibilities to integrate protection of shunt reactors and shunt capacitor banks into the busbar protection IED.

It is normal practice to have just one busbar protection IED per busbar. Nevertheless some utilities do apply two independent busbar protection IEDs per zone of protection. REB670 IED fits both solutions.

A simplified bus differential protection for multi-phase faults and earth faults can be obtained by using a single, one-phase REB670 IED with external auxiliary summation current transformers.

Optional apparatus control for up to 30 objects can provide a facility to draw simplified single line diagram (SLD) of the station on the local HMI.

Note that customized REB670 is delivered without any configuration. Thus the complete IED engineering shall be done by the customer or its system integrator. In order to secure proper operation of the busbar protection it is strictly recommended to always start engineering work...
from the PCM600 project for the pre-configured REB670 which is the closest to the actual application. Then, necessary modifications shall be applied in order to adopt the customized IED configuration to suite the actual station layout. The PCM600 project for the pre-configured REB670 IEDs is available in the Connectivity Package DVD.

2.2 Main protection functions

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**Differential protection**

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Section 2

Application manual

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### Section 2

#### Application

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### Multipurpose protection

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1) 67 requires voltage  
2) 67N requires voltage

#### 2.4 Control and monitoring functions

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**Secondary system supervision**

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**Logic**

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### IEC 61850 Function Description

#### Busbar

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#### Metering

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### 2.5 Communication

#### Station communication

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<th>REB670 (A31)</th>
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Remote communication

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## 2.6 Basic IED functions

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<td>TIMEZONE</td>
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<td>LONSPA</td>
<td>SPA communication protocol</td>
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<td>LEDGEN</td>
<td>General LED indication part for LHMI</td>
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Section 3 Configuration

3.1 Description of configuration REB670

3.1.1 Available ACT configurations for pre-configured REB670

Three configurations have been made available for pre-configured REB670 IED. It shall be noted that all three configurations include the following features:

- fully configured for the total available number of bays in each REB670 variant
- facility to take any bay out of service via the local HMI or externally via binary input
- facility to block any of the two zones via the local HMI or externally via binary input
- facility to block all bay trips via the local HMI or externally via binary input, but leaving all other function in service (that is BBP Zones, BFP and OCP where applicable)
- facility to externally initiate built-in disturbance recorder
- facility to connect external breaker failure backup trip signal from every bay
- facility to connect external bay trip signal

3.1.2 Configuration X01

This configuration includes only busbar protection for simple stations layouts (in other words, one-and-a-half breaker, double breaker or single breaker stations). Additionally it can be used for double busbar-single breaker stations where disconnector replica is done by using only b auxiliary contact from every disconnector and/or circuit breakers. As a consequence no disconnector/breaker supervision will be available. It is as well possible to adapt this configuration by the signal matrix tool to be used as direct replacement of RED521 terminals. This configuration is available for all five REB670 variants (that is A20, A31, B20, B21 & B31). It shall be noted that optional functions breaker failure protection CCRBRF, end fault protection and overcurrent protection PH4SPTOC can be ordered together with this configuration, but they will not be pre-configured. Thus these optional functions shall be configured by the end user.

3.1.3 Configuration X02

This configuration includes only busbar protection for double busbar-single breaker stations, where Zone Selection is done by using a and b auxiliary contacts from every disconnector and/or circuit breaker. Thus full disconnector/breaker supervision is available. This configuration is available for only three REB670 variants (that is A31,
B21 and B31). It shall be noted that optional functions breaker failure protection CCRBRF, end fault protection and overcurrent protection PH4SPTOC can be ordered together with this configuration, but they will not be pre-configured. Thus these optional functions shall be configured by the end user.

3.1.4 Configuration X03

This configuration includes BBP with breaker failure protection CCRBRF, end fault protection and overcurrent protection PH4SPTOC for double busbar-single breaker stations, where Zone Selection is done by using a and b auxiliary contacts from every disconnectors and/or circuit breakers. Thus full disconnector/breaker supervision is available. This configuration is available for only three REB670 variants (that is A31, B21 and B31).

In order to use X03 configuration, optional breaker failure and overcurrent functions must be ordered.

3.1.5 Description of 3 ph package A20

Three-phase version of the IED with two low-impedance differential protection zones and four three-phase CT inputs A20. The version is intended for simpler applications such as T-connections, meshed corners, and so on.
Figure 3: Configuration diagram for A20, configuration X01

3.1.6 Description of 3 ph package A31

Three-phase version of the IED with two low-impedance differential protection zones and eight three-phase CT inputs A31. The version is intended for applications on smaller busbars, with up to two zones and eight CT inputs.
Figure 4: Configuration diagram for A31, configuration X01
Figure 5: Configuration diagram for A31, configuration X01_1
Figure 6: Configuration diagram for A31, configuration X02
Figure 7: Configuration diagram for A31, configuration X03

3.1.7 Description of 1 ph packages B20 and B21

One-phase version of the IED with two low-impedance differential protection zones and twelve CT inputs B20, B21.

- Due to three available binary input modules, the B20 is intended for applications without need for dynamic Zone Selection such as substations with single busbar with or without bus-section breaker, one-and-half breaker or double breaker
arrangements. Three such IEDs offer cost effective solutions for such simple substation arrangements with up to twelve CT inputs.

- The B21 is intended for applications in substations where dynamic Zone Selection or bigger number of binary inputs and outputs is needed. Such stations for example are double busbar station with or without transfer bus with up to 12 CT inputs. Note that binary inputs can be shared between phases by including the LDCM communication module. This simplifies panel wiring and saves IO boards.

- This version can be used with external auxiliary 3-phase to 1-phase summation current transformers with different turns ratio for each phase.

**Figure 8:** Configuration diagram for B20, configuration X01
3.1.8 Description of 1 ph package B31

One-phase version of the IED with two low-impedance differential protection zones and twenty-four CT inputs B31.
• The IED is intended for busbar protection applications in big substations where dynamic Zone Selection, quite large number of binary inputs and outputs and many CT inputs are needed. The IED includes two differential zones and twenty-four CT inputs. Note that binary inputs can be shared between phases by including the LDCM communication module. This simplifies panel wiring and saves IO boards.

• This version can be used with external auxiliary 3-phase to 1-phase summation current transformers with different turns ratio for each phase.
REB670(B20-X01) / REB670(B21-X01) / REB670(B31-X01)
PHASE L3
REB670(B20-X01) / REB670(B21-X01) / REB670(B31-X01)
PHASE L2
REB670(B20-X01) / REB670(B21-X01) / REB670(B31-X01)
PHASE L1

Other Functions in Library

<table>
<thead>
<tr>
<th>Optional Functions</th>
</tr>
</thead>
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<tr>
<td>IEC 61850-9-2</td>
</tr>
<tr>
<td>BUS PTRC</td>
</tr>
</tbody>
</table>

Figure 10: Configuration diagram for B31, configuration X01

Application manual
**Figure 11:** Configuration diagram for B31, configuration X02

<table>
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<tr>
<th>Version of REB670</th>
<th>Number of Feeders in the Station (excluding bus coupler bay)</th>
<th>Number of REB670 Required by the Scheme</th>
</tr>
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<tbody>
<tr>
<td>REB670(B21-X02) 1-Phase, 12 Bays, 2 Zones for Double Busbar Station 12AI</td>
<td>11*</td>
<td>3</td>
</tr>
<tr>
<td>REB670(B31-X02) 1-Phase, 24 Bays, 2 Zones for Double Busbar Station 24AI</td>
<td>23*</td>
<td>3</td>
</tr>
</tbody>
</table>

* With Just one CT in the Bus Section Bay
Figure 12: Configuration diagram for B31, configuration X03
4.1 Introduction

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

A reference PhaseAngleRef can be defined to facilitate service values reading. This analog channels phase angle will always be fixed to zero degrees and all other angle information will be shown in relation to this analog input. During testing and commissioning of the IED the reference channel can be changed to facilitate testing and service values reading.

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.

4.2.1 Setting of the phase reference channel

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

4.2.1.1 Example

Usually the L1 phase-to-earth voltage connected to the first VT channel number of the transformer input module (TRM) is selected as the phase reference. The first VT channel number depends on the type of transformer input module.
For a TRM with 6 current and 6 voltage inputs the first VT channel is 7. The setting `PhaseAngleRef=7` shall be used if the phase reference voltage is connected to that channel.

### 4.2.2 Setting of current channels

The direction of a current to the IED is depending on the connection of the CT. Unless indicated otherwise, the main CTs are supposed to be star connected and can be connected with the earthing point to the object or from the object. This information must be set in the IED. The convention of the directionality is defined as follows: A positive value of current, power, and so on means that the quantity has the direction into the object and a negative value means direction out from the object. For directional functions the direction into the object is defined as Forward and the direction out from the object is defined as Reverse. See figure 13.

A positive value of current, power, and so on (forward) means that the quantity has a direction towards the object. A negative value of current, power, and so on (reverse) means a direction away from the object. See figure 13.

![Internal convention of the directionality in the IED](en05000456.vsd)

**Figure 13:** Internal convention of the directionality in the IED

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

#### 4.2.2.1 Example 1

Two IEDs used for protection of two objects.
Figure 14: Example how to set CTStarPoint parameters in the IED

The figure 14 shows the normal case where the objects have their own CTs. The settings for CT direction shall be done according to the figure. To protect the line the direction of the directional functions of the line protection shall be set to Forward. This means that the protection is looking towards the line.

4.2.2.2 Example 2

Two IEDs used for protection of two objects and sharing a CT.
Figure 15: Example how to set CTStarPoint parameters in the IED

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

4.2.2.3 Example 3

One IED used to protect two objects.
Figure 16: Example how to set CTStarPoint parameters in the IED

In this example one IED includes both transformer and line protection 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 a sufficient number of analog current inputs an alternative solution is shown in figure 17. 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 CTStarPoint with Transformer as reference object. Correct setting is "ToObject".

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

Figure 17: Example how to set CTStarPoint parameters in the IED
Figure 18: Example how to set CTStarPoint parameters in the IED

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

The first solution will be to use busbar as a reference object. In that case for all CT inputs marked with 1 in figure 18, set CTStarPoint = ToObject, and for all CT inputs marked with 2 in figure 18, set CTStarPoint = FromObject.

The second solution will be to use all connected bays as reference objects. In that case for all CT inputs marked with 1 in figure 18, set CTStarPoint = FromObject, and for all CT inputs marked with 2 in figure 18, set CTStarPoint = ToObject.

Regardless which one of the above two options is selected busbar differential protection will behave correctly.
The main CT ratios must also be set. This is done by setting the two parameters \( CT_{sec} \) and \( CT_{prim} \) for each current channel. For a 1000/1 A CT the following setting shall be used:

- \( CT_{prim} = 1000 \) (value in A)
- \( CT_{sec} = 1 \) (value in A).

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

Figure 19 defines the marking of current transformer terminals commonly used around the world:

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

![Commonly used markings of CT terminals](en06000641.vsd)

**Figure 19**: Commonly used markings of CT terminals

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

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

- 1A
- 5A
However in some cases the following rated secondary currents are used as well:

- 2A
- 10A

The IED fully supports all of these rated secondary values.

It is recommended to:

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

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

Figure 20 gives an example about the wiring of a star connected three-phase CT set to the IED. It gives also 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 20: Star connected three-phase CT set with star point towards the protected object

Where:

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

2) The current inputs are located in the TRM. It shall be noted that for all these current inputs the following setting values shall be entered for the example shown in Figure 20.

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

Inside the IED only the ratio of the first two parameters is used. 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.

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

4) The preprocessing block that has the task to digitally filter the connected analog inputs and calculate:

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

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

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

5) AI3P in the SMAI function block is a grouped signal which contains all the data about the phases L1, L2, L3 and neutral quantity; in particular the data about fundamental frequency phasors, harmonic content and positive sequence, negative and zero sequence quantities are available.

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

AIN is the signal which contains the fundamental frequency phasors and the harmonic content of the neutral quantity. In this example GRP2N is not connected so this data is calculated by the preprocessing function block on the basis of the inputs GRPL1, GRPL2 and GRPL3. If GRP2N is connected, the data reflects the measured value of GRP2N.

Another alternative is to have the star point of the three-phase CT set as shown in the figure below:
Figure 21: Star connected three-phase CT set with its star point away from the protected object

In the example in figure 21 case everything is done in a similar way as in the above described example (figure 20). The only difference is the setting of the parameter CTStarPoint of the used current inputs on the TRM (item 2 in the figure):

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

Inside the IED only the ratio of the first two parameters is used. 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 the figure below.
Figure 22: Star connected three-phase CT set with its star point away from the protected object and the residual/neutral current connected to the IED

Where:

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

2) shows how to connect residual/neutral current from the three-phase CT set to the fourth inputs 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.

- CTprim=800A
- CTsec=1A
- CTStarPoint=FromObject
- ConnectionType=Ph-N

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

4) are three connections made in the Signal Matrix tool (SMT), 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), 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. In that case the pre-processing block will calculate it by vectorial summation of the three individual phase currents.

6) 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.

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

Figure 23 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 23: 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.
   \[ \text{CT}_{\text{prim}} = 600A \]
   \[ \text{CT}_{\text{sec}} = 5A \]
   - \( \text{CTStarPoint} = \text{ToObject} \)
   - \( \text{ConnectionType} = \text{Ph-Ph} \)

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

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

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

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

Another alternative is to have the delta connected CT set as shown in figure 24:
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:

\[
\begin{align*}
CT_{\text{prim}} &= 800\text{A} \\
CT_{\text{sec}} &= 1\text{A}
\end{align*}
\]

- \(CT\text{StarPoint}=\text{ToObject}\)
- \(ConnectionType=\text{Ph-Ph}\)

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

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

Figure 25 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 25: 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 25:
   
   \[
   \begin{align*}
   CT_{\text{prim}} &= 1000 \text{ A} \\
   CT_{\text{sec}} &= 1 \text{ A} \\
   CT_{\text{StarPoint}} &= \text{ToObject}
   \end{align*}
   \]

   For connection (b) shown in figure 25:
   
   \[
   \begin{align*}
   CT_{\text{prim}} &= 1000 \text{ A} \\
   CT_{\text{sec}} &= 1 \text{ A} \\
   CT_{\text{StarPoint}} &= \text{FromObject}
   \end{align*}
   \]

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 Setting of voltage channels

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

4.2.3.1 Example

Consider a VT with the following data:

\[
\frac{132kV}{\sqrt{3}} / \frac{110V}{\sqrt{3}}
\]

(Equation 1)

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

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

Figure 26 defines the marking of voltage transformer terminals commonly used around the world.

**Figure 26:** Commonly used markings of VT terminals

Where:

- **a)** is the symbol and terminal marking used in this document. Terminals marked with a square indicate the primary and secondary winding terminals with the same (positive) polarity
- **b)** is the equivalent symbol and terminal marking used by IEC (ANSI) standard for phase-to-earth connected VTs
- **c)** is the equivalent symbol and terminal marking used by IEC (ANSI) standard for open delta connected VTs
- **d)** is the equivalent symbol and terminal marking used by IEC (ANSI) standard for phase-to-phase connected VTs
It shall be noted that depending on national standard and utility practices the rated secondary voltage of a VT has typically one of the following values:

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

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

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

Figure 27 gives an example on how to connect a three phase-to-earth connected VT to the IED. It as well gives overview of required actions by the user in order to make this measurement available to the built-in protection and control functions within the IED.

For correct terminal designations, see the connection diagrams valid for the delivered IED.
**Figure 27:** A Three phase-to-earth connected VT

Where:

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

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

\[ VT_{\text{prim}} = 66 \text{ kV} \]
\[ VT_{\text{sec}} = 110 \text{ V} \]

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

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

(Equation 2)

Table continues on next page
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 3U₀ inside by vectorial sum from the three phase to earth voltages connected to the first three input channels of the same preprocessing block. Alternatively, the fourth input channel can be connected to open delta VT input, as shown in figure 29.

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. However the following settings shall be set as shown here:

- 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.

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

Figure 28 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 as well. It shall be noted that this VT connection is only used on lower voltage levels (that is, rated primary voltage below 40 kV).
Figure 28: 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:

\[
\begin{align*}
V_{\text{prim}} &= 13.8 \text{ kV} \\
V_{\text{sec}} &= 120 \text{ V}
\end{align*}
\]

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 \( U_{L1}, U_{L2}, U_{L3}, U_N \) should be used the open delta must be connected here.

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

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

- **ConnectionType=Ph-Ph**
- **UBase=13.8 kV**

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

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

Figure 29 gives an example about the wiring of an open delta VT to the IED for high impedance earthed or unearthed power systems. It shall be noted that this type of VT connection presents a secondary voltage proportional to 3U0 to the IED.

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

\[
3U0 = \sqrt{3} \cdot U_{ph-ph} = 3 \cdot U_{ph-N}
\]

(Equation 3)

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

Figure 29 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 29: Open delta connected VT in high impedance earthed power system
Where:

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

   +3U0 shall be connected to the IED

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

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

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

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

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

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

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

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

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

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

   If frequency tracking and compensation is required (this feature is typically required only for IEDs installed in the generating stations) then the setting parameters DFTReference shall be set accordingly.
4.2.3.6 Example how to connect the open delta VT to the IED for low impedance earthed or solidly earthed power systems

Figure 30 gives an example about the connection of an open delta VT to the IED for low impedance earthed or solidly earthed power systems. It shall be noted that this type of VT connection presents secondary voltage proportional to $3U_0$ to the IED.

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

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

(Equation 7)

The primary rated voltage of such VT is always equal to $U_{Ph-E}$. Therefore, three series connected VT secondary windings will give the secondary voltage equal only to one individual VT secondary winding rating. Thus the secondary windings of such open delta VTs quite often has a secondary rated voltage close to rated phase-to-phase VT secondary voltage, that is, 115V or $115/\sqrt{3}$V as in this particular example. Figure 30 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 30: Open delta connected VT in low impedance or solidly earthed power system
Section 4
Analog inputs

Where:

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

+3U₀ shall be connected to the IED.

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

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

(Equation 8)

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

(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.

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

(Equation 10)

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

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

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

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

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

Figure 31 gives an example on how to connect a neutral point VT to the IED. This type of VT connection presents secondary voltage proportional to U₀ to the IED.
In case of a solid earth fault in high impedance earthed or unearthed systems the primary value of Uo voltage will be equal to:

\[
U_0 = \frac{U_{n_r} - \epsilon}{\sqrt{3}} = U_{n_e} - \epsilon
\]

(Equation 11)

Figure 31 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 as well.

**Figure 31:** Neutral point connected VT
Where:

1) shows how to connect the secondary side of neutral point VT to one VT input in the IED. $U_0$ shall be connected to the IED.

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

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

(Equation 12)

$$VT_{sec} = 100V$$

(Equation 13)

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

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 32: Local human-machine interface

The LHMI of the IED contains the following elements:
The LHMI is used for setting, monitoring and controlling.

### 5.1 Display

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

The display view is divided into four basic areas.

**Figure 33: Display layout**

1. Path
2. Content
3. Status
4. Scroll bar (appears when needed)
The function button panel shows on request what actions are possible with the function buttons. Each function button has a LED indication that can be used as a feedback signal for the function button control action. The LED is connected to the required signal with PCM600.

**Figure 34: Function button panel**

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

**Figure 35: Alarm LED panel**

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

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

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

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
5.4 Local HMI functionality

5.4.1 Protection and alarm indication

Protection indicators

The protection indicator LEDs are Ready, Start and Trip.

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

Table 3: Ready LED (green)

<table>
<thead>
<tr>
<th>LED state</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Off</td>
<td>Auxiliary supply voltage is disconnected.</td>
</tr>
<tr>
<td>On</td>
<td>Normal operation.</td>
</tr>
<tr>
<td>Flashing</td>
<td>Internal fault has occurred.</td>
</tr>
</tbody>
</table>

Table 4: Start LED (yellow)

<table>
<thead>
<tr>
<th>LED state</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Off</td>
<td>Normal operation.</td>
</tr>
<tr>
<td>On</td>
<td>A protection function has started and an indication message is displayed. The start indication is latching and must be reset via communication, LHMI or binary input on the LEDGEN component. To open the reset menu on the LHMI, press Clear.</td>
</tr>
<tr>
<td>Flashing</td>
<td>The IED is in test mode and protection functions are blocked, or the IEC61850 protocol is blocking one or more functions. The indication disappears when the IED is no longer in test mode and blocking is removed. The blocking of functions through the IEC61850 protocol can be reset in Main menu/Test/Reset IEC61850 Mod. The yellow LED changes to either On or Off state depending on the state of operation.</td>
</tr>
</tbody>
</table>
### Table 5: Trip LED (red)

<table>
<thead>
<tr>
<th>LED state</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Off</td>
<td>Normal operation.</td>
</tr>
<tr>
<td>On</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 [button].</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 6: Alarm indications

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

### 5.4.2 Parameter management

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

- Numerical values
- String values
- Enumerated values

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

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

- The green uplink LED on the left is lit when the cable is successfully connected to the port.

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

1 RJ-45 connector
2 Green indicator LED
## Section 6  Differential protection

### 6.1  Busbar differential protection

#### 6.1.1  Identification

**Busbar differential protection, 3-phase version**

<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>Busbar differential protection, 2 zones, three phase/4 bays</td>
<td>BUTPTRC</td>
<td>3Id/I</td>
<td>87B</td>
</tr>
<tr>
<td>Busbar differential protection, 2 zones, three phase/4 or 8 bays</td>
<td>BTCZPDIF</td>
<td>3Id/I</td>
<td>87B</td>
</tr>
<tr>
<td>Busbar differential protection, 2 zones, three phase/4 or 8 bays</td>
<td>BZNTPDIF_A</td>
<td>3Id/I</td>
<td>87B</td>
</tr>
<tr>
<td>Busbar differential protection, 2 zones, three phase/4 or 8 bays</td>
<td>BZNTPDIF_B</td>
<td>3Id/I</td>
<td>87B</td>
</tr>
<tr>
<td>Busbar differential protection, 2 zones, three phase/4 or 8 bays</td>
<td>BZITGGIO</td>
<td>3Id/I</td>
<td>87B</td>
</tr>
</tbody>
</table>
### Busbar differential protection, 1-phase version

<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>Busbar differential protection, 2 zones, single phase/12 or 24 bays</td>
<td>BUSPTRC</td>
<td>3l</td>
<td>l</td>
</tr>
<tr>
<td>Busbar differential protection, 2 zones, single phase/12 or 24 bays</td>
<td>BCZSPDIF</td>
<td>3l</td>
<td>l</td>
</tr>
<tr>
<td>Busbar differential protection, 2 zones, single phase/12 or 24 bays</td>
<td>BZNSPDIF_A</td>
<td>3l</td>
<td>l</td>
</tr>
<tr>
<td>Busbar differential protection, 2 zones, single phase/12 or 24 bays</td>
<td>BZNSPDIF_B</td>
<td>3l</td>
<td>l</td>
</tr>
<tr>
<td>Busbar differential protection, 2 zones, single phase/12 or 24 bays</td>
<td>BZISGGIO</td>
<td>3l</td>
<td>l</td>
</tr>
</tbody>
</table>

### Status of primary switching object for Busbar protection zone selection

<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>Status of primary switching object for Busbar protection zone selection</td>
<td>BDCGAPC</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

### 6.1.2 Basic applications

#### 6.1.2.1 General

Basic types of applications for REB670 IED are shown and described in this chapter. For these applications usually three phase version of the IED, with two differential zone and four (or even eight) 3-phase CT inputs, is used.
6.1.2.2 Meshed corner application and T-connection application

The REB670 general differential function is suitable for application on mesh-corner arrangements. Mesh corners might have four or even up to six CT inputs and are basically simple single busbar arrangements. A similar application will occur when a T-protection is required for one-and-half breaker or ring busbar arrangements.

![Figure 38: Example of REB670 application on T-connection](IEC11000237-1-en.vsd)

6.1.3 Busbar protection applications

6.1.3.1 General

A busbar protection is a device which protects busbars against short-circuits and earth-faults. In the early development of electricity systems, no separate protection device was used for busbar protection. Remote end line protections were used as main protection for busbar faults. With the increased short-circuit power in the network separate differential IEDs for busbar protection have to be installed in order to limit the damage caused by the primary fault currents. In the same time, it is also a must to secure the network stability, as a delayed tripping for busbar faults can also lead to network instability, pole slip of near-by generators and even total system collapse.

For bus zone protection applications, it is extremely important to have good security since an unwanted operation might have severe consequences. The unwanted operation of the bus differential IED will have the similar effect from the operational point of view as simultaneous faults on all power system elements connected to the bus. On the other hand, the IED has to be dependable as well. Failure to operate or even slow operation of the differential IED, in case of an actual internal fault, can have serious consequences. Human injuries, power system blackout, transient instability or considerable damage to the surrounding substation equipment and the close-by generators are some of the possible outcomes.

Therefore, Busbar differential protection must fulfill the following requirements:

1. Must be absolutely stable during all external faults. External faults are much more common than internal faults. The magnitude of external faults can be equal to the stations maximum short circuit capacity. Heavy CT-saturation due to high DC components and/or remanence at external faults must not lead to maloperation of
the busbar differential protection. The security against misoperation must be extremely high due to the heavy impact on the overall network service.

2. Must have as short tripping time as possible in order to minimize the damage, minimize the danger and possible injury to the people who might be working in the station at the moment of internal fault, and secure the network stability.

3. Must be able to detect and securely operate for internal faults even with heavy CT saturation. The protection must also be sensitive enough to operate for minimum fault currents, which sometimes can be lower than the maximum load currents.

4. Must be able to selectively detect faults and trip only the faulty part of the busbar system.

5. Must be secure against maloperation due to auxiliary contact failure, possible human mistakes and faults in the secondary circuits and so on.

### 6.1.3.2 Distinctive features of busbar protection schemes

A busbar protection scheme design, depends very much on the substation arrangement. Complexity of the scheme can drastically vary from station to station. Typical applications problems, for the most common busbar protection schemes, are described in this chapter.

### 6.1.3.3 Differential protection

The basic concept for any differential IED is that the sum of all currents, which flow to and from the protection zone, must be equal to zero. If this is not the case, an internal fault has occurred. This is practically a direct use of well known Kirchhoff’s first law. However, busbar differential IEDs do not measure directly the primary currents in the high voltage conductors, but the secondary currents of magnetic core current transformers (that is, CTs), which are installed in all high-voltage bays connected to the busbar.

Therefore, the busbar differential IED is unique in this respect, that usually quite a few CTs, often with very different ratios and classes, are connected to the same differential protection zone. Because the magnetic core current transformers are non-linear measuring devices, under high current conditions in the primary CT circuits the individual secondary CT currents can be drastically different from the original primary currents. This is caused by CT saturation, a phenomenon that is well known to protection engineers. During the time when any of the current transformer connected to the differential IED is saturated, the sum of all CT secondary currents will not be equal to zero and the IED will measure false differential current. This phenomenon is especially predominant for busbar differential protection applications, because it has the strong tendency to cause unwanted operation of the differential IED.

Reemanence in the magnetic core of a current transformer is an additional factor, which can influence the secondary CT current. It can improve or reduce the capability of the current transformer to properly transfer the primary current to the secondary side. However, the CT remanence is a random parameter and it is not possible in practice to precisely predict it.
Another, and maybe less known, transient phenomenon appears in the CT secondary circuit at the instant when a high primary current is interrupted. It is particularly dominant if the HV circuit breaker chops the primary current before its natural zero crossing. This phenomenon is manifested as an exponentially decaying dc current component in the CT secondary circuit. This secondary dc current has no corresponding primary current in the power system. The phenomenon can be simply explained as a discharge of the magnetic energy stored in the magnetic core of the current transformer during the high primary current condition. Depending on the type and design of the current transformer this discharging current can have a time constant in the order of a hundred milliseconds.

Consequently, all these phenomena have to be considered during the design stage of a busbar differential IED in order to prevent the unwanted operation of the IED during external fault conditions.

The analog generation of the busbar differential IEDs (that is, RADHA, RADSS, REB 103) generally solves all these problems caused by the CT non-linear characteristics by using the galvanic connection between the secondary circuits of all CTs connected to the protected zone. These IEDs are designed in such a way that the current distribution through the IED differential branch during all transient conditions caused by non-linearity of the CTs will not cause the unwanted operation of the differential IED. In order to obtain the required secondary CT current distribution, the resistive burden in the individual CT secondary circuits must be kept below the pre-calculated value in order to guaranty the stability of the IED.

In new numerical protection IEDs, all CT and VT inputs are galvanically separated from each other. All analog input quantities are sampled with a constant sampling rate and these discreet values are then transferred to corresponding numerical values (that is, AD conversion). After these conversions, only the numbers are used in the protection algorithms. Therefore, for the modern numerical differential IEDs the secondary CT circuit resistance might not be a decisive factor any more.

The important factor for the numerical differential IED is the time available to the IED to make the measurements before the CT saturation, which will enable the IED to take the necessary corrective actions. This practically means that the IED has to be able to make the measurement and the decision during the short period of time, within each power system cycle, when the CTs are not saturated. From the practical experience, obtained from heavy current testing, this time, even under extremely heavy CT saturation, is for practical CTs around two milliseconds. Because of this, it was decided to take this time as the design criterion in REB 670 IED, for the minimum acceptable time before saturation of a practical magnetic core CT. Thus, the CT requirements for REB 670 IED are kept to an absolute minimum. Refer to section "Rated equivalent secondary e.m.f. requirements" for more details.

However, if the necessary preventive action has to be taken for every single CT input connected to the differential IED, the IED algorithm would be quite complex. Thus, it was decided to re-use the ABB excellent experience from the analog percentage restrained differential protection IED (that is, RADSS and REB 103), and use only the following three quantities:
1. incoming current (that is, sum of all currents which are entering the protection zone)

2. outgoing current (that is, sum of all currents which are leaving the protection zone)

3. differential current (that is, sum of all currents connected to the protection zone)

as inputs into the differential algorithm in the numerical IED design.

These three quantities can be easily calculated numerically from the raw sample values (that is, twenty times within each power system cycle in the IED) from all analog CT inputs connected to the differential zone. At the same time, they have extremely valuable physical meaning, which clearly describes the condition of the protected zone during all operating conditions.

By using the properties of only these three quantities, a new patented differential algorithm has been formed in the IED. This differential algorithm is completely stable for all external faults. All problems caused by the non-linearity of the CTs are solved in an innovative numerical way. In the same time, very fast tripping time, down to 10 ms, can be commonly obtained for heavy internal faults.

Please refer to the technical reference manual for more details about the working principles of the Differential Function algorithm.

6.1.3.4 Zone selection (CT switching)

The so-called CT switching (that is, zone selection) is required in situation when one particular circuit (that is, bay) can be connected to different busbars by individual disconnectors. Typical example is a station with double busbars with or without transfer bus as shown in figure 67 and figure 60, where any feeder bay can be connected to any of the two buses. In such cases the status of all busbar disconnectors and all transfer disconnectors shall be given to the busbar protection.

Traditionally, the CT switching has been done in CT secondary circuits. However, with REB670 this is not the case. All necessary zone selection (that is, CT switching) is done in software. Therefore, the CT secondary circuits are always intact and without any auxiliary relay contacts.

To provide proper zone selection (that is, busbar replica) the position information from all relevant primary switches (that is, disconnectors and/or circuit breakers) must be given to the IED. This is typically done by connecting two auxiliary contacts (that is, normally open and normally closed aux contacts) from each primary switch to the IED binary inputs (that is, optocouplers). In REB670 configuration one SwitchStatus function block shall be associated with each primary switching device. This block is then used internally to derive the primary object status and then pass this information to the busbar protection internal Zone Selection logic.
6.1.3.5 **Auxiliary contact requirement and evaluation**

**Auxiliary contact requirements for disconnectors and circuit breakers**

The position of the primary switching object is typically obtained via two auxiliary contacts of the primary apparatus. The first auxiliary contact indicates that primary device is closed. In protection literature it is called by different names as stated below:

- Normally open auxiliary contact
- “a” contact (that is, 52a)
- “closed”

The second auxiliary contact indicates that primary device is open. In protection literature it is called by different names as stated below:

- Normally closed auxiliary contact
- “b” contact (that is, 52b)
- “open”

Typically both contacts are used to provide position indication and supervision for busbar protection.

6.1.3.6 **Minimum contact requirements**

The minimum requirement for the busbar replica is the record of the disconnector position by using just one auxiliary contact, either NO or NC type. However recording a pair of auxiliary contacts, representing the OPEN and CLOSE position, offer additional features which can improve the reliability of the bus replica including supervision possibilities.

6.1.3.7 **Auxiliary contact evaluation logic**

Two logic schemes can be found.

**Scheme1_RADSS "If not OPEN then CLOSED"**

As the name of the scheme suggests, only when the auxiliary contacts signal clean open position ("normally open auxiliary (NO) contact input" = inactive and "normally closed auxiliary (NC) contact input" = active), the disconnector is taken to be open. For all other signal combinations the disconnector is considered to be closed. This scheme does not pose any special requirements to the auxiliary contact timing. Only the disconnector NC contact must open before the disconnector main contact is within arcing distance. The time during which the OPEN and CLOSED signal inputs disagree (that is, both binary inputs are active or both are inactive) is monitored by the isolator supervision function. The maximum time allowed before an alarm is given can be set according to the disconnector timing.
Scheme2_INX "Closed or open if clear indication available otherwise last position saved"

As the name of the scheme suggests, only when the auxiliary contacts signal clean OPEN or clean CLOSED position disconnector is considered to be open respectively closed. However this poses the stringent requirements on the auxiliary contacts that the CLOSED signal must become active a certain time (>150 ms) before current starts flowing for example, through arcing. Otherwise this current will not be taken into account in the busbar protection and this can result in a maloperation. Therefore, good timing of two auxiliary contacts is definitely required.

The time during which the OPEN and CLOSED signals disagree (that is, both binary inputs are active or both are inactive) is monitored by the isolator supervision function for both of the above two schemes. The maximum time allowed before an alarm is given can be set according to the disconnector timing.

Table 7 and the following two figures summarize the properties of these two schemes.

<table>
<thead>
<tr>
<th>Primary equipment</th>
<th>Status in busbar protection</th>
<th>Alarm facility</th>
<th>Information visible on local HMI</th>
</tr>
</thead>
<tbody>
<tr>
<td>Normally Open auxiliary contact status (&quot;closed&quot; or &quot;a&quot; contact)</td>
<td>Normally Closed auxiliary contact status (&quot;open&quot; or &quot;b&quot; contact)</td>
<td>when &quot;Scheme 1 RADSS&quot; is selected</td>
<td>when &quot;Scheme 2 INX&quot; is selected</td>
</tr>
<tr>
<td>open</td>
<td>open</td>
<td>closed</td>
<td>Last position saved</td>
</tr>
<tr>
<td>open</td>
<td>closed</td>
<td>open</td>
<td>open</td>
</tr>
<tr>
<td>closed</td>
<td>open</td>
<td>closed</td>
<td>closed</td>
</tr>
<tr>
<td>closed</td>
<td>closed</td>
<td>closed</td>
<td>closed</td>
</tr>
</tbody>
</table>
The circuit breaker position from a bay shall be given to the busbar protection when the position of this particular breaker can influence the busbar protection operation. Typical examples are Blind Spot protection in Bus-section and Bus-coupler bays or End Fault Protection in feeder bays. In both cases the measuring range of a busbar protection is limited by the CT location. By additionally recording the CB position of a feeder or a coupler the zone between the CT and the CB can be better protected while CB is open. However in such cases it is of utmost importance to connect the CB closing command to the busbar protection in order to include again the CT current to the busbar protection zones in time. It is as strongly recommended to always use Scheme1_RADSS for all CBs positions connected to the IED in order to minimize any
risk of possible problems due to late inclusion of CT current to the relevant differential zones.

**Line disconnector replica**

The line disconnector position from a feeder bay might be required for busbar protection under certain circumstances. Typical example is when the line disconnector QB9 and associated earthing switch are located between CT and protected busbar as indicated in figure 41.

![Diagram of Feeder Bay Layout](en06000086.vsd)

**Figure 41:** Feeder bay layout when line disconnector position might be required for busbar protection

Such feeder set-up can be often found in GIS stations where cable CTs are used for busbar protection. If in such feeder the line disconnector QB9 is open and then immediately the earthing switch QC1 is closed before the busbar disconnectors QB1 & QB2 are open there is a danger to get current unbalance into the zone differential measurement under following circumstances:

- In case of parallel lines zero sequence mutual coupling can induce zero sequence current into the grounded line especially during external earth-faults.
- In case of cable feeder the stored energy in the cable will be discharged through the earthing switch at the moment of its closing.

In order to avoid such problems for busbar protection the status of line disconnector can be monitored by busbar protection and CT measurement can be disconnected from both differential zones as soon line disconnector is open. Similar functionality can be obtained by instead monitoring the position of feeder breaker QA1. In such case the breaker closing signal shall be connected to busbar protection as well.

**6.1.3.8 Zone selection features**

The IED offers an extremely effective solution for stations where zone selection (that is, CT switching) is required. This is possible due to the software facility, which gives full and easy control over all CT inputs connected to the IED. The philosophy is to allow every CT input to be individually controlled by a setting parameter. This
parameter called ZoneSel can be individually configured for every CT input. This parameter, for every bay, can be set to only one of the following five alternatives:

1. **FIXEDtoZA**
2. **FIXEDtoZB**
3. **FIXEDtoZA&-ZB**
4. **CtrlIncludes**
5. **CtrlExcludes**

If for a particular CT input setting parameter ZoneSel is set to **FIXEDtoZA**, then this CT input will be only included to the differential zone A. This setting is typically used for simple single zone application such as: single busbar staions, one-and-a-half breaker stations or double breaker stations.

If for a particular CT input setting parameter ZoneSel is set to **FIXEDtoZB**, then this CT input will be only included to the differential zone B. This setting is typically used for applications such as: one-and-a-half breaker stations or double breaker stations.

If for a particular CT input setting parameter ZoneSel is set to **FIXEDtoZA&-ZB**, then this CT input will be included to the differential zone A, but its inverted current value will be as well included to the differential zone B. This setting is typically used for bus coupler or bus section bays when only one current transformer is available see figure 43.

If for a particular CT input setting parameter ZoneSel is set to **CtrlIncludes**, then this CT input will be:

- included to the differential zone A when input signal CTRLZA on corresponding bay block is given logical value one and it will be excluded from the differential zone A when input signal CTRLZA on corresponding bay block is given logical value zero.
- included to the differential zone B when input signal CTRLZB on corresponding bay block is given logical value one and it will be excluded from the differential zone B when input signal CTRLZB on corresponding bay block is given logical value zero.

This setting is typically used for feeder bays in double busbar stations in order to form proper busbar disconnector replica. It is especially suitable when normally open and normally closed (that is, a and b) auxiliary contacts from the busbar disconnectors are available to the IED.

If for a particular CT input setting parameter ZoneSel is set to **Ctrl_Excludes**, then this CT input will be:

- excluded from the differential zone A when input signal CTRLZA on corresponding bay block is given logical value one and it will be included to the differential zone A when input signal CTRLZA on corresponding bay block is given logical value zero
- excluded from the differential zone B when input signal CTRLZB on corresponding bay block is given logical value one and it will be included to the
differential zone B when input signal CTRLZB on corresponding bay block is given logical value zero

This setting is typically used for feeder bays in double busbar single breaker stations in order to form proper busbar disconnector replica. It is especially suitable when only normally closed (that is, b) auxiliary contact from the busbar disconnector(s) is available to the IED. For more information please refer to figure 62.

In applications where zone selection (that is, CT switching) is required (for example double or multiple busbar stations) all CTs will be permanently connected to the analogue input module(s), as shown in figure 61. Therefore, all necessary switching of currents will be performed in internal software logic.

6.1.3.9 CT disconnection for bus section and bus coupler current transformer cores

In practice there are three different solutions for bus section or bus coupler bay layout. First solution is with two sets of main CTs, which are located on both sides of the circuit breaker, as shown in figure 42.

![Diagram of station with two sets of main CTs in the bus-section bay](en01000013.vsd)

*Figure 42: Example of station with two sets of main CTs in the bus-section bay*

This is the most expensive, but good solution for busbar protection. Two differential zones overlapping across the bus-section or bus-coupler circuit breaker. All faults in the overlapping zone will be instantly tripped by both zones irrespective of the section/coupler circuit breaker status. However with modern busbar protection it is possible to disconnect both CTs from the relevant zones when the bus-section or bus-coupler circuit breaker is open. This will insure that if internal fault happen, in the overlapping zone, while breaker is open, only the faulty zone will be tripped while other busbar section will remain in service. However, due to low probability of such fault happening, while the breaker is open, such special considerations are typically not included in the busbar protection scheme for this type of stations. In such application
the bus section or bus coupler current transformers shall be wired just to two separate current input of the IED. Then in the parameter setting tool (PST) for the corresponding bays the parameter ZoneSel shall be set to FIXEDtoZA in one bay and FIXEDtoZB in another bay. This will insure that these currents are given to both differential zones.

When live tank circuit breakers are used, owing to the high cost of the HV current transformer often only one current transformer is available in bus-section or bus-coupler bay. The suggested solution in such applications is shown in figure 43.

For this type of solution just one main CT is located on only one side of the circuit breaker. Thus, there is no zone overlapping across the section/coupler circuit breaker as shown in figure 42. A blind spot exists between the current transformer and the circuit breaker in the bus section or bus-coupler bay as shown in figure 43.

For an internal fault in the blind spot, the differential zone ZA will unnecessarily operate and open the bus section breaker and all other feeder breakers associated with it. Nevertheless the fault will still exists on other busbar section, but it is outside the current transformer in the bus section bay and hence outside the zone ZB (that is, it is external fault for zone ZB). Similar problem will also exist if section/coupler circuit breaker was open before the internal fault in the blind zone. Therefore, the busbar protection scheme does not protect the complete busbar.

In order to improve the busbar protection scheme with this type of station layout, it is often required to disconnect the bus-section or bus-coupler CT from the two differential zones as soon as the bus-section or bus-coupler circuit breaker is opened. This arrangement can be easily achieved within the IED. In such application the bus section or bus coupler current transformer shall be wired just to one current input of the IED. Then in the Parameter Setting tool for the corresponding bay parameter ZoneSel shall be set to FIXEDtoZA&-ZB. This will insure that this current is given to
both differential zones. In order to disconnect this current from both zones, when the coupler/section breaker is open additional logic as shown in figure 44 have to be done in the configuration. The following two binary inputs are at least necessary in order to guaranty proper operation of such logic:

- Normally closed contact of the bus section or bus coupler circuit breaker
- Signal from the bus section or bus coupler circuit breaker closing circuit that somebody wants to close the breaker

This solution does not depend on contact timing between the main contacts and auxiliary contact of the circuit breaker. It directly follows the philosophy used for RADSS/REB 103 schemes used for similar applications before. Principle connection between the bus-coupler CB normally closed auxiliary contact (b-contact), REB670 and internal configuration logic, as shown in figure 44.

Figure 44: Bus coupler bay with one CT and b aux. contact only from CB

This scheme will disconnect the section/coupler CTs after about 80 ms (pre-set time under parameter setting \( t_{\text{ZeroCurrent}} \) in the relevant bay function block) from the moment of opening of the section/coupler CB (that is, from the moment when auxiliary b contact makes). Nevertheless this time delay is absolutely necessary in order to prevent racing between the opening of the main breaker contact and disconnection of the CT from the differential zones. This scheme will as well disconnect the CT in case of the operation of any of the two internal differential zones.
used in the scheme. This will secure the delayed (about 150 ms) clearing and tripping of the internal fault within the blind zone even in case of section/coupler circuit breaker failure during such fault. This facility will improve the performance of the busbar protection scheme when one CT is located on only one side of the bus-section / bus-coupler circuit breaker.

With GIS or live tank circuit breakers, owing to high cost of HV CT installations, sometimes no current transformers are available in bus-section or bus-coupler bay. This is the third solution shown in figure 45.

![Diagram of busbar protection scheme](en04000283.vsd)

**Figure 45: Example of station without main CTs in the bus-section bay**

In such case two separate zones can be maintained only while bus coupler breaker is open. As soon as bus coupler breaker is going to be closed the zone interconnection feature must be activated and complete busbars will be automatically protected with just one overall differential zone.

Since there are no current transformer in the bus coupler bay, there is no need to allocate internal bay function block for the bus coupler bay. However some additional configuration logic is required to obtain automatic zone interconnection activation when bus coupler breaker shall be closed. Example of such logic, as shown in figure 46.
Section 6  
Differential protection

6.1.3.10 End fault protection

When Live tank CBs or GIS are involved, there is a physical separation between the CT and the CB. End Fault Protection is related to primary faults between main CT and CB in a feeder bay. Therefore, it is directly related to the position of the main CT in feeder bay. Three CT positions in feeder bays are typically used in power systems around the world, as shown in figure 47.

Figure 47: Typical CT locations in a feeder bay

where:
A = two CTs are available one on each side of the feeder circuit breaker
B = one CT is available on the line side of the feeder circuit breaker
C = one CT is available on the bus side of the feeder circuit breaker
1 = End fault region

Figure 46: Configuration logic for bus coupler without main CTs
In figure 47/A where two CTs are available in a feeder bay the end fault protection is not an issue. The busbar and feeder protection zones overlap across feeder circuit breaker and all faults between these two CTs will be instantly detected and tripped by both protection schemes. As a consequence of such fault both busbar and feeder will be disconnected from the power system.

In figure 47/B where one CT is available on the line side of the feeder circuit breaker the primary fault between CT and CB will cause certain problems. Typically such fault will be detected and tripped by busbar protection. However to completely clear such fault the remote feeder end CB must be tripped as well. It shall be noted that for the feeder protection such fault will be either a reverse fault (that is, distance protection used for feeder protection) or external fault (that is, line/transformer differential protection used for feeder protection).

In figure 47/C where one CT is available on the bus side of the feeder circuit breaker the primary fault between CT and CB will cause problem as well. Typically such fault will be detected and tripped by feeder protection. However, to completely clear such fault the associated busbar section must be tripped as well. It shall be noted that the busbar differential protection will classify such fault as external and without any additional measures the busbar protection will remain stable.

For better understanding end fault protection applications within busbar protection, the figure 48 is used.

**Figure 48: Busbar protection measuring and fault clearing boundaries**

where:

1. is Busbar Protection measuring boundary determined by feeder CT locations
2. is Busbar Protection internal fault clearing boundary determined by feeder CB locations
3. is End fault region for feeders as shown in figure 47/B
4. is End fault region for feeders as shown in figure 47/C

In figure 48 single busbar station is shown. Two feeders on the left-hand side have CTs on the line side of the breaker. The two feeders on the right-hand side of the busbar...
have CTs on the busbar side of the breaker. It is assumed that busbar protection is connected to all four set of CTs in this station.

Due to CT location in feeder bays, busbar protection will detect all primary faults located within measuring boundary determined by CT locations, see figure 48. However its operation will only completely clear faults within clearing boundary determined by CB locations as shown in figure 48. Obviously, the primary faults in-between these two boundaries do pose certain practical problems.

First of all it shall be noted that there is no ideal solution for faults within end zone region in a feeder bay when the feeder breaker is closed. Such faults, within end fault region, will be then cleared with additional time delay either by operation of local backup protection (that is, feeder circuit breaker failure protection) or by operation of remote backup protection (that is, remote ends zone 2 distance protection).

However, the overall busbar protection behavior can be improved for primary faults within end fault regions, when feeder breaker is open. Under such circumstances the following actions can be taken:

- For feeders with CT on the line side of the circuit breaker (that is, two feeders on the left-hand side in figure 48), the current measurement can be disconnected from the busbar protection zone some time after feeder CB opening (for example, 400 ms for transformer and cable feeders or longest autoreclosing dead time +300 ms for overhead line feeders). At the same time, appropriately set and fast (that is, typically 40 ms time delayed) overcurrent protection shall be enabled to detect fault within end fault region. Any operation of this overcurrent protection shall only issue inter-trip command to the remote feeder end CB. Such overcurrent protection is often called end fault protection in relay literature. It shall be noted that at the same time busbar protection will remain stable (that is, selective) for such fault.

- For feeders with CT on the bus side of the circuit breaker (that is, two feeders on the right-hand side in figure 48), the current measurement can be disconnected from the busbar protection zone some time after feeder CB opening (that is, after 400 ms). This measure will insure fast busbar protection tripping for faults within end fault region in that feeder bay, while feeder CB is open.

However, it shall be noted that in order to utilize end fault protection feeder circuit breaker status and its closing command must be connected to the binary inputs of busbar protection scheme in order to be available for Zone Selection logic. Please refer to Zone Selection section for more info.

End fault protection logic can be easily done with help of graphical configuration tool. One stage (that is, 4th stage) from optionally available overcurrent protection can be used as dedicated end fault protection for feeders with CT on the line side of the CB.

End fault protection is here explained for simple single busbar station. However the same principles are applicable to almost all other station layouts. However, under certain circumstances, for stations with a transfer bus more extensive logic for end fault protection implementation might be required.
6.1.3.11 Zone interconnection (Load transfer)

In double busbar stations or double busbar with transfer bus stations it is common requirement to use the possibility of zone interconnection of load current in any feeder bay from one busbar to the other. The sequence of operation during zone interconnection is normally as the following:

- bus coupler bay is closed (that is, CB and both disconnectors).
- feeder bay busbar disconnector to the busbar not already in service is then closed. The switchgear interlocking system shall allow this only when the bus coupler breaker is already closed. Depending on the thermal capacity of the feeder busbar disconnectors (QB1 and QB2) the opening of the bus coupler circuit breaker is sometimes interlocked while both busbar disconnectors within one of the feeder bays are closed.
- opening of the feeder bay busbar disconnector originally closed. The load is now transferred from one to other bus.
- opening of bus coupler CB.

The zone interconnection has to be taken into consideration for the busbar differential protection scheme, as the two busbar zones are interconnected together via two disconnectors. The primary current split between the two busbars is not known and the two separate measuring zones cannot be maintained.

In conventional, analog busbar protection systems the solutions have been to, by extensive zone switching IEDs, disconnect one zone (normally zone B) and to connect all feeders to other zone (normally zone A). At the same time the current from the bus-coupler bay, which just circulates between two zones, must be disconnected from the measuring differential zone.

Similar situation regarding busbar protection can occur between two single busbar sections interconnected via sectionalizing disconnector, as shown in figure 53. When sectionalizer is closed then two separate protection zones becomes one and busbar protection must be able to dynamically handle this.

Due to the numerical design the IED can manage this situation in an elegant and simple way. Internal feature called ZoneInterconnection will be used to handle both situations. This feature can be activated either externally via binary input or derived internally by built-in logic. Internally, this “zone switching” feature will be activated if the following conditions are met:

- bays have parameter ZoneSel set to either CtrlInclude or CtrlExcludes
- internal zone selection logic concludes that this particular bay shall be simultaneously connected to both internal differential zones

This situation only means that for this particular bay both busbar disconnectors are closed and therefore zone interconnection switching is happening in the station.

When zone switching feature is activated inside the IED, each individual bay current will behave in the predetermined way as dictated by a parameter setting.
ZoneSwitching. This parameter, for every bay, can be set to only one of the following three alternatives

- ForceOut
- ForceIn
- Conditionally

If for a particular CT input setting parameter ZoneSwitching is set to ForceOut, then this CT input will be disconnected from both the differential zones, regardless of any other set value or active binary input, while zone switching feature is active within the IED. This setting is typically used for bus coupler bay in double busbar stations.

If for a particular CT input setting parameter ZoneSwitching is set to ForceIn, then this CT input will be connected to both the differential zones, regardless of any other set value or active binary input, while zone switching feature is active within the IED. This setting is typically used for all feeders bay in a station with two single zone interconnected by a sectionalizing disconnector.

If for a particular CT input setting parameter ZoneSwitching is set to Conditionally, then this CT input will be connected to both the differential zones only if it was included to any of the two zones for 2ms before the zone switching feature was activated. This setting is typically used for all feeders bay in double busbar stations. With this setting all feeder bays, which were not connected to any of the two zones before the zone interconnection activation (that is, out for scheduled maintenance), will not either be included during zone interconnection.

This practically means that for double busbar station, when zone switching feature is active, all feeder bays will be connected to both differential zones, while bus coupler CT will be disconnected from both zones. In this way simple but effective solution is formed. It is as well important to notice that all necessary changes in the individual bay tripping arrangements will be automatically performed within the internal logic.

A dedicated binary signal will be immediately activated in the internal logic when zone interconnection feature is activated. If this feature is active longer than the preset time separate alarm binary signal is activated, in order to alarm the station personnel about such operating conditions. ZoneInterconnection feature can be disabled by a parameter setting for substation arrangements where it is not required that is, single busbar stations, one-and-half breaker-and-a-half stations and so on.

Discriminating zones (that is, Zone A and Zone B) in the IED includes a sensitive operational level. This sensitive operational level is designed to be able to detect busbar earth faults in low impedance earth power systems (that is, power systems where the earth-fault current is limited to a certain level, typically between 300 A and 2000 A by neutral point reactor or resistor) or for some other special applications where increased sensitivity is required. Operation and operating characteristic of the sensitive differential protection can be set independently from the operating characteristic of the main differential protection. The sensitive differential level is blocked as soon as the total incoming current exceeds the pre-set level. By appropriate setting then it can be insured that this sensitive level is blocked for external phase-to-
phase or three-phase faults, which can cause CT saturation. Comparison between these two characteristics is shown in figure 49.

Figure 49: Differential protection operation characteristic

Additionally the sensitive differential protection can be time delayed and it must be externally enabled by a binary signal (that is, from external open delta VT overvoltage relay or power transformer neutral point overcurrent relay).

The setting parameters for the check zone are set via the local HMI or PCM600.

Such check zone is included in the IED. By a parameter setting CheckZoneSel = NotConnected/Connected can be decided, individually for every bay, if it shall be connected to the check zone or not. This setting is available in bay function block.

For every zone there is a setting parameter CheckZoneSup, which can be set to On or Off. This setting parameter determines if the individual zone shall be supervised or not by a check zone. This setting is available in both Zone functions. Finally the check zone shall be enabled (that is, setting parameter Operation shall be set to On) in order to fully enable the check zone. Operating characteristics for the check zone can be set independently from the two discriminating zones.

However, it is to be observed that the check zone has slightly different operating characteristic from the usual discriminating zones. For the check zone the resultant outgoing current is used as stabilizing current instead of total incoming current in order to guarantee the check zone operation for all possible operating conditions in the station. The check zone operating characteristic is shown in figure 50:
Figure 50: Check zone operation characteristic

Note that the check zone minimum differential operational level OperLevel shall be set equal to or less than the corresponding operating level of the usual discriminating zones.

For substations where traditional “CT switching” is not required (that is, single busbar station or one-and-half breaker station) the check zone must not be used. For such applications the check zone shall be disabled by setting check zone setting parameter Operation to Off.

When CT-circuits are switched depending on the position of the busbar disconnectors there is a possibility that some of the CT secondary circuits can be open circuited by a mistake. At the same time this can cause unwanted operation of the differential protection scheme.

For this reason, a so-called check zone is often required for a traditional high-impedance busbar protection scheme when switching in CT-circuit is done. The check zone is fixed and has no switching of CTs in any of the outgoing circuits and is not connected to busbar section and busbar coupler bays. The check zone, will detect faults anywhere in the substation but can not distinguish in which part of the station the fault is located. When the check zone detects a fault it gives a release signal to the busbar protection relays in all individual, discriminating zones. The busbar protection discriminating zones will than trip the part of the substation that is faulty. However, this principle creates not only a high cost as separate CT cores are required, but also a need for extra cabling and a separate check zone differential relay.

There is no need for an external check zone due to the following facts:

- the CT switching is made only in software, and CT secondary current circuits do not include any auxiliary contacts, as shown in figure 61.
- the IED is always supplied with a special zone and phase selective “Open CT Detection” algorithm, which can instantly block the differential function in case of an open CT secondary circuits caused by accidents or mistakes.
- internal check zone feature is available
This means that a very cost effective solution can be achieved using REB670, producing extra savings during scheme engineering, installation, commissioning, service and maintenance.

The pre-configured binary output contacts, are provided in the IED in order to alarm the open CT circuit condition. At the same time, one of the LEDs on the local HMI can be programmed to light up. It shall be noted that the Open CT Circuit alarm can only be manually reset by one of the three following ways:

1. By using the reset menu on the local HMI
2. By energizing the dedicated binary input called “Reset OCT” via communication links
3. By energizing the dedicated binary input called “Reset OCT” via logic done in the internal configuration

For more details about the working principles of the Open CT Detection algorithm, refer to Technical reference manual.

6.1.3.12 Tripping circuit arrangement

The contact outputs are of medium duty type. It is possible to use them to directly trip the individual bay circuit breakers. This solution is suitable for all types of station arrangements. The internal zone selection logic provides individual bay trip signals in the internal software and no external relay for this purpose are required. This arrangement insures correct trip signal distribution to all circuit breakers in case of busbar protection operation or individual bay breaker failure protection operation. Breaker failure protection can be internal or external to the IED.

By a parameter setting it is possible to provide self-rest or latched trip output contacts from the IED. However it shall be noted that the latching is electrical (that is, if dc supply to the IED is lost the output contacts will reset).

However, sometimes due to a large number of required trip output contacts (that is, single pole operated circuit breakers and/or main and backup trip coils), a separate trip repeat relay unit is applied for the tripping of the circuit breakers in the station. In that case the tripping arrangement can be done in different ways.

6.1.3.13 Trip arrangement with one-phase version

When one-phase version of the IED is used it is typically required to have three IEDs (that is, one per phase). Thus, when busbar protection in one IED operates the trip commands will be given to all bays but internal circuit breaker failure function will be started in the same phase only. In order to secure internal breaker failure starting in all three phases it is advisable to do the following. Connect Zone A trip signal from one IED to the external trip input of the Zone A in the other two IEDs. Thus all three IEDs will then issue trip in Zone A and start internally circuit breaker failure protection in all three phases.

Note that:
similar arrangements shall be done for Zone B
this have to be done between all three IEDs (that is, three times)

Such a scheme can be arranged in one of the following ways:

by wiring between three IEDs
by using GOOSE messages when IEC 61850-8-1 is used
by using LDCM communication module.

Note that in this case the external trip signal from other two IEDs shall be arranged via pulse timer in configuration in order to avoid locking of the trip signal between three IED. Such arrangement via GOOSE is given in figure 51:

![Diagram of Centralized trip unit](en06000227.vsd)

**Figure 51:** Principal trip arrangement via GOOSE between three one-phase IEDs

### 6.1.3.14 Centralized trip unit

Tripping is performed directly from the IED contacts, which then activate an auxiliary trip unit, which multiplies the number of required trip contacts. Separate potential free contacts are provided for each bay and are supplied by the bay auxiliary voltage and will activate the trip coil of each bay circuit breaker at operation. This tripping setup is suitable when no individual circuit breaker failure IEDs or lock-out of individual bay CB closing coils is required. A suitable external trip unit consists of a combination
6.1.3.15 Decentralized trip arrangement

Tripping is performed directly from the IED contacts, which then activate dedicated auxiliary trip unit per bay. This individual auxiliary trip unit can be mounted either in the busbar protection cubicle or in the individual bay cubicles. This tripping setup is suitable when individual circuit breaker failure relays exist in all bays. A suitable external trip unit consists of a combination of RXMS1/RXMH 2 when heavy duty contacts are required and only RXMS 1 relays when medium duty contacts are sufficient.

This solution is especially suitable for the station arrangements, which require the dynamic zone selection logic (that is, so called CT switching).

6.1.3.16 Mechanical lock-out function

It is sometimes required to use lock-out relays for busbar protection operation.

The IED has built-in feature to provide either self-reset or latched tripping in case of busbar protection operation. Which type of trip signal each zone will issue is determined by a parameter setting DiffTripOut which can be set either to SelfReset or Latched. When Latched is selected the trip output from the IED will only reset if:

1. Manual reset command is given to the IED
2. DC power auxiliary supply to the IED is interrupted (that is, switched-off)

However, if it is required to have mechanically latched tripping and lock-out in the circuit breaker closing circuit, then it is recommended to use one dedicated lockout IED for each bay. Such mechanical lock-out trip IEDs are available in the COMBIFLEX range (for example RXMVB2 or RXMVB4 bistable IEDs).

From the application point of view lock-out trip IEDs might have the following drawbacks:

- The trip contacts will remain closed. If the breaker would fail to open the tripping coil will be burnt and the DC supply short-circuited.
- The trip circuit supervision (TCS) IEDs will reset and give alarm for a failure in the trip circuit if the alarm is not opened by the lock-out IED or a double trip circuit supervision is recommended where the trip circuit is supervised with two alternatively, TCS IEDs.

6.1.3.17 Contact reinforcement with heavy duty relays

There is sometimes a request for heavy duty trip relays. Normally the circuit breaker trip coils, with a power consumption of 200 to 300 W, are provided with an auxiliary contact opening the trip circuit immediately at breaker tripping. Therefore, no heavy
duty breaking capacity is required for the tripping relays. Nevertheless heavy duty trip relays are still often specified to ensure trip circuit opening also if the circuit breaker fails due to a mechanical failure or a lack of energy for operation. This can particularly occur during site testing. In this case it is recommended to use COMBIFLEX RXMH 2 or RXMVB 2 heavy duty relays.

### 6.1.3.18 Trip circuit supervision for busbar protection

Trip circuit supervision is mostly required to supervise the trip circuit from the individual bay IED panel to the circuit breaker. It can be arranged also for the tripping circuits from the busbar protection.

However, it can be stated that the circuit from a busbar protection trip relay located in the busbar protection panel is not so essential to supervise as busbar faults are very rare compared to faults in bays, especially on overhead power lines. Also it is normally a small risk for faults in the tripping circuit and if there is a fault it affects only one bay and all other bays are thus correctly tripped meaning that the fault current disappears or is limited to a low value.

### 6.1.4 Different busbar arrangements

#### 6.1.4.1 General

Busbar differential protection application principles for typical busbar arrangements are shown and described in this chapter.

#### 6.1.4.2 Single busbar arrangements

The simplest form of busbar protection is a one-zone protection for single busbar configuration, as shown in figure 52. When different CT ratios exist in the bays compensation is done by setting the CT ratio individually for each bay.

The only requirement for busbar protection is that the protection scheme must have one differential zone. For any internal fault all circuit breakers must be tripped, which will cause loss of supply to all loads connected to the station.

![Figure 52: Example of single busbar section with six feeder bays](xx06000087.vsd)
This type of busbar arrangement can be very easily protected. The most common setups for this type of station are described in the following table.

**Table 8: Typical solutions for single busbar arrangement**

<table>
<thead>
<tr>
<th>Version of REB670 IED</th>
<th>Numbers of feeders per busbar</th>
<th>Number of REB670 IEDs required for the scheme</th>
</tr>
</thead>
<tbody>
<tr>
<td>3PH; 2-zones, 4-bays BBP (A20)</td>
<td>4</td>
<td>1</td>
</tr>
<tr>
<td>3PH; 2-zones, 8-bays BBP (A31)</td>
<td>8</td>
<td>1</td>
</tr>
<tr>
<td>1Ph; 2-zones, 12-bays BBP (B20)</td>
<td>12</td>
<td>3</td>
</tr>
<tr>
<td>1Ph; 2-zones, 12-bays BBP (B21)</td>
<td>12</td>
<td>3</td>
</tr>
<tr>
<td>1Ph; 2-zones, 24-bays BBP (B31)</td>
<td>24</td>
<td>3</td>
</tr>
</tbody>
</table>

Please note that the above table 8 is given for the preconfigured versions of REB670 which do not contain any VT inputs.

### 6.1.4.3 Single busbar arrangements with sectionalizer

This arrangement is very similar to the single busbar arrangement. The sectionalizer allows the operator to split the station into two separate buses. However, switching of the sectionalizing disconnector has to be done without any load. This means that one of the two busbars has to be de-energized before any opening or closing of the sectionalizer.

For this case the protection scheme must have two differential zones, which can be either split to work independently from each other or switched to one overall differential zone when sectionalizing disconnector is closed. Nevertheless, when sectionalizer is closed, for internal fault on any of the two buses all feeder circuit breakers have to be tripped, which causes loss of supply to all loads connected to this station.

![Figure 53: Example of two single busbar sections with bus-sectionalizing disconnector and eight feeder bays per each busbar section](IEC11000238-1-en.vsd)

The most common setups for this type of station are described in the following table.
Table 9: Typical solutions for stations with two single busbar sections with bus-sectionalizing disconnector

<table>
<thead>
<tr>
<th>Version of REB670 IED</th>
<th>Total Number of feeders in both busbar sections</th>
<th>Number of REB670 IEDs required for the scheme</th>
</tr>
</thead>
<tbody>
<tr>
<td>3PH; 2-zones, 4-bays BBP (A20)</td>
<td>4</td>
<td>1</td>
</tr>
<tr>
<td>3PH; 2-zones, 8-bays BBP (A31)</td>
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<td>3</td>
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<tr>
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<td>12</td>
<td>3</td>
</tr>
<tr>
<td>1Ph; 2-zones, 24-bays BBP (B31)</td>
<td>24</td>
<td>3</td>
</tr>
</tbody>
</table>

Please note that table 9 is given for the preconfigured versions of REB670 which do not contain any VT inputs.

Two differential zones are available in the IED and the connecting of the two zones is simply controlled via zone interconnection logic, as described in section "Zone interconnection (Load transfer)". In practice, the closed position of the sectionalizer shall start the zone interconnection logic inside the IED. All other thinks (that is, tripping) will automatically be arranged.

6.1.4.4 Single busbar arrangements with bus-section breaker

This arrangement is very similar to the single busbar arrangement. The bus-section breaker allows the operator to split the station into two separate buses under full load. The requirement for busbar protection scheme is that the scheme must have two independent differential zones, one for each busbar section. If there is an internal fault on one of the two sections, bus-section circuit breaker and all feeder circuit breakers associated with this section have to be tripped, leaving the other busbar section in normal operation.

Figure 54: Example of two single busbar sections with bus-section circuit breaker and eight feeder bays per each busbar section

This type of busbar arrangement can be quite easily protected. The most common setups for this type of station are described in the following table.
Table 10: Typical solutions for single busbar arrangements with bus-section breaker

<table>
<thead>
<tr>
<th>Version of REB670 IED</th>
<th>Total number of feeders in both busbar sections</th>
<th>Number of REB670 IEDs required for the scheme</th>
</tr>
</thead>
<tbody>
<tr>
<td>3PH; 2-zones, 4-bays BBP (A20)</td>
<td>3*/6</td>
<td>1/2</td>
</tr>
<tr>
<td>3PH; 2-zones, 8-bays BBP (A31)</td>
<td>7*/14</td>
<td>1/2</td>
</tr>
<tr>
<td>1Ph; 2-zones, 12-bays BBP (B20)</td>
<td>11*/22</td>
<td>3/6</td>
</tr>
<tr>
<td>1Ph; 2-zones, 12-bays BBP (B21)</td>
<td>11*/22</td>
<td>3/6</td>
</tr>
<tr>
<td>1Ph; 2-zones, 24-bays BBP (B31)</td>
<td>23*/46</td>
<td>3/6</td>
</tr>
</tbody>
</table>

* with just one CT input from bus-section bay

Please note that table 10 is given for the preconfigured versions of REB670 which do not contain any VT inputs.

For station with just one CT in the bus-section bay, it might be required, depending on the client requirements, to provide the special scheme for disconnection of bus-section CT when the bus-section CB is open. For more information, refer to figure 44.

### 6.1.4.5 H-type busbar arrangements

The H-type stations are often used in transmission and sub-transmission networks as load-centre substations, as shown in figure 55. These arrangements are very similar to the single busbar station with sectionalizer or bus-section breaker, but are characterized by very limited number of feeder bays connected to the station (normally only two OHL and two transformers).
The requirement for the busbar protection scheme for this type of station may differ from utility to utility. It is possible to apply just one overall differential zone, which protects both busbar sections. However, at an internal fault on any of the two buses all feeder circuit breakers have to be tripped, which will cause loss of supply to all loads connected to this station. Some utilities prefer to have two differential zones, one for each bus section.

The most common setups for this type of station are given in the following table.

**Table 11: Typical solutions for H-type stations**

<table>
<thead>
<tr>
<th>Version of REB670 IED</th>
<th>Number of differential zones/number of feeders per zone</th>
<th>Number of REB670 IEDs required for the scheme</th>
</tr>
</thead>
<tbody>
<tr>
<td>3PH; 2-zones, 4-bays BBP (A20)</td>
<td>1/4</td>
<td>1</td>
</tr>
<tr>
<td>3PH; 2-zones, 8-bays BBP (A31)</td>
<td>2/3</td>
<td>1</td>
</tr>
<tr>
<td>1Ph; 2-zones, 12-bays BBP (B20)</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>1Ph; 2-zones, 12-bays BBP (B21)</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>1Ph; 2-zones, 24-bays BBP (B31)</td>
<td>NA</td>
<td>NA</td>
</tr>
</tbody>
</table>

Please note that table 11 is given for the preconfigured versions of REB670 which do not contain any VT inputs.
For station with double zone protection and just one set of CTs in the bus-section bay, it might be required, depending on the client requirements, to provide the special scheme for disconnection of bus-section CT when the bus-section CB is open. For more information, refer to figure 44.

6.1.4.6 Double circuit breaker busbar arrangement

The circuit breaker, disconnectors and instrument transformers are duplicated for every feeder, as shown in figure 56.

![Example of double breaker station](xx06000018.vsd)

**Figure 56:** Example of double breaker station

This is an extremely flexible solution. In normal service all breakers are closed. The requirement for busbar protection scheme is that the scheme must have two independent differential zones, one for each busbar. If there is an internal fault on one of the two buses all circuit breakers associated with the faulty busbar have to be tripped, but supply to any load will not be interrupted. The tripping logic for the circuit breaker failure protection must be carefully arranged.

The most common setups for this type of busbar arrangement are described in the following table.

<table>
<thead>
<tr>
<th>Version of REB670 IED</th>
<th>Numbers of feeders per station</th>
<th>Number of REB670 IEDs required for the scheme</th>
</tr>
</thead>
<tbody>
<tr>
<td>3PH; 2-zones, 4-bays BBP (A20)</td>
<td>4/8</td>
<td>1/2</td>
</tr>
<tr>
<td>3PH; 2-zones, 8-bays BBP (A31)</td>
<td>6/12</td>
<td>3/6</td>
</tr>
<tr>
<td>1Ph; 2-zones, 12-bays BBP (B20)</td>
<td>6/12</td>
<td>3/6</td>
</tr>
<tr>
<td>1Ph; 2-zones, 12-bays BBP (B21)</td>
<td>6/12</td>
<td>3/6</td>
</tr>
<tr>
<td>1Ph; 2-zones, 24-bays BBP (B31)</td>
<td>12/24</td>
<td>3/6</td>
</tr>
</tbody>
</table>

Please note that table 12 is given for the preconfigured versions of REB670 which do not contain any VT inputs.

A principle overall drawing of how to use REB670 for this type of station is given in figure 57.
Figure 57: Feeder bay in double bus – double breaker station

6.1.4.7 One-and-half circuit breaker

A fewer number of circuit breakers are needed for the same flexibility as for double circuit breaker busbar arrangement, as shown in figure 58.
All breakers are normally closed. The requirement for the busbar protection scheme is that the scheme must have two independent differential zones, one for each busbar. In case of an internal fault on one of the two buses, all circuit breakers associated with the faulty busbar have to be tripped, but the supply to any load will not be interrupted. The breaker failure protection tripping logic also needs careful design.

This type of busbar arrangement can be very easily protected. The most common setups for this type of station are described in the following table.

<table>
<thead>
<tr>
<th>Version of REB670 IED</th>
<th>Number of diameters in the station</th>
<th>Number of REB670 IEDs required for the scheme</th>
</tr>
</thead>
<tbody>
<tr>
<td>3PH; 2-zones, 4-bays BBP (A20)</td>
<td>2/4</td>
<td>1/2</td>
</tr>
<tr>
<td>3PH; 2-zones, 8-bays BBP (A31)</td>
<td>4/8</td>
<td>1/2</td>
</tr>
<tr>
<td>1Ph; 2-zones, 12-bays BBP (B20)</td>
<td>6/12</td>
<td>3/6</td>
</tr>
<tr>
<td>1Ph; 2-zones, 12-bays BBP (B21)</td>
<td>6/12</td>
<td>3/6</td>
</tr>
<tr>
<td>1Ph; 2-zones, 24-bays BBP (B31)</td>
<td>12/24</td>
<td>3/6</td>
</tr>
</tbody>
</table>

Please note that table 13 is given for the preconfigured versions of REB670 which do not contain any VT inputs.

A principle overall drawing of how to use REB670 for one-and-half circuit breaker station including internal CBF protection for middle breaker is given in figure 59.
Figure 59: Diameter in one-and-half breaker station with breaker failure protection for all three breakers inside REB670

6.1.4.8 Double busbar single breaker arrangement

This type of arrangement is shown in figure 60.

Figure 60: Example of double busbar station
This type of busbar arrangement is very common. It is often preferred for larger installations. It provides good balance between maintenance work requirements and security of supply. If needed, two busbars can be split during normal service. The requirement for busbar protection scheme is that the scheme must have two independent differential zones, one for each busbar. In case of an internal fault on one of the two buses, bus-coupler circuit breaker and all feeder circuit breakers associated with the faulty bus have to be tripped, leaving other busbar still in normal operation. Provision for zone selection, disconnector replica and zone interconnection have to be included into the scheme design.

This type of busbar arrangement can be protected as described in the following table:

Table 14: Typical solutions for double busbar stations

<table>
<thead>
<tr>
<th>Version of REB670 IED</th>
<th>Number of feeders in the station (excluding bus-coupler bay)</th>
<th>Number of REB670 IED required for the scheme</th>
</tr>
</thead>
<tbody>
<tr>
<td>3PH; 2-zones, 4-bays BBP (A20)</td>
<td>3*)</td>
<td>1</td>
</tr>
<tr>
<td>3PH; 2-zones, 8-bays BBP (A31)</td>
<td>7*)</td>
<td>1</td>
</tr>
<tr>
<td>1Ph; 2-zones, 12-bays BBP (B20)</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>1Ph; 2-zones, 12-bays BBP (B21)</td>
<td>11*)</td>
<td>3</td>
</tr>
<tr>
<td>1Ph; 2-zones, 24-bays BBP (B31)</td>
<td>23*)</td>
<td>3</td>
</tr>
</tbody>
</table>

*) with just one CT input from bus-coupler bay

Please note that table 14 is given for the preconfigured versions of REB670 which do not contain any VT inputs.

For station with just one CT in the bus-coupler bay, it might be required, depending on the client requirements, to provide the special scheme for disconnection of bus-coupler CT when the bus-coupler CB is open. For more info please refer to figure 44.

Some principle overall drawings of how to use REB670 in this type of station are given in figure 61 to figure 65.
Figure 61: Feeder bay where a&b aux. contacts are used

Disconnector aux. contact timing
(Aux. contact a timing is only crucial when Scheme2_INX is used)

<table>
<thead>
<tr>
<th></th>
<th>Main contact</th>
<th>Aux. a contact</th>
<th>Aux. b contact</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Open</td>
<td>Open</td>
<td>Closed</td>
</tr>
<tr>
<td></td>
<td>Closed</td>
<td>Closed</td>
<td>Open</td>
</tr>
</tbody>
</table>

Set Parameter
ZoneSel="CtrlIncludes"

BBP & BFP trip command to feeder breaker

Section 6
Differential protection
Figure 62: Feeder bay where b aux. contacts are used
Figure 63: Bus coupler bay with two sets of CTs
Figure 64: Bus coupler bay with one CT and a&b aux. contact from CB
Figure 65: Bus coupler bay with one CT and b aux. contact only from CB

6.1.4.9 Double busbar arrangements with two bus-section breakers and two bus-coupler breakers

This type of station is commonly used for GIS installations. It offers high operational flexibility. For this type of stations, two schemes similar to the double busbar station scheme can be used.

Figure 66: Example of typical GIS station layout

With REB670 this type of arrangement can be protected as described in the following table.
**Table 15: Possible solutions for a typical GIS station**

<table>
<thead>
<tr>
<th>Version of REB670 IED</th>
<th>Number of feeders on each side of the station (excluding bus-coupler &amp; bus-section bays)</th>
<th>Number of REB670 IEDs required for the scheme</th>
</tr>
</thead>
<tbody>
<tr>
<td>3PH; 2-zones, 4-bays BBP (A20)</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>3PH; 2-zones, 8-bays BBP (A31)</td>
<td>5(^{+})</td>
<td>2</td>
</tr>
<tr>
<td>1Ph; 2-zones, 12-bays BBP (B20)</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>1Ph; 2-zones, 12-bays BBP (B21)</td>
<td>9(^{+})</td>
<td>6</td>
</tr>
<tr>
<td>1Ph; 2-zones, 24-bays BBP (B31)</td>
<td>21(^{+})</td>
<td>6</td>
</tr>
</tbody>
</table>

\(^{+}\) with just one CT input from bus-coupler bay

Please note that table 15 is given for the preconfigured versions of REB670 which do not contain any VT inputs.

Provision for zone selection, disconnector replica and zone interconnection have to be included into the scheme design.

For station with just one CT in the bus-coupler or bus-section bays, it might be required, depending on the client requirements, to provide the special scheme for disconnection of bus-coupler or bus-section CT when the bus-coupler or bus-section CB is open. For more info please refer to figure 44.

### 6.1.4.10 Double busbar-single breaker with transfer bus arrangements

This type of arrangement is shown in figure 67.

**Figure 67:** Example of double busbar-single breaker with transfer bus arrangement

This type of busbar arrangement is very common in some countries. It provides good balance between maintenance work requirements and security of supply. If needed, two busbars can be split during normal service. Additionally any feeder CB can be taken out for maintenance without interruption of supply to the end customers connected to this feeder.

The requirement for busbar protection scheme is that the scheme must have two independent differential zones, one for each busbar. In case of an internal fault on one
of the two buses, bus-coupler circuit breaker and all feeder circuit breakers associated with the faulty bus have to be tripped, leaving other busbar still in normal operation. When transfer bus is in operation it will be protected as an integral part of one of the two internally available zones. Special attention shall be given that appropriate logic for zone selection is done with help of graphical configuration tool. At the same time, load transfer and possible transfer of trip signals from the feeder under transfer to the transfer circuit breaker shall be arranged in appropriate way as well. This type of busbar arrangement can be protected as described in the following table:

Table 16: Possible solutions for double busbar-single breaker with transfer bus arrangements

<table>
<thead>
<tr>
<th>Version of REB670 IED</th>
<th>Total number of feeder bays in the station (excluding buscoupler &amp; bus-section bays)</th>
<th>Number of REB670 IEDs required for the scheme</th>
</tr>
</thead>
<tbody>
<tr>
<td>3PH; 2-zones, 4-bays BBP (A20)</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>3PH; 2-zones, 8-bays BBP (A31)</td>
<td>7*</td>
<td>1</td>
</tr>
<tr>
<td>1PH; 2-zones, 12-bays BBP (B20)</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>1PH; 2-zones, 12-bays BBP (B21)</td>
<td>11*</td>
<td>3</td>
</tr>
<tr>
<td>1PH; 2-zones, 24-bays BBP (B31)</td>
<td>23*</td>
<td>3</td>
</tr>
</tbody>
</table>

* with one set of CTs in bus-coupler bay and separate transfer and bus-coupler breaker

Please note that table 16 is given for the preconfigured versions of REB670 which do not contain any VT inputs.

Note that for station layouts where combined transfer and bus-coupler bay is used, as for example is shown in figure 67, two internal bay function blocks must be allocated to such primary bay, reducing number of available feeder bays. In such station maximum available number of feeder bays is less for one from the values shown in table 16, on condition that just one main CT is available from Bus-Coupler/Transfer bay. For station with just one CT in the bus-coupler bay, it might be required, depending on the client requirements, to provide the logic scheme for disconnection of bus-coupler CT when the bus-coupler CB is open. For more information, refer to figure 44.

6.1.4.11 Combined busbar arrangements

There are stations which are practically a combination between two normal types of station arrangements, which are already previously described. Some typical examples will be shown here:
Figure 68: Combination between one-and-half and double breaker station layouts

This type of stations can be encountered very often in practice. Usually the station is arranged in such a way that double breaker bays can be, at a later stage, transformed into one-and-half breaker setup. For busbar protection this type of station can be protected in exactly the same way as one-and-half breaker stations described above. The same type of IEDs can be used, and same limitations regarding the number of diameters apply.

Figure 69: Combination between double breaker and double busbar station layouts

In this type of arrangement the double breaker bay has in the same time the role of the bus-coupler bay for normal double busbar single breaker stations. Therefore, zone interconnection, zone selection and disconnector replica facilities have to be provided for all double busbar bays. Because of the very specific requirements on zone interconnection feature, the following should be considered for this type of application:
current inputs CT1 and CT2 shall be used for the first double breaker bay.
• current inputs CT3 and CT4 shall be used for the second double breaker bay.
• current inputs CT5 and CT6 shall be used for the third double breaker bay (only available in 1ph version).

Accordingly the following solutions are possible:

Table 17: Typical solutions for combination between double breaker and double busbar station layouts

<table>
<thead>
<tr>
<th>Version of REB670 IED</th>
<th>Number of double breaker feeders / Number of double busbar feeders in the station</th>
<th>Number of REB670 IEDs required for the scheme</th>
</tr>
</thead>
<tbody>
<tr>
<td>3PH; 2-zones, 4-bays BBP (A20)</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>3PH; 2-zones, 8-bays BBP (A31)</td>
<td>2/4</td>
<td>1</td>
</tr>
<tr>
<td>1Ph; 2-zones, 12-bays BBP (B20)</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>1Ph; 2-zones, 12-bays BBP (B21)</td>
<td>3/6</td>
<td>3</td>
</tr>
<tr>
<td>1Ph; 2-zones, 24-bays BBP (B31)</td>
<td>3/18</td>
<td>3</td>
</tr>
</tbody>
</table>

Please note that table 17 is given for the preconfigured versions of REB670 which do not contain any VT inputs.

For this type of busbar arrangement the double busbar bay is usually connected to the reactive power compensation equipment (that is, shunt reactor or shunt capacitor). The diameters in the one-and-half breaker part of the station have at the same time the...
role of the bus-coupler bay. Therefore, zone interconnection, zone selection and disconnector replica facilities have to be provided for all double busbar bays.

6.1.5 Summation principle

6.1.5.1 Introduction

A simplified bus differential protection for phase and earth faults can be obtained by using a single, one-phase IED with external auxiliarysummation current transformers. By using this approach, more cost effective bus differential protection can be obtained. Such a solution makes it feasible to apply bus differential protection even to medium voltage substations. The principal differences between full, phase-segregated bus differential protection scheme and summation type bus differential protection scheme are shown in figure 71.

\[ \text{Three one-phase REB670} \quad \equiv \quad \text{Single one-phase REB670} \quad \text{Auxiliary Summation CT}^*) \quad \text{type SLCE 8, 1/1A, 2/1A or 5/1A} \\
\]

\[ \text{REB670} \quad \text{with 1A CT inputs} \quad \text{Up to 18 pcs auxiliary CTs} \]

*) One SLCE 8 per main CT

Figure 71: Difference between phase segregated & summation type differential protection

In the full, phase-segregated design three, one-phase REB670 IEDs (that is, one per phase) are used. However for the summation type only single, one-phase REB670 IED plus one auxiliary summation CT per each main CT is required. These auxiliary summation CTs convert each main CT three-phase currents to a single-phase output current, which are all measured by one REB670 IED. The differential calculation is then made on a single-phase basis. By doing so, this more cost effective bus differential protection can be applied. Due to this characteristic, this summation type of bus differential protection can be applied for all types of stations arrangements as shown section "Different busbar arrangements", for three, one-phase IEDs.

As an example, the necessary equipment for the summation type, busbar differential protection for a single busbar station with up to 24 bays, is shown in figure 72.
Figure 72: Principle CT connections for the complete station

This summation type bus differential protection still has the same main CT requirements as outlined in section "Rated equivalent secondary e.m.f. requirements". Some of these are:

- main CT ratio differences can be tolerated up to 10:1 (for example, 3000/5A CT can be balanced against CT"s as low as 300/5)
- different main CT ratios are compensated numerically by a parameter setting
- main CT shall not saturate quicker than 2 ms (refer to section "Rated equivalent secondary e.m.f. requirements" for detailed CT requirements regarding main CT knee-point voltage)

However, due to the summation principle this type of busbar protection scheme has the following limitations:
• Only one measuring circuit is utilized for all fault types (that is, no redundancy for multi-phase faults)
• Primary fault sensitivity varies depending on the type of fault and involved phase(s), see table 19
• The load currents in the healthy phases might produce the stabilizing current when an internal, single phase to ground fault occurs. However, there is no problem for solidly earthed systems with high earth-fault currents
• No indication of faulty phase(s) in case of an internal fault
• Not possible to fully utilize Open CT detection feature

6.1.5.2 Auxiliary summation CTs

Auxiliary Summation Current Transformer (that is, ASCT in further text) of the type SLCE 8 is used with the summation principle of the IED. The principle drawing of one such ASCT is shown in figure 73.

![Auxiliary Summation CT type SLCE 8; X/1A](en03000118.vsd)

**Figure 73: Principle ASCT drawing**

The ASCT has three primary windings and one secondary winding. In further text, turn numbers of these windings will be marked with N1, N2, N3 & N4, respectively (see figure 73 for more information).

There are three types of ASCT for REB670:

1. ASCT type with ratio 1/1A, for balanced 3-Ph current input, shall be used with all main current transformers with 1A rated secondary current (that is, 2000/1A)
2. ASCT type with ratio 5/1A, for balanced 3-Ph current input, shall be used with all main current transformers with 5A rated secondary current (that is, 3000/5A)
3. ASCT type with ratio 2/1A, for balanced 3-Ph current input, shall be used with all main current transformers with 2A rated secondary current (that is, 1000/2A)
Note the following:

- main CT rated primary current is not important for ASCT selection
- possible main CT ratio differences will be compensated by a parameter setting in the IED
- rated secondary current of ASCT is 1A for all types. That means that secondary ASCT winding should be always connected to the IED with 1A CT inputs, irrespective of the rated secondary current of the main CT

All of these features simplify the ordering of the ASCTs. Practically, in order to purchase ASCTs, the only required information is the main CT rated secondary current that is, (1A, 2A or 5A).

Table 18 summarizes the ASCT data:

<table>
<thead>
<tr>
<th>Type of fault</th>
<th>N1</th>
<th>N2</th>
<th>N3</th>
<th>N4</th>
<th>Ukp [V]</th>
<th>Burden [VA]</th>
</tr>
</thead>
<tbody>
<tr>
<td>ASCT SLCE 8; 1/1A</td>
<td>52</td>
<td>52</td>
<td>104</td>
<td>90</td>
<td>33</td>
<td>1.0</td>
</tr>
<tr>
<td>ASCT SLCE 8; 5/1A</td>
<td>12</td>
<td>12</td>
<td>24</td>
<td>104</td>
<td>38</td>
<td>1.0</td>
</tr>
<tr>
<td>ASCT SLCE 8; 2/1A</td>
<td>26</td>
<td>26</td>
<td>52</td>
<td>90</td>
<td>33</td>
<td>1.0</td>
</tr>
</tbody>
</table>

where:

- N1, N2, N3 & N4 are ASCT windings turn numbers (see figure 73)
- Ukp is knee point voltage, at 1.6T, of the secondary winding with N4 turns
- Burden is the total 3Ph load of ASCT imposed to the main CT

Due to ASCT design, the ASCTs for summated bus differential protection, must always be mounted as close as possible to the IED (that is, in the same protection cubicle).

**6.1.5.3 Possible ASCT connections for REB670**

It is possible to connect the ASCTs for summated bus differential protection with REB670:

- at the end of the main CT circuit (for example, beyond the other protective relays, as shown in figure 74)
- in series with other secondary equipment when some other relay must be located at the end of the main CT circuit, as shown in figure 75
End connection is the preferred arrangement as it gives greater sensitivity for summation type bus differential protection (as shown in table 19 for more information).

However, it should be noted that these two connection types must not be mixed. This means that within one busbar installation all auxiliary summation CTs have to be either end-connected or series-connected.

Typical end-connection with ASCT is shown in figure 74.

![End-connection diagram](image)

**Figure 74:** End-connection with ASCT connected to CT3 input

It is important to notice that even in the case of 5A or 2A main CTs, secondary current of the summation CTs shall be connected to the IED with 1A CT inputs (as shown in figure 74). The reason for this is that the rated secondary current of ASCT is always 1A irrespective of the rated secondary current of the main CT.

Refer to section "SLCE 8/ASCT characteristics for end-connection" for detailed ASCT current calculations for end-connection.

Typical series-connection with ASCT is shown in figure 75.
6.1.5.4 Main CT ratio mismatch correction

As stated before, three types of ASCTs for REB670 are available. The first type shall be used for main CTs with 1A rated secondary current. The second type shall be used for main CTs with 5A rated secondary current. The third type shall be used with 2A main CTs. However, REB670 with 1A CT inputs is always used. Therefore main CT ratio shall always be set in such a way that the primary current is entered as for the main CT, but secondary current is always entered as 1A (that is, 3000/5 main CT will be entered as 3000/1 CT in REB670).

6.1.5.5 Primary pick-up levels for summation type differential protection

The minimal differential operating current level is entered directly in primary amperes. However, as stated previously, in case of the summated differential protection the primary fault sensitivity varies depending on the type of fault and involved phase(s). The entered value, for the minimal differential operating current level, will exactly correspond to the REB670 start value in the event of a 3-phase internal fault. For all other fault types this value must be multiplied by a coefficient shown in the table 19 in order to calculate the actual primary start value.
Table 19: Start coefficients for Summated Differential Protection

<table>
<thead>
<tr>
<th>Type of fault</th>
<th>L1-Gnd</th>
<th>L2-Gnd</th>
<th>L3-Gnd</th>
<th>L1-L2</th>
<th>L2-L3</th>
<th>L3-L1</th>
<th>L1L2L3</th>
</tr>
</thead>
<tbody>
<tr>
<td>ASCT end connected</td>
<td>0.434</td>
<td>0.578</td>
<td>0.867</td>
<td>1.732</td>
<td>1.732</td>
<td>0.867</td>
<td>1.0</td>
</tr>
<tr>
<td>ASCT series connected</td>
<td>1.732</td>
<td>0.867</td>
<td>0.578</td>
<td>1.732</td>
<td>1.732</td>
<td>0.867</td>
<td>1.0</td>
</tr>
</tbody>
</table>

The coefficients in table 19 are only relevant for ideal internal faults (that is, load currents do not exist in the healthy phases).

Example 1:

The minimal differential operating current level in the IED is set to 1250A. All ASCTs are series connected. What is the theoretical primary start value in case of L3-Gnd fault?

Answer 1:

According to table 19, pickup coefficient for this type of ASCT connection and this type of fault is 0.578. Therefore:

\[ I_{\text{pickup}}(L3 - \text{Gnd}) = 0.578 \times 1250 = 722.5A \]  
(Equation 14)

\[ I_{\text{pickup}}(C - \text{Gnd}) = 0.578 \times 1250 = 722.5A \]  
(Equation 14)

This means that if 722.5 primary amperes is injected only in phase L3 of any of the connected main CTs, the IED shall display the differential current of 1250A (primary) and should be on the point of the start (that is, trip).

In addition to busbar protection differential zones, the IED can incorporate other additional functions and features. If and how they can be used together with summation busbar protection design is shown in table 20:
Table 20: Functions

<table>
<thead>
<tr>
<th>Functions</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Busbar Differential Protection</td>
<td>Differential Protection, Sensitive differential protection, OCT algorithm, Check Zone and Differential Supervision features will be connected to the summed bay currents. Therefore, they will have different start level depending on the type of fault and involved phase(s). For more information, refer to table 19. However, if all these limitations are acceptable it is still possible to use all these internal busbar protection features. Note that OCT operating logic will not work properly in case of opening or shorting the main CT secondary leads (that is, in-between main CT and ASCT). In case of opening or shorting the ASCT secondary leads (that is, in-between ASCT and the IED) the OCT logic will operate correctly.</td>
</tr>
<tr>
<td>Dynamic Zone Selection feature</td>
<td>Zone Selection feature in the IED can be used in the exactly same way as with phase segregated design. All built-in features, even including breaker failure protection, protection back-up trip command routing, EnFP logic can be used in the exactly same way as for phase segregated design.</td>
</tr>
<tr>
<td>CCRBRF/CCSRBRF function</td>
<td>Breaker Fail Protection function will be connected to the summed bay current. Therefore it will have different start level depending on the type of fault and involved phase(s). See table 19 for more info. It will not be possible to have individual starting per phase, but only three-phase starting can be effectively used. However, if all these limitations are acceptable it is still possible to use internal CCRBRF/CCSRBRF functions.</td>
</tr>
<tr>
<td>OC4PTOC/PHS4PTOC function</td>
<td>Overcurrent Protection function will be connected to the summed bay current. Therefore, it will have different start level depending on the type of fault and involved phase(s). See table 19 for more info. Thus it will be very difficult to insure proper start and time grading with downstream overcurrent protection relays. Hence it will be quite difficult to use OC4PTOC/PHS4PTOC as backup feeder protection with summation design.</td>
</tr>
<tr>
<td>OC4PTOC/PHS4PTOC function</td>
<td>End Fault Protection feature will be connected to the summed bay current. Therefore it will have different start level depending on the type of fault and involved phase(s). See table 19 for more info. However, OC4PTOC/PHS4PTOC do not need any start or time coordination with any other overcurrent protection. Thus if above limitations are acceptable OC4PTOC/PHS4PTOC can be used with summation design.</td>
</tr>
<tr>
<td>DRPRDRE function</td>
<td>Disturbance Recording feature will be connected to the individual summed bay current. Therefore recorded currents will not correspond to any actual primary currents. However such DRPRDRE records can still be used to evaluate internal busbar protection, CCRBRF/CCSRBRF and OC4PTOC/PHS4PTOC protections operation.</td>
</tr>
<tr>
<td>DRPRDRE function</td>
<td>Event List feature in the IED can be used in the exactly the same way as with phase segregated design.</td>
</tr>
</tbody>
</table>

Table continues on next page
### Functions and Comment

<table>
<thead>
<tr>
<th>Functions</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>DRPRDRE function</td>
<td>Trip Value Recording feature will be connected to the individual summated bay current. Therefore recorded trip current values will not correspond to any actual primary currents. However such records can still be used to evaluate internal busbar protection, CCRBREF/CCSRBREF and OC4PTOC/PHS4PTOC protections operation.</td>
</tr>
<tr>
<td>Communication</td>
<td>All communication features in the IED can be used in the exactly the same way as with phase segregated design</td>
</tr>
<tr>
<td>SMBRREC function</td>
<td>Autoreclosing function in the IED can be used in the exactly same way as with phase segregated design.</td>
</tr>
</tbody>
</table>

### 6.1.5.6 SLCE 8/ASCT characteristics for end-connection

Typical ASCT end-connection is shown in figure 74. For this ASCT connection type, the ampere-turn balance equation has the form according to equation 15:

\[
N_4 \cdot I_{\text{SUMM}} = N_1 \cdot I_{L1} + N_2 \cdot (I_{L1} + I_{L2}) + N_3 \cdot (I_{L1} + I_{L2} + I_{L3})
\]

(Equation 15)

The relationships between number of turns for this SLCE 8, ASCT for REB670, is shown in equation 16, equation 17 and equation 18:

\[
N_1 = N_2 = N;
\]

(Equation 16)

\[
N_3 = 2 \cdot N
\]

(Equation 17)

\[
N_4 = k \cdot \sqrt{3} \cdot N
\]

(Equation 18)

where:

- \( k \) is a constant, which depends on the type of ASCT
  (that is, \( k=1 \) for 1/1A ASCT or \( k=5 \) for 5/1A ASCT or \( k=2 \) for 2/1A ASCT)

The well-known relationship, between positive, negative and zero sequence current components and individual phase current quantities is shown in equation 19:
\[
\begin{bmatrix}
I_{L1} \\
I_{L2} \\
I_{L3}
\end{bmatrix} =
\begin{bmatrix}
1 & 1 & 1 \\
a^2 & a & 1 \\
a & a^2 & 1
\end{bmatrix}
\begin{bmatrix}
l_1 \\
l_2 \\
l_0
\end{bmatrix}
\]
(Equation 19)

where:
\(a\) is complex constant (that is, \(a=-0.5+j0.866\)).

By including equation 16, equation 17, equation 18 and equation 19 into the equation 15 the equation for the end-connected, ASCT secondary current (that is, summated current) can be derived according to equation 20:

\[
I_{SUMM} = \frac{1}{k} \cdot (l_1 \cdot e^{-j30^\circ} + l_2 \cdot e^{j30^\circ} + 3 \cdot \sqrt{3} \cdot l_0)
\]
(Equation 20)

From equation 20 it is obvious that the ASCT rated ratio is declared for balanced three phase current system, when only positive sequence current component exist. For any unbalanced condition (that is, external or internal fault), both negative and zero sequence current components will give their own contribution to the summated current.

### 6.1.5.7 SLCE 8/ASCT characteristics for series-connection

Typical ASCT series-connection is shown in figure 75. For this ASCT connection type, the ampere-turn balance equation has the form according to equation 21:

\[
N_4 \cdot I_{SUMM} = N_1 \cdot I_{L1} - N_2 \cdot I_{L3} - N_3 \cdot (I_{L1} + I_{L2} + I_{L3})
\]
(Equation 21)

The relationships between the number of turns for this SLCE 8 ASCT for REB670, is shown in equation 22, equation 23, equation 24:

\[
N_1 = N_2 = N;
\]
(Equation 22)

\[
N_3 = 2 \cdot N
\]
(Equation 23)
\[ N4 = k \cdot \sqrt{3} \cdot N \]

(Equation 24)

where:

\( k \) is a constant, which depends on the type of ASCT

(that is, \( k=1 \) for 1/1A ASCT or \( k=5 \) for 5/1A ASCT or \( k=2 \) for 2/1A ASCT).

The well-known relationship, between positive, negative and zero sequence current components and individual phase current quantities is shown in equation 25:

\[
\begin{bmatrix}
I_L1 \\
I_L2 \\
I_L3
\end{bmatrix} = \begin{bmatrix}
1 & 1 & 1 \\
\text{a}^2 & \text{a} & 1 \\
\text{a} & \text{a}^2 & 1
\end{bmatrix} \begin{bmatrix}
I_1 \\
I_2 \\
I_0
\end{bmatrix}
\]

(Equation 25)

where:

\( \text{a} \) is complex constant (that is, \( \text{a}=-0.5+j0.866 \)).

By including equation 22, equation 23, equation 24 and equation 25 into the equation 21 the equation for the series-connected, ASCT secondary current (that is, summated current) can be derived according to equation 26:

\[ I_{\text{SUMM}} = \frac{1}{k} \cdot (I_1 \cdot e^{30^\circ} + I_2 \cdot e^{30^\circ} + 2 \cdot \sqrt{3} \cdot I_0) \]

(Equation 26)

From equation 26 it is obvious that the ASCT rated ratio is declared for balanced three phase current system, when only positive sequence current component exist. For any unbalanced condition (that is, external or internal fault), both negative and zero sequence current components will give their own contribution to the summated current.
Section 7  
Current protection

7.1  
Four step phase overcurrent protection 3-phase output OC4PTOC

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>Four step phase overcurrent protection 3-phase output</td>
<td>OC4PTOC</td>
<td></td>
<td>51/67</td>
</tr>
</tbody>
</table>

7.1.2  
Application

The Four step phase overcurrent protection 3-phase output OC4PTOC is used in several applications in the power system. Some applications are:

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

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

In many applications several steps with different current pick up levels and time delays are needed. OC4PTOC can have up to four different, individual settable, steps. The flexibility of each step of OC4PTOC is great. The following options are possible:

Non-directional / Directional function: In most applications the non-directional functionality is used. This is mostly the case when no fault current can be fed from the protected object itself. In order to achieve both selectivity and fast fault clearance, the directional function can be necessary.
Choice of delay time characteristics: There are several types of delay time characteristics available such as definite time delay and different types of inverse time delay characteristics. The selectivity between different overcurrent protections is normally enabled by co-ordination between the function time delays of the different protections. To enable optimal co-ordination between all overcurrent protections, they should have the same time delay characteristic. Therefore a wide range of standardized inverse time characteristics are available: IEC and ANSI. It is also possible to tailor make the inverse time characteristic.

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

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

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

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

7.1.3 Setting guidelines

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

In version 2.0, a typical starting time delay of 24ms is subtracted from the set trip time delay, so that the resulting trip time will take the internal IED start time into consideration.
The parameters for Four step phase overcurrent protection 3-phase output OC4PTOC are set via the local HMI or PCM600.

The following settings can be done for OC4PTOC.

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 Off or On

AngleRCA: Protection characteristic angle set in degrees. If the angle of the fault loop current has the angle RCA the direction to fault is forward.

AngleROA: Angle value, given in degrees, to define the angle sector of the directional function, see figure 76.

IminOpPhSel: Minimum current for phase selection set in % of IBase. This setting should be less than the lowest step setting. Default setting is 7%.

StartPhSel: Number of phases, with high current, required for operation. The setting possibilities are: Not used, 1 out of 3, 2 out of 3 and 3 out of 3. Default setting is 1 out of 3.

2ndHarmStab: Operate level of 2nd harmonic current restrain set in % of the fundamental current. The setting range is 5 - 100% in steps of 1%. Default setting is 20%.
7.1.3.1 Settings for each step

- DirModex: The directional mode of step x. Possible settings are Off/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 21.
Table 21: 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>

The different characteristics are described in Technical reference manual.

I1>MinEd2Set: Minimum settable operating phase current level for step 1 in % of IBase, for 61850 Ed.2 settings

I1>MaxEd2Set: Maximum settable operating phase current level for step 1 in % of IBase, for 61850 Ed.2 settings

I2>MinEd2Set: Minimum settable operating phase current level for step 2 in % of IBase, for 61850 Ed.2 settings

I2>MaxEd2Set: Maximum settable operating phase current level for step 2 in % of IBase, for 61850 Ed.2 settings

I3>MinEd2Set: Minimum settable operating phase current level for step 3 in % of IBase, for 61850 Ed.2 settings

I3>MaxEd2Set: Maximum settable operating phase current level for step 3 in % of IBase, for 61850 Ed.2 settings

I4>MinEd2Set: Minimum settable operating phase current level for step 4 in % of IBase, for 61850 Ed.2 settings

I4>MaxEd2Set: Maximum settable operating phase current level for step 4 in % of IBase, for 61850 Ed.2 settings
$I_x^\triangleright$: Operate phase current level for step $x$ given in % of $I_{Base}$.

$tx$: Definite time delay for step $x$. The definite time $tx$ is added to the inverse time when inverse time characteristic is selected.

$kx$: Time multiplier for inverse time delay for step $x$.

$IMin_x$: Minimum operate current for step $x$ in % of $I_{Base}$. Set $IMin_x$ below $I_x^\triangleright$ for every step to achieve ANSI reset characteristic according to standard. If $IMin_x$ is set above $I_x^\triangleright$ for any step the ANSI reset works as if current is zero when current drops below $IMin_x$.

$IMxMult$: Multiplier for scaling of the current setting value. If a binary input signal (enableMultiplier) is activated the current operation level is increase by this setting constant. Setting range: 1.0-10.0

$txMin$: Minimum operate time for all inverse time characteristics. At high currents the inverse time characteristic might give a very short operation time. By setting this parameter the operation time of the step can never be shorter than the setting. Setting range: 0.000 - 60.000s in steps of 0.001s.

**Figure 77:** Minimum operate current and operation time for inverse time characteristics

In order to fully comply with curves definition setting parameter $txMin$ shall be set to the value, which is equal to the operating time of the selected inverse curve for measured current of twenty times the set current pickup value. Note that the operating time value is dependent on the selected setting value for time multiplier $kx$.

$ResetTypeCrv_x$: The reset of the delay timer can be made in different ways. By choosing setting the possibilities are according to table 22.
Table 22: Reset possibilities

<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 the technical reference manual. There are some restrictions regarding the choice of reset delay.

For the definite time delay characteristics the possible delay time settings are 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.

HarmRestrainx: Enable block of step x from the harmonic restrain function (2nd harmonic). This function should be used when there is a risk if power transformer inrush currents might cause unwanted trip. Can be set Off/On.

tPCrvx, tACrvx, tBCrvx, tCCrvx: Parameters for customer creation of inverse time characteristic curve (Curve type = 17). See equation 27 for the time characteristic equation.

\[
t[s] = \left( \frac{A}{\left( \frac{i}{in>} \right)^r} + B \right) \cdot IxMult
\]

(Equation 27)

For more information, refer to the technical reference manual.

tPRCrvx, tTRCrvx, tCRCrvx: Parameters for customer creation of inverse reset time characteristic curve (Reset Curve type = 3). Further description can be found in the technical reference manual.
7.2 Four step single phase overcurrent protection
PH4SPTOC

7.2.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 80617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Four step single phase overcurrent protection</td>
<td>PH4SPTOC</td>
<td></td>
<td>51</td>
</tr>
</tbody>
</table>

7.2.2 Application

The Four step single phase overcurrent protection (PH4SPTOC) function is used in several applications in the power system. Some applications are:

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

The single phase overcurrent protection is used in IEDs having only input from one phase, for example busbar protection for large busbars (with many bays).

In many applications several steps with different current pick up levels and time delays are needed. PH4SPTOC can have up to four different, individual settable, steps. The flexibility of each step of PH4SPTOC function is great. The following options are possible:

Choice of delay time 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 all overcurrent IEDs, to be co-ordinated against each other, should have the same time delay characteristic. Therefore a wide range of standardised inverse time characteristics are available: IEC and ANSI. It is also possible to programme a user defined inverse time characteristic.

Normally it is required that the phase overcurrent function shall reset as fast as possible when the current level gets lower than the operation level. In some cases
some sort of time delayed reset is required. Therefore three different kinds of reset
time 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 then 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 second harmonic
content. This can be used to avoid unwanted operation of the protection. Therefore the
Four step phase overcurrent protection (OC4PTOC) function have a possibility of
second harmonic restrain if the level of this harmonic current reaches a value above a
set percentage of the fundamental current.

7.2.3 Setting guidelines

In version 2.0, a typical starting time delay of 24ms is subtracted from
the set trip time delay, so that the resulting trip time will take the
internal IED start time into consideration.

The parameters for the four step phase overcurrent protection function (OC) are set via
the local HMI or Protection and Control IED Manager (PCM 600).

The following settings can be done for the four step phase overcurrent protection.

Operation: Off/On

IBase: Base current in primary A. This current is used as reference for current setting.
It can be suitable to set this parameter to the rated primary current of the protected
object.

2ndHarmStab: Operate level of 2nd harmonic current restrain set in % of the
fundamental current. The setting range is 5-100% of IBase in steps of 1%. Default
setting is 20%.

HarmRestrainx: Disabled/Enabled, enables blocking from harmonic restrain.

7.2.3.1 Settings for each step (x = 1-4)

Characteristx: Selection of time delay characteristic for step x. Definite time delay
and different types of inverse time delay characteristics are available according to
table 23.
Table 23: Inverse time delay 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>
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</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>

The different characteristics are described in the “Technical reference manual”.

Ix>: Operation phase current level for step x given in % of IBase.

tx: Definite time delay for step x. Used if definite time characteristic is chosen. Setting range: 0.000-60.000 s in step of 0.001 s. Note that the value set is the time between activation of the start and the trip outputs.

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

InxMult: Multiplier for scaling of the current setting value. If a binary input signal (enableMultiplier) is activated the current operation level is increase by this setting constant. Setting range: 1.0-10.0

txMin: Minimum operation time for IEC 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: 0.000-60.000 s in step of 0.001 s.

ResetTypeCrvx: The reset of the delay timer can be made in different ways. By choosing setting the possibilities are according to table 24.
Table 24: Reset possibilities

<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 the “Technical reference manual”. 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 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 then settings pr, tr and cr must be given.

\[ t[s] = \left( \frac{A}{(i)^p} + B \right) \cdot IxMult \]

(Equation 28)

For more information, please refer to the “Technical reference manual”.

tPRCrvx, tTRCrvx, tCRCr vx: Parameters for customer creation of inverse reset time characteristic curve (Reset Curve type = 3). Further description can be found in the “Technical reference manual”.

HarmRestrainx: Enable block of step x from the harmonic restrain function (2nd harmonic). This function should be used when there is a risk if power transformer inrush currents might cause unwanted trip. Can be set Off/On.

tPCrvx, tACrvx, tBCrvx, tCCrvx: Parameters for customer creation of inverse time characteristic curve (Curve type = 17). See equation 28 for the time characteristic equation.
7.2.3.2 Second harmonic restrain

If a power transformer is energized there is a risk that the transformer core will saturate during part of the period, resulting in an inrush transformer current. This will give a declining residual current in the network, as the inrush current is deviating between the phases. There is a risk that the phase 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.

The settings for the 2nd harmonic restrain are described below.

2ndHarmStab: The rate of second harmonic current content for activation of the 2nd harmonic restrain signal, to block chosen steps. The setting is given in % of the fundamental frequency residual current. The setting range is 5-100% in step of 1%. The default setting is 20%.

HarmRestrainX: This parameter can be set Off/On, disable or enable the 2nd harmonic restrain.

The four-step phase overcurrent protection can be used in different ways, depending on the application where the protection is used. A general description is given below.

The pick up current setting inverse time protection or the lowest current step constant inverse time protection must be given a current setting so that the highest possible load current does not cause protection operation. Here consideration also has to be taken to the protection reset current, so that a short peak of overcurrent does not cause operation of the protection even when the overcurrent has ceased. This phenomenon is described in figure 78.
Figure 78: Pick up and reset current for an overcurrent protection

The lowest setting value can be written according to equation 29.

\[ I_{pu} \geq 1.2 \cdot \frac{I_{\text{max}}}{k} \]  

(Equation 29)

where:

1.2 is a safety factor,
\( k \) is the resetting ratio of the protection, and
\( I_{\text{max}} \) is the maximum load current.

The maximum load current on the line has to be estimated. From operation statistics the load current up to the present situation can be found. The current setting must be valid also for some years ahead. It is, in most cases, realistic that the setting values are updated not more often than once every five years. In many cases this time interval is still longer. Investigate the maximum load current that different 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.
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 $I_{\text{sc min}}$ to be detected by the protection, must be calculated. Taking this value as a base, the highest pick up current setting can be written according to equation 30.

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

(Equation 30)

where:
- $0.7$ is a safety factor and
- $I_{sc \text{ min}}$ is the smallest fault current to be detected by the overcurrent protection.

As a summary the pick up current shall be chosen within the interval stated in equation 31.

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

(Equation 31)

The high current function of the overcurrent protection, which only has a short delay of the operation, must be given a current setting so that the protection is selective to other protection in the power system. It is desirable to have a rapid tripping of faults within as large portion as possible of the part of the power system to be protected by the protection (primary protected zone). A fault current calculation gives the largest current of faults, $I_{sc \text{ max}}$, at the most remote part of the primary protected zone. Considerations have to be made to the risk of transient overreach, due to a possible DC component of the fault current. The lowest current setting of the most rapid stage, of the phase overcurrent protection, can be written according to

$$I_{\text{high}} \geq 1.2 \cdot k_t \cdot I_{sc \text{ max}}$$

(Equation 32)

where:
- $1.2$ is a safety factor,
- $k_t$ is a factor that takes care of the transient overreach due to the DC component of the fault current and can be considered to be less than 1.1
- $I_{sc \text{ max}}$ is the largest fault current at a fault at the most remote point of the primary protection zone.

The operate times of the phase overcurrent protection has to be chosen so that the fault time is so short so that equipment will not be destroyed due to thermal overload, at the same time as selectivity is assured. For overcurrent protection, in a radial fed network, the time setting can be chosen in a graphical way. This is mostly used in the case of inverse time overcurrent protection. In the figure below is shown how the time-versus-
current curves are plotted in a diagram. The time setting is chosen to get the shortest fault time with maintained selectivity. Selectivity is assured if the time difference between the curves is larger than a critical time difference.

Figure 79: Fault time with maintained selectivity

The operation time can be set individually for each overcurrent protection. To assure selectivity between different protective protections, in the radial network, there have to be a minimum time difference $\Delta t$ between the time delays of two protections. The minimum time difference can be determined for different cases. To determine the shortest possible time difference between we must have knowledge about operation time of protections, breaker opening time and protection resetting time. These time delays can vary significantly between different pieces of equipment. The following time delays can be estimated:

- protection operation time: 15-60 ms
- protection resetting time: 15-60 ms
- Breaker opening time: 20-120 ms

Example

Assume two substations A and B directly connected to each other via one line, as shown in the figure below. We study a fault located at another line from the station B.
The fault current to the overcurrent protection of IED B1 has a magnitude so that the protection will have instantaneous function. The overcurrent protection of IED A1 must have a delayed function. The sequence of events during the fault can be described using a time axis, see figure 80.

![Diagram of sequence of events during fault](en05000205.vsd)

**Figure 80: Sequence of events during fault**

where:
- \( t=0 \) is the fault occurs,
- \( t=t_1 \) is the trip signal from the overcurrent protection at IED B1 is sent. Operation time of this protection is \( t_1 \),
- \( t=t_2 \) is the circuit breaker at IED B1 opens. The circuit breaker opening time is \( t_2 - t_1 \),
- \( t=t_3 \) is the overcurrent protection at IED A1 resets. The protection resetting time is \( t_3 - t_2 \).

To ensure that the overcurrent protection at IED A1, is selective to the overcurrent protection at IED B1, the minimum time difference must be larger that the time \( t_3 \). There are uncertainties in the values of protection operation time, breaker opening time and protection resetting time. Therefor a safety margin has to be included. With normal values the needed time difference can be calculated according to equation 33.

\[
\Delta t \geq 40\, ms + 100\, ms + 40\, ms + 40\, ms = 220\, ms
\]

(Equation 33)

where it is considered that:
- the operation time of overcurrent protection B1 is 40 ms
- the breaker open time is 100 ms
- the resetting time of protection A1 is 40 ms and
- the additional margin is 40 ms
7.3 Four step residual overcurrent protection, (Zero sequence or negative sequence directionality) EF4PTOC

### 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>Four step residual overcurrent protection</td>
<td>EF4PTOC</td>
<td></td>
<td>51N/67N</td>
</tr>
</tbody>
</table>

### 7.3.2 Setting guidelines

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

In version 2.0, a typical starting time delay of 24ms is subtracted from the set trip time delay, so that the resulting trip time will take the internal IED start time into consideration.

The parameters for the four step residual overcurrent protection, zero or negative sequence direction EF4PTOC are set via the local HMI or PCM600.

The following settings can be done for the four step residual overcurrent protection.

*Operation:* Sets the protection to *On* or *Off*.

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

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

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

Inverse time characteristic enables fast fault clearance of high current faults at the same time as selectivity to other inverse time phase overcurrent protections can be
assured. This is mainly used in radial fed networks but can also be used in meshed networks. In meshed networks the settings must be based on network fault calculations.

To assure selectivity between different protections, in the radial network, there have to be a minimum time difference $\Delta t$ between the time delays of two protections. The minimum time difference can be determined for different cases. To determine the shortest possible time difference, the operation time of protections, breaker opening time and protection resetting time must be known. These time delays can vary significantly between different protective equipment. The following time delays can be estimated:

- Protection operate time: 15-60 ms
- Protection resetting time: 15-60 ms
- Breaker opening time: 20-120 ms

The different characteristics are described in the technical reference manual.

$INx>$: Operate residual current level for step $x$ given in % of $IBase$.

$kx$: Time multiplier for the dependent (inverse) characteristic for step $x$.

$IMinx$: Minimum operate current for step $x$ in % of $IBase$. Set $IMinx$ below $Ix>$ for every step to achieve ANSI reset characteristic according to standard. If $IMinx$ is set above $Ix>$ for any step then signal will reset at current equals to zero.

$INxMult$: Multiplier for scaling of the current setting value. If a binary input signal (ENMULTx) is activated the current operation level is increased by this setting constant.

$txMin$: Minimum operating time for inverse time characteristics. At high currents the inverse time characteristic might give a very short operation time. By setting this parameter the operation time of the step can never be shorter than the setting.
Figure 81: Minimum operate current and operate time for inverse time characteristics

In order to fully comply with curves definition the setting parameter \( t_{x\text{Min}} \) 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 \( k_x \).

ResetType\( Crv_x \): The reset of the delay timer can be made in different ways. The possibilities are described in the technical reference manual.

t\( PCrv_x \), t\( ACrv_x \), t\( BCrv_x \), t\( CCrv_x \): Parameters for user programmable of inverse time characteristic curve. The time characteristic equation is according to equation 34:

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

(Equation 34)

Further description can be found in the technical reference manual.

t\( PRCrv_x \), t\( TRCrv_x \), t\( CRCrv_x \): Parameters for user programmable of inverse reset time characteristic curve. Further description can be found in the technical reference manual.

### 7.3.2.2 Common settings for all steps

\( tx \): Definite time delay for step \( x \). Used if definite time characteristic is chosen.
AngleRCA: Relay characteristic angle given in degree. This angle is defined as shown in figure 82. The angle is defined positive when the residual current lags the reference voltage ($U_{pol} = 3U_0$ or $U_2$)

$$U_{pol} = 3U_0 \text{ or } U_2$$

\[I>\text{Dir}\]

**Operation**

![Relay characteristic angle diagram](en 05000135-nsi.vsd)

**Figure 82:** 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 ($3U_0$ or $U_2$)
- Current ($3I_0 \cdot ZNpol$ or $3I_2 \cdot ZNpol$ where $ZNpol$ is $RNpol + jXNpol$), or
- both currents and voltage, Dual (dual polarizing, $3U_0 + 3I_0 \cdot ZNpol$) or ($U_2 + I_2 \cdot ZNpol$)).

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 ($3U_0$) 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-earth voltage is definitely higher than 1% (minimum $3U_0>UPolMin$ 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 \((Z_{S1} - Z_{S0})/3\), that is the earth return impedance of the source behind the protection. The maximum earth-fault current at the local source can be used to calculate the value of \(Z_N\) as \(U/(\sqrt{3} \cdot 3I_0)\). Typically, the minimum \(Z_{NPOL}\) (3 · zero sequence source) is set. Setting is in primary ohms.

When the dual polarizing method is used, it is important that the setting \(I_{NPOL} > I_0\) or the product \(3I_0 \cdot Z_{NPOL}\) is not greater than \(3U_0\). If so, there is a risk for incorrect operation for faults in the reverse direction.

\(IPolMin\): is the minimum earth-fault current accepted for directional evaluation. For smaller currents than this value, the operation will be blocked. Typical setting is 5-10% of \(IBase\).

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

\(I_{>Dir}\): Operate residual current release level in % of \(IBase\) for directional comparison scheme. The setting is given in % of \(IBase\) and must be set below the lowest \(I_{NPOL}\) setting for the directional measurement. The output signals, STFW and STRV, can be used in a teleprotection scheme. The appropriate signal should be configured to the communication scheme block.

### 7.2.3 2nd harmonic restrain

If a power transformer is energized, there is a risk that the current transformer core will saturate during part of the period, resulting in 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. Also here the 2nd harmonic restrain can prevent unwanted operation.

\(2ndHarmStab\): The rate of 2nd harmonic current content for activation of the 2nd harmonic restrain signal. The setting is given in % of the fundamental frequency residual current.

\(HarmRestrainx\): Enable block of step \(x\) from the harmonic restrain function.

### 7.2.4 Parallel transformer inrush current logic

In case of parallel transformers there is a risk of sympathetic inrush current. If one of the transformers is in operation, and the parallel transformer is switched in, the asymmetric inrush current of the switched in transformer will cause partial saturation of the transformer already in service. This is called transferred saturation. The 2nd harmonic of the inrush currents of the two transformers will be in phase opposition. The summation of the two currents will thus give a small 2nd harmonic current. The
residual fundamental current will however be significant. The inrush current of the transformer in service before the parallel transformer energizing, will be a little delayed compared to the first transformer. Therefore we will have high 2nd harmonic current initially. After a short period this current will however be small and the normal 2nd harmonic blocking will reset.

![Diagram](en05000136.vsd)

**Figure 83:** Application for parallel transformer inrush current logic

If the `BlkParTransf` function is activated the 2nd harmonic restrain signal will latch as long as the residual current measured by the relay is larger than a selected step current level. Assume that step 4 is chosen to be the most sensitive step of the four step residual overcurrent protection function EF4PTOC. The harmonic restrain blocking is enabled for this step. Also the same current setting as this step is chosen for the blocking at parallel transformer energizing.

Below the settings for the parallel transformer logic are described.

*UseStartValue:* Gives which current level that should be used for 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.

*BlkParTransf:* This parameter can be set *Off*/ *On*, the parallel transformer logic.

### 7.3.2.5 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 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 operation mode:** This parameter can be set: Off/SOTF/Under Time/SOTF + Under Time.

**Activation SOTF:** This setting will select the signal to activate SOTF function; CB position open/CB position closed/CB close command.

**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

**StepForSOTF:** If this parameter is set on the step 3 start signal will be used as current set level. If set off step 2 start signal will be used as current set level.

**t4U:** Time interval when the SOTF function is active after breaker closing. The setting range is 0.000 - 60.000 s in step of 0.001 s. The default setting is 1.000 s.

**ActUnderTime:** Describes the mode to activate the sensitive undertime function. The function can be activated by Circuit breaker position (change) or Circuit breaker command.

**tUnderTime:** Time delay for operation of the sensitive undertime function. The setting range is 0.000 - 60.000 s in step of 0.001 s. The default setting is 0.300 s

### 7.4

**Four step directional negative phase sequence overcurrent protection NS4PTOC**

#### 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>Four step negative sequence overcurrent protection</td>
<td>NS4PTOC</td>
<td></td>
<td>4612</td>
</tr>
</tbody>
</table>

#### 7.4.2 Application

Four step negative sequence overcurrent protection NS4PTOC is used in several applications in the power system. Some applications are:
• Earth-fault and phase-phase short circuit protection of feeders in effectively earthed distribution and subtransmission systems. Normally these feeders have radial structure.
• Back-up earth-fault and phase-phase short circuit protection of transmission lines.
• Sensitive earth-fault protection of transmission lines. NS4PTOC can have better sensitivity to detect resistive phase-to-earth-faults compared to distance protection.
• Back-up earth-fault and phase-phase short circuit protection of power transformers.
• Earth-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 operating levels and time delays are needed. NS4PTOC can have up to four, individual settable steps. The flexibility of each step of NS4PTOC 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 earthed 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>
<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>
</tbody>
</table>

Table 25: Inverse time characteristics

Table continues on next page
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 operating level for some time. Therefore there is a possibility to give a setting of a multiplication factor $I_x Mult$ to the negative sequence current pick-up level. This multiplication factor is activated from a binary input signal $ENMULTx$ to the function.

### Setting guidelines

The parameters for Four step negative sequence overcurrent protection NS4PTOC 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 **On** or **Off**.

Common base IED values for primary current ($I_{Base}$), primary voltage ($U_{Base}$) 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.

When inverse time overcurrent characteristic is selected, the operate time of the stage will be the sum of the inverse time delay and the set definite time delay. Thus, if only the inverse time delay is required, it is of utmost importance to set the definite time delay for that stage to zero.
In version 2.0, a typical starting time delay of 24ms is subtracted from the set trip time delay, so that the resulting trip time will take the internal IED start time into consideration.

### 7.4.3.1 Settings for each step

$x$ means step 1, 2, 3 and 4.

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

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

<table>
<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>

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

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

\(kx\): Time multiplier for the dependent (inverse) characteristic.

\(IMinx\): Minimum operate current for step x in % of \(IBase\). Set \(IMinx\) below \(Ix>\) for every step to achieve ANSI reset characteristic according to standard. If \(IMinx\) is set above \(Ix>\) for any step the ANSI reset works as if current is zero when current drops below \(IMinx\).

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

\(txMin\): 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 84: 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.

\[ t[x] = \left( \frac{A}{\left( \frac{i}{in} \right)^{\beta}} - C \right) \cdot k \]

(Equation 35)

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

For customer creation of inverse reset time characteristic curve. Further description can be found in the Technical Reference Manual.

### Common settings for all steps

\( x \) means step 1, 2, 3 and 4.

*AngleRCA*: Relay characteristic angle given in degrees. This angle is defined as shown in figure 82. The angle is defined positive when the residual current lags the reference voltage (Upol = -U2)
In a transmission network a normal value of RCA is about 80°.

$UPolMin$: Minimum polarization (reference) voltage % of $U_{Base}$.

$I_{>Dir}$: Operate residual current level for directional comparison scheme. The setting is given in % of $I_{Base}$. The start forward or start reverse signals can be used in a communication scheme. The appropriate signal must be configured to the communication scheme block.

### 7.5 Thermal overload protection, two time constants $TRPTTR$
### 7.5.1 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>Thermal overload protection, two time constants</td>
<td>TRPTTR</td>
<td></td>
<td>49</td>
</tr>
</tbody>
</table>

### 7.5.2 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-earth 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.

7.5.3 Setting guideline

The parameters for the thermal overload protection, two time constants (TRPTTR) 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: Off/On

Operation: Sets the mode of operation. Off switches off the complete function.

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

IRef: Reference level of the current given in % of IBase. When the current is equal to IRef 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.

IRefMult: If a binary input ENMULT is activated the reference current value can be multiplied by the factor IRefMult. 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. IRefMult can be set within a range: 0.01 - 10.00.

IBase1: Base current for setting given as percentage of IBase. 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).

IBase2: Base current for setting given as percentage of IBase. 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 IBase2 can be set equal to IBase1.

Tau1: The thermal time constant of the protected transformer, related to IBase1 (no cooling) given in minutes.

Tau2: The thermal time constant of the protected transformer, related to IBase2 (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 36)

If the transformer has forced cooling (FOA) the measurement should be made both with and without the forced cooling in operation, giving $\tau1$ and $\tau2$.

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.

$\tau1High$: Multiplication factor to adjust the time constant $\tau1$ if the current is higher than the set value $IHighest\tau1$. $IHighest\tau1$ is set in % of $IBase1$.

$\tau1Low$: Multiplication factor to adjust the time constant $\tau1$ if the current is lower than the set value $ILowest\tau1$. $ILowest\tau1$ is set in % of $IBase1$.

$\tau2High$: Multiplication factor to adjust the time constant $\tau2$ if the current is higher than the set value $IHighest\tau2$. $IHighest\tau2$ is set in % of $IBase2$.

$\tau2Low$: Multiplication factor to adjust the time constant $\tau2$ if the current is lower than the set value $ILowest\tau2$. $ILowest\tau2$ is set in % of $IBase2$.

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.
**ITrip:** The steady state current that the transformer can withstand. The setting is given in % of *IBase1* or *IBase2*.

**Alarm1:** Heat content level for activation of the signal ALARM1. ALARM1 is set in % of the trip heat content level.

**Alarm2:** Heat content level for activation of the output signal ALARM2. ALARM2 is set in % of the trip heat content level.

**ResLo:** 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. *ResLo* 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.

### 7.6 Breaker failure protection 3-phase activation and output CCRBRF

#### 7.6.1 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>Breaker failure protection, 3-phase activation and output</td>
<td>CCRBRF</td>
<td></td>
<td>50BF</td>
</tr>
</tbody>
</table>

#### 7.6.2 Application

In the design of the fault clearance system the N-1 criterion is often used. This means that a fault needs to be cleared even if any component in the fault clearance system is faulty. One necessary component in the fault clearance system is the circuit breaker. It is from practical and economical reason not feasible to duplicate the circuit breaker for the protected component. Instead a breaker failure protection is used.
Breaker failure protection, 3-phase activation and output (CCRBRF) will issue a back-up trip command to adjacent circuit breakers in case of failure to trip of the “normal” circuit breaker for the protected component. The detection of failure to break the current through the breaker is made by means of current measurement or as detection of remaining trip signal (unconditional).

CCRBRF can also give a re-trip. This means that a second trip signal is sent to the protected circuit breaker. The re-trip function can be used to increase the probability of operation of the breaker, or it can be used to avoid back-up trip of many breakers in case of mistakes during relay maintenance and test.

### 7.6.3 Setting guidelines

The parameters for Breaker failure protection 3-phase activation and output CCRBRF are set via the local HMI or PCM600.

The following settings can be done for the breaker failure protection.

**Operation:** Off/On

**FunctionMode** This parameter can be set Current or Contact. This states the way the detection of failure of the breaker is performed. In the mode current the current measurement is used for the detection. In the mode Contact the long duration of breaker position signal is used as indicator of failure of the breaker. The mode Current&Contact means that both ways of detections are activated. Contact mode can be usable in applications where the fault current through the circuit breaker is small. This can be the case for some generator protection application (for example reverse power protection) or in case of line ends with weak end infeed.

**RetripMode:** This setting states how the re-trip function shall operate. Retrip Off means that the re-trip function is not activated. CB Pos Check (circuit breaker position check) and Current means that a phase current must be larger than the operate level to allow re-trip. CB Pos Check (circuit breaker position check) and Contact means re-trip is done when circuit breaker is closed (breaker position is used). No CBPos Check means re-trip is done without check of breaker position.

<table>
<thead>
<tr>
<th>RetripMode</th>
<th>FunctionMode</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Retrip Off</td>
<td>N/A</td>
<td>the re-trip function is not activated</td>
</tr>
<tr>
<td>CB Pos Check</td>
<td>Current</td>
<td>a phase current must be larger than the operate level to allow re-trip</td>
</tr>
<tr>
<td></td>
<td>Contact</td>
<td>re-trip is done when breaker position indicates that breaker is still closed after re-trip time has elapsed</td>
</tr>
<tr>
<td></td>
<td>Current&amp;Contact</td>
<td>both methods are used</td>
</tr>
</tbody>
</table>

Table continues on next page
BuTripMode: Back-up trip mode is given to state sufficient current criteria to detect failure to break. For Current operation 2 out of 4 means that at least two currents, of the three-phase currents and the residual current, shall be high to indicate breaker failure. 1 out of 3 means that at least one current of the three-phase currents shall be high to indicate breaker failure. 1 out of 4 means that at least one current of the three-phase currents or the residual current shall be high to indicate breaker failure. In most applications 1 out of 3 is sufficient. For Contact operation means back-up trip is done when circuit breaker is closed (breaker position is used).

IP>: Current level for detection of breaker failure, set in % of IBase. This parameter should be set so that faults with small fault current can be detected. The setting can be chosen in accordance with the most sensitive protection function to start the breaker failure protection. Typical setting is 10% of IBase.

I>BlkCont: If any contact based detection of breaker failure is used this function can be blocked if any phase current is larger than this setting level. If the FunctionMode is set Current&Contact breaker failure for high current faults are safely detected by the current measurement function. To increase security the contact based function should be disabled for high currents. The setting can be given within the range 5 – 200% of IBase.

IN>: Residual current level for detection of breaker failure set in % of IBase. In high impedance earthed systems the residual current at phase- to-earth faults are normally much smaller than the short circuit currents. In order to detect breaker failure at single-phase-earth faults in these systems it is necessary to measure the residual current separately. Also in effectively earthed systems the setting of the earth-fault current protection can be chosen to relatively low current level. The BuTripMode is set 1 out of 4. The current setting should be chosen in accordance to the setting of the sensitive earth-fault protection. The setting can be given within the range 2 – 200 % of IBase.

t1: Time delay of the re-trip. The setting can be given within the range 0 – 60s in steps of 0.001 s. Typical setting is 0 – 50ms.

t2: Time delay of the back-up trip. The choice of this setting is made as short as possible at the same time as unwanted operation must be avoided. Typical setting is 90 – 200ms (also dependent of re-trip timer).

The minimum time delay for the re-trip can be estimated as:

\[ t_2 \geq t_1 + t_{chopen} + t_{BFP\_reset} + t_{margin} \]

(Equation 37)
where:

- $t_{\text{cbopen}}$ 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 to maintain transient stability in case of a fault close to a power plant.

**Figure 86: Time sequence**

- $t_{2\text{MPh}}$: Time delay of the back-up trip at multi-phase start. The critical fault clearance time is often shorter in case of multi-phase faults, compared to single phase-to-earth faults. Therefore there is a possibility to reduce the back-up trip delay for multi-phase faults. Typical setting is 90 – 150 ms.

- $t_3$: Additional time delay to $t_2$ for a second back-up trip TRBU2. In some applications there might be a requirement to have separated back-up trip functions, tripping different back-up circuit breakers.

- $t_{\text{CBAlarm}}$: Time delay for alarm in case of indication of faulty circuit breaker. There is a binary input CBFLT from the circuit breaker. This signal is activated when internal supervision in the circuit breaker detect that the circuit breaker is unable to clear fault. This could be the case when gas pressure is low in a SF6 circuit breaker, of others. After the set time an alarm is given, so that actions can be done to repair the
circuit breaker. The time delay for back-up trip is bypassed when the CBFLT is active. Typical setting is 2.0 seconds.

$tPulse$: Trip pulse duration. This setting must be larger than the critical impulse time of circuit breakers to be tripped from the breaker failure protection. Typical setting is 200 ms.

### 7.7 Breaker failure protection, single phase version

**CCSRBRF**

#### 7.7.1 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>Breaker failure protection, single phase version</td>
<td>CCSRBRF</td>
<td></td>
<td>50BF</td>
</tr>
</tbody>
</table>

#### 7.7.2 Application

In the design of the fault clearance system the N-1 criterion is often used. This means that a fault shall be cleared even if any component in the fault clearance system is faulty. One necessary component in the fault clearance system is the circuit breaker. It is from practical and economical reason not feasible to duplicate the circuit breaker for the protected component. Instead a breaker failure protection is used.

Breaker failure protection, single phase version (CCSRBRF) function will issue a back-up trip command to adjacent circuit breakers in case of failure to trip of the “normal” circuit breaker for the protected component. The detection of failure to break the current through the breaker is made by means of current measurement or as detection of remaining trip signal (unconditional).

CCSRBRF function can also give a re-trip. This means that a second trip signal is sent to the protected circuit breaker. The re-trip function can be used to increase the probability of operation of the breaker, or it can be used to avoid back-up trip of many breakers in case of mistakes during relay maintenance and test.

#### 7.7.3 Setting guidelines

The parameters for Breaker failure protection, single phase version (CCSRBRF) are set via the local HMI or PCM600.

The following settings can be done for the breaker failure protection.
**Operation:** Off or On

*FunctionMode:* This parameter can be set to *Current* or *Contact*. This states the way the detection of failure of the breaker is performed. In the mode *Current* the current measurement is used for the detection. In the mode *Contact* the long duration of start signal (trip) is used as indicator of failure of the breaker. The mode *Current&Contact* means that both ways of detections are activated. *Contact* mode can be usable in applications where the fault current through the circuit breaker is small. This can be the case for some generator protection application (for example, reverse power protection) or in case of line ends with weak end infed.

*RetripMode:* This setting states how the re-trip function shall operate. *Retrip Off* means that the re-trip function is not activated. *CB Pos Check* (circuit breaker position check) and *Current* means that a phase current must be larger than the operate level to allow re-trip. *CB Pos Check* (circuit breaker position check) and *Contact* means retrip is done when circuit breaker is closed (breaker position is used). *No CB Pos Check* means re-trip is done without check of breaker position.

*IP >:* Current level for detection of breaker failure, set in % of *IBase*. This parameter must be set so that faults with small fault current can be detected. The setting can be chosen in accordance with the most sensitive protection function to start the breaker failure protection. Typical setting is 10% of *IBase*.

*I>BlkCont:* If any contact based detection of breaker failure is used this function can be blocked if the current is larger than this setting level. If the *FunctionMode* is set to *Current&Contact* breaker failure for high current faults are safely detected by the current measurement function. To increase security the contact based function must be disabled for high currents. The setting can be given within the range 5 – 200% of *IBase*.

*t1:* Time delay of the re-trip. The setting can be given within the range 0 – 60 s in steps of 0.001 s. Typical setting is 0 – 50 ms.

*t2:* Time delay of the back-up trip. The choice of this setting is made as short as possible at the same time as unwanted operation must be avoided. Typical setting is 90 – 150 ms (also dependent of re-trip timer).

The minimum time delay for the re-trip can be estimated as:

\[
t2 \geq t1 + t_{chopen} + t_{BFP\_reset} + t_{margin}
\]

(Equation 38)

where:

- \( t_{chopen} \) is the maximum opening time for the circuit breaker
- \( t_{BFP\_reset} \) is the maximum time for breaker failure protection to detect correct breaker function (the current criteria reset)
- \( t_{margin} \) is a safety margin
It is often required that the total fault clearance time shall be less than a given critical time. This time is often dependent of the ability to maintain transient stability in case of a fault close to a power plant.

Figure 87: Time sequence

$t_3$: Additional time delay to $t_2$ for a second back-up trip TRBU2. In some applications there might be a requirement to have separated back-up trip functions, tripping different back-up circuit breakers.

$t_{CBA}\text{Alarm}$: Time delay for alarm in case of indication of faulty circuit breaker. There is a binary input CBFLT from the circuit breaker. This signal is activated when internal supervision in the circuit breaker detect that the circuit breaker is unable to clear fault. This could be the case when gas pressure is low in a SF6 circuit breaker, of others. After the set time an alarm is given, so that actions can be done to repair the circuit breaker. The time delay for back-up trip is bypassed when the CBFLT is active. Typical setting is 2.0 seconds.

$t_{Pulse}$: Trip pulse duration. This setting must be larger than the critical impulse time of circuit breakers to be tripped from the breaker failure protection. Typical setting is 200 ms.

7.8 Directional underpower protection GUPPDUP
7.8.1 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>Directional underpower protection</td>
<td>GUPPDUP</td>
<td></td>
<td>37</td>
</tr>
</tbody>
</table>

7.8.2 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 88 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%.
7.8.3 Setting guidelines

Operation: With the parameter Operation the function can be set On/Off.

Mode: The voltage and current used for the power measurement. The setting possibilities are shown in table 28.

Table 28: Complex power calculation

<table>
<thead>
<tr>
<th>Set value Mode</th>
<th>Formula used for complex power calculation</th>
</tr>
</thead>
<tbody>
<tr>
<td>L1, L2, L3</td>
<td>$\bar{S} = \bar{U}<em>{L1} \cdot \bar{I}</em>{L1}^* + \bar{U}<em>{L2} \cdot \bar{I}</em>{L2}^* + \bar{U}<em>{L3} \cdot \bar{I}</em>{L3}^*$</td>
</tr>
<tr>
<td></td>
<td>(Equation 40)</td>
</tr>
<tr>
<td>Arone</td>
<td>$\bar{S} = \bar{U}<em>{L1L2} \cdot \bar{I}</em>{L1}^* - \bar{U}<em>{L2L3} \cdot \bar{I}</em>{L3}^*$</td>
</tr>
<tr>
<td></td>
<td>(Equation 41)</td>
</tr>
<tr>
<td>PosSeq</td>
<td>$\bar{S} = 3 \cdot \bar{U}<em>{\text{PosSeq}} \cdot \bar{I}</em>{\text{PosSeq}}^*$</td>
</tr>
<tr>
<td></td>
<td>(Equation 42)</td>
</tr>
<tr>
<td>L1L2</td>
<td>$\bar{S} = \bar{U}<em>{L1L2} \cdot (\bar{I}</em>{L1}^* - \bar{I}_{L2}^*)$</td>
</tr>
<tr>
<td></td>
<td>(Equation 43)</td>
</tr>
<tr>
<td>L2L3</td>
<td>$\bar{S} = \bar{U}<em>{L2L3} \cdot (\bar{I}</em>{L2}^* - \bar{I}_{L3}^*)$</td>
</tr>
<tr>
<td></td>
<td>(Equation 44)</td>
</tr>
<tr>
<td>L3L1</td>
<td>$\bar{S} = \bar{U}<em>{L3L1} \cdot (\bar{I}</em>{L3}^* - \bar{I}_{L1}^*)$</td>
</tr>
<tr>
<td></td>
<td>(Equation 45)</td>
</tr>
</tbody>
</table>

Table continues on next page
The function has two stages that can be set independently.

With the parameter OpMode1(2) the function can be set On/Off.

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

---

**Table: Set value Mode and Formula used for complex power calculation**

<table>
<thead>
<tr>
<th>Set value Mode</th>
<th>Formula used for complex power calculation</th>
</tr>
</thead>
<tbody>
<tr>
<td>L1</td>
<td>$\bar{S} = 3 \cdot \bar{U}<em>{L1} \cdot \bar{I}</em>{L1}^*$</td>
</tr>
<tr>
<td>L2</td>
<td>$\bar{S} = 3 \cdot \bar{U}<em>{L2} \cdot \bar{I}</em>{L2}^*$</td>
</tr>
<tr>
<td>L3</td>
<td>$\bar{S} = 3 \cdot \bar{U}<em>{L3} \cdot \bar{I}</em>{L3}^*$</td>
</tr>
</tbody>
</table>

(Equation 46)  
(Equation 47)  
(Equation 48)

---

Figure 89: Underpower mode

The setting $Power1(2)$ gives the power component pick up value in the $Angle1(2)$ direction. The setting is given in p.u. of the generator rated power, see equation 49.

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 $0^\circ$ or $180^\circ$. $0^\circ$ should be used for generator low forward active power protection.

\[ S_N = \sqrt{3} \cdot U\text{Base} \cdot I\text{Base} \]

(Equation 49)

For low forward power the set angle should be $0^\circ$ in the underpower 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 50.

\[ S_N = \sqrt{3} \cdot U\text{Base} \cdot I\text{Base} \]

(Equation 50)

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:
\( S = k \cdot S_{\text{old}} + (1 - k) \cdot S_{\text{Calculated}} \)  

(Equation 51)

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
- \( k \) 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:

- \( I_{\text{AmpComp5}}, I_{\text{AmpComp30}}, I_{\text{AmpComp100}} \)
- \( U_{\text{AmpComp5}}, U_{\text{AmpComp30}}, U_{\text{AmpComp100}} \)
- \( I_{\text{AngComp5}}, I_{\text{AngComp30}}, I_{\text{AngComp100}} \)

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.

### 7.9 Directional overpower protection GOPPDOP

#### 7.9.1 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>Directional overpower protection</td>
<td>GOPPDOP</td>
<td></td>
<td>32</td>
</tr>
</tbody>
</table>

#### 7.9.2 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 91 illustrates the reverse power protection with underpower IED and with overpower IED. The underpower IED gives a higher margin and should provide better dependability. On the other hand, the risk for unwanted operation immediately after synchronization may be higher. One should set the underpower IED to trip if the active power from the generator is less than about 2%. One should set the overpower IED to trip if the power flow from the network to the generator is higher than 1%.

Figure 91: Reverse power protection with underpower IED and overpower IED

7.9.3 Setting guidelines

Operation: With the parameter Operation the function can be set On/Off.

Mode: The voltage and current used for the power measurement. The setting possibilities are shown in table 29.
Table 29: Complex power calculation

<table>
<thead>
<tr>
<th>Set value Mode</th>
<th>Formula used for complex power calculation</th>
</tr>
</thead>
<tbody>
<tr>
<td>L1, L2, L3</td>
<td>$\bar{S} = U_{L1} \cdot I_{L1}^* + U_{L2} \cdot I_{L2}^* + U_{L3} \cdot I_{L3}^*$</td>
</tr>
<tr>
<td></td>
<td>(Equation 53)</td>
</tr>
<tr>
<td>Arone</td>
<td>$\bar{S} = U_{L1L2} \cdot I_{L1}^* - U_{L2L3} \cdot I_{L3}^*$</td>
</tr>
<tr>
<td></td>
<td>(Equation 54)</td>
</tr>
<tr>
<td>PosSeq</td>
<td>$\bar{S} = 3 \cdot U_{PosSeq} \cdot I_{PosSeq}^*$</td>
</tr>
<tr>
<td></td>
<td>(Equation 55)</td>
</tr>
<tr>
<td>L1L2</td>
<td>$\bar{S} = U_{L1L2} \cdot (I_{L1}^* - I_{L2}^*)$</td>
</tr>
<tr>
<td></td>
<td>(Equation 56)</td>
</tr>
<tr>
<td>L2L3</td>
<td>$\bar{S} = U_{L2L3} \cdot (I_{L2}^* - I_{L3}^*)$</td>
</tr>
<tr>
<td></td>
<td>(Equation 57)</td>
</tr>
<tr>
<td>L3L1</td>
<td>$\bar{S} = U_{L3L1} \cdot (I_{L3}^* - I_{L1}^*)$</td>
</tr>
<tr>
<td></td>
<td>(Equation 58)</td>
</tr>
<tr>
<td>L1</td>
<td>$\bar{S} = 3 \cdot U_{L1} \cdot I_{L1}^*$</td>
</tr>
<tr>
<td></td>
<td>(Equation 59)</td>
</tr>
<tr>
<td>L2</td>
<td>$\bar{S} = 3 \cdot U_{L2} \cdot I_{L2}^*$</td>
</tr>
<tr>
<td></td>
<td>(Equation 60)</td>
</tr>
<tr>
<td>L3</td>
<td>$\bar{S} = 3 \cdot U_{L3} \cdot I_{L3}^*$</td>
</tr>
<tr>
<td></td>
<td>(Equation 61)</td>
</tr>
</tbody>
</table>

The function has two stages that can be set independently.

With the parameter $OpMode1(2)$ the function can be set $On/Off$.

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 92: Overpower mode

The setting $\text{Power1}(2)$ gives the power component pick up value in the $\text{Angle1}(2)$ direction. The setting is given in p.u. of the generator rated power, see equation 62.

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

$$S_N = \sqrt{3} \cdot U_{\text{Base}} \cdot I_{\text{Base}}$$

(Equation 62)

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.
Figure 93: For reverse power the set angle should be 180° in the overpower function.

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

Hysteresis1(2) is given in p.u. of generator rated power according to equation 63.

\[ S_N = \sqrt{3} \cdot U_{\text{Base}} \cdot I_{\text{Base}} \]

(Equation 63)

The drop out power will be \( P_{\text{ower}1(2)} - Hysteresis1(2) \).

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

\[ S = k \cdot S_{\text{Old}} + (1-k) \cdot S_{\text{Calculated}} \]

(Equation 64)

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
- \( k \) 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:

\[ I_{\text{AmpComp5}}, I_{\text{AmpComp30}}, I_{\text{AmpComp100}} \]
\[ U_{\text{AmpComp5}}, U_{\text{AmpComp30}}, U_{\text{AmpComp100}} \]
\[ I_{\text{AngComp5}}, I_{\text{AngComp30}}, I_{\text{AngComp100}} \]

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.

### 7.10 Capacitor bank protection CBPGAPC

#### 7.10.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60817 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacitor bank protection</td>
<td>CBPGAPC</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### 7.10.2 Application

Shunt capacitor banks (SCBs) are somewhat specific and different from other power system elements. These specific features of SCB are briefly summarized in this section.

A capacitor unit is the building block used for SCB construction. The capacitor unit is made up of individual capacitor elements, arranged in parallel or series connections. Capacitor elements normally consist of aluminum foil, paper, or film-insulated cells immersed in a biodegradable insulating fluid and are sealed in a metallic container. The internal discharge resistor is also integrated within the capacitor unit in order to reduce trapped residual voltage after disconnection of the SCB from the power system. Units are available in a variety of voltage ratings (240V to 25kV) and sizes (2.5kVAr to about 1000kVAr). Capacitor unit can be designed with one or two bushings.

The high-voltage SCB is normally constructed using individual capacitor units connected in series and/or parallel to obtain the required voltage and MVAr rating. Typically the neighboring capacitor units are mounted in racks. Each rack must be
insulated from the other by insulators because the can casing within each rack are at a certain potential. Refer figure 94 for an example:

Figure 94: Replacement of a faulty capacitor unit within SCB

There are four types of the capacitor unit fusing designs which are used for construction of SCBs:

- **Externally fused**: where an individual fuse, externally mounted, protects each capacitor unit.
- **Internally fused**: where each capacitor element is fused inside the capacitor unit.
- **Fuseless**: where SCB is built from series connections of the individual capacitor units (that is, strings) and without any fuses.
- **Unfused**: where, in contrary to the fuseless configuration, a series or parallel connection of the capacitor units is used to form SCB, still without any fuses.
Which type of fusing is used may depend on can manufacturer or utility preference and previous experience.

Because the SCBs are built from the individual capacitor units the overall connections may vary. Typically used SCB configurations are:

1. Delta-connected banks (generally used only at distribution voltages)
2. Single wye-connected banks
3. Double wye-connected banks
4. H-configuration, where each phase is connected in a bridge

Additionally, the SCB star point, when available, can be either directly earthed, earthed via impedance or isolated from earth. Which type of SCB earthing is used depends on voltage level, used circuit breaker, utility preference and previous experience. Many utilities have standard system earthing principle to earth neutrals of SCB above 100 kV.

Switching of SCB will produce transients in power system. The transient inrush current during SCB energizing typically has high frequency components and can reach peak current values, which are multiples of SCB rating. Opening of capacitor bank circuit breaker may produce step recovery voltages across open CB contact, which can consequently cause restrikes upon the first interruption of capacitive current. In modern power system the synchronized CB closing/opening may be utilized in such a manner that transients caused by SCB switching are avoided.

7.10.2.1 SCB protection

IED protection of shunt capacitor banks requires an understanding of the capabilities and limitations of the individual capacitor units and associated electrical equipment. Different types of shunt capacitor bank fusing, configuration or earthing may affect the IED selection for the protection scheme. Availability and placement of CTs and VTs can be additional limiting factor during protection scheme design.

SCB protection schemes are provided in order to detect and clear faults within the capacitor bank itself or in the connected leads to the substation busbar. Bank protection may include items such as a means to disconnect a faulted capacitor unit or capacitor element(s), a means to initiate a shutdown of the bank in case of faults that may lead to a catastrophic failure and alarms to indicate unbalance within the bank.

Capacitor bank outages and failures are often caused by accidental contact by animals. Vermin, monkeys, birds, may use the SCB as a resting place or a landing site. When the animal touches the HV live parts this can result in a flash-over, can rapture or a cascading failures that might cause extensive damages, fire or even total destruction of the whole SCB, unless the bank is sufficiently fitted with protection IEDs.

In addition, to fault conditions SCB can be exposed to different types of abnormal operating conditions. In accordance with IEC and ANSI standards capacitors shall be capable of continuous operation under contingency system and bank conditions, provided the following limitations are not exceeded:
1. Capacitor units should be capable of continuous operation including harmonics, but excluding transients, to 110% of rated IED root-mean-square (RMS) voltage and a crest voltage not exceeding of rated RMS voltage. The capacitor should also be able to carry 135% of nominal current. The voltage capability of any series element of a capacitor unit shall be considered to be its share of the total capacitor unit voltage capability.

2. Capacitor units should not give less than 100% nor more than 110% of rated reactive power at rated sinusoidal voltage and frequency, measured at a uniform case and internal temperature of 25°C.

3. Capacitor units mounted in multiple rows and tiers should be designed for continuous operation for a 24h average temperature of 40 °C during the hottest day, or −40 °C during the coldest day expected at the location.

4. Capacitor units should be suitable for continuous operation at up to 135% of rated reactive power caused by the combined effects of:
   - Voltage in excess of the nameplate rating at fundamental frequency, but not over 110% of rated RMS voltage
   - Harmonic voltages superimposed on the fundamental frequency
   - Reactive power manufacturing tolerance of up to 115% of rated reactive power

5. Capacitor units rated above 600 V shall have an internal discharge device to reduce the residual voltage to 50 V or less in 5 or 10 minutes (depending on national standard).

Note that capacitor units designed for special applications can exceed these ratings.

Thus, as a general rule, the minimum number of capacitor units connected in parallel within a SCB is such that isolation of one capacitor unit in a group should not cause a voltage unbalance sufficient to place more than 110% of rated voltage on the remaining capacitors of that parallel group. Equally, the minimum number of series connected groups within a SCB is such that complete bypass of one group should not cause voltage higher than 110% of the rated voltage on the remaining capacitors of that serial group. The value of 110% is the maximum continuous overvoltage capability of capacitor units as per IEEE Std 18-1992.

The SCB typically requires the following types of IED protection:

1. Short circuit protection for SCB and connecting leads (can be provided by using PHPIOC, OC4PTOC, CVGAPC, T2WPDIFF/T3WPDIFF or HZPDIF functions)
2. Earth-fault protection for SCB and connecting leads (can be provided by using EFPIOC, EF4PTOC, CVGAPC, T2WPDIFF/T3WPDIFF or HZPDIF functions)
3. Current or Voltage based unbalance protection for SCB (can be provided by using EF4PTOC, OC4PTOC, CVGAPC or VDCPTOV functions)
4. Overload protection for SCB
5. Undercurrent protection for SCB
6. Reconnection inhibit protection for SCB
7. Restrike condition detection
CBPGAPC function can be used to provide the last four types of protection mentioned in the above list.

### 7.10.3 Setting guidelines

This setting example will be done for application as shown in figure 95:

![Single line diagram for the application example](IEC006000754-1-en.vsd)

**Figure 95:** Single line diagram for the application example

From figure 95 it is possible to calculate the following rated fundamental frequency current for this SCB:

\[ I_r = \frac{1000 \cdot 200[MVA]}{\sqrt{3} \cdot 400[kV]} = 289 A \]

(Equation 65)

or on the secondary CT side:

\[ I_{r, \text{sec}} = \frac{289 A}{500/1} = 0.578 A \]

(Equation 66)

Note that the SCB rated current on the secondary CT side is important for secondary injection of the function.

The parameters for the Capacitor bank protection function CBPGAPC are set via the local HMI or PCM600. The following settings are done for this function:
General Settings:

Operation = On; to enable the function

IBase = 289A; Fundamental frequency SCB rated current in primary amperes. This value is used as a base value for pickup settings of all other features integrated in this function.

Reconnection inhibit feature:

OperationRecIn = On; to enable this feature

IRecnInhibit< = 10% (of IBase); Current level under which function will detect that SCB is disconnected from the power system

tReconnInhibit = 300s; Time period under which SCB shall discharge remaining residual voltage to less than 5%.

Overcurrent feature:

OperationOC = On; to enable this feature

IOC> = 135% (of IBase); Current level for overcurrent pickup. Selected value gives pickup recommended by international standards.

tOC = 30s; Time delay for overcurrent trip

Undercurrent feature:

OperationUC = On; to enable this feature

IUC< = 70% (of IBase); Current level for undercurrent pickup

tUC = 5s; Time delay for undercurrent trip

Undercurrent feature is blocked by operation of Reconnection inhibit feature.

Reactive power overload feature:

OperationQOL = On; to enable this feature

QOL> = 130% (of SCB MVAr rating); Reactive power level required for pickup. Selected value gives pickup recommended by international standards.

tQOL = 60s; Time delay for reactive power overload trip

Harmonic voltage overload feature:

OperationHOL = On; to enable this feature

Settings for definite time delay step
$HOLDTU> = 200\%$ (of SCB voltage rating); Voltage level required for pickup

$tHOLDT = 10s$; Definite time delay for harmonic overload trip

Settings for IDMT delay step

$HOLIDMTU> = 110\%$ (of SCB voltage rating); Voltage level required for pickup of IDMT stage. Selected value gives pickup recommended by international standards.

$kHOLIDMT = 1.0$; Time multiplier for IDMT stage. Selected value gives operate time in accordance with international standards

$tMaxHOLIDMT = 2000s$; Maximum time delay for IDMT stage for very low level of harmonic overload

$tMinHOLIDMT = 0.1s$; Minimum time delay for IDMT stage. Selected value gives operate time in accordance with international standards

**7.10.3.1 Restrike detection**

Opening of SCBs can be quite problematic for certain types of circuit breakers (CBs). Typically such problems are manifested as CB restrikes.

In simple words this means that the CB is not breaking the current at the first zero crossing after separation of the CB contacts. Instead current is re-ignited and only braked at consecutive current zero crossings. This condition is manifested as high current pulses at the moment of current re-ignition.

To detect this CB condition, the built in overcurrent feature can be used. Simply, any start of the overcurrent feature during breaker normal opening means a restrike. Therefore simple logic can be created in the Application Configuration tool to detect such CB behavior. Such CB condition can be just alarmed, and if required, the built in disturbance recorder can also be triggered.

To create this logic, a binary signal that the CB is going to be opened (but not trip command) shall be made available to the IED.
Section 8 Voltage protection

8.1 Two step undervoltage protection UV2PTUV

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>Two step undervoltage protection UV2PTUV</td>
<td>UV2PTUV</td>
<td></td>
<td>27</td>
</tr>
</tbody>
</table>

8.1.2 Setting guidelines

All the voltage conditions in the system where UV2PTUV performs its functions should be considered. The same also applies to the associated equipment, its voltage and time characteristic.

There is a very wide application area where general undervoltage functions are used. All voltage related settings are made as a percentage of the global settings base voltage $U_{Base}$, which normally is set to the primary rated voltage level (phase-to-phase) of the power system or the high voltage equipment under consideration.

The setting for UV2PTUV is normally not critical, since there must be enough time available for the main protection to clear short circuits and earth faults.

Some applications and related setting guidelines for the voltage level are described in the following sections.

8.1.2.1 Equipment protection, such as for motors and generators

The setting must be below the lowest occurring "normal" voltage and above the lowest acceptable voltage for the equipment.

8.1.2.2 Disconnected equipment detection

The setting must be below the lowest occurring "normal" voltage and above the highest occurring voltage, caused by inductive or capacitive coupling, when the equipment is disconnected.
8.1.2.3 Power supply quality

The setting must be below the lowest occurring "normal" voltage and above the lowest acceptable voltage, due to regulation, good practice or other agreements.

8.1.2.4 Voltage instability mitigation

This setting is very much dependent on the power system characteristics, and thorough studies have to be made to find the suitable levels.

8.1.2.5 Backup protection for power system faults

The setting must be below the lowest occurring "normal" voltage and above the highest occurring voltage during the fault conditions under consideration.

8.1.2.6 Settings for Two step undervoltage protection

The following settings can be done for Two step undervoltage protection UV2PTUV:

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

Operation: Off or On.

UBase (given in GlobalBaseSel): Base voltage phase-to-phase in primary kV. This voltage is used as reference for voltage setting. UV2PTUV measures selectively phase-to-earth voltages, or phase-to-phase voltage chosen by the setting ConnType. The function will operate if the voltage gets lower than the set percentage of UBase. When ConnType is set to PhN DFT or PhN RMS then the IED automatically divides set value for UBase by √3. UBase is used when ConnType is set to PhPh DFT or PhPh RMS. Therefore, always set UBase as rated primary phase-to-phase voltage of the protected object. This means operation for phase-to-earth voltage under:

\[ U < (\%) \cdot \frac{UBase(kV)}{\sqrt{3}} \]  

(Equation 67)

and operation for phase-to-phase voltage under:

\[ U < (\%) \cdot UBase(kV) \]

(Equation 68)

The below described setting parameters 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.

OpModen: This parameter describes how many of the three measured voltages that should be below the set level to give operation for step n. The setting can be 1 out of 3, 2 out of 3 or 3 out of 3. In most applications, it is sufficient that one phase voltage is low to give operation. If UV2PTUV shall be insensitive for single phase-to-earth faults, 2 out of 3 can be chosen. In subtransmission and transmission networks the undervoltage function is mainly a system supervision function and 3 out of 3 is selected.

Un<: Set operate undervoltage operation value for step n, given as % of the parameter UBase. The setting is highly dependent of the protection application. It is essential to consider the minimum voltage at non-faulted situations. Normally this voltage is larger than 90% of nominal voltage.

tn: time delay of step n, given in s. This setting is dependent of the protection application. In many applications the protection function shall not directly trip when there is a short circuit or earth faults in the system. The time delay must be coordinated to the short circuit protections.

$tRersetn$: Reset time for step n if definite time delay is used, given in s. The default value is 25 ms.

tnMin: Minimum operation time for inverse time characteristic for step n, given in s. When using inverse time characteristic for the undervoltage function during very low voltages can give a short operation time. This might lead to unselective trip. By setting t1Min longer than the operation time for other protections such unselective tripping can be avoided.

ResetTypeCrvn: This parameter for inverse time characteristic can be set to Instantaneous, Frozen time, Linearly decreased. The default setting is Instantaneous.

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

kn: Time multiplier for inverse time characteristic. This parameter is used for coordination between different inverse time delayed undervoltage protections.

ACrvn, BCrvn, CCrvn, DCrvn, PCrvn: Parameters to set to create programmable under voltage inverse time characteristic. Description of this can be found in the technical reference manual.

CrvSatn: When the denominator in the expression of the programmable curve is equal to zero the time delay will be infinity. There will be an undesired discontinuity. Therefore, a tuning parameter CrvSatn is set to compensate for this phenomenon. In the voltage interval Un< down to Un< · (1.0 - CrvSatn/100) the used voltage will be: Un< · (1.0 - CrvSatn/100). If the programmable curve is used this parameter must be calculated so that:
\[ B \cdot \frac{\text{CrvSatn}}{100} - C > 0 \]

(Equation 69)

*IntBlkSeln*: This parameter can be set to *Off*, *Block of trip*, *Block all*. In case of a low voltage the undervoltage function can be blocked. This function can be used to prevent function when the protected object is switched off. If the parameter is set *Block of trip* or *Block all* unwanted trip is prevented.

*IntBlkStValn*: Voltage level under which the blocking is activated set in \% of *UBase*. This setting must be lower than the setting *Un<*. As switch of shall be detected the setting can be very low, that is, about 10%.

*tBlkUVn*: Time delay to block the undervoltage step \( n \) when the voltage level is below *IntBlkStValn*, given in s. It is important that this delay is shorter than the operate time delay of the undervoltage protection step.

8.2 Two step overvoltage protection OV2PTOV

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>
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<tr>
<td>Two step overvoltage protection</td>
<td>OV2PTOV</td>
<td>3U&gt;</td>
<td>59</td>
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</tbody>
</table>

8.2.2 Application

Two step overvoltage protection OV2PTOV is applicable in all situations, where reliable detection of high voltage is necessary. OV2PTOV is used for supervision and detection of abnormal conditions, which, in combination with other protection functions, increase the security of a complete protection system.

High overvoltage conditions are caused by abnormal situations in the power system. OV2PTOV is applied to power system elements, such as generators, transformers, motors and power lines in order to detect high voltage conditions. OV2PTOV is used in combination with low current signals, to identify a transmission line, open in the remote end. In addition to that, OV2PTOV is also used to initiate voltage correction measures, like insertion of shunt reactors, to compensate for low load, and thereby decreasing the voltage. The function has a high measuring accuracy and hysteresis setting to allow applications to control reactive load.
OV2PTOV is used to disconnect apparatuses, like electric motors, which will be damaged when subject to service under high voltage conditions. It deals with high voltage conditions at power system frequency, which can be caused by:

1. Different kinds of faults, where a too high voltage appears in a certain power system, like metallic connection to a higher voltage level (broken conductor falling down to a crossing overhead line, transformer flash over fault from the high voltage winding to the low voltage winding and so on).
2. Malfunctioning of a voltage regulator or wrong settings under manual control (symmetrical voltage decrease).
3. Low load compared to the reactive power generation (symmetrical voltage decrease).
4. Earth-faults in high impedance earthed systems causes, beside the high voltage in the neutral, high voltages in the two non-faulted phases, (unsymmetrical voltage increase).

OV2PTOV prevents sensitive equipment from running under conditions that could cause their overheating or stress of insulation material, and, thus, shorten their life time expectancy. In many cases, it is a useful function in circuits for local or remote automation processes in the power system.

8.2.3 Setting guidelines

The parameters for Two step overvoltage protection (OV2PTOV) are set via the local HMI or PCM600.

All the voltage conditions in the system where OV2PTOV performs its functions should be considered. The same also applies to the associated equipment, its voltage and time characteristic.

There is a very wide application area where general overvoltage functions are used. All voltage related settings are made as a percentage of a settable base primary voltage, which normally is set to the nominal voltage level (phase-to-phase) of the power system or the high voltage equipment under consideration.

The time delay for the OV2PTOV 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%.
8.2.3.1 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.

8.2.3.2 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.

8.2.3.3 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.

8.2.3.4 High impedance earthed systems

In high impedance earthed systems, earth-faults cause a voltage increase in the non-faulty phases. Two step overvoltage protection (OV2PTOV) is used to detect such faults. The setting must be above the highest occurring "normal" voltage and below the lowest occurring voltage during faults. A metallic single-phase earth-fault causes the non-faulted phase voltages to increase a factor of $\sqrt{3}$.

8.2.3.5 The following settings can be done for the two step overvoltage protection

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

Operation: Off/On.

UBase (given in GlobalBaseSel): Base voltage phase to phase in primary kV. This voltage is used as reference for voltage setting. OV2PTOV measures selectively phase-to-earth voltages, or phase-to-phase voltage chosen by the setting ConnType. The function will operate if the voltage gets lower than the set percentage of UBase. When ConnType is set to PhN DFT or PhN RMS then the IED automatically divides set value for UBase by $\sqrt{3}$. When ConnType is set to PhPh DFT or PhPh RMS then set value for UBase is used. Therefore, always set UBase as rated primary phase-to-phase voltage of the protected object. If phase to neutral (PhN) measurement is selected as setting, the operation of phase-to-earth over voltage is automatically divided by sqrt3. This means operation for phase-to-earth voltage over:

$$U > (\%) \cdot U_{\text{Base}}(kV) / \sqrt{3}$$
and operation for phase-to-phase voltage over:

\[ U > (\%) \cdot U_{\text{Base}}(kV) \]

(Equation 71)

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

**Un>**: Set operate overvoltage operation value for step \(n\), given as % of \(U_{\text{Base}}\). The setting is highly dependent of the protection application. Here it is essential to consider the maximum voltage at non-faulted situations. Normally this voltage is less than 110% of nominal voltage.

**tn**: time delay of step \(n\), given in s. The setting is highly dependent of the protection application. In many applications the protection function is used to prevent damages to the protected object. The speed might be important for example in case of protection of transformer that might be overexcited. The time delay must be co-ordinated with other automated actions in the system.

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

**tnMin**: Minimum operation time for inverse time characteristic for step \(n\), given in s. For very high voltages the overvoltage function, using inverse time characteristic, can give very short operation time. This might lead to unselective trip. By setting *t1Min* longer than the operation time for other protections such unselective tripping can be avoided.

**ResetTypeCrvn**: This parameter for inverse time characteristic can be set: *Instantaneous*, *Frozen time*, *Linearly decreased*. The default setting is *Instantaneous*.

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

**kn**: Time multiplier for inverse time characteristic. This parameter is used for co-ordination between different inverse time delayed undervoltage protections.
ACrvn, BCrvn, CCrvn, DCrvn, PCrvn: Parameters to set to create programmable under voltage inverse time characteristic. Description of this can be found in the technical reference manual.

CrvSatn: When the denominator in the expression of the programmable curve is equal to zero the time delay will be infinity. There will be an undesired discontinuity. Therefore a tuning parameter CrvSatn is set to compensate for this phenomenon. In the voltage interval \( Un > \) up to \( Un > \cdot (1.0 + \text{CrvSatn}/100) \) the used voltage will be: \( Un > \cdot (1.0 + \text{CrvSatn}/100) \). If the programmable curve is used, this parameter must be calculated so that:

\[
B \cdot \frac{\text{CrvSatn}}{100} - C > 0
\]

(Equation 72)

HystAbsn: Absolute hysteresis set in % of UB\text{\textsubscript{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.

### 8.3 Two step residual overvoltage protection ROV2PTOV

#### 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>
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<td>Two step residual overvoltage protection</td>
<td>ROV2PTOV</td>
<td></td>
<td>59N</td>
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</tbody>
</table>

#### 8.3.2 Application

Two step residual overvoltage protection ROV2PTOV is primarily used in high impedance earthed distribution networks, mainly as a backup for the primary earth-fault protection of the feeders and the transformer. To increase the security for different earth-fault related functions, the residual overvoltage signal can be used as a release signal. The residual voltage can be measured either at the transformer neutral or from a voltage transformer open delta connection. The residual voltage can also be calculated internally, based on measurement of the three-phase voltages.

In high impedance earthed systems the residual voltage will increase in case of any fault connected to earth. Depending on the type of fault and fault resistance the residual voltage will reach different values. The highest residual voltage, equal to...
three times the phase-to-earth voltage, is achieved for a single phase-to-earth fault. The residual voltage increases approximately to the same level in the whole system and does not provide any guidance in finding the faulted component. Therefore, ROV2PTOV is often used as a backup protection or as a release signal for the feeder earth-fault protection.

8.3.3 Setting guidelines

All the voltage conditions in the system where ROV2PTOV performs its functions should be considered. The same also applies to the associated equipment, its voltage and time characteristic.

There is a very wide application area where general single input or residual overvoltage functions are used. All voltage related settings are made as a percentage of a settable base voltage, which can be set to the primary nominal voltage (phase-phase) level of the power system or the high voltage equipment under consideration.

The time delay for ROV2PTOV is seldom critical, since residual voltage is related to earth-faults in a high impedance earthed system, and enough time must normally be given for the primary protection to clear the fault. In some more specific situations, where the single overvoltage protection is used to protect some specific equipment, the time delay is shorter.

Some applications and related setting guidelines for the residual voltage level are given below.

8.3.3.1 Equipment protection, such as for motors, generators, reactors and transformers

High residual voltage indicates earth-fault in the system, perhaps in the component to which Two step residual overvoltage protection (ROV2PTOV) is connected. For selectivity reasons to the primary protection for the faulted device ROV2PTOV must trip the component with some time delay. The setting must be above the highest occurring "normal" residual voltage and below the highest acceptable residual voltage for the equipment.

8.3.3.2 Equipment protection, capacitors

High voltage will deteriorate the dielectric and the insulation. Two step residual overvoltage protection (ROV2PTOV) has to be connected to a neutral or open delta winding. The setting must be above the highest occurring "normal" residual voltage and below the highest acceptable residual voltage for the capacitor.

8.3.3.3 Power supply quality

The setting must be above the highest occurring "normal" residual voltage and below the highest acceptable residual voltage, due to regulation, good practice or other agreements.
8.3.3.4 High impedance earthed systems

In high impedance earthed systems, earth faults cause a neutral voltage in the feeding transformer neutral. Two step residual overvoltage protection ROV2PTOV is used to trip the transformer, as a backup protection for the feeder earth-fault protection, and as a backup for the transformer primary earth-fault protection. The setting must be above the highest occurring "normal" residual voltage, and below the lowest occurring residual voltage during the faults under consideration. A metallic single-phase earth fault causes a transformer neutral to reach a voltage equal to the nominal phase-to-earth voltage.

The voltage transformers measuring the phase-to-earth voltages measure zero voltage in the faulty phase. The two healthy phases will measure full phase-to-phase voltage, as the faulty phase will be connected to earth. The residual overvoltage will be three times the phase-to-earth voltage. See figure 96.
8.3.3.5 Direct earthed system

In direct earthed systems, an earth fault on one phase indicates a voltage collapse in that phase. The two healthy phases will have normal phase-to-earth voltages. The residual sum will have the same value as the remaining phase-to-earth voltage. See figure 97.
8.3.3.6 Settings for Two step residual overvoltage protection

*Operation: Off or On*

*UBase* (given in *GlobalBaseSel*) is used as voltage reference for the voltage. The voltage can be fed to the IED in different ways:

1. The IED is fed from a normal voltage transformer group where the residual voltage is calculated internally from the phase-to-earth voltages within the protection. The setting of the analog input is given as \( U_{\text{Base}} = U_{\text{ph-ph}} \).
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 \( 3U_0 \) (single input). The Setting chapter in the application manual explains how the analog input needs to be set.
3. The IED is fed from a single voltage transformer connected to the neutral point of a power transformer in the power system. In this connection the protection is fed by the voltage \( U_{N}=U_0 \) (single input). The Setting chapter in the application manual explains how the analog input needs to be set. ROV2PTOV will measure the residual voltage corresponding nominal phase-to-earth voltage for a high impedance earthed system. The measurement will be based on the neutral voltage displacement.

The below described setting parameters are identical for the two steps \((n = \text{step 1 and 2})\). Therefore the setting parameters are described only once.
Characteristic: Selected inverse time characteristic for step n. This parameter gives the type of time delay to be used. The setting can be, Definite time or Inverse curve A or Inverse curve B or Inverse curve C or Prog. inv. curve. The choice is highly dependent of the protection application.

Un>: Set operate overvoltage operation value for step n, given as % of residual voltage corresponding to UBase:

\[ U > \left( \% \right) \cdot U_{\text{Base}}(kV) / \sqrt{3} \]

(Equation 73)

The setting is dependent of the required sensitivity of the protection and the system earthing. In non-effectively earthed systems the residual voltage can be maximum the rated phase-to-earth voltage, which should correspond to 100%.

In effectively earthed systems this value is dependent of the ratio Z0/Z1. The required setting to detect high resistive earth-faults must be based on network calculations.

tn: time delay of step n, given in s. The setting is highly dependent of the protection application. In many applications, the protection function has the task to prevent damages to the protected object. The speed might be important for example in case of protection of transformer that might be overexcited. The time delay must be co-ordinated with other automated actions in the system.

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

tnMin: Minimum operation time for inverse time characteristic for step n, given in s. For very high voltages the overvoltage function, using inverse time characteristic, can give very short operation time. This might lead to unselective trip. By setting t1Min longer than the operation time for other protections such unselective tripping can be avoided.

ResetTypeCrvn: Set reset type curve for step n. This parameter can be set: Instantaneous, Frozen time, Linearly decreased. The default setting is Instantaneous.

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

kn: Time multiplier for inverse time characteristic. This parameter is used for co-ordination between different inverse time delayed undervoltage protections.

ACrvn, BCrvn, CCrvn, DCrvn, PCrvn: Parameters for step n, to set to create programmable undervoltage inverse time characteristic. Description of this can be found in the technical reference manual.

CrvSatn: Set tuning parameter for step n. When the denominator in the expression of the programmable curve is equal to zero the time delay will be infinity. There will be an undesired discontinuity. Therefore, a tuning parameter CrvSatn is set to compensate for this phenomenon. In the voltage interval U> up to U> · (1.0 +
CrvSatn/100) the used voltage will be: \( U > (1.0 + \frac{CrvSatn}{100}) \). If the programmable curve is used this parameter must be calculated so that:

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

(Equation 74)

\( HystAbsn \): Absolute hysteresis for step \( n \), set in % of \( U_{Base} \). The setting of this parameter is highly dependent of the application.

## 8.4 Voltage differential protection VDCPTOV

### 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>
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<tr>
<td>Voltage differential protection</td>
<td>VDCPTOV</td>
<td>-</td>
<td>60</td>
</tr>
</tbody>
</table>

### 8.4.2 Application

The Voltage differential protection VDCPTOV 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 98 shows some different alternative connections of this function.
Figure 98: Connection of voltage differential protection VDCPTOV function to detect unbalance in capacitor banks (one phase only is shown)

VDCPTOV function has a block input (BLOCK) where a fuse failure supervision (or MCB tripped) can be connected to prevent problems if one fuse in the capacitor bank voltage transformer set has opened and not the other (capacitor voltage is connected to input U2). It will also ensure that a fuse failure alarm is given instead of a Undervoltage or Differential voltage alarm and/or tripping.

8.4.3 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*

*BlkDiffAtULow*: The setting is to block the function when the voltages in the phases are low.
**RFLx**: Is the setting of the voltage ratio compensation factor where possible differences between the voltages is compensated for. The differences can be due to different voltage transformer ratios, different voltage levels e.g. the voltage measurement inside the capacitor bank can have a different voltage level but the difference can also e.g. be used by voltage drop in the secondary circuits. The setting is normally done at site by evaluating the differential voltage achieved as a service value for each phase. The factor is defined as $U2 \cdot RFLx$ and shall be equal to the $U1$ voltage. Each phase has its own ratio factor.

**UDTrip**: The voltage differential level required for tripping is set with this parameter. For application on capacitor banks the setting will depend of the capacitor bank voltage and the number of elements per phase in series and parallel. Capacitor banks must be tripped before excessive voltage occurs on the healthy capacitor elements. The setting values required are normally given by the capacitor bank supplier. For other applications it has to be decided case by case. For fuse supervision normally only the alarm level is used.

**tTrip**: The time delay for tripping is set by this parameter. Normally, the delay does not need to be so short in capacitor bank applications as there is no fault requiring urgent tripping.

**tReset**: The time delay for reset of tripping level element is set by this parameter. Normally, it can be set to a short delay as faults are permanent when they occur.

For the advanced users following parameters are also available for setting. Default values are here expected to be acceptable.

**U1Low**: The setting of the undervoltage level for the first voltage input is decided by this parameter. The proposed default setting is 70%.

**U2Low**: The setting of the undervoltage level for the second voltage input is decided by this parameter. The proposed default setting is 70%.

**tBlock**: The time delay for blocking of the function at detected undervoltages is set by this parameter.

**UDAAlarm**: 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.
8.5 Loss of voltage check LOVPTUV

8.5.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 80617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
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<tbody>
<tr>
<td>Loss of voltage check</td>
<td>LOVPTUV</td>
<td>-</td>
<td>27</td>
</tr>
</tbody>
</table>

8.5.2 Application

The trip of the circuit breaker at a prolonged loss of voltage at all the three phases is normally used in automatic restoration systems to facilitate the system restoration after a major blackout. Loss of voltage check (LOVPTUV) generates a TRIP signal only if the voltage in all the three phases is low for more than the set time. If the trip to the circuit breaker is not required, LOVPTUV is used for signalization only through an output contact or through the event recording function.

8.5.3 Setting guidelines

Loss of voltage check (LOVPTUV) is in principle independent of the protection functions. It requires to be set to open the circuit breaker in order to allow a simple system restoration following a main voltage loss of a big part of the network and only when the voltage is lost with breakers still closed.

All settings are in primary values or per unit. Set operate level per phase to typically 70% of the global parameter $U_{Base}$ level. Set the time delay $t_{Trip}=5-20$ seconds.

8.5.3.1 Advanced users settings

For advanced users the following parameters need also to be set. Set the length of the trip pulse to typical $t_{Pulse}=0.15$ sec. Set the blocking time $t_{Block}$ to block Loss of voltage check (LOVPTUV), if some but not all voltage are low, to typical 5.0 seconds and set the time delay for enabling the function after restoration $t_{Restore}$ to 3 - 40 seconds.
Section 9 Frequency protection

9.1 Underfrequency protection SAPTUF

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>
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<tbody>
<tr>
<td>Underfrequency protection</td>
<td>SAPTUF</td>
<td></td>
<td>81</td>
</tr>
</tbody>
</table>

9.1.2 Application

Underfrequency protection SAPTUF is applicable in all situations, where reliable detection of low fundamental power system frequency is needed. The power system frequency, and the rate of change of frequency, is a measure of the unbalance between the actual generation and the load demand. Low fundamental frequency in a power system indicates that the available generation is too low to fully supply the power demanded by the load connected to the power grid. SAPTUF detects such situations and provides an output signal, suitable for load shedding, generator boosting, HVDC-set-point change, gas turbine start up and so on. Sometimes shunt reactors are automatically switched in due to low frequency, in order to reduce the power system voltage and hence also reduce the voltage dependent part of the load.

SAPTUF is very sensitive and accurate and is used to alert operators that frequency has slightly deviated from the set-point, and that manual actions might be enough. The underfrequency signal is also used for overexcitation detection. This is especially important for generator step-up transformers, which might be connected to the generator but disconnected from the grid, during a roll-out sequence. If the generator is still energized, the system will experience overexcitation, due to the low frequency.

9.1.3 Setting guidelines

All the frequency and voltage magnitude conditions in the system where SAPTUF performs its functions should be considered. The same also applies to the associated equipment, its frequency and time characteristic.

There are two specific application areas for SAPTUF:
1. to protect equipment against damage due to low frequency, such as generators, transformers, and motors. Overexcitation is also related to low frequency
2. to protect a power system, or a part of a power system, against breakdown, by shedding load, in generation deficit situations.

The under frequency START value is set in Hz. All voltage magnitude related settings are made as a percentage of a global base voltage parameter. The UBase value should be set as a primary phase-to-phase value.

Some applications and related setting guidelines for the frequency level are given below:

**Equipment protection, such as for motors and generators**

The setting has to be well below the lowest occurring "normal" frequency and well above the lowest acceptable frequency for the equipment.

**Power system protection, by load shedding**

The setting has to be below the lowest occurring "normal" frequency and well above the lowest acceptable frequency for power stations, or sensitive loads. The setting level, the number of levels and the distance between two levels (in time and/or in frequency) depends very much on the characteristics of the power system under consideration. The size of the "largest loss of production" compared to "the size of the power system" is a critical parameter. In large systems, the load shedding can be set at a fairly high frequency level, and the time delay is normally not critical. In smaller systems the frequency START level has to be set at a lower value, and the time delay must be rather short.

The voltage related time delay is used for load shedding. The settings of SAPTUF could be the same all over the power system. The load shedding is then performed firstly in areas with low voltage magnitude, which normally are the most problematic areas, where the load shedding also is most efficient.

### 9.2 Overfrequency protection SAPTOF

#### 9.2.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
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<th>IEC 80617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
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<tr>
<td>Overfrequency protection</td>
<td>SAPTOF</td>
<td></td>
<td>81</td>
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</tbody>
</table>
9.2.2 Application

Overfrequency protection function SAPTOF is applicable in all situations, where reliable detection of high fundamental power system frequency is needed. The power system frequency, and rate of change of frequency, is a measure of the unbalance between the actual generation and the load demand. High fundamental frequency in a power system indicates that the available generation is too large compared to the power demanded by the load connected to the power grid. SAPTOF detects such situations and provides an output signal, suitable for generator shedding, HVDC-set-point change and so on. SAPTOF is very sensitive and accurate and can also be used to alert operators that frequency has slightly deviated from the set-point, and that manual actions might be enough.

9.2.3 Setting guidelines

All the frequency and voltage magnitude conditions in the system where SAPTOF performs its functions must be considered. The same also applies to the associated equipment, its frequency and time characteristic.

There are two application areas for SAPTOF:

1. to protect equipment against damage due to high frequency, such as generators, and motors
2. to protect a power system, or a part of a power system, against breakdown, by shedding generation, in over production situations.

The overfrequency start value is set in Hz. All voltage magnitude related settings are made as a percentage of a settable global base voltage parameter $U_{Base}$. 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 START level has to be set at a higher value, and the time delay must be rather short.
9.3 Rate-of-change frequency protection SAPFRC

9.3.1 Identification

<table>
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<td>SAPFRC</td>
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</table>

9.3.2 Application

Rate-of-change frequency protection (SAPFRC), is applicable in all situations, where reliable detection of change of the fundamental power system voltage frequency is needed. SAPFRC can be used both for increasing frequency and for decreasing frequency. SAPFRC provides an output signal, suitable for load shedding or generator shedding, generator boosting, HVDC-set-point change, gas turbine start up and so on. Very often SAPFRC is used in combination with a low frequency signal, especially in smaller power systems, where loss of a fairly large generator will require quick remedial actions to secure the power system integrity. In such situations load shedding actions are required at a rather high frequency level, but in combination with a large negative rate-of-change of frequency the underfrequency protection can be used at a rather high setting.

9.3.3 Setting guidelines

The parameters for Rate-of-change frequency protection SAPFRC are set via the local HMI or or through the Protection and Control Manager (PCM600).

All the frequency and voltage magnitude conditions in the system where SAPFRC performs its functions should be considered. The same also applies to the associated equipment, its frequency and time characteristic.

There are two application areas for SAPFRC:

1. to protect equipment against damage due to high or too low frequency, such as generators, transformers, and motors
2. to protect a power system, or a part of a power system, against breakdown by shedding load or generation, in situations where load and generation are not in balance.

SAPFRC is normally used together with an overfrequency or underfrequency function, in small power systems, where a single event can cause a large imbalance between load and generation. In such situations load or generation shedding has to
take place very quickly, and there might not be enough time to wait until the frequency signal has reached an abnormal value. Actions are therefore taken at a frequency level closer to the primary nominal level, if the rate-of-change frequency is large (with respect to sign).

SAPFRCSTART value is set in Hz/s. All voltage magnitude related settings are made as a percentage of a settable base voltage, which normally is set to the primary nominal voltage level (phase-phase) of the power system or the high voltage equipment under consideration.

SAPFRC is not instantaneous, since the function needs some time to supply a stable value. It is recommended to have a time delay long enough to take care of signal noise. However, the time, rate-of-change frequency and frequency steps between different actions might be critical, and sometimes a rather short operation time is required, for example, down to 70 ms.

Smaller industrial systems might experience rate-of-change frequency as large as 5 Hz/s, due to a single event. Even large power systems may form small islands with a large imbalance between load and generation, when severe faults (or combinations of faults) are cleared - up to 3 Hz/s has been experienced when a small island was isolated from a large system. For more "normal" severe disturbances in large power systems, rate-of-change of frequency is much less, most often just a fraction of 1.0 Hz/s.
Section 10  Multipurpose protection

10.1  General current and voltage protection CVGAPC

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>General current and voltage protection</td>
<td>CVGAPC</td>
<td>2(I&gt;/U&lt;)</td>
<td>-</td>
</tr>
</tbody>
</table>

10.1.2  Application

A breakdown of the insulation between phase conductors or a phase conductor and earth results in a short circuit or an earth 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, earth or sequence current components can be used to clear 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-earth, 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:
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 it shall be once more noted that all these four protection elements measure one selected current quantity and one selected voltage quantity (see table 30 and table 31). It is possible to simultaneously use all four-protection elements and their individual stages. Sometimes in order to obtain desired application functionality it is necessary to provide interaction between two or more protection elements/stages within one CVGAPC function by appropriate IED configuration (for example, dead machine protection for generators).

### 10.1.2.1 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 (selected current quantity and selected voltage quantity).

The user can select, by a setting parameter CurrentInput, to measure one of the following current quantities shown in table 30.
### Table 30: 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 phase1</td>
<td>CVGAPC function will measure the phase L1 current phasor</td>
</tr>
<tr>
<td>2 phase2</td>
<td>CVGAPC function will measure the phase L2 current phasor</td>
</tr>
<tr>
<td>3 phase3</td>
<td>CVGAPC function will measure the phase L3 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>
<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 phase1-phase2</td>
<td>CVGAPC function will measure the current phasor internally calculated as the vector difference between the phase L1 current phasor and phase L2 current phasor (IL1-IL2)</td>
</tr>
<tr>
<td>11 phase2-phase3</td>
<td>CVGAPC function will measure the current phasor internally calculated as the vector difference between the phase L2 current phasor and phase L3 current phasor (IL2-IL3)</td>
</tr>
<tr>
<td>12 phase3-phase1</td>
<td>CVGAPC function will measure the current phasor internally calculated as the vector difference between the phase L3 current phasor and phase L1 current phasor (IL3-IL1)</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, by a setting parameter VoltageInput, to measure one of the following voltage quantities shown in table 31.

### Table 31: Available selection for voltage quantity within CVGAPC function

<table>
<thead>
<tr>
<th>Set value for parameter &quot;VoltageInput&quot;</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 phase1</td>
<td>CVGAPC function will measure the phase L1 voltage phasor</td>
</tr>
<tr>
<td>2 phase2</td>
<td>CVGAPC function will measure the phase L2 voltage phasor</td>
</tr>
<tr>
<td>3 phase3</td>
<td>CVGAPC function will measure the phase L3 voltage phasor</td>
</tr>
<tr>
<td>Set value for parameter &quot;VoltageInput&quot;</td>
<td>Comment</td>
</tr>
<tr>
<td>----------------------------------------</td>
<td>---------</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>
<tr>
<td>9 UnbalancePh</td>
<td>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</td>
</tr>
<tr>
<td>10 phase1-phase2</td>
<td>CVGAPC function will measure the voltage phasor internally calculated as the vector difference between the phase L1 voltage phasor and phase L2 voltage phasor (UL1-UL2)</td>
</tr>
<tr>
<td>11 phase2-phase3</td>
<td>CVGAPC function will measure the voltage phasor internally calculated as the vector difference between the phase L2 voltage phasor and phase L3 voltage phasor (UL2-UL3)</td>
</tr>
<tr>
<td>12 phase3-phase1</td>
<td>CVGAPC function will measure the voltage phasor internally calculated as the vector difference between the phase L3 voltage phasor and phase L1 voltage phasor (UL3-UL1)</td>
</tr>
<tr>
<td>13 MaxPh-Ph</td>
<td>CVGAPC function will measure ph-ph voltage phasor with the maximum magnitude</td>
</tr>
<tr>
<td>14 MinPh-Ph</td>
<td>CVGAPC function will measure ph-ph voltage phasor with the minimum magnitude</td>
</tr>
<tr>
<td>15 UnbalancePh-Ph</td>
<td>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</td>
</tr>
</tbody>
</table>

It is important to notice that the voltage selection from table 31 is always applicable regardless the actual external VT connections. The three-phase VT inputs can be connected to IED as either three phase-to-earth voltages $U_{L1}$, $U_{L2}$ & $U_{L3}$ or three phase-to-phase voltages $U_{L1L2}$, $U_{L2L3}$ & $U_{L3L1}$ VAB, VBC and VCA. This information about actual VT connection is entered as a setting parameter for the preprocessing block, which will then take automatically care about it.

### 10.1.2.2 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 current of the protected object in primary amperes, when the measured Current Quantity is selected from 1 to 9, as shown in table 30.
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 30.

Base voltage shall be entered as:

1. rated phase-to-earth voltage of the protected object in primary kV, when the measured Voltage Quantity is selected from 1 to 9, as shown in table 31.
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 31.

10.1.2.3 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)
   • Underimpedance protection (circular mho characteristic)
   • Voltage Controlled/Restrained Overcurrent protection
   • Phase or Negative/Positive/Zero Sequence (Non-Directional or Directional) Overcurrent protection
   • Phase or phase-to-phase or Negative/Positive/Zero Sequence over/under voltage protection
   • Special thermal overload protection
   • Open Phase protection
   • Unbalance protection

2. Generator protection
   • 80-95% Stator earth fault protection (measured or calculated 3Uo)
   • Rotor earth fault protection (with external COMBIFLEX RXTTE4 injection unit)
   • Underimpedance protection
   • Voltage Controlled/Restrained Overcurrent protection
   • Turn-to-Turn & Differential Backup protection (directional Negative Sequence. Overcurrent protection connected to generator HV terminal CTs looking into generator)
   • Stator Overload protection
   • Rotor Overload protection
   • Loss of Excitation protection (directional pos. seq. OC protection)
   • Reverse power/Low forward power protection (directional pos. seq. OC protection, 2% sensitivity)
   • Dead-Machine/Inadvertent-Energizing protection
   • Breaker head flashover protection
Improper synchronizing detection
Sensitive negative sequence generator over current protection and alarm
Phase or phase-to-phase or Negative/Positive/Zero Sequence over/under voltage protection
Generator out-of-step detection (based on directional pos. seq. OC)
Inadvertent generator energizing

10.1.2.4 Inadvertent generator energization

When the generator is taken out of service, and non-rotating, 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.
10.1.3 Setting guidelines

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

In version 2.0, a typical starting time delay of 24ms is subtracted from the set trip time delay, so that the resulting trip time will take the internal IED start time into consideration.

The parameters for the general current and voltage protection function (CVGAPC) are set via the local HMI or Protection and Control Manager (PCM600).

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 $I_{Minx}$.

10.1.3.1 Directional negative sequence overcurrent protection

Directional negative sequence overcurrent protection is typically used as sensitive earth-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-earth-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 $I_{Base}$ value equal to the rated primary current of power line CTs
5. Set base voltage $U_{Base}$ 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 $StartCurr_{OC1}$ to value between $3-10\%$ (typical values)
12. Set $tDef_{OC1}$ or parameter “$k$” when TOC/IDMT curves are used to insure proper time coordination with other earth-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 $ActLowVolt1_{VM}$ 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 $0.10$

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 $StartCurr_{OC2}$ 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

- start 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 start signals

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

**10.1.3.2 Negative sequence overcurrent protection**

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

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

\[
t_{op} = \frac{k}{\left(\frac{I_{NS}}{I_r}\right)^2}
\]

(Equation 75)

where:
- \(t_{op}\) is the operating time in seconds of the negative sequence overcurrent IED
- \(k\) 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 76)

Equation 75 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

\[
t_{op} = \frac{k \cdot \frac{1}{x^2}}{\left(\frac{I_{NS}}{x \cdot I_r}\right)^2}
\]

(Equation 77)

where:
- \(t_{op}\) is the operating time in seconds of the Inverse Time Overcurrent TOC/IDMT algorithm
- \(k\) 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 75 is compared with the equation 77 for the inverse time characteristic of the OC1 it is obvious that if the following rules are followed:

1. set \(k\) 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 \(StartCurr_{OC1}\) 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 $k_{OC1} = 20$
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 $StartCurr_{OC1} = 7\%$

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).

### 10.1.3.3 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:

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

(Equation 79)

where:

- $t_{op}$ is the operating time of the generator stator overload IED
- $k$ is the generator capability constant in accordance with the relevant standard ($k = 37.5$ for the IEC standard or $k = 41.4$ 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 80)

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

\[
t_{op} = \frac{k \cdot \frac{1}{x^2}}{\left( \frac{I_m}{x \cdot I_r} \right)^2 - \frac{1}{x^2}}
\]

(Equation 81)

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 \( \text{CurrentInput} \) to value \( \text{PosSeq} \)
3. Set base current value to the rated generator current in primary amperes
4. Enable one overcurrent step (for example OC1)
5. Select parameter \( \text{CurveType}_\text{OC1} \) to value \( \text{Programmable} \)

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

(Equation 82)

where:
- \( t_{op} \) is the operating time in seconds of the Inverse Time Overcurrent TOC/IDMT algorithm
- \( k \) 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 81 is compared with the equation 82 for the inverse time characteristic of the OC1 step it is obvious that if the following rules are followed:

1. set \( k \) equal to the IEC or ANSI standard generator capability value
2. set parameter \( A_{\text{OC1}} \) equal to the value \( 1/x^2 \)
3. set parameter \( C_{\text{OC1}} \) equal to the value \( 1/x^2 \)
4. set parameters \( B_{\text{OC1}} = 0.0 \) and \( P_{\text{OC1}} = 2.0 \)
5. set \( \text{StartCurr}_{\text{OC1}} \) 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 $k = 37.5$ for the IEC standard or $k = 41.4$ 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 $StartCurr_{OC1} = 116$

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.

### 10.1.3.4 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 $StartCurr_{OC1}$ 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.

10.1.3.5 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 StartCurr_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 UHighLimit_OC1 to value 100%
14. Set ULowLimit_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.
10.1.3.6 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 StartCurr_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&U
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 99 shows overall protection characteristic

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


Figure 99: Loss of excitation
Section 11  Secondary system supervision

11.1  Fuse failure supervision FUFSPVC

11.1.1  Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
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<tbody>
<tr>
<td>Fuse failure supervision</td>
<td>FUFSPVC</td>
<td>-</td>
<td>-</td>
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11.1.2  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, located as close as possible to the voltage instrument transformers, are one of them. Separate fuse-failure monitoring IEDs or elements within the protection and monitoring devices are another possibilities. These solutions are combined to get the best possible effect in the fuse failure supervision function (SDDRFUF).

SDDRFUF function built into the IED products can operate on the basis of external binary signals from the miniature circuit breaker or from the line disconnector. The first case influences the operation of all voltage-dependent functions while the second one does not affect the impedance measuring functions.

The negative sequence detection algorithm, based on the negative-sequence measuring quantities, a high value of voltage $3U_2$ without the presence of the negative-sequence current $3I_2$, is recommended for use in isolated or high-impedance earthed networks.

The zero sequence detection algorithm, based on the zero sequence measuring quantities, a high value of voltage $3U_0$ without the presence of the residual current
A criterion based on delta current and delta voltage measurements can be added to the fuse failure supervision function in order to detect a three phase fuse failure. This is beneficial for example during three phase transformer switching.

11.1.3 Setting guidelines

11.1.3.1 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 \( I_{\text{Base}} \), primary voltage \( U_{\text{Base}} \) and primary power \( S_{\text{Base}} \) are set in Global Base Values GBASVAL. The setting GlobalBaseSel is used to select a particular GBASVAL and used its base values.

11.1.3.2 Setting of common parameters

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

The voltage threshold \( U_{\text{SealIn}} \) is used to identify low voltage condition in the system. Set \( U_{\text{SealIn}} \) below the minimum operating voltage that might occur during emergency conditions. We propose a setting of approximately 70% of \( U_{\text{Base}} \).

The drop off time of 200 ms for dead phase detection makes it recommended to always set SealIn to On since this will secure a fuse failure indication at persistent fuse fail when closing the local breaker when the line is already energized from the other end. When the remote breaker closes the voltage will return except in the phase that has a persistent fuse fail. Since the local breaker is open there is no current and the dead phase indication will persist in the phase with the blown fuse. When the local breaker closes the current will start to flow and the function detects the fuse failure situation. But due to the 200 ms drop off timer the output BLKZ will not be activated until after 200 ms. This means that distance functions are not blocked and due to the “no voltage but current” situation might issue a trip.

The operation mode selector OpMode has been introduced for better adaptation to system requirements. The mode selector enables selecting interactions between the negative sequence and zero sequence algorithm. In normal applications, the OpMode
is set to either UNsINs for selecting negative sequence algorithm or UZsIZs for zero sequence based algorithm. If system studies or field experiences shows that there is a risk that the fuse failure function will not be activated due to the system conditions, the dependability of the fuse failure function can be increased if the OpMode is set to UZsIZs OR UNsINs OR OptimZsNs. In mode UZsIZs OR UNsINs both negative and zero sequence based algorithms are activated and working in an OR-condition. Also in mode OptimZsNs both negative and zero sequence algorithms are activated and the one that has the highest magnitude of measured negative or zero sequence current will operate. If there is a requirement to increase the security of the fuse failure function OpMode can be selected to UZsIZs AND UNsINs which gives that both negative and zero sequence algorithms are activated and working in an AND-condition, that is, both algorithms must give condition for block in order to activate the output signals BLKU or BLKZ.

11.1.3.3 Negative sequence based

The relay setting value $3U^2>_2$ is given in percentage of the base voltage $UBase$ and should not be set lower than the value that is calculated according to equation 83.

$$3U^2 >_2 = \frac{U^2}{UBase/\sqrt{3}} \cdot 100$$

(Equation 83)

where:

$U^2$ is the maximal negative sequence voltage during normal operation conditions, plus a margin of 10...20%

$UBase$ is the base voltage for the function according to the setting GlobalBaseSel

The setting of the current limit $3I^2<_2$ is in percentage of parameter $IBase$. The setting of $3I^2<_2$ must be higher than the normal unbalance current that might exist in the system and can be calculated according to equation 84.

$$3I^2 <_2 = \frac{I^2}{IBase} \cdot 100$$

(Equation 84)

where:

$I^2$ is the maximal negative sequence current during normal operating conditions, plus a margin of 10...20%

$IBase$ is the base current for the function according to the setting GlobalBaseSel
11.1.3.4 Zero sequence based

The IED setting value $3U0>$ is given in percentage of the base voltage $U_{Base}$. The setting of $3U0>$ should not be set lower than the value that is calculated according to equation 85.

$$3U0 > = \frac{3U0}{U_{Base}/\sqrt{3}} \cdot 100$$

(Equation 85)

where:

- $3U0$ is the maximal zero sequence voltage during normal operation conditions, plus a margin of 10...20%
- $U_{Base}$ is the base voltage for the function according to the setting $GlobalBaseSel$

The setting of the current limit $3I0<$ is done in percentage of $IBase$. The setting of $3I0<$ must be higher than the normal unbalance current that might exist in the system. The setting can be calculated according to equation 86.

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

(Equation 86)

where:

- $3I0$ is the maximal zero sequence current during normal operating conditions, plus a margin of 10...20%
- $IBase$ is the base current for the function according to the setting $GlobalBaseSel$

11.1.3.5 Delta U and delta I

Set the operation mode selector $OpDUDI$ to $On$ if the delta function shall be in operation.

The setting of $DU>$ should be set high (approximately 60% of $U_{Base}$) and the current threshold $DI<$ low (approximately 10% of $IBase$) to avoid unwanted operation due to normal switching conditions in the network. The delta current and delta voltage function shall always be used together with either the negative or zero sequence algorithm. If $U_{Set\,prim}$ is the primary voltage for operation of $dU/dt$ and $I_{Set\,prim}$ the primary current for operation of $dl/dt$, the setting of $DU>$ and $DI<$ will be given according to equation 87 and equation 88.

$$DU> = \frac{U_{Set\,prim}}{U_{Base}} \cdot 100$$

(Equation 87)
The voltage thresholds $U_{Ph}^>$ is used to identify low voltage condition in the system. Set $U_{Ph}^>$ below the minimum operating voltage that might occur during emergency conditions. A setting of approximately 70% of $U_{Base}$ is recommended.

The current threshold $I_{Ph}^>$ shall be set lower than the $I_{MinOp}$ for the distance protection function. A 5...10% lower value is recommended.

### 11.3.6 Dead line detection

The condition for operation of the dead line detection is set by the parameters $I_{LDL}^<$ for the current threshold and $U_{LDL}^<$ for the voltage threshold.

Set the $I_{LDL}^<$ 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 $U_{LDL}^<$ with a sufficient margin below the minimum expected operating voltage. A safety margin of at least 15% is recommended.

### 11.2 Fuse failure supervision VDSPVC

#### 11.2.1 Identification

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<tbody>
<tr>
<td>Fuse failure supervision</td>
<td>VDSPVC</td>
<td>VTS</td>
<td>60</td>
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#### 11.2.2 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.

![Diagram of fuse failure supervision VDSPVC](IEC12000143-1-en.vsd)

**Figure 100: Application of VDSPVC**

### 11.2.3 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 \( Ud>\text{MainBlock} \), \( Ud>\text{PilotAlarm} \) and \( U\text{SealIn} \) are in percentage of the base voltage, \( U_{\text{Base}} \). Set \( U_{\text{Base}} \) to the primary rated phase-to-phase voltage of the potential voltage transformer. \( U_{\text{Base}} \) is available in the Global Base Value groups; the particular Global Base Value group, that is used by VDSPVC, is set by the setting parameter \( \text{GlobalBaseSel} \).

The settings \( Ud>\text{MainBlock} \) and \( Ud>\text{PilotAlarm} \) should be set low (approximately 30% of \( U_{\text{Base}} \)) 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 \( U_{\text{SetPrim}} \) is the desired pick up primary phase-to-phase voltage of measured fuse group, the setting of \( Ud>\text{MainBlock} \) and \( Ud>\text{PilotAlarm} \) will be given according to equation 89.

\[
U_{\text{SetPrim}} \times Ud>\text{MainBlock} \quad \text{or} \quad U_{\text{SetPrim}} \times Ud>\text{PilotAlarm} = \frac{U_{\text{SetPrim}} \times 100}{U_{\text{Base}}}
\]

(Equation 89)

\( U_{\text{SetPrim}} \) is defined as phase to neutral or phase to phase voltage dependent of the selected \( \text{ConTypeMain} \) and \( \text{ConTypePilot} \). If \( \text{ConTypeMain} \) and \( \text{ConTypePilot} \) are set to \( \text{Ph-N} \) than the function performs internally the rescaling of \( U_{\text{SetPrim}} \).

When \( \text{SealIn} \) is set to \( \text{On} \) and the fuse failure has lasted for more than 5 seconds, the blocked protection functions will remain blocked until normal voltage conditions are restored above the \( U_{\text{SealIn}} \) setting. The fuse failure outputs are deactivated when the normal voltage conditions are restored.
Section 12  Control

12.1  Synchrocheck, energizing check, and synchronizing SESRSYN

12.1.1  Identification

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<th>Function description</th>
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<tbody>
<tr>
<td>Synchrocheck, energizing check, and synchronizing</td>
<td>SESRSYN</td>
<td>sc/vc</td>
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12.1.2  Application

12.1.2.1  Synchronizing

To allow closing of breakers between asynchronous networks a synchronizing function is provided. The breaker close command is issued at the optimum time when conditions across the breaker are satisfied in order to avoid stress on the network and its components.

The systems are defined to be asynchronous when the frequency difference between bus and line is larger than an adjustable parameter. If the frequency difference is less than this threshold value the system is defined to have a parallel circuit and the synchrocheck function is used.

The synchronizing function measures the difference between the U-Line and the U-Bus. It operates and enables a closing command to the circuit breaker when the calculated closing angle is equal to the measured phase angle and the following conditions are simultaneously fulfilled:

- The voltages U-Line and U-Bus are higher than the set values for $U_{HighBusSynch}$ and $U_{HighLineSynch}$ of the base voltages $G_{blBaseSelBus}$ and $G_{blBaseSelLine}$.
- The difference in the voltage is smaller than the set value of $UDiffSynch$.
- The difference in frequency is less than the set value of $FreqDiffMax$ and larger than the set value of $FreqDiffMin$. If the frequency is less than $FreqDiffMin$ the synchrocheck is used and the value of $FreqDiffMin$ must thus be identical to the value $FreqDiffM$ resp $FreqDiffA$ for synchrocheck function. The bus and line...
frequencies must also be within a range of +/- 5 Hz from the rated frequency. When the synchronizing option is included also for autoreclose there is no reason to have different frequency setting for the manual and automatic reclosing and the frequency difference values for synchronism check should be kept low.

- The frequency rate of change is less than set value for both U-Bus and U-Line.
- The closing angle is decided by the calculation of slip frequency and required preclosing time.

The synchronizing function compensates for measured slip frequency as well as the circuit breaker closing delay. The phase angle advance is calculated continuously. Closing angle is the change in angle during the set breaker closing operate time \( t_{\text{Breaker}} \).

The reference voltage can be phase-neutral L1, L2, L3 or phase-phase L1-L2, L2-L3, L3-L1 or positive sequence (Require a three phase voltage, that is UL1, UL2 and UL3). By setting the phases used for SESRSYN, with the settings \( \text{SelPhaseBus1}, \text{SelPhaseBus2}, \text{SelPhaseLine1}, \text{SelPhaseLine2} \), 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 \( \text{PhaseShift} \) setting.

### 12.1.2.2 Synchrocheck

The main purpose of the synchrocheck function is to provide control over the closing of circuit breakers in power networks in order to prevent closing if conditions for synchronism are not detected. It is also used to prevent the re-connection of two systems, which are divided after islanding and after a three pole reclosing.

Single pole auto-reclosing does not require any synchrocheck since the system is tied together by two phases.

SESRSYN function block includes both the synchrocheck function and the energizing function to allow closing when one side of the breaker is dead. SESRSYN function also includes a built-in voltage selection scheme which allows adoption to various busbar arrangements.

![Figure 101: Two interconnected power systems](en04000179.vsd)
Figure 101 shows two interconnected power systems. The cloud means that the interconnection can be further away, that is, a weak connection through other stations. The need for a check of synchronization increases if the meshed system decreases since the risk of the two networks being out of synchronization at manual or automatic closing is greater.

The synchrocheck function measures the conditions across the circuit breaker and compares them to set limits. Output is generated only when all measured conditions are within their set limits simultaneously. The check consists of:

- Live line and live bus.
- Voltage level difference.
- Frequency difference (slip). The bus and line frequency must also be within a range of ±5 Hz from rated frequency.
- Phase angle difference.

A time delay is available to ensure that the conditions are fulfilled for a minimum period of time.

In very stable power systems the frequency difference is insignificant or zero for manually initiated closing or closing by automatic restoration. In steady conditions a bigger phase angle difference can be allowed as this is sometimes the case in a long and loaded parallel power line. For this application we accept a synchrocheck with a long operation time and high sensitivity regarding the frequency difference. The phase angle difference setting can be set for steady state conditions.

Another example is the operation of a power network that is disturbed by a fault event: after the fault clearance a highspeed auto-reclosing takes place. This can cause a power swing in the net and the phase angle difference may begin to oscillate. Generally, the frequency difference is the time derivative of the phase angle difference and will, typically oscillate between positive and negative values. When the circuit breaker needs to be closed by auto-reclosing after fault-clearance some frequency difference should be tolerated, to a greater extent than in the steady condition mentioned in the case above. But if a big phase angle difference is allowed at the same time, there is some risk that auto-reclosing will take place when the phase angle difference is big and increasing. In this case it should be safer to close when the phase angle difference is smaller.

To fulfill the above requirements the synchrocheck function is provided with duplicate settings, one for steady (Manual) conditions and one for operation under disturbed conditions (Auto).
12.1.2.3 Energizing check

The main purpose of the energizing check function is to facilitate the controlled re-connection of disconnected lines and buses to energized lines and buses.

The energizing check function measures the bus and line voltages and compares them to both high and low threshold values. The output is given only when the actual measured conditions match the set conditions. Figure 103 shows two substations, where one (1) is energized and the other (2) is not energized. Power system 2 is energized (DLLB) from substation 1 via the circuit breaker A.
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 80% of the base voltage $U_{Base}$, which is defined in the Global Base Value group, according to the setting of $GblBaseSelBus$ and $GblBaseSelLine$; in a similar way, the equipment is considered non-energized (Dead) if the voltage is below 40% of the base voltage $U_{Base}$ of the Global Base Value group. A disconnected line can have a considerable potential because of factors such as induction from a line running in parallel, or feeding via extinguishing capacitors in the circuit breakers. This voltage can be as high as 50% or more of the base voltage of the line. Normally, for breakers with single breaking elements (<330 kV) the level is well below 30%.

When the energizing direction corresponds to the settings, the situation has to remain constant for a certain period of time before the close signal is permitted. The purpose of the delayed operate time is to ensure that the dead side remains de-energized and that the condition is not due to temporary interference.

**12.1.2.4 Voltage selection**

The voltage selection function is used for the connection of appropriate voltages to the synchrocheck, synchronizing and energizing check functions. For example, when the IED is used in a double bus arrangement, the voltage that should be selected depends on the status of the breakers and/or disconnectors. By checking the status of the disconnectors auxiliary contacts, the right voltages for the synchronizing, synchrocheck and energizing check functions can be selected.
Available voltage selection types are for single circuit breaker with double busbars and the 1½ circuit breaker 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 1½ circuit breaker 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 functions available in the IED.

### 12.1.2.5 External fuse failure

Either external fuse-failure signals or signals from a tripped fuse (or miniature circuit breaker) are connected to HW binary inputs of the IED; these signals are connected to inputs of SESRSYN function in the application configuration tool of PCM600. The internal fuse failure supervision function can also be used, for at least the line voltage supply. The signal BLKU, from the internal fuse failure supervision function, is then used and connected to the fuse supervision inputs of the energizing check function block. In case of a fuse failure, the SESRSYN energizing function is blocked.

The UB1OK/UB2OK and UB1FF/UB2FF inputs are related to the busbar voltage and the ULN1OK/ULN2OK and ULN1FF/ULN2FF inputs are related to the line voltage.

### External selection of energizing direction

The energizing can be selected by use of the available logic function blocks. Below is an example where the choice of mode is done from a symbol created in the Graphical Design Editor (GDE) tool on the local HMI, through selector switch function block, but alternatively there can for example, be a physical selector switch on the front of the panel which is connected to a binary to integer function block (B16I).

If the PSTO input is used, connected to the Local-Remote switch on the local HMI, the choice can also be from the station HMI system, typically ABB Microscada through IEC 61850–8–1 communication.

The connection example for selection of the manual energizing mode is shown in figure 104. Selected names are just examples but note that the symbol on the local HMI can only show the active position of the virtual selector.
12.1.3 Application examples

The synchronizing function block can also be used in some switchyard arrangements, but with different parameter settings. Below are some examples of how different arrangements are connected to the IED analogue inputs and to the function block SESRSYN. One function block is used per circuit breaker.

The input used below in example are typical and can be changed by use of configuration and signal matrix tools.

The SESRSYN and connected SMAI function block instances must have the same cycle time in the application configuration.
12.1.3.1 Single circuit breaker with single busbar

Figure 105: Connection of SESRSYN function block in a single busbar arrangement

Figure 105 illustrates connection principles. For the SESRSYN function there is one voltage transformer on each side of the circuit breaker. The voltage transformer circuit connections are straightforward; no special voltage selection is necessary.

The voltage from busbar VT is connected to U3PBB1 and the voltage from the line VT is connected to U3PLN1. The positions of the VT fuses shall also be connected as shown above. The voltage selection parameter \( \text{CBConfig} \) is set to \text{No voltage sel.}

12.1.3.2 Single circuit breaker with double busbar, external voltage selection

Figure 106: Connection of SESRSYN function block in a single breaker, double busbar arrangement with external voltage selection
In this type of arrangement no internal voltage selection is required. The voltage selection is made by external relays typically connected according to figure 106. Suitable voltage and VT fuse failure supervision from the two busbars are selected based on the position of the busbar disconnectors. This means that the connections to the function block will be the same as for the single busbar arrangement. The voltage selection parameter CBConfig is set to No voltage sel.

12.1.3.3 Single circuit breaker with double busbar, internal voltage selection

When internal voltage selection is needed, the voltage transformer circuit connections are made according to figure 107. The voltage from the busbar 1 VT is connected to U3PBB1 and the voltage from busbar 2 is connected to U3PBB2. The voltage from the line VT is connected to U3PLN1. The positions of the disconnectors and VT fuses shall be connected as shown in figure 107. The voltage selection parameter CBConfig is set to Double bus.

Figure 107: Connection of the SESRSYN function block in a single breaker, double busbar arrangement with internal voltage selection
12.1.3.4 Double circuit breaker

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 U3PBB1 on SESRSYN for WA1_QA1 and the voltage from busbar 2 VT is connected to U3PBB1 on SESRSYN for WA2_QA1. The voltage from the line VT is connected to U3PLN1 on both function blocks. The condition of VT fuses shall also be connected as shown in figure 107. The voltage selection parameter CBConfig is set to No voltage sel. for both function blocks.

12.1.3.5 1 1/2 circuit breaker

Figure 109 describes a 1 ½ breaker 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 U3PBB1 on all three function blocks and the voltage from busbar 2 VT is connected to U3PBB2 on all three function blocks. The voltage from line1 VT is connected to U3PLN1 on all three function blocks and the voltage from line2 VT is connected to U3PLN2 on all three function blocks. The positions of the disconnectors and VT fuses shall be connected as shown in Figure 109.
Figure 109: Connections of the SESRSYN function block in a 1 ½ breaker 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 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:
- B1QOPEN/CLD = Position of TIE_QA1 breaker and belonging disconnectors
- B2QOPEN/CLD = Position of WA2_QA1 breaker and belonging disconnectors
- LN1QOPEN/CLD = Position of LINE1_QB9 disconnector
- LN2QOPEN/CLD = Position of LINE2_QB9 disconnector
- UB1OK/FF = Supervision of WA1_MCB fuse
- UB2OK/FF = Supervision of WA2_MCB fuse
- ULN1OK/FF = Supervision of LINE1_MCB fuse
- ULN2OK/FF = Supervision of LINE2_MCB fuse
- Setting CBConfig = 1 1/2 bus CB

TIE_QA1:
- B1QOPEN/CLD = Position of WA1_QA1 breaker and belonging disconnectors
- B2QOPEN/CLD = Position of WA2_QA1 breaker and belonging disconnectors
- LN1QOPEN/CLD = Position of LINE1_QB9 disconnector
- LN2QOPEN/CLD = Position of LINE2_QB9 disconnector
- UB1OK/FF = Supervision of WA1_MCB fuse
- UB2OK/FF = Supervision of WA2_MCB fuse
- ULN1OK/FF = Supervision of LINE1_MCB fuse
- ULN2OK/FF = Supervision of LINE2_MCB fuse
- Setting CBConfig = Tie CB

WA2_QA1:
- B1QOPEN/CLD = Position of WA1_QA1 breaker and belonging disconnectors
- B2QOPEN/CLD = Position of TIE_QA1 breaker and belonging disconnectors
- LN1QOPEN/CLD = Position of LINE1_QB9 disconnector
- LN2QOPEN/CLD = Position of LINE2_QB9 disconnector
- UB1OK/FF = Supervision of WA1_MCB fuse
- UB2OK/FF = Supervision of WA2_MCB fuse
- ULN1OK/FF = Supervision of LINE1_MCB fuse
- ULN2OK/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.
12.1.4 Setting guidelines

The setting parameters for the Synchronizing, synchrocheck and energizing check function SESRSYN are set via the local HMI (LHMI) or PCM600.

This setting guidelines describes the settings of the SESRSYN function via the LHMI.

The SESRSYN function has the following four configuration parameters, which on the LHMI are found under Settings/General Settings/Control/Synchronizing(RSYN,25)/SESRSYN:X.

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.

The same voltages must be used for both Bus and Line or, alternatively, a compensation of angle difference can be set. See setting PhaseShift below under General Settings.

The SESRSYN function has one setting for the bus reference voltage (UBaseBus) and one setting for the line reference voltage (UBaseLine), which can be set as a reference of base values independently of each other. This means that the reference voltage of bus and line can be set to different values, which is necessary, for example, when synchronizing via a transformer.

The settings for the SESRSYN function are found under Settings/Setting group N/Control/Synchronizing(RSYN,25)/SESRSYN:X on the LHMI and are divided into four different groups: General, Synchronizing, Synchrocheck and Energizingcheck.

General settings

Operation: The operation mode can be set On or Off from PST. The setting Off disables the whole SESRSYN function.

CBConfig

This configuration setting is used to define type of voltage selection. Type of voltage selection can be selected as:
- no voltage selection
- single circuit breaker with double bus
- 1 1/2 circuit breaker arrangement with the breaker connected to busbar 1
- 1 1/2 circuit breaker arrangement with the breaker connected to busbar 2
- 1 1/2 circuit breaker arrangement with the breaker connected to line 1 and 2 (tie breaker)

$U_{BaseBus}$ and $U_{BaseLine}$

These are the configuration settings for the base voltages.

$U_{Ratio}$

The $U_{Ratio}$ is defined as $U_{Ratio} = \text{bus voltage/line voltage}$. This setting scales up the line voltage to an equal level with the bus voltage.

$PhaseShift$

This setting is used to compensate for a phase shift caused by a transformer between the two measurement points for bus voltage and line voltage, or by a use of different voltages as a reference for the bus and line voltages. The set value is added to the measured line phase angle. The bus voltage is the 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.

$U_{HighBusSynch}$ and $U_{HighLineSynch}$

The voltage level settings shall be chosen in relation to the bus/line network voltage. The threshold voltages $U_{HighBusSynch}$ and $U_{HighLineSynch}$ have to be set smaller than the value where the network is expected to be synchronized. A typical value is 80% of the rated voltage.

$UDiffSynch$

Setting of the voltage difference between the line voltage and the bus voltage. The difference is set depending on the network configuration and expected voltages in the two networks running asynchronously. A normal setting is 0.10-0.15 p.u.

$FreqDiffMin$

The setting $FreqDiffMin$ is the minimum frequency difference where the systems are defined to be asynchronous. For frequency differences lower than this value, the systems are considered to be in parallel. A typical value for $FreqDiffMin$ is 10 mHz. Generally, the value should be low if both synchronizing and synchrocheck functions are provided, and it is better to let the synchronizing function close, as it will close at exactly the right instance if the networks run with a frequency difference.
FreqDiffMin must be set to the same value as FreqDiffM, respective FreqDiffA for SESRSYN depending on whether the functions are used for manual operation, autoreclosing, or both.

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.

tBreaker

The setting $tBreaker$ shall be set to match the closing time for the circuit breaker and must also include the possible auxiliary relays in the closing circuit. A typical setting is 80-150 ms, depending on the breaker closing time.

It is important to check that no slow logic components are used in the configuration of the IED, as this may cause variations in the closing time.

tClosePulse

The setting for the duration of the breaker close pulse.

tMaxSynch

The setting $tMaxSynch$ is set to reset the operation of the synchronizing function if the operation does not take place within this time. The setting must allow for the setting of FreqDiffMin, which will decide how long it will take maximum to reach phase equality. At the setting of 10 ms, the beat time is 100 seconds and the setting would thus need to be at least $tMinSynch$ plus 100 seconds. If the network frequencies are expected to be outside the limits from the start, a margin needs to be added. A typical setting is 600 seconds.

tMinSynch

The setting $tMinSynch$ is set to limit the minimum time at which the synchronizing closing attempt is given. The synchronizing function will not give a closing command within this time, from when the synchronizing is started, even if a synchronizing condition is fulfilled. A typical setting is 200 ms.
Synchrocheck settings

OperationSC

The OperationSC setting Off disables the synchrocheck function and sets the outputs AUTOSYOK, MANSYOK, TSTAUTSY and TSTMANSY to low. With the setting On, the function is in the service mode and the output signal depends on the input conditions.

UHighBusSC and UHighLineSC

The voltage level settings must be chosen in relation to the bus or line network voltage. The threshold voltages UHighBusSC and UHighLineSC have to be set lower than the value at which the breaker is expected to close with the synchronism check. A typical value can be 80% of the base voltages.

UDiffSC

The setting for voltage difference between line and bus in p.u, defined as (U-Bus/UBaseBus) - (U-Line/UBaseLine).

FreqDiffM and FreqDiffA

The frequency difference level settings, FreqDiffM and FreqDiffA, are chosen depending on network conditions. At steady conditions, a low frequency difference setting is needed, where the FreqDiffM setting is used. For autoreclosing, a bigger frequency difference setting is preferable, where the FreqDiffA setting is used. A typical value for FreqDiffM can be 10 mHz, and a typical value for FreqDiffA can be 100-200 mHz.

PhaseDiffM and PhaseDiffA

The phase angle difference level settings, PhaseDiffM and PhaseDiffA, are also chosen depending on conditions in the network. The phase angle setting must be chosen to allow closing under maximum load. A typical maximum value in heavy-loaded networks can be 45 degrees, whereas in most networks the maximum occurring angle is below 25 degrees. The PhaseDiffM setting will be a limitation also for PhaseDiffA as it is expected that, due to the fluctuations, which can occur at high speed autoreclosing, the PhaseDiffA is limited in setting.

tSCM and tSCA

The purpose of the timer delay settings, tSCM and tSCA, is to ensure that the synchrocheck conditions remain constant and that the situation is not due to a temporary interference. If the conditions do 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. Under stable conditions, a longer operation time delay setting is needed, where the tSCM setting is used. During auto-reclosing, a shorter operation time delay setting is preferable, where the tSCA
setting is used. A typical value for $t_{SCM}$ 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:

- **Off**, the energizing function is disabled.
- **DLLB**, Dead Line Live Bus, the line voltage is below set value of $U_{LowLineEnerg}$ and the bus voltage is above set value of $U_{HighBusEnerg}$.
- **DBLL**, Dead Bus Live Line, the bus voltage is below set value of $U_{LowBusEnerg}$ and the line voltage is above set value of $U_{HighLineEnerg}$.
- **Both**, energizing can be done in both directions, DLLB or DBLL.

*ManEnergDBDL*

If the parameter is set to *On*, manual closing is enabled when both line voltage and bus voltage are below $U_{LowLineEnerg}$ and $U_{LowBusEnerg}$ respectively, and *ManEnerg* is set to DLLB, DBLL or Both.

*$U_{HighBusEnerg}$ and *$U_{HighLineEnerg}$*

The voltage level settings must be chosen in relation to the bus or line network voltage. The threshold voltages $U_{HighBusEnerg}$ and $U_{HighLineEnerg}$ 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.

*$U_{LowBusEnerg}$ and *$U_{LowLineEnerg}$*

The threshold voltages $U_{LowBusEnerg}$ and $U_{LowLineEnerg}$ 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 $U_{HighBusEnerg}$/$U_{HighLineEnerg}$ and $U_{LowBusEnerg}$/$U_{LowLineEnerg}$ 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 the setting conditions mentioned above.

*$UMaxEnerg$
This setting is used to block the closing when the voltage on the live side is above the set value of \(U_{\text{MaxEnerg}}\).

\(t_{\text{AutoEnerg}}\) and \(t_{\text{ManEnerg}}\)

The purpose of the timer delay settings, \(t_{\text{AutoEnerg}}\) and \(t_{\text{ManEnerg}}\), is to ensure that the dead side remains de-energized and that the condition is not due to a temporary interference. If the conditions do not persist for the specified time, the delay timer is reset and the procedure is restarted when the conditions are fulfilled again. Circuit breaker closing is thus not permitted until the energizing condition has remained constant throughout the set delay setting time.

12.2 Autorecloser for 1 phase, 2 phase and/or 3 phase operation SMBRREC

12.2.1 Identification

<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>
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<tbody>
<tr>
<td>Autorecloser for 1 phase, 2 phase and/or 3 phase</td>
<td>SMBRREC</td>
<td></td>
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</table>

12.2.2 Application

In certain countries it is standard practice to provide delayed restoration after busbar protection operation for internal fault, reason being that many busbar faults are of the transient natures that is, animals, birds, storm, flying objects, etc. In such applications, typically one pre-selected feeder is automatically closed with certain time delay in order to try to re-energize the faulty bus. Typically, the longest overhead line is selected in order to limit the fault current in case of permanent busbar fault. If the first feeder is successfully closed, all other feeder which have been connected to the same bus, are automatically put back into service.

Sensitive differential protection level available in REB670 can be used during such operation, if increased sensitivity from busbar protection is required. Such busbar restoration logic can be implemented by using optionally available autoreclosing functions and built-in logical gates. Two autoreclosing functions are available, one for each zone.

Automatic reclosing is a well-established method for the restoration of service in a power system after a transient line fault. The majority of line faults are flashover arcs, which are transient by nature. When the power line is switched off by the operation of
line protection and line breakers, the arc de-ionizes and recovers its ability to withstand voltage at a somewhat variable rate. Thus, a certain dead time with a de-energized line is necessary. Line service can then be resumed by automatic reclosing of the line breakers. The dead time selected should be long enough to ensure a high probability of arc de-ionization and successful reclosing.

For individual line breakers, auto-reclosing equipment, the auto-reclosing open time is used to determine line “dead time”. When simultaneous tripping and reclosing at the two line ends occurs, auto-reclosing open time is approximately equal to the line “dead time”. If the open time and dead time differ then, the line will be energized until the breakers at both ends have opened.

**Figure 110:** Single-shot automatic reclosing at a permanent fault

Single-phase tripping and single-phase automatic reclosing is a way of limiting the effect of a single-phase line fault on power system operation. Especially at higher voltage levels, the majority of faults are of single-phase type (around 90%). To maintain system stability in power systems with limited meshing or parallel routing single phase auto reclosing is of particular value. During the single phase dead time the system is still capable of transmitting load on the two healthy phases and the system is still synchronized. It requires that each phase breaker operates individually, which is usually the case for higher transmission voltages.
A somewhat longer dead time may be required for single-phase reclosing compared to high-speed three-phase reclosing. This is due to the influence on the fault arc from the voltage and the current in the non-tripped phases.

To maximize the availability of the power system it is possible to choose single pole tripping and automatic reclosing during single-phase faults and three pole tripping and automatic reclosing during multi-phase faults. Three-phase automatic reclosing can be performed with or without the use of a synchronicity check, and an energizing check, such as dead line or dead busbar check.

During the single-pole open time there is an equivalent "series"-fault in the system resulting in a flow of zero sequence current. It is therefore necessary to coordinate the residual current protections (earth fault protection) with the single pole tripping and the auto-reclosing function. Attention shall also be paid to "pole discordance" that arises when circuit breakers are provided with single pole operating devices. These breakers need pole discordance protection. They must also be coordinated with the single pole auto-recloser and blocked during the dead time when a normal discordance occurs. Alternatively, they should use a trip time longer than the set single phase dead time.

For the individual line breakers and auto-reclosing equipment, the "auto-reclosing open time" expression is used. This is the dead time setting for the Auto-Recloser. During simultaneous tripping and reclosing at the two line ends, auto-reclosing open time is approximately equal to the line dead time. Otherwise these two times may differ as one line end might have a slower trip than the other end which means that the line will not be dead until both ends have opened.

If the fault is permanent, the line protection will trip again when reclosing is attempted in order to clear the fault.

It is common to use one automatic reclosing function per line circuit-breaker (CB). When one CB per line end is used, then there is one auto-reclosing function per line end. If auto-reclosing functions are included in duplicated line protection, which means two auto-reclosing functions per CB, one should take measures to avoid uncoordinated reclosing commands. In 1 1/2 breaker, double-breaker and ring bus arrangements, two CBs per line end are operated. One auto-reclosing function per CB is recommended. Arranged in such a way, sequential reclosing of the two CBs can be arranged with a priority circuit available in the auto-reclose function. In case of a permanent fault and unsuccessful reclosing of the first CB, reclosing of the second CB is cancelled and thus the stress on the power system is limited. Another advantage with the breaker connected auto-recloser is that checking that the breaker closed before the sequence, breaker prepared for an auto-reclose sequence and so on. is much simpler.

The auto-reclosing function can be selected to perform single-phase and/or three-phase automatic-reclosing from several single-shot to multiple-shot reclosing programs. The three-phase auto-reclosing open time can be set to give either High-Speed Automatic Reclosing (HSAR) or Delayed Automatic-Reclosing (DAR). These expressions, HSAR and DAR, are mostly used for three-phase Reclosing as single phase is always high speed to avoid maintaining the unsymmetrical condition. HSAR usually means a dead time of less than 1 second.
In power transmission systems it is common practise to apply single and/or three phase, single-shot Auto-Reclosing. In Sub-transmission and Distribution systems tripping and auto-reclosing are usually three-phase. The mode of automatic-reclosing varies however. Single-shot and multi-shot are in use. The first shot can have a short delay, HSAR, or a longer delay, DAR. The second and following reclosing shots have a rather long delay. When multiple shots are used the dead time must harmonize with the breaker duty-cycle capacity.

Automatic-reclosing is usually started by the line protection and in particular by instantaneous tripping of such protection. The auto-reclosing function can be inhibited (blocked) when certain protection functions detecting permanent faults, such as shunt reactor, cable or busbar protection are in operation. Back-up protection zones indicating faults outside the own line are also connected to inhibit the Auto-Reclose.

Automatic-reclosing should not be attempted when closing a CB and energizing a line onto a fault (SOTF), except when multiple-shots are used where shots 2 etc. will be started at SOTF. Likewise a CB in a multi-breaker busbar arrangement which was not closed when a fault occurred should not be closed by operation of the Auto-Reclosing function. Auto-Reclosing is often combined with a release condition from synchrocheck and dead line or dead busbar check. In order to limit the stress on turbo-generator sets from Auto-Reclosing onto a permanent fault, one can arrange to combine Auto-Reclosing with a synchrocheck on line terminals close to such power stations and attempt energizing from the side furthest away from the power station and perform the synchrocheck at the local end if the energizing was successful.

Transmission protection systems are usually sub-divided and provided with two redundant protection IEDs. In such systems it is common to provide auto-reclosing in only one of the sub-systems as the requirement is for fault clearance and a failure to reclose because of the auto-recloser being out of service is not considered a major disturbance. If two auto-reclosers are provided on the same breaker, the application must be carefully checked and normally one must be the master and be connected to inhibit the other auto-recloser if it has started. This inhibit can for example be done from Autorecloser for 3-phase operation(SMBRREC) In progress.

When Single and/or three phase auto-reclosing is considered, there are a number of cases where the tripping shall be three phase anyway. For example:

- Evolving fault where the fault during the dead-time spreads to another phase. The other two phases must then be tripped and a three phase dead-time and auto-reclose initiated
- Permanent fault
- Fault during three phase dead-time
- Auto-reclose out of service or CB not ready for an auto-reclosing cycle

“Prepare three-phase tripping” is then used to switch the tripping to three-phase. This signal is generated by the auto-recloser and connected to the trip function block and also connected outside the IED through IO when a common auto-recloser is provided for two sub-systems. An alternative signal “Prepare 1 Phase tripping” is also provided.
and can be used as an alternative when the autorecloser is shared with another subsystem. This provides a fail safe connection so that even a failure in the IED with the auto-recloser will mean that the other sub-system will start a three-phase trip.

A permanent fault will cause the line protection to trip again when it recloses in an attempt to energize the line.

The auto-reclosing function allows a number of parameters to be adjusted.

Examples:

- number of auto-reclosing shots
- auto-reclosing program
- auto-reclosing open times (dead time) for each shot

### 12.2.2.1 Auto-reclosing operation OFF and ON

Operation of the automatic reclosing can be set OFF and ON by a setting parameter and by external control. Parameter \( Operation = \text{Off} \), or \( On \) sets the function OFF and ON. With the settings \( Operation = \text{On} \) and \( ExternalCtrl = \text{On} \), the control is made by input signal pulses to the inputs ON and OFF, for example, from the control system or from the binary input (and other systems).

When the function is set ON, the output SETON is set, and it becomes operative if other conditions such as CB closed and CB Ready are also fulfilled, the output READY is activated (high). When the function is ready to accept a reclosing start.

### 12.2.2.2 Start auto-reclosing and conditions for start of a reclosing cycle

The usual way to start a reclosing cycle, or sequence, is to start it at selective tripping by line protection by applying a signal to the input START. Starting signals can be either, General Trip signals or, only the conditions for Differential, Distance protection Zone 1 and Distance protection Aided trip. In some cases also Directional Earth fault function Aided trip can be connected to start an Auto-Reclose attempt. If general trip is used to start the auto-recloser it is important to block it from other functions that should not start a reclosing sequence.

In cases where one wants to differentiate three-phase “auto-reclosing open time”, (“dead time”) for different power system configuration or at tripping by different protection stages, one can also use the input STARTHS (Start High-Speed Reclosing). When initiating STARTHS, the auto-reclosing open time for three-phase shot 1, \( t1 \) 3PhHS is used and the closing is done without checking the synchrocheck condition.

A number of conditions need to be fulfilled for the start to be accepted and a new auto-reclosing cycle to be started. They are linked to dedicated inputs. The inputs are:
• CBREADY, CB ready for a reclosing cycle, for example, charged operating gear.
• CBPOS to ensure that the CB was closed when the line fault occurred and start was applied.
• No signal at input INHIBIT that is, no blocking or inhibit signal present. After the start has been accepted, it is latched in and an internal signal “Started” is set. It can be interrupted by certain events, like an “Inhibit” signal.

12.2.2.3 Start auto-reclosing from CB open information

If a user wants to initiate auto-reclosing from the "CB open" position instead of from protection trip signals, the function offers such a possibility. This starting mode is selected with the setting parameter StartByCBOpen=On. It is then necessary to block reclosing for all manual trip operations. Typically CBAuxContType=NormClosed is also set and a CB auxiliary contact of type NC (normally closed) is connected to inputs CBPOS and START. When the signal changes from “CB closed” to “CB open” an auto-reclosing start pulse is generated and latched in the function, subject to the usual checks. Then the reclosing sequence continues as usual. One needs to connect signals from manual tripping and other functions, which shall not be reclosed automatically to the input INHIBIT.

12.2.2.4 Blocking of the autorecloser

Auto-Reclose attempts are expected to take place only for faults on the own line. The Auto-Recloser must be blocked by activating the INHIBIT input for the following conditions:

• Tripping from Delayed Distance protection zones
• Tripping from Back-up protection functions
• Tripping from Breaker failure function
• Intertrip received from remote end Breaker failure function
• Busbar protection tripping

Depending of the starting principle (General Trip or only Instantaneous trip) adopted above the delayed and back-up zones might not be required. Breaker failure trip local and remote must however always be connected.

12.2.2.5 Control of the auto-reclosing open time for shot 1

Up to four different time settings can be used for the first shot, and one extension time. There are separate settings for single-, two- and three-phase auto-reclosing open time, t1 1Ph, t1 2Ph, t1 3Ph. If no particular input signal is applied, and an auto-reclosing program with single-phase reclosing is selected, the auto-reclosing open time t1 1Ph will be used. If one of the inputs TR2P or TR3P is activated in connection with the start, the auto-reclosing open time for two-phase or three-phase reclosing is used. There is also a separate time setting facility for three-phase high-speed auto-reclosing without Synchrocheck, t1 3PhHS, available for use when required. It is activated by the STARTHS input.
An auto-reclosing open time extension delay, $t_{Extended\ t1}$, can be added to the normal shot 1 delay. It is intended to come into use if the communication channel for permissive line protection is lost. In such a case there can be a significant time difference in fault clearance at the two ends of the line. A longer “auto-reclosing open time” can then be useful. This extension time is controlled by setting parameter $Extended\ t1=On$ and the input PLCLOST. If this function is used the autorecloser start must also be allowed from distance protection Zone 2 time delayed trip.

12.2.2.6 Long trip signal

In normal circumstances the trip command resets quickly because of fault clearance. The user can set a maximum trip pulse duration $t_{Trip}$. If $Extended\ t1=Off$, a long trip signal interrupts the reclosing sequence in the same way as a signal to input INHIBIT. If $Extended\ t1=On$ the long trip time inhibit is disabled and $Extended\ t1$ is used instead.

12.2.2.7 Maximum number of reclosing shots

The maximum number of reclosing shots in an auto-reclosing cycle is selected by the setting parameter $NoOfShots$. The type of reclosing used at the first reclosing shot is set by parameter $ARMode$. The first alternative is three-phase reclosing. The other alternatives include some single-phase or two-phase reclosing. Usually there is no two-phase tripping arranged, and then there will be no two-phase reclosing.

The decision for single and 3 phase trip is also made in the tripping logic (SMPTTRC) function block where the setting $3Ph, 1/3Ph$ (or $1/2/3Ph$) is selected.

12.2.2.8 $ARMode=3ph$, (normal setting for a single 3 phase shot)

3-phase reclosing, one to five shots according to setting $NoOfShots$. The output Prepare three-phase trip PREP3P is always set (high). A trip operation is made as a three-phase trip at all types of fault. The reclosing is as a three-phase Reclosing as in mode $1/2/3ph$ described below. All signals, blockings, inhibits, timers, requirements and so on. are the same as in the example described below.

12.2.2.9 $ARMode=1/2/3ph$

1-phase, 2-phase or 3-phase reclosing first shot, followed by 3-phase reclosing shots, if selected. Here, the auto-reclosing function is assumed to be "On" and "Ready". The breaker is closed and the operation gear ready (operating energy stored). Input START (or STARTHS) is received and sealed-in. The output READY is reset (set to false). Output ACTIVE is set.

- If inputs TR2P is low and TR3P is low (1-phase trip): The timer for 1-phase reclosing open time is started and the output 1PT1 (1-phase reclosing in progress)
is activated. It can be used to suppress pole disagreement and earth-fault protection trip during the 1-phase open interval.

- If TR2P is high and TR3P is low (2-phase trip): The timer for 2-phase reclosing open time is started and the output 2PT1 (2-phase reclosing in progress) is activated.
- If TR3P is high (3-phase trip): The timer for 3-phase auto-reclosing open time, \( t_{3Ph} \) is started and output 3PT1 (3-phase auto-reclosing shot 1 in progress) is set.
- If STARTHS is high (3-phase trip): The timer for 3-phase auto-reclosing open time, \( t_{3PhHS} \) is started and output 3PT1 (3-phase auto-reclosing shot 1 in progress) is set.

While any of the auto-reclosing open time timers are running, the output INPROGR is activated. When the "open time" timer runs out, the respective internal signal is transmitted to the output module for further checks and to issue a closing command to the circuit breaker.

When a CB closing command is issued the output prepare 3-phase trip is set. When issuing a CB closing command a “reclaim” timer \( t_{Reclaim} \) is started. If no tripping takes place during that time the auto-reclosing function resets to the “Ready” state and the signal ACTIVE resets. If the first reclosing shot fails, a 3-phase trip will be initiated and 3-phase reclosing can follow, if selected.

12.2.2.10 \( ARMode=1/2ph, \text{ 1-phase or 2-phase reclosing in the first shot.} \)

In 1-phase or 2-phase tripping, the operation is as in the above described example, program mode \( 1/2/3ph \). If the first reclosing shot fails, a 3-phase trip will be issued and 3-phase reclosing can follow, if selected. In the event of a 3-phase trip, TR3P high, the auto-reclosing will be blocked and no reclosing takes place.

12.2.2.11 \( ARMode=1ph+1*2ph, \text{ 1-phase or 2-phase reclosing in the first shot} \)

The 1-phase reclosing attempt can be followed by 3-phase reclosing, if selected. A failure of a 2-phase reclosing attempt will block the auto-reclosing. If the first trip is a 3-phase trip the auto-reclosing will be blocked. In the event of a 1-phase trip, (TR2P low and TR3P low), the operation is as in the example described above, program mode \( 1/2/3ph \). If the first reclosing shot fails, a 3-phase trip will be initiated and 3-phase reclosing can follow, if selected. A maximum of four additional shots can be done (according to the \( NoOfShots \) parameter). At 2-phase trip (TR2P high and TR3P low), the operation is similar to the above. But, if the first reclosing shot fails, a 3-phase trip will be issued and the auto-reclosing will be blocked. No more shots are attempted! The expression \( 1*2ph \) should be understood as “Just one shot at 2-phase reclosing” During 3-phase trip (TR2P low and TR3P high) the auto-reclosing will be blocked and no reclosing takes place.
12.2.2.12 \textbf{ARMode}=1/2ph + 1*3ph, 1-phase, 2-phase or 3-phase reclosing in the first shot

At 1-phase or 2-phase trip, the operation is as described above. If the first reclosing shot fails, a 3-phase trip will be issued and 3-phase reclosing will follow, if selected. At 3-phase trip, the operation is similar to the above. But, if the first reclosing shot fails, a 3-phase trip command will be issued and the auto-reclosing will be blocked. No more shots take place! 1*3ph should be understood as “Just one shot at 3-phase reclosing”.

12.2.2.13 \textbf{ARMode}=1ph + 1*2/3ph, 1-phase, 2-phase or 3-phase reclosing in the first shot

At 1-phase trip, the operation is as described above. If the first reclosing shot fails, a 3-phase trip will be issued and 3-phase reclosing will follow, if selected. At 2-phase or 3-phase trip, the operation is similar as above. But, if the first reclosing shot fails, a 3-phase trip will be issued and the auto-reclosing will be blocked. No more shots take place! “1*2/3ph” should be understood as “Just one shot at 2-phase or 3-phase reclosing”.

\begin{table}[h]
\centering
\begin{tabular}{|c|c|c|c|}
\hline
\textbf{MODEINT (integer)} & \textbf{ARMode} & \textbf{Type of fault} & \textbf{1st shot} & \textbf{2nd-5th shot} \\
\hline
1 & 3ph & 1ph & 3ph & 3ph \\
& & 2ph & 3ph & 3ph \\
& & 3ph & 3ph & 3ph \\
\hline
2 & 1/2/3ph & 1ph & 1ph & 3ph \\
& & 2ph & 2ph & 3ph \\
& & 3ph & 3ph & 3ph \\
\hline
3 & 1/2ph & 1ph & 1ph & 3ph \\
& & 2ph & 2ph & 3ph \\
& & 3ph & ..... & ..... \\
\hline
4 & 1ph + 1*2ph & 1ph & 1ph & 3ph \\
& & 2ph & 2ph & ..... \\
& & 3ph & ..... & ..... \\
\hline
5 & 1/2ph + 1*3ph & 1ph & 1ph & 3ph \\
& & 2ph & 2ph & 3ph \\
& & 3ph & 3ph & ..... \\
\hline
6 & 1ph + 1*2/3ph & 1ph & 1ph & 3ph \\
& & 2ph & 2ph & ..... \\
& & 3ph & 3ph & ..... \\
\hline
\end{tabular}
\caption{Type of reclosing shots at different settings of ARMode or integer inputs to MODEINT}
\end{table}

A start of a new reclosing cycle is blocked during the set “reclaim time” after the selected number of reclosing shots have been made.
12.2.2.14 External selection of auto-reclose mode

The auto-reclose mode can be selected by use of the available logic function blocks. Below is an example where the choice of mode is done from a hardware function key in front of the IED with only 3 phase or 1/3 phase mode, but alternatively there can for example, be a physical selector switch on the front of the panel which is connected to a binary to integer function block (BTIGAPC).

The connection example for selection of the auto-reclose mode is shown in figure 111.

![Figure 111: Selection of the auto-reclose mode from a hardware functional key in front of the IED](image)

12.2.2.15 Reclosing reclaim timer

The reclaim timer $t_{Reclaim}$ defines the time it takes from issue of the reclosing command, until the reclosing function resets. Should a new trip occur during this time, it is treated as a continuation of the first fault. The reclaim timer is started when the CB closing command is given.

12.2.2.16 Pulsing of the CB closing command and Counter

The CB closing command, CLOSECB is given as a pulse with a duration set by parameter $t_{Pulse}$. For circuit-breakers without an anti-pumping function, close pulse cutting can be used. It is selected by parameter $CutPulse=On$. In case of a new trip pulse (start), the closing command pulse is then cut (interrupted). The minimum closing pulse length is always 50 ms. At the issue of the Reclosing command, the appropriate Reclosing operation counter is incremented. There is a counter for each type of Reclosing and one for the total number of Reclosing commands.

12.2.2.17 Transient fault

After the Reclosing command the reclaim timer keeps running for the set time. If no tripping occurs within this time, $t_{Reclaim}$, the Auto-Reclosing will reset. The CB remains closed and the operating gear recharges. The input signals CBPOS and CBREADY will be set.
Permanent fault and reclosing unsuccessful signal

If a new trip occurs, and number of reclosing shots is set to 1, a new input signal START or TRSOTF appears, after the CB closing command, the output UNSUCL (unsuccessful closing) is set high. The timer for the first shot can no longer be started. Depending on the set number of Reclosing shots further shots may be made or the Reclosing sequence is ended. After reclaim timer time-out the Auto-Reclosing function resets, but the CB remains open. The “CB closed” information through the input CBPOS is missing. Thus, the reclosing function is not ready for a new reclosing cycle.

Normally, the signal UNSUCL appears when a new trip and start is received after the last reclosing shot has been made and the auto-reclosing function is blocked. The signal resets after reclaim time. The “unsuccessful” signal can also be made to depend on CB position input. The parameter UnsucClByCBChk should then be set to CBCheck, and a timer tUnsucCl should be set too. If the CB does not respond to the closing command and does not close, but remains open, the output UNSUCL is set high after time tUnsucCl. The Unsuccessful output can for example, be used in Multi-Breaker arrangement to cancel the auto-reclosing function for the second breaker, if the first breaker closed onto a persistent fault. It can also be used to generate a Lock-out of manual closing until the operator has reset the Lock-out, see separate section.

Lock-out initiation

In many cases there is a requirement that a Lock-out is generated when the auto-reclosing attempt fails. This is done with logic connected to the in- and outputs of the Autoreclose function and connected to Binary IO as required. Many alternative ways of performing the logic exist depending on whether manual closing is interlocked in the IED, whether an external physical Lock-out relay exists and whether the reset is hardwired, or carried out by means of communication. There are also different alternatives regarding what shall generate Lock-out. Examples of questions are:

- Shall back-up time delayed trip give Lock-out (normally yes)
- Shall Lock-out be generated when closing onto a fault (mostly)
- Shall Lock-out be generated when the Autorecloser was OFF at the fault or for example, in Single phase AR mode and the fault was multi-phase (normally not as no closing attempt has been given)
- Shall Lock-out be generated if the Breaker did not have sufficient operating power for an auto-reclosing sequence (normally not as no closing attempt has been given)

In figures 112 and 113 the logic shows how a closing Lock-out logic can be designed with the Lock-out relay as an external relay alternatively with the Lock-out created internally with the manual closing going through the Synchro-check function. An example of Lock-out logic.
12.2.2.20 Evolving fault

An evolving fault starts as a single-phase fault which leads to single-phase tripping and then the fault spreads to another phase. The second fault is then cleared by three-phase tripping.

The Auto-Recovering function will first receive a trip and start signal (START) without any three-phase signal (TR3P). The Auto-Recovering function will start a single-phase reclosing, if programmed to do so. At the evolving fault clearance there will be a new signal START and three-phase trip information, TR3P. The single-phase reclosing sequence will then be stopped, and instead the timer, \( t1 \ 3Ph \), for three-phase reclosing will be started from zero. The sequence will continue as a three-phase reclosing sequence, if it is a selected alternative reclosing mode.
The second fault which can be single phase is tripped three phase because trip module (TR) in the IED has an evolving fault timer which ensures that second fault is always tripped three phase. For other types of relays where the relays do not include this function the output PREP3PH (or the inverted PERMIT1PH) is used to prepare the other sub-system for three phase tripping. This signal will, for evolving fault situations be activated a short time after the first trip has reset and will thus ensure that new trips will be three phase.

12.2.2.21 Automatic continuation of the reclosing sequence

SMBRREC function can be programmed to proceed to the following reclosing shots (if multiple shots are selected) even if start signals are not received from the protection functions, but the breaker is still not closed. This is done by setting parameter \textit{AutoCont} = \textit{On} and \textit{tAutoContWait} to the required delay for the function to proceed without a new start.

12.2.2.22 Thermal overload protection holding the auto-reclosing function back

If the input THOLHOLD (thermal overload protection holding reclosing back) is activated, it will keep the reclosing function on a hold until it is reset. There may thus be a considerable delay between start of Auto-Reclosing and reclosing command to the circuit-breaker. An external logic limiting the time and sending an inhibit to the INHIBIT input can be used. The input can also be used to set the Auto-Reclosing on hold for a longer or shorter period.

12.2.3 Setting guidelines

12.2.3.1 Configuration

Use the PCM600 configuration tool to configure signals.

Autorecloser function parameters are set via the local HMI or Parameter Setting Tool (PST). Parameter Setting Tool is a part of PCM600.

Recommendations for input signals

Please see figure 114, figure 115 and figure 116 and default factory configuration for examples.

ON and OFF

These inputs can be connected to binary inputs or to a communication interface block for external control.

START

It should be connected to the trip output protection function, which starts the autorecloser for 1/2/3-phase operation (SMBRREC) function. It can also be connected to a binary input for start from an external contact. A logical OR-gate can be used to combine the number of start sources.
If StartByCBOpen is used, the CB Open condition shall also be connected to the input START.

**STARTHS, Start High-speed auto-reclosing**

It may be used when one wants to use two different dead times in different protection trip operations. This input starts the dead time **t**<sub>1</sub> **3PhHS**. High-speed reclosing shot 1 started by this input is without a synchronization check.

**INHIBIT**

To this input shall be connected signals that interrupt a reclosing cycle or prevent a start from being accepted. Such signals can come from protection for a line connected shunt reactor, from transfer trip receive, from back-up protection functions, busbar protection trip or from breaker failure protection. When the CB open position is set to start SMBRREC, then manual opening must also be connected here. The inhibit is often a combination of signals from external IEDs via the IO and internal functions. An OR gate is then used for the combination.

**CBPOS and CBREADY**

These should be connected to binary inputs to pick-up information from the CB. The CBPOS input is interpreted as CB Closed, if parameter **CBAuxContType** is set **NormOpen**, which is the default setting. At three operating gears in the breaker (single pole operated breakers) the connection should be “All poles closed” (series connection of the NO contacts) or “At least one pole open” (parallel connection of NC contacts) if the **CBAuxContType** is set to **NormClosed**. The “CB Ready” is a signal meaning that the CB is ready for a reclosing operation, either Close-Open (CO), or Open-Close-Open (OCO). If the available signal is of type “CB not charged” or “not ready”, an inverter can be inserted in front of the CBREADY input.

**SYNC**

This is connected to the internal synchrocheck function when required. It can also be connected to a binary input for synchronization from an external device. If neither internal nor external synchronism or energizing check is required, it can be connected to a permanently high source, TRUE. The signal is required for three phase shots 1-5 to proceed (Note! Not the HS step).

**PLCLOST**

This is intended for line protection permissive signal channel lost (fail) for example, PLC= Power Line Carrier fail. It can be connected, when required to prolong the AutoReclosing time when communication is not working, that is, one line end might trip with a zone 2 delay. If this is used the autorecloser must also be started from Zone2 time delayed trip.
TRSOTF

This is the signal “Trip by Switch Onto Fault”. It is usually connected to the “switch onto fault” output of line protection if multi-shot Auto-Reclose attempts are used. The input will start the shots 2-5.

THOLHOLD

Signal “Thermal overload protection holding back Auto-Reclosing”. It can be connected to a thermal overload protection trip signal which resets only when the thermal content has fallen to an acceptable level, for example, 70%. As long as the signal is high, indicating that the line is hot, the Auto-Reclosing is held back. When the signal resets, a reclosing cycle will continue. Please observe that this have a considerable delay. Input can also be used for other purposes if for some reason the Auto-Reclose shot need to be halted.

TR2P and TR3P

Signals for two-phase and three-phase trip. They are usually connected to the corresponding output of the TRIP block. They control the choice of dead time and the reclosing cycle according to the selected program. Signal TR2P needs to be connected only if the trip has been selected to give 1/2/3 phase trip and an auto reclosing cycle with two phase reclosing is foreseen.

WAIT

Used to hold back reclosing of the “low priority unit” during sequential reclosing. See “Recommendation for multi-breaker arrangement” below. The signal is activated from output WFMASTER on the second breaker Auto-Recloser in multi-breaker arrangements.

BLKON

Used to block the autorecloser for 3-phase operation (SMBRREC) function for example, when certain special service conditions arise. When used, blocking must be reset with BLOCKOFF.

BLOCKOFF

Used to Unblock SMBRREC function when it has gone to Block due to activating input BLKON or by an unsuccessful Auto-Reclose attempt if the setting BlockByUnsucCl is set to On.

RESET

Used to Reset SMBRREC to start condition. Possible Thermal overload Hold will be reset. Positions, setting On-Off. will be started and checked with set times.

Recommendations for output signals

Please see figure 114, figure 115 and figure 116 and default factory configuration for examples.
SETON
Indicates that Autorecloser for 1/2/3-phase operation (SMBRREC) function is switched on and operative.

BLOCKED
Indicates that SMRREC function is temporarily or permanently blocked.

ACTIVE
Indicates that SMBRREC is active, from start until end of Reclaim time.

INPROGR
Indicates that a sequence is in progress, from start until reclosing command.

UNSUCCL
Indicates unsuccessful reclosing.

CLOSECB
Connect to a binary output for circuit-breaker closing command.

READY
Indicates that SMBRREC function is ready for a new and complete reclosing sequence. It can be connected to the zone extension if a line protection should extended zone reach before automatic reclosing.

1PT1 and 2PT1
Indicates that single-phase or two-phase automatic reclosing is in progress. It is used to temporarily block an earth-fault and/or pole disagreement function during the single-phase or two-phase open interval.

3PT1, 3PT2, 3PT3, 3PT4 and 3PT5
Indicates that three-phase automatic reclosing shots 1-5 are in progress. The signals can be used as an indication of progress or for own logic.

PREP3P
Prepare three-phase trip is usually connected to the trip block to force a coming trip to be a three-phase one. If the function cannot make a single-phase or two-phase reclosing, the tripping should be three-phase.

PERMIT1P
Permit single-phase trip is the inverse of PREP3P. It can be connected to a binary output relay for connection to external protection or trip relays. In case of a total loss of auxiliary power, the output relay drops and does not allow single-phase trip.
**WFMASTER**

Wait from master is used in high priority units to hold back reclosing of the low priority unit during sequential reclosing. Refer to the recommendation for multi-breaker arrangements in figure 116.

**Other outputs**

The other outputs can be connected for indication, disturbance recording, as required.

![I/O-signal connections at a three-phase reclosing function](image)

**Setting recommendations for multi-breaker arrangements**

Sequential reclosing in multi-breaker arrangements, like 1 1/2-breaker, double breaker and ring bus, is achieved by giving the two line breakers different priorities. Please refer to figure 116. In a single breaker arrangement the setting is Priority = None. In a multi-breaker arrangement the setting for the first CB, the Master, is Priority = High and for the other CB Priority = Low.

While the reclosing of the master is in progress, it issues the signal WFMASTER. A reset delay of one second ensures that the WAIT signal is kept high for the duration of the breaker closing time. After an unsuccessful reclosing it is also maintained by the
signal UNSUCCCL. In the slave unit, the signal WAIT holds back a reclosing operation. When the WAIT signal is reset at the time of a successful reclosing of the first CB, the slave unit is released to continue the reclosing sequence. A parameter \( t_{\text{Wait}} \) sets a maximum waiting time for the reset of the WAIT. At time-out it interrupts the reclosing cycle of the slave unit. If reclosing of the first breaker is unsuccessful, the output signal UNSUCCCL connected to the input INHIBIT of the slave unit interrupts the reclosing sequence of the latter.

The signals can be cross-connected to allow simple changing of the priority by just setting the High and the Low priorities without changing the configuration. The inputs CBPOS for each breaker are important in multi breaker arrangements to ensure that the CB was closed at the beginning of the cycle. If the High priority breaker is not closed the High priority moves to the low priority breaker.

**Figure 115:** Example of I/O-signal connections in a single-phase, two-phase or three-phase reclosing function
*) Other input/output signals as in previous single breaker arrangements

Figure 116: Additional input and output signals at multi-breaker arrangement. The connections can be made "symmetrical" to make it possible to control the priority by the settings, Priority:High/Low
12.2.3.2 Auto-recloser parameter settings

Operation

The operation of the Autorecloser for 1/2/3-phase operation (SMBRREC) function can be switched On and Off. The setting ExternalCtrl makes it possible to switch it On or Off using an external switch via IO or communication ports.

NoOfShots, Number of reclosing shots

In power transmission 1 shot is mostly used. In most cases one reclosing shot is sufficient as the majority of arcing faults will cease after the first reclosing shot. In power systems with many other types of faults caused by other phenomena, for example wind, a greater number of reclose attempts (shots) can be motivated.

First shot and reclosing program

There are six different possibilities in the selection of reclosing programs. The type of reclosing used for different kinds of faults depends on the power system configuration and the users practices and preferences. When the circuit-breakers only have three-phase operation, then three-phase reclosing has to be chosen. This is usually the case in subtransmission and distribution lines. Three-phase tripping and reclosing for all types of faults is also widely accepted in completely meshed power systems. In transmission systems with few parallel circuits, single-phase reclosing for single-phase faults is an attractive alternative for maintaining service and system stability.

Auto-reclosing open times, dead times

Single-phase auto-reclosing time: A typical setting is \( t_{1\ Ph} = 800\ ms \). Due to the influence of energized phases the arc extinction may not be instantaneous. In long lines with high voltage the use of shunt reactors in the form of a star with a neutral reactor improves the arc extinction.

Three-phase shot 1 delay: For three-phase High-Speed Auto-Reclosing (HSAR) a typical open time is 400ms. Different local phenomena, such as moisture, salt, pollution, can influence the required dead time. Some users apply Delayed Auto-Reclosing (DAR) with delays of 10s or more. The delay of reclosing shot 2 and possible later shots are usually set at 30s or more. A check that the CB duty cycle can manage the selected setting must be done. The setting can in some cases be restricted by national regulations. For multiple shots the setting of shots 2-5 must be longer than the circuit breaker duty cycle time.

Extended \( t_1 \) and \( t_{Extended\ t_1} \), Extended auto-reclosing open time for shot 1.

The communication link in a permissive (not strict) line protection scheme, for instance a power line carrier (PLC) link, may not always be available. If lost, it can result in delayed tripping at one end of a line. There is a possibility to extend the auto-reclosing open time in such a case by use of an input to PLCLOST, and the setting parameters. Typical setting in such a case: \( Extended\ t_1 = On \) and \( t_{Extended\ t_1} = 0.8\ s \).
**tSync, Maximum wait time for synchronizationcheck**

The time window should be coordinated with the operate time and other settings of the synchronization check function. Attention should also be paid to the possibility of a power swing when reclosing after a line fault. Too short a time may prevent a potentially successful reclosing.

**tTrip, Long trip pulse**

Usually the trip command and start auto-reclosing signal reset quickly as the fault is cleared. A prolonged trip command may depend on a CB failing to clear the fault. A trip signal present when the CB is reclosed will result in a new trip. Depending on the setting Extended t1 = Off or On a trip/start pulse longer than the set time tTrip will either block the reclosing or extend the auto-reclosing open time. A trip pulse longer than the set time tTrip will inhibit the reclosing. A typical setting of tTrip could be close to the auto-reclosing open time.

**tInhibit, Inhibit resetting delay**

A typical setting is tInhibit = 5.0 s to ensure reliable interruption and temporary blocking of the function. Function will be blocked during this time after the tInhibit has been activated.

**tReclaim, Reclaim time**

The Reclaim time sets the time for resetting the function to its original state, after which a line fault and tripping will be treated as an independent new case with a new reclosing cycle. One may consider a nominal CB duty cycle of for instance, O-0.3sec CO- 3 min. – CO. However the 3 minute (180 s) recovery time is usually not critical as fault levels are mostly lower than rated value and the risk of a new fault within a short time is negligible. A typical time may be tReclaim = 60 or 180 s dependent of the fault level and breaker duty cycle.

**StartByCBOpen**

The normal setting is Off. It is used when the function is started by protection trip signals. If set On the start of the autorecloser is controlled by an CB auxiliary contact.

**FollowCB**

The usual setting is Follow CB = Off. The setting On can be used for delayed reclosing with long delay, to cover the case when a CB is being manually closed during the “auto-reclosing open time” before the auto-reclosing function has issued its CB closing command.

**tCBClosedMin**

A typical setting is 5.0 s. If the CB has not been closed for at least this minimum time, a reclosing start will not be accepted.
**CBAuxContType**, CB auxiliary contact type

It shall be set to correspond to the CB auxiliary contact used. A *NormOpen* contact is recommended in order to generate a positive signal when the CB is in the closed position.

**CBReadyType**, Type of CB ready signal connected

The selection depends on the type of performance available from the CB operating gear. At setting *OCO* (CB ready for an Open – Close – Open cycle), the condition is checked only at the start of the reclosing cycle. The signal will disappear after tripping, but the CB will still be able to perform the C-O sequence. For the selection *CO* (CB ready for a Close – Open cycle) the condition is also checked after the set auto-reclosing dead time. This selection has a value first of all at multi-shot reclosing to ensure that the CB is ready for a C-O sequence at shot 2 and further shots. During single-shot reclosing, the *OCO* selection can be used. A breaker shall according to its duty cycle always have storing energy for a CO operation after the first trip. (IEC 56 duty cycle is O-0.3sec CO-3minCO).

**tPulse**, Breaker closing command pulse duration

The pulse should be long enough to ensure reliable operation of the CB. A typical setting may be \( t_{\text{Pulse}} = 200 \text{ ms} \). A longer pulse setting may facilitate dynamic indication at testing, for example, in “Debug” mode of Application Configuration tool (ACT). In CBs without anti-pumping relays, the setting \( \text{CutPulse} = \text{On} \) can be used to avoid repeated closing operation when reclosing onto a fault. A new start will then cut the ongoing pulse.

**BlockByUnsucCl**

Setting of whether an unsuccessful auto-reclose attempt shall set the Auto-Reclose in block. If used the inputs BLOCKOFF must be configured to unblock the function after an unsuccessful Reclosing attempt. Normal setting is *Off*.

**UnsuccClByCBCheck**, Unsuccessful closing by CB check

The normal setting is *NoCBCheck*. The “auto-reclosing unsuccessful” event is then decided by a new trip within the reclaim time after the last reclosing shot. If one wants to get the UNSUCCL (Unsuccessful closing) signal in the case the CB does not respond to the closing command, CLOSECB, one can set \( \text{UnsuccClByCBCheck} = \text{CB Check} \) and set \( t_{\text{UnsuccCl}} \) for instance to 1.0 s.

**Priority and time tWaitForMaster**

In single CB applications, one sets *Priority = None*. At sequential reclosing the function of the first CB, e.g. near the busbar, is set *Priority = High* and for the second CB *Priority = Low*. The maximum waiting time, \( t_{\text{WaitForMaster}} \) of the second CB is set longer than the “auto-reclosing open time” and a margin for synchrocheck at the first CB. Typical setting is \( t_{\text{WaitForMaster}} = 2\text{sec} \).
**AutoCont and tAutoContWait, Automatic continuation to the next shot if the CB is not closed within the set time**

The normal setting is AutoCont = Off. The tAutoContWait is the length of time SMBRREC waits to see if the breaker is closed when AutoCont is set to On. Normally, the setting can be $t_{AutoContWait} = 2 \text{ sec}$.

### 12.3 Apparatus control APC

#### 12.3.1 Application

The apparatus control is a function for control and supervising of circuit breakers, disconnectors, and earthing switches within a bay. Permission to operate is given after evaluation of conditions from other functions such as interlocking, synchrocheck, operator place selection and external or internal blockings.

Figure 117 gives an overview from what places the apparatus control function receive commands. Commands to an apparatus can be initiated from the Control Centre (CC), the station HMI or the local HMI on the IED front.

*Figure 117: Overview of the apparatus control functions*

Features in the apparatus control function:
• Operation of primary apparatuses
• Select-Execute principle to give high security
• Selection and 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 synchrocheck
• Pole discordance supervision
• Operation counter
• Suppression of mid position

The apparatus control function is realized by means of a number of function blocks designated:

• Switch controller SCSWI
• Circuit breaker SXCBR
• Circuit switch SXSWI
• Bay control QCAY
• Position evaluation POS_EVAL
• Bay reserve QCRSV
• Reservation input RESIN
• Local remote LOCREM
• Local remote control LOCREMCTRL

The signal flow between the function blocks is shown in Figure 118. 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.

Control operation can be performed from the local IED HMI. If the administrator has defined users with the IED Users tool in PCM600, then the local/remote switch is under authority control. If not, the default (factory) user is the SuperUser that can perform control operations from the local IED HMI without LogOn. 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, 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 33.

Table 33: 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>
</tbody>
</table>

Table continues on next page
PSTO = All, then it is no priority between operator places. All operator places are allowed to operate.

According to IEC61850 standard the orCat attribute in originator category are defined in Table 34.

**Table 34: orCat attribute according to IEC61850**

<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>

**12.3.1.1 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 IEC61850-8-1 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
12.3.1.2 Switch controller (SCSWI)

SCSWI may handle and operate on one three-phase device or three one-phase switching devices.

After the selection of an apparatus and before the execution, the switch controller performs the following checks and actions:

- A request initiates to reserve other bays to prevent simultaneous operation.
- Actual position inputs for interlocking information are read and evaluated if the operation is permitted.
- The synchrocheck/synchronizing conditions are read and checked, and performs operation upon positive response.
- The blocking conditions are evaluated.
- The position indications are evaluated according to given command and its requested direction (open or closed).

The command sequence is supervised regarding the time between:
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 discordance situation, that is, the positions of the one-phase switches are not equal for a time longer than a settable time; an error signal will be given.

The switch controller 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.

12.3.1.3 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, earthing switches etc.

The purpose of these functions is to provide the actual status of positions and to perform the control operations, that is, pass all the commands to the primary apparatus via output boards and to supervise the switching operation and position.

Switches have the following functionalities:

- Local/Remote switch intended for the switchyard
- Block/deblock for open/close command respectively
- Update block/deblock of position indication
- Substitution of position indication
- Supervision timer that the primary device starts moving after a command
- Supervision of allowed time for intermediate position
- Definition of pulse duration for open/close command respectively

The realizations of these function are done with SXCBR representing a circuit breaker and with SXSWI representing a circuit switch that is, a disconnector or an earthing 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.
12.3.1.4 Reservation function (QCRSV and RESIN)

The purpose of the reservation function is primarily to transfer interlocking information between IEDs in a safe way and to prevent double operation in a bay, switchyard part, or complete substation.

For interlocking evaluation in a substation, the position information from switching devices, such as circuit breakers, disconnectors and earthing switches can be required from the same bay or from several other bays. When information is needed from other bays, it is exchanged over the station bus between the distributed IEDs. The problem that arises, even at a high speed of communication, is a space of time during which the information about the position of the switching devices are uncertain. The interlocking function uses this information for evaluation, which means that also the interlocking conditions are uncertain.

To ensure that the interlocking information is correct at the time of operation, a unique reservation method is available in the IEDs. With this reservation method, the bay that wants the reservation sends a reservation request to other bays and then waits for a reservation granted signal from the other bays. Actual position indications from these bays are then transferred over the station bus for evaluation in the IED. After the evaluation the operation can be executed with high security.

This functionality is realized over the station bus by means of the function blocks QCRSV and RESIN. The application principle is shown in Figure 120.

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 acknowledgement from each bay respectively, which have received a request from this bay. Also the information of valid transmission over the station bus must be received.
Figure 120: Application principles for reservation over the station bus

The reservation can also be realized with external wiring according to the application example in Figure 121. 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 121: Application principles for reservation with external wiring

The solution in Figure 121 can also be realized over the station bus according to the application example in Figure 122. The solutions in Figure 121 and Figure 122 do not have the same high security compared to the solution in Figure 120, but instead have a higher availability, since no acknowledgment is required.
12.3.2 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 earthing 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) connects the "trip" outputs of one or more protection functions to a common "trip" to be transmitted to SXCBR.
- The Autorecloser (SMBRREC) consists of the facilities to automatically close a tripped breaker with respect to a number of configurable conditions.
- The logical node Interlocking (SCILO) provides the information to SCSWI whether it is permitted to operate due to the switchyard topology. The interlocking conditions are evaluated with separate logic and connected to SCILO.
- The Synchrocheck, energizing check, and synchronizing (SESRSYN) calculates and compares the voltage phasor difference from both sides of an open breaker with predefined switching conditions (synchrocheck). Also the case that one side is dead (energizing-check) is included.
- The Generic Automatic Process Control function, GAPC, handles generic commands from the operator to the system.
The overview of the interaction between these functions is shown in Figure 123 below.

Figure 123: Example overview of the interactions between functions in a typical bay
12.3.3 Setting guidelines

The setting parameters for the apparatus control function are set via the local HMI or PCM600.

12.3.3.1 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 IEC61850-8-1 clients at both station and remote level are accepted, when the QCBAY function is in Remote. If set to No, the command LocSta controls which operator place is accepted when QCBAY is in Remote. If LocSta is true, only commands from station level are accepted, otherwise only commands from remote level are accepted.

The parameter RemoteIncStation has only effect on the IEC61850-8-1 communication. Further, when using IEC61850 edition 1 communication, the parameter should be set to Yes, since the command LocSta is not defined in IEC61850-8-1 edition 1.

12.3.3.2 Switch controller (SCSWI)

The parameter CtlModel specifies the type of control model according to IEC 61850. The default for control of circuit breakers, disconnectors and earthing switches the control model is set to SBO Enh (Select-Before-Operate) with enhanced security.

When the operation shall be performed in one step, and no monitoring of the result of the command is desired, the model direct control with normal security is used.

At control with enhanced security there is an additional supervision of the status value by the control object, which means that each command sequence 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 synchrocheck function to fulfill the close conditions. When the time has expired, the function tries to start the synchronizing function. If *tSynchrocheck* is set to 0, no synchrocheck is done, before starting the synchronizing function.

The timer *tSynchronizing* supervises that the signal synchronizing in progress is obtained in SCSWI after start of the synchronizing function. The start signal for the synchronizing is set if the synchrocheck conditions are not fulfilled. When the time has expired, the control function is reset, and a cause-code is given. If no synchronizing function is included, the time is set to 0, which means no start of the synchronizing function is done, and when *tSynchrocheck* has expired, the control function is reset and a cause-code is given.

*tExecutionFB* is the maximum time between the execute command signal and the command termination. When the time has expired, the control function is reset and a cause-code is given.

*tPoleDiscord* is the allowed time to have discrepancy between the poles at control of three one-phase breakers. At discrepancy an output signal is activated to be used for trip or alarm, and during a command, the control function is reset, and a cause-code is given.

SuppressMidPos when *On* suppresses the mid-position during the time *tIntermediate* of the connected switches.

The parameter *InterlockCheck* decides if interlock check should be done at both select and operate, Sel & Op phase, or only at operate, Op phase.

### 12.3.3.3 Switch (SXCBR/SXSWI)

*tStartMove* is the supervision time for the apparatus to start moving after a command execution. When the time has expired, the switch function 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 switch function 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).

12.3.3.4 Bay Reserve (QCRSV)

The timer tCancelRes defines the supervision time for canceling the reservation, when this cannot be done by requesting bay due to for example communication failure.

When the parameter ParamRequestx (x=1-8) is set to Only own bay res. individually for each apparatus (x) in the bay, only the own bay is reserved, that is, the output for reservation request of other bays (RES_BAYS) will not be activated at selection of apparatus x.

12.3.3.5 Reservation input (RESIN)

With the FutureUse parameter set to Bay future use the function can handle bays not yet installed in the SA system.

12.4 Logic rotating switch for function selection and LHMI presentation SLGAPC

12.4.1 Identification

<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>

12.4.2 Application

The logic rotating switch for function selection and LHMI presentation function (SLGAPC) (or the selector switch function block, as it is also known) is used to get a selector switch functionality similar with the one provided by a hardware multi-position selector switch. Hardware selector switches are used extensively by utilities, in order to have different functions operating on pre-set values. Hardware switches are however sources for maintenance issues, lower system reliability and extended purchase portfolio. The virtual selector switches eliminate all these problems.

SLGAPC function block has two operating inputs (UP and DOWN), one blocking input (BLOCK) and one operator position input (PSTO).
SLGAPC can be activated both from the local HMI and from external sources (switches), via the IED binary inputs. It also allows the operation from remote (like the station computer). SWPOSN is an integer value output, giving the actual output number. Since the number of positions of the switch can be established by settings (see below), one must be careful in coordinating the settings with the configuration (if one sets the number of positions to x in settings – for example, there will be only the first x outputs available from the block in the configuration). Also the frequency of the (UP or DOWN) pulses should be lower than the setting $t_{Pulse}$.

From the local HMI, the selector switch can be operated from Single-line diagram (SLD).

12.4.3 Setting guidelines

The following settings are available for the Logic rotating switch for function selection and LHMI presentation (SLGAPC) function:

*Operation*: Sets the operation of the function On or Off.

*NrPos*: Sets the number of positions in the switch (max. 32).

*OutType*: Steady or Pulsed.

*tPulse*: In case of a pulsed output, it gives the length of the pulse (in seconds).

*tDelay*: The delay between the UP or DOWN activation signal positive front and the output activation.

*StopAtExtremes*: Sets the behavior of the switch at the end positions – if set to Disabled, when pressing UP while on first position, the switch will jump to the last position; when pressing DOWN at the last position, the switch will jump to the first position; when set to Enabled, no jump will be allowed.

12.5 Selector mini switch VSGAPC

12.5.1 Identification

<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>-</td>
</tr>
</tbody>
</table>

12.5.2 Application

Selector mini switch (VSGAPC) function is a multipurpose function used in the configuration tool in PCM600 for a variety of applications, as a general purpose...
switch. VSGAPC can be used for both acquiring an external switch position (through the IPOS1 and the IPOS2 inputs) and represent it through the single line diagram symbols (or use it in the configuration through the outputs POS1 and POS2) as well as, a command function (controlled by the PSTO input), giving switching commands through the CMDPOS12 and CMDPOS21 outputs.

The output POSITION is an integer output, showing the actual position as an integer number \(0 \to 3\).

An example where VSGAPC is configured to switch Autorecloser on–off from a button symbol on the local HMI is shown in figure 124. The I and O buttons on the local HMI are normally used for on–off operations of the circuit breaker.

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

### 12.5.3 Setting guidelines

Selector mini switch (VSGAPC) function can generate pulsed or steady commands (by setting the `Mode` parameter). When pulsed commands are generated, the length of the pulse can be set using the `tPulse` parameter. Also, being accessible on the single line diagram (SLD), this function block has two control modes (settable through `CtlModel`): Dir Norm and SBO Enh.

### 12.6 Generic communication function for Double Point indication DPGAPC

### 12.6.1 Identification

<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>
12.6.2 Application

DPGAPC function block is used to combine three logical input signals into a two bit position indication, and publish the position indication to other systems, equipment or functions in the substation. The three inputs are named OPEN, CLOSE and VALID. DPGAPC is intended to be used as a position indicator block in the interlocking stationwide logics.

The OPEN and CLOSE inputs set one bit each in the two bit position indication, POSITION. If both OPEN and CLOSE are set at the same time the quality of the output is set to invalid. The quality of the output is also set to invalid if the VALID input is not set.

12.6.3 Setting guidelines

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

12.7 Single point generic control 8 signals SPC8GAPC

12.7.1 Identification

<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</td>
<td>SPC8GAPC</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

12.7.2 Application

The Single point generic control 8 signals (SPC8GAPC) function block is a collection of 8 single point commands that can be used for direct commands for example reset of LED's or putting IED in "ChangeLock" state from remote. In this way, simple commands can be sent directly to the IED outputs, without confirmation. Confirmation (status) of the result of the commands is supposed to be achieved by other means, such as binary inputs and SPGGIO function blocks.

PSTO is the universal operator place selector for all control functions. Even if PSTO can be configured to allow LOCAL or ALL operator positions, the only functional position usable with the SPC8GAPC function block is REMOTE.
12.7.3 Setting guidelines

The parameters for the single point generic control 8 signals (SPC8GAPC) function are set via the local HMI or PCM600.

*Operation*: turning the function operation *On/Off*.

There are two settings for every command output (totally 8):

*Latchedx*: decides if the command signal for output $x$ is *Latched* (steady) or *Pulsed*.

*tPulsex*: if *Latchedx* is set to *Pulsed*, then *tPulsex* will set the length of the pulse (in seconds).

12.8 AutomationBits, command function for DNP3.0 AUTOBITS

12.8.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60817 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>

12.8.2 Application

Automation bits, command function for DNP3 (AUTOBITS) is used within PCM600 in order to get into the configuration the commands coming through the DNP3.0 protocol. The AUTOBITS function plays the same role as functions GOOSEBINRCV (for IEC 61850) and MULTICMDRCV (for LON). AUTOBITS function block have 32 individual outputs which each can be mapped as a Binary Output point in DNP3. The output is operated by a "Object 12" in DNP3. This object contains parameters for control-code, count, on-time and off-time. To operate an AUTOBITS output point, send a control-code of latch-On, latch-Off, pulse-On, pulse-Off, Trip or Close. The remaining parameters are regarded as appropriate. For example, pulse-On, on-time=100, off-time=300, count=5 would give 5 positive 100 ms pulses, 300 ms apart.

For description of the DNP3 protocol implementation, refer to the Communication manual.

12.8.3 Setting guidelines

AUTOBITS function block has one setting, *Operation: On/Off* enabling or disabling the function. These names will be seen in the DNP3 communication management tool in PCM600.
12.9 Single command, 16 signals SINGLECMD

12.9.1 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>Single command, 16 signals</td>
<td>SINGLECMD</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

12.9.2 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 125 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 125 shows a close operation. An open breaker operation is performed in a similar way but without the synchro-check condition.

![Diagram](en040000206.vsd)

_Figure 125: Application example showing a logic diagram for control of a circuit breaker via configuration logic circuits_
Figure 126 and figure 127 show other ways to control functions, which require steady On/Off signals. Here, the output is used to control built-in functions or external devices.

**Figure 126:** Application example showing a logic diagram for control of built-in functions

**Figure 127:** Application example showing a logic diagram for control of external devices via configuration logic circuits
12.9.3 Setting guidelines

The parameters for Single command, 16 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 Off, Steady, or Pulse.

- Off, sets all outputs to 0, independent of the values sent from the station level, that is, the operator station or remote-control gateway.
- Steady, sets the outputs to a steady signal 0 or 1, depending on the values sent from the station level.
- Pulse, gives a pulse with 100 ms duration, if a value sent from the station level is changed from 0 to 1. That means the configured logic connected to the command function block may not have a cycle time longer than the cycle time for the command function block.

12.10 Interlocking

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 earthing 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.

Earthing switches are allowed to connect and disconnect earthing of isolated points. Due to capacitive or inductive coupling there may be some voltage (for example <
40% of rated voltage) before earthing and some current (for example < 100A) after earthing 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 earthing switch is usually not fully interlocked. The operator must be convinced that the line is not energized from the other side before closing the earthing 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.

12.10.1 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:

- QB9_EX2 and QB9_EX4 in modules BH_LINE_A and BH_LINE_B
- QA1_EX3 in module AB_TRAFO

when they are set to 0=FALSE.
12.10.2 Interlocking for line bay ABC_LINE

12.10.2.1 Application

The interlocking for line bay (ABC_LINE) function is used for a line connected to a double busbar arrangement with a transfer busbar according to figure 128. The function can also be used for a double busbar arrangement without transfer busbar or a single busbar arrangement with/without transfer busbar.

![Switchyard layout ABC_LINE](en04000478.vsd)

**Figure 128:** Switchyard layout ABC_LINE

The signals from other bays connected to the module ABC_LINE are described below.

12.10.2.2 Signals from bypass busbar

To derive the signals:

**Signal**

<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_BP8</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) except that of the own bay are needed:

**Signal**

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>QB7OPTR</td>
<td>Q7 is open</td>
</tr>
<tr>
<td>VPQB7TR</td>
<td>The switch status for QB7 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:

\[
\begin{align*}
QB7OPTR & \quad \text{(bay 1)} \\
QB7OPTR & \quad \text{(bay 2)} \\
\vdots \\
QB7OPTR & \quad \text{(bay n-1)} \\
\hline \\
VPQB7TR & \quad \text{(bay 1)} \\
VPQB7TR & \quad \text{(bay 2)} \\
\vdots \\
VPQB7TR & \quad \text{(bay n-1)} \\
\hline \\
EXDU_BPB & \quad \text{(bay 1)} \\
EXDU_BPB & \quad \text{(bay 2)} \\
\vdots \\
EXDU_BPB & \quad \text{(bay n-1)} \\
\hline
\end{align*}
\]

\[\& \quad BB7_D_{OP} \]

\[\& \quad VP_{BB7_D} \]

\[\& \quad EXDU_{BPB} \]

\[en04000477.vsd\]

**Figure 129**: Signals from bypass busbar in line bay n

### 12.10.2.3 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.

\[en04000479.vsd\]

**Figure 130**: Busbars divided by bus-section disconnectors (circuit breakers)

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
The switch status of BC_17 is valid.

The switch status of BC_27 is valid.

No transmission error from any bus-coupler bay (BC).

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>

A bus-coupler connection through the own bus-coupler exists between busbar WA1 and WA2.

No bus-coupler connection through the own bus-coupler between busbar WA1 and WA7.

A bus-coupler connection through the own bus-coupler exists between busbar WA1 and WA7.

No bus-coupler connection through the own bus-coupler between busbar WA2 and WA7.

A bus-coupler connection through the own bus-coupler exists between busbar WA2 and WA7.

The switch status of BC_12 is valid.

The switch status of BC_17 is valid.

The switch status of BC_27 is valid.

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.

<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>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) 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:

For a line bay in section 2, the same conditions as above are valid by changing section 1 to section 2 and vice versa.

Figure 131: Signals to a line bay in section 1 from the bus-coupler bays in each section
12.10.2.4 Configuration setting

If there is no bypass busbar and therefore no QB7 disconnector, then the interlocking for QB7 is not used. The states for QB7, QC71, 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:

- QB7_OP = 1
- QB7_CL = 0
- QC71_OP = 1
- QC71_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 QB2 disconnector, then the interlocking for QB2 is not used. The state for QB2, QC21, 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:

- QB2_OP = 1
- QB2_CL = 0
- QC21_OP = 1
- QC21_CL = 0
- BC_12_CL = 0
- BC_27_OP = 1
- BC_27_CL = 0
- VP_BC_12 = 1

12.10.3 Interlocking for bus-coupler bay ABC_BC
12.10.3.1 Application

The interlocking for bus-coupler bay (ABC_BC) function is used for a bus-coupler bay connected to a double busbar arrangement according to figure 132. The function can also be used for a single busbar arrangement with transfer busbar or double busbar arrangement without transfer busbar.

Figure 132: Switchyard layout ABC_BC

12.10.3.2 Configuration

The signals from the other bays connected to the bus-coupler module ABC_BC are described below.

12.10.3.3 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>QB12OPTR</td>
<td>QB1 or QB2 or both are open.</td>
</tr>
<tr>
<td>VPQB12TR</td>
<td>The switch status of QB1 and QB2 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:

\[
\begin{align*}
QB12OPTR (\text{bay 1}) & \quad \& \quad \text{BBTR_OP} \\
QB12OPTR (\text{bay 2}) & \quad \& \quad \text{VP_BBTR} \\
\ldots & \quad \& \quad \ldots \\
QB12OPTR (\text{bay } n-1) & \quad \& \quad \text{EXDU_12} \\
VPQB12TR (\text{bay 1}) & \quad \& \quad \text{VPQB12TR (bay 2)} \\
\ldots & \quad \& \quad \ldots \\
VPQB12TR (\text{bay } n-1) & \\
\text{EXDU}_12 (\text{bay 1}) & \quad \& \quad \text{EXDU}_12 (\text{bay 2}) \\
\ldots & \quad \& \quad \ldots \\
\text{EXDU}_12 (\text{bay } n-1) & 
\end{align*}
\]

**Figure 133:** 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:

\[
\begin{align*}
(WA1)A1 & \quad (WA2)B1 & \quad (WA7)C \\
\text{ABC_LINE} & \quad \text{ABC_BC} & \quad \text{ABC_LINE} & \quad \text{AB_TRAFO} \\
\text{Section 1} & \quad \text{Section 2} & \\
A2 & \quad B2 & \quad C \\
A1A2\_DC(BS) & \quad B1B2\_DC(BS) & \\
\text{ABC_BC} & \quad \text{ABC_LINE} & \\
\end{align*}
\]

**Figure 134:** Busbars divided by bus-section disconnectors (circuit breakers)

The following signals from each bus-section disconnecter 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 disconnecter 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 disconnecter is open.</td>
</tr>
<tr>
<td>VPDCTR</td>
<td>The switch status of bus-section disconnecter 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 disconnecter 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.

<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-coupler bay in section 1, these conditions are valid:

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.

**12.10.3.4 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 135:** Signals to a bus-coupler bay in section 1 from any bays in each section

**Figure 136:** Busbars divided by bus-section disconnectors (circuit breakers)
To derive the signals:

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>BC_12_CL</td>
<td>Another 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 any bus-coupler bay (BC).</td>
</tr>
</tbody>
</table>

These signals from each bus-coupler bay (ABC_BC), except the own bay, are needed:

<table>
<thead>
<tr>
<th>Signal</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>BC12CLTR</td>
<td>A bus-coupler connection through the own bus-coupler exists 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 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>DCCLTR</td>
<td>The bus-section disconnector is closed.</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), 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>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 containing the above information.</td>
</tr>
</tbody>
</table>

For a bus-coupler bay in section 1, these conditions are valid:
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.

### 12.10.3.5 Configuration setting

If there is no bypass busbar and therefore no QB2 and QB7 disconnectors, then the interlocking for QB2 and QB7 is not used. The states for QB2, QB7, QC71 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:

- QB2_OP = 1
- QB2_CL = 0
- QB7_OP = 1
- QB7_CL = 0
- QC71_OP = 1
- QC71_CL = 0

If there is no second busbar B and therefore no QB2 and QB20 disconnectors, then the interlocking for QB2 and QB20 are not used. The states for QB2, QB20, QC21, 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:

- QB2_OP = 1
- QB2_CL = 0
- QB20_OP = 1
- QB20_CL = 0
- QC21_OP = 1
- QC21_CL = 0
12.10.4 Interlocking for transformer bay AB_TRAFO

12.10.4.1 Application

The interlocking for transformer bay (AB_TRAFO) function is used for a transformer bay connected to a double busbar arrangement according to figure 138. The function is used when there is no disconnector between circuit breaker and transformer. Otherwise, the interlocking for line bay (ABC_LINE) function can be used. This function can also be used in single busbar arrangements.

Figure 138: Switchyard layout AB_TRAFO

The signals from other bays connected to the module AB_TRAFO are described below.
12.10.4.2 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.

![Diagram showing busbar configuration](en04000487.vsd)

**Figure 139:** 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“.

12.10.4.3 Configuration setting

If there are no second busbar B and therefore no QB2 disconnector, then the interlocking for QB2 is not used. The state for QB2, QC21, 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:

- QB2_OP = 1
- QB2QB2_CL = 0
- QC21_OP = 1
- QC21_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 QB4 disconnector, then the state for QB4 is set to open by setting the appropriate module inputs as follows:
12.10.5  Interlocking for bus-section breaker A1A2_BS

12.10.5.1  Application

The interlocking for bus-section breaker (A1A2_BS) function is used for one bus-section circuit breaker between section 1 and 2 according to figure 140. The function can be used for different busbars, which includes a bus-section circuit breaker.

![Switchyard layout A1A2_BS](en04000516.vsd)

**Figure 140:**  Switchyard layout A1A2_BS

The signals from other bays connected to the module A1A2_BS are described below.

12.10.5.2  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.

![Busbars divided by bus-section circuit breakers](en04000489.vsd)

**Figure 141:**  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>QB12OPTR</td>
<td>QB1 or QB2 or both are open.</td>
</tr>
<tr>
<td>VPQB12TR</td>
<td>The switch status of QB1 and QB2 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 142:  
*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 143: Signals from any bays for a bus-section circuit breaker between sections B1 and B2

12.10.5.3 Configuration setting

If there is no other busbar via the busbar loops that are possible, then either the interlocking for the QA1 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:

- $BBTR_{\text{OP}} = 1$
- $VP_{\text{BBTR}} = 1$
12.10.6 Interlocking for bus-section disconnector A1A2_DC

12.10.6.1 Application

The interlocking for bus-section disconnector (A1A2_DC) function is used for one bus-section disconnector between section 1 and 2 according to figure 144. A1A2_DC function can be used for different busbars, which includes a bus-section disconnector.

![Switchyard layout A1A2_DC](en04000492.vsd)

Figure 144: Switchyard layout A1A2_DC

The signals from other bays connected to the module A1A2_DC are described below.

12.10.6.2 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.

![Busbars divided by bus-section disconnectors (circuit breakers)](en04000493.vsd)

Figure 145: Busbars divided by bus-section disconnectors (circuit breakers)

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>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>

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>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 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>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>QB1OPTR</td>
<td>QB1 is open.</td>
</tr>
<tr>
<td>QB2OPTR</td>
<td>QB2 is open (AB_TRAFO, ABC_LINE).</td>
</tr>
<tr>
<td>QB220OTR</td>
<td>QB2 and QB20 are open (ABC_BC).</td>
</tr>
<tr>
<td>VPQB1TR</td>
<td>The switch status of QB1 is valid.</td>
</tr>
<tr>
<td>VPQB2TR</td>
<td>The switch status of QB2 is valid.</td>
</tr>
<tr>
<td>VQB220TR</td>
<td>The switch status of QB2 and QB20 are 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:
Figure 146: 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:

Figure 147: 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:
Signals in double-breaker arrangement

If the busbar is divided by bus-section disconnectors, the condition for the busbar disconnecter 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 disconnecter A1A2_DC and B1B2_DC. But for B1B2_DC, corresponding signals from busbar B are used.
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 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>QB1OPTR</td>
<td>QB1 is open.</td>
</tr>
<tr>
<td>QB2OPTR</td>
<td>QB2 is open.</td>
</tr>
<tr>
<td>VPQB1TR</td>
<td>The switch status of QB1 is valid.</td>
</tr>
<tr>
<td>VPQB2TR</td>
<td>The switch status of QB2 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:
Figure 151: 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:

Figure 152: 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 153: 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 154: Signals from double-breaker bays in section B2 to a bus-section disconnector

12.10.6.4 Signals in 1 1/2 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.
12.10.7 Interlocking for busbar earthing switch BB_ES

12.10.7.1 Application

The interlocking for busbar earthing switch (BB_ES) function is used for one busbar earthing switch on any busbar parts according to figure 156.

![Figure 156: Switchyard layout BB_ES](en04000504.vsd)

The signals from other bays connected to the module BB_ES are described below.

12.10.7.2 Signals in single breaker arrangement

The busbar earthing switch is only allowed to operate if all disconnectors of the bus-section are open.
To derive the signals:

<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 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>QB1OPTR</td>
<td>QB1 is open.</td>
</tr>
<tr>
<td>QB2OPTR</td>
<td>QB2 is open (AB_TRAFO, ABC_LINE)</td>
</tr>
<tr>
<td>QB2200TR</td>
<td>QB2 and QB20 are open (ABC_BC)</td>
</tr>
<tr>
<td>QB7OPTR</td>
<td>QB7 is open.</td>
</tr>
<tr>
<td>VPQB1TR</td>
<td>The switch status of QB1 is valid.</td>
</tr>
<tr>
<td>VPQB2TR</td>
<td>The switch status of QB2 is valid.</td>
</tr>
<tr>
<td>VQB220TR</td>
<td>The switch status of QB2 and QB20 is valid.</td>
</tr>
<tr>
<td>VPQB7TR</td>
<td>The switch status of QB7 is valid.</td>
</tr>
<tr>
<td>EXDU_BB</td>
<td>No transmission error from the bay that contains 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>QB1OPTR</td>
<td>QB1 is open.</td>
</tr>
<tr>
<td>QB2OPTR</td>
<td>QB2 is open.</td>
</tr>
<tr>
<td>VPQB1TR</td>
<td>The switch status of QB1 is valid.</td>
</tr>
<tr>
<td>VPQB2TR</td>
<td>The switch status of QB2 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 earthing switch, these conditions from the A1 busbar section are valid:

For a busbar earthing switch, these conditions from the A2 busbar section are valid:
For a busbar earthing switch, these conditions from the B1 busbar section are valid:

For a busbar earthing switch, these conditions from the B2 busbar section are valid:
For a busbar earthing switch on bypass busbar C, these conditions are valid:

**Figure 162: Signals from bypass busbar to busbar earthing switch**

### 12.10.7.3 Signals in double-breaker arrangement

The busbar earthing switch is only allowed to operate if all disconnectors of the bus section are open.
To derive the signals:

- **BB_DC_OP**: All disconnectors of this part of the busbar are open.
- **VP_BB_DC**: The switch status of all disconnectors on this part of the busbar are valid.
- **EXDU_BB**: No transmission error from any bay that contains the above information.

These signals from each double-breaker bay (DB_BUS) are needed:

- **QB1OPTR**: QB1 is open.
- **QB2OPTR**: QB2 is open.
- **VPQB1TR**: The switch status of QB1 is valid.
- **VPQB2TR**: The switch status of QB2 is valid.
- **EXDU_DB**: 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 disconnectors A1A2_DC and B1B2_DC.

- **DCOPTR**: The bus-section disconnector is open.
- **VPDCTR**: The switch status of bus-section disconnector DC is valid.
- **EXDU_DC**: No transmission error from the bay that contains the above information.

The logic is identical to the double busbar configuration described in section “Signals in single breaker arrangement”.

### 12.10.7.4 Signals in 1 1/2 breaker arrangement

The busbar earthing switch is only allowed to operate if all disconnectors of the bus-section are open.
12.10.8  Interlocking for double CB bay DB

12.10.8.1  Application

The interlocking for a double busbar double circuit breaker bay including DB_BUS_A, DB_BUS_B and DB_LINE functions are used for a line connected to a double busbar arrangement according to figure 165.
Three types of interlocking modules per double circuit breaker bay are defined. DB_BUS_A handles the circuit breaker QA1 that is connected to busbar WA1 and the disconnectors and earthing switches of this section. DB_BUS_B handles the circuit breaker QA2 that is connected to busbar WA2 and the disconnectors and earthing switches of this section.

For a double circuit-breaker bay, the modules DB_BUS_A, DB_LINE and DB_BUS_B must be used.

12.10.8.2 Configuration setting

For application without QB9 and QC9, 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:

- QB9_OP = 1
- QB9_CL = 0
- QC9_OP = 1
- QC9_CL = 0

If, in this case, line voltage supervision is added, then rather than setting QB9 to open state, specify the state of the voltage supervision:
• QB9\_OP = VOLT\_OFF
• QB9\_CL = VOLT\_ON

If there is no voltage supervision, then set the corresponding inputs as follows:

• VOLT\_OFF = 1
• VOLT\_ON = 0

12.10.9 Interlocking for 1 1/2 CB BH

12.10.9.1 Application

The interlocking for 1 1/2 breaker diameter (BH\_CONN, BH\_LINE\_A, BH\_LINE\_B) functions are used for lines connected to a 1 1/2 breaker diameter according to figure 166.

![Interlocking Circuit Diagram](en04000513.vsd)

**Figure 166:** Switchyard layout 1 1/2 breaker

Three types of interlocking modules per diameter are defined. BH\_LINE\_A and BH\_LINE\_B are the connections from a line to a busbar. BH\_CONN is the connection between the two lines of the diameter in the 1 1/2 breaker switchyard layout.
For a 1 1/2 breaker arrangement, the modules BH_LINE_A, BH_CONN and BH_LINE_B must be used.

12.10.9.2 Configuration setting

For application without QB9 and QC9, 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:

- QB9_OP = 1
- QB9_CL = 0
- QC9_OP = 1
- QC9_CL = 0

If, in this case, line voltage supervision is added, then rather than setting QB9 to open state, specify the state of the voltage supervision:

- QB9_OP = VOLT_OFF
- QB9_CL = VOLT_ON

If there is no voltage supervision, then set the corresponding inputs as follows:

- VOLT_OFF = 1
- VOLT_ON = 0
Section 13 Logic

13.1 Trip matrix logic TMAGAPC

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>Trip matrix logic</td>
<td>TMAGAPC</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

13.1.2 Application

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.

13.1.3 Setting guidelines

*Operation*: Operation of function On/Off.

*PulseTime*: Defines the pulse time when in Pulsed mode. When used for direct tripping of circuit breaker(s) the pulse time delay shall be set to approximately 0.150 seconds in order to obtain satisfactory minimum duration of the trip pulse to the circuit breaker trip coils.

*OnDelay*: Used to prevent output signals to be given for spurious inputs. Normally set to 0 or a low value.

*OffDelay*: Defines a delay of the reset of the outputs after the activation conditions no longer are fulfilled. It is only used in Steady mode. When used for direct tripping of circuit breaker(s) the off delay time shall be set to at least 0.150 seconds in order to obtain a satisfactory minimum duration of the trip pulse to the circuit breaker trip coils.

*ModeOutputx*: Defines if output signal OUTPUTx (where x=1-3) is Steady or Pulsed.
13.2 Logic for group alarm ALMCALH

13.2.1 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>Logic for group alarm</td>
<td>ALMCALH</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

13.2.2 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.

13.2.3 Setting guidelines

Operation: On or Off

13.3 Logic for group alarm WRNCALH

13.3.1 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 warning</td>
<td>WRNCALH</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

13.3.1.1 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.

13.3.1.2 Setting guidelines

Operation: On or Off
13.4 Logic for group indication INDCALH

13.4.1 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 indication</td>
<td>INDCALH</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

13.4.1.1 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.

13.4.1.2 Setting guidelines

Operation: On or Off

13.5 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.

13.5.1 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.
13.5.2 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.

13.5.2.1 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 a 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](IEC9000695_2_en.vsd)

*Figure 167: 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.

13.6 Fixed signal function block FXDSIGN

13.6.1 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>Fixed signals</td>
<td>FXDSIGN</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

13.6.2 Application

The Fixed signals function FXDSIGN generates 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.

Example for use of GRP_OFF signal in FXDSIGN

The Restricted earth fault function REFPDIF can be used both for auto-transformers and normal transformers.

When used for auto-transformers, information from both windings parts, together with the neutral point current, needs to be available to the function. This means that three inputs are needed.

Figure 168: REFPDIF function inputs for autotransformer application

For normal transformers only one winding and the neutral point is available. This means that only two inputs are used. Since all group connections are mandatory to be connected, the third input needs to be connected to something, which is the GRP_OFF signal in FXDSIGN function block.
13.7 Boolean 16 to Integer conversion B16I

13.7.1 Identification

The 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.

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60817 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>

13.7.2 Application

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: INx = 2x-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.

13.8 Boolean 16 to Integer conversion with logic node representation BTIGAPC

13.8.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60871 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boolean 16 to integer conversion with logic node representation</td>
<td>BTIGAPC</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

13.8.2 Application

Boolean 16 to integer conversion with logic node representation function BTIGAPC is used to transform a set of 16 binary (logical) signals into an integer. BTIGAPC can receive an integer from a station computer – for example, over IEC 61850–8–1. These functions are very useful when you want to generate logical commands (for selector
switches or voltage controllers) by inputting an integer number. BTIGAPC has a logical node mapping in IEC 61850.

The Boolean 16 to integer conversion function (BTIGAPC) will transfer a combination of up to 16 binary inputs INx where \(1 \leq x \leq 16\) to an integer. Each INx represents a value according to the table below from 0 to 32768. This follows the general formula: \(INx = 2^{x-1}\) where \(1 \leq x \leq 16\). The sum of all the values on the activated INx will be available on the output OUT as a sum of the values of all the inputs INx that are activated. OUT is an integer. When all INx where \(1 \leq x \leq 16\) are activated that is = Boolean 1 it corresponds to that integer 65535 is available on the output OUT. 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 \(1 \leq x \leq 16\).

The sum of the value on each INx corresponds to the integer presented on the output OUT on the function block 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>
<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 \(1 \leq x \leq 16\)) are active that is=1; is 65535. 65535 is the highest boolean value that can be converted to an integer by the BTIGAPC function block.

13.9 Integer to Boolean 16 conversion IB16
13.9.1 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>Integer to boolean 16 conversion</td>
<td>IB16</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

13.9.2 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.

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>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 IB16 function block.

13.10 Integer to Boolean 16 conversion with logic node representation ITBGAPC

13.10.1 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 with logic node representation</td>
<td>ITBGAPC</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

13.10.2 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 35.

If the BLOCK input is activated, it freezes the logical outputs at the last value.

Table 35: 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>
</tbody>
</table>

Table continues on next page
<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>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.

13.11 Elapsed time integrator with limit transgression and overflow supervision TEIGAPC

13.11.1 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>Elapsed time integrator</td>
<td>TEIGAPC</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

13.11.2 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.

13.11.3 Setting guidelines

The settings tAlarm and tWarning 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 second \( \leq t_{\text{Warning}} \leq 99\,999.99 \) seconds.

If the values are above this range the resolution becomes lower

\[
99\,999.99 \text{ seconds} \leq t_{\text{Alarm}} \leq 999\,999.9 \text{ seconds}
\]

\[
99\,999.99 \text{ seconds} \leq t_{\text{Warning}} \leq 999\,999.9 \text{ seconds}
\]

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 9999999.9 seconds.
## Section 14 Monitoring

### 14.1 Measurement

#### 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>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>

- Measurements: CVMMXN, I, U, P, Q, S, I, U, I
- Phase current measurement: CMMXU
- Phase-phase voltage measurement: VMMXU
- Current sequence component measurement: CMSQI
- Voltage sequence component measurement: VMSQI
- Phase-neutral voltage measurement: VNMMXU

#### 14.1.2 Application

Measurement functions is used for power system measurement, supervision and reporting to the local HMI, monitoring tool within PCM600 or to station level for example, via IEC 61850. The possibility to continuously monitor measured values of active power, reactive power, currents, voltages, frequency, power factor etc. is vital.
for efficient production, transmission and distribution of electrical energy. It provides to the system operator fast and easy overview of the present status of the power system. Additionally, it can be used during testing and commissioning of protection and control IEDs in order to verify proper operation and connection of instrument transformers (CTs and VTs). During normal service by periodic comparison of the measured value from the IED with other independent meters the proper operation of the IED analog measurement chain can be verified. Finally, it can be used to verify proper direction orientation for distance or directional overcurrent protection function.

The available measured values of an IED are depending on the actual hardware (TRM) and the logic configuration made in PCM600.

All measured values can be supervised with four settable limits that is, low-low limit, low limit, high limit and high-high limit. A zero clamping reduction is also supported, that is, the measured value below a settable limit is forced to zero which reduces the impact of noise in the inputs.

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
- U: phase-to-phase voltage amplitude
- I: phase current amplitude
- F: power system frequency

The measuring functions CMMXU, VMMXU and VNMMXU provide physical quantities:

- I: phase currents (amplitude and angle) (CMMXU)
- U: voltages (phase-to-earth and phase-to-phase voltage, amplitude and angle) (VMMXU, VNMMXU)

The CVMMXN function calculates three-phase power quantities by using fundamental frequency phasors (DFT values) of the measured current respectively voltage signals. The measured power quantities are available either, as instantaneously calculated quantities or, averaged values over a period of time (low pass filtered) depending on the selected settings.
It is possible to calibrate the measuring function above to get better than class 0.5 presentation. This is accomplished by angle and amplitude compensation at 5, 30 and 100% of rated current and at 100% of rated voltage.

The power system quantities provided, depends on the actual hardware, (TRM) and the logic configuration made in PCM600.

The measuring functions CMSQI and VMSQI provide sequence component quantities:

- **I**: sequence currents (positive, zero, negative sequence, amplitude and angle)
- **U**: sequence voltages (positive, zero and negative sequence, amplitude and angle).

### 14.1.3 Zero clamping

The measuring functions, CVMMXN, CMMXU, VMMXU and VNMMXU have no interconnections regarding any setting or parameter.

Zero clampings are also entirely handled by the ZeroDb for each and every signal separately for each of the functions. For example, the zero clamping of \( U_{12} \) is handled by \( U_{12ZeroDb} \) in VMMXU, zero clamping of I1 is handled by \( I_{1ZeroDb} \) in CMMXU ETC.

Example how CVMMXN is operating:

The following outputs can be observed on the local HMI under Monitoring/Servicevalues/SRV1:

- \( S \): 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

The settings for this function is found under Setting/General setting/Monitoring/Service values/SRV1

It can be seen that:
• When system voltage falls below $UGenZeroDB$, the shown value for $S$, $P$, $Q$, $PF$, $ILAG$, $ILEAD$, $U$ and $F$ on the local HMI is forced to zero
• When system current falls below $IGenZeroDB$, the shown value for $S$, $P$, $Q$, $PF$, $ILAG$, $ILEAD$, $U$ and $F$ on the local HMI is forced to zero
• When the value of a single signal falls below the set dead band for that specific signal, the value shown on the local HMI is forced to zero. For example, if apparent three-phase power falls below $SZeroDb$ the value for $S$ on the local HMI is forced to zero.

14.1.4 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.

Operation: $Off/On$. Every function instance (CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU) can be taken in operation ($On$) or out of operation ($Off$).

The following general settings can be set for the Measurement function (CVMMXN).

$PowAmpFact$: Amplitude factor to scale power calculations.

$PowAngComp$: Angle compensation for phase shift between measured $I$ & $U$.

$Mode$: Selection of measured current and voltage. There are 9 different ways of calculating monitored three-phase values depending on the available VT inputs connected to the IED. See parameter group setting table.

$k$: Low pass filter coefficient for power measurement, $U$ and $I$.

$UGenZeroDb$: Minimum level of voltage in $\%$ of $UBase$ used as indication of zero voltage (zero point clamping). If measured value is below $UGenZeroDb$ calculated $S$, $P$, $Q$ and $PF$ will be zero.

$IGenZeroDb$: Minimum level of current in $\%$ of $IBase$ used as indication of zero current (zero point clamping). If measured value is below $IGenZeroDb$ calculated $S$, $P$, $Q$ and $PF$ will be zero.

$UBase$: Base voltage in primary kV. This voltage is used as reference for voltage setting. It can be suitable to set this parameter to the rated primary voltage supervised object.

$IBase$: Base current in primary A. This current is used as reference for current setting. It can be suitable to set this parameter to the rated primary current of the supervised object.
**SBase**: Base setting for power values in MVA.

**UAmpCompY**: Amplitude compensation to calibrate voltage measurements at Y% of Ur, where Y is equal to 5, 30 or 100.

**IAmpCompY**: Amplitude compensation to calibrate current measurements at Y% of Ir, where Y is equal to 5, 30 or 100.

**IAngCompY**: Angle compensation to calibrate angle measurements at Y% of Ir, where Y is equal to 5, 30 or 100.

Parameters **IBase**, **Ubase** and **SBase** have been implemented as a settings instead of a parameters, which means that if the values of the parameters are changed there will be no restart of the application. As restart is required to activate new parameters values, the IED must be restarted in some way. Either manually or by changing some other parameter at the same time.

The following general settings can be set for the **Phase-phase current measurement** (CMMXU).

**IAmpCompY**: Amplitude compensation to calibrate current measurements at Y% of Ir, where Y is equal to 5, 30 or 100.

**IAngCompY**: Angle compensation to calibrate angle measurements at Y% of Ir, where Y is equal to 5, 30 or 100.

The following general settings can be set for the **Phase-phase voltage measurement** (VMMXU).

**UAmpCompY**: Amplitude compensation to calibrate voltage measurements at Y% of Ur, where Y is equal to 5, 30 or 100.

**UAngCompY**: Angle compensation to calibrate angle measurements at Y% of Ur, where Y is equal to 5, 30 or 100.

The following general settings can be set for **all monitored quantities** included in the functions (CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU) X in setting names below equals S, P, Q, PF, U, I, F, IL1-3, UL1-3UL12-3L1, I1, I2, 3I0, U1, U2 or 3U0.

**Xmin**: Minimum value for analog signal X set directly in applicable measuring unit.

**Xmax**: Maximum value for analog signal X.

**XZeroDb**: Zero point clamping. A signal value less than **XZeroDb** is forced to zero.

Observe the related zero point clamping settings in Setting group N for CVMMXN (UgenZeroDb and IgenZeroDb). If measured value is below UgenZeroDb and/or IgenZeroDb calculated S, P, Q and PF will be zero and these settings will override XZeroDb.
**XRepTyp**: Reporting type. Cyclic (*Cyclic*), amplitude deadband (*Dead band*) or integral deadband (*Int deadband*). The reporting interval is controlled by the parameter **XDbRepInt**.

**XDbRepInt**: Reporting deadband setting. Cyclic reporting is the setting value and is reporting interval in seconds. Amplitude deadband is the setting value in % of measuring range. Integral deadband setting is the integral area, that is, measured value in % of measuring range multiplied by the time between two measured values.

**XHiHiLim**: High-high limit. Set in applicable measuring unit.

**XHiLim**: High limit.

**XLowLim**: Low limit.

**XLowLowLim**: Low-low limit.

**XLimHyst**: Hysteresis value in % of range and is common for all limits.

All phase angles are presented in relation to defined reference channel. The parameter **PhaseAngleRef** defines the reference.

**Calibration curves**

It is possible to calibrate the functions (CVMMXN, CMMXU, VNMMXU and VMMXU) to get class 0.5 presentations of currents, voltages and powers. This is accomplished by amplitude and angle compensation at 5, 30 and 100% of rated current and voltage. The compensation curve will have the characteristic for amplitude and angle compensation of currents as shown in figure 170 (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.
14.1.4.1 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 110kV OHL

Single line diagram for this application is given in figure 171:
In order to monitor, supervise and calibrate the active and reactive power as indicated in figure 171, 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 36.
   - level supervision of active power as shown in table 37.
   - calibration parameters as shown in table 38.

### Table 36: 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-earth VT inputs are available</td>
</tr>
<tr>
<td>k</td>
<td>Low pass filter coefficient for power measurement, U and I</td>
<td>0.00</td>
<td>Typically no additional filtering is required</td>
</tr>
</tbody>
</table>

Table continues on next page
<table>
<thead>
<tr>
<th>Setting</th>
<th>Short Description</th>
<th>Selected value</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>UGenZeroDb</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>
<tr>
<td>UBase (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>800</td>
<td>Set rated primary CT current used for OHL</td>
</tr>
</tbody>
</table>

Table 37: 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>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 45 MW that is, 3% of 200 MW</td>
</tr>
<tr>
<td>PRepTyp</td>
<td>Reporting type</td>
<td>db</td>
<td>Select amplitude deadband supervision</td>
</tr>
<tr>
<td>PDbReplInt</td>
<td>Cyc: Report interval (s), Db: In % of range, Int Db: In %s</td>
<td>2</td>
<td>Set ±Δdb=30 MW that is, 2% (larger changes than 30 MW will be reported)</td>
</tr>
<tr>
<td>PHiHiLim</td>
<td>High High limit (physical value)</td>
<td>60</td>
<td>High alarm limit that is, extreme overload alarm</td>
</tr>
<tr>
<td>PHiLim</td>
<td>High limit (physical value)</td>
<td>50</td>
<td>High warning limit that is, overload warning</td>
</tr>
<tr>
<td>PLowLim</td>
<td>Low limit (physical value)</td>
<td>-50</td>
<td>Low warning limit. Not active</td>
</tr>
<tr>
<td>PLowLowLim</td>
<td>Low Low limit (physical value)</td>
<td>-60</td>
<td>Low alarm limit. Not active</td>
</tr>
<tr>
<td>PLimHyst</td>
<td>Hysteresis value in % of range (common for all limits)</td>
<td>2</td>
<td>Set ±Δ Hysteresis MW that is, 2%</td>
</tr>
</tbody>
</table>

Table 38: 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>IAmpComp5</td>
<td>Amplitude factor to calibrate current at 5% of Ir</td>
<td>0.00</td>
<td></td>
</tr>
<tr>
<td>IAmpComp30</td>
<td>Amplitude factor to calibrate current at 30% of Ir</td>
<td>0.00</td>
<td></td>
</tr>
<tr>
<td>IAmpComp100</td>
<td>Amplitude factor to calibrate current at 100% of Ir</td>
<td>0.00</td>
<td></td>
</tr>
<tr>
<td>UAmpComp5</td>
<td>Amplitude factor to calibrate voltage at 5% of Ur</td>
<td>0.00</td>
<td></td>
</tr>
<tr>
<td>UAmpComp30</td>
<td>Amplitude factor to calibrate voltage at 30% of Ur</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 172.
In order to measure the active and reactive power as indicated in figure 172, 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 39:
### Table 39: 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><strong>Operation</strong></td>
<td>Operation Off/On</td>
<td>On</td>
<td>Function must be On</td>
</tr>
<tr>
<td><strong>PowAmpFact</strong></td>
<td>Amplitude factor to scale power calculations</td>
<td>1.000</td>
<td>Typically no scaling is required</td>
</tr>
<tr>
<td><strong>PowAngComp</strong></td>
<td>Angle compensation for phase shift between measured I &amp; U</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 alignment with the required direction.</td>
</tr>
<tr>
<td><strong>Mode</strong></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><strong>k</strong></td>
<td>Low pass filter coefficient for power measurement, U and I</td>
<td>0.00</td>
<td>Typically no additional filtering is required</td>
</tr>
<tr>
<td><strong>UGenZeroDb</strong></td>
<td>Zero point clamping in % of Ubase</td>
<td>25</td>
<td>Set minimum voltage level to 25%</td>
</tr>
<tr>
<td><strong>IGenZeroDb</strong></td>
<td>Zero point clamping in % of Ibase</td>
<td>3</td>
<td>Set minimum current level to 3%</td>
</tr>
<tr>
<td><strong>UBase (set in Global base)</strong></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><strong>IBase (set in Global base)</strong></td>
<td>Base setting for current level in A</td>
<td>495</td>
<td>Set transformer LV winding rated current</td>
</tr>
</tbody>
</table>

**Measurement function application for a generator**

Single line diagram for this application is given in figure 173.
In order to measure the active and reactive power as indicated in figure 173, it is necessary to do the following:

1. Set correctly all CT and VT data and phase angle reference channel \textit{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:

\begin{figure}
\centering
\includegraphics[width=\textwidth]{IEC09000041-1-en.vsd}
\caption{Single line diagram for generator application}
\end{figure}
<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>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>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>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>
<tr>
<td>k</td>
<td>Low pass filter coefficient for power measurement, U and I</td>
<td>0.00</td>
<td>Typically no additional filtering is required</td>
</tr>
<tr>
<td>UGenZeroDb</td>
<td>Zero point clamping in % of Ubase</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>UBase (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>

### 14.2 Gas medium supervision SSIMG

#### 14.2.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas medium supervision</td>
<td>SSIMG</td>
<td>63</td>
</tr>
</tbody>
</table>

#### 14.2.2 Application

Gas medium supervision (SSIMG) is used for monitoring the circuit breaker condition. Proper arc extinction by the compressed gas in the circuit breaker is very important. When the pressure becomes too low compared to the required value, the circuit breaker operation shall be blocked to minimize the risk of internal failure. 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.

#### 14.2.3 Setting guidelines

The parameters for the gas medium supervision SSIMG are set via the local HMI or PCM600.
14.3 Liquid medium supervision SSIML

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>Liquid medium supervision</td>
<td>SSIML</td>
<td>-</td>
<td>71</td>
</tr>
</tbody>
</table>

14.3.2 Application

Liquid medium supervision (SSIML) is used for monitoring the circuit breaker condition. Proper arc extinction by the compressed oil in the circuit breaker is very important. When the level becomes too low, compared to the required value, the circuit breaker operation is blocked to minimize the risk of internal failures. Binary information based on the oil level in the circuit breaker is used as input signals to the function. In addition to that, the function generates alarms based on received information.

14.3.3 Setting guidelines

The parameters for the Liquid medium supervision SSIML are set via the local HMI or PCM600.

- **Operation**: Off/On
- **LevelAlmLimit**: Alarm setting level limit for liquid medium supervision
- **LevelLOLimit**: Level lockout setting limit for liquid medium supervision
- **TempAlmLimit**: Temperature alarm level setting of the liquid medium
- **TempLOLimit**: Temperature lockout level of the liquid medium
- **tLevelAlarm**: Time delay for level alarm of the liquid medium
- **tLevelLockOut**: Time delay for level lockout indication of the liquid medium
- `tTempAlarm`: Time delay for temperature alarm of the liquid medium
- `tTempLockOut`: Time delay for temperature lockout of the liquid medium
- `tResetLevelAlm`: Reset time delay for level alarm of the liquid medium
- `tResetLevelLO`: Reset time delay for level lockout of the liquid medium
- `tResetTempAlm`: Reset time delay for temperature lockout of the liquid medium
- `tResetTempLO`: Reset time delay for temperature alarm of the liquid medium

### 14.4 Breaker monitoring SSCBR

#### 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>Breaker monitoring</td>
<td>SSCBR</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

#### 14.4.2 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 174.

Figure 174: 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, \(\text{RSTIPOW}\).

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.

14.4.3 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.

14.4.3.1 Setting procedure on the IED

The parameters for breaker monitoring (SSCBR) can be set using the local HMI or Protection and Control Manager (PCM600).

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

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

$\text{Operation}$: $\text{On}$ or $\text{Off}$.

$I_{Base}$: Base phase current in primary A. This current is used as reference for current settings.

$\text{OpenTimeCorr}$: Correction factor for circuit breaker opening travel time.

$\text{CloseTimeCorr}$: Correction factor for circuit breaker closing travel time.

$\text{tTrOpenAlm}$: Setting of alarm level for opening travel time.

$\text{tTrCloseAlm}$: Setting of alarm level for closing travel time.

$\text{OperAlmLevel}$: Alarm limit for number of mechanical operations.

$\text{OperLOLevel}$: Lockout limit for number of mechanical operations.

$\text{CurrExponent}$: Current exponent setting for energy calculation. It varies for different types of circuit breakers. This factor ranges from 0.5 to 3.0.

$\text{AccStopCurr}$: RMS current setting below which calculation of energy accumulation stops. It is given as a percentage of $I_{Base}$.

$\text{ContTrCorr}$: Correction factor for time difference in auxiliary and main contacts' opening time.

$\text{AlmAccCurrPwr}$: Setting of alarm level for accumulated energy.

$\text{LOAccCurrPwr}$: Lockout limit setting for accumulated energy.

$\text{SpChAlmTime}$: Time delay for spring charging time alarm.

$\text{tDGasPresAlm}$: Time delay for gas pressure alarm.

$\text{tDGasPresLO}$: Time delay for gas pressure lockout.

$\text{DirCoef}$: Directional coefficient for circuit breaker life calculation.

$\text{RatedOperCurr}$: 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.

14.5 Event function EVENT

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>Event function</td>
<td>EVENT</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

14.5.2 Application

When using a Substation Automation system with LON or SPA communication, time-tagged events can be sent at change or cyclically from the IED to the station level. These events are created from any available signal in the IED that is connected to the Event function (EVENT). The event function block is used for LON and SPA communication.

Analog and double indication values are also transferred through EVENT function.

14.5.3 Setting guidelines

The parameters for the Event (EVENT) function are set via the local HMI or PCM600.

EventMask (Ch_1 - 16)

The inputs can be set individually as:

- NoEvents
- OnSet, at pick-up of the signal
- OnReset, at drop-out of the signal
- OnChange, at both pick-up and drop-out of the signal
- AutoDetect
**LONChannelMask or SPACchannelMask**
Definition of which part of the event function block that shall generate events:

- **Off**
- **Channel 1-8**
- **Channel 9-16**
- **Channel 1-16**

**MinRepIntVal (1 - 16)**
A time interval between cyclic events can be set individually for each input channel. This can be set between 0 s to 3600 s in steps of 1 s. It should normally be set to 0, that is, no cyclic communication.

It is important to set the time interval for cyclic events in an optimized way to minimize the load on the station bus.

**14.6 Disturbance report DRPRDRE**

**14.6.1 Identification**

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60817 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Analog input signals</td>
<td>A1RADR</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Disturbance report</td>
<td>DRPRDRE</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Disturbance report</td>
<td>A1RADR</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Disturbance report</td>
<td>A2RADR</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Disturbance report</td>
<td>A3RADR</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Disturbance report</td>
<td>A4RADR</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Disturbance report</td>
<td>B1RBDR</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Disturbance report</td>
<td>B2RBDR</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Disturbance report</td>
<td>B3RBDR</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Disturbance report</td>
<td>B4RBDR</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Disturbance report</td>
<td>B5RBDR</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Disturbance report</td>
<td>B6RBDR</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

**14.6.2 Application**
To get fast, complete and reliable information about disturbances in the primary and/or in the secondary system it is very important to gather information on fault currents, voltages and events. It is also important having a continuous event-logging to be able
to monitor in an overview perspective. These tasks are accomplished by the
disturbance report function DRPRDRE and facilitate a better understanding of the
power system behavior and related primary and secondary equipment during and after
a disturbance. An analysis of the recorded data provides valuable information that can
be used to explain a disturbance, basis for change of IED setting plan, improve
existing equipment, and so on. This information can also be used in a longer
perspective when planning for and designing new installations, that is, a disturbance
recording could be a part of Functional Analysis (FA).

Disturbance report DRPRDRE, always included in the IED, acquires sampled data of
all selected analog and binary signals connected to the function blocks that is,

- maximum 30 external analog signals,
- 10 internal derived analog signals, and
- 96 binary signals.

Disturbance report function is a common name for several functions that is,
Indications (IND), Event recorder (ER), Event list (EL), Trip value recorder (TVR),
Disturbance recorder (DR).

Disturbance report function is characterized by great flexibility as far as
configuration, starting conditions, recording times, and large storage capacity are
concerned. Thus, disturbance report is not dependent on the operation of protective
functions, and it can record disturbances that were not discovered by protective
functions for one reason or another. Disturbance report can be used as an advanced
stand-alone disturbance recorder.

Every disturbance report recording is saved in the IED. The same applies to all events,
which are continuously saved in a ring-buffer. Local HMI can be used to get
information about the recordings, and the disturbance report files may be uploaded in
the PCM600 using the Disturbance handling tool, for report reading or further analysis
(using WaveWin, that can be found on the PCM600 installation CD). The user can
also upload disturbance report files using FTP or MMS (over 61850–8–1) 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 as
GOOSE or Report Control data. The same information is obtainable if
IEC60870-5-103 is used.

14.6.3 Setting guidelines

The setting parameters for the Disturbance report function DRPRDRE are set via the
local HMI or PCM600.

It is possible to handle up to 40 analog and 96 binary signals, either internal signals or
signals coming from external inputs. The binary signals are identical in all functions
that is, Disturbance recorder (DR), Event recorder (ER), Indication (IND), Trip value
recorder (TVR) and Event list (EL) function.
User-defined names of binary and analog input signals is set using PCM600. The analog and binary signals appear with their user-defined names. The name is used in all related functions (Disturbance recorder (DR), Event recorder (ER), Indication (IND), Trip value recorder (TVR) and Event list (EL)).

Figure 175 shows the relations between Disturbance report, included functions and function blocks. Event list (EL), Event recorder (ER) and Indication (IND) uses information from the binary input function blocks (BxRBDR). Trip value recorder (TVR) uses analog information from the analog input function blocks (AxRADR). Disturbance report function acquires information from both AxRADR and BxRBDR.

Figure 175: 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: A Disturbance Report is triggered
- Flashing light: The IED is in test mode

Red LED:
- Steady light: Triggered on binary signal N with SetLEDN = On

Operation
The operation of Disturbance report function DRPRDRE has to be set On or Off. If Off is selected, note that no disturbance report is registered, and none sub-function will operate (the only general parameter that influences Event list (EL)).

Operation = Off:
- Disturbance reports are not stored.
- LED information (yellow - start, red - trip) is not stored or changed.

Operation = On:
- Disturbance reports are stored, disturbance data can be read from the local HMI and from a PC using PCM600.
- LED information (yellow - start, red - trip) is stored.
Every recording will get a number (0 to 999) which is used as identifier (local HMI, disturbance handling tool and IEC 61850). An alternative recording identification is date, time and sequence number. The sequence number is automatically increased by one for each new recording and is reset to zero at midnight. The maximum number of recordings stored in the IED is 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 On.

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.

14.6.3.1 Recording times

The different recording times for Disturbance report are set (the pre-fault time, post-fault time, and limit time). These recording times affect all sub-functions more or less but not the Event list (EL) function.

Prefault recording time (PreFaultRecT) is the recording time before the starting point of the disturbance. The setting should be at least 0.1 s to ensure enough samples for the estimation of pre-fault values in the Trip value recorder (TVR) function.

Postfault recording time (PostFaultRecT) is the maximum recording time after the disappearance of the trig-signal (does not influence the Trip value recorder (TVR) function).

Recording time limit (TimeLimit) is the maximum recording time after trig. The parameter limits the recording time if some triggering condition (fault-time) is very long or permanently set (does not influence the Trip value recorder (TVR) function).

Post retrigger (PostRetrig) can be set to On or Off. Makes it possible to choose performance of Disturbance report function if a new trig signal appears in the post-fault window.

PostRetrig = Off

The function is insensitive for new trig signals during post fault time.

PostRetrig = On
The function completes current report and starts a new complete report that is, the latter will include:

- new pre-fault- and fault-time (which will overlap previous report)
- events and indications might be saved in the previous report too, due to overlap
- new trip value calculations if installed, in operation and started

**Operation in test mode**

If the IED is in test mode and \textit{OpModeTest} = \textit{Off}. Disturbance report function does not save any recordings and no LED information is displayed.

If the IED is in test mode and \textit{OpModeTest} = \textit{On}. Disturbance report function works in normal mode and the status is indicated in the saved recording.

### 14.6.3.2 Binary input signals

Up to 96 binary signals can be selected among internal logical and binary input signals. The configuration tool is used to configure the signals.

For each of the 96 signals, it is also possible to select if the signal is to be used as a trigger for the start of the Disturbance report and if the trigger should be activated on positive (1) or negative (0) slope.

\textit{OperationN}: Disturbance report may trig for binary input N (\textit{On}) or not (\textit{Off}).

\textit{TrigLevelN}: Trig on positive (\textit{Trig on 1}) or negative (\textit{Trig on 0}) slope for binary input N.

\textit{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.

\textit{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.

### 14.6.3.3 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 not be connected to a 3 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 (\textit{OperationM} = \textit{On/Off}).
If $\text{OperationM} = \text{Off}$, no waveform (samples) will be recorded and reported in graph. However, Trip value, pre-fault and fault value will be recorded and reported. The input channel can still be used to trig the disturbance recorder.

If $\text{OperationM} = \text{On}$, waveform (samples) will also be recorded and reported in graph.

$\text{NomValueM}$: Nominal value for input M.

$\text{OverTrigOpM, UnderTrigOpM}$: Over or Under trig operation, Disturbance report may trig for high/low level of analog input M ($\text{On}$) or not ($\text{Off}$).

$\text{OverTrigLeM, UnderTrigLeM}$: Over or under trig level, Trig high/low level relative nominal value for analog input M in percent of nominal value.

### 14.6.3.4 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 ($\text{Show}$), a status change of that particular input, will be fetched and shown in the disturbance summary on local HMI. If not set ($\text{Hide}$), 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 ($\text{On}$) or not ($\text{Off}$).

If $\text{OperationM} = \text{Off}$, no waveform (samples) will be recorded and reported in graph. However, Trip value, pre-fault and fault value will be recorded and reported. The input channel can still be used to trig the disturbance recorder.

If $\text{OperationM} = \text{On}$, waveform (samples) will also be recorded and reported in graph.

**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).

**Event list**

Event list (EL) (SOE) function has no dedicated parameters.
14.6.3.5 Consideration

The density of recording equipment in power systems is increasing, since the number of modern IEDs, where recorders are included, is increasing. This leads to a vast number of recordings at every single disturbance and a lot of information has to be handled if the recording functions do not have proper settings. The goal is to optimize the settings in each IED to be able to capture just valuable disturbances and to maximize the number that is possible to save in the IED.

The recording time should not be longer than necessary (PostFaultrecT and TimeLimit).

- Should the function record faults only for the protected object or cover more?
- How long is the longest expected fault clearing time?
- Is it necessary to include reclosure in the recording or should a persistent fault generate a second recording (PostRetrig)?

Minimize the number of recordings:

- Binary signals: Use only relevant signals to start the recording that is, protection trip, carrier receive and/or start signals.
- Analog signals: The level triggering should be used with great care, since unfortunate settings will cause enormously number of recordings. If nevertheless analog input triggering is used, chose settings by a sufficient margin from normal operation values. Phase voltages are not recommended for trigging.

Remember that values of parameters set elsewhere are linked to the information on a report. Such parameters are, for example, station and object identifiers, CT and VT ratios.

14.7 Logical signal status report BINSTATREP

14.7.1 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>

14.7.2 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.

![Input and Output Diagram]

\[ \text{INPUTn} \]
\[ \text{OUTPUTn} \]
\[ \text{t} \]

**Figure 176: BINSTATREP logical diagram**

14.7.3 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.

14.8 Limit counter L4UFCNT

14.8.1 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>

14.8.2 Application

Limit counter (L4UFCNT) is intended for applications where positive and/or negative flanks on a binary signal need to be counted.

The limit counter provides four independent limits to be checked against the accumulated counted value. The four limit reach indication outputs can be utilized to initiate proceeding actions. The output indicators remain high until the reset of the function.

It is also possible to initiate the counter from a non-zero value by resetting the function to the wanted initial value provided as a setting.

If applicable, the counter can be set to stop or rollover to zero and continue counting after reaching the maximum count value. The steady overflow output flag indicates...
the next count after reaching the maximum count value. It is also possible to set the counter to rollover and indicate the overflow as a pulse, which lasts up to the first count after rolling over to zero. In this case, periodic pulses will be generated at multiple overflow of the function.

### 14.8.3 Setting guidelines

The parameters for Limit counter L4UFCNT are set via the local HMI or PCM600.
15.1 Pulse-counter logic PCFCNT

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>Pulse-counter logic</td>
<td>PCFCNT</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

15.1.2 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.

15.1.3 Setting guidelines

From PCM600, these parameters can be set individually for each pulse counter:

- **Operation**: Off/On
- **tReporting**: 0-3600s
- **EventMask**: NoEvents/ReportEvents

The configuration of the inputs and outputs of the pulse counter-logic PCFCNT function block is made with PCM600.
On the Binary Input Module, 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. That means that the counter finds the input oscillating if the input frequency is greater than 40 Hz. The oscillation suppression is released at 30 Hz. The values for blocking/release of the oscillation can be changed in the local HMI and PCM600 under Main menu/Configurations/I/O modules.

The setting is common for all input channels on a Binary Input Module, that is, if changes of the limits are made for inputs not connected to the pulse counter, the setting also influences the inputs on the same board used for pulse counting.

15.2 Function for energy calculation and demand handling
ETPMMMTR

15.2.1 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>

15.2.2 Application

Energy calculation and demand handling function (ETPMMMTR) 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 177.
Figure 177: Connection of energy calculation and demand handling function ETPMMTR to the measurements function (CVMMXN)

The energy values can be read through communication in MWh and MVArh in monitoring tool of PCM600 and/or alternatively the values can be presented on the local HMI. The local HMI graphical display is configured with PCM600 Graphical Display Editor tool (GDE) with a measuring value which is selected to the active and reactive component as preferred. Also all Accumulated Active Forward, Active Reverse, Reactive Forward and Reactive Reverse energy values can be presented. Maximum demand values are presented in MWh or MVArh in the same way.

Alternatively, the energy values can be presented with use of the pulse counters function (PCGGIO). The output energy values are scaled with the pulse output setting values \( EAFAccPlsQty \), \( EARAccPlsQty \), \( ERFAccPlsQty \) and \( ERVAccPlsQty \) of the energy metering function and then the pulse counter can be set-up to present the correct values by scaling in this function. Pulse counter values can then be presented on the local HMI in the same way and/or sent to the SA (Substation Automation) system through communication where the total energy then is calculated by summation of the energy pulses. This principle is good for very high values of energy as the saturation of numbers else will limit energy integration to about one year with 50 kV and 3000 A. After that the accumulation will start on zero again.

15.2.3 Setting guidelines

The parameters are set via the local HMI or PCM600.

The following settings can be done for the energy calculation and demand handling function ETPMMTR:

**Operation**: Off/On

**EnaAcc**: Off/On is used to switch the accumulation of energy on and off.

**tEnergy**: Time interval when energy is measured.
\( tEnergyOnPls \): gives the pulse length ON time of the pulse. It should be at least 100 ms when connected to the Pulse counter function block. Typical value can be 100 ms.

\( tEnergyOffPls \): gives the OFF time between pulses. Typical value can be 100 ms.

\( EAFAccPlsQty \) and \( EARAccPlsQty \): gives the MWh value in each pulse. It should be selected together with the setting of the Pulse counter (PCGGIO) settings to give the correct total pulse value.

\( ERFAccPlsQty \) and \( ERVAccPlsQty \): gives the MVArh value in each pulse. It should be selected together with the setting of the Pulse counter (PCGGIO) settings to give the correct total pulse value.

For the advanced user there are a number of settings for direction, zero clamping, max limit, and so on. Normally, the default values are suitable for these parameters.
Section 16  Station communication

16.1  670 series protocols

Each IED is provided with a communication interface, 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.

Following communication protocols are available:

- IEC 61850-8-1 communication protocol
- LON communication protocol
- SPA or IEC 60870-5-103 communication protocol
- DNP3.0 communication protocol

Several protocols can be combined in the same IED.

16.2  IEC 61850-8-1 communication protocol

16.2.1  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 178 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 178: SA system with IEC 61850–8–1

Figure 179 shows the GOOSE peer-to-peer communication.

Figure 179: Example of a broadcasted GOOSE message
16.2.2 Horizontal communication via GOOSE for interlocking GOOSEINTLKRCV

Table 41: GOOSEINTLKRCV Non group settings (basic)

<table>
<thead>
<tr>
<th>Name</th>
<th>Values (Range)</th>
<th>Unit</th>
<th>Step</th>
<th>Default</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operation</td>
<td>Off</td>
<td>-</td>
<td>-</td>
<td>Off</td>
<td>Operation Off/On</td>
</tr>
<tr>
<td></td>
<td>On</td>
<td>-</td>
<td>-</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

16.2.3 Setting guidelines

There are two settings related to the IEC 61850–8–1 protocol:

Operation User can set IEC 61850 communication to On or Off.

GOOSE has to be set to the Ethernet link where GOOSE traffic shall be send and received.

16.2.4 Generic communication function for Single Point indication SPGAPC, SP16GAPC

16.2.4.1 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. It has one visible input, that should be connected in ACT tool.

16.2.4.2 Setting guidelines

There are no settings available for the user for SPGAPC.

16.2.5 Generic communication function for Measured Value MVGAPC

16.2.5.1 Application

Generic communication function for Measured Value 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.
16.2.5.2 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.

16.2.6 IEC 61850-8-1 redundant station bus communication

16.2.6.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>LHMI and ACT identification</th>
<th>IEC 61850 identification</th>
<th>IEC 60617 identification</th>
<th>ANSI/IEEE C37.2 device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parallel Redundancy Protocol Status</td>
<td>PRPSTATUS</td>
<td>RCHLCCH</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Duo driver configuration</td>
<td>PRP</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

16.2.6.2 Application

Parallel redundancy protocol status (PRPSTATUS) together with Duo driver configuration (PRP) are 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. Together PRPSTATUS and PRP provide redundant communication over station bus running IEC 61850-8-1 protocol. The redundant communication use both port AB and CD on OEM module.
16.2.6.3 Setting guidelines

Redundant communication (PRP) is configured in the local HMI under **Main menu/Configuration/Communication/Ethernet configuration/PRP**

The settings are found in the Parameter Setting tool in PCM600 under **IED Configuration/Communication/Ethernet configuration/PRP**. By default the settings are read only in the Parameter Settings tool, but can be unlocked by right clicking the parameter and selecting Lock/Unlock Parameter.

*Operation:* The redundant communication will be activated when this parameter is set to *On*. After confirmation the IED will restart and the setting alternatives *Rear OEM - Port AB* and *CD* will not be further displayed in the local HMI. The *ETHLANAB* and
**ETHLANCD** in the Parameter Setting Tool are irrelevant when the redundant communication is activated, only PRP IPAdress and IPMask are valid.

### Table: Ethernet configuration

<table>
<thead>
<tr>
<th>Group / Parameter Name</th>
<th>IED Value [SG1/Common]</th>
<th>PC Value [SG1/Common]</th>
<th>Link</th>
<th>Min</th>
<th>Max</th>
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</thead>
<tbody>
<tr>
<td><strong>FRONT: 1</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>✓ iAddress</td>
<td>10.1.150.3</td>
<td>10.1.150.3</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>✓ IPMask</td>
<td>255.255.255.0</td>
<td>255.255.255.0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>✓ LANDC: 1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>✓ Mode</td>
<td>PRP</td>
<td>PRP</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>✓ iAddress</td>
<td>138.227.103.131</td>
<td>138.227.103.131</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>✓ IPMask</td>
<td>255.255.254.0</td>
<td>255.255.254.0</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>✓ GATEWAY: 1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>✓ GWAddress</td>
<td>10.1.150.1</td>
<td>10.1.150.1</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>✓ PRP: 1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>✓ Operation</td>
<td>On</td>
<td>On</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>✓ PRPMode</td>
<td>PRP:1</td>
<td>PRP:1</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>✓ iAddress</td>
<td>138.227.103.131</td>
<td>138.227.103.131</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>✓ IPMask</td>
<td>255.255.254.0</td>
<td>255.255.254.0</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Figure 181:** PST screen: PRP Operation is set to On, which affect Rear OEM - Port AB and CD which are both set to PRP
16.3 LON communication protocol

16.3.1 Application

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.

The fibre optic LON bus is implemented using either glass core or plastic core fibre optic cables.

<table>
<thead>
<tr>
<th>Specification of the fibre optic connectors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Glass fibre</td>
</tr>
<tr>
<td>Cable connector</td>
</tr>
<tr>
<td>Cable diameter</td>
</tr>
<tr>
<td>Max. cable length</td>
</tr>
<tr>
<td>Wavelength</td>
</tr>
<tr>
<td>Transmitted power</td>
</tr>
<tr>
<td>Receiver sensitivity</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 fibres 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.

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.

16.3.2 MULTICMDRCV and MULTICMDSND
16.3.2.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 60817 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>

16.3.2.2 Application

The IED provides two function blocks enabling several IEDs to send and receive signals via the interbay bus. The sending function block, MULTICMDSND, takes 16 binary inputs. LON enables these to be transmitted to the equivalent receiving function block, MULTICMDRCV, which has 16 binary outputs.

16.3.2.3 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.

16.4 SPA communication protocol

16.4.1 Application

SPA communication protocol as an alternative to IEC 60870-5-103. The same communication port as for IEC 60870-5-103 is used.

When communicating with a PC connected to the utility substation LAN, via WAN and the utility office LAN, as shown in figure 183, and using the rear Ethernet port on the optical Ethernet module (OEM), the only hardware required for a station monitoring system is:

- Optical fibres from the IED to the utility substation LAN.
- PC connected to the utility office LAN.
The SPA communication is mainly used for the Station Monitoring System. It can include different IEDs with remote communication possibilities. Connection to a computer (PC) can be made directly (if the PC is located in the substation) or by telephone modem through a telephone network with ITU (former CCITT) characteristics or via a LAN/WAN connection.

<table>
<thead>
<tr>
<th>Material</th>
<th>Distance Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>glass</td>
<td>&lt;1000 m according to optical budget</td>
</tr>
<tr>
<td>plastic</td>
<td>&lt;25 m (inside cubicle) according to optical budget</td>
</tr>
</tbody>
</table>

**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 fibre 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.

### 16.4.2 Setting guidelines

The setting parameters for the SPA communication are set via the local HMI.

SPA, IEC 60870-5-103 and DNP3 uses the same rear communication port. Set the parameter *Operation*, under **Main menu/Configuration/Communication/Station communication/Port configuration/SLM optical serial port/Protocol**.

When the communication protocols have been selected, the IED is automatically restarted.
The most important settings in the IED for SPA communication are the slave number and baud rate (communication speed). These settings are absolutely essential for all communication contact to the IED.

These settings can only be done on the local HMI for rear channel communication and for front channel communication.

The slave number can be set to any value from 1 to 899, as long as the slave number is unique within the used SPA loop.

The baud rate, which is the communication speed, can be set to between 300 and 38400 baud. Refer to technical data to determine the rated communication speed for the selected communication interfaces. The baud rate should be the same for the whole station, although different baud rates in a loop are possible. If different baud rates in the same fibre optical loop or RS485 network are used, consider this when making the communication setup in the communication master, the PC.

For local fibre optic communication, 19200 or 38400 baud is the normal setting. If telephone communication is used, the communication speed depends on the quality of the connection and on the type of modem used. But remember that the IED does not adapt its speed to the actual communication conditions, because the speed is set on the local HMI.
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 fibres and an opto/electrical converter for the PC/RTU, or a RS-485 connection depending on the used IED communication interface.

**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.
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 fibres, 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 a dedicated function blocks. These blocks have output signals for all available commands according to the protocol.

- IED commands in control direction

Function block with defined IED functions in control direction, I103IEDCMD. This block use PARAMETR as FUNCTION TYPE, and INFORMATION NUMBER parameter is defined for each output signal.

- Function commands in control direction

Function block with pre defined functions in control direction, I103CMD. This block includes the FUNCTION TYPE parameter, and the INFORMATION NUMBER parameter is defined for each output signal.

- Function commands in control direction

Function block with user defined functions in control direction, I103UserCMD. These function blocks include the FUNCTION TYPE parameter for each block in the private range, and the INFORMATION NUMBER parameter for each output signal.

Status
The events created in the IED available for the IEC 60870-5-103 protocol are based on the:
• IED status indication in monitor direction

Function block with defined IED functions in monitor direction, I103IED. This block use PARAMETER as FUNCTION TYPE, and INFORMATION NUMBER parameter is defined for each input signal.

• Function status indication in monitor direction, user-defined

Function blocks with user defined input signals in monitor direction, I103UserDef. These function blocks include the FUNCTION TYPE parameter for each block in the private range, and the INFORMATION NUMBER parameter for each input signal.

• Supervision indications in monitor direction

Function block with defined functions for supervision indications in monitor direction, I103Superv. This block includes the FUNCTION TYPE parameter, and the INFORMATION NUMBER parameter is defined for each output signal.

• Earth fault indications in monitor direction

Function block with defined functions for earth fault indications in monitor direction, I103EF. This block includes the FUNCTION TYPE parameter, and the INFORMATION NUMBER parameter is defined for each output signal.

• Fault indications in monitor direction

Function block with defined functions for fault indications in monitor direction, I103FLTPROT. This block includes the FUNCTION TYPE parameter, and the INFORMATION NUMBER parameter is defined for each input signal.

This block is suitable for distance protection, line differential, transformer differential, over-current and earth-fault protection functions.

• Autorecloser indications in monitor direction

Function block with defined functions for autorecloser indications in monitor direction, I103AR. This block includes the FUNCTION TYPE parameter, and the INFORMATION NUMBER parameter is defined for each output signal.

Measurands
The measurands can be included as type 3.1, 3.2, 3.3, 3.4 and type 9 according to the standard.

• Measurands in public range

Function block that reports all valid measuring types depending on connected signals, I103Meas.
• Measurands in private range

Function blocks with user defined input measurands in monitor direction, 1103MeasUsr. 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 B6RBDR. 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.

Settings

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 only 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/IEC6870-5-103/
   • <config-selector>
   • SlaveAddress
   • BaudRate
   • RevPolarity (optical channel only)
   • CycMeasRepTime
   • MasterTimeDomain
   • TimeSyncMode
Section 16  
Station communication

- EvalTimeAccuracy
- EventRepMode
- CmdMode

<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 185: Settings for IEC 60870-5-103 communication](image)

The general settings for IEC 60870-5-103 communication are the following:
- **SlaveAddress and BaudRate**: Settings for slave number and communication speed (baud rate).
  The slave number can be set to any value between 1 and 254. The communication speed can be set either to 9600 bits/s or 19200 bits/s.
- **RevPolarity**: Setting for inverting the light (or not). Standard IEC 60870-5-103 setting is **On**.
- **CycMeasRepTime**: See I103MEAS function block for more information.
- **EventRepMode**: Defines the mode for how events are reported. The event buffer size is 1000 events.

**Event reporting mode**

If **SeqOfEvent** is selected, 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 **HiPriSpont** is selected, 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.

The settings for communication parameters slave number and baud rate can be found on the local HMI under: **Main menu/Configuration/Communication /Station configuration /SPA/SPA:1** and then select a protocol.

**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 43.

**Table 43: Channels on disturbance recorder sent with a given ACC**

<table>
<thead>
<tr>
<th>DRAI-Input</th>
<th>ACC</th>
<th>IEC 60870-5-103 meaning</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>IL1</td>
</tr>
<tr>
<td>2</td>
<td>2</td>
<td>IL2</td>
</tr>
<tr>
<td>3</td>
<td>3</td>
<td>IL3</td>
</tr>
<tr>
<td>4</td>
<td>4</td>
<td>IN</td>
</tr>
<tr>
<td>5</td>
<td>5</td>
<td>UL1</td>
</tr>
</tbody>
</table>

Table continues on next page
### Function and information types

Product type IEC103mainFunType value Comment:

REL 128 Compatible range

<table>
<thead>
<tr>
<th>DRA#-Input</th>
<th>ACC</th>
<th>IEC 60870-5-103 meaning</th>
</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>6</td>
<td>UL2</td>
</tr>
<tr>
<td>7</td>
<td>7</td>
<td>UL3</td>
</tr>
<tr>
<td>8</td>
<td>8</td>
<td>UN</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>
<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>
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
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 fibre 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.

### 16.6 DNP3 Communication protocol

#### 16.6.1 Application

For more information on the application and setting guidelines for the DNP3 communication protocol refer to the DNP3 Communication protocol manual.
Section 17  Remote communication

17.1  Binary signal transfer

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>Binary signal transfer</td>
<td>BinSignReceive</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Binary signal transfer</td>
<td>BinSignTransm</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

17.1.2  Application

The IEDs can be equipped with communication devices for line differential communication and/or communication of binary signals between IEDs. The same communication hardware is used for both purposes.

Communication between two IEDs geographically on different locations is a fundamental part of the line differential function.

Sending of binary signals between two IEDs, one in each end of a power line 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.

When equipped with a LDCM, a 64 kbit/s communication channel can be connected to the IED, which will then have the capacity of 192 binary signals to be communicated with a remote IED.

17.1.2.1  Communication hardware solutions

The LDCM (Line Data Communication Module) has an optical connection such that two IEDs can be connected over a direct fibre (multimode), as shown in figure 186. The protocol used is IEEE/ANSI C37.94. The distance with this solution is typical 110 km.
Figure 186: Direct fibre 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 converter as shown in figure 187. These solutions are aimed for connections to a multiplexer, which in turn is connected to a telecommunications transmission network (for example, SDH or PDH).

Figure 187: LDCM with an external optical to galvanic converter and a multiplexer

When an external modem G.703 or X21 is used, the connection between LDCM and the modem is made with a multimode fibre of max. 3 km 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.

17.1.2.2 Application possibility with one-phase REB670

For busbar protection applications in substations where dynamic zone selection is required, it is typically necessary to wire the normally open and normally closed
auxiliary contacts from every monitored disconnector and/or circuit breaker to the optocoupler inputs of the busbar protection. When one phase version of REB670 is used, then six optocoupler inputs (that is, two in each phase/IED) are required for every primary switchgear object. For big stations (for example, with 24 bays) this will require quite a lot of binary inputs into every IED. To limit the number of required optocoupler inputs into every IED it is possible to use LDCM communication modules to effectively share the binary Ios between three units, as shown in figure 188.

![Diagram showing sharing of binary inputs between phases](en06000198.vsd)

**Figure 188:** Example how to share binary IO between one-phase REB670 IEDs by using LDCM modules

As shown in figure 188, it is possible to wire only the status for bays 01-08 to L1-IED. After that the information about auxiliary contact status for switchgear objects from these eight bays can be sent via LDCM modules to other two phases. In the similar way information from other bays can be only wired to L2, respectively L3 phase IED and then shared to the other two phases via LDCM communication.

Typical LDCM communication delay between two IEDs is in order of 30-40 ms. Note that for disconnector status this delay will not pose any practical problems. However, time delay caused by LDCM communication can be crucial for circuit breakers status. In such cases it is strongly recommended that at least the circuit breaker closing command from every circuit breaker is directly wired to all three phases/IEDs to minimize any risk for unwanted operation of the busbar differential protection zones due to late inclusion of respective bay current into the differential measuring circuit.
17.1.3 Setting guidelines

ChannelMode: This parameter can be set Normal or Blocked. Besides this, it can be set OutOfService which signifies that the local LDCM is out of service. Thus, with this setting, the communication channel is active and a message is sent to the remote IED that the local IED is out of service, but there is no COMFAIL signal and the analog and binary values are sent as zero.

TerminalNo: This setting shall be used to assign an unique address to each LDCM, in all current differential IEDs. Up to 256 LDCMs can be assigned a unique number. Consider a local IED with two LDCMs:

- LDCM for slot 302: Set TerminalNo to 1 and RemoteTermNo to 2
- LDCM for slot 303: Set TerminalNo to 3 and RemoteTermNo to 4

In multiterminal current differential applications, with 4 LDCMs in each IED, up to 20 unique addresses must be set.

The unique address is necessary to give high security against incorrect addressing in the communication system. Using the same number for setting TerminalNo in some of the LDCMs, a loop-back test in the communication system can give incorrect trip.

RemoteTermNo: This setting assigns a number to each related LDCM in the remote IED. For each LDCM, the parameter RemoteTermNo shall be set to a different value than parameter TerminalNo, but equal to the TerminalNo of the remote end LDCM. In the remote IED the TerminalNo and RemoteTermNo settings are reversed as follows:

- LDCM for slot 302: Set TerminalNo to 2 and RemoteTermNo to 1
- LDCM for slot 303: Set TerminalNo to 4 and RemoteTermNo to 3

The redundant channel is always configured in the lower position, for example

- Slot 302: Main channel
- Slot 303: Redundant channel

The same is applicable for slot 312-313 and slot 322-323.

DiffSync: Here the method of time synchronization, Echo or GPS, for the line differential function is selected.

Using Echo in this situation is safe only as long as there is no risk of varying transmission asymmetry.
GPSSyncErr: If GPS synchronization is lost, the synchronization of the line differential function will continue during 16 s. based on the stability in the local IED clocks. Thereafter the setting Block will block the line differential function or the setting Echo will make it continue by using the Echo synchronization method. It shall be noticed that using Echo in this situation is only safe as long as there is no risk of varying transmission asymmetry.

CommSync: This setting decides the Master or Slave relation in the communication system and shall not be mistaken for the synchronization of line differential current samples. When direct fibre is used, one LDCM is set as Master and the other one as Slave. When a modem and multiplexer is used, the IED is always set as Slave, as the telecommunication system will provide the clock master.

OptoPower: The setting LowPower is used for fibres 0 – 1 km and HighPower for fibres >1 km.

TransmCurr: This setting decides which of 2 possible local currents that shall be transmitted, or if and how the sum of 2 local currents shall be transmitted, or finally if the channel shall be used as a redundant channel.

In a 1½ breaker arrangement, there will be 2 local currents, and the earthing on the CTs can be different for these. CT-SUM will transmit the sum of the 2 CT groups. CT-DIFF1 will transmit CT group 1 minus CT group 2 and CT-DIFF2 will transmit CT group 2 minus CT group 1.

CT-GRP1 or CT-GRP2 will transmit the respective CT group, and the setting RedundantChannel makes the channel be used as a backup channel.

ComFailAlrmDel: Time delay of communication failure alarm. In communication systems, route switching can sometimes cause interruptions with a duration up to 50 ms. Thus, a too short time delay setting might cause nuisance alarms in these situations.

ComFailResDel: Time delay of communication failure alarm reset.

RedChSwTime: Time delay before switchover to a redundant channel in case of primary channel failure.

RedChRturnTime: Time delay before switchback to a the primary channel after channel failure.

AsymDelay: The asymmetry is defined as transmission delay minus receive delay. If a fixed asymmetry is known, the Echo synchronization method can be used if the parameter AsymDelay is properly set. From the definition follows that the asymmetry will always be positive in one end, and negative in the other end.

AnalogLatency: Local analog latency; A parameter which specifies the time delay (number of samples) between actual sampling and the time the sample reaches the local communication module, LDCM. The parameter shall be set to 2 when transmitting analog data from the.
RemAinLatency: Remote analog latency; This parameter corresponds to the LocAinLatency set in the remote IED.

MaxTransmDelay: Data for maximum 40 ms transmission delay can be buffered up. Delay times in the range of some ms are common. It shall be noticed that if data arrive in the wrong order, the oldest data will just be disregarded.

CompRange: The set value is the current peak value over which truncation will be made. To set this value, knowledge of the fault current levels should be known. The setting is not overly critical as it considers very high current values for which correct operation normally still can be achieved.

MaxtDiffLevel: Allowed maximum time difference between the internal clocks in respective line end.
Section 18  Basic IED functions

18.1  Authority status ATHSTAT

18.1.1  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.

18.2  Change lock CHNGLCK

18.2.1  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.

18.3 Denial of service DOS

18.3.1 Application

The denial of service functions (DOSFRNT, DOSLANAB and DOSLANCD) are designed to limit the CPU load that can be produced by Ethernet network traffic on the IED. The communication facilities must not be allowed to compromise the primary functionality of the device. All inbound network traffic will be quota controlled so that too heavy network loads can be controlled. Heavy network load might for instance be the result of malfunctioning equipment connected to the network.

DOSFRNT, DOSLANAB and DOSLANCD 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 outputs:

• LINKUP indicates the Ethernet link status
• WARNING indicates that communication (frame rate) is higher than normal
• ALARM indicates that the IED limits communication

18.3.2 Setting guidelines

The function does not have any parameters available in the local HMI or PCM600.
18.4 IED identifiers TERMINALID

18.4.1 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.

18.5 Product information PRODINF

18.5.1 Application

The Product identifiers function contains constant data (i.e. not possible to change) that uniquely identifies the IED:

- ProductVer
- ProductDef
- FirmwareVer
- SerialNo
- OrderingNo
- ProductionDate
- IEDProdType

The settings are visible on the local HMI, under Main menu/Diagnostics/IED status/Product identifiers and under Main menu/Diagnostics/IED Status/IED identifiers.

This information is very helpful when interacting with ABB product support (e.g. during repair and maintenance).

18.5.2 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 (like REL, REC or RET). Example: REL670
- ProductDef
  - Describes the release number, from the production. Example: 1.2.2.0
- ProductVer
  - Describes the product version. Example: 1.2.3

<table>
<thead>
<tr>
<th></th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>is the Major version of the manufactured product this means, new platform of the product</td>
</tr>
<tr>
<td>2</td>
<td>is the Minor version of the manufactured product this means, new functions or new hardware added to the product</td>
</tr>
<tr>
<td>3</td>
<td>is the Major revision of the manufactured product this means, functions or hardware is either changed or enhanced in the product</td>
</tr>
</tbody>
</table>

- IEDMainFunType
  - Main function type code according to IEC 60870-5-103. Example: 128 (meaning line protection).
- SerialNo
- OrderingNo
- ProductionDate

18.6 Measured value expander block RANGE_XP

18.6.1 Identification

<table>
<thead>
<tr>
<th>Function description</th>
<th>IEC 61850 identification</th>
<th>IEC 80617 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>

18.6.2 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.
18.6.3 Setting guidelines

There are no settable parameters for the measured value expander block function.

18.7 Parameter setting groups

18.7.1 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 (PST) for activation with the ActiveGroup function block.

18.7.2 Setting guidelines

The setting ActiveSetGrp, is used to select which parameter group to be active. The active group can also be selected with configured input to the function block SETGRPS.

The length of the pulse, sent out by the output signal SETCHGD when an active group has changed, is set with the parameter $t$.

The parameter MAXSETGR defines the maximum number of setting groups in use to switch between. Only the selected number of setting groups will be available in the Parameter Setting tool (PST) for activation with the ActiveGroup function block.

18.8 Rated system frequency PRIMVAL
18.8.1 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>Primary system values</td>
<td>PRIMVAL</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

18.8.2 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.

18.8.3 Setting guidelines

Set the system rated frequency. Refer to section "Signal matrix for analog inputs SMAI" for description on frequency tracking.

18.9 Summation block 3 phase 3PHSUM

18.9.1 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.

18.9.2 Setting guidelines

The summation block receives the three-phase signals from SMAI blocks. The summation block has several settings.

- **SummationType**: Summation type (Group 1 + Group 2, Group 1 - Group 2, Group 2 - Group 1 or -(Group 1 + Group 2)).

- **DFTReference**: The reference DFT block (InternalDFT Ref, DFTRefGrp1 or External DFT ref).

- **FreqMeasMinVal**: The minimum value of the voltage for which the frequency is calculated, expressed as percent of $U_{Base}$ base voltage setting (for each instance x).

- **GlobalBaseSel**: Selects the global base value group used by the function to define ($I_{Base}$), ($U_{Base}$) and ($S_{Base}$).
18.10 Global base values GBASVAL

18.10.1 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>Global base values</td>
<td>GBASVAL</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

18.10.2 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.

18.10.3 Setting guidelines

UBase: Phase-to-phase voltage value to be used as a base value for applicable functions throughout the IED.

IBase: Phase current value to be used as a base value for applicable functions throughout the IED.

SBase: Standard apparent power value to be used as a base value for applicable functions throughout the IED, typically SBase=√3·UBase·IBase.

18.11 Signal matrix for binary inputs SMBI

18.11.1 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.
18.11.2 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.

18.12 Signal matrix for binary outputs SMBO

18.12.1 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.

18.12.2 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.

18.13 Signal matrix for analog inputs SMAI

18.13.1 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).

18.13.2 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 \( \sqrt[3]{U_{\text{Base}}} \)

If SMAI setting \textit{ConnectionType} is \textit{Ph-Ph}, at least two of the inputs GRP\( x \)L1, GRP\( x \)L2 and GRP\( x \)L3, where \( 1 \leq x \leq 12 \), must be connected in order to calculate the positive sequence voltage. Note that phase to phase inputs shall always be connected as follows: L1-L2 to GRP\( x \)L1, L2-L3 to GRP\( x \)L2, L3-L1 to GRP\( x \)L3. If SMAI setting \textit{ConnectionType} is \textit{Ph-N}, all three inputs GRP\( x \)L1, GRP\( x \)L2 and GRP\( x \)L3 must be connected in order to calculate the positive sequence voltage.

If only one phase-phase voltage is available and SMAI setting \textit{ConnectionType} is \textit{Ph-Ph}, the user is advised to connect two (not three) of the inputs GRP\( x \)L1, GRP\( x \)L2 and GRP\( x \)L3 to the same voltage input as shown in figure 189 to make SMAI calculate a positive sequence voltage.

![Diagram](image)

Figure 189: Connection example

The above described scenario does not work if SMAI setting \textit{ConnectionType} is \textit{Ph-N}. If only one phase-earth voltage is available, the same type of connection can be used but the SMAI \textit{ConnectionType} setting must still be \textit{Ph-Ph} and this has to be accounted for when setting \text{MinValFreqMeas}. If SMAI setting \textit{ConnectionType} is \textit{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 (SAPTOPF), Underfrequency protection (SAPTUF) and Rate-of-change frequency protection (SAPFRC) due to that all other information except frequency and positive sequence voltage might be wrongly calculated.
18.13.3 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 L1, L2 and L3 will be calculated for use in symmetrical situations. If N component should be used respectively the phase component during faults I_N/U_N must be connected to input 4.

*Negation*: If the user wants to negate the 3ph signal, it is possible to choose to negate only the phase signals *Negate3Ph*, only the neutral signal *NegateN* or both *Negate3Ph +N*. negation means rotation with 180° of the vectors.

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

*MinValFreqMeas*: The minimum value of the voltage for which the frequency is calculated, expressed as percent of UBase (for each instance n).

**Settings DFTRefExtOut and DFTReference shall be set to default value InternalDFTRef if no VT inputs are available.**
Even if the user sets the AnalogInputType of a SMAI block to “Current”, the MinValFreqMeas is still visible. However, using the current channel values as base for frequency measurement is not recommendable for a number of reasons, not last among them being the low level of currents that one can have in normal operating conditions.

Examples of adaptive frequency tracking

Preprocessing block shall only be used to feed functions within the same execution cycles (e.g. use preprocessing block with cycle 1 to feed transformer differential protection). The only exceptions are measurement functions (CVMMXN, CMMXU, VMMXU, etc.) which shall be fed by preprocessing blocks with cycle 8.

When two or more preprocessing blocks are used to feed one protection function (e.g. over-power function GOPPDOP), it is of outmost importance that parameter setting DFTReference has the same set value for all of the preprocessing blocks involved.
### Task time group 1

<table>
<thead>
<tr>
<th>SMAI instance</th>
<th>3 phase group</th>
</tr>
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<tbody>
<tr>
<td>SMAI1:1</td>
<td>1</td>
</tr>
<tr>
<td>SMAI2:2</td>
<td>2</td>
</tr>
<tr>
<td>SMAI3:3</td>
<td>3</td>
</tr>
<tr>
<td>SMAI4:4</td>
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<tr>
<td>SMAI5:5</td>
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<td>SMAI6:6</td>
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<td>SMAI7:7</td>
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<td>SMAI12:12</td>
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### Task time group 2

<table>
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<tbody>
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<td>SMAI12:36</td>
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</table>

Figure 190: Twelve SMAI instances are grouped within one task time. SMAI blocks are available in three different task times in the IED. Two pointed instances are used in the following examples.

The examples shows a situation with adaptive frequency tracking with one reference selected for all instances. In practice each instance can be adapted to the needs of the actual application. The adaptive frequency tracking is needed in IEDs that belong to the protection system of synchronous machines and that are active during run-up and shut-down of the machine. In other application the usual setting of the parameter DFTReference of SMAI is InternalDFTRef.

**Example 1**
Assume instance SMAI7:7 in task time group 1 has been selected in the configuration to control the frequency tracking. Observe that the selected reference instance (i.e. frequency tracking master) must be a voltage type. Observe that positive sequence voltage is used for the frequency tracking feature.

For task time group 1 this gives the following settings (see Figure 190 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 191) SMAI2:2 – SMAI12:12: $DFTReference = DFTRefGrp7$ for SMAI2:2 – SMAI12:12 to use SMAI7:7 as reference.

For task time group 2 this gives the following settings:

SMAI1:13 – SMAI12:24: $DFTReference = ExternalDFTRef$ to use DFTSPFC input of SMAI1:13 as reference (SMAI7:7)

For task time group 3 this gives the following settings:

SMAI1:25 – SMAI12:36: $DFTReference = ExternalDFTRef$ to use DFTSPFC input as reference (SMAI7:7)

Example 2
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 190 for numbering):

SMAI1:1 – SMAI12:12: \textit{DFTReference} = \textit{ExternalDFTRef} to use DFTSPFC input as reference (SMAI4:16)

For task time group 2 this gives the following settings:

SMAI11:13: \textit{DFTRefExtOut} = \textit{DFTRefGrp4} to route SMAI4:16 reference to the SPFCOUT output, \textit{DFTReference} = \textit{DFTRefGrp4} for SMAI11:13 to use SMAI4:16 as reference (see Figure 192) SMAI12:14 – SMAI12:24: \textit{DFTReference} = \textit{DFTRefGrp4} to use SMAI4:16 as reference.

For task time group 3 this gives the following settings:

SMAI11:25 – SMAI12:36: \textit{DFTReference} = \textit{ExternalDFTRef} to use DFTSPFC input as reference (SMAI4:16)
18.14 Test mode functionality TESTMODE

18.14.1 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 so on.

18.14.1.1 IEC 61850 protocol test mode

The IEC 61850 Test Mode has improved testing capabilities for IEC 61850 systems. Operator commands sent to the IEC 61850 Mod determine the behavior of the functions. The command can be given from the LHMI under the Main menu/Test/Function test modes menu or remotely from an IEC 61850 client. The possible values of IEC 61850 Mod are described in Communication protocol manual, IEC 61850 Edition 1 and Edition 2.

To be able to set the IEC 61850 Mod the parameter remotely, the PST setting RemoteModControl may not be set to Off. The possible values are Off, Maintenance or All levels. The Off value denies all access to data object Mod from remote, Maintenance requires that the category of the originator (orCat) is Maintenance and All levels allow any orCat.

The mod of the Root LD.LNN0 can be configured under Main menu/Test/Function test modes/Communication/Station communication/IEC61850 LD0 LLN0/LD0LLN0:1

When the Mod is changed at this level, all components under the logical device update their own behavior according to IEC 61850-7-4. The supported values of IEC 61850 Mod are described in Communication protocol manual, IEC 61850 Edition 2. The IEC 61850 test mode is indicated with the Start LED on the LHMI.

The mod of an specific component can be configured under Main menu/Test/Function test modes/Communication/Station Communication

It is possible that the behavior is also influenced by other sources as well, independent of the mode, such as the insertion of the test handle, loss of SV, and IED configuration or LHMI. If a function of an IED is set to Off, the related Beh is set to Off as well. The related mod keeps its current state.
When the setting *Operation* is set to *Off*, the behavior 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.

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.

- When the *Beh* of a component is set to *Test*, the component is not blocked and all control commands with a test bit are accepted.
- When the *Beh* of a component 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 LN. Only process-related outputs on LNs related to primary equipment are blocked. If there is an XCBR, the outputs EXC_Open and EXC_Close are blocked.
- When the *Beh* of a component 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 LN. In addition, the components can be blocked when their *Beh* is *blocked*. This can be done if the component has a block input. The block status of a component is shown as the *Blk* output under the *Test/Function status* menu. If the *Blk* output is not shown, the component cannot be blocked.

### 18.14.2 Setting guidelines

There are two possible ways to place the IED in the *TestMode= On* state. If the IED is set to normal operation (*TestMode = Off*), but the functions are still shown being in the test mode, the input signal INPUT on the TESTMODE function block might be activated in the configuration.

Forcing of binary input and output signals is only possible when the IED is in IED test mode.

### 18.15 Self supervision with internal event list INTERRSIG

#### 18.15.1 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 software communication.
Internal events are generated by the built-in supervisory functions. The supervisory functions supervise the status of the various modules in the IED and, in case of failure, a corresponding event is generated. Similarly, when the failure is corrected, a corresponding event is generated.

Apart from the built-in supervision of the various modules, events are also generated when the status changes for the:

- built-in real time clock (in operation/out of order).
- external time synchronization (in operation/out of order).

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 only be retrieved with the aid of PCM600 Event Monitoring Tool. The PC can either be connected to the front port, or to the port at the back of the IED.

18.16 Time synchronization TIMESYNCHGEN

18.16.1 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
For IEDs using IEC 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 either optical PPS or IRIG-B. For IED's using IEC 61850-9-2LE from one single MU as analog data source, the MU and IED still needs to be synchronized to each other. This could be done by letting the MU supply a PPS signal to the IED.

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 set a backup time-source for GPS signal, for instance SNTP. In this case, when the GPS signal quality is bad, the IED will automatically choose SNTP as the time-source. At a given point in time, only one time-source will be used.

### 18.16.2 Setting guidelines

All the parameters related to time are divided into two categories: System time and Synchronization.

#### 18.16.2.1 System time

The time is set with years, month, day, hour, minute, second and millisecond.

#### 18.16.2.2 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** which can have the following values:

- Off
- SPA
- LON
- BIN (Binary Minute Pulse)
- GPS
- GPS+SPA
- GPS+LON
- GPS+BIN
- SNTP
- GPS+SNTP
- GPS+IRIG-B
- IRIG-B
- PPS

**CoarseSyncSrc** which can have the following values:

- Off
- SPA
- LON
- SNTP
- DNP

**CoarseSyncSrc** which can have the following values:

- Off
- SNTP
- DNP
- IEC60870-5-103

The function input to be used for minute-pulse synchronization is called **TIME-MINSYNC**.

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 in a system of IEDs connected in a communication network (IEC61850-8-1). The **SyncMaster** can have the following values:

- Off
- SNTP-Server

Set the course time synchronizing source (**CoarseSyncSrc**) to Off 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.
Section 19 Requirements

19.1 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.

19.1.1 Current transformer classification

To guarantee correct operation, the current transformers (CTs) must be able to correctly reproduce the current for a minimum time before the CT will begin to saturate. To fulfill the requirement on a specified time to saturation the CTs must fulfill the requirements of a minimum secondary e.m.f. that is specified below.

There are several different ways to specify CTs. Conventional magnetic core CTs are usually specified and manufactured according to some international or national standards, which specify different protection classes as well. There are many different standards and a lot of classes but fundamentally there are three different types of CTs:

- High remanence type CT
- Low remanence type CT
- Non remanence type CT

The high remanence type has no limit for the remanent flux. This CT has a magnetic core without any airgaps and a remanent flux might remain almost infinite time. In this type of transformers the remanence can be up to around 80% of the saturation flux. Typical examples of high remanence type CT are class P, PX, TPX according to IEC, class P, X according to BS (old British Standard) and non gapped class C, K according to ANSI/IEEE.

The low remanence type has a specified limit for the remanent flux. This CT is made with a small air gap to reduce the remanence to a level that does not exceed 10% of the saturation flux. The small air gap has only very limited influences on the other properties of the CT. Class PXR, TPY according to IEC are low remanence type CTs.

The non remanence type CT has practically negligible level of remanent flux. This type of CT has relatively big air gaps in order to reduce the remanence to practically zero level. In the same time, these air gaps reduce the influence of the DC-component from the primary fault current. The air gaps will also decrease the measuring accuracy...
in the non-saturated region of operation. Class TPZ according to IEC is a non remanence type CT.

Different standards and classes specify the saturation e.m.f. in different ways but it is possible to approximately compare values from different classes. The rated equivalent limiting secondary e.m.f. $E_{al}$ according to the IEC 61869–2 standard is used to specify the CT requirements for the IED. The requirements are also specified according to other standards.

19.1.2 Conditions

The requirements are a result of investigations performed in our network simulator. The current transformer models are representative for current transformers of high remanence and low remanence type. The results may not always be valid for non remanence type CTs (TPZ).

The performances of the protection functions have been checked in the range from symmetrical to fully asymmetrical fault currents. Primary time constants of at least 120 ms have been considered at the tests. The current requirements below are thus applicable both for symmetrical and asymmetrical fault currents.

Depending on the protection function phase-to-earth, phase-to-phase and three-phase faults have been tested for different relevant fault positions for example, close in forward and reverse faults, zone 1 reach faults, internal and external faults. The dependability and security of the protection was verified by checking for example, time delays, unwanted operations, directionality, overreach and stability.

The remanence in the current transformer core can cause unwanted operations or minor additional time delays for some protection functions. As unwanted operations are not acceptable at all maximum remanence has been considered for fault cases critical for the security, for example, faults in reverse direction and external faults. Because of the almost negligible risk of additional time delays and the non-existent risk of failure to operate the remanence have not been considered for the dependability cases. The requirements below are therefore fully valid for all normal applications.

It is difficult to give general recommendations for additional margins for remanence to avoid the minor risk of an additional time delay. They depend on the performance and economy requirements. When current transformers of low remanence type (for example, TPY, PR) are used, normally no additional margin is needed. For current transformers of high remanence type (for example, P, PX, TPX) the small probability of fully asymmetrical faults, together with high remanence in the same direction as the flux generated by the fault, has to be kept in mind at the decision of an additional margin. Fully asymmetrical fault current will be achieved when the fault occurs at approximately zero voltage (0°). Investigations have shown that 95% of the faults in the network will occur when the voltage is between 40° and 90°. In addition fully asymmetrical fault current will not exist in all phases at the same time.

19.1.3 Fault current
The current transformer requirements are based on the maximum fault current for faults in different positions. Maximum fault current will occur for three-phase faults or single phase-to-earth faults. The current for a single phase-to-earth fault will exceed the current for a three-phase fault when the zero sequence impedance in the total fault loop is less than the positive sequence impedance.

When calculating the current transformer requirements, maximum fault current for the relevant fault position should be used and therefore both fault types have to be considered.

19.1.4 Secondary wire resistance and additional load

The voltage at the current transformer secondary terminals directly affects the current transformer saturation. This voltage is developed in a loop containing the secondary wires and the burden of all relays in the circuit. For earth faults the loop includes the phase and neutral wire, normally twice the resistance of the single secondary wire. For three-phase faults the neutral current is zero and it is just necessary to consider the resistance up to the point where the phase wires are connected to the common neutral wire. The most common practice is to use four wires secondary cables so it normally is sufficient to consider just a single secondary wire for the three-phase case.

The conclusion is that the loop resistance, twice the resistance of the single secondary wire, must be used in the calculation for phase-to-earth faults and the phase resistance, the resistance of a single secondary wire, may normally be used in the calculation for three-phase faults.

As the burden can be considerable different for three-phase faults and phase-to-earth faults it is important to consider both cases. Even in a case where the phase-to-earth fault current is smaller than the three-phase fault current the phase-to-earth fault can be dimensioning for the CT depending on the higher burden.

In isolated or high impedance earthed systems the phase-to-earth fault is not the dimensioning case. Therefore, the resistance of the single secondary wire can always be used in the calculation for this kind of power systems.

19.1.5 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.

19.1.6 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.

19.1.6.1 Busbar protection

The CT can be of high remanence or low remanence type and they can be used together within the same zone of protection. Each of them 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:

The high remanence type CT must fulfill

$$E_{al} \geq E_{alreq} = 0.5 \cdot I_{fmax} \cdot \frac{I_{nr}}{I_{pr}} \cdot \left( R_{ct} + R_{L} + \frac{S_{pr}}{I_{r}} \right)$$

(Equation 90)

The low remanence type CT must fulfill

$$E_{al} \geq E_{alreq} = 0.2 \cdot I_{fmax} \cdot \frac{I_{nr}}{I_{pr}} \cdot \left( R_{ct} + R_{L} + \frac{S_{pr}}{I_{r}} \right)$$

(Equation 91)

where

- $I_{fmax}$: Maximum primary fundamental frequency fault current on the busbar (A)
- $I_{pr}$: The rated primary CT current (A)
- $I_{nr}$: The rated secondary CT current (A)
- $I_{r}$: The rated current of the protection IED (A)

Table continues on next page
The secondary resistance of the CT \((\Omega)\)

\(R_{ct}\)

The resistance of the secondary wire and additional load \((\Omega)\). The loop resistance containing the phase and neutral wires, must be used for faults in solidly earthed systems. The resistance of a single secondary wire should be used for faults in high impedance earthed systems.

\(R_L\)

The burden of an IED current input channel (VA). \(S_R=0.020\) VA/channel for \(I_r=1\) A and \(S_R=0.150\) VA/channel for \(I_r=5\) A.

**The non remanence type CT**

CTs of non remanence type (for example, TPZ) can be used but in this case the CTs within the differential zone must be of non remanence type. They must fulfill the same requirements as for the low remanence type CTs and have a rated equivalent secondary e.m.f. \(E_{al}\) that is larger than or equal to required secondary e.m.f. \(E_{alreq}\) below:

\[
E_{al} \geq E_{alreq} = 0.2 \cdot I_{f\text{ max}} \cdot \frac{I_{sr}}{I_{pr}} \left( R_{ct} + R_L + \frac{S_R}{I_r^2} \right)
\]

(Equation 92)

**19.1.6.2 Breaker failure protection**

The CTs must have a rated equivalent limiting secondary e.m.f. \(E_{al}\) that is larger than or equal to the required rated equivalent limiting secondary e.m.f. \(E_{alreq}\) below:

\[
E_{al} \geq E_{alreq} = 5 \cdot I_{op} \cdot \frac{I_{sr}}{I_{pr}} \left( R_{ct} + R_L + \frac{S_R}{I_r^2} \right)
\]

(Equation 93)

where:

- \(I_{op}\) The primary operate value (A)
- \(I_{pr}\) The rated primary CT current (A)
- \(I_{sr}\) The rated secondary CT current (A)
- \(I_r\) The rated current of the protection IED (A)
- \(R_{ct}\) The secondary resistance of the CT \((\Omega)\)
- \(R_L\) The resistance of the secondary cable and additional load \((\Omega)\). The loop resistance containing the phase and neutral wires, must be used for faults in solidly earthed systems. The resistance of a single secondary wire should be used for faults in high impedance earthed systems.
- \(S_R\) The burden of an IED current input channel (VA). \(S_R=0.020\) VA/channel for \(I_r=1\) A and \(S_R=0.150\) VA/channel for \(I_r=5\) A
19.1.6.3 Non-directional instantaneous and definitive time, phase and residual overcurrent protection

The CTs must have a rated equivalent limiting secondary e.m.f. \( E_{al} \) that is larger than or equal to the required rated equivalent limiting secondary e.m.f. \( E_{alreq} \) below:

\[
E_{al} \geq E_{alreq} = 1,5 \cdot I_{op} \cdot \frac{I_{sr}}{I_{pr}} \left( R_{ct} + R_{L} + \frac{S_{R}}{I_{r}^2} \right)
\]

(Equation 94)

where:
- \( I_{op} \) The primary operate value (A)
- \( I_{pr} \) The rated primary CT current (A)
- \( I_{sr} \) The rated secondary CT current (A)
- \( I_{r} \) The rated current of the protection IED (A)
- \( R_{ct} \) The secondary resistance of the CT (\( \Omega \))
- \( R_{L} \) The resistance of the secondary cable and additional load (\( \Omega \)). The loop resistance containing the phase and neutral wires, must be used for faults in solidly earthed systems. The resistance of a single secondary wire should be used for faults in high impedance earthed systems.
- \( S_{R} \) The burden of an IED current input channel (VA).
  - \( S_{R} = 0.020 \text{ VA/channel for } I_{r} = 1 \text{ A} \)
  - \( S_{R} = 0.150 \text{ VA/channel for } I_{r} = 5 \text{ A} \)

19.1.6.4 Non-directional inverse time delayed phase and residual overcurrent protection

The requirement according to Equation 95 and Equation 96 does not need to be fulfilled if the high set instantaneous or definitive time stage is used. In this case Equation 94 is the only necessary requirement.

If the inverse time delayed function is the only used overcurrent protection function the CTs must have a rated equivalent 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:

\[
E_{al} \geq E_{alreq} = 20 \cdot I_{op} \cdot \frac{I_{sr}}{I_{pr}} \left( R_{ct} + R_{L} + \frac{S_{R}}{I_{r}^2} \right)
\]

(Equation 95)

where:
- \( I_{op} \) The primary current set value of the inverse time function (A)
- \( I_{pr} \) The rated primary CT current (A)
- \( I_{sr} \) The rated secondary CT current (A)
The rated current of the protection IED (A)

The secondary resistance of the CT (\(\Omega\))

The resistance of the secondary cable and additional load (\(\Omega\)). The loop resistance containing the phase and neutral wires, must be used for faults in solidly earthed systems. The resistance of a single secondary wire should be used for faults in high impedance earthed systems.

The burden of an IED current input channel (VA). \(S_R=0.020\) VA/channel for \(I_r=1\) A and \(S_R=0.150\) VA/channel for \(I_r=5\) A

Independent of the value of \(I_{op}\) the maximum required \(E_{al}\) is specified according to the following:

\[
E_{al} \geq E_{alreq\max} = I_{k,max} \cdot \frac{I_{op}}{I_{pr}} \left( R_{ct} + R_L + \frac{S_R}{I_r^2} \right)
\]

(Equation 96)

where

\(I_{k,max}\) Maximum primary fundamental frequency current for close-in faults (A)

19.1.7 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.

19.1.7.1 Current transformers according to IEC 61869-2, class P, PR

A CT according to IEC 61869-2 is specified by the secondary limiting e.m.f. \(E_{alf}\). The value of the \(E_{alf}\) is approximately equal to the corresponding \(E_{al}\). Therefore, the CTs according to class P and PR must have a secondary limiting e.m.f. \(E_{alf}\) that fulfills the following:

\[
E_{2\text{max}} > \max E_{alreq}
\]

(Equation 97)
19.1.7.2 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. \( E_{\text{knee}} \) (\( E_k \) for class PX and PXR, \( E_{\text{kneeBS}} \) for class X and the limiting secondary voltage \( U_{\text{al}} \) 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:

\[
E_{\text{knee}} \approx E_k \approx E_{\text{kneeBS}} \approx U_{\text{al}} > 0.8 \left( \text{maximum of } E_{\text{alreq}} \right)
\]

(Equation 98)

19.1.7.3 Current transformers according to ANSI/IEEE

Current transformers according to ANSI/IEEE are partly specified in different ways. A rated secondary terminal voltage \( U_{\text{ANSI}} \) is specified for a CT of class C. \( U_{\text{ANSI}} \) 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 \( U_{\text{ANSI}} \) values for example, \( U_{\text{ANSI}} \) is 400 V for a C400 CT. A corresponding rated equivalent limiting secondary e.m.f. \( E_{\text{alANSI}} \) can be estimated as follows:

\[
E_{\text{alANSI}} = \left| 20 \cdot I_{\text{sr}} \cdot R_{\text{ct}} + U_{\text{ANSI}} \right| = \left| 20 \cdot I_{\text{sr}} \cdot R_{\text{ct}} + 20 \cdot I_{\text{sr}} \cdot Z_{\text{bANSI}} \right|
\]

(Equation 99)

where:
- \( Z_{\text{bANSI}} \) The impedance (that is, with a complex quantity) of the standard ANSI burden for the specific C class (Ω)
- \( U_{\text{ANSI}} \) 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:

\[
E_{\text{alANSI}} > \text{maximum of } E_{\text{alreq}}
\]

(Equation 100)

A CT according to ANSI/IEEE is also specified by the knee point voltage \( U_{\text{kneeANSI}} \) that is graphically defined from an excitation curve. The knee point voltage \( U_{\text{kneeANSI}} \) normally has a lower value than the knee-point e.m.f. according to IEC and BS. \( U_{\text{kneeANSI}} \) 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 $U_{\text{kneeANSI}}$ that fulfills the following:

$$V_{\text{kneeANSI}} > 0.75 \cdot \text{maximum of \ } E_{nreq}$$

(Equation 101)

19.2 Voltage transformer requirements

The performance of a protection function will depend on the quality of the measured input signal. Transients caused by capacitive voltage transformers (CVTs) can affect some protection functions. Magnetic or capacitive voltage transformers can be used.

The capacitive voltage transformers (CVTs) should fulfill the requirements according to the IEC 61869-5 standard regarding ferro-resonance and transients. The ferro-resonance requirements of the CVTs are specified in chapter 6.502 of the standard.

The transient responses for three different standard transient response classes, T1, T2 and T3 are specified in chapter 6.503 of the standard. CVTs according to all classes can be used.

The protection IED has effective filters for these transients, which gives secure and correct operation with CVTs.

19.3 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.

19.4 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 >100ms. (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.
- 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.
## Section 20 Glossary

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<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 fibre 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>Acronym</td>
<td>Description</td>
</tr>
<tr>
<td>---------</td>
<td>-------------</td>
</tr>
<tr>
<td>CCM</td>
<td>CAN carrier module</td>
</tr>
<tr>
<td>CCVT</td>
<td>Capacitive Coupled Voltage Transformer</td>
</tr>
<tr>
<td>Class C</td>
<td>Protection Current Transformer class as per IEEE/ANSI</td>
</tr>
<tr>
<td>CMPPS</td>
<td>Combined megapulses per second</td>
</tr>
<tr>
<td>CMT</td>
<td>Communication Management tool in PCM600</td>
</tr>
<tr>
<td>CO cycle</td>
<td>Close-open cycle</td>
</tr>
<tr>
<td>Codirectional</td>
<td>Way of transmitting G.703 over a balanced line. Involves two twisted pairs making it possible to transmit information in both directions</td>
</tr>
<tr>
<td>COM</td>
<td>Command</td>
</tr>
<tr>
<td>COMTRADE</td>
<td>Standard Common Format for Transient Data Exchange format for Disturbance recorder according to IEEE/ANSI C37.111, 1999 / IEC 60255-24</td>
</tr>
<tr>
<td>Contra-directional</td>
<td>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</td>
</tr>
<tr>
<td>COT</td>
<td>Cause of transmission</td>
</tr>
<tr>
<td>CPU</td>
<td>Central processing unit</td>
</tr>
<tr>
<td>CR</td>
<td>Carrier receive</td>
</tr>
<tr>
<td>CRC</td>
<td>Cyclic redundancy check</td>
</tr>
<tr>
<td>CROB</td>
<td>Control relay output block</td>
</tr>
<tr>
<td>CS</td>
<td>Carrier send</td>
</tr>
<tr>
<td>CT</td>
<td>Current transformer</td>
</tr>
<tr>
<td>CU</td>
<td>Communication unit</td>
</tr>
<tr>
<td>CVT or CCVT</td>
<td>Capacitive voltage transformer</td>
</tr>
<tr>
<td>DAR</td>
<td>Delayed autoreclosing</td>
</tr>
<tr>
<td>DARPA</td>
<td>Defense Advanced Research Projects Agency (The US developer of the TCP/IP protocol etc.)</td>
</tr>
<tr>
<td>DBDL</td>
<td>Dead bus dead line</td>
</tr>
<tr>
<td>DBLL</td>
<td>Dead bus live line</td>
</tr>
<tr>
<td>DC</td>
<td>Direct current</td>
</tr>
<tr>
<td>DFC</td>
<td>Data flow control</td>
</tr>
<tr>
<td>DFT</td>
<td>Discrete Fourier transform</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
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<tr>
<td>--------------</td>
<td>-------------</td>
</tr>
<tr>
<td>DHCP</td>
<td>Dynamic Host Configuration Protocol</td>
</tr>
<tr>
<td>DIP-switch</td>
<td>Small switch mounted on a printed circuit board</td>
</tr>
<tr>
<td>DI</td>
<td>Digital input</td>
</tr>
<tr>
<td>DLLB</td>
<td>Dead line live bus</td>
</tr>
<tr>
<td>DNP</td>
<td>Distributed Network Protocol as per IEEE Std 1815-2012</td>
</tr>
<tr>
<td>DR</td>
<td>Disturbance recorder</td>
</tr>
<tr>
<td>DRAM</td>
<td>Dynamic random access memory</td>
</tr>
<tr>
<td>DRH</td>
<td>Disturbance report handler</td>
</tr>
<tr>
<td>DSP</td>
<td>Digital signal processor</td>
</tr>
<tr>
<td>DTT</td>
<td>Direct transfer trip scheme</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 fibre 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>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><strong>Abbreviation</strong></td>
<td><strong>Description</strong></td>
</tr>
<tr>
<td>------------------</td>
<td>-----------------</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>HMI</td>
<td>Human-machine interface</td>
</tr>
<tr>
<td>HSAR</td>
<td>High speed autoreclosing</td>
</tr>
<tr>
<td>HV</td>
<td>High-voltage</td>
</tr>
<tr>
<td>HVDC</td>
<td>High-voltage direct current</td>
</tr>
<tr>
<td>IDBS</td>
<td>Integrating deadband supervision</td>
</tr>
<tr>
<td>IEC</td>
<td>International Electrical Committee</td>
</tr>
<tr>
<td>IEC 60044-6</td>
<td>IEC Standard, Instrument transformers – Part 6: Requirements for protective current transformers for transient performance</td>
</tr>
<tr>
<td>IEC 60870-5-103</td>
<td>Communication standard for protection equipment. A serial master/slave protocol for point-to-point communication</td>
</tr>
<tr>
<td>IEC 61850</td>
<td>Substation automation communication standard</td>
</tr>
<tr>
<td>IEC 61850–8–1</td>
<td>Communication protocol standard</td>
</tr>
<tr>
<td>IEEE</td>
<td>Institute of Electrical and Electronics Engineers</td>
</tr>
<tr>
<td>IEEE 802.12</td>
<td>A network technology standard that provides 100 Mbits/s on twisted-pair or optical fiber cable</td>
</tr>
<tr>
<td>IEEE P1386.1</td>
<td>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).</td>
</tr>
<tr>
<td>IEEE 1686</td>
<td>Standard for Substation Intelligent Electronic Devices (IEDs) Cyber Security Capabilities</td>
</tr>
<tr>
<td>IED</td>
<td>Intelligent electronic device</td>
</tr>
<tr>
<td>I-GIS</td>
<td>Intelligent gas-insulated switchgear</td>
</tr>
<tr>
<td>IOM</td>
<td>Binary input/output module</td>
</tr>
</tbody>
</table>

**Instance**

When several occurrences of the same function are available in the IED, they are referred to as instances of that function. One instance of a function is identical to another of the same kind but has a different number in the IED user interfaces. The word "instance" is sometimes defined as an...
item of information that is representative of a type. In the same way an instance of a function in the IED is representative of a type of function.

**IP**
1. Internet protocol. The network layer for the TCP/IP protocol suite widely used on Ethernet networks. IP is a connectionless, best-effort packet-switching protocol. It provides packet routing, fragmentation and reassembly through the data link layer.
2. Ingression protection, according to IEC 60529

**IP 20**
Ingression protection, according to IEC 60529, level 20

**IP 40**
Ingression protection, according to IEC 60529, level 40

**IP 54**
Ingression protection, according to IEC 60529, level 54

**IRF**
Internal failure signal

**IRIG-B:**
InterRange Instrumentation Group Time code format B, standard 200

**ITU**
International Telecommunications Union

**LAN**
Local area network

**LIB 520**
High-voltage software module

**LCD**
Liquid crystal display

**LDCM**
Line differential communication module

**LDD**
Local detection device

**LED**
Light-emitting diode

**LNT**
LON network tool

**LON**
Local operating network

**MCB**
Miniature circuit breaker

**MCM**
Mezzanine carrier module

**MIM**
Milli-ampere module

**MPM**
Main processing module

**MVAL**
Value of measurement

**MVB**
Multifunction vehicle bus. Standardized serial bus originally developed for use in trains.

**NCC**
National Control Centre

**NOF**
Number of grid faults

**NUM**
Numerical module

**OCO cycle**
Open-close-open cycle

**OCP**
Overcurrent protection

**OEM**
Optical Ethernet module
<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<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>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>
<tr>
<td>Process bus</td>
<td>Bus or LAN used at the process level, that is, in near proximity to the measured and/or controlled components</td>
</tr>
<tr>
<td>PSM</td>
<td>Power supply module</td>
</tr>
<tr>
<td>PST</td>
<td>Parameter setting tool within PCM600</td>
</tr>
<tr>
<td>PT ratio</td>
<td>Potential transformer or voltage transformer ratio</td>
</tr>
<tr>
<td>PUTT</td>
<td>Permissive underreach transfer trip</td>
</tr>
<tr>
<td>RASC</td>
<td>Synchrocheck relay, COMBIFLEX</td>
</tr>
<tr>
<td>RCA</td>
<td>Relay characteristic angle</td>
</tr>
<tr>
<td>RISC</td>
<td>Reduced instruction set computer</td>
</tr>
<tr>
<td>RMS value</td>
<td>Root mean square value</td>
</tr>
<tr>
<td>RS422</td>
<td>A balanced serial interface for the transmission of digital data in point-to-point connections</td>
</tr>
<tr>
<td>RS485</td>
<td>Serial link according to EIA standard RS485</td>
</tr>
<tr>
<td>RTC</td>
<td>Real-time clock</td>
</tr>
<tr>
<td>RTU</td>
<td>Remote terminal unit</td>
</tr>
<tr>
<td>SA</td>
<td>Substation Automation</td>
</tr>
<tr>
<td>SBO</td>
<td>Select-before-operate</td>
</tr>
<tr>
<td>SC</td>
<td>Switch or push button to close</td>
</tr>
<tr>
<td>SCL</td>
<td>Short circuit location</td>
</tr>
<tr>
<td>SCS</td>
<td>Station control system</td>
</tr>
<tr>
<td><strong>SCADA</strong></td>
<td>Supervision, control and data acquisition</td>
</tr>
<tr>
<td><strong>SCT</strong></td>
<td>System configuration tool according to standard IEC 61850</td>
</tr>
<tr>
<td><strong>SDU</strong></td>
<td>Service data unit</td>
</tr>
<tr>
<td><strong>SLM</strong></td>
<td>Serial communication module.</td>
</tr>
<tr>
<td><strong>SMA connector</strong></td>
<td>Subminiature version A, A threaded connector with constant impedance.</td>
</tr>
<tr>
<td><strong>SMT</strong></td>
<td>Signal matrix tool within PCM600</td>
</tr>
<tr>
<td><strong>SMS</strong></td>
<td>Station monitoring system</td>
</tr>
<tr>
<td><strong>SNTP</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>SOF</strong></td>
<td>Status of fault</td>
</tr>
<tr>
<td><strong>SPA</strong></td>
<td>Strömberg Protection Acquisition (SPA), a serial master/slave protocol for point-to-point and ring communication.</td>
</tr>
<tr>
<td><strong>SRY</strong></td>
<td>Switch for CB ready condition</td>
</tr>
<tr>
<td><strong>ST</strong></td>
<td>Switch or push button to trip</td>
</tr>
<tr>
<td><strong>Starpoint</strong></td>
<td>Neutral point of transformer or generator</td>
</tr>
<tr>
<td><strong>SVC</strong></td>
<td>Static VAr compensation</td>
</tr>
<tr>
<td><strong>TC</strong></td>
<td>Trip coil</td>
</tr>
<tr>
<td><strong>TCS</strong></td>
<td>Trip circuit supervision</td>
</tr>
<tr>
<td><strong>TCP</strong></td>
<td>Transmission control protocol. The most common transport layer protocol used on Ethernet and the Internet.</td>
</tr>
<tr>
<td><strong>TCP/IP</strong></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><strong>TEF</strong></td>
<td>Time delayed earth-fault protection function</td>
</tr>
<tr>
<td><strong>TLS</strong></td>
<td>Transport Layer Security</td>
</tr>
<tr>
<td><strong>TM</strong></td>
<td>Transmit (disturbance data)</td>
</tr>
<tr>
<td><strong>TNC connector</strong></td>
<td>Threaded Neill-Concelman, a threaded constant impedance version of a BNC connector</td>
</tr>
<tr>
<td><strong>TP</strong></td>
<td>Trip (recorded fault)</td>
</tr>
<tr>
<td><strong>TPZ, TPY, TPX, TPS</strong></td>
<td>Current transformer class according to IEC</td>
</tr>
<tr>
<td>-------------------------</td>
<td>---------------------------------------------</td>
</tr>
<tr>
<td><strong>TRM</strong></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><strong>TYP</strong></td>
<td>Type identification</td>
</tr>
<tr>
<td><strong>UMT</strong></td>
<td>User management tool</td>
</tr>
<tr>
<td><strong>Underreach</strong></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><strong>UTC</strong></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 &quot;leap seconds&quot; 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, &quot;Zulu time.&quot; &quot;Zulu&quot; in the phonetic alphabet stands for &quot;Z&quot;, which stands for longitude zero.</td>
</tr>
<tr>
<td><strong>UV</strong></td>
<td>Undervoltage</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 earth-fault current</td>
</tr>
<tr>
<td><strong>3U₀</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>
For more information please contact:

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