Contents

Technical descriptions

The chapter "Functional descriptions".

This chapter describes the functions and logics within protection terminal RET 521. The descriptions deals with how the functions are designed, how they operate, and their signals and setting parameters. For hardware descriptions refer to the chapter "Design descriptions".

RET 521 terminal functionality

1 Terminal identification

1.1 General

You can store the identification names and numbers of the station, the transformer, and the terminal itself in the terminal. This information can be read on the built-in HMI or when communicating with the terminal through a PC using SMS or SCS.

The internal clock is used for time tagging of:

- Internal events
- Disturbance reports
- Events in a disturbance report
- Events transmitted to the SCS substation control system

This implies that the internal clock is very important. The clock can be synchronised, (see the section “Time syncronisation”), to achieve higher time tagging correlation accuracy between terminals. Without synchronisation, the internal clock is only useful for comparisons among events within the terminal.

The ordering number, serial number, software version and identity number of I/O modules are displayed on the local HMI. For each hardware module and for the frame there is the possibility to store a user defined note.

1.2 Terminal identification settings

The user configurable identification settings can be set from the HMI menu branch:

Config
Ident

The following parameters can be set

Table 1: User configurable terminal identification settings

Parameter	Setting range	Description
Unit No	(0 - 99999)	Unit No.
Unit Name	16 character string	Unit Name
Object No	(0 - 99999)	Object No.
Object Name	16 character string	Object Name
Station No	(0 - 99999)	Station No.
Station Name	16 character string	Station Name

1.3 Setting the terminal clock

The internal clock are set from the HMI menu branch:

Set
Time

Time is set by modifying the following parameters:

Table 2: Terminal date and time

Parameter	Setting range	Description
Date		Date in the format YYYY-MM-DD
Time		Time in the format HH:MM:SS

The current internal time is read from:

ServRep
Time

Note: When time syncronisation is enabled, time setting is not possible.

1.4 Displaying terminal identification numbers

The terminal serial number and software version and more can be displayed from the HMI menu branch:

TermSt
  IdentNo
    Observe
      General

The following terminal information are displayed:

Table 3: Terminal identification numbers

Parameter	Description
OrderingNo	RET 521 terminal ordering number
TermSerialNo	RET 521 terminal serial number
SW-version	SW version for main program
CPU-module	CPU-module

1.5 I/O module identification

The identity of each I/O module can be displayed on the HMI by following the menu branch:

TermStat
  IdentNo
    Observe
      I/O-mod

The present I/O module is identified by its parameter. However, these parameters are configuration dependent. In the following table the mnemonic <*iomodulename*> should be replaced by whatever type of module present, e.g. AIM1, BIM1, BOM2 etc.

Table 4: I/O module identification

Parameter	Description
PCIP3-<*iomodulename*>	Identity number of module in HW SlotNo 3
PCIP7-<*iomodulename*>	Identity number of module in HW SlotNo 7
CANP9-<*iomodulename*>	Identity number of module in HW SlotNo 9
CANP10-<*iomodulename*>	Identity number of module in HW SlotNo 10
CANP11-<*iomodulename*>	Identity number of module in HW SlotNo 11
CANP12-<*iomodulename*>	Identity number of module in HW SlotNo 12

1.6 User configurable module identification

The identity of some modules can be user defined using the HMI menu branch:

TermStat
  IdentNo
    Noted

The following parameters can be edited to enter a custom text for description of each module.

Table 5: User configurable module identification

Parameter	Description
Trafo-module	Trafo-module
ADC-module	ADC-module
HMI-module	HMI-module
Frame	Mechanical frame
Power-module	Power-module
LON-module	LON-module

2 Analog input data

In order to get correct measurement results as well as correct protection functionality, the analog input channels must be configured. The channel used as a phase reference for phase angle calculations must be selected, and rated primary and secondary currents and voltages must be set.

Note: Channel identification labels (e.g. AIM1-CH03) used in this section are the default labels used when no user defined labels are set.The labels are set from CAP 531 configuration tool by configuring the AIM1 and AIM2 function blocks.

Because all protection algorithms in RET 521 are calculated using the primary system quantities it is extremely important to properly set the data about connected current and voltage transformers. These data are calculated by the system engineer and normally set by the commissioner from the built-in HMI or from SMS.

2.1 Setting the phase reference channel

The reference channel is set from the MMI menu branch:

Config
  AnalogIn

The parameter RefCh is then set to the appropriate channel (e.g. AIM1-CH07, usually the L1 phase-to-ground voltage).

2.2 Configuration for analog inputs

The terminal can be equipped with a maximum of two analog input cards, each having ten analog input channels. The cards, named AIM1 and AIM2 respectively, allows for individual setting for each channel of the following parameters:

Parameter:	Setting range:	Description:	Type:
InputCTTap	1A, 5A	Connected input CT Tap on AIM card in A	Current
CTprim	(1-99999)A	Rated CT primary current in A	Current
CTsec	(1-5)A	Rated CT secondary current in A	Current
CTearth	Bus1, Tfr1, Neut1, Earth1, Bus23, Tfr23, Neut23, Earth23	Current transf. earthing, Towards power transf./ Towards bus	Current
VTprim	(0.1-999.9)kV	Rated VT primary voltage in kV	Voltage
VTsec	(1-999)V	Rated VT secondary voltage in V	Voltage

Note: CT parameters only present when the selected channel is a current channel, VT parameters only present when input channel is a voltage channel.

Channels are configured from the MMI menu branch:

Config
PCIP3-AIM1
AIM1-CH*nn*

for the first analog input card, or:

Config
PCIP7-AIM2
AIM2-CH*nn*

In both cases, *nn* is the channel number, ranging from 01-10.

2.2.1 Setting of current channels

The parameter InputCTTap is used to determine to which tap, on RET 521 input terminals, the wire from the main CT is connected. For more info about that see figure 1. It should be noted that this parameter can be only set from the built-in HMI.

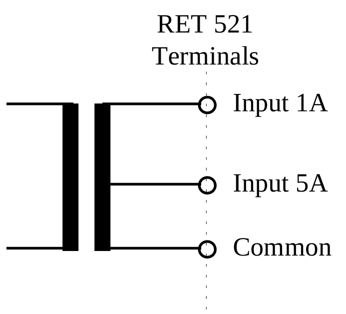


Fig. 1 CT Connections to RET 521

Parameter CTearth determines the way to configure according to the main CTs star connection and their polarity, or from RET 521 point of view, in which direction current is measured. Suffix 1 indicates primary side of the power transformer while suffix 23 indicates secondary or tertiary side of the power transformer.

An example for setup of all CT parameters is shown in figure 2.

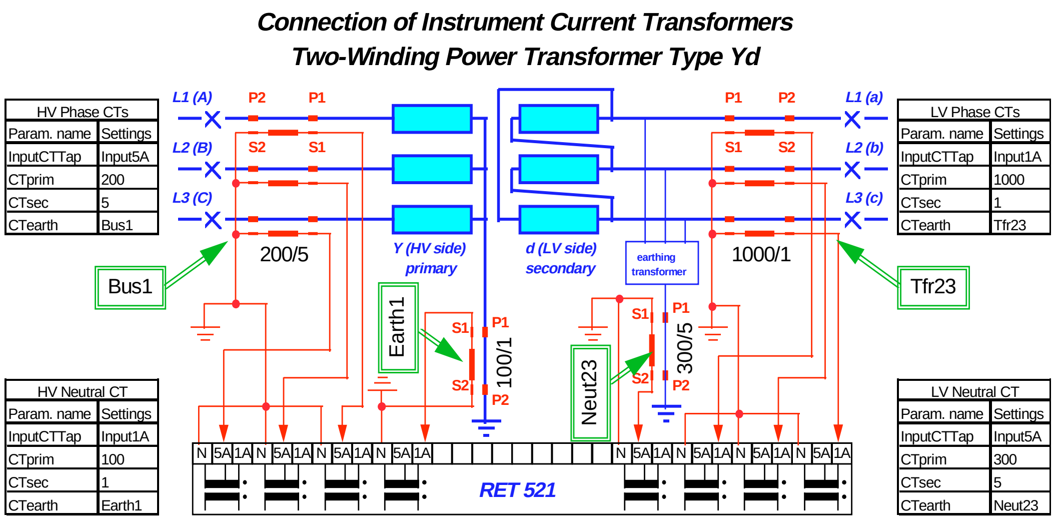


Fig. 2 CT Setup Example

When the configuration parameters of the CTs are made according to these instructions, functions depending on the direction of the current, will automatically be set up correctly. That means that the differential protection now is set up correctly.

In order to make other directional protection functions such as directional overcurrent protection or directional earth fault protection operate properly, the supposed sides of the power transformer must be defined. This is set with the configuration parameters Side2w or Side3w for each function block respectively. Now the directionality is set up so that the setting “*forward*” means the direction out from the transformer into the surrounding network and vice versa for the ”*reverse*” setting.

If a custom defined setting for the time delayed overcurrent and the time delayed earth fault protection functions, both the direction and the reference operate value has to be set and controlled separately.

2.2.2 Setting of voltage channels

It should be noted that in case of phase to earth voltage measurement with the following VT data,

$$\frac{132\ \text{kV} / \sqrt{3}}{110\ \text{V} / \sqrt{3}}$$

the following settings should be used:

VTprim = 132kV

VTsec = 110V.

2.3 Service value report

Table 6: Service values for AIM measuring current

Parameter:	Range:	Step:	Description:
AngleCI0n	0.0 - 359.9	0.1	Current angle, input n (n=1-10), in degrees
MagCI0n	0 - 99999	1	Current magnitude, input n, in A

Table 7: Service values for AIM measuring voltage

Parameter:	Range:	Step:	Description:
AngleVI0n	0.0 - 359.9	0.1	Voltage angle, input n (n=1-10), in degrees
MagVI0n	0 - 1999.9	0.1	Voltage magnitude, input n, in kV

3 Power transformer data

Because all protection algorithms in RET 521 do all calculations in primary system quantities, and all settings are related to the rated quantities of the protected power transformer it is extremely important to properly set the data about protected transformer. Required data can be easily found on transformer name plate. These data are normally set by the commissioner using the built-in HMI or SMS/SCS.

Please note that all data need to be set. Rated voltage values, as an example, are required even when there is no over-/undervoltage functions installed, because the transformer differential protection function uses these values to calculate the turns ratio of the power transformer.

Note: The power transformer data is part of the functions found under setting groups 1-4, functions that are managed in four separately configurable groups for extended flexibilty. Depending on which group is used for setting, *n* ranges from 1-4. If the protection scheme requires more than one setting group, transformer data must be copied to or set for each used setting group.

3.1 Basic transformer data

When using the built-in HMI, basic transformer data can be set using the menu branch:

Settings
Functions
Group *n*
TransfData
Basic Data

Table 8: Basic transformer data, two winding transformer

Parameter description	Parameter name	Range	Default
Transformer Vector Group	VectorGroup 2W	See Fig. 3	Yy00
Rated Transformer Power in MVA	Sr	0.1-999.9	173.2

In a three winding transformer system, the rated power is set for each winding, thus excluded from the basic data.

Table 9: Basic transformer data, three winding transformer

Parameter description	Parameter name	Range	Default
Transformer Vector Group	VectorGroup 3W	See Fig. 4	Yy00y00

3.1.1 Vector group setting strings

When setting the vector group, a number between 1 and 24 (two winding transformer) or between 1 and 288 (three winding transformer) is entered, corresponding to a certain vector group. When viewing the set vector group a three or four character string, constructed by combining the primary winding coupling (Y or D) with a vector code for the secondary winding, is displayed instead of the number.The following illustrations displays the correspondance between entered number and vector groups.

W1=Y (Primary Winding)	W2 (Secondary Winding)											
	y00	y02	y04	y06	y08	y10	d01	d03	d05	d07	d09	d11
	1	2	3	4	5	6	7	8	9	10	11	12

Settings for Vector Group No for Two Winding Power Transformers with Star Connected Primary Winding

W1=D (Primary Winding)	W2 (Secondary Winding)											
	y01	y03	y05	y07	y09	y11	d00	d02	d04	d06	d08	d10
	13	14	15	16	17	18	19	20	21	22	23	24

Settings for Vector Group No for Two Winding Power Transformers with Delta Connected Primary Winding

99000001.ppt

Fig. 3 Vector group reference table for two winding systems

W1=Y		W3 (Tertiary Winding)											
(Primary Winding)		y00	y02	y04	y06	y08	y10	d01	d03	d05	d07	d09	d11
	y00	1	2	3	4	5	6	7	8	9	10	11	12
W2	y02	13	14	15	16	17	18	19	20	21	22	23	24
	y04	25	26	27	28	29	30	31	32	33	34	35	36
Sec	y06	37	38	39	40	41	42	43	44	45	46	47	48
	y08	49	50	51	52	53	54	55	56	57	58	59	60
W	y10	61	62	63	64	65	66	67	68	69	70	71	72
i	d01	73	74	75	76	77	78	79	80	81	82	83	84
n	d03	85	86	87	88	89	90	91	92	93	94	95	96
d	d05	97	98	99	100	101	102	103	104	105	106	107	108
i	d07	109	110	111	112	113	114	115	116	117	118	119	120
n	d09	121	122	123	124	125	126	127	128	129	130	131	132
g	d11	133	134	135	136	137	138	139	140	141	142	143	144

Settings for Vector Group No for Three Winding Power Transformers with Star Connected Primary Winding

W1=D		W3 (Tertiary Winding)											
(Primary Winding)		y01	y03	y05	y07	y09	y11	d00	d02	d04	d06	d08	d10
	y01	145	146	147	148	149	150	151	152	153	154	155	156
W2	y03	157	158	159	160	161	162	163	164	165	166	167	168
	y05	169	170	171	172	173	174	175	176	177	178	179	180
Sec	y07	181	182	183	184	185	186	187	188	189	190	191	192
	y09	193	194	195	196	197	198	199	200	201	202	203	204
W	y11	205	206	207	208	209	210	211	212	213	214	215	216
i	d00	217	218	219	220	221	222	223	224	225	226	227	228
n	d02	229	230	231	232	233	234	235	236	237	238	239	240
d	d04	241	242	243	244	245	246	247	248	249	250	251	252
i	d06	253	254	255	256	257	258	259	260	261	262	263	264
n	d08	265	266	267	268	269	270	271	272	273	274	275	276
g	d10	277	278	279	280	281	282	283	284	285	286	287	288

Settings for Vector Group No for Three Winding Power Transformers with Delta Connected Primary Winding

99000003.ppt

Fig. 4 Vector group reference table for three winding systems

3.2 Two winding transformer system

Primary winding data is set using the menu branch:

Settings
Functions
Group *n*
TransfData
Winding 1

Table 10: Primary winding transformer data

Parameter description	Parameter name	Range	Default
Rated Current for Primary Winding in A	Ir1	1-99999	1000
Rated Phase to Phase Voltage for Primary Winding in kV	Ur1	1.0-999.9	100.0

Secondary winding data is set using the menu branch:

Settings
Functions
Group *n*
TransfData
Winding 2

Table 11: Secondary winding data

Parameter description	Parameter name	Range	Default
Rated Current for Secondary Winding in A	Ir2	1-99999	1000
Rated Phase to Phase Voltage for Secondary Winding in kV	Ur2	1.0-999.9	100.0

3.3 Three winding transformer systems

When the terminal is intended for protection of a three winding transformer, the parameters are somewhat different. Primary winding data is set using the HMI menu branch:

Settings
Functions
Group *n*
TransfData
Winding 1

Table 12: Three winding transformer data, primary winding

Parameter Description	Parameter Name	Range	Default
Rated Power of Primary Winding in MVA	Sr1	0.1-999.9	173.2
Rated Current for Primary Winding in A	Ir1	1-99999	1000
Rated Phase to Phase Voltage for Primary Winding in kV	Ur1	1.0-999.9	100.0

Secondary winding data is set using the HMI menu branch:

Settings
Functions
Group *n*
TransfData
Winding 2

Table 13: Three winding transformer data, secondary winding

Parameter Description	Parameter Name	Range	Default
Rated Power of Primary Winding in MVA	Sr2	0.1-999.9	173.2
Rated Current for Primary Winding in A	Ir2	1-99999	1000
Rated Phase to Phase Voltage for Primary Winding in kV	Ur2	1.0-999.9	100.0

Tertiary winding data is set using the HMI branch:

Settings
Functions
Group *n*
TransfData
Winding 3

Table 14: Three winding transformer data, secondary winding

Parameter Description	Parameter Name	Range	Default
Rated Power of Primary Winding in MVA	Sr3	0.1-999.9	173.2
Rated Current for Primary Winding in A	Ir3	1-99999	1000
Rated Phase to Phase Voltage for Primary Winding in kV	Ur3	1.0-999.9	100.0

4 Activation of setting groups

4.1 General

Different conditions in networks of different voltage levels require high adaptability of the used protection and control units to best provide for dependability, security and selectivity requirements. Protection units operate with higher degree of availability, especially, if the setting values of their parameters are continuously optimised regarding the conditions in power system.

Therefore, the terminal has been equipped with four independent groups (sets) of setting parameters. These groups can be activated at any time in five different ways:

- Locally by means of the local human-machine interface (HMI).
- Locally by means of a front-connected personal computer (PC).
- Remotely through the Station Monitoring System (SMS).
- Remotely through the Station Control System (SCS).
- Locally by means of up to four, programmable binary inputs, using the GRP function block.

5 Internal events

Internal events are generated by the built-in supervisory functions. The supervisory functions supervise the status of the various modules in the terminal 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 these functions change status:

- Built-in real time clock (in operation/out of order)
- External time synchronization (in operation/out of order)

Events are also generated on these occasions:

- Whenever any setting in the terminal is changed
- When the content of the disturbance report is erased

Internal events can be presented at three different locations:

- At the terminal using the built-in HMI
- Remotely using front-connected PC or SMS
- Remotely using SCS

5.1 Using the built-in HMI

If an internal fault has occurred, the built-in HMI displays information under:

Terminal Status
Self Superv

Here, there are indications of internal failure (serious fault), or internal warning (minor problem).

There are also indications regarding the faulty unit, according to Table 15.

Table 15: Self-supervision signals in the built-in HMI

HMI information:	Status:	Signal name:	Activates summary signal:	Description:
InternFail	OK / FAIL	INT--FAIL		Internal fail summary. Signal activation will reset the terminal
Intern Warning	OK /WARNING	INT--WARNING		Internal warning summary
NUM-modFail	OK / FAIL	INT--NUMFAIL	INT--FAIL	Numerical module failed. Signal activation will reset the terminal
NUM-modWarning	OK /WARNING	INT--NUMWARN	INT--WARNING	Numerical module warning (failure of clock, time synch.
PCIPx-AIMn	OK / FAIL	AIMn-Error	INT--FAIL	Analogue input module n failed. Signal activation will reset the terminal
CANPx-YYYn	OK / FAIL	IOn--Error	INT--FAIL	I/O module (YYY = BIM, BOM, IOM) n failed. Signal activation will reset the terminal
CANPx-MIM1	OK / FAIL	MIM1-Error	INT--FAIL	mA input module MIM1 failed. Signal activation will reset the terminal
Real Time Clock	OK /WARNING	INT--RTC	INT--WARNING	Internal clock is reset - Set the clock
Time Sync	OK /WARNING	INT--TSYNC	INT--WARNING	No time synchronisation

You can also connect the internal signals, such as INT--FAIL and INT--WARN to binary output contacts for signalling to a control room.

In the Terminal Status information, you can view the present information from the self-supervision function. Indications of failure or warnings for each hardware module are provided, as well as information about the external time synchronization and the internal clock, according to Table 15. Recommendations are given on measures to be taken to correct the fault. Loss of time synchronisation can be considered as a warning only. The terminal has full functionality without time synchronisation.

5.2 Using front-connected PC or SMS

Here two summary signals appear, self-supervision summary and numerical module status summary. These signals can be compared to the internal signals as:

- Self-supervision summary = INT--FAIL and INT--WARNING
- CPU-module status summary = INT--NUMFAIL and INT--NUMWARN

When an internal fault has occurred, you can retrieve extensive information about the fault from the list of internal events available in the SMS part:

TRM-STAT TermStatus - Internal Events

The list of internal events provides valuable information, which can be used during commissioning and during fault tracing.

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, when it is full, the oldest event is overwritten. The list cannot be cleared; its content cannot be erased.

The internal events in this list not only refer to faults in the terminal, but also to other activities, such as change of settings, clearing of disturbance reports, and loss of external time synchronisation.

The information can only be retrieved with the aid of the SM/RET 521 software package. The PC can be connected either to the port at the front or at the rear of the terminal.

These events are logged as internal events.

Table 16: Events available for the internal event list in the terminal

Event message:		Description:	Generating signal:
INT--FAIL	Off	Internal fail status	INT--FAIL (reset event)
INT--FAIL	■On		INT--FAIL (set event)
INT--WARNING	Off	Internal warning status	INT--WARNING (reset event)
INT--WARNING	■On		INT--WARNING (set event)
INT--NUMFAIL	Off	Numerical module fatal error status	INT--NUMFAIL (reset event)
INT--NUMFAIL	■On		INT--NUMFAIL (set event)
INT--NUMWARN	Off	Numerical module non-fatal error status	INT--NUMWARN (reset event)
INT--NUMWARN	■On		INT--NUMWARN (set event)
IOn--Error	Off	In/Out module No. n status	IOn--Error (reset event)
IOn--Error	■On		IOn--Error (set event)
AIMn-Error	Off	Analogue input module No. n status	AIMn-Error (reset event)
AIMn-Error	■On		AIMn-Error (set event)
MIM1-Error	Off	mA-input module status	MIM1-Error (reset event)
MIM1-Error	■On		MIM1-Error (set event)
INT--RTC	Off	Real Time Clock (RTC) status	INT--RTC (reset event)
INT--RTC	■On		INT--RTC (set event)
INT--TSYNC	Off	External time synchronisation status	INT--TSYNC (reset event)
INT--TSYNC	■On		INT--TSYNC (set event)
INT--SETCHGD		Any settings in terminal changed	
DRPC-CLEARED		All disturbances in Disturbance report cleared	

5.3 Using SCS

Internal events can also be sent to the Station HMI in a Substation Control System (SCS). Some signals are available from a function block InternSignals (INT). The signals from this function block are connected to an Event function block, which generates and sends these signals as events to the station level of the SCS. The signals from the INT-function block can also be connected to binary outputs for signalisation via output relays or they can be used as conditions for certain functions. These connections are performed from the CAP 531 Configuration tool.

Individual error signals from I/O modules and time synchronisation can be obtained from respective function block of IOM-, BIM-, BOM-, MIM- and AIM-modules and from the time synchronisation block TIME.

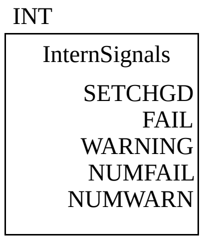


Fig. 5 Simplified terminal diagram of the Internal Signals function

The output signals from the function block INT:

Table 17: Output signals for INT

Out:	Description:
INT--SETCHGD	Setting changed
INT--FAIL	Internal fail status
INT--WARNING	Internal warning status
INT--NUMFAIL	NUM module fail status
INT--NUMWARN	NUM module warning status

6 Time synchronisation

6.1 System overview

The terminal has a built-in real time clock (RTC) with a resolution of one nanosecond. The terminal is also provided with a calendar. The starting date and time is 1970-01-01 00:00:00. The last date and time is 2037-12-31 23:59:59. The clock and calendar is battery- backed to provide safe operation also during supply failure.

The terminal can be synchronised via the serial ports and via a binary input.

On the serial buses (both LON and SPA) two types of synchronisation messages are sent.

- Coarse message is sent every minute and comprises complete date and time, i.e. year, month, day, hours, minutes, seconds and milliseconds
- Fine message is sent every second and comprises only seconds and milliseconds.

Synchronisation via a binary input is intended for minute pulses from e.g. a station master clock. Both positive and negative edge on the signal can be accepted.This signal is also considered as a fine signal.

6.2 Configuration

The following configuration alternatives for time synchronisation are available in the RET 521 terminal:

FineTimeSrc:

- None
- LON
- SPA
- BinIn_Pos
- BinIn_Neg

CoarseTimeSrc:

- None
- LON
- SPA

Table 18: Time source configuration alternatives

	FineTimeSrc	Coarse-TimeSrc	Description
1.	None	None	No external time sync, time is set from terminal HMI.
2.	LON	LON	Time sychronization from LON. Coarse time from LON.
3.	LON	SPA	Time sychronization from LON. Coarse time from SPA.
4.	SPA	SPA	Time sychronization from SPA. Coarse time from SPA.
5.	SPA	LON	Time sychronization from SPA. Coarse time from LON.
6.	BinIn_Pos	None	Time sychronization from Binary Minute pulse, positive edge. No coarse time.
7.	BinIn_Neg	None	Time sychronization from Binary Minute pulse, negative edge. No coarse time.
8.	BinIn_Pos	LON	Time sychronization from Binary Minute pulse, positive edge. Coarse time from LON.
9.	BinIn_Neg	LON	Time sychronization from Binary Minute pulse, negative edge. Coarse time from LON.
10.	BinIn_Pos	SPA	Time sychronization from Binary Minute pulse, positive edge. Coarse time from SPA.
11.	BinIn_Neg	SPA	Time sychronization from Binary Minute pulse, negative edge. Coarse time from SPA.
12.	SPA	None	Time sychronization from SPA. No coarse time.
13.	LON	None	Time sychronization from LON. No coarse time.
14.	None	SPA	No time synchronization. Coarse time from SPA
15.	None	LON	No time synchronization. Coarse time from LON.

If no external time is available (alt.1), the system time will be taken from the battery-backed RTC at start-up. After that the terminal time can be set from the built in HMI.

If no coarse time is available (alt. 6,7,12,13) and fine time exists, the RTC time is used as terminal time at start-up. Then the fine time is used for synchronisation.

If no fine time is available (alt. 14,15) and coarse time exists, the coarse time is used for synchronisation of the system time as long as it does not deviate more than 0,5 seconds from the terminal time. If the deviation is larger than 0,5 seconds the terminal time will be set to the value of the coarse time message.

If both fine and coarse time exists (alt. 2-5, 8-11), the first coarse time message will set the terminal time. After that the fine time is used for synchronisation. If coarse time deviates more than 0,5 seconds from the terminal time, the terminal time will be set to the value of the coarse time message.

Configuration of time sources can be done from the built-in HMI at:

Configuration
  Time
    FineTimeSrc
    CoarseTimeSrc

...and from the graphical configuration tool CAP 531 tool:

In the function block **TIME** the following inputs are used:

- M**INSYNC** Minute pulse synchronisation input. Should be connected to a binary input if SYNSOURC is set to BinIn_XXX.
- **SYNSOURC** Fine time source
- **COARSE** Coarse time source

6.3 Setting date and time

If no external time is available (alternative 1 in table 1) the internal time can be set on the built-in HMI display at:

Settings
  Time

If CoarseTimeSrc is set to SPA (alternative 3, 4, 10, 11, 14 in table 1) the internal time can be set via SMS (Station Monitoring System) at:

Settings
  Terminal Time

The time is set with year, date and time.

The maximum time that can be set is 2037-Dec-31 23:59:59. When the internal clock has overflowed, this will be handled so that the protection functions of the terminal will not be disturbed.

The minimum time that can be set is 1970-Jan-01 00:00:00

6.4 Error signals

Two error signals are available for time errors:

- TIME-RTCERR internal RTC errors
- TIME-SYNCERR time synchronisation error

Both signals are normally in state *OK* and will change to *WARNING* when an error occurs.

6.4.1 TIME-SYNCERR

If no external time synchronisation is available, i.e. both FineTimeSrc and CoarseTimeSrc is set to *none*, TIME-SYNCERR is always *OK*.

If external time synchronisation is available, TIME-SYNCERR will change from WARNING to OK at start or restart of each configured source. This means that time synchronisation is up and running. It should however be noted, that TIME-SYNCERR = OK does not indicate that the system time has been synchronised to the required accuracy specified in section 1.1.

The status of these error signals is shown on the HMI at:

Terminal Status
  Self Superv
    Time Sync
    Real Time Clock

The error signals can also be found in the **TIME** function block in the CAP 531 tool, refer to Appendix. Both error signals are reported to the RET 521 internal event list which can be uploaded to the SMS PC software for evaluation.

6.4.1.1 Causes for error signals

TIME_SYNCERR:

- Malfunctioning or missing binary IO-card.
- The internal time has not been synchronised to the external time within a specified number of periods after start or restart. Synchronisation level = 1,25 ms (1/2 system time accuracy).
- The internal time has deviated from the external time more than 1,25 ms during a specified number of periods.
- Time setting. A coarse time value deviating more than 0,5 seconds from the internal during continous synchronised operation will set the internal time and generate TIME_SYNCERR.
- Error in synchronisation signals. Refer to description below.

6.4.1.2 Check of synchronisation signals

- Binary minute pulses:

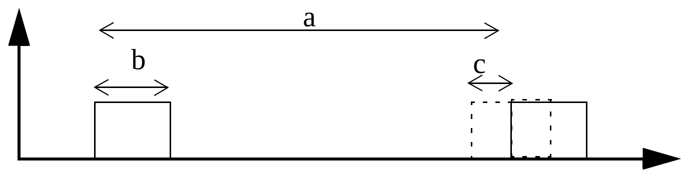


Fig. 6 Binary minute pulses

1 Frequency check. Period time (a) should be 60 seconds. Deviations larger than +/- 50 ms indicates a large frequency deviation and will cause TIME_SYNCERR.

2 Pulse width check. Pulse width (b) must be in the range 5-100 milliseconds.

3 Individual pulse jitter (c). 10 consecutive pulses with period time variations exceeding +/- 5 ms will generate TIME_SYNCERR.

Loss of minute pulse signals will cause an internal timer to generate TIME_SYNCERR after 2 minutes.

- SPA and LON:

1. Time messages from SPA and LON should have a period time of 1 second for fine synchronisation messages. Loss of SPA or LON synchronisation signals will cause an internal timer to generate TIME_SYNCERR after 2 seconds.
2. In a synchronised node, a discrepancy between message time and terminal time of more than 0,5 seconds will cause TIME_SYNCERR.

6.4.2 TIME-RTCERR

Activation of this signal can have two causes:

1. Failure in reading the RTC time at start-up.
2. Overflow of the internal clock. This will happen in the year 2038.

6.5 CAP 531 terminal diagram for Time function block

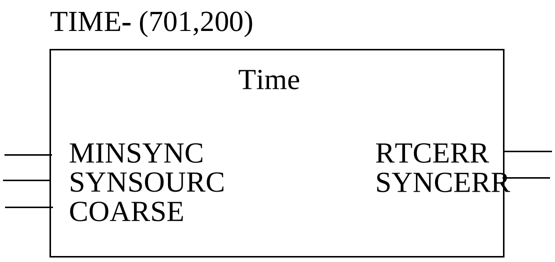


Fig. 7 Function block

6.6 CAP 531 signal lists for Time function block

Input signals:	**Description:**
TIME-MINSYNC	Minute pulse synchronisation input
TIME-SYNSOURC	fine time source input. Setting range: refer to table 3.3
TIME-COARSE	Coarse time source input. Setting range: refer to table 3.3

Output signals:	**Description:**
TIME-SYNCERR	Synchronisation error
TIME-RTCERR	Internal clock error

6.7 Setting table for time sources on built-in HMI

Parameter:	**Setting range:**
FineTimeSrc	None, LON, SPA, BinIn Pos, BinIn Neg
CoarseTimeSrc	None, LON, SPA

7 Restricted settings

Do not set this function in operation before carefully reading these instructions and configuring the HMI--BLOCKSET functional input to the selected binary input.

The HMI--BLOCKSET functional input is configurable only to one of the available binary inputs. For this reason, the terminal is delivered with the default configuration, where the HMI--BLOCKSET signal is connected to NONE-NOSIGNAL.

7.1 General

Setting values of different control and protection parameters and the configuration of different function and logic circuits within the terminal are important not only for reliable and secure operation of the terminal, but also for the entire power system.

Non-permitted and non-coordinated changes, done by unauthorised personnel, can cause severe damages in primary and secondary power circuits. They can influence the security of people working in close vicinity of the primary and secondary apparatuses and those using electric energy in everyday life.

For this reason, the terminal include a special feature that, when activated, blocks the possibility to change the settings and/or configuration of the terminal from the HMI module.

All other functions of the local human-machine communication remain intact. This means that an operator can read all disturbance reports and other information and setting values for different protection parameters and the configuration of different logic circuits.

This function permits remote resetting and reconfiguration through the serial communication ports, when the setting restrictions permit remote changes of settings. The setting restrictions can be set only on the local HMI.

7.2 Installation and setting instructions

Fig. 8 presents the combined connection and logic diagram for the function.

Configuration of the HMI--BLOCKSET functional input signal under the submenu is possible only to one of the built-in binary inputs:

Configuration
  BuiltInHMI

Carefully select a binary input not used by or reserved for any other functions or logic circuits, before activating the function.

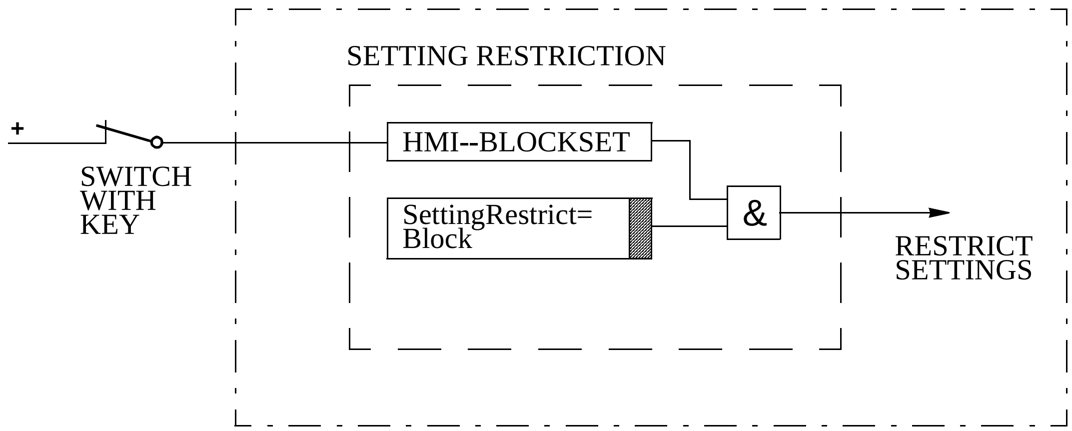


Fig. 8 Connection and logic diagram for the BLOCKSET function.

Set the setting restriction under the submenu:

Configuration
BuiltInHMI
SettingRestrict

to SettingRestrict = Block.

The selected binary input must be connected to the control DC voltage via a normally closed contact of a control switch, which can be locked by a key. Only when the normally closed contact is open, the setting and configuration of the terminal via the HMI is possible.

7.3 Function block

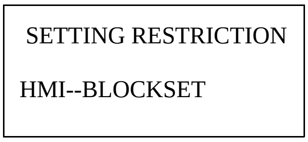


Fig. 9

7.4 Inputs and outputs

In:	Description:
BLOCKSET	Input signal to restrict the setting and configuration options by the HMI unit. **Warning:** Read the instructions before use. Default configuration to NONE-NOSIGNAL.

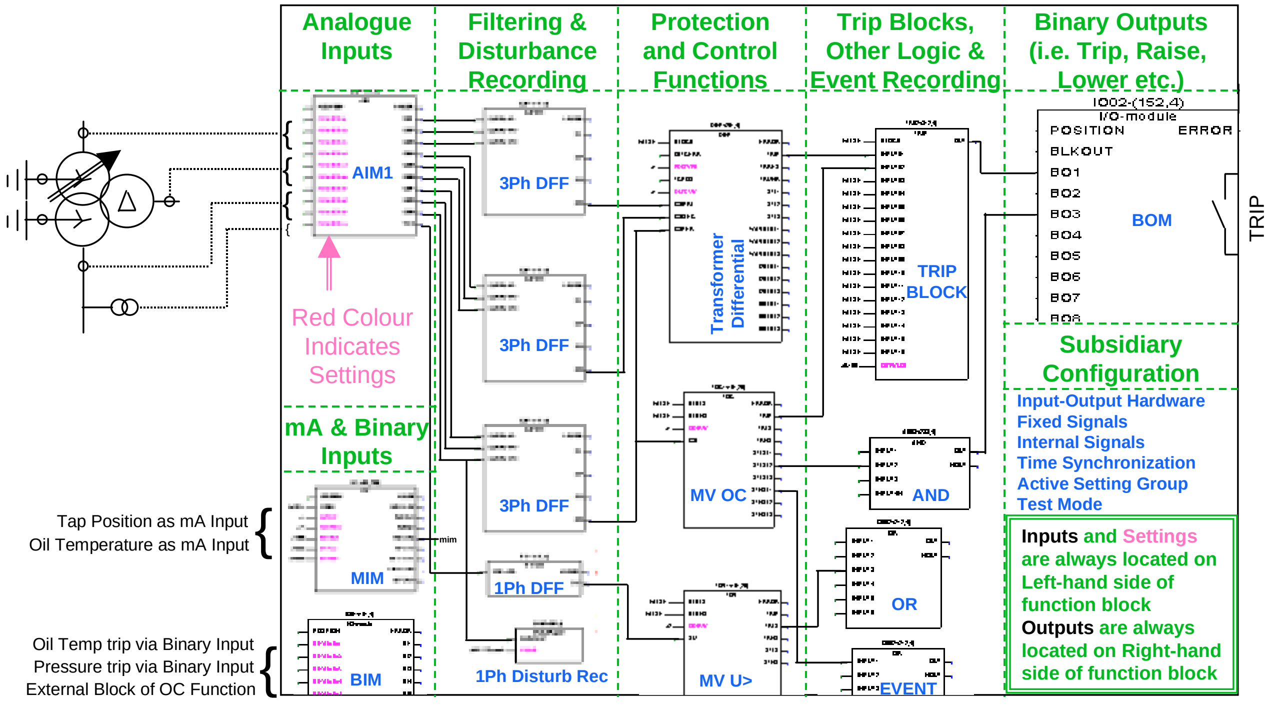
7.5 Setting parameters and ranges

Table 19:

Parameter:	Range:	Description:
SettingRe-strict	Open, Block	*Open:* Permits changes of settings and configuration by means of the HMI unit regardless of the status of input HMI--BLOCKSET. *Block:* Inhibits changes of settings and configuration via the HMI unit when the HMI--BLOCKSET input signal is equal to logic one.

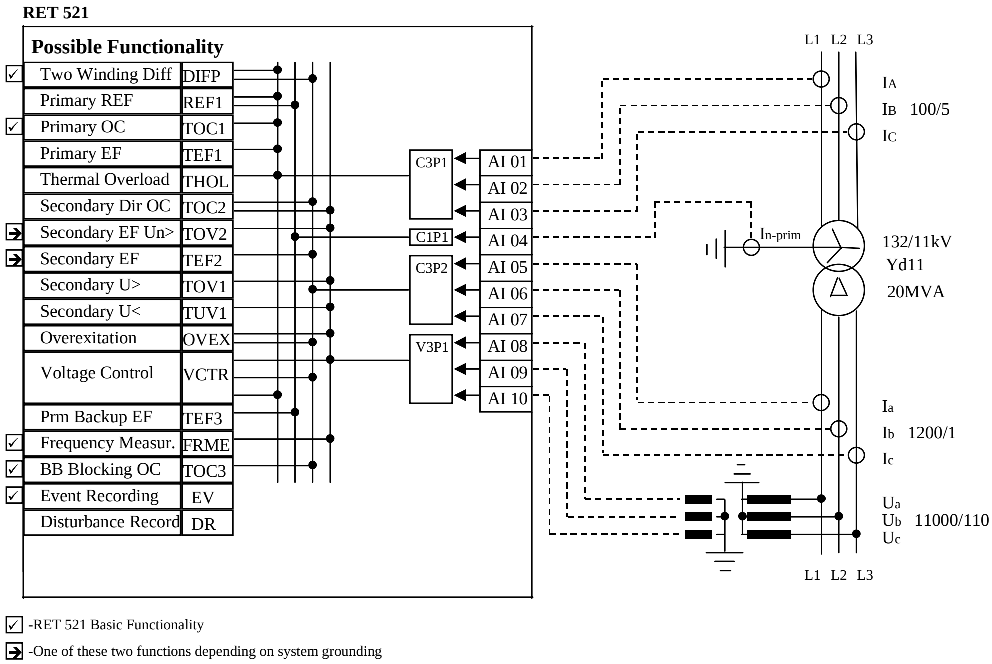
Default configuration

8 Configuration overview

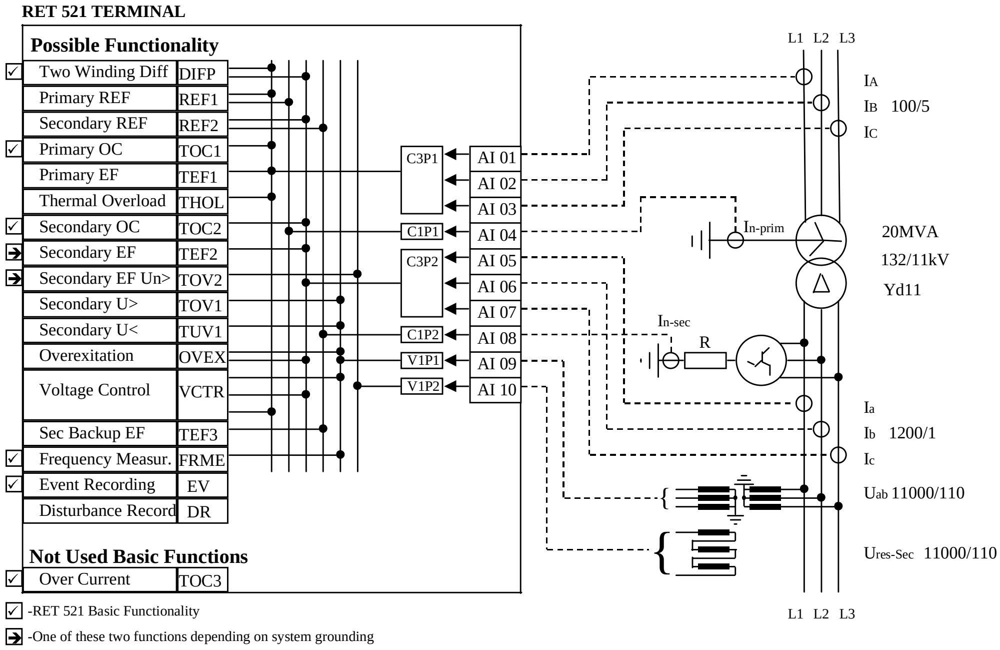


9 Description of configurations

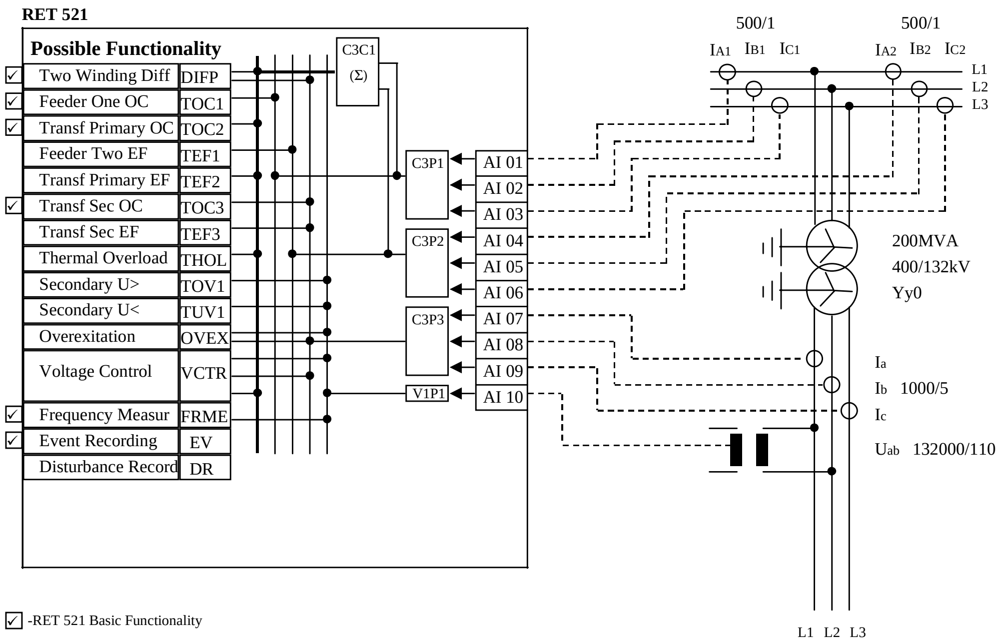
9.1 Configuration 1 (7I + 3U)



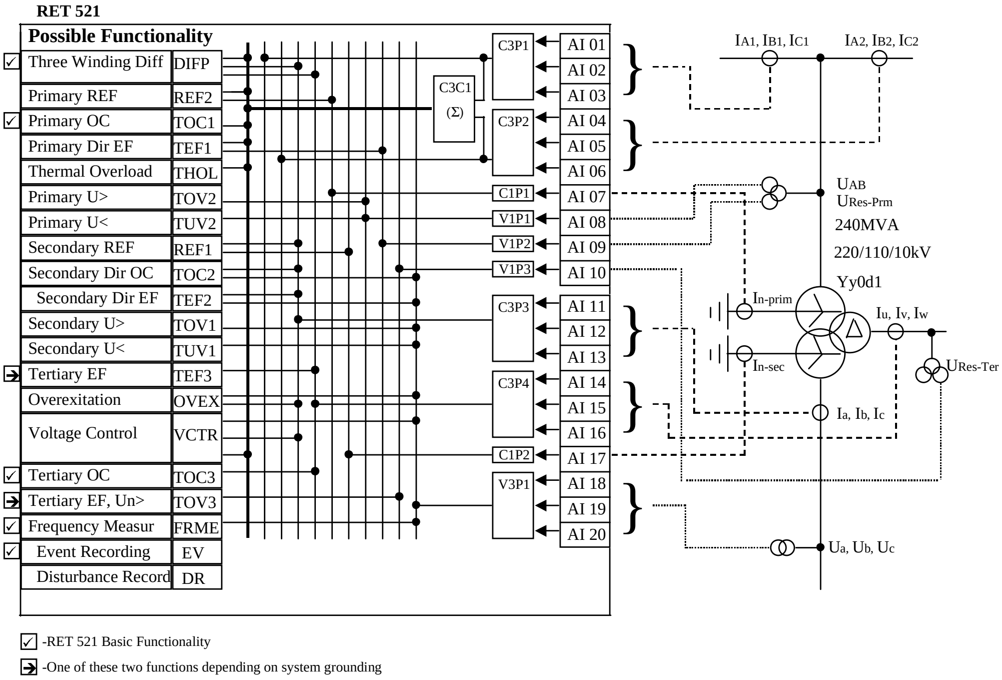
9.2 Configuration 2 (2I + 8U)



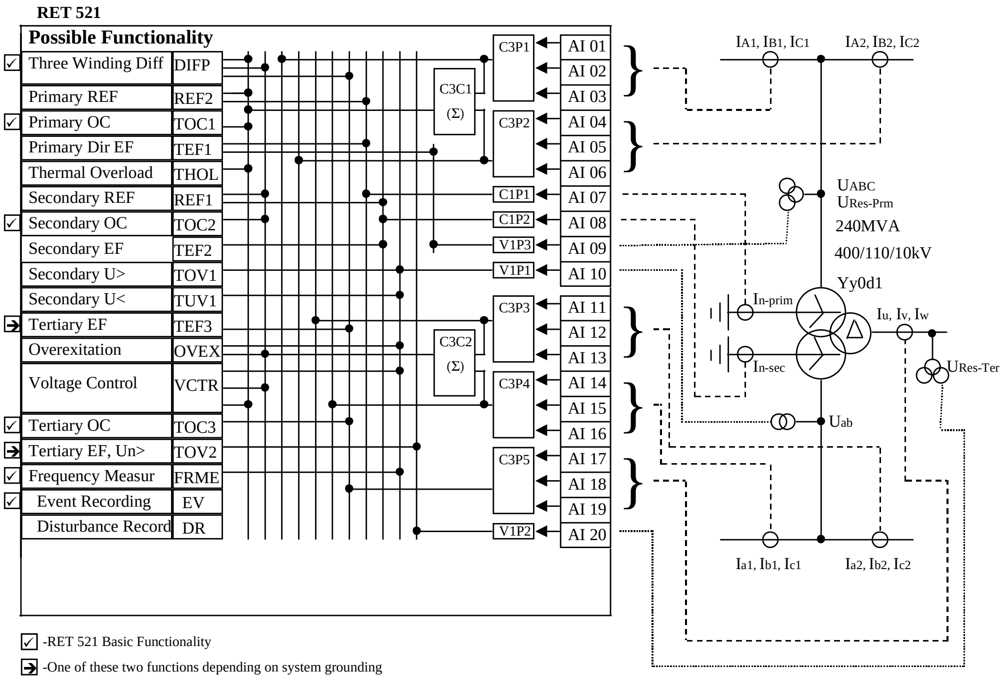
9.3 Configuration 3 (9I + 1U)



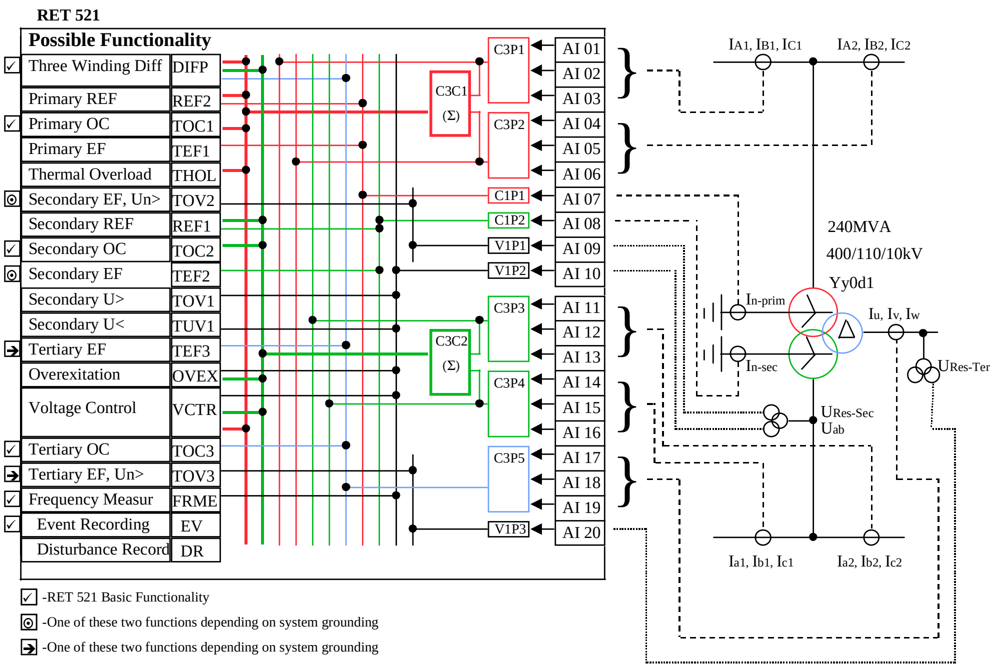
9.4 Configuration No 4 (2x (7I + 3U))



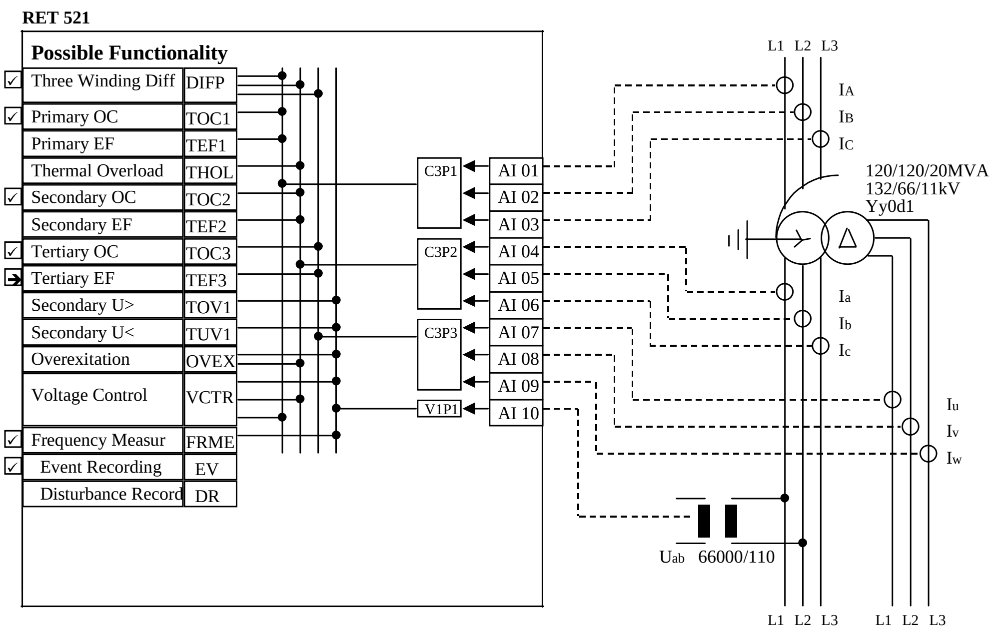
9.5 Configuration No 5 ([8I+2U]&[9I+1U])



9.6 Configuration No 5a ([8I+2U]&[9I+1U])



9.7 Configuration No 6 [9I+1U]



-RET 521 Basic Functionality
-If this function is applicable (depends on system grounding)

General functionality

10 Tripping logic (TR)

10.1 Summary of function

A trip logic block is provided where up to sixteen input signals can be gated together in an or-gate and then connected to e.g. a trip output relay. Furthermore up to twelve individual trip logic blocks exist so that as many individual output relays can be managed. Each block has been provided with possibility to set a minimum pulse length of the trip signal.

10.2 Description of logic

There are 12 instances (equal pieces) available of the trip logic function, each with the same logic diagram and function block appearance in CAP 531 configuration tool. The text, TRxx-(....,..), on the top of the function block is showing the function block name, TR, together with the instance number, xx, and details of the execution order and execution cycle time. How many of these 12 instances that are needed in an individual terminal is depending on configuration requirements.

Each trip logic instance has 16 equal logic inputs, INPUT01 to INPUT16, to an or-gate.

A settable time pulse circuit is available, which will make sure that a minimum duration of the output trip pulse is achieved for a short activation of an input signal. The settable time can be set to zero seconds, when no extra delay at reset of an input signal is allowed.

A blocking input is available which, when activated, will inhibit an eventual trip output. This blocking input does not reset the time pulse circuit if this did not time out. To securely block the output, the BLOCK must be activated at least as long as the SET-PULSE time setting and also at least as long as any input signal is active.

The inputs and outputs can only be connected with the help of the CAP 531 configuration tool to the outputs and inputs of other function blocks. The time setting, SET-PULSE, of the time pulse circuit will also be made by the CAP 531 configuration tool.

10.3 Logic diagram

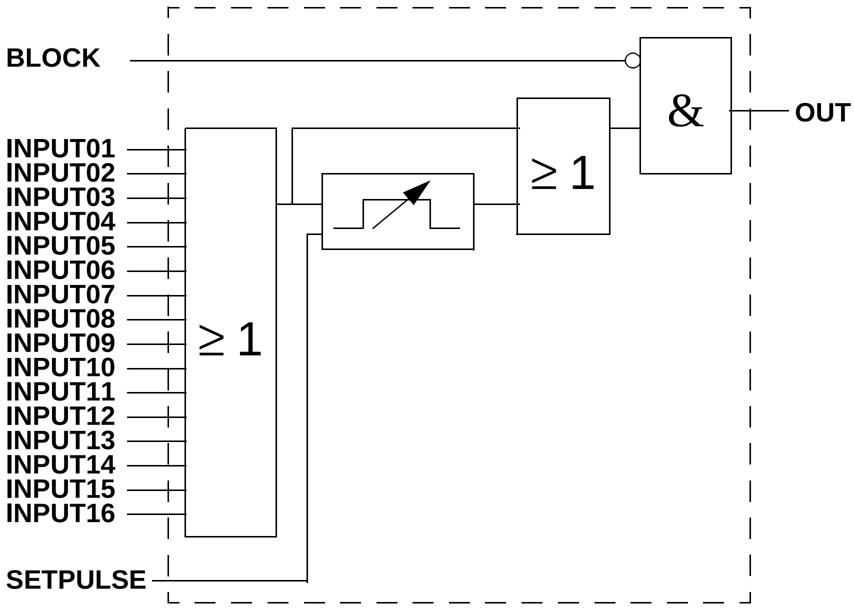


Fig. 10 Logic diagram of the trip logic function

10.4 Function block

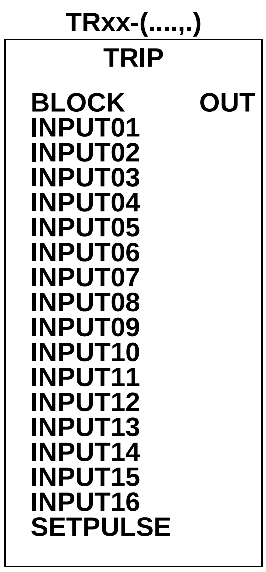


Fig. 11 Function block for trip logic TRxx

10.5 Input and output signals

Table 20: Input signals of trip logic TRxx

In:	Description:
TRxx-BLOCK	Activated BLOCK Inhibits an eventual output signal, OUT. It is not resetting the internal pulse timer.
TRxx-INPUT01	Logic input signal one for trip logic No xx
TRxx-INPUT02	Logic input signal two for trip logic No xx
TRxx-INPUT03	Logic input signal three for trip logic No xx
TRxx-INPUT04	Logic input signal four for trip logic No xx
TRxx-INPUT05	Logic input signal five for trip logic No xx
TRxx-INPUT06	Logic input signal six for trip logic No xx
TRxx-INPUT07	Logic input signal seven for trip logic No xx
TRxx-INPUT08	Logic input signal eight for trip logic No xx
TRxx-INPUT09	Logic input signal nine for trip logic No xx
TRxx-INPUT10	Logic input signal ten for trip logic No xx
TRxx-INPUT11	Logic input signal eleven for trip logic No xx
TRxx-INPUT12	Logic input signal twelve for trip logic No xx
TRxx-INPUT13	Logic input signal thirteen for trip logic No xx
TRxx-INPUT14	Logic input signal fourteen for trip logic No xx
TRxx-INPUT15	Logic input signal fifteen for trip logic No xx
TRxx-INPUT16	Logic input signal sixteen for trip logic No xx

Table 21: Output signal of trip logic TRxx

Out:	Description:
TRxx-OUT	Logic output signal for trip logic No xx. When OUT is activated, the HMI red LED is activated. See the section “How to use the human machine interface” for details.

10.6 Setting parameters and ranges

Table 22: Setting parameter and range of trip logic TRxx

Parameter:	Setting range:	Description:
TRxx-SETPULSE	0.00 - 50.00 s (step 0.01 s) (def. 0.15 s)	Sets the minimum duration in seconds of the output pulse, by setting the time of the internal pulse timer circuit. To be set from CAP 531

11 I/O-system configuration (IOHW)

11.1 Summary of application

I/O modules can be placed in PCI bus and CAN bus slots in the RET 521 transformer terminal. The analogue input module (AIM) is placed in any PCI bus slot and all other I/O modules can be placed in any CAN bus slot. The hardware reconfiguration of the product can easily be made from the graphical configuration tool, CAP 531.

11.2 Summary of function

The I/O system configuration means the function to add, remove, or move I/O modules in the RET 521 transformer terminal. The I/O modules can be connected to two different I/O-busses in the terminal. These are the PCI and the CAN. The analogue input module (AIM) is connected to the PCI bus and all the other I/O modules are connected to the CAN bus.

11.3 Description of logic

11.3.1 Analogue input module (AIM)

The analogue input module has 10 inputs. These inputs appear as outputs on the AIMx function block. The AIM can be configured with function selectors to get three different types. The difference between the types is the number of current and voltage inputs.

- Type 1 has 9 current inputs and 1 voltage input.
- Type 2 has 8 current inputs and 2 voltage inputs.
- Type 3 has 7 current inputs and 3 voltage inputs.

Every input can be given a name with up to 13 characters from the CAP 531 configuration tool. Parameters not settable from the graphical tool refer to a separate document describing the analog input module.

11.3.2 Binary input module (BIM)

The binary input module has 16 inputs. These inputs appear as outputs on the IOxx function block. The BIM supervises oscillating input signals. These oscillation blocking/release parameters are set from the SMS or from the built-in HMI. Every input can be given a name with up to 13 characters from the CAP 531 configuration tool.

11.3.3 Binary output module (BOM)

The binary output module has 24 outputs. These outputs appear as inputs on the IOxx function block. The outputs are used in pairs when used as command outputs. Activation of the BLKOUT input, resets and blocks the outputs. Every output can be given a name with up to 13 characters from the CAP 531 configuration tool.

11.3.4 Input/output module (IOM)

The input/output module has 8 inputs and 12 outputs. The functionality of the oscillating input blocking that is available on BIM and of the supervised outputs on BOM are not available on this module. Activation of the BLKOUT input, reset and block the outputs. Every input and output can be given a name with up to 13 characters from the CAP 531 configuration tool.

11.3.5 mA input module (MIM)

The mA input module has 6 inputs for mA signals. The POSITION input is located on the first MIM channel, as well as functionality for on-load tap-changer (OLTC) tap position reading, for each MIM module. If the configuration is incorrect, these outputs are set:

- ERROR output on the first MIM channel (MI11) of that MIM
- INPUTERR outputs on all MIM channels of that MIM

For more information about the mA input module including the OLTC functionality and the signal list and setting table, refer to a separate document describing the mA input module.

11.3.6 I/O hardware position (IOHW)

The IOHW (I/O Hardware Position) function block has 6 outputs in the RET 521 product, which equals the number of available slots. The CANPxx outputs are connected to the POSITION input of the BIMs, BOMs, IOMs, or MIMs and the PCIPxx outputs are connected to the POSITION input of the AIMs.

11.4 Function block

11.4.1 Analogue input module (AIM)

TYPE 1:

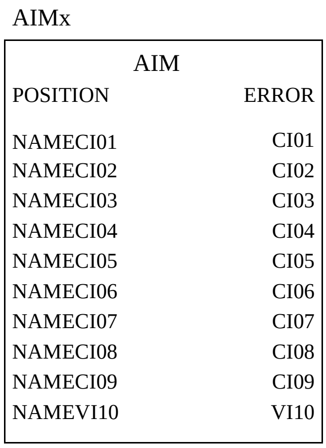


Fig. 12 Terminal diagram of the analogue input module (AIM) type 1

TYPE 2:

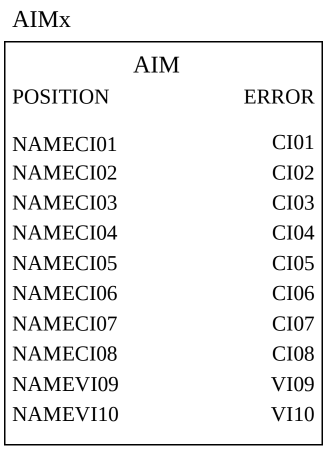


Fig. 13 Terminal diagram of the analogue input module (AIM) type 2

TYPE 3:

AIMx

AIM	
POSITION	ERROR
NAMECI01	CI01
NAMECI02	CI02
NAMECI03	CI03
NAMECI04	CI04
NAMECI05	CI05
NAMECI06	CI06
NAMECI07	CI07
NAMEVI08	VI08
NAMEVI09	VI09
NAMEVI10	VI10

Fig. 14 Terminal diagram of the analogue input module (AIM) type 3

11.4.2 Binary input module (BIM)

.

IOxx

I/O-module	
POSITION	ERROR
BINAME01	BI1
BINAME02	BI2
BINAME03	BI3
BINAME04	BI4
BINAME05	BI5
BINAME06	BI6
BINAME07	BI7
BINAME08	BI8
BINAME09	BI9
BINAME10	BI10
BINAME11	BI11
BINAME12	BI12
BINAME13	BI13
BINAME14	BI14
BINAME15	BI15
BINAME16	BI16

Fig. 15 Terminal diagram of the binary input module (BIM)

11.4.3 Binary output module (BOM)

IOxx

I/O-module

POSITION ERROR
BLKOUT

BO1
BO2
BO3
BO4
BO5
BO6
BO7
BO8
BO9
BO10
BO11
BO12
BO13
BO14
BO15
BO16
BO17
BO18
BO19
BO20
BO21
BO22
BO23
BO24

BONAME01
BONAME02
BONAME03
BONAME04
BONAME05
BONAME06
BONAME07
BONAME08
BONAME09
BONAME10
BONAME11
BONAME12
BONAME13
BONAME14
BONAME15
BONAME16
BONAME17
BONAME18
BONAME19
BONAME20
BONAME21
BONAME22
BONAME23
BONAME24

Fig. 16 Terminal diagram of the binary output module (BOM)

11.4.4 Input/output module (IOM)

IOxx

I/O-module	
POSITION	ERROR
BLKOUT	
BO1	BI1
BO2	BI2
BO3	BI3
BO4	BI4
BO5	BI5
BO6	BI6
BO7	BI7
BO8	BI8
BO9	
BO10	
BO11	
BO12	
BONAME01	
BONAME02	
BONAME03	
BONAME04	
BONAME05	
BONAME06	
BONAME07	
BONAME08	
BONAME09	
BONAME10	
BONAME11	
BONAME12	
BINAME01	
BINAME02	
BINAME03	
BINAME04	
BINAME05	
BINAME06	
BINAME07	
BINAME08	

Fig. 17 Terminal diagram of the input/output module (IOM)

11.4.5 mA input module (MIM)

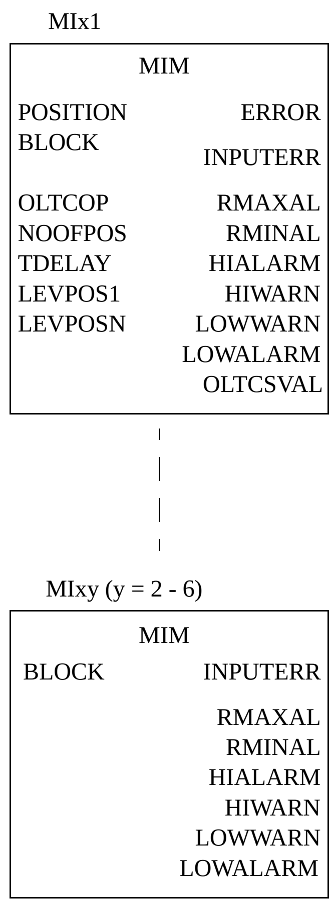


Fig. 18 Terminal diagram of the mA input module (MIM)

11.4.6 I/O hardware position (IOHW)

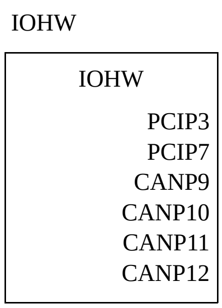


Fig. 19 Terminal diagram of the I/O hardware position module (IOHW)

11.5 Input and output signals

Table 23: Signal list for binary input module (BIM), binary output module (BOM), and input/output module (IOM)

In:	Description:
IOxx-POSITION	Slot position input of the I/O module. Is connected to a CAN slot position output of the IOHW function block.
IOxx-BLKOUT	Input to reset and block the outputs, applicable for IOM and BOM
IOxx-BOy	Binary output no. y, applicable for IOM and BOM.
Out:	**Description:**
IOxx-BIy	Binary input no. y, applicable for IOM and BIM.
IOxx-ERROR	Status of the I/O module. Is activated if the I/O module is failed.

Table 24: Signal list for analogue input module (AIM)

In	Description
AIMx-POSITION	Slot position input of the AIM module. Is connected to a PCI slot position output of the IOHW function block.
Out	**Description**
AIMx-CIyy	Current output, where yy = 01 to 09 for type 1, yy = 01 to 08 for type 2, and yy = 01 to 07 for type 3.
AIMx-VIyy	Voltage output, where yy = 10 for type 1, yy = 09 and 10 for type 2, and yy = 08 to 10 for type 3.
AIMx-ERROR	Status of the AIM module. Is activated if the AIM module is failed.

Table 25: Signal list for I/O hardware position block (IOHW)

Out	Description
IOHW-PCIPz	I/O module located in slot number z for the PCI bus. z = 3 and 7. Is connected to the I/O module function block for AIM.
IOHW-CANPzz	I/O module located in slot number zz for the CAN bus. zz = 10, 11 and 12. Is connected to the I/O module function block for BIM, BOM, IOM, and MIM.

11.6 Setting parameters and ranges

Table 26: Setting table for binary input module (BIM), binary output module (BOM), and input/output module (IOM)

Parameter:	Setting range:	Description:
IOxx-BINAMEy	13 characters	Name of binary input No. y, used for BIM and IOM. To be set from CAP 531.
IOxx-BONAMEy	13 characters	Name of binary output No. y, used for BOM and IOM. To be set from CAP 531.
OscBlock	1-40 Hz	Oscillation blocking frequency, common for all channels on I/O module BIM. To be set from SMS or built-in MMI.
OscRel	1-40 Hz	Oscillation release frequency, common for all channels on I/O module BIM. To be set from SMS or built-in MMI.
Operation	On, Off	I/O module in operation. Operation Off puts the I/O module in a non-active state. To be set from SMS or built-in MMI.

Table 27: Setting table for analogue input module (AIM)

Parameter:	Setting range:	Description:
AIMx-NAMECIyy	13 characters	Name of the analogue current output No. yy, where yy = 01 to 09 for type 1, yy = 01 to 08 for type 2, and yy = 01 to 07 for type 3. To be set from CAP 531.
AIMx-NAMEVIyy	13 characters	Name of the analogue voltage output No. yy where yy = 10 for type 1, yy = 09 and 10 for type 2, and yy = 08 to 10 for type 3. To be set from CAP 531.

11.7 Service report values

Table 28: Service report values for BOM modules

Parameter:	Range:	Step:	Description:
IO01-BO1	0-1		Status of binary ouput 1
IO01-BO10	0-1		Status of binary ouput 10
IO01-BO11	0-1		Status of binary ouput 11
IO01-BO12	0-1		Status of binary ouput 12
IO01-BO13	0-1		Status of binary ouput 13
IO01-BO14	0-1		Status of binary ouput 14
IO01-BO15	0-1		Status of binary ouput 15
IO01-BO16	0-1		Status of binary ouput 16
IO01-BO17	0-1		Status of binary ouput 17
IO01-BO18	0-1		Status of binary ouput 18
IO01-BO19	0-1		Status of binary ouput 19
IO01-BO2	0-1		Status of binary ouput 2
IO01-BO20	0-1		Status of binary ouput 20
IO01-BO21	0-1		Status of binary ouput 21
IO01-BO22	0-1		Status of binary ouput 22
IO01-BO23	0-1		Status of binary ouput 23
IO01-BO24	0-1		Status of binary ouput 24
IO01-BO3	0-1		Status of binary output 3
IO01-BO4	0-1		Status of binary ouput 4
IO01-BO5	0-1		Status of binary ouput 5
IO01-BO6	0-1		Status of binary ouput 6
IO01-BO7	0-1		Status of binary ouput 7
IO01-BO8	0-1		Status of binary ouput 8
IO01-BO9	0-1		Status of binary ouput 9
IO02-BO1	0-1		Status of binary ouput 1
IO02-BO10	0-1		Status of binary ouput 10
IO02-BO11	0-1		Status of binary ouput 11
IO02-BO12	0-1		Status of binary ouput 12
IO02-BO13	0-1		Status of binary ouput 13
IO02-BO14	0-1		Status of binary ouput 14
IO02-BO15	0-1		Status of binary ouput 15
IO02-BO16	0-1		Status of binary ouput 16
IO02-BO17	0-1		Status of binary ouput 17
IO02-BO18	0-1		Status of binary ouput 18

Table 28: Service report values for BOM modules

Parameter:	Range:	Step:	Description:
IO02-BO19	0-1		Status of binary ouput 19
IO02-BO2	0-1		Status of binary ouput 2
IO02-BO20	0-1		Status of binary ouput 20
IO02-BO21	0-1		Status of binary ouput 21
IO02-BO22	0-1		Status of binary ouput 22
IO02-BO23	0-1		Status of binary ouput 23
IO02-BO24	0-1		Status of binary ouput 24
IO02-BO3	0-1		Status of binary output 3
IO02-BO4	0-1		Status of binary ouput 4
IO02-BO5	0-1		Status of binary ouput 5
IO02-BO6	0-1		Status of binary ouput 6
IO02-BO7	0-1		Status of binary ouput 7
IO02-BO8	0-1		Status of binary ouput 8
IO02-BO9	0-1		Status of binary ouput 9
IO03-BO1	0-1		Status of binary ouput 1
IO03-BO10	0-1		Status of binary ouput 10
IO03-BO11	0-1		Status of binary ouput 11
IO03-BO12	0-1		Status of binary ouput 12
IO03-BO13	0-1		Status of binary ouput 13
IO03-BO14	0-1		Status of binary ouput 14
IO03-BO15	0-1		Status of binary ouput 15
IO03-BO16	0-1		Status of binary ouput 16
IO03-BO17	0-1		Status of binary ouput 17
IO03-BO18	0-1		Status of binary ouput 18
IO03-BO19	0-1		Status of binary ouput 19
IO03-BO2	0-1		Status of binary ouput 2
IO03-BO20	0-1		Status of binary ouput 20
IO03-BO21	0-1		Status of binary ouput 21
IO03-BO22	0-1		Status of binary ouput 22
IO03-BO23	0-1		Status of binary ouput 23
IO03-BO24	0-1		Status of binary ouput 24
IO03-BO3	0-1		Status of binary output 3
IO03-BO4	0-1		Status of binary ouput 4
IO03-BO5	0-1		Status of binary ouput 5
IO03-BO6	0-1		Status of binary ouput 6
IO03-BO7	0-1		Status of binary ouput 7
IO03-BO8	0-1		Status of binary ouput 8

Table 28: Service report values for BOM modules

Parameter:	Range:	Step:	Description:
IO03-BO9	0-1		Status of binary ouput 9
IO04-BO1	0-1		Status of binary ouput 1
IO04-BO10	0-1		Status of binary ouput 10
IO04-BO11	0-1		Status of binary ouput 11
IO04-BO12	0-1		Status of binary ouput 12
IO04-BO13	0-1		Status of binary ouput 13
IO04-BO14	0-1		Status of binary ouput 14
IO04-BO15	0-1		Status of binary ouput 15
IO04-BO16	0-1		Status of binary ouput 16
IO04-BO17	0-1		Status of binary ouput 17
IO04-BO18	0-1		Status of binary ouput 18
IO04-BO19	0-1		Status of binary ouput 19
IO04-BO2	0-1		Status of binary ouput 2
IO04-BO20	0-1		Status of binary ouput 20
IO04-BO21	0-1		Status of binary ouput 21
IO04-BO22	0-1		Status of binary ouput 22
IO04-BO23	0-1		Status of binary ouput 23
IO04-BO24	0-1		Status of binary ouput 24
IO04-BO3	0-1		Status of binary output 3
IO04-BO4	0-1		Status of binary ouput 4
IO04-BO5	0-1		Status of binary ouput 5
IO04-BO6	0-1		Status of binary ouput 6
IO04-BO7	0-1		Status of binary ouput 7
IO04-BO8	0-1		Status of binary ouput 8
IO04-BO9	0-1		Status of binary ouput 9

Table 29: Service report values for MIM

Parameter:	Range:	Step:	Description:
MI11-Oltc	0 - 64	1	Service value OLTC MIM1
MI11-Value	-9999.99 - 9999.99	0.01	Service value input 1
MI12-Value	-9999.99 - 9999.99	0.01	Service value input 2
MI13-Value	-9999.99 - 9999.99	0.01	Service value input 3
MI14-Value	-9999.99 - 9999.99	0.01	Service value input 4
MI15-Value	-9999.99 - 9999.99	0.01	Service value input 5
MI16-Value	-9999.99 - 9999.99	0.01	Service value input 6

12 Activation of setting groups (GRP)

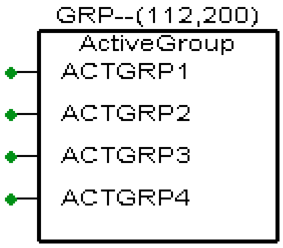
12.1 Summary of function

The terminal have four independent groups (sets) of setting parameters. These groups can be activated at any time, by using the HMI, SMS/SCS or by connecting binary inputs to the function block GRP. Each input is configurable to any of the binary inputs in the terminal. Configuration must be performed in the CAP 531 configuration tool. The number of the signals configured must correspond to the number of the setting groups to be controlled by the external signals (contacts).

The voltage need not be permanently present on one binary input. Any pulse, which must be longer than 400 ms, activates the corresponding setting group. The group remains active until some other command, issued either through one of the binary inputs or by other means (local HMI, SMS, SCS), activates another group.

One or more inputs can be activated at the same time. If a function is represented in two different groups and both the groups are active, the group with lowest identity has priority. This means that group 2 has higher priority than group 4 etc.

12.2 Function block



12.3 Input and output signals

Table 30:

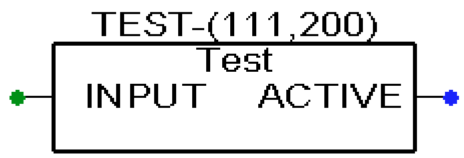
In:	Description:
ACTGRP1	Active Group-Select setting group 1 as active group
ACTGRP2	Active Group-Select setting group 2 as active group
ACTGRP3	Active Group-Select setting group 3 as active group
ACTGRP4	Active Group-Select setting group 4 as active group

13 Blocking during test (TEST)

13.1 Summary of function

The function block TEST has got one signal input and one signal output When the input signal gets a logical one, the TEST function block activates the blocking functions, which have been set to on during test mode, for protection functions and other functions.

13.2 Function block



13.3 Input and output signals

Table 31:

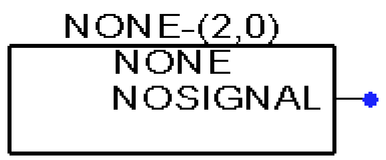
In:	**Description:**
INPUT	Sets terminal in test-mode while input is activated
Out:	**Description:**
ACTIVATE	Terminal in test mode

14 No signal (NONE)

14.1 Summary of function

The function block NONE has got one signal output, for connection to a relevant function block input e g a logical function block or a protection function block

14.2 Function block



14.3 Input and output signals

Table 32:

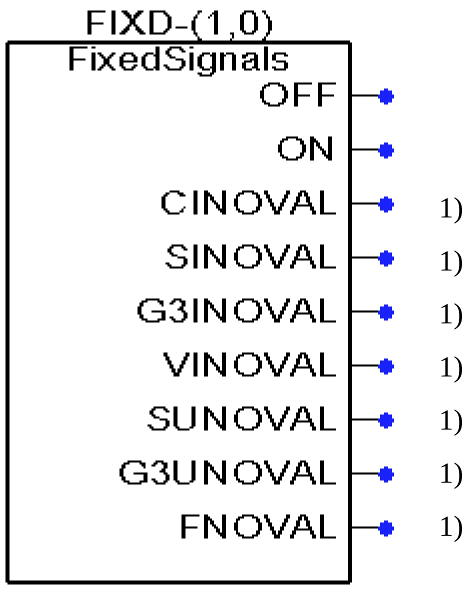
Out:	**Description:**
NONE	No logical signal for connection to function inputs

15 Fixed signals (FIXD)

15.1 Summary of function

The function block FIXD has got nine signal outputs, for connection to a relevant function block input e g a protection function block or a logic function block. Only the signals OFF and ON are of importance for customer applications.

15.2 Function block



1) only internal use

15.3 Input and output signals

Table 33:

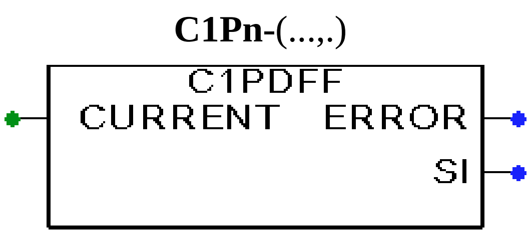
Out:	**Description:**
OFF	Off signal (=0)
ON	On signal (=1)
CINOVAL	Current
SINOVAL	Single phase current
G3INOVAL	Three phase current group
VINOVAL	Voltage
SUNOVAL	Single phase voltage
G3UNOVAL	Three phase voltage group
FNOVAL	Frequency

16 Fourier filter for single phase current (C1P)

16.1 Summary of function

The function block C1Pn where n is a number from 1 to 5 has got one analog signal input, CURRENT, which only can be connected to one of the current channel outputs of the AIM function block. The block C1Pn has got one analog signal output, SI, for connection to a relevant function block input e g a protection function block. It has also got one boolean output signal, ERROR

16.2 Function block



16.3 Input and output signals

Table 34:

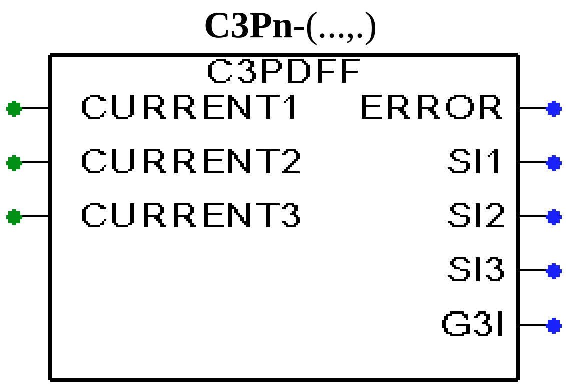
In:	**Description:**
CURRENT	Current, C1Pn
Out:	**Description:**
SI	Single phase current, C1Pn
ERROR	General C1Pn function error

17 Fourier filter for three phase current (C3P)

17.1 Summary of function

The function block C3Pn where n is a number from 1 to 5 has got three analog signal inputs, CURRENTx, which only can be connected to the current channel outputs of the AIM function block. The block C3Pn has got four analog signal outputs, SIx and G3I, for connection to a relevant function block input eg a protection function block. The SIx outputs represents the individual single-phase currents and the G3I output represent the three-phase group. It has also got one boolean output signal, ERROR

17.2 Function block



17.3 Input and output signals

Table 35:

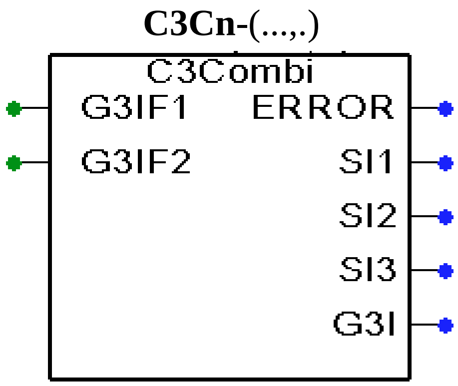
In:	**Description:**
CURRENT1	Current1, C3Pn
CURRENT2	Current2, C3Pn
CURRENT3	Current3, C3Pn
Out:	**Description:**
SI1	Single phase current 1, C3Pn
SI2	Single phase current 2, C3Pn
SI3	Single phase current 3, C3Pn
G3I	Three phase current group, C3Pn
ERROR	General C3Pn function error

18 Sum function for three phase currents (C3C)

18.1 Summary of function

The function block C3Cn where n is a number from 1 to 2 has got two analog three-phase group signal inputs, G3IFx, which only can be connected to the outputs of the C3Pn function block. The block C3Cn has got four analog signal outputs, SIx and G3I, for connection to a relevant function block input eg a protection function block. The SIx outputs represents the sum of the single-phase currents of the two inputs and the G3I output represent the three-phase group sum of the two inputs. The C3Cn function block is used when the sum of two currents e g from a breaker and half configuration is needed for the protection function The C3Cn function block has also got one boolean output signal, ERROR.

18.2 Function block



18.3 Input and output signals

Table 36:

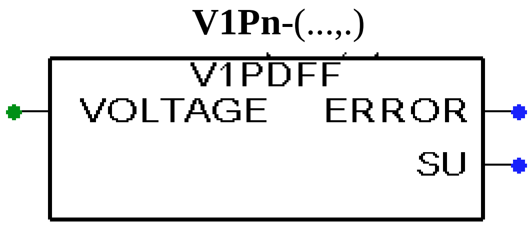
In:	**Description:**
G3IF1	Three phase current group, feeder 1, C3Cn
G3IF2	Three phase current group, feeder 2, C3Cn
Out:	**Description:**
SI1	Single phase current 1, C3Cn
SI2	Single phase current 2, C3Cn
SI3	Single phase current 3, C3Cn
G3I	Three phase current group, C3Cn
ERROR	General C3Cn function error

19 Fourier filter for single phase voltage (V1P)

19.1 Summary of function

The function block V1Pn where n is a number from 1 to 5 has got one analog signal input, VOLTAGE, which only can be connected to one of the voltage channel outputs of the AIM function block. The block V1Pn has got one analog signal output, SU, for connection to a relevant function block input e g a protection function block. It has also got one boolean output signal, ERROR

19.2 Function block



19.3 Input and output signals

Table 37:

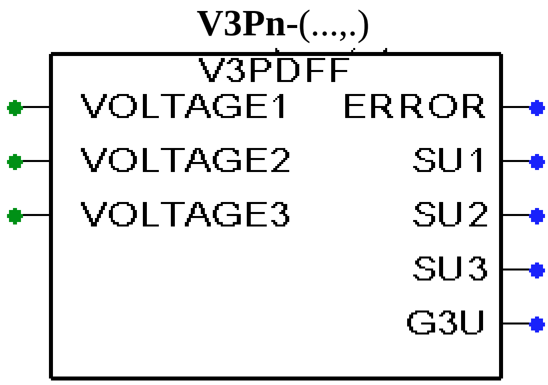
In:	**Description:**
VOLTAGE	Voltage, V1Pn
Out:	**Description:**
SU	Single phase voltage, V1Pn
ERROR	General V1Pn function error

20 Fourier filter for three phase voltage (V3P)

20.1 Summary of function

The function block V3Pn where n is a number from 1 to 5 has got three analog signal inputs, VOLTAGEx, which only can be connected to the voltage channel outputs of the AIM function block. The block V3Pn has got four analog signal outputs, SUx and G3U, for connection to a relevant function block input e g a protection function block. The SUx outputs represents the individual single-phase voltages and the G3U output represent the three-phase group. It has also got one boolean output signal, ERROR.

20.2 Function block



20.3 Input and output signals

Table 38:

In:	**Description:**
VOLTAGE1	Voltage1, V3Pn
VOLTAGE2	Voltage2, V3Pn
VOLTAGE3	Voltage3, V3Pn
Out:	**Description:**
SU1	Single phase voltage 1, V3Pn
SU2	Single phase voltage 2, V3Pn
SU3	Single phase voltage 3, V3Pn
G3U	Three phase voltaget group, V3Pn
ERROR	General V3Pn function error

21 Binary converter (CNV)

21.1 Summary of function

The function block CNV, binary converter, has got three parameter setting inputs, eight signal inputs and two signal outputs. The block is used to convert binary or decimal binary coded signals to their decimal equivalent, when tap position indication is got with the help of coded binary inputs from the IO board.

The setting parameters set the type of coding BIN or BCD and if parity is used or not and the time the bit signal have to be stable before it is accepted. The bit input signals are arranged so that the BIT 1 is the least significant bit and BIT 6 the most significant bit.

The parity input takes care of the parity bit if parity is used. The BIERR signal can be connected to an external incoming error signal for a faulty situation.The output signal VALUE gives the decimal value and the ERROR output shows the error status. The truth table below shows the conversion for BIN and BCD coded signals.

Table 39: BIN and BCD conversion

INPUTS								OUTPUTS			
								BIN coded		BCD coded	
BIT 6 (MSB)	BIT 5	BIT 4	BIT 3	BIT 2	BIT 1 (LSB)	PARITY PARUSE=1	BIERR	VALUE	ERROR	VALUE	ERROR
0	0	0	0	0	0	0	0	0	0	**0**	0
0	0	0	0	0	1	1	0	1	0	**1**	0
0	0	0	0	1	0	1	0	2	0	**2**	0
0	0	0	0	1	1	0	0	3	0	**3**	0
0	0	0	1	0	0	1	0	4	0	**4**	0
0	0	0	1	0	1	0	0	5	0	**5**	0
0	0	0	1	1	0	0	0	6	0	**6**	0
0	0	0	1	1	1	1	0	7	0	**7**	0
0	0	1	0	0	0	1	0	8	0	**8**	0
0	0	1	0	0	1	0	0	9	0	**9**	0
0	0	1	0	1	0	0	0	10	0	**0**	1
0	0	1	0	1	1	1	0	11	0	**0**	1
0	0	1	1	0	0	0	0	12	0	**0**	1
0	0	1	1	0	1	1	0	13	0	**0**	1
0	0	1	1	1	0	1	0	14	0	**0**	1
0	0	1	1	1	1	0	0	15	0	**0**	1
0	1	0	0	0	0	1	0	16	0	**10**	0
0	1	0	0	0	1	0	0	17	0	**11**	0
0	1	0	0	1	0	0	0	18	0	**12**	0
0	1	0	0	1	1	1	0	19	0	**13**	0
0	1	0	1	0	0	0	0	20	0	**14**	0
0	1	0	1	0	1	1	0	21	0	**15**	0
0	1	0	1	1	0	1	0	22	0	**16**	0
0	1	0	1	1	1	0	0	23	0	**17**	0
0	1	1	0	0	0	0	0	24	0	**18**	0
0	1	1	0	0	1	1	0	24	0	**19**	0
0	1	1	0	1	0	1	0	26	0	**0**	1
0	1	1	0	1	1	0	0	27	0	**0**	1
0	1	1	1	0	0	1	0	28	0	**0**	1
0	1	1	1	0	1	0	0	29	0	**0**	1
0	1	1	1	1	0	0	0	30	0	**0**	1
0	1	1	1	1	1	1	0	31	0	**0**	1
1	0	0	0	0	0	1	0	32	0	**20**	0
1	0	0	0	0	1	0	0	33	0	**21**	0
1	0	0	0	1	0	0	0	34	0	**22**	0

Table 39: BIN and BCD conversion (Continued)

INPUTS								OUTPUTS			
								BIN coded		BCD coded	
BIT 6 (MSB)	BIT 5	BIT 4	BIT 3	BIT 2	BIT 1 (LSB)	PARITY PARUSE=1	BIERR	VALUE	ERROR	VALUE	ERROR
1	0	0	0	1	1	1	0	35	0	**23**	0
1	0	0	1	0	0	0	0	36	0	**24**	0
1	0	0	1	0	1	1	0	37	0	**24**	0
1	0	0	1	1	0	1	0	38	0	**26**	0
1	0	0	1	1	1	0	0	39	0	**27**	0
1	0	1	0	0	0	0	0	40	0	**28**	0
1	0	1	0	0	1	1	0	41	0	**29**	0
1	0	1	0	1	0	1	0	41	0	**0**	1
1	0	1	0	1	1	0	0	43	0	**0**	1
1	0	1	1	0	0	1	0	44	0	**0**	1
1	0	1	1	0	1	0	0	45	0	**0**	1
1	0	1	1	1	0	0	0	46	0	**0**	1
1	0	1	1	1	1	1	0	47	0	**0**	1
1	1	0	0	0	0	0	0	48	0	**30**	0
1	1	0	0	0	1	1	0	49	0	**31**	0
1	1	0	0	1	0	1	0	50	0	**32**	0
1	1	0	0	1	1	0	0	51	0	**33**	0
1	1	0	1	0	0	1	0	52	0	**34**	0
1	1	0	1	0	1	0	0	53	0	**35**	0
1	1	0	1	1	0	0	0	54	0	**36**	0
1	1	0	1	1	1	1	0	55	0	**37**	0
1	1	1	0	0	0	1	0	56	0	**38**	0
1	1	1	0	0	1	0	0	57	0	**39**	0
1	1	1	0	1	0	0	0	58	0	**0**	1
1	1	1	0	1	1	1	0	59	0	**0**	1
1	1	1	1	0	0	0	0	60	0	**0**	1
1	1	1	1	0	1	1	0	61	0	**0**	1
1	1	1	1	1	0	1	0	62	0	**0**	1
1	1	1	1	1	1	0	0	63	0	**0**	1
-	-	-	-	-	-	-	-	-	-	**-**	-
1	1	0	1	0	0	**0 (wrong)**	0	0	1	**0**	1
1	1	0	1	0	0	1	**1**	0	1	**0**	1

21.2 Function block

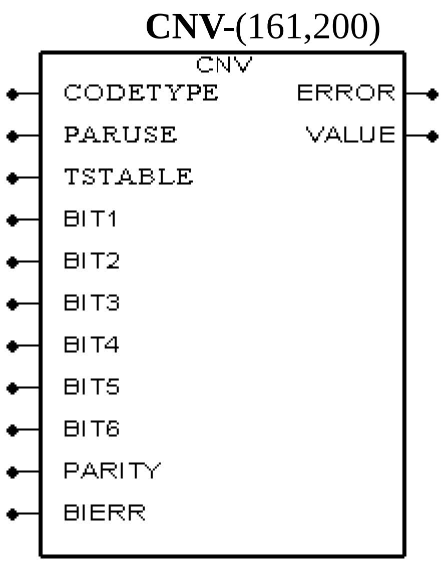


Fig. 20

21.3 Input and output signals

Table 40:

In:	Description:
BIT1	Bit 1 Least Sign Bit, CNV
BIT2	Bit 2 in binary word, CNV
BIT3	Bit 3 in binary word, CNV
BIT4	Bit 4 in binary word, CNV
BIT5	Bit 5 in binary word, CNV
BIT6	Bit 6 in binary word, CNV
PARITY	Parity bit, CNV
BIERR	Error status, CNV
Out:	**Description:**
ERROR	General CNV function error
VALUE	Value of conversion, CNV

21.4 Setting parameters and ranges

Table 41:

Parameter:	Setting range:	Description:
CNV--CODETYPE	BIN, BCD	Type of binary code
CNV--PARUSE	OFF, ON	Even parity check
CNV--TSTABLE	0.0 - 10.0s	Required stable time for inputs

22 Configurable logic (CL)

22.1 Summary of application

Additional logic circuits in the form of AND-, OR-gates with inverter possibility, inverters, timers, and pulse functions are available and can be combined by the user to suit particular requirements.

22.2 Summary of function

The configuration logic contains the following functional blocks: 20 inverters, 40 OR, 40 AND, 10 timers, and 10 pulse-timers. The configuration and parameter setting are performed from the CAP 531 configuration tool.

22.3 Description of logic

22.3.1 General

In the RET 521 terminal, 20 inverters, 40 OR, 40 AND, 10 timers, 10 pulse-timers, and 6 MOVE function blocks are available.

- 4 inverters, 8 OR, 8 AND, 2 timers, and 2 pulse-timers are executed in a loop with maximum speed.
- 4 inverters, 8 OR, 8 AND, 2 timers, 2 pulse-timers, and 2 MOVE are executed in a loop with mediate speed.
- 12 inverters, 24 OR, 24 AND, 6 timers, 6 pulse-timers, and 4 MOVE are executed in a loop with lowest speed.

Refer to other document describing the execution details.

22.3.2 Inverter (INV)

The configuration logic Inverter (INV) (Fig. 21) has one input, designated IVnn-INPUT, where nn runs from 01 to 20 and presents the serial number of the block. Each INV circuit has one output, IVnn-OUT.

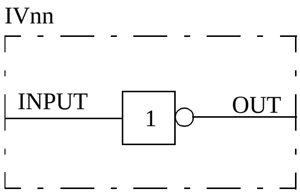


Fig. 21 Block diagram of the inverter (INV) function

22.3.3 OR

The configuration logic OR gate (Fig. 22) has six inputs, designated Onnn-INPUTm, where nnn runs from 001 to 040 and presents the serial number of the block, and m presents the serial number of the inputs in the block. Each OR circuit has two outputs, Onnn-OUT and Onnn-NOUT (inverted).

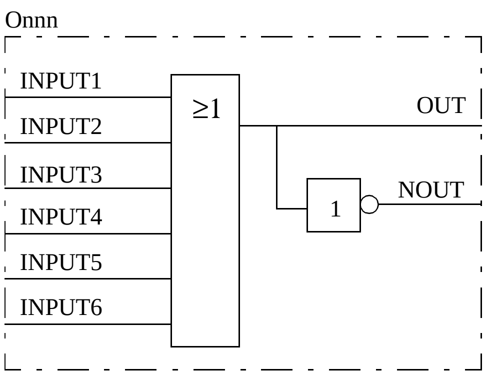


Fig. 22 Block diagram of the OR function

22.3.4 AND

The configuration logic AND gate (Fig. 23) has four inputs (one of them inverted), designated Annn-INPUTm (Annn-INPUT4N is inverted), where nnn runs from 001 to 040 and presents the serial number of the block, and m presents the serial number of the inputs in the block. Each AND circuit has two outputs, Annn-OUT and Annn-NOUT (inverted).

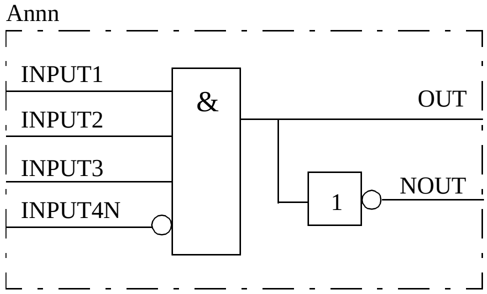


Fig. 23 Block diagram of the AND function

22.3.5 Timer

The configuration logic TM timer, delayed at pick-up and at drop-out (Fig. 24), has a settable time delay TMnn-T between 0 and 60.000 s in steps of 0.001 s, settable from CAP 531 configuration tool. The input signal for each time delay block has the designation TMnn-INPUT, where nn runs from 01 to 10 and presents the serial number of the logic block. The output signals of each time delay block are TMnn-ON and TMnn-OFF. The first one belongs to the timer delayed on pick-up and the second one to the timer delayed on drop-out. Both timers within one block always have the same setting.

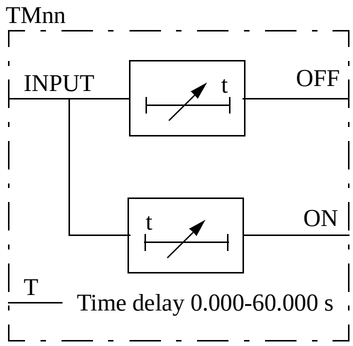


Fig. 24 Block diagram of the Timer function

22.3.6 Pulse

The configuration logic pulse timer TP (Fig. 25), has a settable length of a pulse between 0.000 s and 60.000 s in steps of 0.001 s, settable from CAP 531 configuration tool. The input signal for each pulse timer has the designation TPnn-INPUT, where nn runs from 01 to 10 and presents the serial number of the logic block. Each pulse timer has one output, designated by TPnn-OUT. The pulse timer is not retriggable, that is, it can be restarted only when the time T has elapsed.

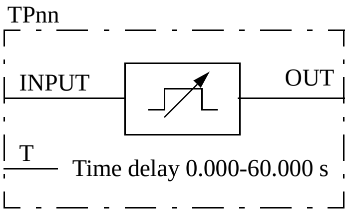


Fig. 25 Block diagram of the Pulse function

22.3.7 MOVE

There are two types of MOVE function blocks - MOF located ***F***irst in the slow logic and MOL located ***L***ast in the slow logic. The MOF function blocks are used for signals coming into the slower logic and the MOL function blocks are used for signals going out from the slower logic.

In the RET 521 terminal, the logic is running with three different execution cycle times, maximum, medium and low speed. There are two MOVE blocks (one MOF and one MOL) with 16 signals each available for the medium speed and four MOVE blocks (two MOF and two MOL) for the low speed.

This means that a maximum of 16 signals into and 16 signals out from the medium speed logic and 32 signals into and 32 signals out from the low speed logic can be synchronized. The MOF and MOL function blocks are only a temporary storage for the signals and do not change any value between input and output.

22.4 Function block

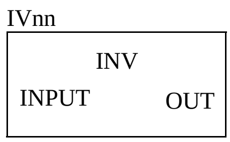


Fig. 26 Simplified terminal diagram of the Inverter function

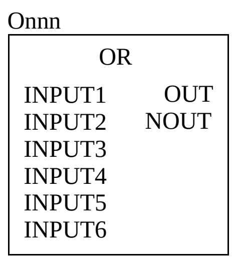


Fig. 27 Simplified terminal diagram of the OR function

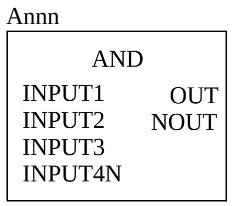


Fig. 28 Simplified terminal diagram of the AND function

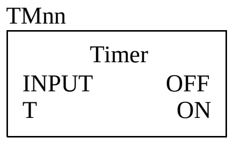


Fig. 29 Simplified terminal diagram of the Timer function

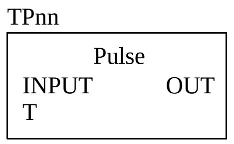


Fig. 30 Simplified terminal diagram of the Pulse function

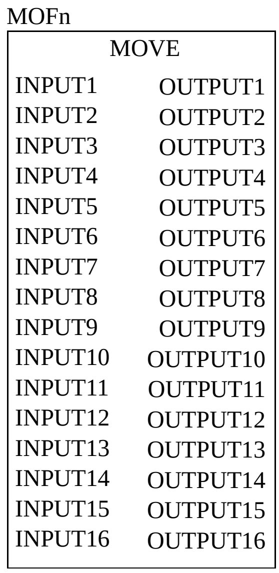


Fig. 31 Simplified terminal diagram of the MOVE First (MOF) function

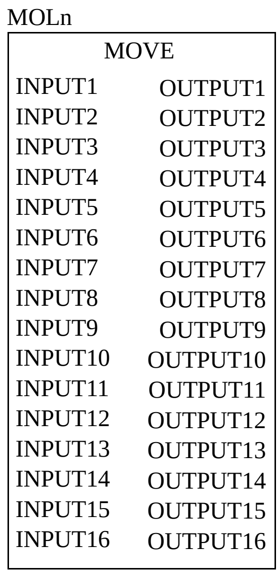


Fig. 22.1 Simplified terminal diagram of the MOVE Last (MOL) function

22.5 Input and output signals

Table 42: Signal list for the Inverter function

In:	**Description:**
IVnn-INPUT	Logic INV input to INV gate number nn
Out:	**Description:**
IVnn-OUT	Logic INV output from INV gate number nn

Table 43: Signal list for the OR function

In:	**Description:**
Onnn-INPUTm	Logic OR input m (m=1-6) to OR gate number nnn
Out:	**Description:**
Onnn-OUT	Output from OR gate number nnn
Onnn-NOUT	Inverted output from OR gate number nnn

Table 44: Signal list for the AND function

In:	**Description:**
Annn-INPUTm	Logic AND input m (m=1-3) to AND gate number nnn
Annn-INPUT4N	Logic AND input 4 (inverted) to AND gate number nnn
Out:	**Description:**
Annn-OUT	Output from AND gate number nnn
Annn-NOUT	Inverted output from AND gate number nnn

Table 45: Signal list for the Timer function

In:	Description:
TMnn-INPUT	Logic Timer input to timer number nn
Out:	**Description:**
TMnn-OFF	Output from timer number nn, Off delay
TMnn-ON	Output from timer number nn, On delay

Table 46: Signal list for the Pulse function

In:	Description:
TPnn-INPUT	Logic pulse timer input to pulse timer number nn
Out:	**Description:**
TPnn-OUT	Output from pulse timer number nn

Table 47: Signal list for the MOVE First (MOF) function

In:	Description:
MOFn-INPUTm	Logic MOVE input m (m=1-16) to MOF number n
Out:	**Description:**
MOFn-OUTPUTm	Output m (m=1-16) from MOF number n

Table 48: Signal list for the MOVE Last (MOL) function

In:	Description:
MOLn-INPUTm	Logic MOVE input m (m=1-16) to MOL number n
Out:	**Description:**
MOLn-OUTPUTm	Output m (m=1-16) from MOL number n

22.6 Setting parameters and ranges

Table 49: Setting table for the Timer function

Parameter:	Setting range:	Description:
TMnn-T	0.000-60.000 s	Time delay for timer TM number nn. To be set from CAP 531.

Table 50: Setting table for the Pulse function

Parameter:	Setting range:	Description:
TPnn-T	0.000-60.000 s	Pulse length for pulse timer TP number nn. To be set from CAP 531.

23 Command function (CM/CD)

23.1 Summary of application

The protection and control terminals may be provided with output functions that can be controlled either from a Substation Automation system or from the built-in HMI. The output functions can be used, for example, to control high-voltage apparatuses in switchyards. For local control functions, the built-in HMI can be used. It is also possible to receive data from other terminals via the LON bus and the Command function block.

23.2 Summary of function

The outputs from the Command function blocks can be individually controlled from the operator station, remote-control gateway, or from the built-in HMI. Together with the configuration logic circuits, the user can govern pulses or steady output signals for control purposes within the terminal or via binary outputs.

23.3 Description of logic

23.3.1 General

Two types of command function blocks are available, Single Command and Multiple Command. In the RET 521 terminal, one Single Command function block and up to 20 Multiple Command function blocks are available.

The output signals can be of the types Off, Steady, or Pulse. The setting is done on the MODE input, common for the whole block, from the CAP 531 configuration tool.

0=Off sets all outputs to 0, independent of the values sent from the station level, that is, the operator station or remote-control gateway.

1=Steady sets the outputs to a steady signal 0 or 1, depending on the values sent from the station level.

2=Pulse gives a pulse with a duration equal to one execution cycle of the command function block, if a value sent from the station level is changed from 0 to 1. That means that the configured logic connected to the command function blocks may not have a cycle time longer than the cycle time of the command function block.

23.3.2 Single Command function

The Single Command function block has 16 outputs. The outputs can be individually controlled from the operator station, remote-control gateway, or from the built-in HMI. Each output signal can be given a name with a maximum of 13 characters from the CAP 531 configuration tool.

The output signals, here CDxx-OUT1 to CDxx-OUT16, are then available for configuration to built-in functions or via the configuration logic circuits to the binary outputs of the terminal.

23.3.3 Multiple Command function

The Multiple Command function block has 16 outputs combined in one block, which can be controlled from the operator station, that is, the whole block is sent at the same time from the operator station. One common name, with a maximum of 19 characters for the block, is set from the configuration tool CAP 531.

The output signals, here CMxx-OUT1 to CMxx-OUT16, are then available for configuration to built-in functions or via the configuration logic circuits to the binary outputs of the terminal.

23.3.4 Communication between terminals

The Multiple Command function block has a supervision function, which sets the output VALID to 0 if the block did not receive data within an INTERVAL time, that could be set. This function is applicable only during communication between terminals over the LON bus. The INTERVAL input time is set a little bit longer than the interval time set on the Event function block. If INTERVAL=0, then VALID will be 1, that is, not applicable. The MODE input is set to Steady at communication between control terminals and then the data are mapped between the terminals.

23.4 Function block

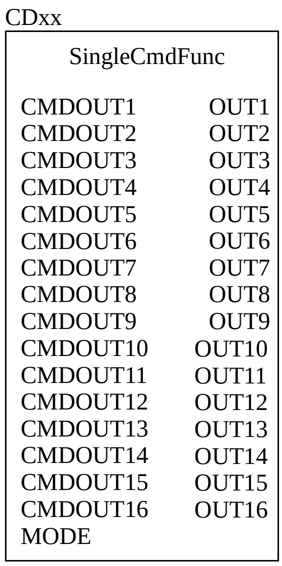


Fig. 32 Simplified terminal diagram of the Single Command function

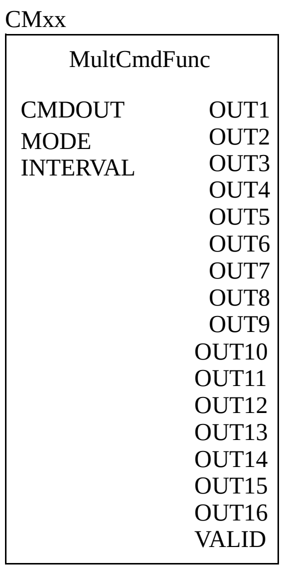


Fig. 33 Simplified terminal diagram of the Multiple Command function

23.5 Input and output signals

Table 51: Signal list for Single Command function No. xx

In:	Description:
CDxx-OUT1	Command output 1 for single command block No xx
CDxx-OUT2	Command output 2 for single command block No xx
CDxx-OUT3	Command output 3 for single command block No xx
CDxx-OUT4	Command output 4 for single command block No xx
CDxx-OUT5	Command output 5 for single command block No xx
CDxx-OUT6	Command output 6 for single command block No xx
CDxx-OUT7	Command output 7 for single command block No xx
CDxx-OUT8	Command output 8 for single command block No xx
CDxx-OUT9	Command output 9 for single command block No xx
CDxx-OUT10	Command output 10 for single command block No xx
CDxx-OUT11	Command output 11 for single command block No xx
CDxx-OUT12	Command output 12 for single command block No xx
CDxx-OUT13	Command output 13 for single command block No xx
CDxx-OUT14	Command output 14 for single command block No xx
CDxx-OUT15	Command output 15 for single command block No xx
CDxx-OUT16	Command output 16 for single command block No xx

Table 52: Signal list for Multiple Command function No. xx

Out:	Description:
CMxx-OUT1	Command output 1 for multiple command block No xx
CMxx-OUT2	Command output 2 for multiple command block No xx
CMxx-OUT3	Command output 3 for multiple command block No xx
CMxx-OUT4	Command output 4 for multiple command block No xx
CMxx-OUT5	Command output 5 for multiple command block No xx
CMxx-OUT6	Command output 6 for multiple command block No xx
CMxx-OUT7	Command output 7 for multiple command block No xx
CMxx-OUT8	Command output 8 for multiple command block No xx
CMxx-OUT9	Command output 9 for multiple command block No xx
CMxx-OUT10	Command output 10 for multiple command block No xx
CMxx-OUT11	Command output 11 for multiple command block No xx
CMxx-OUT12	Command output 12 for multiple command block No xx
CMxx-OUT13	Command output 13 for multiple command block No xx
CMxx-OUT14	Command output 14 for multiple command block No xx
CMxx-OUT15	Command output 15 for multiple command block No xx

Table 52: Signal list for Multiple Command function No. xx

Out:	Description:
CMxx-OUT16	Command output 16 for multiple command block No xx
CMxx-VALID	Received data is valid=1 or invalid=0

23.6 Setting parameters and ranges

Table 53: Setting table for Single Command function No. xx

Parameter:	Setting range:	Description:
CDxx-CMDOUT1	13 characters string	User name for Output 1, to be set from CAP 531 or from SMS for REL 531
CDxx-CMDOUT2	13 characters string	User name for Output 2, to be set from CAP 531 or from SMS for REL 531
CDxx-CMDOUT3	13 characters string	User name for Output 3, to be set from CAP 531 or from SMS for REL 531
CDxx-CMDOUT4	13 characters string	User name for Output 4, to be set from CAP 531 or from SMS for REL 531
CDxx-CMDOUT5	13 characters string	User name for Output 5, to be set from CAP 531 or from SMS for REL 531
CDxx-CMDOUT6	13 characters string	User name for Output 6, to be set from CAP 531 or from SMS for REL 531
CDxx-CMDOUT7	13 characters string	User name for Output 7, to be set from CAP 531 or from SMS for REL 531

Table 53: Setting table for Single Command function No. xx

Parameter:	Setting range:	Description:
CDxx-CMDOUT8	13 characters string	User name for Output 8, to be set from CAP 531 or from SMS for REL 531
CDxx-CMDOUT9	13 characters string	User name for Output 9, to be set from CAP 531 or from SMS for REL 531
CDxx-CMDOUT10	13 characters string	User name for Output 10, to be set from CAP 531 or from SMS for REL 531
CDxx-CMDOUT11	13 characters string	User name for Output 11, to be set from CAP 531 or from SMS for REL 531
CDxx-CMDOUT12	13 characters string	User name for Output 12, to be set from CAP 531 or from SMS for REL 531
CDxx-CMDOUT13	13 characters string	User name for Output 13, to be set from CAP 531 or from SMS for REL 531
CDxx-CMDOUT14	13 characters string	User name for Output 14, to be set from CAP 531 or from SMS for REL 531
CDxx-CMDOUT15	13 characters string	User name for Output 15, to be set from CAP 531 or from SMS for REL 531
CDxx-CMDOUT16	13 characters string	User name for Output 16, to be set from CAP 531 or from SMS for REL 531
CDxx-MODE	0=Off, 1=Steady, 2=Pulse	Output mode common for the command block, to be set from CAP 531 or from SMS for REL 531

Table 54: Setting table for Multiple Command function No. xx

Parameter:	Setting range:	Description:
CMxx-CMDOUT	19 characters string	Common user name for the outputs in the multiple command block, to be set from CAP 531
CMxx-MODE	0=Off, 1=Steady, 2=Pulse	Output mode common for the command block, to be set from CAP 531
CMxx-INTERVAL	0-60 s	Time interval for supervision of received data

Protection functions

24 Frequency measurement function (FRME)

24.1 Summary of application

The frequency measurement function FRME is used to measure the power system fundamental frequency. The frequency is given in Hertz (Hz).

The measured frequency can be read directly on the local display, placed on the front side of RET 521, or via the Station Monitoring System (SMS). Format of the display is DD.DD Hz, e.g. 49.99 Hz.

The output F of the FRME function block in CAP 531 which contains the value of frequency, should be connected to corresponding input F of the Overexcitation function block (OVEX), if OVEX is implemented.

FRME function must be used whenever an extended frequency range is required of RET 521. This means that FRME must be applied and connected in CAP 531. In order to obtain an extended frequency range the output F of the FRME function block does not need to be connected to any other function block, for instance when OVEX is not applied.

The extended operative frequency range for 50 Hz configuration is from 33 Hz to 61 Hz and for 60 Hz configuration from 39 Hz to 73 Hz.

When underreaching a lower frequency limit, an error is generated. When overreaching a higher frequency limit, all protection and control functions can beblocked. Inside the frequency range of a selected configuration, all protection and control functions operates as normal.

Within the extended nominal frequency range, that is between 0.7 * fr - 1.2 * fr, the maximum error in estimation of a.c. currents and a.c. voltages is less than 2 % of their respective true values. The accuracy of frequency measurement within this range is better than 0.01 Hz.

The frequency range where FRME function itself performs, that is, where it measures the power system fundamental frequency, is further extended on both sides of the operative range by approximately 10 Hz and is thus for 50 Hz power system from approximately 23 Hz to approximately 70 Hz, and for 60 Hz system from 29 Hz to 83 Hz.

To be able to apply FRME, voltages must be available to RET 521. If three phase-to-earth voltages are connected to RET 521, then FRME type G3U should be applied. If only one phase-to-phase voltage is available, then FRME type SU should be applied. Types G3U or SU are chosen by means of the Function Selector in CAP 531 configuration tool.

Stability of FRME function algorithm is very important, since the measured frequency is used to determine the window length of the adaptive Fourier filter. It is therefore recommended to use FRME type G3U whenever possible. If FRME type SU is applied, it should use a phase-to-phase voltage, while one phase-to-earth voltage as an input to a FRME type SU is not recommended.

24.2 Summary of function

FRME measures the power system fundamental frequency. The measurement principle is based on the rotational velocity of a suitable voltage phasor in the complex plane. The voltage phasor is calculated previously by an adaptive recursive Fourier filter. Due to this “synchroscope” effect the actual power system fundamental frequency can be measured very accurately.

The FRME function measures the system frequency normally 10 times per second in 50 Hz power sytems and 12 times in 60 Hz power systems. In a disturbed system, frequency is usually updated more often. The input voltage to FRME is checked within FRME for its magnitude and stability. If the voltage is too low (less than 40 % rated), the measurement is stopped, and the last “healthy” value of frequency value retained for 10 seconds. If the voltage recovers within 10 seconds, the measurement is resumed. If not, the FRME is reset, and rated frequency fr is assumed.

The frequency range of FRME is for 50 Hz power system from approximately 23 Hz to approximately 70 Hz, and for 60 Hz system from 29 Hz to 83 Hz.

The frequency measurement function is represented in CAP 531 as a function block called FRME. There are two types available of the FRME function block. FRME type G3U is connected to a function block called V3P, which provides the positive sequence voltage phasor that serves as an input to FRME. FRME type SU is connected to a function block named V1P, which provides the phase-to-phase voltage phasor. The type of FRME function can be selected in CAP 531, by pressing

Edit
  Function Selector

when on the RET 521 (terminal) level in the project tree.

The FRME function block has two outputs: the “analog” output F supplies the value of frequency in Hz. The binary output, ERROR, is set to 1 (block) when the measured frequency is out of the extended operative frequency range (for 50 Hz version from 33 Hz to 61 Hz and for 60 Hz version from 39 Hz to 73 Hz). This signal can be used to block the protection/control functions.

The frequency measurement algorithm is practically insensitive to higher harmonics in voltages connected to RET 521. Stability of the algorithm against disturbances, such as for instance total failure of one phase-to-earth voltage, is also good. FRME type G3U (positive sequence voltage input) is superior to FRME type SU (phase-to-phase voltage input) as far as insensitivity to harmonics and stability on disturbances is concerned.

24.3 Measuring principle

The frequency measurement algorithm can only be discussed together with the concept of the adaptive Discrete Fourier Filter (DFF), because they are inherently tied together, as can be seen in Fig. 34.

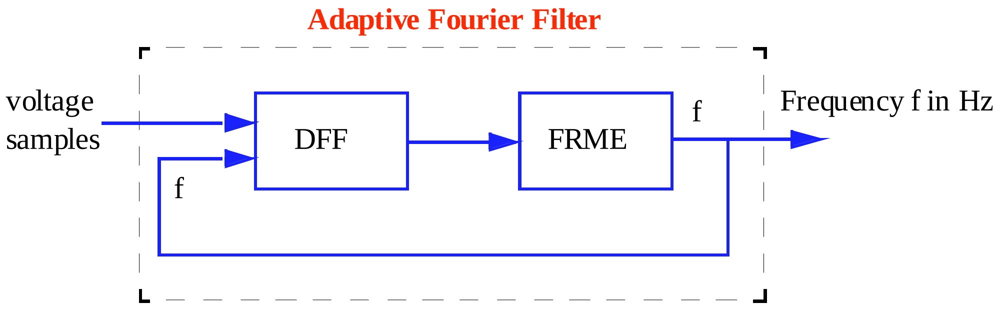


Fig. 34 The closed loop DFF - FRME - DFF

The steady-state frequency response of a nonadaptive DFF is shown in Fig. 35. With “nonadaptive” it is meant that the DFF parameter Ns is constant, Ns = 20 samples per cycle. Ns is the length of the DFF window in the number of samples, for 50 Hz systems at the same time the length of window in ms. Several important features can be observed from the gain - frequency response:

- The measured magnitude of the fundamental harmonic of an input signal is accurate only at the filter design frequency this is 50 Hz or 60 Hz. At frequencies other than rated, an error is obtained. The measured magnitude oscillates between two extreme values within the zone of uncertainty, neither of which is necessarily exact.
- All multiples of rated frequency (0 Hz, 100 Hz, 150 Hz, etc,) are totally suppressed. If the actual fundamental frequency differs from the rated, then all higher harmonics become aliasing signals.

The conclusion can be drawn, that the measurement of magnitudes of sinusoidal inputs would always be accurate under the condition that the DFF design (center) frequency, fo, follows exactly the actual input signal frequency.

A solution is to keep the DFF “sampling” or execution frequency constant, and dynamically alter the DFF window length by changing parameter Ns. By changing Ns, the DFF window is adapted in a stepwise manner to the actual power system fundamental frequency cycle. The concept of the adaptive DFF is based on:

- execution of the DFF algorithm at a rate of 1 kHz (or 1.2 kHz in 60 Hz systems),
- measurement of the actual power system fundamental frequency f in Hz,
- adaptation of the DFF window to the actual power system period (1 / f).

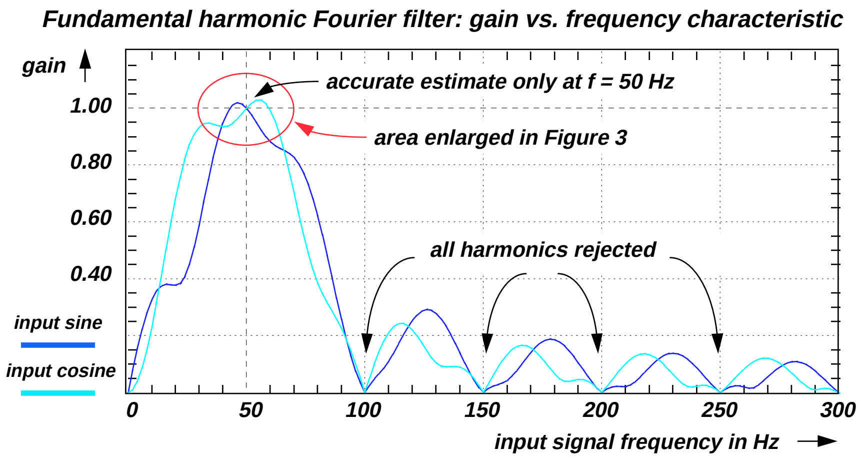


Fig. 35 Steady-state response of the fundamental frequency DFF

Area delimited by the responses for sine and cosine inputs is called the uncertainty area. The calculated values oscillate within the area of uncertainty.

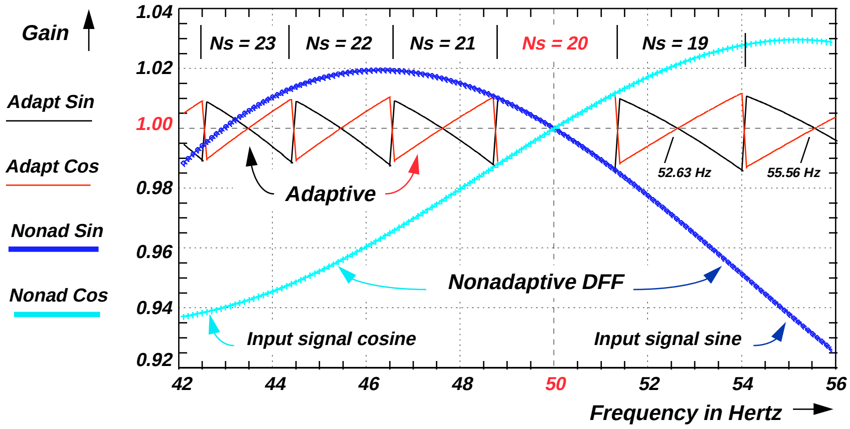


Fig. 36 Gain vs frequency response of an adaptive and nonadaptive DFF

The diagram show the gain at n_s=20 samples/cycle

The main advantages of the fixed-sampling-frequency-adaptive-data-window approach include:

- the whole system has a fixed time reference,
- simplified hardware design,
- simplified disturbance recording function design.

Frequency estimation is an essential part of the concept of an adaptive DFF. It is based on the fact that the phasor, representing an ac input signal, e.g. voltage, will be stationary in the complex plane as long as the fundamental frequency, f, of the input signal is equal to the frequency fo which is “expected” by the filter. Parameter fo is the DFF design, or center, frequency; initially $f_o = f_r$, where f_r is the power system nominal frequency. If the actual input signal frequency, f, and the design frequency, f_o, do not match, then the phasor begins to rotate at a rate which is a rather complicated function of the difference between the actual power system frequency f, and the expected signal frequency f_o, see Fig. 37. Direction of rotation depends on the sign of Δf. If the system frequency is lower than f_o, then the phasor rotates in the negative direction, that is clockwise, and vice versa. Due to this “synchroscope” effect, the actual power system fundamental frequency can be measured.

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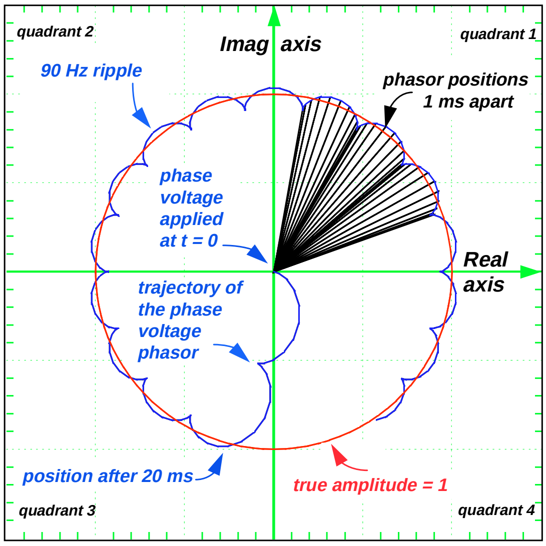


Fig. 37 Rotation of the a phase-to-earth voltage phasor

The example in Fig. 37 shows a situation when the DFF is designed for 50 Hz (Ns=20), while the input voltage signal frequency is f = 45 Hz.

Consider a DFF with Ns = 20 samples per cycle. This filter is designed for 50 Hz. Let the DFF algorithm be executed every 1 ms, that is, at a rate of 1 kHz. If the difference in frequencies is Δf = f - fo = 45 Hz - 50 Hz = -5 Hz, then the phasor rotates clockwise in the complex plane at a rate of 5 revolutions per second, as shown in Fig. 37. It will be observed from Fig. 37, where the subsequent phasor positions (1 ms apart from each other) are drawn in Quadrant 1, that, unfortunately, the actual change of angle varies from one sample to the next. Measurement of frequency, based on such a short interval of time as 1 ms would yield highly oscillatory results. A longer interval must therefore be taken, spanning, if possible, over several (rated frequency) cycles.

In this case, the average speed of rotation over a longer interval is proportional to Δf.

$$\Delta f = f - f_o$$

The following formula can be derived for the measurement of the power system fundamental frequency, which is used by FRME.

$$f(i) = f_o(N_s) \times \left(1 + \frac{\varphi(\boldsymbol{i}) - \varphi(\boldsymbol{i} - k \times N_{sr})}{2 \times \pi \times k \times f_o(N_s)/f_r}\right)$$

where:

fr	system rated frequency (50 or 60 Hz),
f(i)	actual power system frequency in Hz,
$fo(N_s)$	actual DFF design frequency in Hz,
N_s	number of samples per cycle, (16 to 31)
N_{sr}	rated number of samples per cycle (20),
$\varphi(i)$	actual position of the positive sequence voltage phasor,
$\varphi(i-k*N_{sr})$	positive sequence phasor position k * rated cycles before,

The frequency range where DFF is adaptive is only limited by the values of Nsmin and Nsmax. See Fig. 38 for the frequency range and for the DFF center, or design frequencies fo. For an adaptive DFF, the parameter Ns is a variable which is a function of the measured power system fundamental frequency f. When the power system frequency has been determined, Ns is changed, if necessary, in order to place the nearest whole number of samples into the actual power frequency cycle, and in this way adapt the filter window to the actual fundamental frequency cycle. Because Ns is a whole number (integer), the adaptation of the window can only be done in a stepwise manner.

Adaptive DFF design frequency f_o as a function of N_s

System rated frequency →	fr = 50 Hz	fr = 60 Hz
Filter execution frequency →	1000 Hz	1200 Hz
Window length in samples	DFF center frequency in Hz	
16 = Nsmin	62.500	75.000
17	58.824	70.588
18	55.555	66.667
19	52.632	63.158
20 = Nsr	50.000	60.000
21	47.619	57.143
22	45.455	54.545
23	43.478	52.147
24	41.667	50.000
25	40.000	48.000
26	38.462	46.154
27	37.037	44.444
28	35.714	42.857
29	34.482	41.379
30	33.333	40.000
31 = Nsmax	32.258	38.709
32	31.125	37.500
33	30.303	36.364

Fig. 38 DFF window length in samples Ns, and the corresponding DFF “center” frequency f_o

Adaptation of the DFF to the actual power system fundamental frequency is a closed-loop, on-line process, executed in definite intervals of time. The procedure (Swedish Patent 95038808) has the following steps (description for FRME type G3U operating on the positive sequence voltage phasor):

1. Extract the fundamental frequency component of all three phase-to-earth voltages by the DFF. Construct the positive sequence voltage phasor from the three phase-to-earth voltage phasors. (This construction is done within a V3P function block.)
2. Determine the actual power system fundamental frequency by measuring the relative rotational velocity of the (positive sequence) voltage phasor in the complex plane. Use the longest possible time interval (highest possible k) between subsequent measurements of the frequency. (This is done by FRME.)
3. Change, if necessary, the DFF by incrementing or decrementing parameter Ns (number of samples per cycle) so that the DFF becomes tuned to the center frequency fo, which is nearest at that time to the last measured power system fundamental frequency f.

The FRME algorithm is illustrated in Fig. 39. FRME function is executed 50 times in 50 Hz power systems and 60 times in 60 Hz power systems. The frequency itself is estimated normally only every 5-th execution. FRME implements an interval of k rated periods. Dependent on the stability (rate-of-change and magnitude) of the incoming voltage signal, the highest possible k is used for the frequency measurement, where k=4, or 3, or 2 or 1. Thus the interval of k * 20 ms in the case of 50 Hz or k * 16.667 ms in the case of 60 Hz power system is used between successive measurements of the power system fundamental frequency.

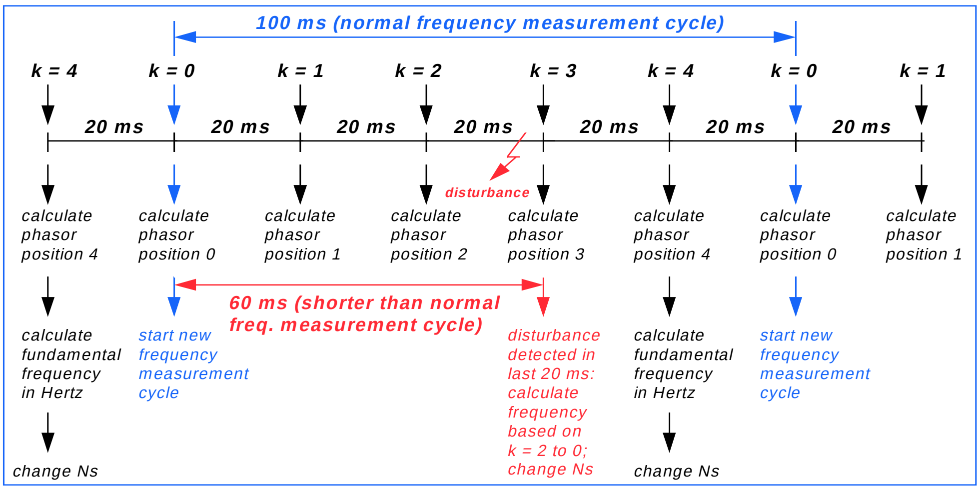
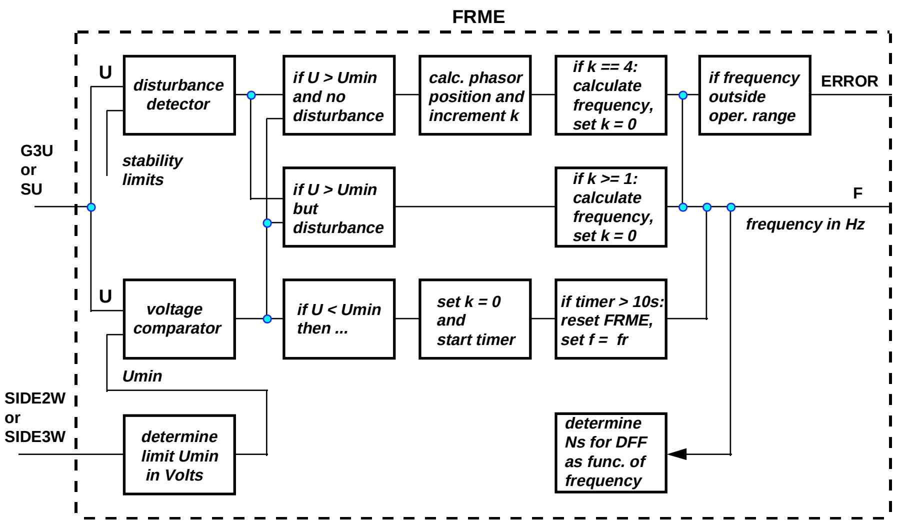


Fig. 39 The frequency measurement algorithm, shown for 50 Hz nominal frequency.

Normally, frequency is measured each 100-th ms, that is, 10 times per second. If a disturbance occurs, the interval from the last measurement can be shorter. The longest possible “healthy” interval will be taken. The interval between successive measurements of frequency is always a multiple of 20 ms.

24.4 Logic diagram



24.5 Function block

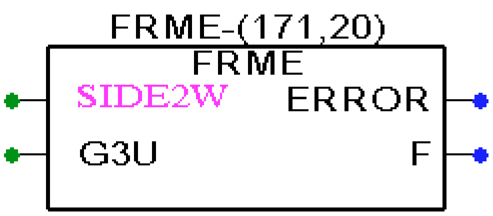


Fig. 40 Function block diagram, single voltage FRME

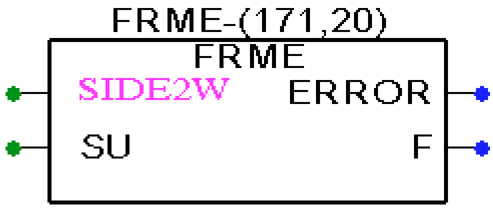


Fig. 41 Function block diagram, postive sequence voltage FRME

FRME for 2-winding power transformer is shown. FRME for 3-winding power transformers is different in that SIDE3W is used instead of SIDE2W.

24.6 Input and output signals

Table 55:

In:	Description:
SIDE2W	The side of the power transformer, where the voltages are taken and used for the measurement of frequency.
SU	The “analog” input of the “single-voltage” type of FRME, where the input voltage signal shall be connected. This input shall be connected to an output of a V1P function block in CAP 531.
G3U	The “analog” input of the “positive sequence voltage” type of FRME, where the input voltage signal shall be connected. This input shall be connected to an output of a V3P function block in CAP 531.

Table 56:

Out:	Description:
ERROR	Set to 1 (block) when the measured frequency is outside the extended frequency range. Can be used to block protection / control functions.
F	Contains the value of the measured frequency, or rated frequency (50 Hz or 60 Hz) if the power system frequency cannot be measured.

24.7 Service report values

Table 57:

Parameter:	Range:	Step:	Description:
f	00.00 - 99.00	0.01	Power system frequency in Hz

25 Differential protection (DIFP)

25.1 Summary of application

The power transformer is one of the most important links in a power system yet, because of its relatively simple construction, it is a highly reliable piece of equipment. This reliability, however, depends upon adequate design, care in erection, proper maintenance and the provision of protective equipment. Adequate design includes proper insulation of windings, laminations, corebolts, etc. Care in erection includes care to avoid physical damage, leaving or dropping anything foreign inside the tank (tools for exemple), etc. Proper maintenance includes checking the oil and winding temperatures, dryness and insulation level of the oil, and analysing any gas that may have accumulated above the oil.

The power transformer possesses a wide range of characteristics and certain special features which make complete protection difficult. These conditions must be reviewed before the detailed application of protection is considered. The choice of suitable protection is also governed by economic considerations. Although this factor is not unique to power transformers, it is brought into prominence by the wide range of transformer ratings used in transmission and distribution systems which can vary from a few kVA up to several hundred MVA. The high rating transformers should have the best protection they can get.

Protective equipment includes surge divertors, gas relays and electrical relays. The gas relay is particularly important, since it gives early warning of a slowly developing fault, permitting shutdown and repair before serious damage can occur. The overall differential protection is the most important of the electrical relays. For this protection only power transformer terminal currents are needed.

Basic conception of differential protection as applied to transformers is that Buchholz relays will detect all faults that occur under the oil, but it is possible to have a fault outside the tank, e.g. across the bushings, and although practically all such faults involve earth, it is usual for large transformers to provide high-speed biased differential protection in addition to earth fault relay. Differential protection detects short circuits outside and inside the tank and will also clear other heavy in-tank faults faster than the Buchholz (typically 25 ms against typically 100 ms). On the other hand, for small interturn faults that do not develop quickly into earth faults, the Buchholz may be the only effective protection.

Differential protection serves as the main protection of transformers against faults in the windings, at the terminal bushings, and on the connection busbars. The section of the circuit taken between the instrument current transformers on both (or three) sides of the power transformer is known as the zone of protection. All objects within zone of protection are in principle covered by the differential protection.

As the differential protection has a strictly limited zone of action (it is a unit protection) it can be designed for fast tripping, thus providing selective disconnection of only the faulty transformer, or, more exactly, all objects included in the zone of protection. A differential protection should never respond to faults beyond the zone of protection.

25.2 Summary of function

- Fast and selective protection of power transformers.
- Protects 2-winding and 3-winding power transformers.
- Multi-breaker arrangements possible.
- 24 connection groups available for 2-winding power transformers.
- 288 connection groups available for 3-winding power transformers.
- Restrained differential protection available with good sensitivity and selectivity.
- Unrestrained differential protection available to cover heavy internal faults.
- Waveform restrain criterion to detect initial, recovery and sympathetic inrush.
- Second harmonic criterion to detect initial, recovery and sympathetic inrush.
- Second harmonic can be disabled automatically after energization of transformer.
- Fifth harmonic criterion applied continuously to detect overexcitation condition.
- Differential current is constructed from fundamental frequency terminal currents.
- Instantaneous differential current is analysed by waveform and harmonic criteria.
- Automatic elimination of zero sequence current from differential currents.
- RET offers a set of 5 operate - bias characteristics.
- Each of the 5 characteristics can be shifted vertically to change base sensitivity.
- Relatively highest of all input terminal currents serves as a common bias current.
- Position of On Load Tap Changer can be tracked and transformer ratio adapted.

- OLTC position reading errors result in temporary desensitisation of the differential protection (DIFP).
- If an external fault has been detected, the differential protection (DIFP) is temporarily desensitized.
- Cross-blocking principle is applied to trip requests and block signals.

25.3 Measuring principles

25.3.1 Some definitions and requirements

1 In this document the windings of a power transformer are referred to as primary winding, secondary winding, and tertiary winding (for 3-winding power transformers) in agreement with IEC 76 standard, Swedish Standard SS 427 01 01, 1982, IEC 76-4 (1976) and British Standard BS 171, 1978.

For 2-winding power transformers the first (capital) letter denotes the connection of the high-voltage (primary) winding, the next small letter the connection of the low-voltage (secondary) winding and the figure the clock-dial reference representing the hour position of the low-voltage phasor in relation to that of the corresponding (similarly lettered) high-voltage (primary) phasor. The latter is being assumed to occupy the 0 (12 o'clock) position. In case of 3-winding power transformers, the third lower voltage winding (tertiary) is treated in the same way as the secondary winding, again using primary winding as a phase reference.

For example, if a power transformer is designated as Yy0d5, then the HV winding (Y) is referred to as primary, the MV winding (y) is referred to as secondary, and the LV winding (d) as tertiary winding.

2 In this document, in agreement with IEC 76 standard, Swedish Standard SS 427 01 01, 1982, IEC 76-4 (1976) and British Standard BS 171, 1978, power transformers with three windings, of which one winding is of appreciably smaller rating (auxiliary winding of less than approximately 10 % rated, designated as +d, or +s, such as for example Yy0 +d, are referred to as 2-winding power transformers. They can be protected by a 2-winding differential scheme.

3 Power transformers can be connected to buses in such ways that the current transformers used for the differential protection will either be in series with the transformer windings, or the current transformers will be in breakers that are part of the bus, such as a ring bus or breaker-and-a-half scheme. In this document the name "T configuration" applies to the bus of two feeders (lines) which is included in the zone protected by the differential protection. The two lines may be connected in parallel, or they may constitute a meshed power network.

4 RET 521 differential protection algorithm expects all the instrument current transformers to be star (y) connected on all power transformer sides (primary, secondary, and tertiary), regardless of the protected power transformer connection group. No intermediate current transformers are generally required.

The polarity of the current transformers is arbitrary. The convention has been that the current transformers were earthed on the side of the protected power transformer, and the polarity marks located away from the power transformer. This convention has been relaxed somewhat in recent years. The terminal accepts an arbitrary configuration of current transformers, as long as current transformer polarities are correctly set.

25.3.2 Power transformer connection groups

RET 521 supports 24 2-winding power transformer connection (vector) groups.

Table 58: 2 winding power transformer vector groups

Yy00	Yy02	Yy04	Yy06	Yy08	Yy10
Yd01	Yd03	Yd05	Yd07	Yd09	Yd11
Dy01	Dy03	Dy05	Dy07	Dy09	Dy11
Dd00	Dd02	Dd04	Dd06	Dd08	Dd10

RET 521 provides 288 3-winding power transformer connection (vector) groups.

Table 59: 3 winding power transformer vector groups

Yy00y00	Yy00y02	Yy00y04	Yy00y06	Yy00y08	Yy00y10	Yy00d01	Yy00d03	Yy00d05	Yy00d07	Yy00d09	Yy00d11
Yy02y00	Yy02y02	Yy02y04	Yy02y06	Yy02y08	Yy02y10	Yy02d01	Yy02d03	Yy02d05	Yy02d07	Yy02d09	Yy02d11
Yy04y00	Yy04y02	Yy04y04	Yy04y06	Yy04y08	Yy04y10	Yy04d01	Yy04d03	Yy04d05	Yy04d07	Yy04d09	Yy04d11
Yy06y00	Yy06y02	Yy06y04	Yy06y06	Yy06y08	Yy06y10	Yy06d01	Yy06d03	Yy06d05	Yy06d07	Yy06d09	Yy06d11
Yy08y00	Yy08y02	Yy08y04	Yy00y06	Yy08y08	Yy08y10	Yy08d01	Yy08d03	Yy08d05	Yy08d07	Yy08d09	Yy08d11
Yy10y00	Yy10y02	Yy10y04	Yy10y06	Yy10y08	Yy10y10	Yy10d01	Yy10d03	Yy10d05	Yy10d07	Yy10d09	Yy10d11
Yd01y00	Yd01y02	Yd01y04	Yd01y06	Yd01y08	Yd01y10	Yd01d01	Yd01d03	Yd01d05	Yd01d07	Yd01d09	Yd01d11
Yd03y00	Yd03y02	Yd03y04	Yd03y06	Yd03y08	Yd03y10	Yd03d01	Yd03d03	Yd03d05	Yd03d07	Yd03d09	Yd03d11
Yd05y00	Yd05y02	Yd05y04	Yd05y06	Yd05y08	Yd05y10	Yd05d01	Yd05d03	Yd05d05	Yd05d07	Yd05d09	Yd05d11
Yd07y00	Yd07y02	Yd07y04	Yd07y06	Yd07y08	Yd07y10	Yd07d01	Yd07d03	Yd07d05	Yd07d07	Yd07d09	Yd07d11
Yd09y00	Yd09y02	Yd09y04	Yd09y06	Yd09y08	Yd09y10	Yd09d01	Yd09d03	Yd09d05	Yd09d07	Yd09d09	Yd09d11
Yd11y00	Yd11y02	Yd11y04	Yd11y06	Yd11y08	Yd11y10	Yd11d01	Yd11d03	Yd11d05	Yd11d07	Yd11d09	Yd11d11
Dy01y01	Dy01y03	Dy01y05	Dy01y07	Dy01y09	Dy01y11	Dy01d00	Dy01d02	Dy01d04	Dy01d06	Dy01d08	Dy01d10
Dy03y01	Dy03y03	Dy03y05	Dy03y07	Dy03y09	Dy03y11	Dy03d00	Dy03d02	Dy03d04	Dy03d06	Dy03d08	Dy03d10
Dy05y01	Dy05y03	Dy05y05	Dy05y07	Dy05y09	Dy05y11	Dy05d00	Dy05d02	Dy05d04	Dy05d06	Dy05d08	Dy05d10
Dy07y01	Dy07y03	Dy07y05	Dy07y07	Dy07y09	Dy07y11	Dy07d00	Dy07d02	Dy07d04	Dy07d06	Dy07d08	Dy07d10
Dy09y01	Dy09y03	Dy09y05	Dy09y07	Dy09y09	Dy09y11	Dy09d00	Dy09d02	Dy09d04	Dy09d06	Dy09d08	Dy09d10
Dy11y01	Dy11y03	Dy11y05	Dy11y07	Dy11y09	Dy11y11	Dy11d00	Dy11d02	Dy11d04	Dy11d06	Dy11d08	Dy11d10

Table 59: 3 winding power transformer vector groups

Dd00y01	Dd00y03	Dd00y05	Dd00y07	Dd00y09	Dd00y11	Dd00d00	Dd00d02	Dd00d04	Dd00d06	Dd00d08	Dd00d10
Dd02y01	Dd02y03	Dd02y05	Dd02y07	Dd02y09	Dd02y11	Dd02d00	Dd02d02	Dd02d04	Dd02d06	Dd02d08	Dd02d10
Dd04y01	Dd04y03	Dd04y05	Dd04y07	Dd04y09	Dd04y11	Dd04d00	Dd04d02	Dd04d04	Dd04d06	Dd04d08	Dd04d10
Dd06y01	Dd06y03	Dd06y05	Dd06y07	Dd06y09	Dd06y11	Dd06d00	Dd06d02	Dd06d04	Dd06d06	Dd06d08	Dd06d10
Dd08y01	Dd08y03	Dd08y05	Dd08y07	Dd08y09	Dd08y11	Dd08d00	Dd08d02	Dd08d04	Dd08d06	Dd08d08	Dd08d10
Dd10y01	Dd10y03	Dd10y05	Dd10y07	Dd10y09	Dd10y11	Dd10d00	Dd10d02	Dd10d04	Dd10d06	Dd10d08	Dd10d10

25.3.3 Determination of differential (operate) currents

25.3.3.1 General

In the healthy state of a loaded power transformer, currents on the opposite sides will usually differ in magnitude as well as in phase position due to power transformer turns-ratio and power transformer connection (vector) group. Power transformers introduce in most cases not only a change in magnitudes of voltages and currents, but also a change in phase angle. These effects must be considered in obtaining the correct analysis of fault conditions by differential relays.

To prevent unwanted operations the zero sequence currents must be eliminated, since, almost invariably, the power transformer connections do not permit transformation of zero sequence currents.

Numerical microprocessor based differential algorithm as implemented compensate for both the turns-ratio and the phase shift internally. Elimination of the zero sequence currents is done internally as well. No intermediate CTs are necessary. Intermediate CTs, as required by older relays, contributed to the distortion of the input signals and added to the cost of the protection scheme. One of the advantages of numerical differential protections is therefore that intermediate CTs are generally no longer needed.

25.3.4 Calculation of fundamental harmonic differential currents

Currents flowing on the primary, secondary (and tertiary) sides of a power transformer can be compared to each other within a numerical relay only if they are brought to a “common denominator”. The “common denominator” is usually the power transformer secondary side. If the secondary side is taken as the reference side, then the primary side currents (and the tertiary side currents) must always be reduced (referred) to the power transformer secondary side, and their respective phase shifts must be allowed for. The power transformer secondary side is the reference side for differential protection algorithms. The differential currents, both:

- the instantaneous differential currents, as well as
- the fundamental frequency differential currents,

are calculated using expressions which were derived from the concept of equality of Ampere-turns for all windings placed on the same power transformer leg. The concept of equality of Ampere-turns holds for any number of windings around a core limb and can therefore be applied to 2-winding as well as 3-winding transformers. This method of forming the differential (operate) currents is straightforward. By applying the concept, both current magnitudes and the phase shifts are taken care of at the same time.

While the instantaneous differential currents are obtained from the instantaneous (pre-filtered) values of the input ac currents, the vectorial fundamental harmonic differential currents are calculated from the fundamental harmonic components of the input ac currents. The input currents are always the power transformer terminal (line) currents.

By applying the concept of Ampere-turn balance on different power transformer connection (vector) groups, the expressions which describe the respective power transformer connection groups are obtained. These differential current calculation routines are therefore as many as there are the connection groups, which is 24 for 2-winding power transformers, and 288 for 3-winding power transformers. By defining which particular connection group the protected transformer belongs to (e.g. Yd01, which is a power transformer setting), the proper calculation routine will applied which describes just the specified protected power transformer.

- There are always 3 differential currents, 1 per phase (a, b, c)

For example, the complex differential currents, based on the fundamental frequency current phasors for a 2-winding power transformer, connection group Yd1 are:

$\bar{I}dif\_a(i) = \bar{I}a(i) - [\bar{I}A(i) - \bar{I}C(i)] * (n1 / n2)$ (phase L1)
$\bar{I}dif\_b(i) = \bar{I}b(i) - [\bar{I}B(i) - \bar{I}A(i)] * (n1 / n2)$ (phase L2)
$\bar{I}dif\_c(i) = \bar{I}c(i) - [\bar{I}C(i) - \bar{I}B(i)] * (n1 / n2)$ (phase L3)

Designations _a, _b, and _c (and not _A, _B, _C, or _L1, _L2, _L3) are chosen in order to emphasize that the differential currents are expressed in the power transformer secondary Amperes. How the equations were derived is shown in Fig. 42. In a real application, the instrument current transformers may be earthed as in Fig. 42, or in any other possible way.

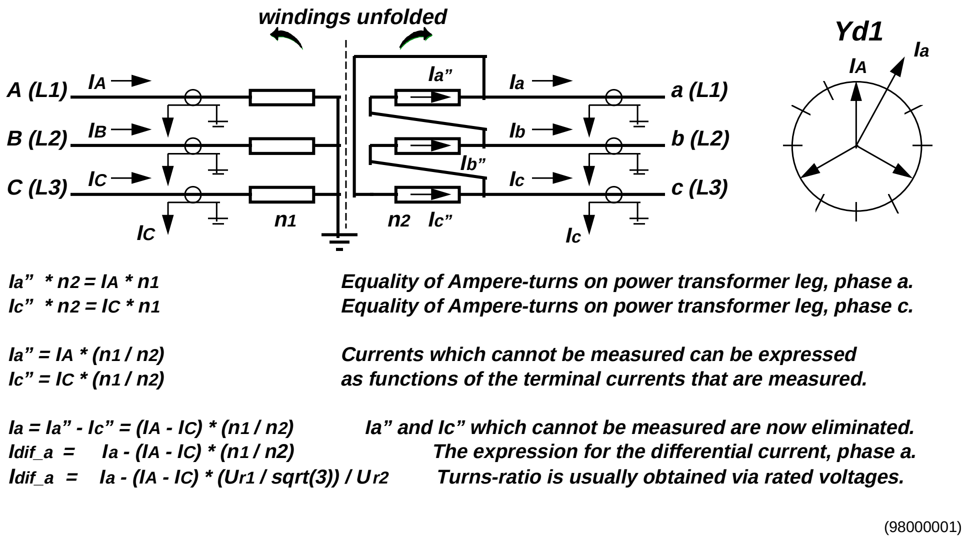


Fig. 42 Determination of differential currents for 2-winding transformer, Yd1

where:

$\bar{I}\text{dif\_a}(i)$	fundamental frequency differential current phasor, phase a (L1).
$\bar{I}\text{dif\_b}(i)$	fundamental frequency differential current phasor, phase b (L2).
$\bar{I}\text{dif\_c}(i)$	fundamental frequency differential current phasor, phase c (L3).
$\bar{I}A(i)$	primary side (Y), fundamental frequency phasor, phase A (L1).
$\bar{I}B(i)$	primary side (Y), fundamental frequency phasor, phase B (L2).
$\bar{I}C(i)$	primary side (Y), fundamental frequency phasor, phase C (L3).
$\bar{I}a(i)$	secondary side (d), fundamental frequency phasor, phase a (L1).
$\bar{I}b(i)$	secondary side (d), fundamental frequency phasor, phase b (L2).
$\bar{I}c(i)$	secondary side (d), fundamental frequency phasor, phase c (L3).
n1	number of turns of the primary, high-voltage side (Y) winding.
n2	number of turns of the secondary, low-voltage side (d) winding.

(i) an index denoting the most recent value, the last calculated value of a quantity. This index is omitted in the text which follows.

These three complex equations do the same job that was once done by the intermediate current transformers, that is:

1 implicitly compensate for transformer phase shift (which is 30° lagging for Yd1),

2 refer the primary side currents to the secondary side base (by using n1 / n2),

3 eliminate eventual Y-side zero sequence currents from the differential currents.

What these three equations do not do is to compensate for the zero sequence currents, which may flow through the main cts on the delta side of the power transformer if the delta winding is earthed via an earthing transformer placed within the zone protected by the differential protection. To do this, an extra procedure must be applied.

The protection computer calculates the magnitudes of the fundamental frequency differential currents.

In a similar way, complex differential currents for 3-winding power transformers can be derived. As an example:

3-windings power transformer connection group Yd1y0:

$$\bar{I}\text{dif\_a} = \bar{I}a - (\bar{I}A - \bar{I}C) * (n1 / n2) + (\bar{I}u - \bar{I}w) * (n3 / n2)$$
$$\bar{I}\text{dif\_b} = \bar{I}b - (\bar{I}B - \bar{I}A) * (n1 / n2) + (\bar{I}v - \bar{I}u) * (n3 / n2)$$
$$\bar{I}\text{dif\_c} = \bar{I}c - (\bar{I}C - \bar{I}B) * (n1 / n2) + (\bar{I}w - \bar{I}v) * (n3 / n2)$$

How these expressions were derived is illustrated by way of example in Fig. 43. In a real application, the instrument current transformers may be earthed as in Fig. 43, or in any other possible way.

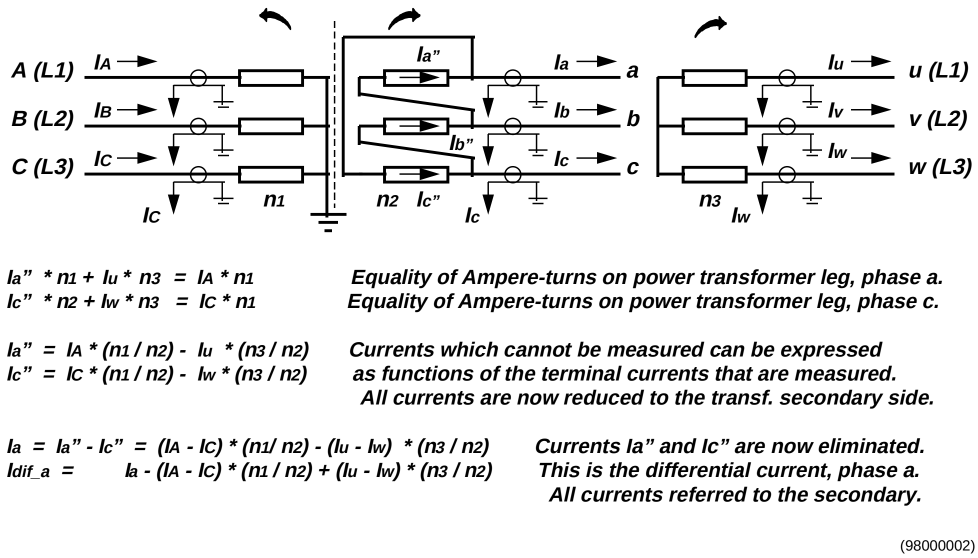


Fig. 43 Determination of differential currents for 3-winding transformer, Yd01y00

25.3.5 Power transformer correction factors (turns-ratio)

The quantities n1, and n2 are usually not known, and are therefore not explicitly used in the algorithms. Instead, correction factors (turns ratio), are used. A turns ratio is the ratio of the turns of 2 windings on the same power transformer leg. It is equal to the voltages on these two windings which are wound around the same power transformer leg and thus share the same magnetic flux. The “rated”correction factors can be derived from:

- power transformer connection group
- power transformer rated voltages
- power transformers rated powers

Table 60: Side factor for connection groups

ConnectionGroup	Primary	Secondary	Tertiary
Yyy	1	1	1
Yyd	0.5774	0.5774	1
Ydy	0.5774	1	0.5774
Ydd	0.5774	1	1

Table 60: Side factor for connection groups

ConnectionGroup	Primary	Secondary	Tertiary
Dyy	1	0.5774	0.5774
Dyd	1	0.5774	1
Ddy	1	1	0.5774
Ddd	1	1	1

The power transformer connection group is a user settable parameter. The power transformer connection group is found, together with other relevant power transformer data, on its rating plate. The power transformer connection group is not a setting of the differential protection, but is set under transformer data..

In case of 3-winding power transformers where the separate windings are of different power ratings, the differential currents are reduced to the winding with the highest rating. This means in practice that the influence of a terminal current of a winding is proportional to that winding's rating relative to the highest rating. For example, if the ratings of the windings are S1/S2/S3 = 1.0/0.5/0.5, and the measurement would indicate that the tertiary winding carried its nominal load, while the other two had no load, then the differential current would be 0.5 per unit.

The respective power transformer correction factors, as defined above, are derived quantities which are calculated internally and automatically, immediately following any change in transformer settings. A user does not have to think about it. Correction factors are constants belonging to differential protection.

The expression for correction factors for different windings:

*CorrFactorX = SideFactorX * UrX / Ur2 * Sr2 / Srmax*

Ur = rated voltage (kV)

Sr = rated power (MVA)

where X = 1, 2 and 3

For some examples of 2-winding transformers the complex equations for differential currents can thus be written as:2-winding power transformer, group Yd1

Idif_a = Ia * CorrFactor2 - (IA - IC) * CorrFactor1
Idif_b = Ib * CorrFactor2 - (IB - IA) * CorrFactor1
Idif_c = Ic * CorrFactor2 - (IC - IB) * CorrFactor1

2-windings power transformer connection group Dd0 (and Yy0):

Idif_a = Ia * CorrFactor2 - IA * CorrFactor1
Idif_b = Ib * CorrFactor2 - IB * CorrFactor1
Idif_c = Ic * CorrFactor2 - IC * CorrFactor1

2-windings power transformer connection group Dy1:

Idif_a = (Ia - Ib) * CorrFactor2 - IA * CorrFactor1
Idif_b = (Ib - Ic) * CorrFactor2 - IB * CorrFactor1
Idif_c = (Ic - Ia) * CorrFactor2 - IC * CorrFactor1

For 3-windings power transformers the equations can be written in a similar way.

25.3.6 Power transformers with On-Load Tap-Changer (OLTC)

The following OLTC data is required in order to be able to track the CorrFactorX when the actual tap position is changed(for details, see Settings, and the DIFP function block):

1 total number of taps, NoOfTaps

2 Rated tap number, RatedTap

3 Minimum tap voltage, MinTapVoltage (kV)

4 Maximum tap voltage, MaxTapVoltage (kV)

The OLTC data are used to calculate the voltage step per tap:

$$VoltPerTap = (MaxTapVolt - MinTapVolt) / (NoOfTaps - 1)$$

RET 521 is capable of allowing for changes of the OLTC tap positions. The actual tap position can be transmitted to the terminal as a value from CNV- or MIM-module. The actual position is stored within RET as an integer number in a buffer and the differential protection (DIFP) has access to its contents. The tap position (TCPOS input on the DIFP function block) is read by the DIFP on every execution (250 times per second in 50 Hz power systems).

- Unless a position reading error signal (OLTCERR input on the DIFP function block) has been issued, then the turns-ratio(s) will be adapted immediately. If an error signal is observed, the rated tap position is assumed. Further, no TRIP will be placed if differential current is below 30 % of rated.

Actual voltage for the tap position is calculated as:

$$UrActualX = UrX + VoltPerTap * (TapPosition - RatedTap)$$

If an On-Load Tap-Changer (OLTC) is used on the protected power transformer, then, dependent on the power transformer side (winding) on which the OLTC is installed, (some) of the correction factors become variable.

OLTC placed on primary winding:

$$CorrFactor1 = SideFactor1 * UrActual1 / Ur2 * Sr2 / Srmax$$

OLTC placed on secondary winding:

*CorrFactor1 = SideFactor1 * Ur1 / UrActual2 * Sr2 / Srmax*

*CorrFactor3 = SideFactor3 * Ur3 / UrActual2 * Sr2 / Srmax*

OLTC placed on tertiary winding:

*CorrFactor3 = SideFactor3 * UrActual3 / Ur2 * Sr2 / Srmax*

Example for a 2-winding transformer, group Yd1with OLTC placed on primary winding, the complex equations for differential currents can thus be written as,

Idif_a = Ia * CorrFactor2 - (IA - IC) * CorrFactor1(TapPosition)
Idif_b = Ib * CorrFactor2 - (IB - IA) * CorrFactor1(TapPosition)
Idif_c = Ic * CorrFactor2 - (IC - IB) * CorrFactor1(TapPosition)

25.3.7 T configuration (Circuit-breaker-and-a-half configuration)

Fig. 44 shows a possible configuration of a power transformer, the so called breaker-and-a-half configuration, or T configuration. The secondary side current (I_2 in Fig. 44 is not directly measured. This current is a vectorial sum of the 2 feeders' currents I_{2f1} and I_{2f1}: $I_2 = I_{2f1} + I_{2f2}$

.

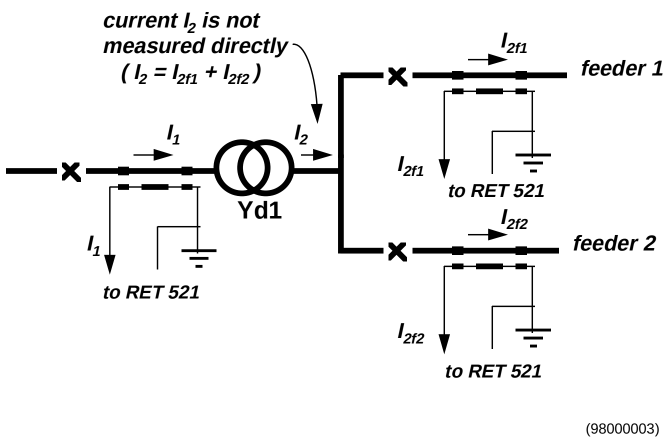


Fig. 44 Yd1 power transformer with T configuration on the secondary side.

The complex expressions for fundamental frequency differential currents can in this case be written as:

2-winding power transformer, group Yd1

Idif_a = (Iaf1 + Iaf2) * CorrFactor2 - (IA - IC) * CorrFactor1
Idif_b = (Ibf1 + Ibf2) * CorrFactor2 - (IB - IA) * CorrFactor1
Idif_c = (Icf 1+ Icf2) * CorrFactor2 - (IC - IB) * CorrFactor1

where:

Iaf1 .... feeder 1, phase a (L1) current as phasor,
Iaf2 .... feeder 2, phase a (L1) current as phasor, etc.

Sums of the type (Iaf1 + Iaf2) in the above expressions for differential currents are made within the terminal by the C3Cx function blocks. The routine for the calculation of the differential currents is fed with the resultant sum currents (Ia, Ib, Ic) and knows nothing about the T configuration.

Yet, currents flowing in both feeders are investigated separately when calculating the bias current.

25.3.8 Instantaneous differential currents

Identical (in form) sets of equations can be derived for instantaneous differential currents. It is clear that the law of equal Ampere-turns must hold for a healthy power transformer at any point of time, that is, also for instantaneous values of currents. The instantaneous differential currents are calculated in the same way as the phasor differential currents, only that the instantaneous (prefiltered) values of the respective input currents are used. There are three instantaneous differential currents, i.e. one per phase (L1, L2, L3)

Instantaneous differential currents are necessary so that they can be checked as to their harmonic content (the 2-nd and the 5-th harmonic), or their waveform can be analyzed in order to detect an eventual inrush or overexcitation. To this purpose, at least Ns most recent values (samples) of instantaneous differential currents must be stored in a circular buffer. RET 521 stores the last Nsmax = 32 values of an instantaneous differential current. There are three such circular buffers, one per phase (L1, L2, L3)

25.3.9 Differential currents due to factors other than faults

All differential currents not caused by faults are unwanted disturbances. Some of these false differential currents can be minimized, while other are unavoidable, and must be recognised and a proper action taken.

When a power transformer differential protection is to be set up, measures must be taken to attain the best possible balance in order to reduce to a minimum the value of the unbalance current (false differential current) during normal load conditions and during occurrence of external (through) short circuits. By having done this, the highest possible base sensitivity and stability of the differential protection will be achieved.

Still, a simple differential protection arrangement such as one based only on the above expressions for differential currents would be handicapped by difficulties due to several natural phenomena which are the cause of false differential currents. Some of these phenomena, such as the inrush and overexcitaion currents, and saturation of instrument current transformers, are the main concern in designing an efficient differential protection algorithm. The main difficulties encountered by a differential protection can be classified as:

1 currents that only flow on one side of a power transformer,
   - zero sequence currents which cannot be transformed to the other side,
   - initial-, recovery- and sympathetic inrush magnetizing currents,
   - overexcitation magnetizing currents.

2 different current transformer characteristics, loads, and operating conditions:
   - unequality of instrument current transformers on power transformer sides,
   - different relative loads on secondaries of instrument current transformers,
   - placement of current transformers in series with the transformer winding, or in circuit breakers which are part of bus, such as a breaker-and-a-half scheme.

3 errors in the protected power transformer turns-ratio(s) as a result of unknown OLTC tap position.

Measures must be taken in order to minimise the negative effects of the above specified phenomena, which might cause a false trip of the protected power transformer. Such measures are:

- elimination of zero sequence currents from differential currents,
- detection of inrush magnetizing currents,
- detection of overexcitation magnetizing currents,
- reading the OLTC tap position,
- detection of heavy external faults causing current transformer saturation,
- calculation of an appropriate bias (restrain) current.

25.3.10 Elimination of zero-sequence currents from differential currents

To make the overall differential protection insensitive to external earth faults in situations where the zero-sequence currents can flow into the protected zone on the faulted side, but cannot be properly transformed to the other side(s) of a protected transformer, (so that they would flow through the power transformer and out into the power system), the zero-sequence currents must be eliminated from the power transformer terminal (line) currents in the expressions for differential currents, so that they cannot appear as false differential currents.

Situations when the zero sequence current cannot be properly transformed to the other side of the power transformer are quite common. Power transformer connection groups of Yd or Dy type cannot transform the zero sequence current.

If a delta winding of a power transformer is earthed via an earthing transformer inside the zone protected by the differential protection, then, for an external earth fault on that side, the zero sequence currents flow into the protected zone, but no correspondent zero sequence current will appear on the other side of the power transformer. See Fig. 45.

In the terminal, the automatic elimination of zero-sequence current is done numerically, and no special intermediate transformers, or “zero-sequence traps” are necessary for the purpose

The compensation is applied to instantaneous, as well as to vectorial fundamental harmonic differential currents. A practical example: a user may for some reason choose to earth the previously unearthed delta (d) winding, as in Fig. 45 and the differential protection will not respond to external earth faults.

It will be observed from the expressions below that the zero sequence currents on the star (y) side eliminate each other in the expressions for differential currents of Yd or Dy type transformers. On the delta side, however, they have to be eliminated explicitly. The zero sequence current is calculated within the terminal from the sets of three terminal currents for a given power transformer side. They are then, where needed, subtracted from each terminal current in the expressions for differential currents.

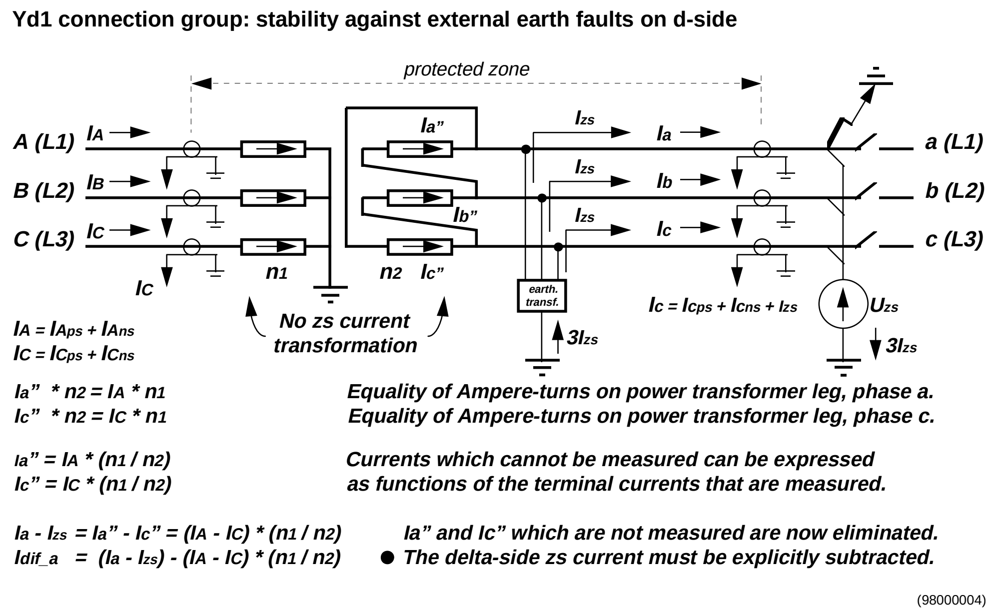


Fig. 45 Yd1 power transformer with the delta winding earthed within the zone of protection.

It will be observed from Fig. 45 that for an external earth fault on the d-side of the Yd1 power transformer, the zero-sequence currents flow into the zone of protection, but cannot be transformed to Y-side. These currents must therefore be explicitly subtracted from d-side terminal currents $\bar{I}a$, $\bar{I}b$, and $\bar{I}c$.

As an example the equations for a 2-winding power transformer connection group Yd1 will be as follows:

Idif_a = (Ia - Izs_2) * CorrFactor2 - (IA - IC) * CorrFactor1
Idif_b = (Ib - Izs_2) * CorrFactor2 - (IB - IA) * CorrFactor1
Idif_c = (Ic - Izs_2) * CorrFactor2 - (IC - IB) * CorrFactor1

where:

Izs_2 the zero sequence current on the secondary (2), d-side of the power transformer, calculated by RET internally from 3 terminal d-side currents.

25.3.11 Detection of inrush magnetizing currents

25.3.11.1 Inrush phenomenon

Inrush is a transient condition which occurs when a power transformer is energized. It is not a fault condition, and therefore does not necessitate the operation of protection, which, on the contrary, must remain stable during the inrush transient, a requirement which is a major factor in the design of differential protection for transformers.

The inrush magnetizing current flows into the protected zone on one power transformer side only (i.e. on the actual power source side), and will tend to operate the relay because the inrush current is seen by the differential protection (DIFP) as a true differential current.

When a previously unconnected power transformer is energized, the initial inrush currents flow, which may attain peak values corresponding to several times the transformer rated current, and which decay relatively slowly. The time constant of the transient is relatively long, being from perhaps 0.1 seconds for a 100 kVA transformer and up to 1.0 second for a large unit. The magnetizing current has been observed to be still changing up to 30 minutes after switching on.

When the power system voltage is reestablished after a short circuit has been cleared elsewhere in the power system, the recovery inrush currents will flow which fortunately are lower than initial inrush currents. Still, a differential relay which has been stable during a heavy external fault may misoperate due to recovery inrush when the fault is cleared. To prevent this, the recovery inrush must be recognized as well.

When a new power transformer is energized in parallel with another which was already in operation, the sympathetic inrush currents will flow in the later, which are lower than initial inrush currents. The phenomenon of sympathetic inrush is quite complex. Although inrush current phenomena associated with the energizing of one single power transformer are well understood, there are certain elements of uniqueness encountered when one transformer is suddenly energized in parallel with another which was already in operation.

Fig. 47 shows a case where a power transformer, vector group Yd1, was exposed to sympathetic inrush currents, when an identical power transformer was switched on in parallel. It will be noticed that:

1 maximum recovery inrush current can appear very late, contrary to initial inrush,

2 peaks of the sympathetic inrush current may reach the rated value or higher.

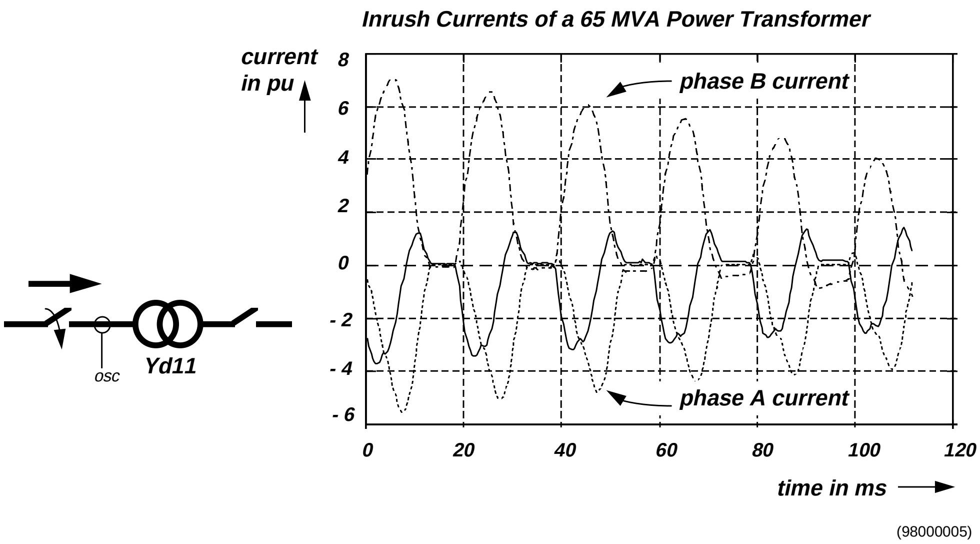


Fig. 46 Initial inrush currents of a Yd11 power transformer

The waveform of transformer magnetizing current contains a proportion of harmonics which increases as the peak flux density is raised to the saturating condition. The inrush current is an offset current with a waveform which is not symmetrical about the horizontal axis (time), but which is symmetrical, neglecting decrement, about some ordinates. Such a wave typically contains both even and odd harmonics. Typical inrush currents contain substantial amounts of second and third harmonics and diminishing amounts of higher orders. The presence of the bi-directional waveforms (phase C current in Fig. 46 substantially increases the proportion of the 2-nd harmonic, even more than 60 % of the fundamental harmonic.

It will be also observed from Fig. 46 that the inrush wave is distinguished from a fault wave by a period in each cycle during which very low magnetizing currents (normal exciting currents) flow, when the core is not in saturation. This property of the inrush current has been exploited to distinguish inrush condition from an internal fault.

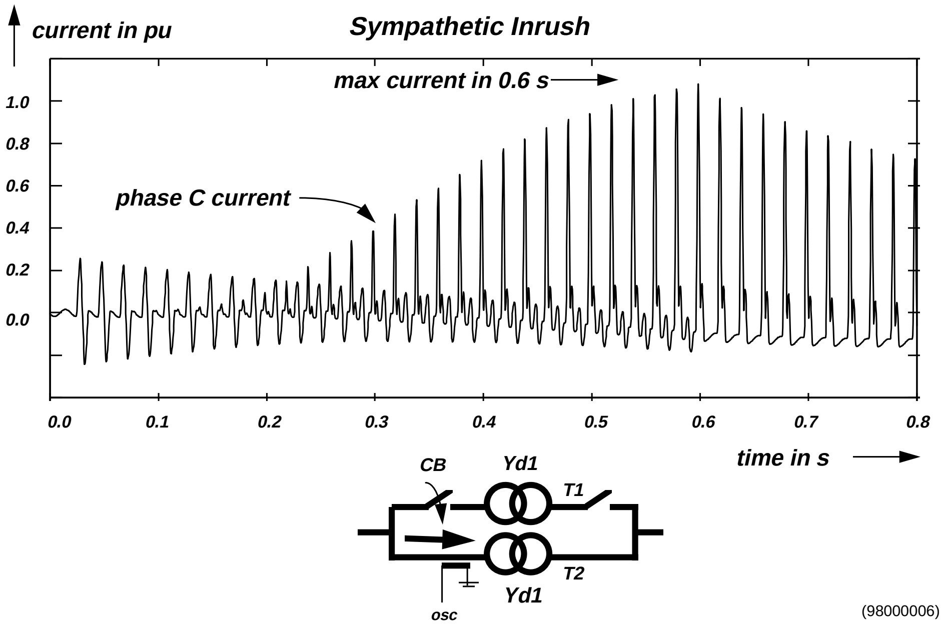


Fig. 47 An example of sympathetic inrush

25.3.12 Detection of inrush

To make a relay stable against inrush currents, measures must be taken in order to make the algoritm capable to distinguish the inrush phenomena from a fault. It is necessary to provide some forms of detection of all inrush conditions and restraint to the differential relay which depend on:

1 harmonic content of the magnetizing inrush currents and / or

2 specific pattern of the magnetizing inrush current waveform.

25.3.12.1 Detection of inrush by harmonic analysis of instantaneous differential currents

Magnitudes of harmonics in a typical magnetizing inrush current are as follows: the dc component varies between 40 % to 60 % of the fundamental, the 2-nd harmonic up to 70 %, the 3-rd harmonic 10 % to 30 %. The other harmonics are progressively less. As the fault current is practically clear of higher harmonics (as long as current transformers are not saturated), it seems appropriate to make use of the harmonic analysis in order to detect an inrush condition.

- As the 3-rd harmonic (which is of zero sequence) does not appear in an inrush current to a delta-type winding, the 2-nd harmonic seems to be most appropriate.
- The 2-nd harmonic content of an instantaneous differential current is compared to the fundamental harmonic of the same differential current. If the ratio is higher than the user-set limit, than an inrush condition is assumed, and a block signal issued for the affected phase by the 2-nd harmonic criterion.
- The 2-nd harmonic check in a phase is only made if a trip request (START output on the DIFP finction block) has previously been placed in the same phase.

Practice has shown that although “I2/I1” approach may prevent false tripping during inrush conditions, it may sometimes be responsible for increased fault clearance times for heavy internal faults with current transformer saturation. The output current of a current transformer which is being pushed into saturation will temporarily contain the 2-nd harmonic. The proportion I2/I1 in the instantaneous differential current may temporarily exceed the user-set limit; the saturation of the current transformers has thus produced a signal which may restrain the differential relay for several cycles. On the profit side, the 2-nd harmonic restrain will give stability on heavy external faults with ct saturation.

25.3.12.2 Detection of inrush by waveform analysis of instantaneous differential currents

It has been observed from Fig. 46 that the inrush wave is distinguished from a fault wave by a period in each cycle during which very low magnetizing currents (i.e. the normal exciting currents) flow, when the core is not in saturation. This property of the inrush current can be used to distinguish this condition from an internal fault. The condition to declare inrush would be that during a power system frequency cycle, there should always be an interval of time when an instantaneous differential current is equal to the normal magnetizing current, which is close to zero (below 0.5 %). This interval must be at least about 1/4 of the period, that is, about 5 ms in 50 Hz power systems.

Unfortunately though, the picture the A/D converter sees is the one of Fig. 46. The instrument current transformers have limited capability of transforming low frequency signals, such as dc signals. This in its turn results in distorted current transformer secondary currents, and consequently distorted instantaneous differential currents. It will be observed from Fig. 46 that during the so called “low current” periods, the currents are progressively larger, and it is possible that the detection of initial inrush condition may fail if one looks for “low current” periods. The detection may not work unless special measures are taken. The solution is as follows.

- Instead of looking for intervals with a very low instantaneous differential current, the terminal searches for intervals with low rate-of-change of an instantaneous differential current.
- The rate-of-change limit to which the rate-of-change of the instantaneous differential current is compared, is a sum of a constant, initial limit, plus a part which is proportional to the magnitude of the fundamental harmonic differential current.

rateOfChange = InstIdiffLast - InstIdiffOld

Formally:

*rateOfChange <= waveBaseLimit + IdiffLx * Const*
where:
*waveBaseLimit = 0.15 * Idmin*
IdiffLx = fundamental differential current in phase Lx

The values of the above constants were determined by way of experiments.

- The waveform check is executed invariably and unconditionally at a rate 1000 Hz in 50 Hz power system, or 1200 Hz in 60 Hz power systems. The low rate-of-change of differential current must be found at least 4 times in succession (4 ms in a 50 Hz power system) if the inrush condition is to be declared.
- The waveform criterion distinguishes between inrush and internal fault, and is not confused by the 2-nd harmonic contents in the instantaneous differential current.

A combination of these two approaches is applied. The leading idea was to be able to offer an option which combines the 2-nd harmonic- and the waveform methods, so that their advantages would be made use of, while at the same time their drawbacks avoided. The two options (a DIFP setting parameter Second harmonic blocking, Conditionally/Always) are:

The terminal uses the 2-nd harmonic criterion to detect initial inrush, and to stabilize the protection against heavy external faults; the criterion is enabled when transformer is not energized and when an external fault has been detected. The algorithm is as follows:

1 employ both the 2-nd harmonic and the waveform criteria to detect initial inrush,

2 switch off the 2-nd harmonic criterion 1 minute after energization, in order to avoid long clearance times for heavy internal faults and let the waveform criterion alone take care of the sympathetic and recovery inrush,

3 switch on the 2-nd harmonic criterion for 6 seconds when a heavy external fault has been detected in order to increase stability against external faults,

Always

This option is like the usual 2-nd harmonic restrain. The 2-nd harmonic criterion is active all the time. In addition to the 2-nd harmonic criterion, the waveform criterion works in parallel.

In normal service with no fault, the differential currents are very small, or zero. In this case, the DIFP function block outputs WAVBLKL1, WAVBLKL2, WAVBLKL3, are set to 1 (WAVBLKL1 = 1, etc).This does not mean that DIFP would be blocked for an internal fault. In case of an internal fault, the WAVBLKLx signals will be set to 0.

25.3.13 Detection of overexcitation magnetizing currents

Overexcitation results from excessive applied voltage, possibly in combination with below-normal frequency, as with generator-transformer units. The risk is greatest for generator-transformers, although overfluxing has been known to occur for other transformers as well.

The overexcitation condition itself usually does not call for high speed tripping of the protected power transformer, but relatively high magnetizing currents, which are seen as differential currents by the differential protection, may cause a false trip of the differential protection, unless quickly detected.

Both excessive voltage and lower frequency will tend to increase transformer flux density. The main difference from inrush is that overexcitation is a symmetrical phenomenon. An overexcitation magnetizing current contains the 1-st, the 3-rd, the 5-th, the 7-th, etc, harmonics, because the waveform is symmetrical about the horizontal axis (time). If the degree of saturation is progressively increased, not only will the harmonic content increase as a whole, but relative proportion of the fifth harmonic will increase and eventually overtake and exceed the third harmonic.

Overexcitation currents will often be superposed to normal load currents (i.e. through currents); consequently, the instantaneous differential currents must be analyzed, as they will include the overexcitation currents only.

As the 3-rd harmonic currents cannot possibly flow into a delta-type winding, the 5-th harmonic is the lowest harmonic which can serve as a criterion for overexcitation. The overexcitation on the delta side will produce exciting currents that contain a large fundamental frequency (50 or 60 Hz) component with little odd harmonics. In this instance, the 5-th harmonic limit must be set to a relatively low value.

The waveform of the excess exciting current is not present for the full period of cycle, occurring around the normal current peaks. As a consequence, there is a low-current gap in each cycle in the instantaneous differential currents. Consequently, the overexcitation condition can be detected by the waveform criterion as well.

No process is started to detect inrush/overexcitation conditions by a harmonic criterion, unless at least 1 (of 3 possible) trip request (START output on the DIFP function block) has been placed by differential protection algorithm. If a trip request has been issued by a phase, then the 2-nd harmonic is extracted by Fourier filters from that phase's instantaneous differential current. The waveform criterion is active all the time, independent of any trip requests.

25.3.14 Determination of bias current

The bias current is supposed to show how high the currents flowing into (or through) the zone protected by the differential protection are, in order to get a measure of how difficult the conditions are under which the instrument current transformers, and the protected power transformer are operating. More difficult conditions mean generally less reliable information about the currents. Less reliable information is then compensated by a suitable shape of the operate - bias characteristic. In general, higher bias currents will require greater differential currents in order to trip the protected power transformer. (See TRIP output signal on the DIFP function block).

It has been found that the relatively highest power transformer current seen by the terminal is the best measure of the conditions under which both the instrument current transformers as well as the protected power transformer are operating at any point of time. This bias quantity gives the best stability against an unwanted operation of the differential protection. Therefore:

- The differential protection has only one bias current, common for all phases.

The RET 521 differential protection algorithm determines the common bias current by a procedure with the following steps:

1. express all the power transformer input (terminal, line) currents as they have been measured in the per unit, based on the primary current rating of their respective instrument current transformers,
2. sort out the relatively highest current,
3. reduce the relatively highest current to the power transformer secondary side (the reference side). This current is then taken as the common bias (restrain) current.

In case of 3-winding power transformers where the separate windings are of different power ratings the procedure is slightly different. Here, the bias current is reduced to the winding with the highest rating. This means in practice that the influence of a terminal current of a winding is proportional to that winding's rating relative to the highest rating. For example, if the ratings of the windings are S1/S2/S3 = 1.0/0.5/0.5, and all windings carry nominal load, then the bias currents of the separate windings will be as Ibias1/Ibias2/Ibias3 = 1.0/0.5/0.5, and Ibias1 will be taken as the common bias; Ibias = Ibias1 = 1.0 per unit. (The primary Ampere ratings of the ct's were taken to be equal to respective rated currents.)

Power transformers can be connected to buses in such ways that the current transformers used for the differential protection will be either in series with the power transformer windings, or the current transformers will be in breakers that are part of the bus, such as a ring bus or a T (breaker-and-half) scheme, see Fig. 44. For the current transformers with primaries in series with the power transformer winding, the current transformer primary current for external (through) faults will be limited by the transformer impedance. When the current transformers are part of the bus scheme, as in the breaker-and-a-half scheme of Fig. 44, then the current transformer primary current is not limited by the power transformer impedance. High primary currents may be expected. In either case, any deficiency of current output caused by saturation of one current transformer that is not matched by a similar deficiency of another will cause a false differential current to appear. In an attempt to counteract this:

- currents of both feeders on the T side are input separately to the terminal, and treated independently as described above under points 1, 2, and 3.

25.3.15 Restrained differential protection: operate - bias characteristics

To make differential relays as sensitive and as stable as possible, differential relays have been developed with bias (restraint) actuated by the input and output currents. Two points to be considered in choosing an operate-bias characteristic are:

1 The value of differential (operate) current required to operate under external fault conditions must be well above the value of anticipated false (spill) differential current.

2 The value of the differential (operate) current under internal fault must be well above the value of current required to operate.

The usual practice for transformer protection is to set the bias characteristic to a value of at least twice the value of the expected spill current under through faults conditions. These criteria can vary considerably from application to application and are often a matter of judgement and therefore a flexible set of operate-bias characteristics is advantageous. Fig. 48 shows the set of 5 operate-bias characteristics that are available.

Table 61: Data sheet of operate - bias characteristics.

Characteristic number	First slope in %	Second slope in %
1	15	50
2	20	50
3	30	50
4	40	50
5	49	50

Default sensitivity means the recommended sensitivity. If the conditions are known more in detail, higher or lower sensitivity can be choosen, except for characteristic 1 and 5.

Table 61: supplies the parameters for the 5 operate-bias characteristics available. In the DIFP algorithm, each of them is represented by a set of 3 equations of a sectionized line. For additional flexibility the base sensitivity (setting Idmin) of an operate-bias characteristic can be changed in the range from 10 % to 50 % rated current in 1 % steps. Fig. 49 shows the area covered if the base sensitivity (Idmin) of the operate-bias characteristic number 3 is swept from 10 % to 50 % power transformer rated current. Whatever sensitivity, the breakpoint between zone 2 and zone 3 is always at 1 per unit operate current.

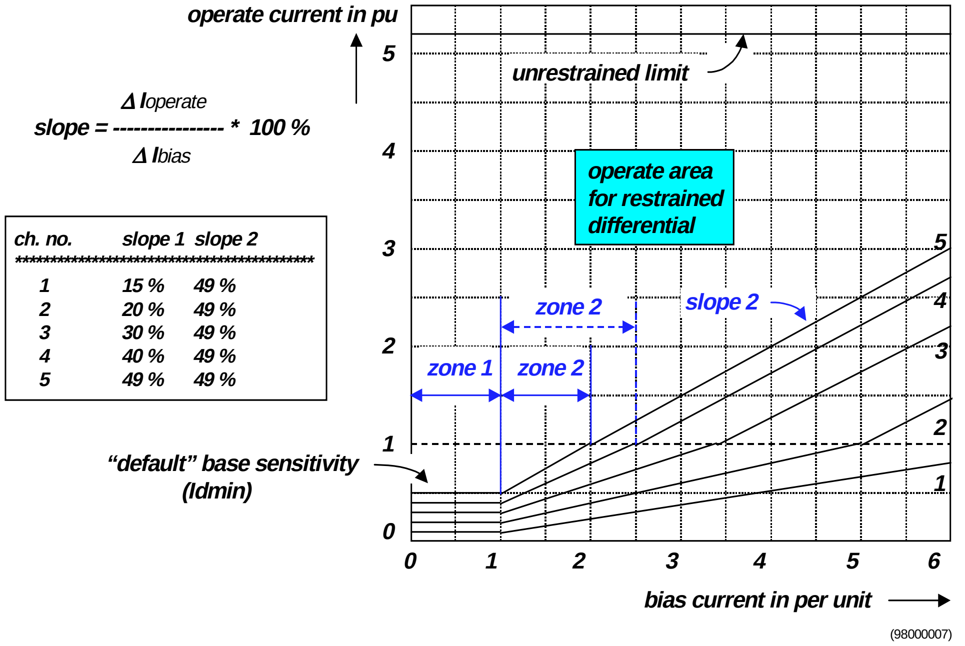


Fig. 48 Set of operate - bias characteristics

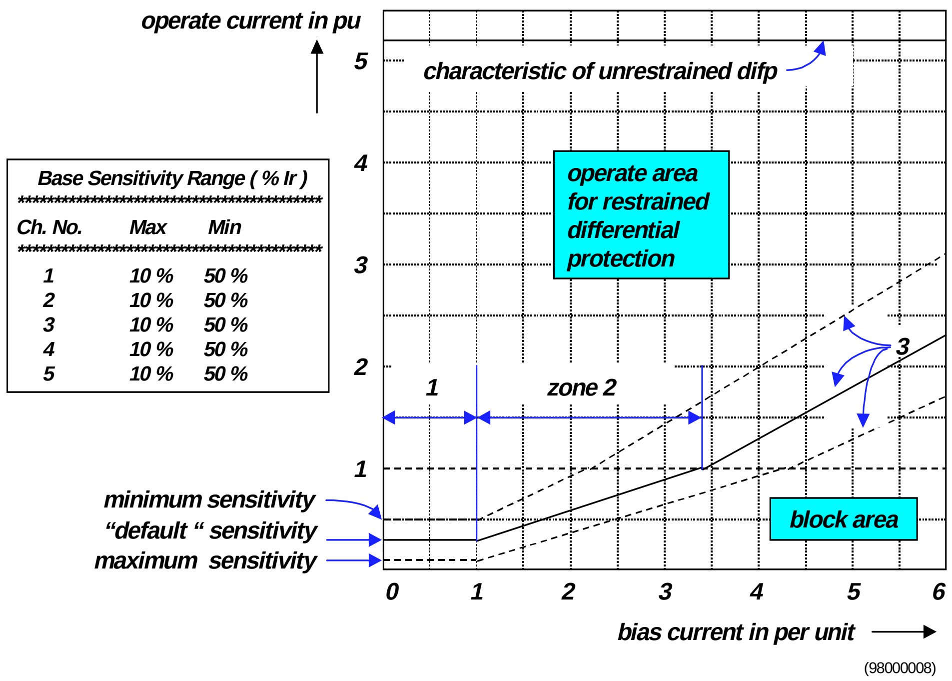


Fig. 49 Set of sensity range

25.3.16 Unrestrained (instantaneous) differential protection

The purpose of the unrestrained differential protection is to bypass the excessive restraint resulting from harmonic distortions of the current transformers’ secondary currents in case of heavy internal faults. To provide for this condition, the differential protection scheme frequently includes an unrestrained “instantaneous” differential protection criterion.

If differential current is found to be higher than a certain limit, called the unrestrained limit, so that a heavy internal fault is beyond any doubt, then no restrain criteria (such as the 2-nd harmonic, the 5-th harmonic, and the waveform) is taken into consideration; a trip request is “instantaneously” issued by the overall differential protection. In fact, 2 consecutive trip requests from the unrestrained differential protection must be counted in order for a TRIP to appear on the DIFP function block output.

The unrestrained differential protection limit can be set in the range 500 % to 2500 % of the power transformer rated current (5 pu to 25 pu) in steps of 1 %.

The unrestrained differential protection limit is shown in Fig. 48, and Fig. 49. It is a horizontal line in the operate-bias current plane.

25.3.17 Stability of differential protection against heavy external faults

Stability against misoperations on external faults is particularly important when one remembers that external faults occur much more often then the faults within a power transformer itself.

Heavy through-faults with high currents with long dc constants may cause instrument current transformers to saturate quickly (in 10 ms or less). The consequence is that:

1. false differential currents appear which can be very high,
2. bias current may not increase proportionally to the true through-fault currents.
   - As a consequence the false differential currents may appear almost of the size of the bias current, and the overall differential protection might misoperate for heavy external faults unless measures were taken in order to make it stable against such faults.
   - If differential protection survives without misoperating during the external fault, it could nevertheless misoperate due to the recovery inrush after the external fault has been cleared by some protection.
   - If the 2-nd harmonic may be responsible for prolonged operate times at heavy internal faults with current transformer saturation, it is at the same time a good protection against misoperation on heavy external faults.

Stabilisation against heavy external faults is mainly based on the 2-nd harmonic criterion. If the 2-nd harmonic is not always active (Option Conditionally) at the time an external fault has been detected, then the 2-nd harmonic is temporarily activated. Stabilisation against heavy external faults thus depends on:

1. detection of an external fault,
2. temporary (6 s) activation of the 2-nd harmonic criterion,
3. temporary (6 s) desensitization of the differential protection.

The maximum sensitivity of the differential protection is temporarily set to 70 % rated current (0.7 pu). No trip request from differential protection can be issued if differential current is less than 0.7 pu.

If Option Always has been set, where the 2-nd harmonic criterion is active all the time, then only the temporarily desensitisation to 0.7 per unit is applied upon the detection of an external fault.

The search for an external fault is made on phase-by-phase basis. An eventual detection in any phase must come before any trip request is placed by differential protection algorithms of the phases a, b, c (L1, L2, L3). For an internal heavy fault the trip requests will always come very quickly. The trip requests appear first, and current transformer saturation may follow later. For a heavy external fault, on the other hand, the bias current will become very high, while a high false differential currents will only appear if and when one or more current transformers saturate. The detection routine requires at least 4 to 6 ms before any saturation sets on to detect a fault. When a trip request is placed, the search ends.

An abnormal situation must be recognized first if the external fault detection algorithm is to start. The detection algorithm is executed only if:

1. the bias current is higher than 1.25 of the power transformer rated current,
2. no trip request has yet been issued by any phase (a, b, c).DIFP output logic (cross-blocking principle)

This increases the security of the DIFP. For example, if all 3 phases place a trip request, but 2 of them also have block signals (e.g. by the I2 / I1 criterion), then the differential protection will not trip the protected power transformer circuit breaker.

25.3.18 Transformer differential protection: a summary of principles

The main principles of the differential protection can be summarized as follows:

1. The differential protection function is executed 250 times in 50 Hz power systems and 300 times in 60 Hz power systems per second.
2. Instantaneous differential currents, based on instantaneous values (prefiltered) of the input currents are formed at 1000 (1200) Hz. The instantaneous currents are reduced to the power transformer secondary side, which serves as the reference side. The three instantaneous differential currents are calculated to be analyzed in order to determine their 2-nd and 5-th harmonic contents and to be searched for the waveform pattern typical of inrush/overexcitation conditions.
3. Three fundamental harmonic differential currents, and one common bias current, are calculated from the fundamental harmonic components of the input currents, which are the power transformer terminal currents. All these currents are reduced to the power transformer secondary side Amperes.
4. One common restrain quantity, i.e. one common bias current is used. It is defined as the relatively highest of all input currents. The fundamental frequency components of input currents are searched for the relatively highest current at any point in time. In order to find the relatively highest current, the input currents are compared to the primary ratings of their respective current transformers. The relatively highest current is then reduced to the power transformer secondary side which is the reference side.
5. The operate area and the block area of the “operate current - bias current” plane is delimited by the differential relay operate - bias characteristic. A set of five characteristics is available. Each of them can be shifted up or down towards more or less sensitivity when the protection setting are being made. All the operate - bias characteristics are expressed in the power transformer secondary side Amperes, i.e. reduced to the protected power transformer secondary side, which serves as the reference side.
6. The operate area itself is divided in two parts by the unrestrained differential characteristic into “unrestrained operate” and “restrained operate” areas. The unrestrained characteristic is a horizontal line. This characteristic is as well expressed in the power transformer secondary side Amperes. If a fundamental harmonic differential current is found to be higher than this limit, the differential protection operates immediately, no blocking criteria is considered.
7. If a fundamental harmonic differential current is found to be above the operate - bias characteristic, but under the unrestrained characteristic, than a trip request is issued (START output on the DIFP function block is set), which is followed by a check to find out if any block signal exists for that phase. Block signals can be issued by the waveform criterion, or by the 2-nd harmonic block criterion (if active), or by the 5-th harmonic block criterion. The block (restrain) criteria are applied to the instantaneous differential currents in a phase-by-phase manner.

8 The 2-nd harmonic criterion can be active conditionally or permanently. It is active permanently if option Always is chosen. If option Conditionally is chosen, it is active when a power transformer is not energized, and for 60 s after power transformer energization. After that, the 2-nd harmonic criterion is automatically deactivated in order to avoid its negative effect on the clearance time at heavy internal faults. It is re-activated for 6 seconds on detection of an external fault, as a means to stabilize the differential protection against misoperation on heavy external faults with ct saturation. The criterion is only executed for a phase if a trip request (START) has been placed first in that phase.

9 The 5-th harmonic criterion is responsible for detection of overexcitation. It is active all the time, it is not possible to deactivate it. Its negative effect on the clearance time of heavy internal faults is less probable than that of the 2-nd harmonic. The 5-th harmonic criterion is only executed for a phase if a trip request (START) has been placed first in that phase.

10 The waveform criterion is active all the time, it is not possible to deactivate it. It is continuously executed at a rate 1000 (1200) Hz. It looks for low rate-of-change-of-current gaps in the instantaneous differential currents in order to detect an inrush-, or overexcitation condition. Its output signals (block signals) are available at any time, but are only taken into consideration if a phase trip request (START) has been issued in that phase.

11 The external fault detection routine is executed on a phase-by-phase basis. It starts searching for an eventual external fault whenever the condition is fulfilled that the bias current is higher than 125 % of the power transformer rated current, while no trip requests have yet been placed. The criterion is based on an assumption that cts will not saturate faster than in about 4 ms to 6 ms, which means that for a heavy external fault, the differential currents will be comparatively low for at least 4 ms to 6 ms, while at the same time, the bias current will be high. If an external heavy fault is detected, the 2-nd harmonic criterion is activated (restrain option Conditionally) and sensitivity is lowered to 0.7 pu for 6 s.

12 The “cross-blocking” principle is applied by the DIFP algorithm when the decision is being made whether the DIFP should issue a common trip request (i.e. set the TRIP output signal on the DIFP function block) or not. To get a differential protection that operates when needed, and only when needed, the “trip” and “block” logical signals are processed within DIFP by a common logical scheme which applies the “cross-blocking” principle. According to this principle, the DIFP only trips the protected power transformer, if all the phases which have issued trip requests (START) are free of any block signals (from the 2-nd, the 5-th, and the waveform restrain criteria).

13 In the case of the unrestrained differential protection, the trip request signal must be confirmed for at least 2 times in succession to result in TRIP output of the DIFP function block. In the case of the restrained differential protection, only 1 common trip request is sufficient to set the TRIP output to 1, that is to switch off the protected power transformer.

25.4 Logic diagram

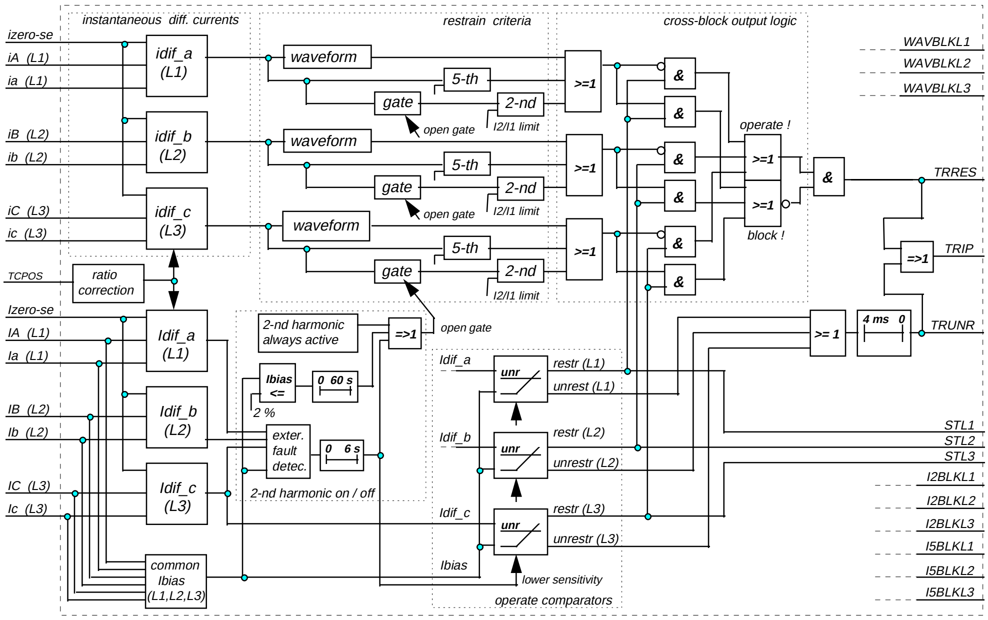


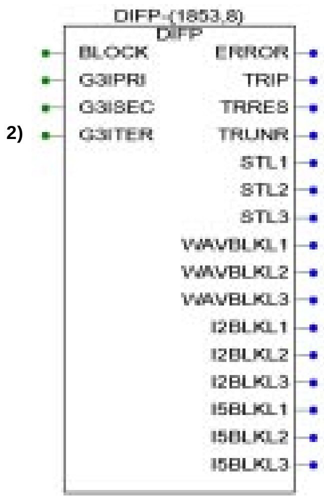
Fig. 50 Simplified DIFP logic diagram for a 2-winding power transformer.

Some simplifications were necessary when drawing the DIFP logic diagram. The major simplifications are:

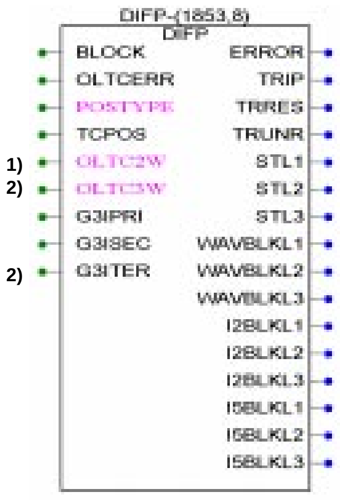
1. The restrain criteria (waveform, 2-nd harmonic, 5-th harmonic) are of equal importance. If, for example, the waveform criterion places a block signal, then the 2-nd and the 5-th harmonic criteria are not executed. If the waveform criterion does not issue a block signal, then the 2-nd harmonic criterion is executed. If the 2-nd harmonic criterion places a block signal, then the 5-th harmonic criterion is bypassed, etc.
2. The limits for the waveform criterion (corresponding to limits I2/I1 limit of the 2-nd harmonic criterion, or I5/I1 limit of the 5-th harmonic criterion) are not shown.
3. The 2-nd and the 5-th harmonic criteria are only executed in those of the phases (L1, L2, L3) where a trip request (shown on the DIFP function block as STL1, STL2, STL3) has been placed. The waveform criterion is executed all the time in a phase-by-phase manner.
4. The zero sequence current compensation is regularly done on all power transformer sides. This is not shown in Fig. 50, where only one (unspecified) zero-sequence current is shown.
5. It is not shown that OLTC position reading error results in temporary decrease of the sensitivity of the DIFP to at least 30 % of the rated current.

25.5 Function block

The function block for Transformer Differential Protection, DIFP, looks like this when no tap changer information is available:



And this is the look of the function block when the Transformer Differential Protection has information about the tap changer position:



1 Only applicable for two winding variant

2 Only applicable for three winding variant

25.6 Input and output signals

Table 62:

In:	Description:
DIFP-BLOCK	External block, DIFP
DIFP-OLTCERR	OLTC position reading error, DIFP
DIFP-POSTYPE	Tap changer position indication type, DIFP
DIFP-TCPOS	Tap changer position indication, DIFP
DIFP-OLTC2W	OLTC side, DIFP
DIFP-OLTC3W	OLTC side, DIFP
DIFP-G3IPRI	Three phase current group primary side, DIFP
DIFP-G3ISEC	Three phase current group secondary , DIFP
DIFP-G3ITER	Three phase current group tertiary side, DIFP

Table 63:

Out:	Description:
DIFP-ERROR	General DIFP function error
DIFP-TRIP	Common trip DIFP
DIFP-TRUNR	Trip unrestrained, DIFP
DIFP-TRRES	Trip restrained, DIFP
DIFP-STL1	Start phase 1, DIFP
DIFP-STL2	Start phase 2, DIFP
DIFP-STL3	Start phase 3, DIFP
DIFP-WAVBLKL1	Waveform block phase 1, DIFP
DIFP-WAVBLKL2	Waveform block phase 2, DIFP
DIFP-WAVBLKL3	Waveform block phase 3, DIFP
DIFP-I2BLKL1	Second harmonic block phase 1, DIFP
DIFP-I2BLKL2	Second harmonic block phase 2, DIFP
DIFP-I2BLKL3	Second harmonic block phase 3, DIFP
DIFP-I5BLKL1	Fifth harmonic block phase 1, DIFP
DIFP-I5BLKL2	Fifth harmonic block phase 2, DIFP
DIFP-I5BLKL3	Fifth harmonic block phase 3, DIFP

25.7 Setting parameters and ranges

Table 64:

Parameter:	Range:	Description:
Operation	0 - 1	Operation Transformer Differential Protection, Off/On
CharactNo	1 - 5	Stabilizing characteristic number
Idmin	10 - 50	Maximum sensitivity in % of Ir
Idunre	500 - 25	Unrestrained limit in % of Ir
StabByOption	0 - 1	Second harmonic blocking, Conditionally/Always
I2/I1ratio	10 - 25	Second to first harmonic ratio in %
I5/I1ratio	10 - 50	Fifth to first harmonic ratio in %
NoOfTaps	1 - 64	Number of taps
RatedTap	1 - 64	Rated tap
MinTapVoltage	0.1 - 99	Voltage for minimum (tap1) tap in kV
MaxTapVoltage	0.1 - 99	Voltage for maximum tap in kV

25.8 Service value report

Table 65:

Parameter:	Range:	Step:	Description:
Ibias	0.0 - 99999.9	0.1	Bias current in A[a]
IdiffL1	0.0 - 99999.9	0.1	Differential current, phase 1, in A[a]
IdiffL2	0.0 - 99999.9	0.1	Differential current, phase 2, in A[a]
IdiffL3	0.0 - 99999.9	0.1	Differential current, phase 3, in A[a]

a. Referred to secondary side

26 Three/phase time overcurrent protection (TOC)

26.1 Summary of application

A fault external to a transformer results in an overload which can cause transformer failure if the fault is not cleared promptly. The transformer can be isolated from the fault before damage occurs by the overcurrent relays. On small transformers, overcurrent relays can also be used to protect against internal faults. On larger transformers, they provide backup protection for differential relays.

The overcurrent protection function is rather simple, but its application is limited by the rather insensitive setting and the delayed operation if coordination with other overcurrent relays is required. The overcurrent protection function should not be confused with overload protection, which directly protects the power transformer and normally make use of the relays that operate in a time related to the thermal capacity of the protected transformer. Overcurrent protection is intended to provide a discriminative protection against system faults, although with the settings adopted some measure of overload protection can be obtained. The function has no (thermal) memory and begins timing always from zero.

26.2 Summary of function

The time overcurrent function:

- is based on the fundamental frequency component of currents flowing to or from the transformer or in lines connected to the power transformer
- reset ratio is >96 %
- has a lowset stage and a highset stage
- the lowset stage can have either definite delay, or inverse delay
- a definite minimum delay is available for inverse delays
- the highest of the three phase currents is taken as a basis for an inverse delay
- the highset stage has always a definite delay
- both stages can be directional or nondirectional, independent of each other
- if both stages are directional, they can look in different directions
- if the directional reference voltage becomes too low, then a directional stage can be made nondirectional, or can be blocked.

26.3 Measuring principles

26.3.1 Time characteristics

There are two different delay types available in the time overcurrent protection (TOC): definite and inverse. Inverse delays can be:

- normal inverse
- very inverse
- extremely inverse
- long-time inverse

Definite delays are not dependent on the magnitude of the fault current. The definite timer in TOC will continue to measure the time as long as at least one (of three) currents is above the set limit. However, the reset ratio, equal to 96%, is applied to each separate current.

In the case of current-dependent relay, the delay is an inverse function of the magnitude of the fault current expressed as a multiple of the set current limit. The highest of the three phase currents above the set current limit serves as a basis for calculation of an inverse delay. IEC 255-4 defines inverse delay characteristics with the following law:

$$t_{op} = \frac{(k \times T_b)}{\left(\frac{I}{I_{set}}\right)^p - 1}$$

t_{op} operate time

I actual value of the measured earth fault current

I_{set} set current limit

p exponent, power

k time multiplier

T_b base time

Table 66: Inverse delay curves, time multiplier k, and setting step of k

Inverse curve	**T_b (s)**	**p**	**k**	**k - step**
normal	0.14	0.02	0.05 - 1,1	0.01
very inverse	13.5	1	0.05 - 1,1	0.01
extremely	80	2	0.05 - 1,1	0.01
longtime	120	1	0.05 - 1,1	0.01

Normal Inverse curves

Fig. 51 illustrates the Normal Inverse curves which are defined by the expression:

$$t_{op} = \frac{(k \times 0.14)}{\left(\frac{I}{I_{set}}\right)^{0.02} - 1}$$

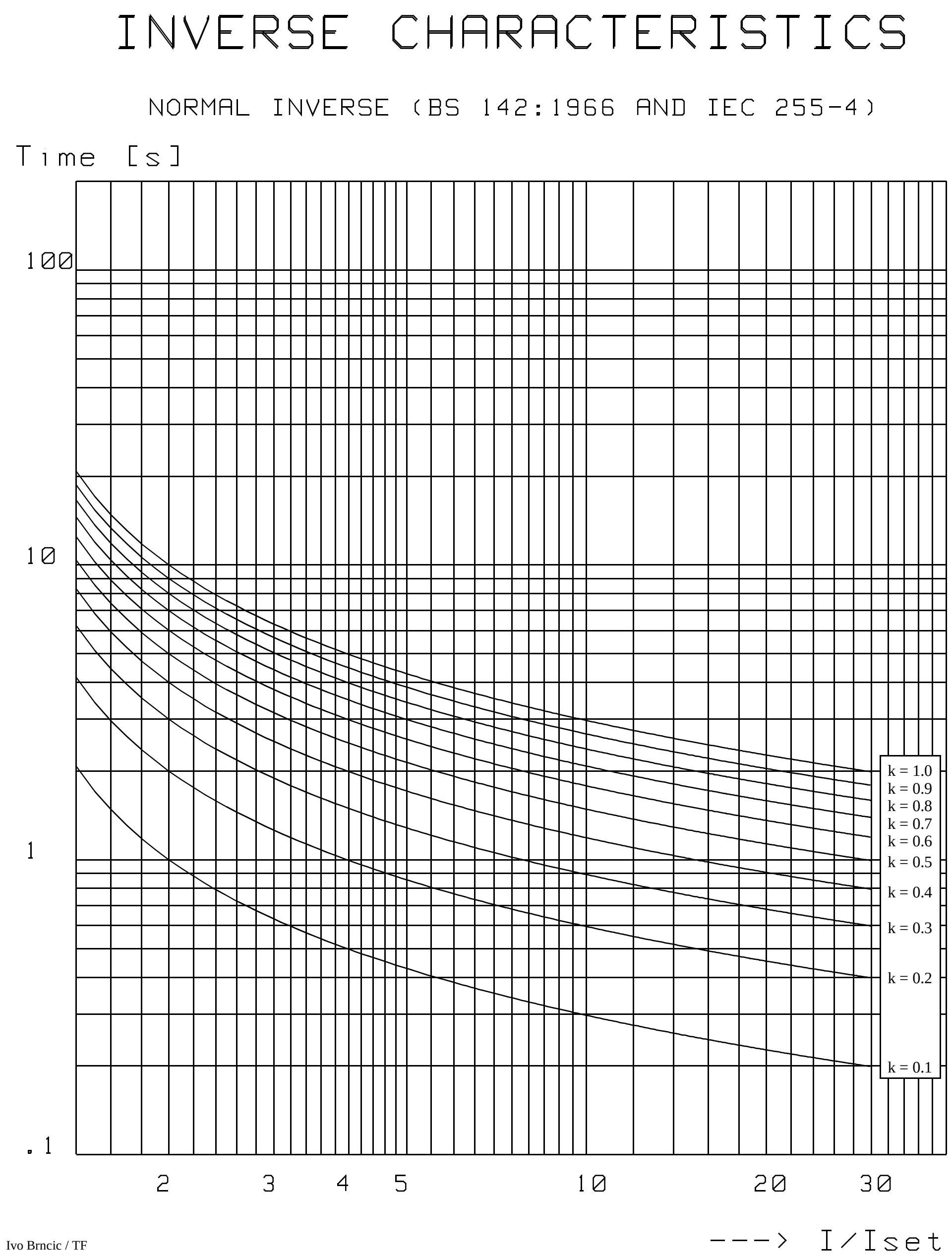


Fig. 51 Normal Inverse curves

Very Inverse curves

Fig. 52 shows the very inverse curves, defined by:

$$t_{op} = \frac{(k \times 13.5)}{\left(\frac{I}{I_{set}}\right) - 1}$$

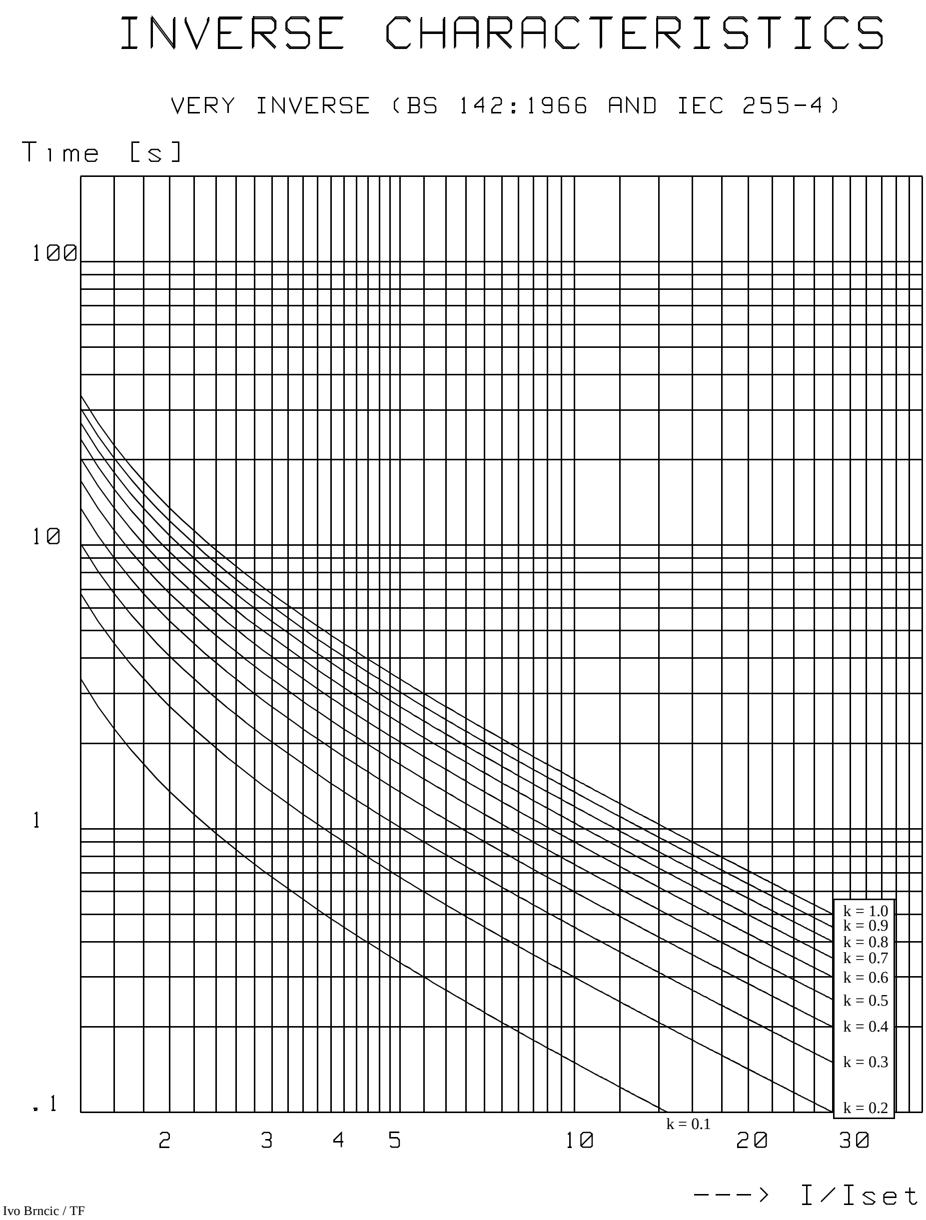


Fig. 52 Very Inverse curves

Extremely Inverse characteristics

Fig. 53 shows the extremely inverse curves, defined by:

$$t_{op} = \frac{(k \times 80)}{\left(\frac{I}{I_{set}}\right)^2 - 1}$$

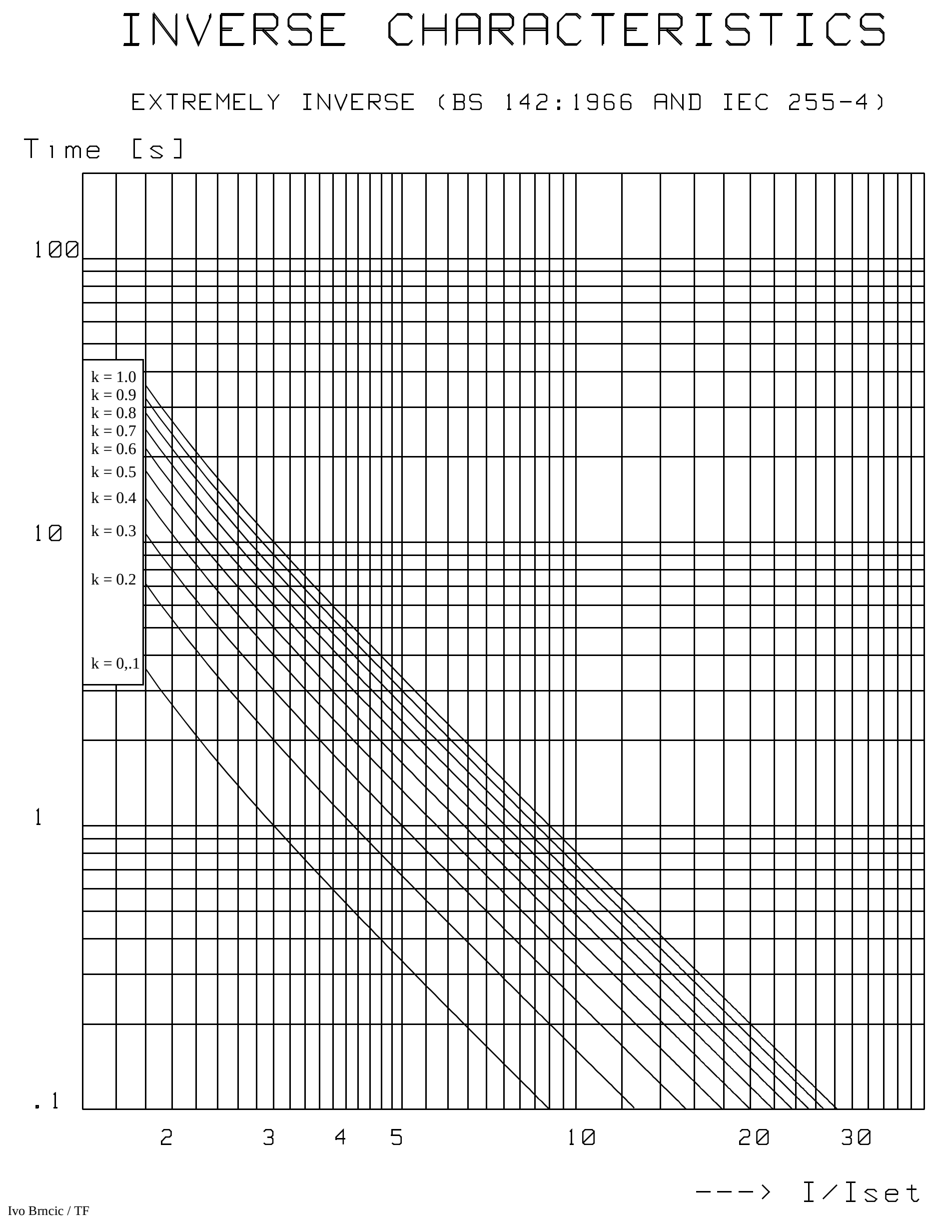


Fig. 53 Extremely Inverse curves

Long-time Inverse characteristics

Fig. 54 shows the long-time inverse curves, defined by:

$$t_{op} = \frac{k \times 120}{(I/I_{set}) - 1}$$

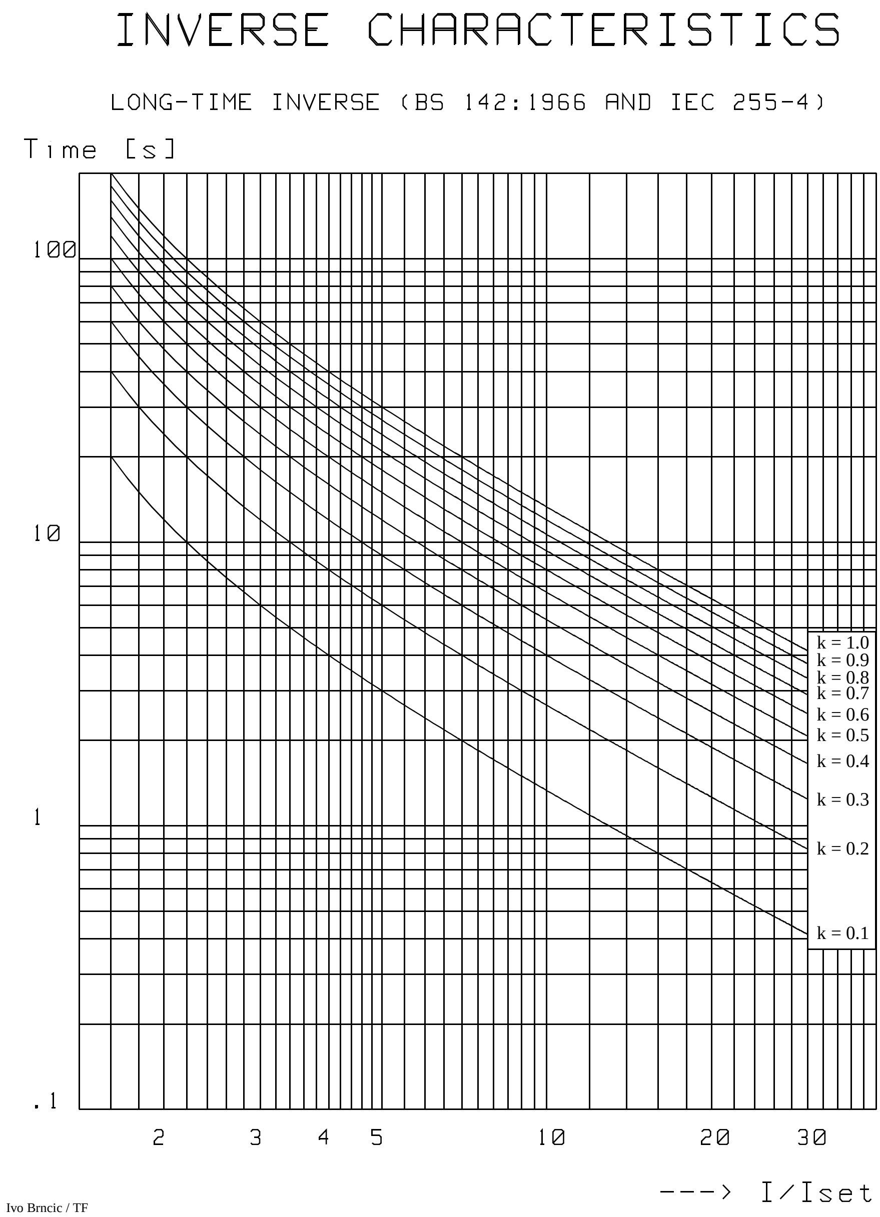


Fig. 54 Long-Time Inverse curves

26.3.2 Calculation of IEC inverse delays

Expression for the operate time t_{op}, can be re-written as:

$$t_{op} \times \left(\left(\frac{I}{I_{set}} \right)^{p} - 1 \right) = k \times T_b = const$$

This expression tells that the operate time t_{op} is a function of the mean value of the variable $[(I/I_{set})^p - 1]$, which in turn is a function of the variable I/I_{set}. For p = 1 this variable is equal to the relative fault current above the set value I_{set}. The operate time t_{op} will be inversely proportional to the mean value of variable $[(I/I_{set})^p - 1]$ up to the point of trip. In an integral form, the decision to trip is made when:

$$\int_0^t \left(\left(\frac{I(t)}{I_{set}} \right)^{p} - 1 \right) \times dt \geq k \times T_b = const$$

A numerical relay must instead make a sum:

$$\Delta t \times \sum_{j=1}^{n} \left(\left(\frac{I(j)}{I_{set}} \right)^{p} - 1 \right) \geq k \times T_b = const$$

where:

j = 1	a fault has been detected, for the first time it is $I / I_{set} > 1$
Δt	time interval between two successive executions of earth fault function. If the earth fault protection is executed with the execution frequency f_{ex} = 50 Hz, then Δt = 1/50 s = 20 ms.
n	an integer, the number of the overcurrent function execution intervals Δt from the inception of the fault to the point of time when the above condition for trip is fulfilled and trip command issued.
I(j)	the actual value of the fault current at point in time j.

26.3.3 Directional control of overcurrent protection

If current (or better power) may flow in either direction through the point where an overcurrent relay is placed, then a directional criterion may be applied in cases where the operation of the overcurrent protection is required for faults on one side of overcurrent relay, but not on the other.

The direction of flow of an ac current is not an absolute quantity; it can only be measured relative to some reference which itself must be an ac quantity. A suitable reference is the power system voltage.

Bearing in mind that it is the direction of the fault that is the sole requirement, the directional element is made very sensitive. Since the system voltage may fall to a low value during a short circuit, directional relay should retain its directional properties down to a low voltage, typically 1 - 2 % rated value. RET's low voltage limit is 1 % rated value.

Considering the different fault types and the fact that the angle between voltage and the current for a fault can vary over a wide range, the problem of directional sensing becomes one of selecting a particular reference voltage to be associated with a particular current. The primary characteristic of the reference voltage is that it will be reasonably constant with respect to the non-faulted system conditions and to the measured current in the protected circuit.

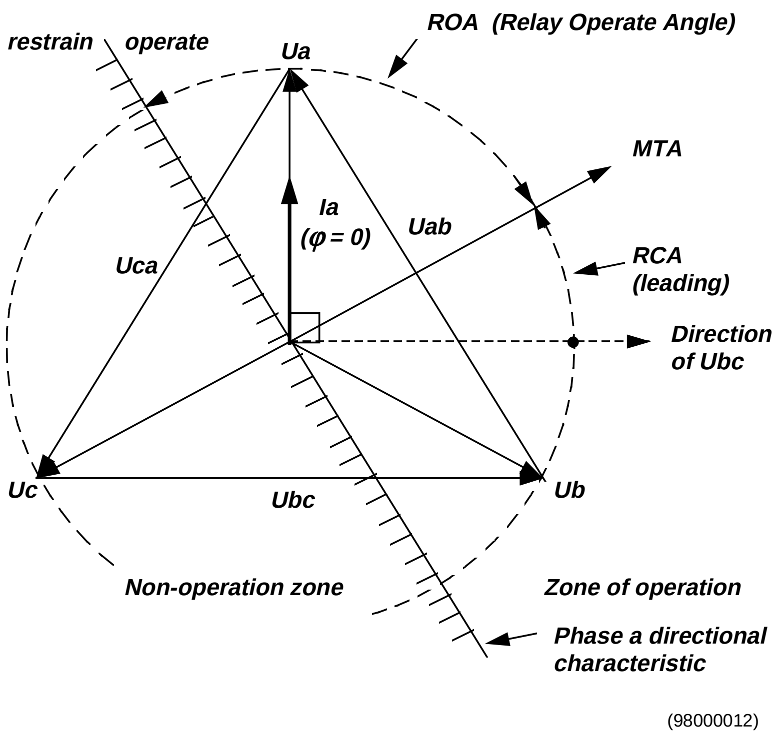


Fig. 55 Definition of 90 degrees connection.

RET's directional overcurrent protection utilises the so called 90 degrees connection where the opposite phase-to-phase voltage is used as a reference voltage. For example, voltage Ubc (UL2L3) is used to polarise the phase a (IL1) current, as shown in Fig. 55.

The 90 degrees connection used traditionally 2 variants: 90 - 30 variant, and 90 - 45 variant, where 30, and 45 degrees are Relay Characteristic Angles (RCA), respectively. RET offer both variants and has the possibility to set RCA between 20-50 which suits any particular application.

The MTA (Maximum Torque Angle) is the angle by which the current applied to the relay must be displaced from the voltage applied to the relay to get the fastest response, the expected fault current position.

The RCA (Relay Characteristic Angle) is the angle by which the MTA is shifted from the directional reference (polarising) voltage.

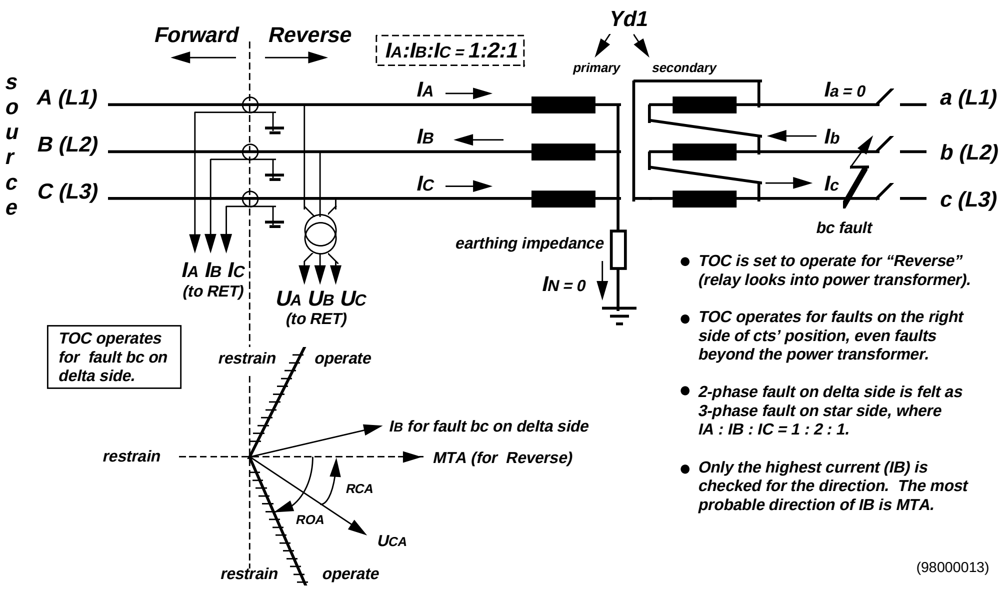


Fig. 56 If set to Reverse, TOC looks into power transformer and beyond the power transformer.

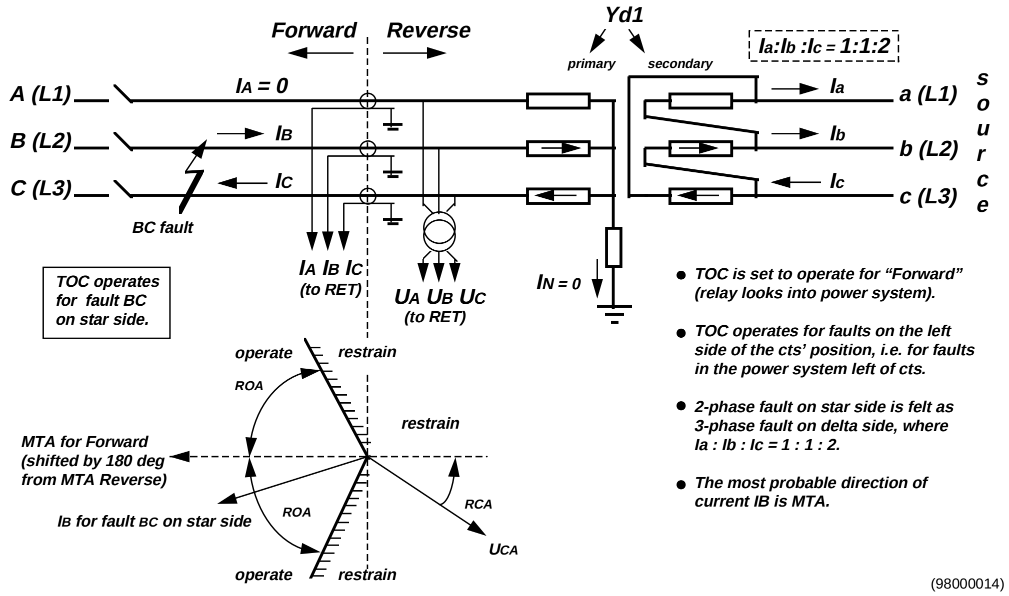


Fig. 57 If set to Forward, TOC looks from the power transformer and into the power system.

The terminal has a 180 degrees zone of operation if ROA = 90 degrees, as in Fig. 55, or a zone of operation which is reduced from 180 degrees if ROA < 90 degrees, as shown in Fig. 56 and Fig. 57. This feature provides an additional discrimination capability.

It is important to remember that only the highest of all three phase currents is checked for its direction. This the numerical equivalent of old polyphase directional relays, where 3 electromagnets operated on a single moving system. The highest current produced the highest torque, which overrode that of the other 2 phases. By doing so the other 2 (unfaulted) phases which may operate in the reverse direction are disregarded.

TOC can look into the power transformer (Reverse), or into the power system, away from the power transformer (Forward). Two examples are given by means of Fig. 56 and Fig. 57. This definition is valid for all power transformer sides.

In certain cases a relatively high current of the "operate" direction may be flowing during the normal, pre-fault conditions. In such cases and for a fault in "block" direction it would be possible to obtain a wrong answer (i.e. operate) from the directional criterion for about one cycle (20 ms). To counteract that, the answer from the directional criterion is delayed by 20 ms (for 50 Hz power systems). This is called the Current Reversal Feature. These 20 ms are added to the delay of the TOC.

If the directional reference voltage is too low to be able to positively determine the direction of a fault (i.e. determine the position of the fault with respect to TOC position), the user has 2 possibilities to choose between. The TOC may be set to become non-directional, or the TOC may be set to become blocked.

The lowset and the highset stages of the TOC are totally independent of each other with regard to directionality. They can be either directional or non-directional independent of each other. If both directional, they can look in opposite directions. If the reference voltage is too low, then they can become non-directional or blocked, independent of each other.

26.4 Logic diagram

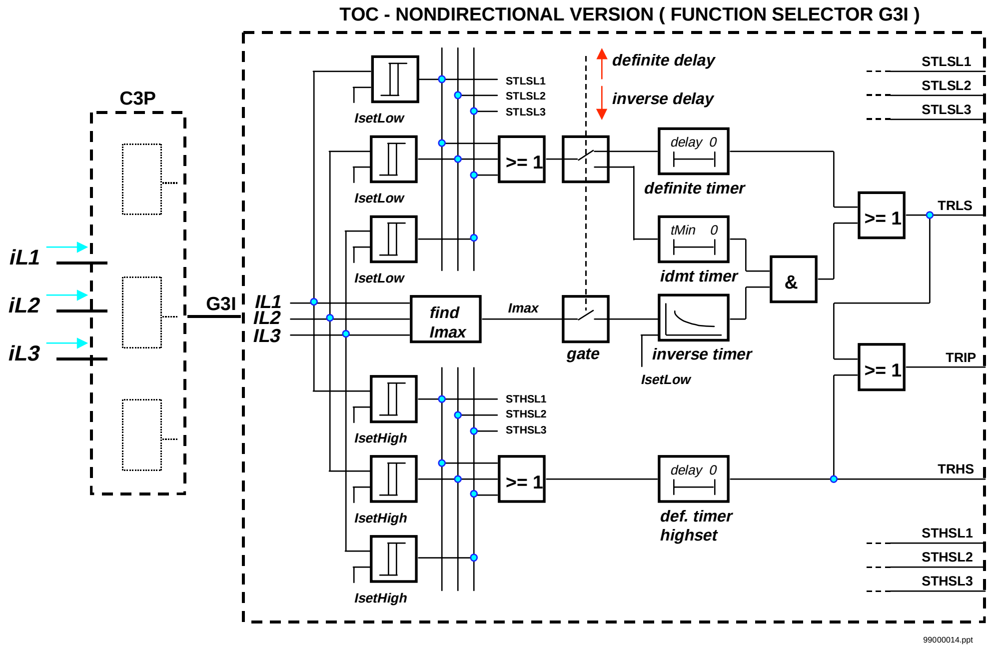


Fig. 58 Logic diagram of the nondirectional TOC.

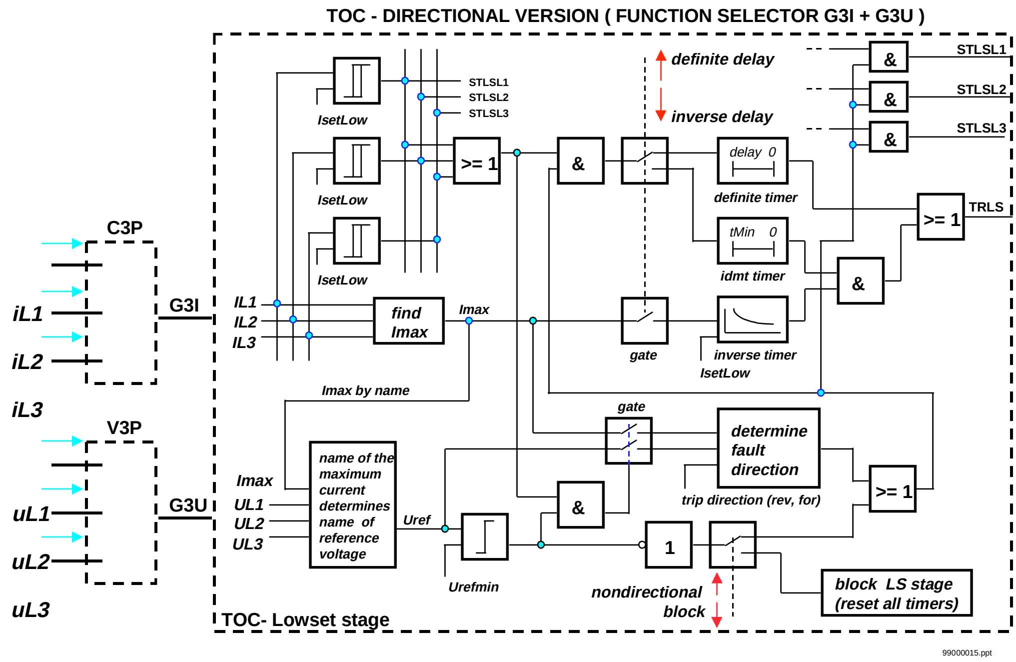
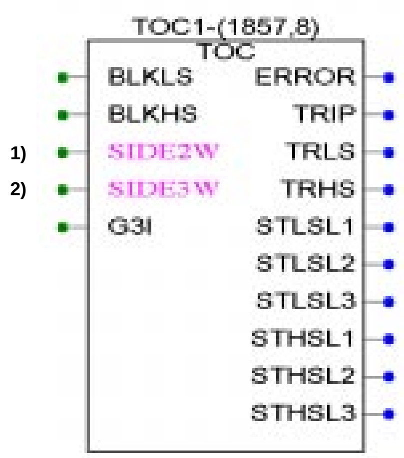


Fig. 59 Logic diagram of the directional TOC (lowset stage only)

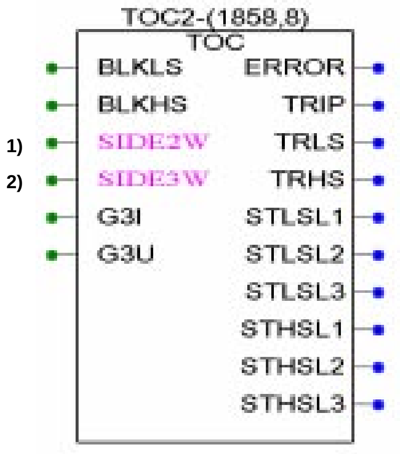
26.5 Function block

For Three-phase Time Overcurrent Protection, TOC, there are two different looks of the function block.

Nondirectional TOC (function selector set to G3I) and Directional TOC but directional facility not used (function selector set to G3I)



Directional TOC (function selector set to G3I+G3U)



1 Only applicable for 2winding variant

2 Only applicable for 3winding variant

26.6 Input and output signals

Table 67:

In:	Description:
TOCx-BLKLS	External block lowset, TOC1
TOCx-BLKHS	External block highset, TOC1
TOCx-SIDE2W	Transformer side, TOC1
TOCx-SIDE3W	Transformer side, TOC1
TOCx-G3I	Three phase current group, TOC1
TOCx-G3U	Three phase voltage group, TOC1

Table 68:

Out:	Description:
TOCx-ERROR	General TOC1 function error
TOCx-TRIP	Common trip TOC1
TOCx-TRLS	Trip lowset, TOC1
TOCx-TRHS	Trip highset, TOC1
TOCx-STLSL1	Start lowset, phase 1, TOC1
TOCx-STLSL2	Start lowset, phase 2, TOC1
TOCx-STLSL3	Start lowset, phase 3, TOC1
TOCx-STHSL1	Start highset, phase 1, TOC1
TOCx-STHSL2	Start highset, phase 2, TOC1
TOCx-STHSL3	Start highset, phase 3, TOC1

26.7 Setting parameters and ranges

Table 69:

Parameter:	Range:	Description:
Operation	0=Off, 1=On	Operation Three-phase Time Overcurrent Protection, Off/On
IrUserDef	1 - 99999	Rated current for user defined side in A
IsetLow	10 - 500	Start current, lowset in % of Ir
IsetHigh	10 - 2000	Start current, highset in % of Ir
CurveType	0=DEF, 1=NI, 2=VI, 3=EI, 4=LI	Time characteristic for TOC1, DEF/NI/VI/EI/LI
tDefLow	0.03 - 240.00	Definite delay lowset in sec.
tMin	0.05 - 1.00	Minimum operating time in sec.
tDefHigh	0.03 - 5.00	Definite delay highset in sec.

Table 69:

Parameter:	Range:	Description:
k	0.05 - 1.10	Time multiplier for inverse time function
BlockLow	0=Off, 1=On	Block lowset, Off/On
BlockHigh	0=Off, 1=On	Block highset, Off/On
DirectionLow	0=NonDir, 1=Forward, 2=Reverse	Direction for trip, lowset, Non-Dir/Forward/Reverse
DirectionHigh	0=NonDir, 1=Forward, 2=Reverse	Direction for trip, highset, Non-Dir/Forward/Reverse
rca	20 - 50	Relay Characteristic Angle in deg.
roa	60 - 90	Relay Operate Angle in deg.
UActionLow	0=NonDir, 1=Block	Action low pol. voltage, lowset , NonDir/Block
UActionHigh	0=NonDir, 1=Block	Action low pol. voltage, highset , NonDir/Block
UrUserDef	1.0 - 999.9	Rated voltage for user defined side, in kV

26.8 Service report values

Table 70:

Parameter:	Range:	Step:	Description:
Imax	0.0 - 99999.9	0.1	Highest current in A

27 Restricted earth fault protection (REF)

27.1 Summary of application

The Restricted Earth Fault (REF) protection is meant to protect a single winding of a power transformer. The winding which should be protected must be earthed. In the case of delta windings, the winding must be earthed by an earthing transformer, which must be electrically placed between the winding and the current transformers.

Protection against a fault to earth within the power transformer can ordinarily be taken care of by the overall differential protection. It is usually sufficiently sensitive to make special protection unnecessary in most cases where the neutral of a transformer is earthed directly or through a small resistor.

In the case of a transformer with its neutral earthed through a high resistance which keeps the earth faults at a relatively low level, overall differential protection (DIFP) should always be supplemented by REF protection. The differential protection does not cover a power transformer earthed through a high resistance or reactance against internal earth faults affecting less than 20 % to 30 % of a winding near the neutral point. A solution to this problem is the REF protection.

If the REF protection is applied when the neutral is solidly earthed, a complete cover for earth faults is obtained, since the fault current remains at a high value virtually to the last turn of the winding.

REF is a unit protection of (low impedance) differential type, which operates only for earth faults on the protected winding. It is in priciple insensitive to phase-to-phase faults, both internal or external, or earth fault external to the zone protected by REF. Within the zone of protection are all elements between the ct in the neutral conductor, and cts in the feeder(s). Up to two feeders connected to the power transformer bus may be included in the protected zone.

REF is based on the fundamental harmonic component of currents, and is thus insensitive to the 3-rd harmonic components which used to be a problem for older types of (high impedance) restricted earth fault protections. All harmonics are efficiently suppressed.

REF is a protection of differential type. As such, it calculates a differential current and a bias current. The differential current is a vectorial difference of the neutral current (i.e. current flowing in the neutral conductor) and the residual current from the lines. This difference is equal to the total earth fault current. REF thus operates on the fault current only, and is not dependent on the load currents. This makes REF a very sensitive protection.

As REF is much less sensitive to inrush currents in comparison to overall differential protection, no restrain criteria (such as harmonic, or waveform) is used which makes REF a faster protection than the overall differential protection DIFP.

27.2 Summary of function

- Fast and selective protection of earthed power transformer windings.
- Restricted earth fault protection (REF) is a unit protection of differential type with good sensitivity and selectivity.
- Restricted earth fault protection (REF) is of low-impedance type where differential current is calculated numerically.

- Up to 3 power transformer windings can be protected by up to 3 instances of the restricted earth fault protection (REF).
- Bus with 2 circuit breakers can be included in the zone of protection.
- One operate - bias characteristic, which can be shifted to change sensitivity.
- Differential current is a difference between neutral and residual current.
- Residual current is constructed from fundamental frequency terminal currents.
- Differential current is for internal faults equal to total earth fault current.
- The relatively highest of all separate input currents serves as a bias current.
- Restricted earth fault protection (REF) is insensitive to initial, recovery and sympathetic inrush, or overexcitation.
- Restricted earth fault protection (REF) is insensitive to On Load Tap Changer switchings.
- If a heavy external earth fault is detected, the restricted earth fault protection (REF) is temporarily desensitized.
- A directional criterion is applied in order to increase stability against external faults.
- Two consecutive trip requests are necessary for a final trip signal by restricted earth fault protection (REF) function.

27.3 Measuring principles

27.3.1 Fundamental principles of the restricted earth fault protection (REF)

The REF should detect earth faults on earthed power transformer windings. The REF is a unit protection of differential type. Because this protection is based on zero sequence currents, which only exist in case of an earth fault, the REF can be made very sensitive; regardless of normal load currents. It is at the fastest protection a power transformer winding can have. It must be borne in mind, however, that the high sensitivity, and the high speed, tend to make such a protection instable, and special measures must be taken to make it unsensitive to conditions, for which it should not operate, for example heavy through faults or heavy external earth faults.

The REF is of “low impedance” type. At least 3 power transformer terminal currents, and the power transformer neutral conductor current, are fed separately to RET 521. These input currents are then conditioned within RET 521 by mathematical tools. Fundamental frequency components of all currents are extracted from all input currents, while other eventual zero sequence components (e.g. the 3-rd harmonic currents) are fully suppressed. Then the residual current phasor is constructed from the three line current phasors. This zero sequence current phasor is then subtracted from the neutral current, which is “per definition” of zero sequence.

The following facts may be observed from Fig. 60 and Fig. 61 (where the 3 line CTs are lumped into a single summation transformer, for the sake of simplicity).

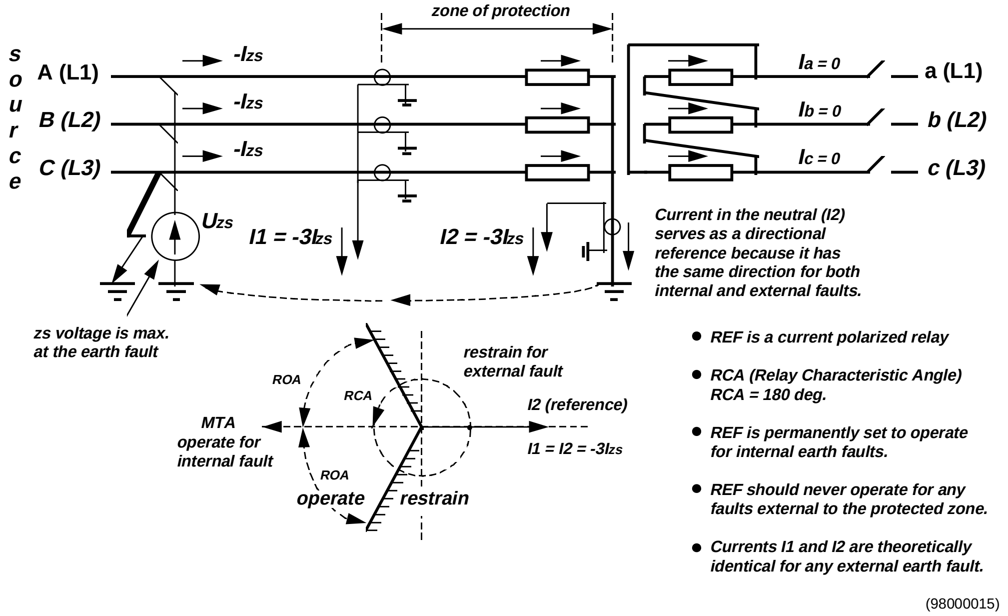


Fig. 60 Currents at an external earth fault

1 For an external earth fault, the residual current (I1 in Fig. 60) and the neutral conductor current (I2 in Fig. 60) are equal, and of the same direction. This is easy to understand, as both CTs ideally measure the same earth fault current

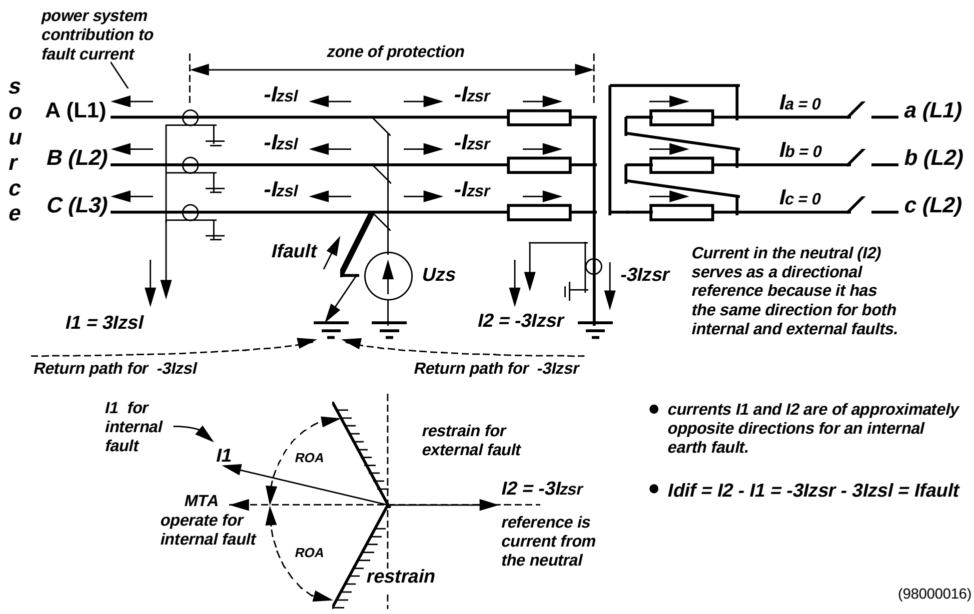


Fig. 61 Currents at an internal earth fault

2 For an internal fault, the total earth fault current (Ifault) is composed generally of two components. One component (-3Izsr) flows towards the power transformer neutral point and into the earth, while the other component (-3Izsl) flows out into the power system. These two currents can be expected to be of approximately opposite directions (about the same zero sequence impedance angle is assumed on both sides of the earth fault). The magnitudes of the two components may be different, dependent on the magnitudes of the magnitudes of zero sequence impedances of both sides. No current can flow towards the power system, if the only point where the system is earthed, is at the protected power transformer. Likewise, no current can flow into the power system, if the winding is not connected to the power system (circuit breaker open and power transformer energized from the other side).

3 For both internal and external earth faults, the current in the neutral connection (I2) has always the same direction, that is, towards the earth.

4 The two components of the fault current are measured as I1 and I2. The difference between them is the differential current which is equal to the total earth fault current; Idif = I2 - I1 = Ifault.

Because REF is a differential protection where the line zero sequence (residual) current is constructed from 3 line (terminal) currents, a bias quantity must give stability against false operations due to high through fault currents. An operate - bias characteristic (only one) has been devised to the purpose.

It is not only external earth faults that REF should be stable against, but also heavy phase-to-phase faults, not including earth. These faults may also give rise to false zero sequence currents due to saturated line CTs. Such faults, however, produce no neutral current, and can thus be eliminated as a source of danger.

As an additional measure against unwanted operation, a directional check is made in agreement with the above points 1, and 2. An operation is only allowed if currents I1 and I2 (see Fig. 60 and Fig. 61) are at least RCA - ROA degrees apart, where RCA is the Relay Characteristic Angle, and ROA is the Relay Operate Angle.

27.3.2 The restricted earth fault protection (REF) as a Differential Protection

The restricted earth fault protection (REF) is a protection of differential type, a unit protection, whose settings are independent of any other protection. Compared to the overall differential protection (DIFP) it has some advantages. It is simpler, as no current phase correction and magnitude correction are needed, not even in the case of an eventual On-Load-Tap-Chager (OLTC). REF is not sensitive to inrush and overexcitation currents. The only danger left is an eventual current transformer saturation.

The REF has only one operate-bias characteristic, which is described in Table 71:, and shown in Fig. 60, Fig. 61 and Fig. 62.

Table 71: Data of the operate - bias characteric of the REF.

Default sensitivity Idmin (zone 1)	Max. base sensitivity Idmin (zone 1)	Min. base sensitivity Idmin (zone 1)	End of zone 1	First slope	Second slope
% Irated	**% Irated**	**% Irated**	**% Irated**	**%**	**%**
30	5	50	125	70	100

As a differential protection, the REF calculates a differential current and a bias current. In case of internal earth faults, the differential current is theoretically equal to the total earth fault current. The bias current is supposed to give stability to REF. The bias current is a measure of how high the currents are, or better, a measure of how difficult the conditions are under which the CTs operate. The higher the bias, the more difficult conditions can be suspected, and the more likely that the calculated differential current has a component of a false current, primarily due to CT saturation. This “law” is formulated by the operate-bias characteristic. This characteristic divides the Idif - Ibias plane into two parts. The part above the operate - bias characteristic is the so called operate area, while that below is the block area, see Fig. 62.

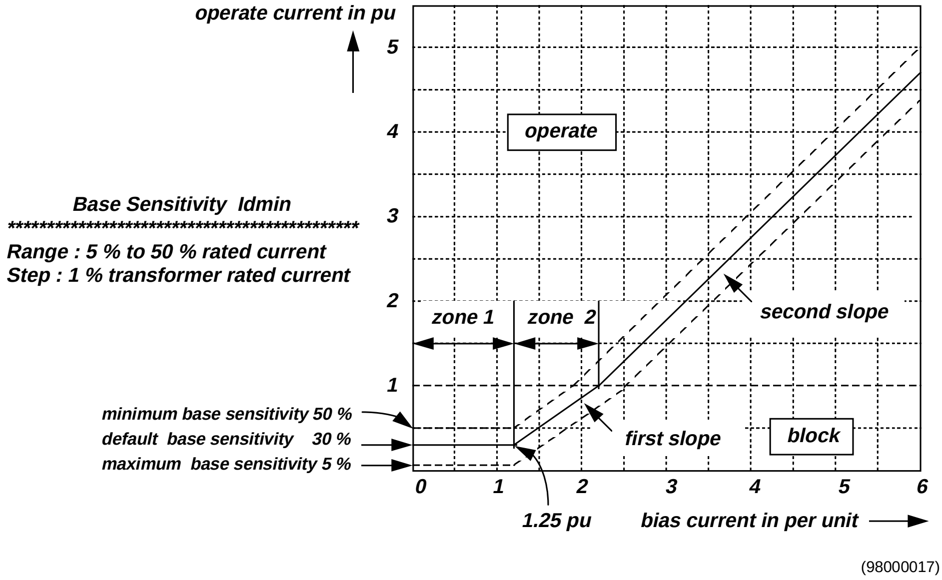


Fig. 62 Operate - bias characteristic of the restricted earth fault protection REF.

27.3.3 Calculation of Differential Current and Bias Current

The differential current, (= operate current), as a fundamental frequency phasor, is calculated as:

$\bar{I}dif = \bar{I}op = \bar{I}2 - \bar{I}1$,

where:

$\bar{I}2$ current in the power transformer neutral as a fundamental frequency phasor,

$\bar{I}1$ residual current of the power transformer line (terminal) currents as a phasor.

If there are 2 feeders included in the zone of protection of the REF (such as in breaker-and-a-half configurations), then their respective residual currents are added within RET so that:

$\bar{I}1 = \bar{I}1\_feeder1 + \bar{I}1\_feeder2$.

The bias current is a measure (expressed as a current) of how difficult the conditions are under which the instrument current transformer operate. Dependent on the magnitude of the bias current, the corresponding zone (section) of the operate - bias characteristic ia applied, when deciding whether “to trip, or “not to trip”.

The bias current is calculated as the relatively highest current of all separate input currents, that is of current in phase a (L1), phase b (L2), phase c (L3), and the neutral current In (I2 in Fig. 60 and Fig. 61). Each of these currents is first compared to the primary rating (in Amperes) of its respective CT, and is then expressed as a multiple of the protected power transformer rated current (of the winding in question). Symbolically:

current[1] = Ia/CTprim*Irated

current[2] = Ib/CTprim*Irated

current[3] = Ic/CTprim*Irated

current[4] = In/CTprim*Irated

If there are 2 feeders included in the zone of protection of the REF, then the respective bias current is found as the highest of the following seven currents:

current[1] = Iaf1/CTprim*Irated

current[2] = Ibf1/CTprim*Irated

current[3] = Icf1/CTprim*Irated

current[4] = Iaf2/CTprim*Irated

current[5] = Ibf2/CTprim*Irated

current[6] = Icf2/CTprim*Irated

current[7] = In/CTprim*Irated

The bias current is thus generally equal to none of the input currents. If all primary ratings of CTs were equal to Irated, then the bias current would be equal to the highest (by RET measured) current.

27.3.4 Detection of External Earth Faults

External faults are more common than the internal earth faults for which the restricted earth fault protection (REF) should operate. It is important that REF remains stable during heavy external earth and phase-to-phase faults, and also when such a heavy external fault has been cleared by some other protection such as overcurrent, or earth fault protection, etc. The conditions during a heavy external fault, and particularly immediately after the clearing of such a fault may be quite complex. The circuit breaker’s poles may not open exactly at the same moment, some of the CTs may still be highly saturated, etc.

The detection of external earth faults is based on the fact that for such a fault a high neutral current appears first, while a false differential current only appears if and when a CT saturates. An external earth fault is thus assumed to have occurred when a high neutral current suddenly appears, while at the same time the differential current Idif remains low. This condition must be detected before any trip request is placed within REF. Any search for external faults is interrupted after a trip request has been placed.

For an internal fault, a true differential current develops immediately, while for an external fault it only develops if a CT saturates. If a trip request comes first, before an external fault could be positively established, then it must be an internal fault. Any search for external fault is aborted if a trip request has been placed. A condition for a successful detection is that it takes not less than 4 ms for the first CT to saturate.

If an external earth fault has been detected, then the REF is desensitised. Under external earth fault condition, no operation is allowed if the current in the neutral is less than 50 % rated current. The condition is removed when the external earth fault is found to be cleared. The external earth fault is considered to be cleared when the neutral current falls below 50 % of the set base sensitivity of the REF, Idmin

Directional criterion

The directional criterion is applied in order to distinguish between internal- and external earth faults. This check is an additional criterion, which should prevent misoperations at heavy external earth faults. Earth faults on lines connecting the power transformer occur much more often than earth faults on a power transformer winding. It is important therefore that the restricted earth fault protection (REF) should remain secure during an external fault, and immediately after the fault has been cleared by some other protection.

For an external earth fault with no CT saturation, the residual current in the lines (I1 in Fig. 60) and the neutral current (I2 in Fig. 60) are equal in magnitude and phase. It is the current in the neutral (I2) which serves as a directional reference because it flows for all earth faults, and it has the same direction for all earth faults. The directional criterion in REF is a so called current-polarized relay.

If one or more CTs saturate, then the measured currents I1 and I2 may no more be equal, nor will their positions in the complex plane be the same. There is a risk that the resulting false differential current Idif enters the operate area when clearing the external fault. If this happens, a directional test may prevent a misoperation.

A directional check is only executed if:

1 a trip request signal (START) has been issued,

2 if the residual current in lines (I1) is at least 3 % of the power transformer rated current.

If a directional check is either unreliable or not possible to do, then directionality is cancelled as a condition for an eventual trip.

If a directional check is executed, REF is only allowed to operate, if the two currents which are being compared (I1 and I2) are at least 180 - ROA degrees apart, see Fig. 60, Fig. 61, and Fig. 62, where ROA was 75 degrees. Quantities which describe the directional boundary of the REF are the following:

RCA = 180 degrees = constant; where RCA stands for Relay Characteristic Angle,

ROA = +- 75 to +-90 degrees;   where ROA stands for Relay Operate Angle.

RCA determines a direction MTA (Maximum Torque Angle) where I1 should lie for an internal earth fault, while ROA sets a tolerance margin.

27.3.5 Algorithm of the restricted earth fault protection (REF) in short

1. Check if current in the neutral Ineutral (I2) is less than 50 % of the base sensitivity. If yes exit REF function.
2. If Ineutral is more than 50 % of Idmin determine the bias current Ibias.
3. Determine the differential (operate) current Idif as a phasor, and calculate its magnitude.
4. Check if the point P(Ibias, Idif) is above the operate - bias characteristic. If yes, increment the trip request counter by 1. If the point P(Ibias, Idif) is found to be below the operate - bias characteristic, then the trip request counter is reset to 0.
5. If the trip request counter is still 0, search for an eventual external earth fault. The search is only made if the neutral current is at least 50 % of the power transformer rated current of the side in question. If an external earth fault has been detected, a flag is set which remains set until the external fault has been cleared. The external fault flag is reset to 0 when Ineutral falls below 50 % of the base sensitivity Idmin. Any search for external fault is aborted if trip request counter is more than 0.
6. For as long as the external fault persists an additional temporary condition is introduced, which requires, that Ineutral has to be higher than 50 % power transformer rated current, for any TRIP to be issued by REF. That means that the REF is temporarily desensitized.
7. If point P(Ibias, Idif) is found to be above the operate - bias characteristic), so that trip request counter is more than 0, a directional check can be made. The directional check is made only if Iresidual (I1) is more than 3 % of the rated current. If the result of the check means “external fault”, then the trip request is reset. If the directional check cannot be executed, then direction is no longer a condition for a trip.
8. Finally, a check is made if the trip request counter is equal to, or higher than 3. If it is, and at the same time, the bias current is at least 50 % of the highest bias current Ibiasmax (measured during the disturbance) then the REF trip request is placed at the REF function output TRIP. If the counter is less than 3, no REF trip signal is placed.

27.4 Logic diagram

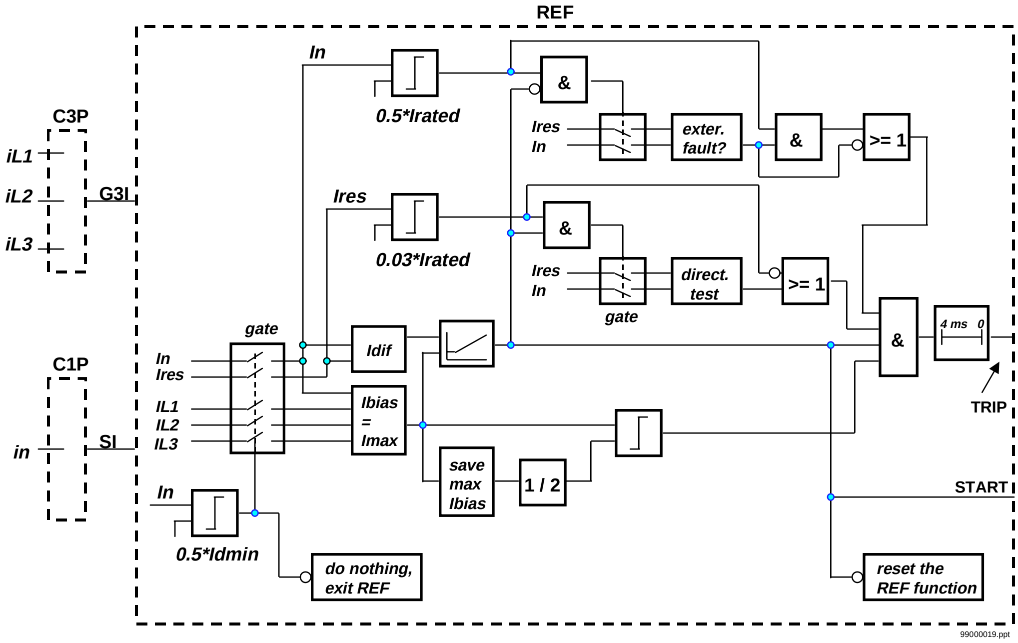
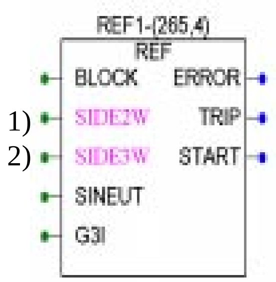


Fig. 63

27.5 Function block



1 Two winding applications only

2 Three winding applications only

27.6 Input and output signals

Table 72:

In:	Description:
REFx-BLOCK	External block, REF1
REFx-SIDE2W	Transformer side, REF1
REFx-SINEUT	Neutral current, REF1
REFx-G3I	Three phase current group, REF1
REFx-SIDE3W	Transformer side, REF1

Table 73:

Out:	Description:
REFx-ERROR	General REF1 function error
REFx-TRIP	Common trip REF1
REFx-START	Start, REF1

27.7 Setting parameter and ranges

Table 74:

Parameter:	Range:	Description:
Operation	0-1	Operation Restricted Earth Fault Protection, Off/On
Idmin	5-50	Maximum sensitivity in % of Ir
roa	60-90	Relay Operate Angle in deg.

27.8 Service report values

Table 75:

Parameter:	Range:	Step:	Description:
Ibias	0.0 - 99999.9	0.1	Bias current in A
Idiff	0.0 - 99999.9	0.1	Differential current in A

28 Earth fault time current protection (TEF)

28.1 Application of function

By using a relay which responds only to the zero sequence current of the system, a more sensitive protection against earth faults is obtained, since the zero sequence component theoretically only exists when fault current flows to earth. The earth fault is therefore theoretically unaffected by load currents, and can be given a setting which is much below the rated load currents. This is very useful, as earth faults are by far the most frequent of all faults.

However, a higher sensitivity for fault currents is paid by a higher sensitivity to false zero sequence currents produced by for example unbalanced leakage to earth, or false zero sequence currents produced by cts for high load, heavy external faults not involving earth, or inrush currents. This sets the limit for the lowest setting of the earth fault relay. As a stabilisation against inrush currents, the 2-nd harmonic restrain can optionally be applied.

The earth fault protection can be optionally provided with a directional element, based on fundamental frequency zero sequence voltage or the measured open delta (residual) voltage. A directional earth fault relay can discriminate between the earth faults in front of, or behind, the relay. An earth fault which occurs between the relay and a power transformer with an earthed neutral point, is a fault behind the relay. The earth fault relay will operate for such a fault if its directional setting is Reverse. An earth fault which happens out in the power system on the same side of the power transformer is a fault in front of the relay. The earth fault relay will operate for such an earth fault only if its directional setting is Forward. An earth fault relay operating on the neutral current (i.e. current flowing in the neutral conductor) cannot be directional, as the neutral current always flows up the neutral conductor regardless of the earth fault position with respect to the relay position.

The earth fault protection has two stages. Both of them can be made directional. The stages can look to different directions independent of each other.

The earth fault protection can be applied to protect a power transformer if it is fed with the power transformer currents, or it can protect a feeder connected to the power transformer bus if the earth fault relay is fed with the feeder currents. In this case, all current limits shall be expressed in % of the rated current of the protected feeder.

Among the various possible methods used to achieve correct earth fault relay coordination are those using either time or current, or a combination of time and current.

In case of the current-independent earthfault relay, the delay is independent of the actual fault current, while in the case of current-dependent relay, the delay is an inverse function of the magnitude of the actually fault current.

There are two different delay types available in TEF:

1 Definite

2 Inverse (Normal Inverse, Very Inverse, Extremely Inverse, Longtime Inverse and LOGarithmic (RXIDG)

The lowset stage can use all delay types, while the highset stage can only use the definite delay type.

28.2 Summary of function

- Earth fault relays offer a very satisfactory means of clearing earth faults.
- The earth fault time current protection (TEF) can be set very sensitive irrespective of normal load currents.
- The earth fault time current protection (TEF) is based on zero sequence current. The zero sequence current may be calculated within the terminal from 3 phase currents, or may be connected to the terminal as a single current.
- Single current can be a direct sum of phase currents, or can be supplied as a single current by a special core-balance current transformer from the transformer neutral.
- Fundamental frequency zero sequence current serves as a basis for comparison and delay.
- The earth fault time current protection (TEF) can be stabilised by 2-nd harmonic criterion against misoperation due to inrush.
- Reset ratio is 96%.
- The earth fault time current protection (TEF) has a lowset stage and a highset stage.
- The lowset stage can have either definite delay, or inverse delay.
- A definite minimum delay is available for inverse delays.
- The highset stage has always a definite delay.
- Both stages can be directional or nondirectional, independent of each other.

- If both stages are directional, they can look in different directions.
- If the directional reference voltage becomes too low, then a directional stage is blocked.
- A range of Relay Characteristic Angles (RCA) is available to cover different kinds of power systems earthing.
- A range of Relay Operate Angles (ROA) is available that allow the limit of operation boundary to be reduced from 180 degrees (+-90 degrees), thereby providing an additional discrimination capability.

28.3 Measuring principles

28.3.1 Non-directional earth fault protection

The earth fault time current protection (TEF) is based on zero sequence current. The zero sequence current maybe:

- calculated within RET 521 (as Izs), from all 3 line (terminal) currents which are fed to RET or
- fed to RET as a single current (as 3*Izs) which can be a direct sum of 3 line (terminal) currents, or is supplied as a single current by a special core balance summation current transformer. Alternatively, current from the power transformer neutral connection can be used.

Being based on zero sequence currents, TEF can be made comparatively very sensitive. However, if the zero sequence current is a sum of the phase (line, terminal) currents, then there is a danger of temporary false zero sequence currents, due to an eventual saturation of one or more CTs. Even in case of heavy phase-to-phase faults not involving earth such false zero sequence currents may appear. In RET 521 this danger is partly diminished by calculating with the fundamental frequency zero sequence currents. In this respect, a TEF fed with a zero sequence current (3*Izs) from a special core balance CT is definitely the best solution.

The lowset stage, or the highset stage, or both, can be stabilised by the second harmonic contents in the zero sequence current. This feature is necessary to prevent misoperations of the TEF due to inrush in case of earthed power transformer windings.

The second harmonic restrain is enabled independently for lowset and highset stage with the settings 2harLow respective 2harHigh. Both stages uses the same setting I2/I1ratio, to detect if the second to first harmonic ratio exceeds this value. The output, 2NDBLK, is set if the ratio is above the limit.

There are two different time characteristics available in TEF:

1 Definite

2 Inverse

- normal inverse

- very inverse
- extremely inverse
- longtime inverse
- LOGarithmic (RXIDG)

There are five different inverse curve types. The lowset stage can use all delay types, while the highset stage only uses the definite delay type.

IEC 255-4 defines the inverse time characteristic with the following equation:

$$t_{op} = \frac{(k \times T_b)}{\left(\frac{I}{I_{set}}\right)^p - 1}$$

where:

t_{op}	operate time
I	actual value of the measured earth fault current
I_{set}	set current limit
p	exponent, power
k	time multiplier
T_b	base time

Table 76: Inverse curves range for time multiplier k, and setting step of k.

Inverse curve	T_b (s)	p	k	k - step
normal	0.14	0.02	0.05 - 1,1	0.01
very inverse	13.5	1	0.05 - 1,1	0.01
extremely	80	2	0.05 - 1,1	0.01
longtime	120	1	0.05 - 1,1	0.01

Normal Inverse curves

The Normal Inverse delay is defined by the following expression:

$$t_{op} = \frac{(k \times 0.14)}{\left(\frac{I}{I_{set}}\right)^{0.02} - 1}$$

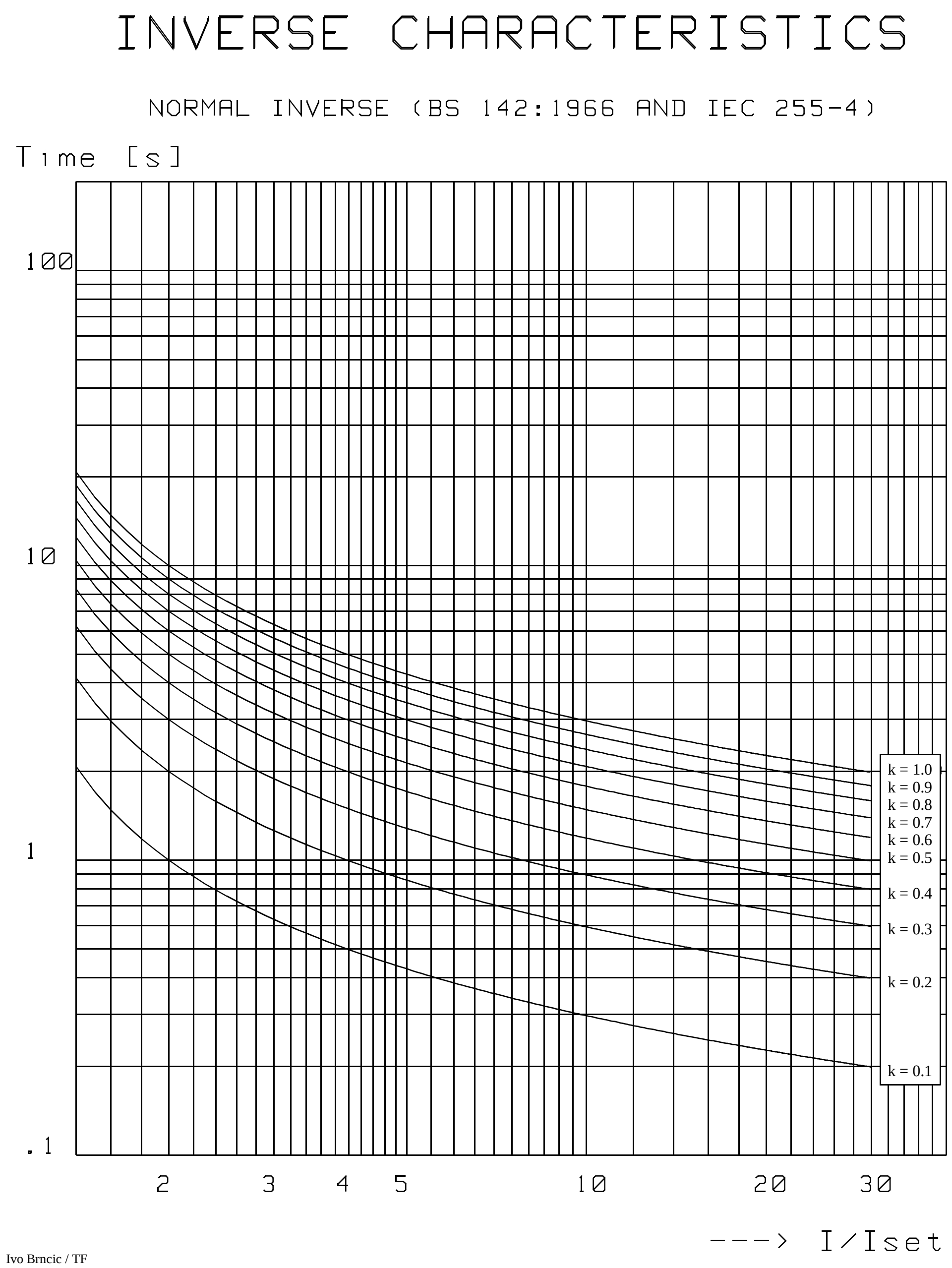


Fig. 64 Normal Inverse curves

Very Inverse curves

Fig. 52 shows the Very Inverse curves, defined by:

$$t_{op} = \frac{(k \times 13.5)}{\left(\frac{I}{I_{set}}\right)^{1} - 1}$$

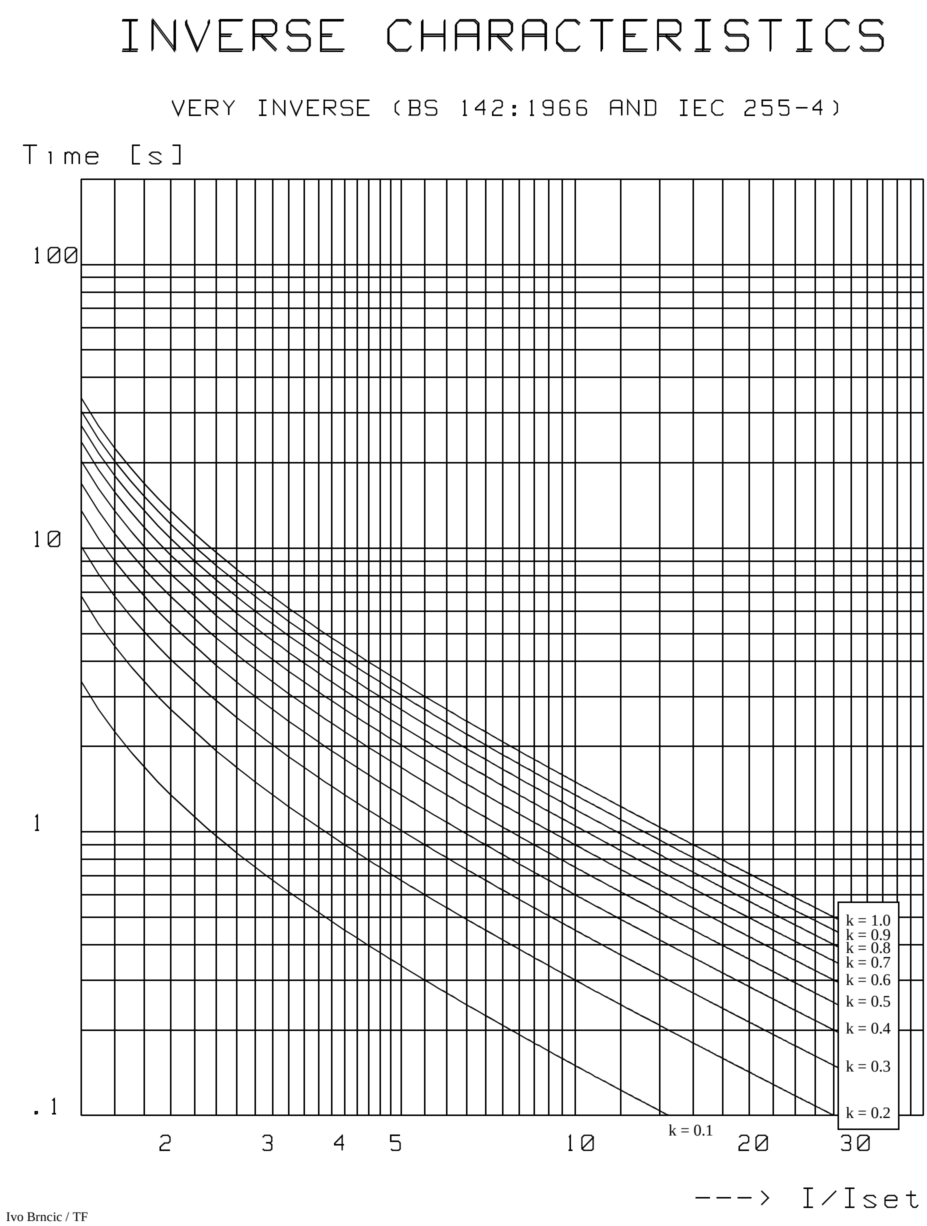


Fig. 65 Very Inverse curves

Extremely Inverse characteristics

Fig. 53 shows the Extremely Inverse curves, defined by:

$$t_{op} = \frac{(k \times 80)}{\left(\frac{I}{I_{set}}\right)^2 - 1}$$

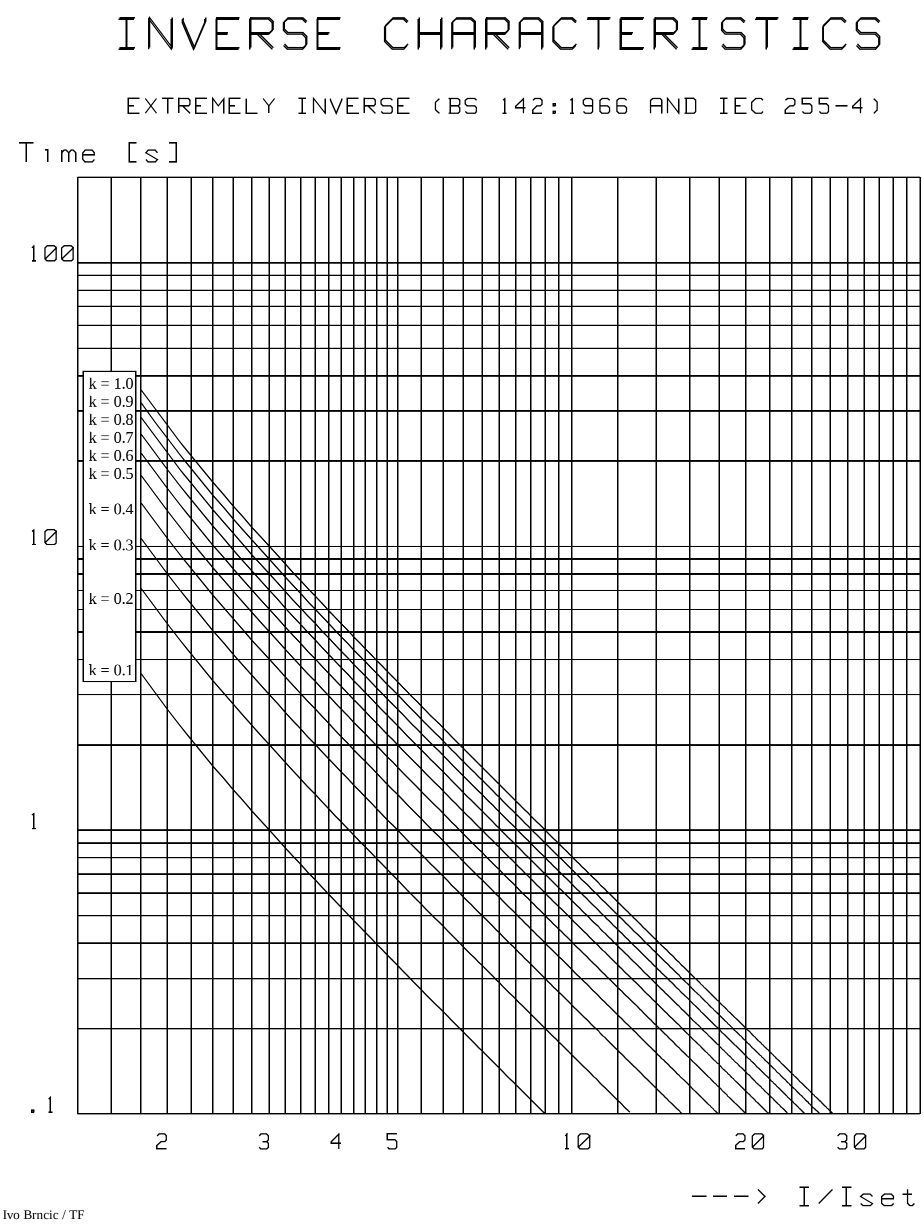


Fig. 66 Extremely Inverse curves

Longtime Inverse characteristics

Fig. 54 shows the Longtime Inverse curves, defined by:

$$t_{op} = \frac{k \times 120}{(I/I_{set}) - 1}$$

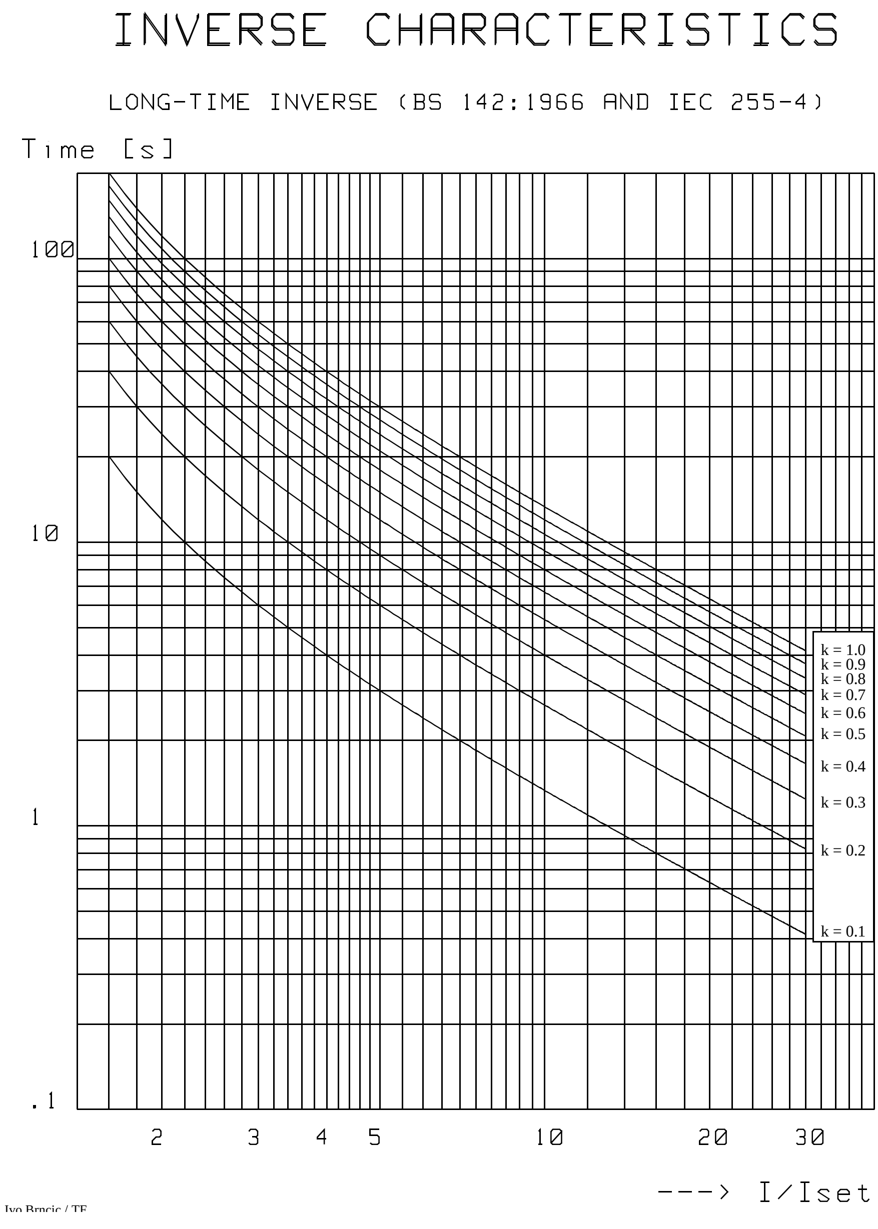


Fig. 67 Long-time Inverse curves

28.3.2 Logarithmic Curves

Fig. 68 shows Logaritmic (RXIDG) curves, defined by:

$$t_{op} = 5,8 - 1,35 \times ln(I / I_{set} / k)$$

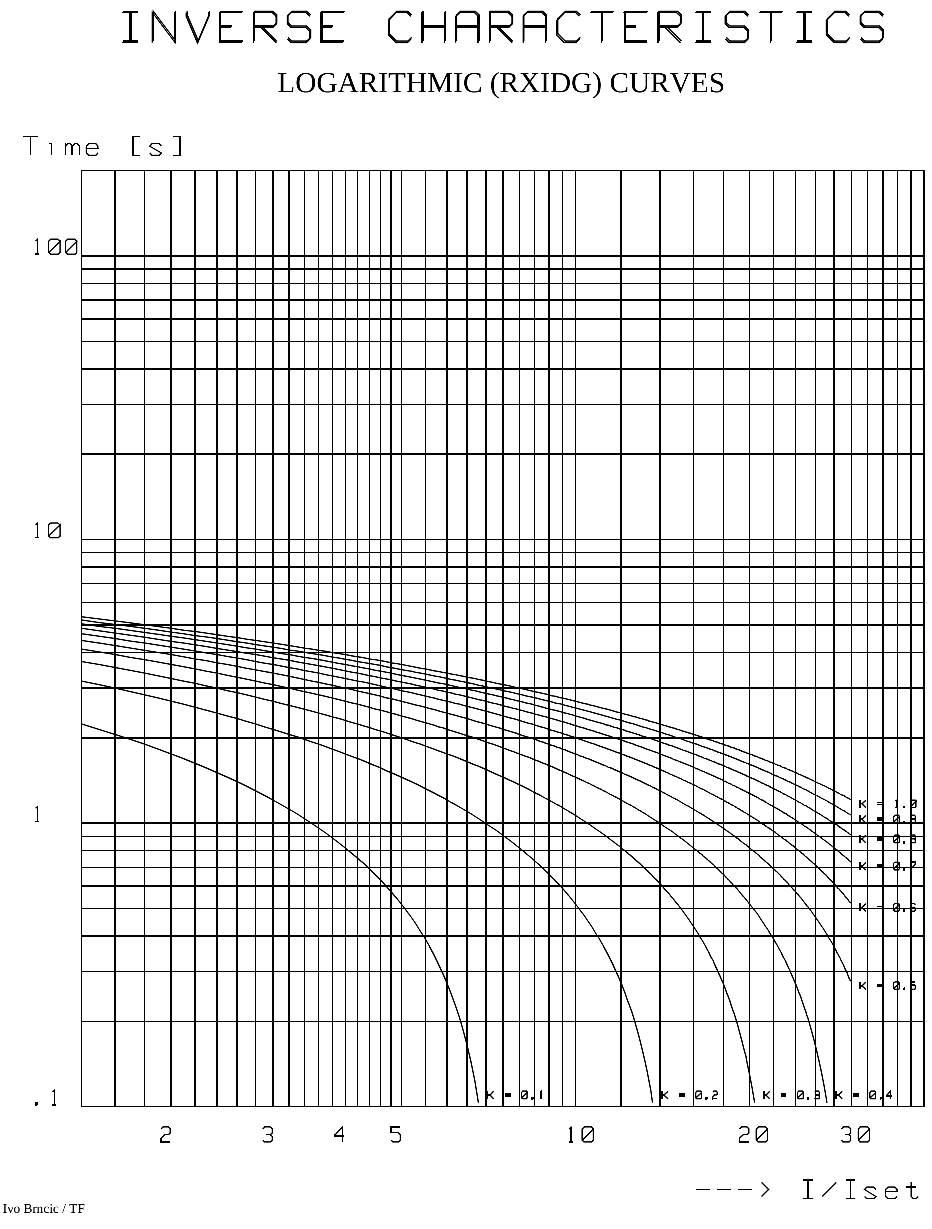


Fig. 68 Logarithmic curves (RXIDG)

28.3.3 Calculation of IEC inverse delays

Expression for the operate time t_{op}, can be re-written as:

$$t_{op} \times \left(\left(\frac{I}{I_{set}} \right)^p - 1 \right) = k \times T_b = const$$

This expression tells that the operate time t_{op} is a function of the mean value of the variable $[(I/I_{set})^p - 1]$, which in turn is a function of the variable I/I_{set}. For p = 1 this variable is equal to the relative earth fault current above the set value I_{set}. The operate time t_{op} will be inversely proportional to the mean value of variable $[(I/I_{set})^p - 1]$ up to the point of trip. In an integral form, the decision to trip is made when:

$$\int_0^t \left(\left(\frac{I(t)}{I_{set}} \right)^p - 1 \right) \times dt \geq k \times T_b = const$$

A numerical relay must instead make a sum:

$$\Delta t \times \sum_{j=1}^{n} \left(\left(\frac{I(j)}{I_{set}} \right)^p - 1 \right) \geq k \times T_b = const$$

where:

j = 1	a fault has been detected, for the first time it is $I / I_{set} > 1$
Δt	time interval between two successive executions of earth fault function. If the earth fault protection is executed with the execution frequency f_{ex} = 50 Hz, then Δt = 1/50 s = 20 ms.
n	an integer, the number of the earth fault function execution intervals Δt from the inception of the fault to the point of time when the above condition for trip is fulfilled and trip command issued.
I(j)	the actual value of the fault current at point in time j.

28.3.4 Directional control of the earth fault time current protection (TEF)

The zero-sequence (residual) quantities (Uzs, -Izs) are applied to the directional element of the TEF. The TEF discriminates between earth faults on different sides (relative to the TEF location) by checking the phase position of the measured zero sequence current (-Izs) with respect to the measured zero sequence voltage (Uzs).

The magnitude of the zero sequence voltage can vary over a wide range. The zero sequence voltage will be a maximum at the fault location and will decrease in magnitude as the system earthing point is approached. The level of this voltage at the TEF location is a function of the ratio of the zero sequence impedance between the earth fault and the TEF, and the zero sequence impedance between the TEF and the system earthing point beyond the TEF. Thus the zero sequence voltage will be a maximum if the fault is at the TEF location and will decrease as the earth fault is moved away from the relay. The kind of power system earthing affects the zero sequence impedance greatly. In stations with large, solidly grounded transformers, the zero sequence voltage will be very low at the relay.

IThe lowset and the highset stages of the TEF are totally independent of each other with regard to directionality. They can be either directional or non-directional independent of each other. If both directional, they can look in opposite directions.

The RCA has a more clear physical ground in case of the TEF compared to overcurrent protection TOC.

For example, if a power system is earthed through a resistance, this will be dominant zero sequence impedance, and the relay may have RCA = 0 degrees. In case of solidly earthed power systems, the zero sequence impedance will be predominantly reactive and the zero sequence impedance angle may be as much as 70 to 87 degrees.

TEF can look into the power transformer (Reverse), or into the power system, away from the power transformer (Forward). This definition is valid for all power transformer sides. Two examples are given by means of Fig. 69 and Fig. 70.

Fig. 69 illustrates the case where TEF is set to look into the power transformer, i.e. Reverse. Because of Yd connection of power transformer, TEF cannot feel faults beyond the power transformer. As far as the earth faults in the Y winding of the power transformer are concerned, TEF only measures the contribution to the total earth fault current which flows from power system to the earth fault. If the circuit breaker on Y side is open, TEF cannot possibly detect such a fault.

Fig. 70 illustrates the case where TEF is set to look from the power transformer and into the power system left of the TEF point (Forward). Then earth faults left of the TEF position can be detected. TEF only measures the contribution to the total earth fault current which flows from power transformer to earth fault.

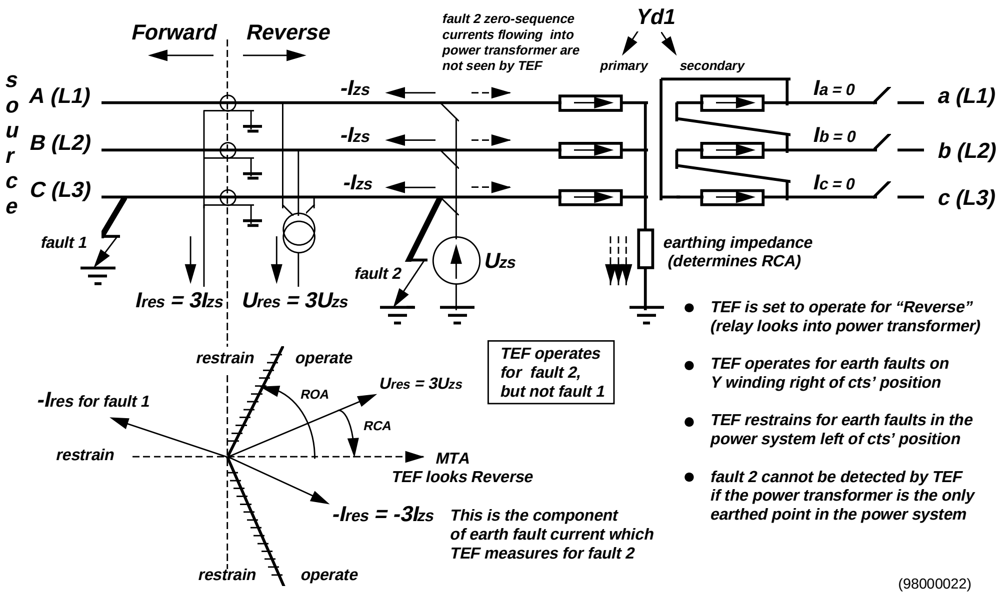


Fig. 69 TEF direction set to reverse

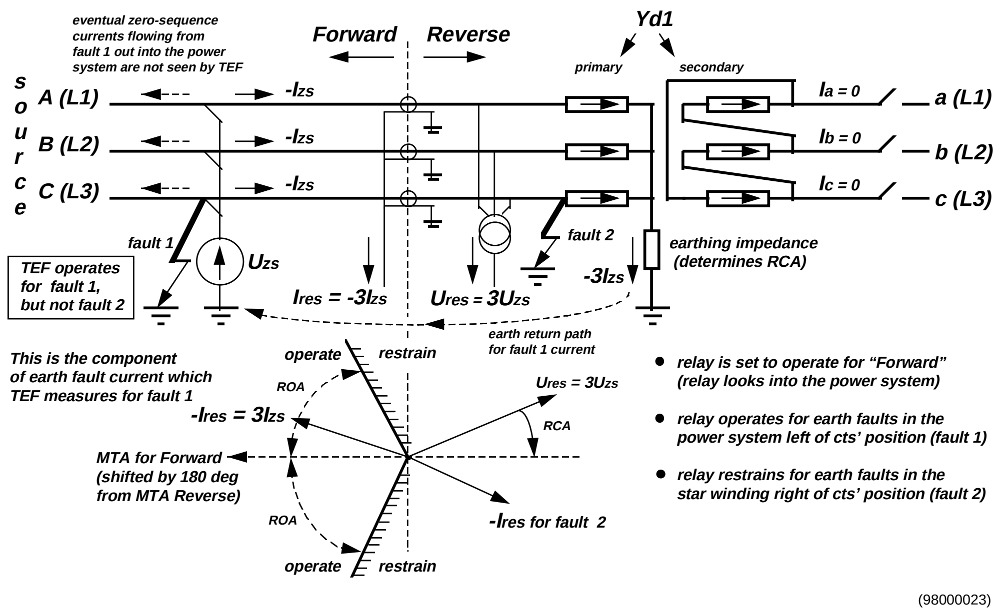


Fig. 70 TEF direction set to Forward

28.4 Logic diagram

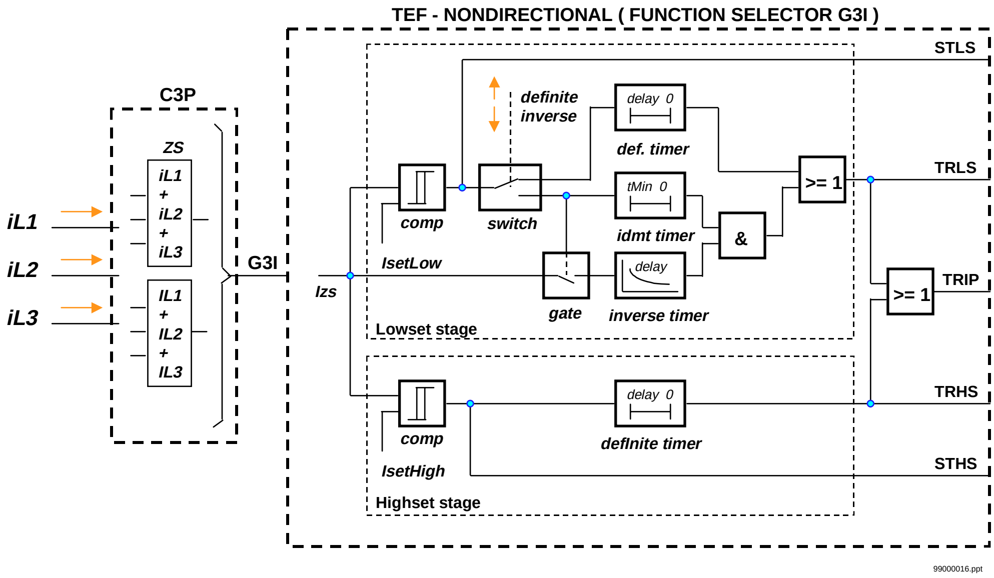


Fig. 71 *Earth fault protection operating on residual current which is supplied by current processing function block C3P.*

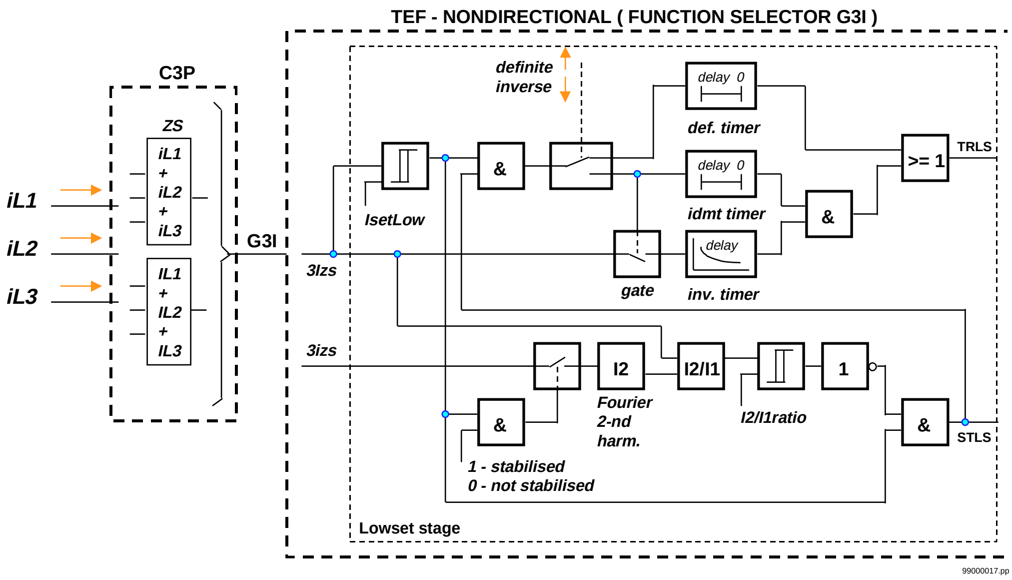


Fig. 72 *Earth fault protection operating on residual current which is supplied by current processing function block C3P. The 2-nd harmonic restrain option applied. Only lowset stage shown.*

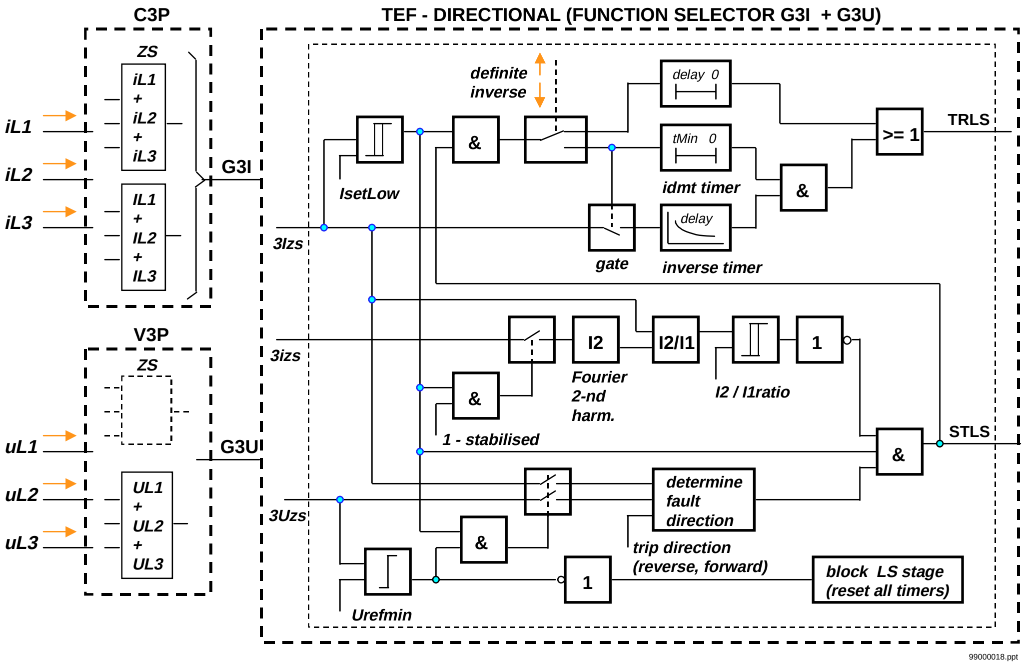
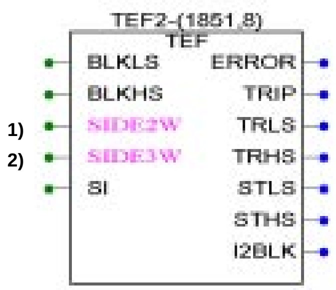


Fig. 73 Directional earth fault protection operating on residual current which is supplied by current processing function block C3P, and residual voltage supplied by voltage processing function block V3P. The 2-nd harmonic restrain option applied. Only lowset stage shown.

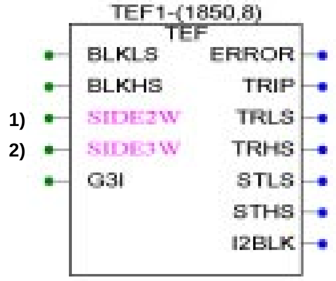
28.5 Function block

For Earth Fault Time Current Protection, TEF, there are six different looks of the function block.

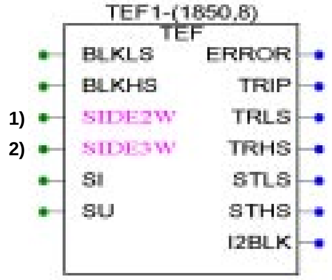
Nondirectional TEF (function selector set to SI) and Directional TEF but directional performance not used (function selector set to SI)
Residual or neutral current connected to the analogue input



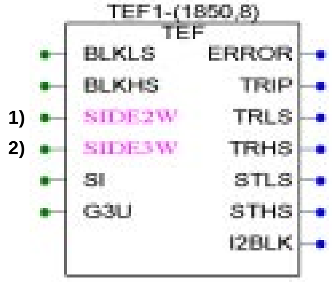
Nondirectional TEF (function selector set to G3I) and Directional TEF but directional performance not used (function selector set to G3I)
Residual current calculated internally



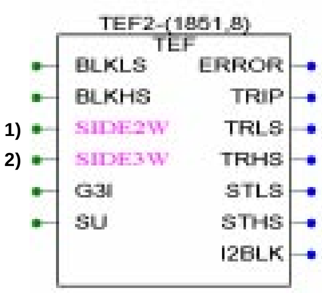
Directional TEF (function selector set to SI+SU)
Residual current and voltage connected to analogue inputs



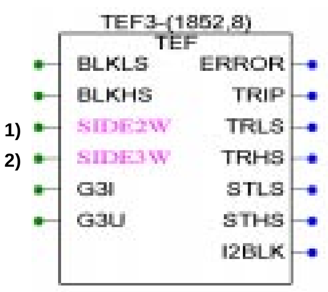
Directional TEF (function selector set to SI+G3U)
Residual current connected to analogue input, residual voltage calculated internally



Directional TEF (function selector set to G3I+SU)
Residual current calculated internally, residual voltage connected to analogue input



Directional TEF (function selector set to G3I+G3U)
Residual current and voltage calculated internally



1 Only applicable for 2-winding variant

2 Only applicable for 3-winding variant

28.6 Input and output signals

Table 77:

In:	Description:
TEFx-BLKLS	External block lowset, TEF1
TEFx-BLKHS	External block highset, TEF1
TEFx-SIDE2W	Transformer side, TEF1
TEFx-SIDE3W	Transformer side, TEF1
TEFx-SI	Single phase current, TEF1
TEFx-G3I	Three phase current group, TEF1
TEFx-SU	Single voltage, TEF1
TEFx-G3U	Three phase voltage group, TEF1

Table 78:

Out:	Description:
TEFx-ERROR	General TEF1 function error
TEFx-TRIP	Common trip TEF1
TEFx-TRLS	Trip lowset, TEF1
TEFx-TRHS	Trip highset, TEF1
TEFx-STLS	Start lowset, TEF1
TEFx-STHS	Start highset, TEF1
TEFx-I2BLK	Second harmonic block, TEF1

28.7 Setting parameters and ranges

Table 79:

Parameter:	Range:	Description:
Operation	0=Off, 1=On	Operation Earth Fault Time Current Protection, Off/On
IrUserDef	1 - 99999	Rated current for user defined side in A
IsetLow	3 - 500	Start current, lowset in % of Ir
IsetHigh	20 - 2000	Start current, highset in % of Ir
IStart	1.0 - 4.0	Start current limit factor for logarithmic (LOG)
CurveType	0 - 5	Time characteristic for TEF1, DEF/NI/VI/EI/LI/LOG
tDefLow	0.03 - 240.00	Definite delay lowset in sec.
tMin	0.05 - 1.00	Minimum operating time in sec.
tLog	0.03 - 10.00	Minimum operating time for LOG delay, in sec.
tDefHigh	0.03 - 10.00	Definite delay highset in sec.
k	0.05 - 1.10	Time multipler for inverse time function

Table 79:

Parameter:	Range:	Description:
2harLow	0=Off, 1=On	2nd Harmonic stabilization lowset, Off/On
2harHigh	0=Off, 1=On	2nd Harmonic stabilization highset, Off/On
I2/I1ratio	10 - 25	Second to first harmonic ratio in %
BlockLow	0=Off, 1=On	Block lowset, Off/On
BlockHigh	0=Off, 1=On	Block highset, Off/On
DirectionLow	0=NonDir, 1=Forward, 2=Reverse	Direction for trip, lowset, NonDir/Forward/Reverse
DirectionHigh	0=NonDir, 1=Forward, 2=Reverse	Direction for trip, highset, NonDir/Forward/Reverse
rca	0 - 90	Relay Characteristic Angle in deg.
roa	60 - 90	Relay Operate Angle in deg.
UrUserDef	1.0 - 999.9	Rated voltage for user defined side, in kV

28.8 Service report values

Table 80:

Parameter:	Range:	Step:	Description:
3Io	0.0 - 99999.9	0.1	EarthFault current in A
3Uo	0.0 - 999.9	0.1	EarthFault voltage in kV (Only valid for directional earth fault protection)

29 Single/three-phase time overvoltage protection (TOV)

29.1 Summary of application

Overvoltage protection is applied on power system elements, such as generators, transformers, motors and power lines in order to prevent excessive voltages that could damage the insulation and/or cause insulation breakdown.

Overvoltage can refer either to a high speed transient or to a sustained condition at power system frequency.

Transient voltages originate largely in the transmission system because of switching and atmospheric disturbances. Such surges are dealt with by different kind of equipment, such as for example diverters, connected to incoming lines or station busbars.

The TOV is concerned with power frequency overvoltages. Power frequency overvoltages may be caused by the following contingencies:

1 Defective operation of a voltage regulator,

2 Operation under manual voltage control,

3 Sudden loss of load on power lines or generators,

4 Phase-to-earth faults in power systems earthed via a high impedance, or unearthed.

29.2 Summary of function

- Single voltage, or three-phase voltage versions available.
- If single voltage input version, a phase-to-earth, or a phase-to-phase, or residual, or neutral point voltage can be applied as an input.
- If three-phase voltage version, three phase-to-earth voltages are applied as inputs. In this case each voltage can be processed separately, or residual voltage calculated and processed. If voltages are processed separately then it is possible to require that only one voltage above the limit is enough for a trip, or that all three voltages are exceeding the limit.
- TOV has a reset ratio of 0.96.
- TOV is an overvoltage protection with a lowset and a highset stage.
- The lowset stage has optionally a voltage independent (definite), or voltage dependent delay (Very Inverse). The inverse delay can not be shorter than the tMin which is settable.
- The highset stage can only have a voltage independent (definite) delay.

29.3 Measuring principles

29.3.1 General on TOV

The overvoltage protection TOV is fed with voltages of the fundamental power system frequency, all higher harmonic components are efficiently suppressed by the Fourier filters. This is particularly important for zero sequence voltage based overvoltage protections, which should not feel any third harmonic components, which are by nature of zero sequence.

Overvoltage protection TOV may optionally have the following inputs:

1 Three phase-to-earth (i.e. line, terminal) voltages, (TOV type G3U)

2 One single voltage, (TOV type SU). This single voltage can be optionally:

2.1 One phase-to-phase voltage, or phase-to-earth voltage.

2.2 Neutral point voltage, (i.e. voltage of the transformer neutral point to earth).

2.3 Residual voltage (from the open delta winding of the line voltage transformer).

A protection such as under 1. (Type G3U) operates on separate values of the three phase-to-earth voltages (L1, L2, L3), or the residual (i.e. 3*Uzs) voltage, which is constructed internally within RET from the three phase-to-earth voltages. The choice is made by the Function Selector (FS) in CAP 531.

Protections with inputs as under 2. (Type SU) are identical, it is only the input voltage which is different. A protection such as under 2.1 operates on the magnitude of the phase-to-phase or phase-to-earth input voltage. A protection as under 2.2 have the neutral point voltage as input. A protection as under 2.3 is fed by the residual voltage from an open-delta line voltage transformer.

- Function Selector = 1: TOV of type G3U, which operates on residual voltage 3*Uzs.
- Function Selector = 2: TOV of type G3U, which operates on separate phase voltages.
- Function Selector = 0: TOV of type SU, which operates on a single input voltage.

Protections which operate on the zero sequence type voltage, (residual or neutral point voltage) have usually the voltage settings which are below the rated voltage, while the protections which operate on phase-to-earth, or a phase-to-phase voltage have usually settings above the respective rated voltage value.

- The rated voltage is the phase-to-phase voltage, specified for the protected object (e.g. power transformer phase-to-phase rated voltage). All limits must be expressed in % of this voltage.
- TOV has a lowset stage, and a highset stage. A user sets the respective voltage limits for both stages. The highset stage can only be set to a value which is equal to, or higher than, the lowset limit.

The relevant voltages are always compared to the set limits. If excessive voltage has been noticed, a start signal (STLS or STHS on the TOV function block outout) is placed for that voltage. If the set limit has been exceeded for the first time, then a hysteresis is applied (that is a reset ratio, which is 0.96), so that the measured voltage must be lower than 0.96 times the lowset limit if the start signal is to be removed. Removal of a start signal may cause a timer to be reset, and a trip request signal to be removed. i.e. reset to 0.

Both the lowset stage, and the highset stage, can be blocked by an external block signal, (external to TOV, and external to RET 521) independently from each other. Besides, both the lowset stage, and/or the highset stage, can be blocked (disabled, deactivated) by a setting parameter, BlockLow, BlockHigh.

The delays are organized so that:

- The lowset stage has optionally definite, or voltage dependent (Very Inverse) delay,
- The highset stage has only definite, voltage independent delay.

Overvoltage Protection With Three Voltage Inputs (Type G3U)

This protection can be used as either a three-phase overvoltage protection, (Function Selector = 2), or residual voltage protection (Function Selector = 1). The choice is made in CAP 531.

29.3.2 The three phase overvoltage protection

If three phase-to-earth voltages are fed to TOV, and the protection is used as three-phase overvoltage protection (Function Selector = 2), then all three voltages are separately compared to the lowset stage limit. If excessive voltage has been noticed in a phase, a start signal (STLS) is placed by the lowset stage for the affected phase.

If a definite (voltage-independent) delay has been set by the user for the lowset stage, (setting: DelayType = DEF), then the following happens. The lowset stage has two definite timers. The first timer starts if at least one voltage has exceeded its limit, and the second timer starts if all voltages have exceeded the lowset limit. The first timer is reset to 0 if no start signals exist, while the second timer is reset to 0 unless all three start signals are placed. When the first timer reaches the set definite delay, a trip request signal is placed by TOV, which is called TRLSONE. If the other timer reaches the definite delay, a trip request is placed, which is called TRLSALL.

If the lowset stage uses Very Inverse delay (setting: DelayType = VI), then the following happens. The lowset stage has two “inverse” timers. The first timer starts if at least one voltage has exedeed its limit, and the second timer starts if all voltages have exedeed the lowset limit. The actually highest of the voltages is taken as a basis for the calculation of each inverse delay. One can make sure that the inverse delay can never be shorter than the so called Inverse Delay Minimum Time (IDMT) by setting an appropriate value for the respective setting, which is called tMin.

There are two IDMT timers. No trip request can be issued by the lowset stage unless both the tMin, and the inverse delay have been exceeded. When the first inverse timer passes the inverse delay, a trip request signal is placed, which is called TRLSONE. When the other inverse timer passes the set inverse delay, a trip request is placed, which is called TRLSALL.

The same procedure as described above, is used by the highset stage, with the difference, that the highset stage only has definite (voltage-independent) delay.

The TOV places a common trip request, if either of stages has issued its respective trip requests. There are two common signals. The first is called TRIPONE, and the second TRIPALL. A user may freely choose which one of the two common trip requests he or she will use by using the appropriate TOV function block output.

29.3.3 The residual voltage protection

If three phase-to-earth voltages are fed to TOV, and the protection is used as residual voltage protection, then the residual voltage is constructed from the three phase-to-earth phasors within a function block V3P, and its magnitude is calculated. This is then read by the TOV. This magnitude is then compared to the lowset stage limit. If excessive voltage has been noticed, a start signal (STLS) is placed by the lowset stage.

If a definite (voltage-independent) delay has been set (setting: CurveType = DEF) by the user for the lowset stage, then as long as the start signal is set, the lowset delay timer will continue to measure time. A trip request signal (TRLS) is issued by the lowset stage when the definite delay has been exceeded.

If the lowset stage uses Very Inverse delay (setting: CurveType = VI), then the residual voltage is taken as a basis for the calculation of the inverse delay. One can make sure that the inverse delay never will be shorter than the IDMT by setting an appropriate value for the respective setting, which is tMin. A trip request signal (TRLS) will be issued by the lowset stage when both the IDMT, and the inverse delay have been exceeded.

The residual voltage is also compared to the highset stage limit. If excessive voltage has been observed, a start signal (STHS) is placed by the highset stage. The highset stage has only a definite, that is voltage-independent delay. As long as the start signal is set, the highset delay timer will continue to measure time. A trip request signal (TRHS) will be issued by the highset stage when the definite delay has been exceeded.

The TOV places a common trip request (TRIP), if either of the stages has issued its respective trip requests.

29.3.4 Single input overvoltage protection

This protection (chosen by setting Function Selector = 1) can be used either as a:

- phase-to-phase (or phase-to-earth) overvoltage protection, or
- residual voltage protection, (input voltage from open delta voltage transformer),
- neutral voltage protection, (input voltage from a neutral point voltage transformer).

29.4 Logic diagrams

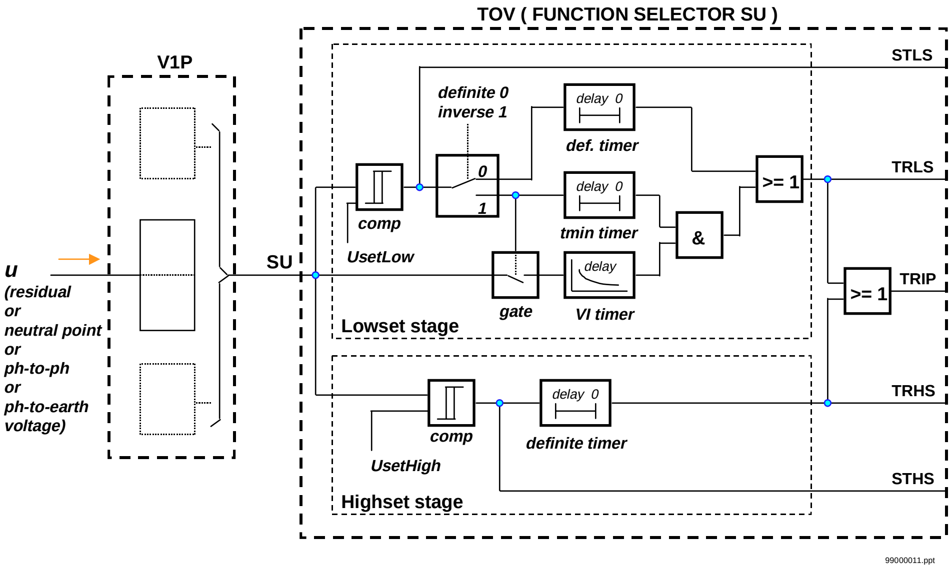


Fig. 74 A single voltage input version of TOV (Function Selector = SU)

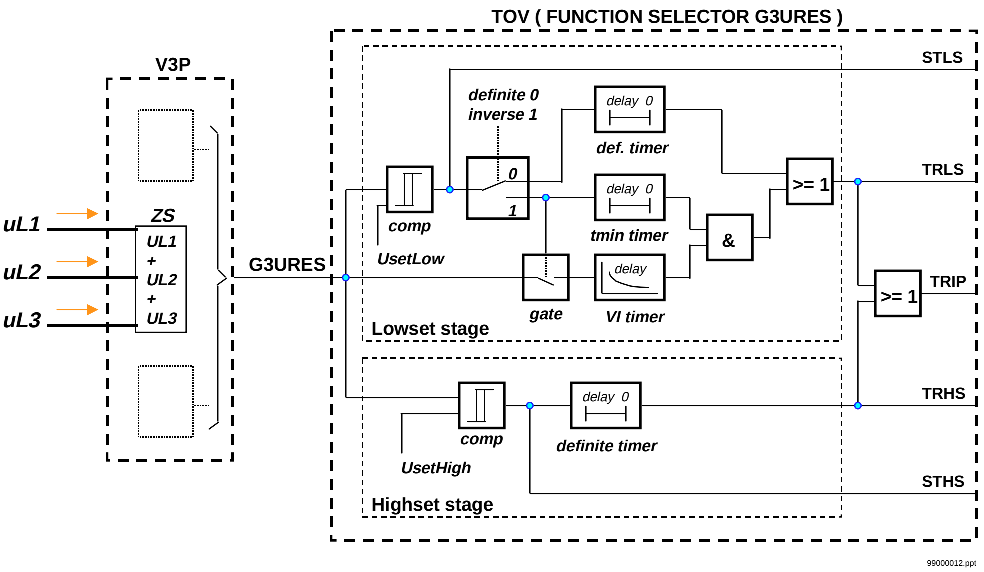


Fig. 75 A three phase voltage input version of TOV (Function Selector = G3URES)

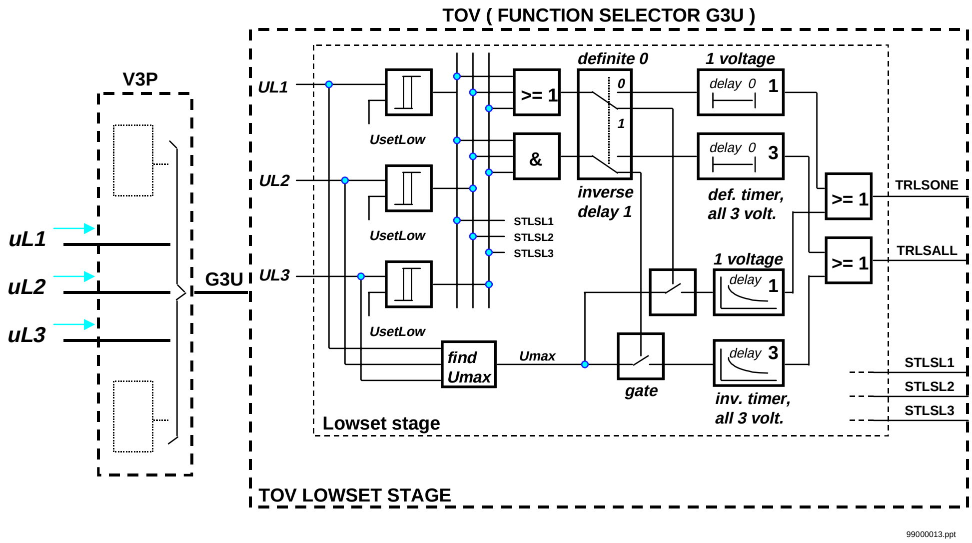
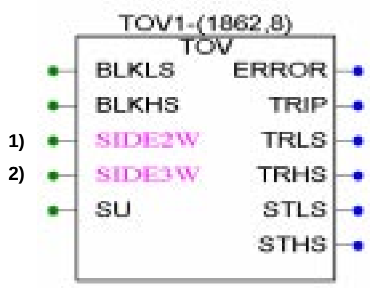


Fig. 76   A three phase voltage input version of TOV (Function Selector = G3U)

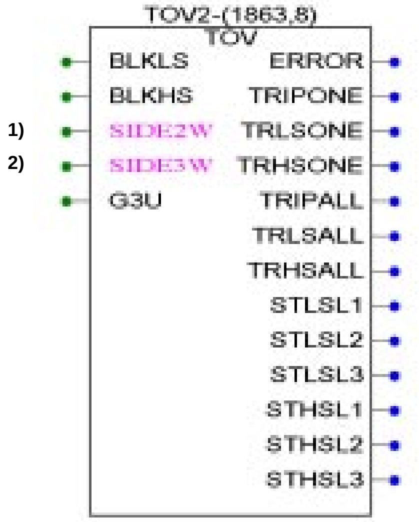
29.5 Function block

For the Single/Three-phase Time Overvoltage Protection, TOV, there are three possibilities of the look of the function block

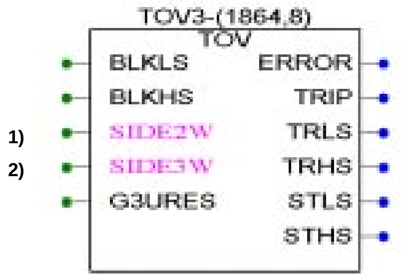
TOV (function selector set to SU)
Single phase, phase to phase, residual or neutral point voltage measurement



TOV (function selector set to G3U)
Three-phase voltage measurement



TOV (function selector set to G3URES)
Residual voltage calculated internally



1) Only applicable for 2-winding variant
2) Only applicable for 3-winding variant

29.6 Input and output signals

Table 81:

In:	Description:
TOV1-BLKLS	External block lowset, TOV1
TOV1-BLKHS	External block highset, TOV1
TOV1-SIDE2W	Transformer side, TOV1
TOV1-SIDE3W	Transformer side, TOV1
TOV1-SU	Single voltage, TOV1
TOV1-G3U	Three phase voltage group, TOV1
TOV1-G3URES	Residual voltage, TOV1

Table 82:

Out:	Description:
TOV1-ERROR	General TOV1 function error
TOV1-TRIP	Common trip TOV1
TOV1-TRLS	Trip lowset, TOV1
TOV1-TRHS	Trip highset, TOV1
TOV1-TRIPONE	Common trip at least one phase, TOV1
TOV1-TRLSONE	Trip lowset at least one phase, TOV1
TOV1-TRHSONE	Trip highset at least one phase, TOV1
TOV1-TRIPALL	Common trip in all phases, TOV1
TOV1-TRLSALL	Trip lowset in all phases, TOV1
TOV1-TRHSALL	Trip highset in all phases, TOV1
TOV1-STLS	Start lowset, TOV1
TOV1-STHS	Start highset, TOV1
TOV1-STLSL1	Start lowset, phase 1, TOV1
TOV1-STLSL2	Start lowset, phase 2, TOV1
TOV1-STLSL3	Start lowset, phase 3, TOV1
TOV1-STHSL1	Start highset, phase 1, TOV1
TOV1-STHSL2	Start highset, phase 2, TOV1
TOV1-STHSL3	Start highset, phase 3, TOV1

29.7 Setting parameters and ranges

Table 83:

Parameter:	Range:	Description:
Operation	0=Off, 1=On	Operation Time Overvoltage Protection, Off/On
UsetLow	5 - 200	Start voltage, lowset in % of Ur
UsetHigh	5 - 200	Start voltage, highset in % of Ur
CurveType	0=DEF, 1=VI	Time characteristic for TOV1, DEF/VI
tDefLow	0.03 - 120.00	Definite delay lowset in sec.
tMin	0.05 - 1.00	Minimum operating time in sec.
tDefHigh	0.03 - 60.00	Definite delay highset in sec.
k	0.05 - 1.10	Time multiplier for inverse time function
BlockLow	0=Off, 1=On	Block lowset, Off/On
BlockHigh	0=Off, 1=On	Block highset, Off/On

29.8 Service report values

Table 84:

Parameter:	Range:	Step:	Description:
Umax	0.0 - 999.9	0.1	Highest of measured voltages in kV

30 Single/three-phase time undervoltage protection (TUV)

30.1 Summary of application

Undervoltage protection is applied on power system elements, such as generators, transformers, motors and power lines in order to detect low voltage profiles that could be a sign that abnormalities, such as short circuits, have happened. An undervoltage protection may also be used to produce a signal that an apparatus, such as a power transformer, is not energized.

The undervoltage protection is often applied in systems with motor drives. Sometimes, the undervoltage protection is used to control, or restrain, the overcurrent protections. It is also possible to have it the other way around, where a trip signal from undervoltage protection is logically combined with some overcurrent protection trip request.

Undervoltages may be caused by the following contingencies:

1 Defective operation of a voltage regulator (usually a symmetrical phenomenon),

2 Operation under manual voltage control, (usually a symmetrical phenomenon),

3 Overloads (usually a symmetrical phenomenon),

4 Short circuits (usually an unsymmetrical phenomenon).

30.2 Summary of function

Features for the undervoltage protection:

- The TUV issues start and trip signals when the voltage is below certain levels
- Function block representation in CAP531
- Single voltage, or three-phase voltage versions available.
- If single voltage input version, a phase-to-earth, or a phase-to-phase can be applied as an input.
- If three-phase voltage version, three phase-to-earth voltages are applied as inputs. In this case each voltage can be processed separately. If voltages are processed separately then it is possible to require that only one voltage below the limit is enough for a trip, or that all three voltages are below the limit.
- TUV has a reset ratio of 1.01.
- TUV is an undervoltage protection with a lowset and a highset stage.
- The lowset and highset stage have only voltage independent (definite) delay.

30.3 Measuring principles

30.3.1 General

Depending on which variant selected , the function input can be either a phase-to-earth or phase-to-phase voltage, or a three phase phase-to-earth voltage. When either a single voltage or all voltages is below a set level a trip delay timer starts.Trip is issued when elapsed time exceeds the set time delay. Both variants have two independent stages, lowset and highset. Any winding of the power transformer can be connected.

30.3.2 Function selector

Which kind of input voltage is selected with the function selector in CAP 531 applied before placing a TUV block, and chooses between single voltage input, SU, or three phase voltage group input, G3U.

30.3.3 Application of function inputs

30.3.3.1 External block inputs, BLKLS and BLKHS

Blocking is possible by using the inputs BLKLS, external block lowset, and BLKHS, external block lowset. It is possible to block lowset and highset stage independently. The blocking prohibit the outputs from being set, but the service value Umin is displayed.

It is also possible to block TUV in test mode by setting BlockTUV = On from the HMI, or by altering the settings BlockLow or BlockHigh

Note: While blocked, TUV internal operation will continue and service values will be updated. Enabling or disabling of test mode or the settings BlockLow and BlockHigh will reset the TUV, i.e. all timers and service values will be reset.

30.3.3.2 Analog inputs with function selector SU

The input SU can be connected to:

- SU output on the V1Px function block.
- SU1, SU2 or SU3 output on the V3Px function block.

30.3.3.3 Analog inputs with function selector G3U

The input G3U can be connected to:

- G3U output on the V3Px function block.

30.3.4 Application of function outputs

30.3.4.1 Outputs with function selector set to SU

Start signals, STLS and STHS

The signal STLS, start lowset, is set when Umin, the measured voltage, gets lower than UsetLow, the start voltage lowset in % of Urated.

STLS is reset when Umin is 101% of UsetLow. The signal STHS, start highset, operates in the same way, with the exception that Umin is compared to UsetHigh, the start voltage highset.

Trip signals, TRIP, TRLS and TRHS

The signal TRIP, common trip, is set if TRLS, trip lowset or TRHS, trip highset is set.

The signal TRLS is set when tElapsed, the time elapsed since the start signal STLS was set, gets longer than tDefLow, the definite delay lowset. The signal TRHS operates in the same way, with the exception that tElapsed is compared to tDefHigh, the definite delay highset.

Resetting STLS also resets the TRIP timer.

Error signal, ERROR

The signal ERROR, general function error, is set if:

- parameter SIDE2W or SIDE3W is set to No, or:
- The analog input SU is connected to SUNOVAL, or:
- Some error in the configuration of the analog input SU.

30.3.4.2 Outputs with function selector set to G3U

With the function selector set for three phase inputs, each phase will have ints individual settings and signals. To simplify descriptions, where applicable, signals and settings will be described only once, having the designation *n*, to mark the possible individual set of signals. *n* can be a integer between 1 and 3.

Start signals, STLSL*n* and STHSL*n*

The signal STLS*n*, start lowset, is set when Umin, the measured voltage, gets lower than UsetLow, the start voltage lowset in % of Urated.

STLS*n* is reset when Umin is 101% of UsetLow. The signal STHS, start highset, operates in the same way, with the exception that Umin is compared to UsetHigh*n*, the start voltage highset.

Trip signals, TRIPONE, TRLSONE and TRHSONE

The signal TRIPONE, common trip at least one phase, is set if TRLSONE or TRHSONE is set.

The signal TRLSONE, trip lowset one phase, is set when the time elapsed since any of the the start signals STLS1, STLS2 or STLS3 was set, gets longer than tDefLow, the definite delay lowset. The signal TRHSONE operates in the same way, with the exception that the elapsed time is compared to tDefHigh, the definite delay highset.

Resetting any of STLS1, STLS2 or STLS3 also resets the TRIPONE timer.

Trip signals, TRIPALL, TRLSALL and TRHSALL

The signal TRIPALL, common trip all phases, is set if TRLSALL or TRHSALL is set.

The signal TRLSALL, trip lowset all phases, is set when the time elapsed since all of the the start signals STLS1, STLS2 or STLS3 was set, gets longer than tDefLow, the definite delay lowset. The signal TRHSALL operates in the same way, with the exception that the elapsed time is compared to tDefHigh, the definite delay highset.

Resetting any of STLS1, STLS2 or STLS3 also resets the TRIPALL timer.

Error signal, ERROR

The signal ERROR, general function error, is set if:

- parameter SIDE2W or SIDE3W is set to No, or:
- The analog input G3U is connected to G3UNOVAL, or:
- Some error in the configuration of the analog input G3U.

30.3.5 Settings

The setting Operation, Operation Time Undervoltage Protection, switch the TUV Off or On. No outputs or service values are shown when operation = Off.

The setting UsetLow, start voltage lowset in % of Ur, is used to set the desired voltage level for lowset. The setting is multiplied by the rated voltage for the selected side for the power transformer.

Example: The parameter SIDE2W = Pri, and the rated voltage for primary side is 100.0 kV. The setting UsetLow is set to 50%. The set level is 50 % * 100.0 = 50.0 kV.

The setting UsetHigh, start voltage lowset in % of Ur, is similar to the setting UsetLow.

The setting tDefLow, definite delay lowset in sec, defines the desired delay from start lowset to trip lowset.

The setting tDefHigh, definite delay highset in sec, is similar to tDefLow.

The setting BlockLow, block lowset, block lowset stage. No output signals from lowset stage is set.

The setting BlockHigh, is similar to BlockLow.

30.3.5.1 Parameter settings CAP 531

The TUV has one parameter setting in the CAP 531, SIDE2W when the terminal is ordered for use with a two winding power transformer, or SIDE3W, when ordered for use with a three winding power transformer.

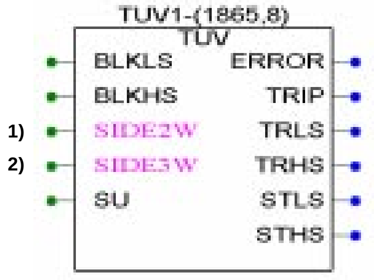
30.3.6 Application of function service values

The service value Umin, shows, depending of the function selector, the measured voltage in kV (function selector set to SU)or the lowest of the measured voltages in kV (function selectorset to G3U).

30.4 Function block

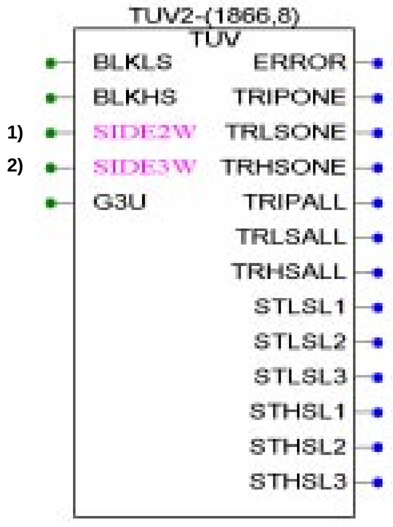
Depending on the function selector setting, one of two possible function block instances will be created:

With function selector set to SU:



Single-phase or phase to phase voltage measurement.

With function selector set to G3U:



Three phase voltage measurement.

1 Two winding systems only

2 Three winding systems only

30.5 Input and output signals

Table 85: Input signals

In:	Description:
TUVx-BLKLS	External block lowset
TUVx-BLKHS	External block highset

Table 85: Input signals

In:	Description:
TUVx-SIDE2W	Transformer side
TUVx-SIDE3W	Transformer side
TUVx-SU	Single voltage
TUVx-G3U	Three phase voltage group

Table 86: Ouput signals with function selector set to SU

Out:	Description:
TUVx-ERROR	General TUV function error
TUVx-TRIP	Common trip
TUVx-TRLS	Trip lowset
TUVx-TRHS	Trip highset
TUVx-STLS	Start lowset
TUVx-STHS	Start highset
TUVx-STLSL	Start lowset
TUVx-STHSL	Start highset

Table 87: Ouput signals with function selector set to G3U

Out:	Description:
TUVx-ERROR	General TUV function error
TUVx-TRLS	Trip lowset
TUVx-TRHS	Trip highset
TUVx-TRIPONE	Common trip at least one phase
TUVx-TRLSONE	Trip lowset at least one phase
TUVx-TRHSONE	Trip highset at least one phase
TUVx-TRIPALL	Common trip in all phases
TUVx-TRLSALL	Trip lowset in all phases
TUVx-TRHSALL	Trip highset in all phases
TUVx-STLS	Start lowset
TUVx-STHS	Start highset
TUVx-STLSL1	Start lowset, phase 1
TUVx-STLSL2	Start lowset, phase 2
TUVx-STLSL3	Start lowset, phase 3

Table 87: Ouput signals with function selector set to G3U

TUVx-STHSL1	Start highset, phase 1
TUVx-STHSL2	Start highset, phase 2
TUVx-STHSL3	Start highset, phase 3

30.6 Setting parameters and ranges

Table 88:

Parameter:	**Range**	**Description**
Operation	0=Off, 1=On	Operation Time Undervoltage Protection, Off/On
UsetLow	5 - 130	Start voltage, lowset in % of Ur
UsetHigh	5 - 130	Start voltage, highset in % of Ur
tDefLow	0.03 - 120.00	Definite delay lowset in sec.
tDefHigh	0.03 - 120.00	Definite delay highset in sec.
BlockLow	0=Off, 1=On	Block lowset, Off/On
BlockHigh	0=Off, 1=On	Block highset, Off/On

30.7 Service report values

Table 89:

Parameter:	**Range:**	**Step:**	**Description:**
Umin	0.0 - 999.9	0.1	Lowest of measured voltages in kV

31 Thermal overload protection (THOL)

31.1 Summary of application

Transformers which can have load currents above permissible continuous currents, are vulnerable to thermal damage to the paper insulation, caused by a winding hot spot temperature. The main purpose for the thermal overload function (THOL) in RET 521 is to prevent such damages, and at the same time better utilise the capacity of the protected transformer.

The THOL function in RET 521 can be used as an alternative or backup to temperature devices mounted on the transformer. It should be noted that this protection calculates the transformer thermal content without any compensations for ambient temperature. There is however a built-in compensation for transformers with forced cooling which can be activated by the cooling equipment via a binary input.

A thermal overload can be caused by situations such as:

1. Overload, i.e. transferring power that exceeds the rating of the unit
2. External fault not cleared fast enough
3. Failure of the cooling system
4. High ambient temperature
5. Other abnormalities such as low frequency, high voltage, current distortion or phase voltage unbalance.

Note: A moderately high winding temperature during long periods of time will result in faster ageing of transformer insulation. High winding temperatures can lead to insulation failure, even when occuring during short time periods.

31.2 Summary of function

Features for the THOL function in RET 521:

- The THOL function uses a heat content model (without ambient temperature measuring input).
- The THOL function issues alarm and trip signals when the heat content is above certain levels.
- A lock-out function insures that the transformer is cooled off properly before it is allowed to be reconnected.
- Functionality for a transformer with extra cooling is provided.
- Supervision of process parameters and output signals is provided.
- Function block representation in CAP 531.

31.3 Measuring principles

31.3.1 General

The function is fed with three phase currents of which the function selects the highest current. The highest current is then used in the heat content calculations. The calculation of the heat content is based on the fact that the temperature in the windings is proportional to the square of the current, and that the temperature increases and decreases exponentially with a certain time constant, see the following equations:

When $\Theta_{\mathrm{stat}} > \Theta_n$:

$$\Theta_{n+1} = \Theta_n + (\Theta_{\mathrm{stat}} - \Theta_n) \times \left(1 - e^{-\frac{\Delta t}{\tau}}\right)$$

When $\Theta_{\mathrm{stat}} < \Theta_n$:

$$\Theta_{n+1} = \Theta_{\mathrm{stat}} - (\Theta_{\mathrm{stat}} - \Theta_n) \times e^{-\frac{\Delta t}{\tau}}$$

Θ_n	Actual heat content
Θ_{n+1}	New actual heat content
Θ_{stat}	Steady state (final) heat content
Δt	Time step
τ	Time constant

31.3.2 Application of function outputs

Trip signal, TRIP

When the heat content, Θ_n, exceeds the overload level, Θ_{trip}, the function sets the TRIP signal, where Θ_{trip} is defined as the square of Itr (see Setting parameters and ranges). The signal is set during one execution loop (approximate 200ms).

Lock-out signal, LOCKOUT

To insure that the heat content has decreased to an acceptable level before the transformer is allowed to be reconnected, the LOCKOUT signal is set. The setting parameter ResetLockOut defines the heat content level for the LOCKOUT signal to reset.

Alarm signal, ALARM1 and ALARM2

The THOL function gives alarms (in two stages) if the heat content exceeds the levels Alarm1 or Alarm2 (see Setting parameters and ranges). The alarm signals are reset if the heat content falls 2% below the alarm level.

31.3.3 Function service values

Time to trip

The service value TimeToTrip is activated when the steady state heat content, Θ_{stat}, arises above trip level. The status of the TimeToTrip service value is indicated by the service value TimeToTrCalc that shows three different values: NotActive, *>1.3**TimeConst and Active.

NotActive indicates that the steady state heat content level is below Θ_{trip}. TimeToTrip is therefore showing the prediction horizon (650 min).

*>1.3**TimeConst indicates that the steady state heat content level is above Θ_{trip}, but predicted trip time is greater than 1.3 times selected time constant of the object, that is, the TimeToTrip value is still showing the prediction horizon.

Active indicates that the steady state heat content level is above Θ_{trip}, and that trip is estimated within the prediction horizon. At this stage the actual time to trip is continuously shown by the TimeToTrip service value

When $\Theta_{stat} > \Theta_{trip}$:

$$\text{TimeToTrip} = \tau \times \ln\frac{\Theta_{stat} - \Theta_n}{\Theta_{stat} - \Theta_{trip}}$$

Θ_n	Actual heat content
Θ_{trip}	Heat content trip level
Θ_{stat}	Steady state (final) heat content

Time to reset

The service value TimeToReset works very much as the TimeToTrip service value. The difference is that now we calculate the time until the LOCKOUT signal should be reset after a trip has been issued. The service value TimeToRstCalc shows the status of the TimeToReset value.

$$\mathrm{TimeToReset} = \tau \times \ln \frac{\Theta_n}{\Theta_{\mathrm{reset}}}$$

Θ_n	Actual heat content
Θ_{reset}	Heat content lockout reset level

Measured current

The service value Imeasured shows the value of the current which contributes to the heat content level in the transformer. The value shown is the highest of the three phase currents fed to the function.

Actual heat content level

The service value ThermalStatus shows the actual heat content level in percentage of Θ_{trip}.

31.3.4 Application of function inputs

Block input, BLOCK

The THOL function is possible to block, i.e. prohibit the outputs TRIP, LOCKOUT, ALARM1 and ALARM2 from being set. It should be noted that THOL continues the calculations of heat content and updating of service values. Setting the input BLOCK to true has the same meaning as enabling Test mode and setting the parameter Block-THOL=On with one difference: enabling/disabling test mode will reset the THOL function, i.e. force the THOL to restart. Same functionality can be obtained by using the input RESET, see below.

Cooling enabled input, COOLING

In order to get a more flexible application for transformers with forced cooling the THOL function is fitted with the COOLING input. In short, the status of the input decides which base current and time constant the heat content model shall use. The relation between COOLING input status and settings is described in Table 90:. When there is a change between the two modes, the relative heat content in per cent is maintained.

Table 90: Application of input COOLING

Status	Setting parameter
COOLING=0	Ib1, TimeConstant1
COOLING=1	Ib2, TimeConstant2

Reset input, RESET

The THOL function performs integration with long time constants which might cause problems, normally during testing of the function. By setting the RESET input the heat content is reset to its initial value defined by the setting ThetaInit and the LOCKOUT, ALARM1 and ALARM2 output signals are set to zero. The value of ThetaInit is always used for initialization of the heat content level at terminal startup or after saving new settings/configurations.

31.3.5 Application of inputs G3I and SIDE2W/SIDE3W

The THOL function block should usually be connected to the transformer primary side to incorporate all losses in the measured currents.

The SIDE2W input parameter selects the winding on which the THOL function is connected. If THOL is connected to the primary side, select Pri, on secondary side, select Sec. For three winding terminals SIDE3W is shown with the additional alternative Ter, tertiary side.

Connect the G3I input on THOL function block to the G3I output on the C3Px/C3Cx function block that forms e.g. the primary side currents.

When the G3I input has been correctly configured and SIDE2W/SIDE3W=NoSide, THOLs error output, ERROR, is set. Downloading CAP-configuration with SIDE2W/SIDE3W=Pri/Sec/Ter solves the problem.

Note: SIDE2W is active only for a two winding terminal and SIDE3W is active only for a three winding terminal.

31.4 Logic diagram

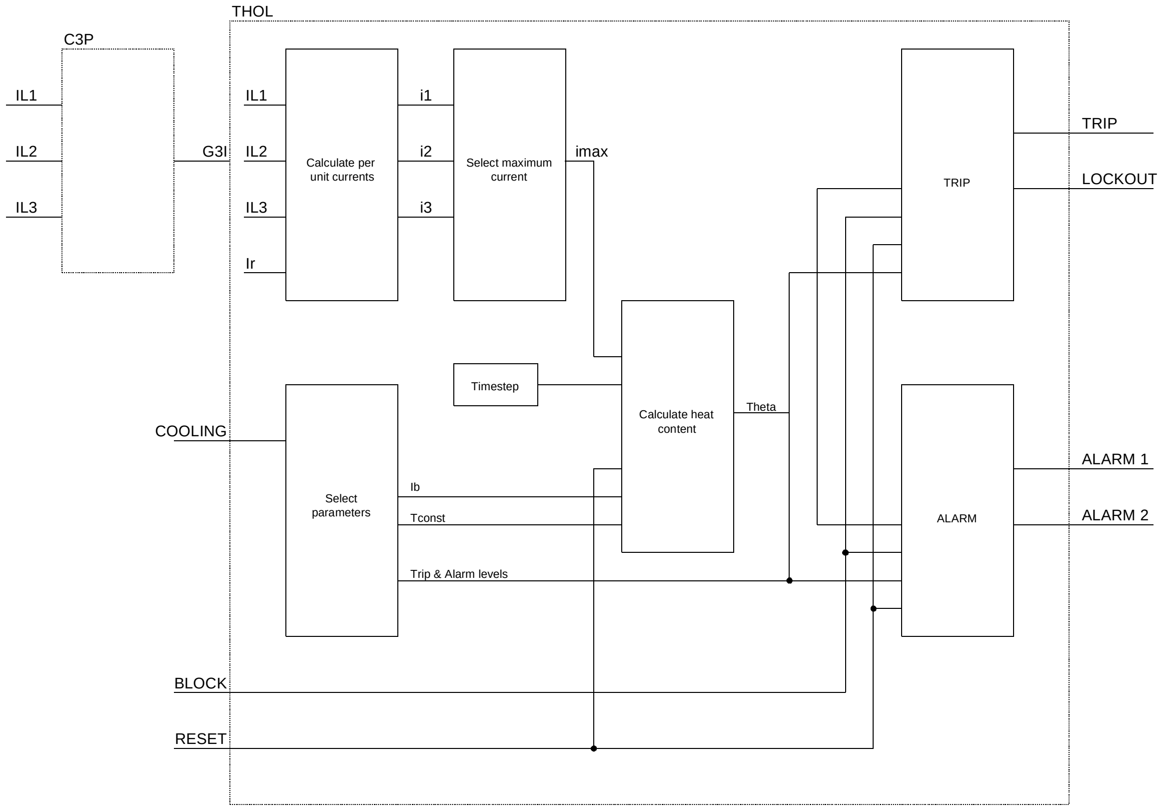
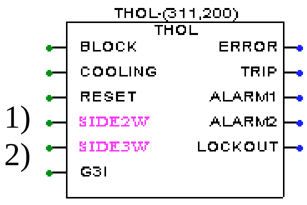


Fig. 77

31.5 Function block



1 Two winding systems only

2 Three winding systems only

31.6 Input and output signals

Table 91:

In:	Description:
THOL-BLOCK	External block, THOL
THOL-COOLING	Transformer extra cooled, changes Ib and time constant, THOL
THOL-RESET	Reset heat content and lockout function, THOL
THOL-SIDE2W	Transformer side, THOL
THOL-G3I	Three phase current group, THOL
THOL-SIDE3W	Transformer side, THOL

Table 92:

Out:	Description:
THOL-ERROR	General THOL function error
THOL-TRIP	Common trip THOL
THOL-ALARM1	First heat content alarm, THOL
THOL-ALARM2	Second heat content alarm, THOL
THOL-LOCKOUT	Transformer locked-out by thermal overload trip, THOL

31.7 Setting parameters and ranges

Table 93:

Parameter:	Range:	Description:
Operation	0 - 1	Operation Thermal Overload Protection, Off/On
Ib1	30 - 250	Normal base current, in % of Ir
Ib2	30 - 250	Base current with true COOLING input signal in % of Ir
Itr	50 - 250	Thermal overload steady state trip current in % of Ibx
ThetaInit	0 - 95	Initial heat content in % of heat content trip
TimeConstant1	1 - 500	Normal time constant, in min, used with Ib1
TimeConstant2	1 - 500	Time constant, in min, used with Ib2
Alarm1	50 - 99	1:st alarm level, in % of heat content trip value
Alarm2	50 - 99	2:nd alarm level, in % of heat content trip value
ResetLockOut	10 - 95	Lockout reset level in % of heat content trip

31.8 Service report values

Table 94:

Parameter:	Range:	Step:	Description:
Imeasured	0 - 250	1	Measured current in % of thermal overload base current
ThermalStatus	0 - 999	1	Thermal status in % of heat content trip level
TimeToReset	1 - 650	1	Time to reset lockout function, in min.
TimeToRstCalc	0 - 2	1	Time to reset lockout calc. NotActive/ >1.3*TimeConst/Active
TimeToTrCalc	0 - 2	1	Time to trip calc. NotActive/>1.3*Time-Const/Active
TimeToTrip	1 - 650	1	Time to trip thermal overload, in min.

32 Overexcitation protection (V/Hz) (OVEX)

32.1 Summary of function

- Importance of overexcitation protection is growing.
- Modern transformers are more sensitive to overexcitation than earlier types.
- Overexcitation results from excessive voltage and below-normal frequency.
- Overexcitation protection is based on calculation of Volts per Hertz.
- Internal voltage can be calculated if leakage rectance of the winding is known, and relevant currents fed to OVEX function block.
- OVEX may be applied on any transformer side, independent of load flow.
- OVEX shall not be aplied on the power transformer side with an OLTC.
- Regarding inputs to OVEX, there are two versions available: the first operating on a single phase-to-phase voltage and two terminal currents, and the second operating on three phase-to-earth voltages and three terminal currents.
- Both OVEX versions are fed with by FRME measured system frequency in Hz.
- Nominal frequency range of OVEX is 0.7 - 1.2 rated frequency.
- Voltage must be over 0.7 rated voltage for OVEX to calculate excitation.
- Actual excitation of the power transformer can be read as a service value.
- There are two types of delay available: the IEEE-, and Tailor-Made law.
- Each type of delays can be further modified by definite maximum, and minimum delays. These extra definite delays are used at very low and very high overexcitations.
- Time to trip service value is available. It can be useful at lower degrees of overexcitation with long delays.
- When an overexcitation condition occurs, an alarm signal is issued after an independent delay.
- The overexcitation is basically a thermal protection. An exponential cooling process has been assumed. The cooling time constant is a setting parameter. If an overexcitation condition returns before the core has cooled down, the delays will be shorter than they would be otherwise.

32.2 Logic diagram

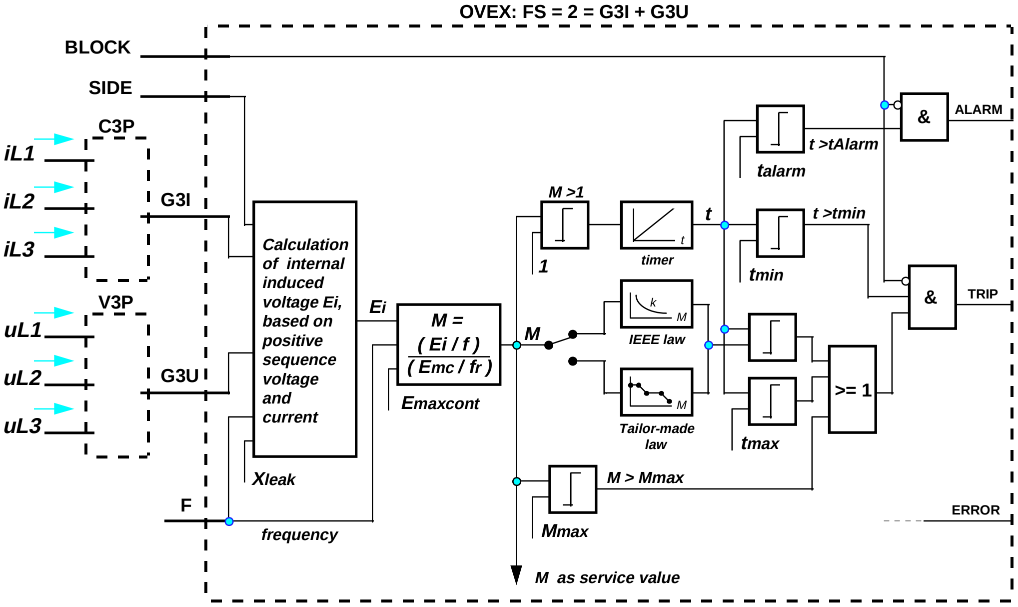


Fig. 78 OVEX with the function selector set to G3I+G3U

The above figure shows a simplified logic diagram of the overexcitation protection function, function selector G3I+G3U, which can be applied when all three phase-to-earth voltages are connected to the terminal. Simplification of the block diagram is in the way the IEEE and tailor-made delays are calculated. Also, the cooling process is not shown.

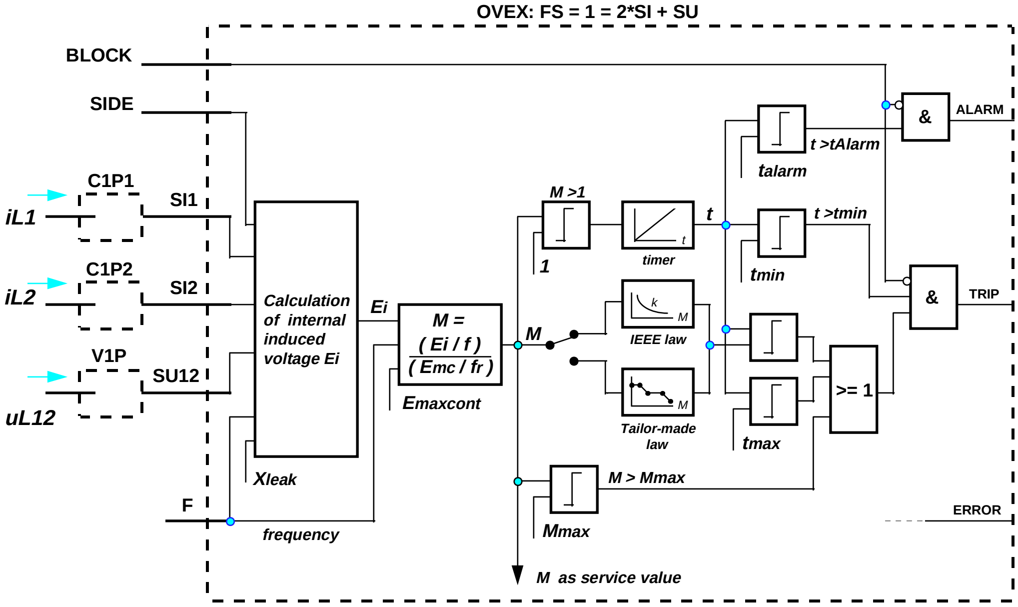


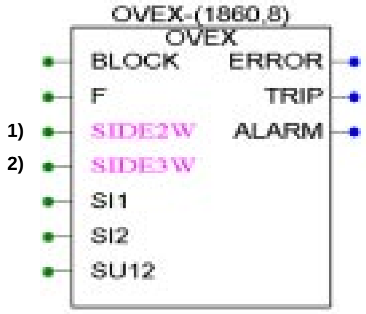
*Fig. 79 OVEX with the function selector set to 2*SI+SU*

The above figure shows a simplified logic diagram of the overexcitation protection function with the function selector set to 2*SI+SU, which can be applied when only one phase-to-phase voltage is connected to RET 521. Simplification of the block diagram is in the way the IEEE and tailor-made delays are calculated. Also, the cooling process is not shown.

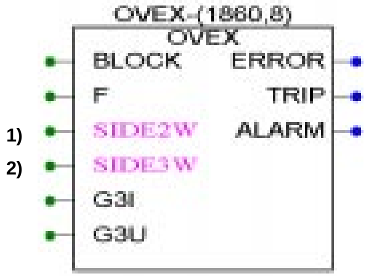
32.3 Function block

For Overexcitation Protection, OVEX, there are two different looks of the function block.

OVEX (function selector set to 2*SI+SU)
Two phase currents and corresponding phase to phase voltage used



OVEX (function selector set to G3I+G3U)
Three-phase currents and three-phase voltages used



1) Only applicable for 2-winding variant
2) Only applicable for 3-winding variant

32.4 Input and output signals

Table 95:

In:	Description:
OVEX-BLOCK	External block, OVEX
OVEX-F	Actual frequency, OVEX
OVEX-SIDE2W	Transformer side, OVEX
OVEX-SIDE3W	Transformer side, OVEX
OVEX-SI1	Single phase current 1, OVEX
OVEX-SI2	Single phase current 2, OVEX
OVEX-G3I	Three phase current group, OVEX
OVEX-SU12	Phase-to-phase voltage, OVEX
OVEX-G3U	Three phase voltage group, OVEX

Table 96:

Out:	Description:
OVEX-ERROR	General OVEX function error
OVEX-TRIP	Common trip OVEX
OVEX-ALARM	Alarm limit exceeded, OVEX

32.5 Setting parameters and ranges

Table 97:

Parameter:	Range:	Description:
tTRIP	1 - 120	Time to trip overexcitation, in min.
V/Hz	0 - 1000	Relative voltage to frequency ratio, in %
Operati	0 - 1	Operation Overexcitation Protection (V/Hz),
Emaxcon	1.00 - 1	Emax continous no-load, in p.u.
Emax	1.20 - 1	Excitation with tMin delay, in p.u.
tMin	0.50 - 3	Minimum operating time in sec.
tMax	10 - 120	Maximum time delay for overexcitation, in min
k	1 - 60	Time multiplier for inverse time function
Tcool	5 - 120	Transformer cooling time constant, in min.
tAlarm	0 - 120	Time delay for alarm, in sec.
t1	0 - 7200	Time value in sec. for Time 1
t2	0 - 7200	Time value in sec. for Time 2
t3	0 - 7200	Time value in sec. for Time 3
t4	0 - 7200	Time value in sec. for Time 4
t5	0 - 7200	Time value in sec. for Time 5
t6	0 - 7200	Time value in sec. for Time 6
CurveTy	0 - 1	Time characteristic for OVEX , IEEE/Tailor made
Xleak	0.000 - 0.250	Winding reactance in p.u. Sr base
FS_OVEX	0 - 2	Function selector for Overexcitation Protect

32.6 Service report values

Table 98:

Parameter:	Range:	Step:	Description:
tTRIP	0 - 7200	1	Time to trip overexcitation, in sec.
V/Hz	0.000 - 2.000	0.001	Relative voltage to frequency ratio.

33 Voltage control (VCTR)

33.1 Summary of function

The voltage control function should be used for control of power transformers with a motor driven on-load tap changer. The function is design to regulate the voltage at the secondary side of the power transformer. Control method is based on the step-by-step principle, which means that a control pulse, one at the time, will be issued to the tap changer mechanism to move it up or down for one position. Length of the control pulse can be set within wide range to accommodate different types of tap changer mechanisms. The pulse is generated by the VCTR whenever the measured voltage, for a given time, deviates from the set reference value by more then the preset deadband (i.e. degree of insensitivity). Time delay is used to avoid unnecessary operation during brief voltage deviations from the set value.

The VCTR function is designed in such a way that always issues RAISE command in order to increase the voltage, and LOWER command in order to decrease the voltage.

The function can also include an option for parallel control of up to four power transformers, based on the circulating current method, with terminal-to-terminal communication via LON bus.

33.2 Measuring principles

33.2.1 VCTR Operation Mode (i.e. Control Location)

It is possible to have the following human-machin-interfaces (i.e. HMI) and four operation modes (i.e. locations from where tap changer can be manually operated) for VCTR function in RET 521:

1 Internal HMI with operation mode (i.e. operation location)

- RET 521 built-in HMI

2 External HMI with operation modes (i.e. operation location)

- Local control panel (usually traditional control panel with selector switches)
- Station Control (station control system i.e. SCS)
- Remote Control (SCADA system)

33.2.2 Control Mode

The control mode of the VCTR can be:

- Manual
- Automatic

The control mode can be changed via the command menu in the built-in HMI when the operation mode is IntMMI or remotely via binary signals connected to the VCTR function block when the operation mode is ExtMMI.

33.2.3 Measured Quantities

The secondary side of the transformer is used as the voltage measuring point. If necessary, the secondary side current is used as load current to calculate the line-voltage drop to the regulation point. It is possible to use two different sets of these analogue quantities. If all three phase-to-earth voltages and all three phase currents are available on the secondary side of the transformer, then VCTR will use internally calculated positive sequence quantities for all calculations. Alternatively if only one phase-to-phase voltage from the secondary side is available it will be used together with corresponding two phase currents for all calculations (see figure 80). It is not possible to use one phase-to-earth voltage for VCTR function.

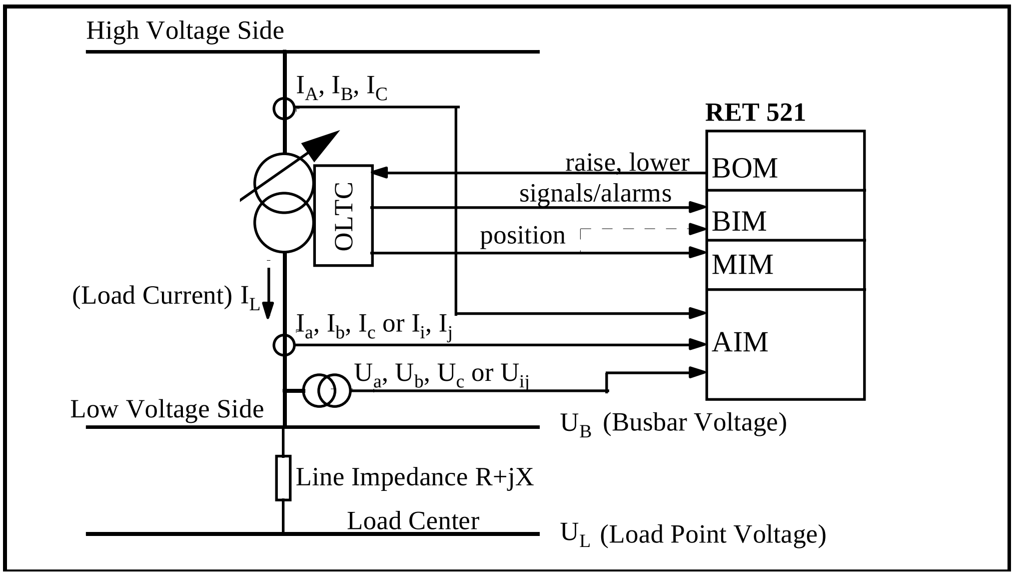


Fig. 80 Wiring for a single transformer with voltage control

In addition, all three phase currents from the primary winding (i.e. winding where the tap changer is situated) are used by VCTR function for overcurrent blocking.

In figure 80, the busbar voltage U_B is a shorter notation for the measured voltages regardless of the type of analogue input. Therefore notation U_B will be used from here on. Similarly notation I_L for load current and U_L for load point voltage will be used in the text further on.

Other inputs to VCTR function is the actual position of the tap changer that can be monitored either by using a mA-input or binary inputs. Alarms and signals from the tap changer can also be connected to binary inputs, e.g. thermal overload switch for motor, oil pressure relay, tap changer in progress etc. The RAISE and LOWER commands to the tap changer are issued via two binary outputs that will be activated during a time corresponding to the output pulse duration time.

33.2.4 Voltage Control for Single Transformer

The VCTR measures the busbar voltage U_B. If no other additional features are enabled (i.e. load drop compensation, voltage adjustment etc.) this voltage is further used for voltage regulation.The VCTR function then compares this voltage with the set voltage, U_{set} and decides which action should be taken. To avoid unnecessary switching around the setpoint, a deadband (i.e. degree of insensitivity) is introduced. The deadband is symmetrical around U_{set} (see figure 81). One half of the deadband will be denoted as ΔU from here on and this symbol will be used. The setting for ΔU, i.e. parameter with name “**Udeadband**” in SMSBASE under VCTR function, should be set to a value near to the power transformer’s tap changer voltage step (typically 75% of the tap changer step).

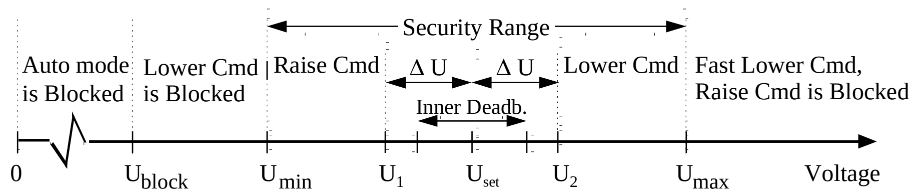


Fig. 81 Voltage Scale

During normal operating conditions the busbar voltage U_B, stays within the deadband (i.e. interval between U_1 and U_2 on figure 81). In that case no actions will be taken by VCTR. However, if U_B becomes smaller then U_1 or bigger than U_2, an appropriate lower or raise timer will start. The timer will run as long as the measured voltage stays outside the inner deadband, which is fixed to 70% of $2 \cdot \Delta U$. If this condition persist longer than a preset time by the voltage/time characteristics the appropriate LOWER or RAISE command will be issued. If necessary, the procedure will be repeated until the busbar voltage is again within the inner deadband.

This way of working is used by VCTR while the busbar voltage is within security range [U_{min} , U_{max}]. If U_B, fall-out of this range this will be regarded as abnormal situation and the following will happen:

When the busbar voltage falls below $\mathbf{U}_{min}$, but still above $\mathbf{U}_{block}$, no further manual or automatic LOWER commands will be executed.

When the busbar voltage falls below the undervoltage limit U_{block}, automatic control will be blocked, but manual commands in both direction can be executed.

If the busbar voltage rises above $\mathbf{U}_{max}$, no further RAISE commands are allowed. In this case the VCTR function can execute one or more fast step down commands (i.e. LOWER commands) in order to bring the voltage back into the security range, [U_{min}, U_{max}]. The fast step down (FSD) function operation can be activated in one of the following three ways: off / auto / auto&manual, according to the setting of “**FSDMode**” parameter. The lower command, in fast step down mode, is always issued with shortest permissible time delay t_2. The measured busbar voltage U_B is shown on the HMI as a service value under menu

Service Report
  Functions
    VoltageControl
      Measurands

33.2.5 Voltage Control for Parallel Transformers

Parallel voltage control, as implemented in RET 521, is based on the circulating current principle. Two main objectives of this type of parallel voltage control are:

1. Regulate the busbar or load voltage to the preset target value
2. Minimize the circulating current, in order to achieve optimal sharing of the reactive load between parallel transformers

First objective is the same as for the voltage control for single transformer while second objective tries to bring the circulating current, which appears due to unequal, LV side unload voltages in each transformer, into an acceptable value. Figure 82 shows an example with two transformers connected in parallel. If transformer T1 on this picture has higher unload voltage it will drive a circulating current which adds to the load current in T1 and subtracts from the load current in T2. It can be shown that magnitude of the circulating current in this case can be approximately calculated with the following formula:

$$|I_{\mathrm{cc\_T1}}| = |I_{\mathrm{cc\_T2}}| = \left|\frac{U_{\mathrm{T1}} - U_{\mathrm{T2}}}{Z_{T1} + Z_{T2}}\right|$$

Because transformer impedance is dominantly inductive it is possible to use just transformer reactances in the above formula. In the same time this means that T1 circulating current lags the busbar voltage for almost 90^{o}, while T2 circulating current leads the busbar voltage for almost 90^{o} (see figure 83 for complete phasor diagram). This shows that circulating current is mainly of reactive nature.

Therefore by minimizing the circulating current flow through transformers the total reactive power flow is optimized as well. In the same time at this optimum state the apparent power flow is distributed among transformers in the group in proportion to their rated power.

The first and most important task for VCTR function for parallel control is the calculation of the circulating current. To achieve this goal certain information and measurements have to be exchanged via the station bus (i.e. LON bus) between the terminals.

It should be noted that the Fourier filters in each RET terminal run asynchronously which means that current and voltage phasors cannot be exchanged and used for calculation directly between the terminals. In order to “synchronize” measurements within all terminals in the parallel group, a common reference have to be selected. The only suitable reference quantity for all transformers, which belong to one parallel group, is the busbar voltage. This means that the measured busbar voltage is used as a reference phasor in all terminals, and the position of the current phasors in the complex plain is calculated in respect to it. This is simple and effective solution which eliminates any additional need for synchronization between terminals regarding VCTR function.

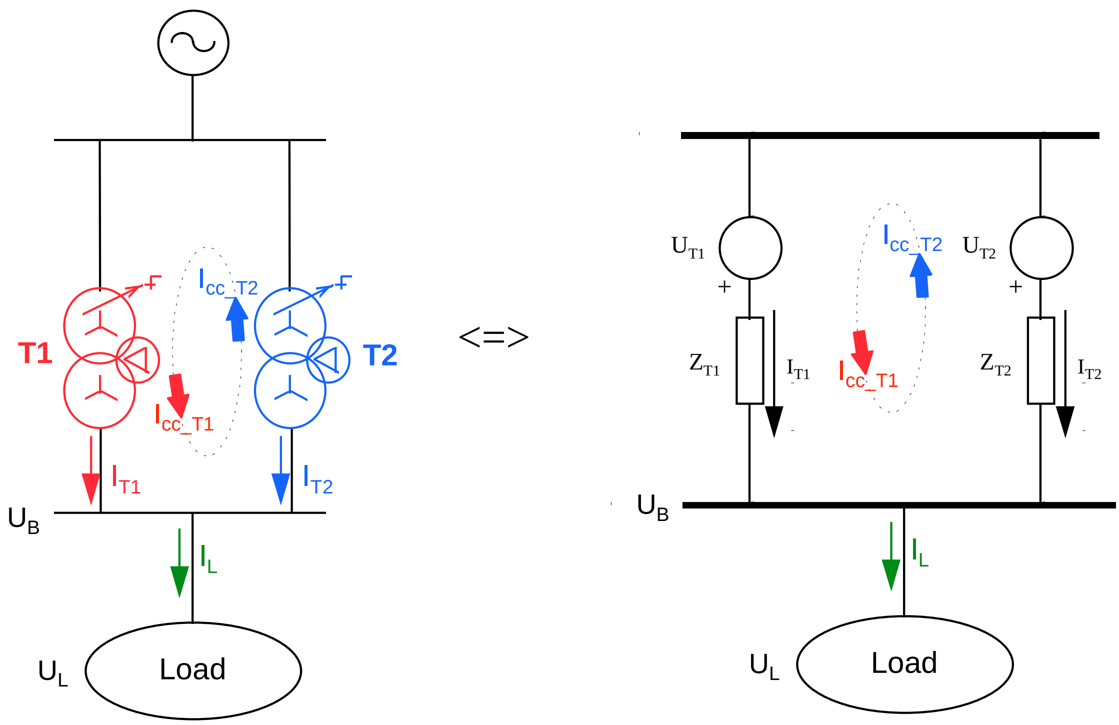


Fig. 82 Parallel group of two power transformers and its electrical model

At each transformer bay the real and imaginary part of the current on the secondary side of the transformer is measured and distributed on the station LON bus to the terminals that belong to the parallel group. Exchanged currents are expressed in per unit and must be referred to a common base power and base voltage. For this purpose the user should set the parameter “**Sbase**” to the same, common value in all terminals. The base power can be different from the transformer rated power if the group consists of transformers with different ratings. The transformer secondary voltage, U_{r2}, serves as the base voltage. From S_{base} and U_{r2} base current can be calculated as

$$I_{\mathrm{base2}} = \frac{S_{\mathrm{base}}}{\sqrt{3} \cdot U_{\mathrm{r2}}}$$

As mentioned before, only the imaginary part (i.e. reactive current component) of the individual transformer current is needed for the circulating current calculations. The real part of the current will, however, be used to calculate the total through load current and will be used by the line voltage drop compensation.

The total load current in pu is defined as sum of all individual transformer currents:

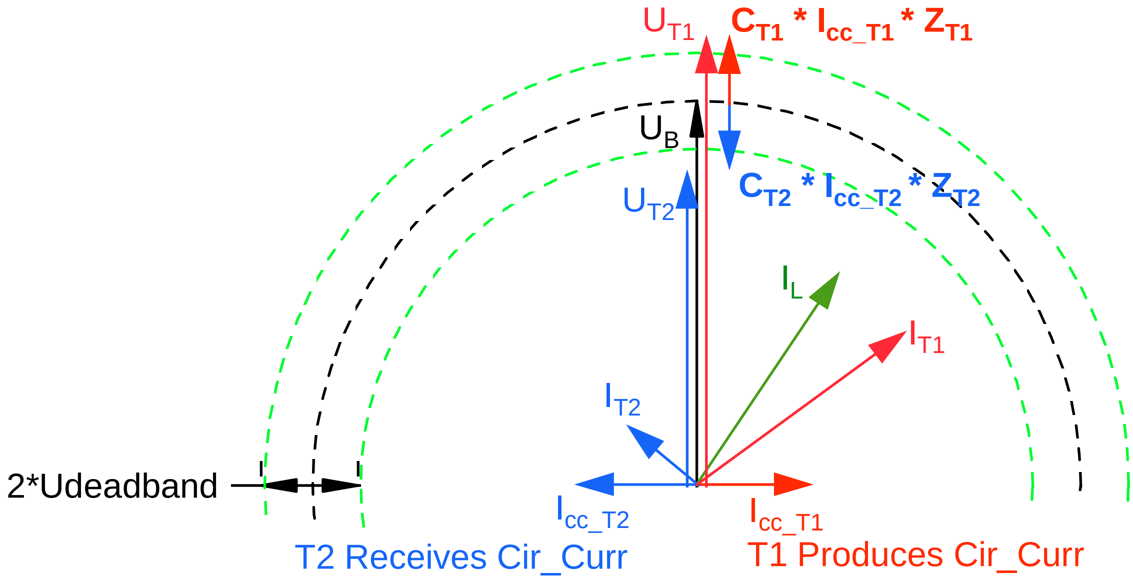
$$\overline{I_L} = \sum_{i=1}^{k} \overline{I_i}$$

where subscript i signifies the transformer bay number and k the number of parallel transformers in the group (kmax=4). Next step is to extract the circulating current I_{cc_i} that flows in bay i. It is possible to identify a term in the bay current which represents the circulating current. The magnitude of the circulating current in bay i, I_{cc_i} , can be calculated according to:

$$I_{\mathrm{cc\_i}} = -\mathrm{Im}(\overline{I_i} - \overline{K_{Li}} \times \overline{I_L})$$

where Im means the imaginary part of the expression in brackets and $\overline{K_i}$ is a constant which depends on the number of transformers in the parallel group and their short-circuit reactances. VCTR function automatically calculates this constant. Transformer reactances should be given in primary ohms, calculated from each transformer rating plate. The reactance is then converted to per unit value by VCTR function.

The minus sign is added in above equation in order to have positive value of the circulating current for the transformer which generates it. This is necessary to do because of mathematical definitions of sin and cos functions i.e. the imaginary part of the current is negative when it lags the reference voltage (see Fig. 83).



$$\underline{I}_L = \underline{I}_{T1} + \underline{I}_{T2}$$
$$I_{cc\_T1} = Imag\,\{\underline{I}_{T1} - (Z_{T2}/(Z_{T1}+Z_{T2})) * \underline{I}_L\}$$
$$I_{cc\_T2} = Imag\,\{\underline{I}_{T2} - (Z_{T1}/(Z_{T1}+Z_{T2})) * \underline{I}_L\}$$

Fig. 83 Vector Diagram for two power transformers working in parallel.

In this way each VCTR function calculates the circulating current for its own bay.

The calculated circulating current I_{cc_i} is shown on the HMI as a service value under menu:

Service Report
Functions
VoltageControl
Measurands

Sign is available as well (i.e. + sign means that the transformer produces circulating current and - sign means that the transformer receives circulating current).

Now it is necessary to estimate the value of the no-load voltage in each transformer. To do that the magnitude of the circulating current, in each bay, is first transferred to a voltage deviation, U_{di}, as per the following formula:

$$U_{\mathrm{di}} = C_i \cdot I_{\mathrm{cc\_i}} \cdot X_i$$

where X_i is the short-circuit reactance for transformer *i* and C_i, called "**Comp**" parameter in VCTR function, is a setting parameter which can increase/decrease the influence of the circulating current on the VCTR function. It should be noted that U_{di} will have positive values for transformer which produces circulating current and negative values for transformers which receives circulating current.

Now for each transformer the magnitude of the no-load voltage can be approximated with:

$$U_i = U_B + U_{\mathrm{di}}$$

This value for the no-load voltage is then simply put into the voltage control function for single transformer, that treats it as the measured busbar voltage, and further control actions are taken as described in section 33.2.4. By doing this the overall control strategy is simple and can be summarized as follows.

For the transformer producing/receiving the circulating current calculated no-load voltage will be greater/lower than measured voltage U_B. This calculated no-load voltage is thereafter compared with the set voltage U_{set}. A steady deviation which is outside the deadband will result in a LOWER / RAISE voltage command to the tap changer. In this way the overall control action is always correct since the position of a tap changer is directly proportional to the transformer no-load voltage.

Complete phasor diagram for case of two transformers connected in parallel is shown on Fig. 83.

33.2.6 Manual Control of the parallel group (Adapt Mode)

In the previous paragraph automatic control of the parallel group was described. If it is necessary to manually control the parallel group, all transformers in the group should follow the commands otherwise the transformers will carry different loadings with large circulating currents as a consequence. For this purpose when one of the transformers working in the parallel group is set to manual mode all other transformers in the group will be automatically put in the adapt mode. As the name indicates they will be ready to adapt to the manual tapping of the selected transformer. The VCTR function in manual mode will send the adapt message via LON bus to the rest of group. It is of no importance for the group members to know from which transformer bay the adapt message was sent.

The VCTR function in adapt mode will continue the calculation of U_{di}, but instead of adding U_{di} to the measured busbar voltage, it will compare it with the deadband ΔU. The following rules are used:

Rule 1: If U_{di} is positive and its module is greater than ΔY, then initiate a LOWER command.

Rule 2: If U_{di} is negative and its module is greater than ΔY, then initiate a RAISE command.

Rule 3: If U_{di} module is smaller than ΔY, then do nothing.

The binary output signal “**ADAPT”** on VCTR function block will be set high to indicate that this terminal is adapting to another RET terminal in the parallel group.

However, it should be noted that correct behavior of all transformers in the parallel group can be guarantied only when one and only one of the transformers is set to the manual mode.

33.3 Logic diagram

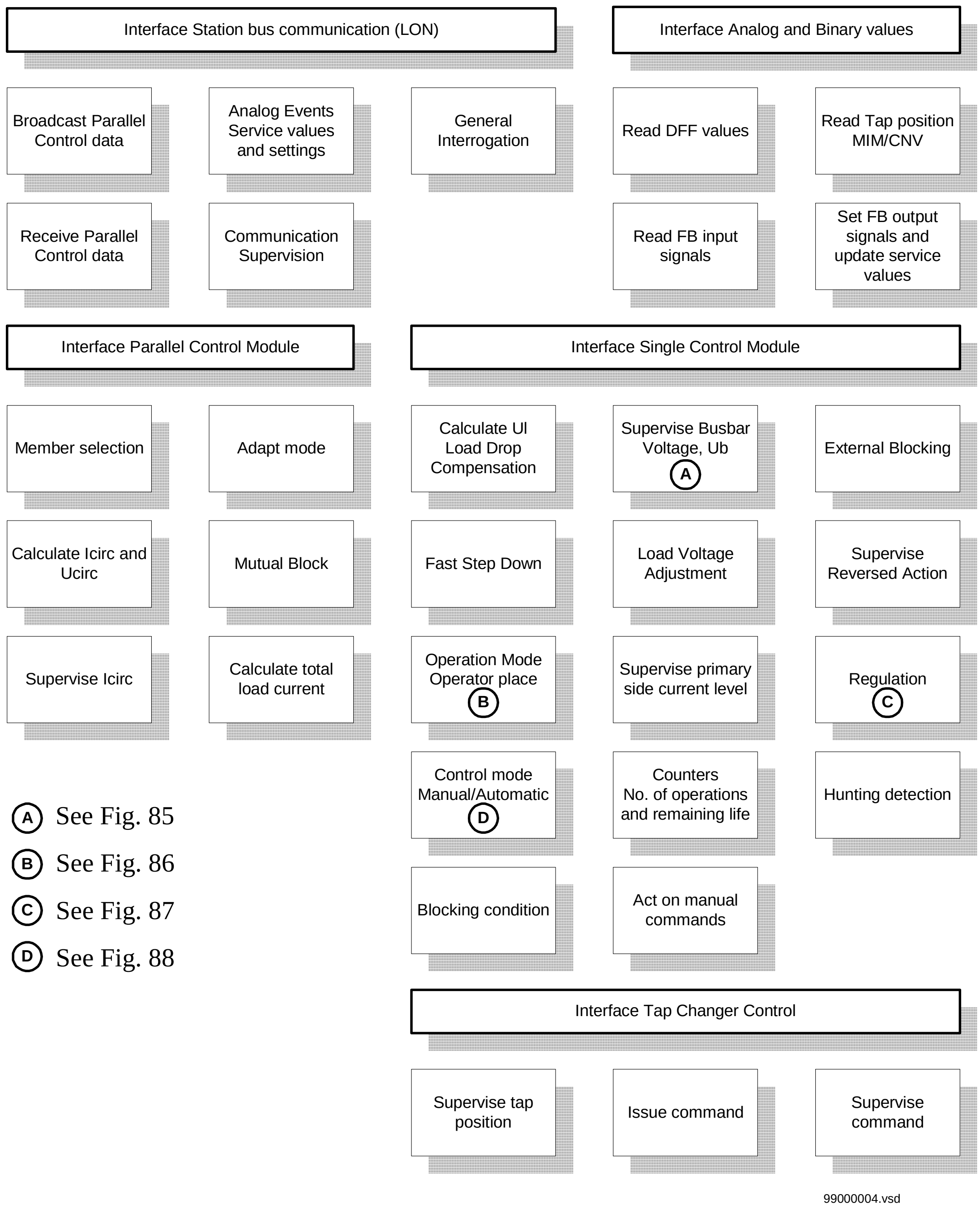


Fig. 84 VCTR overview

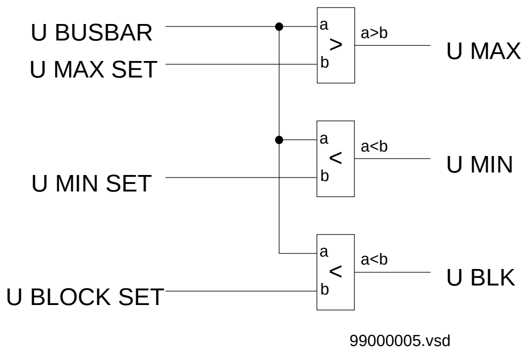


Fig. 85 Supervision of busbar voltage Ub

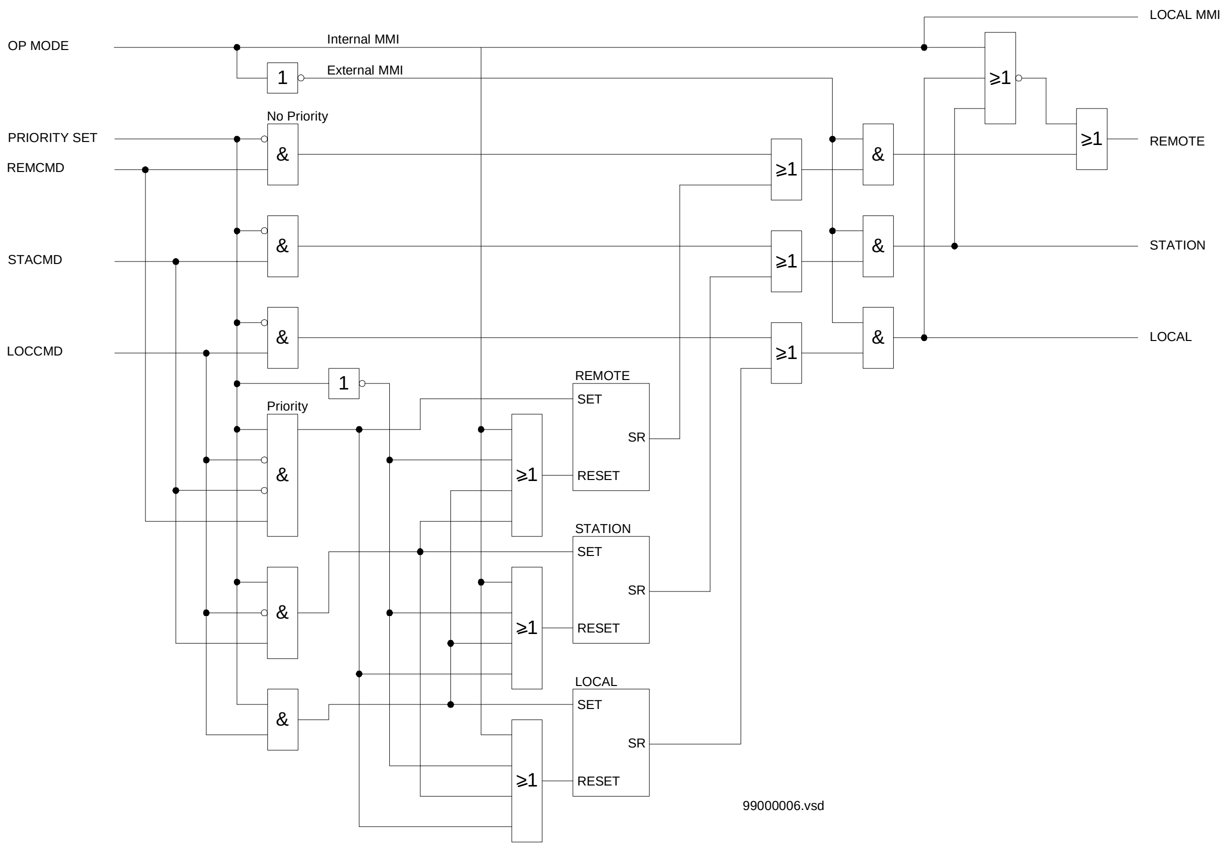


Fig. 86 Operation mode

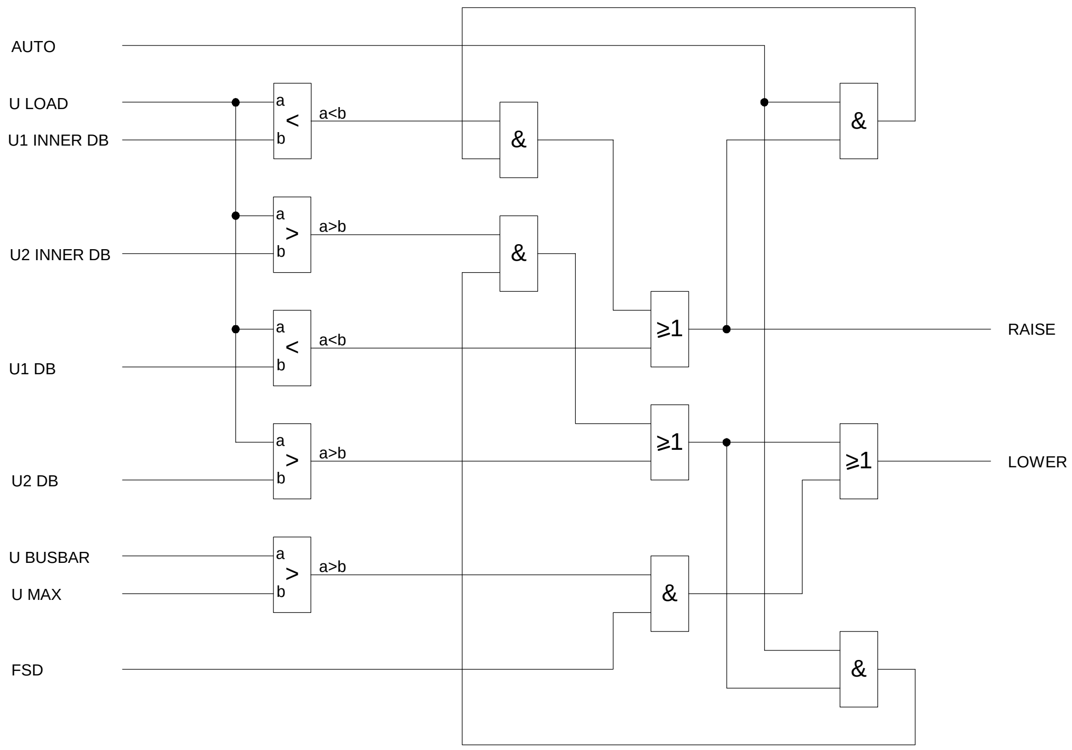


Fig. 87 Regulation

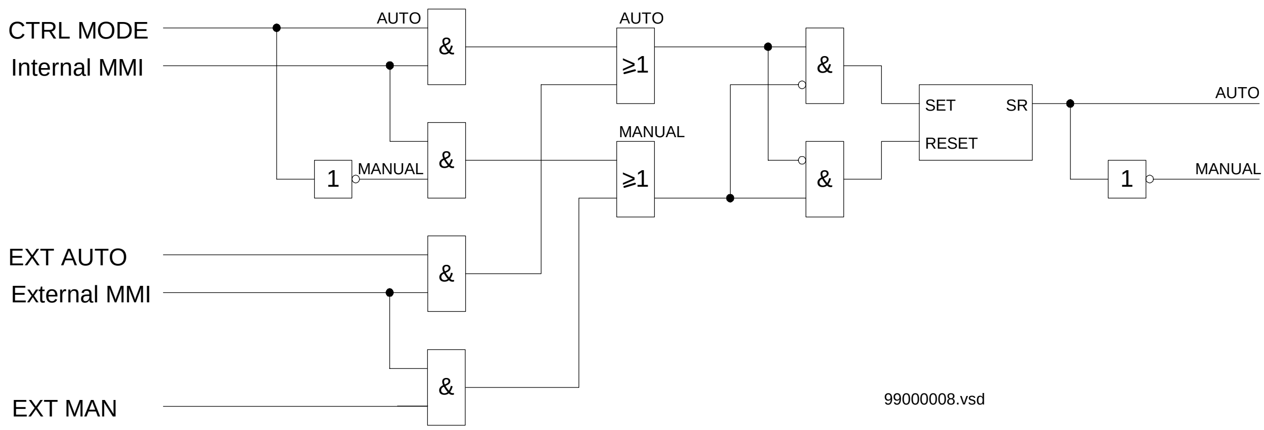
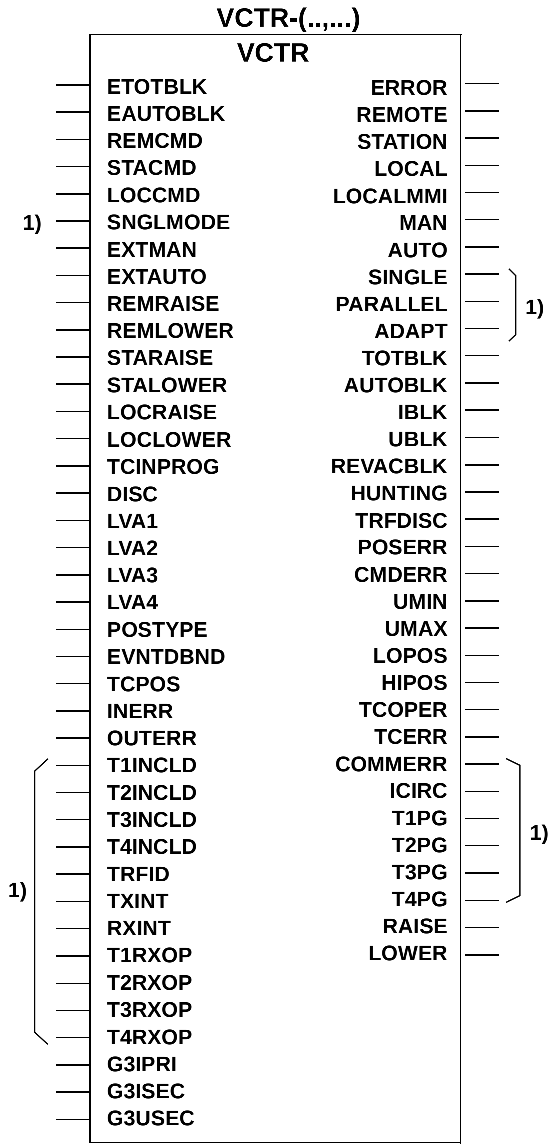


Fig. 88 Control mode

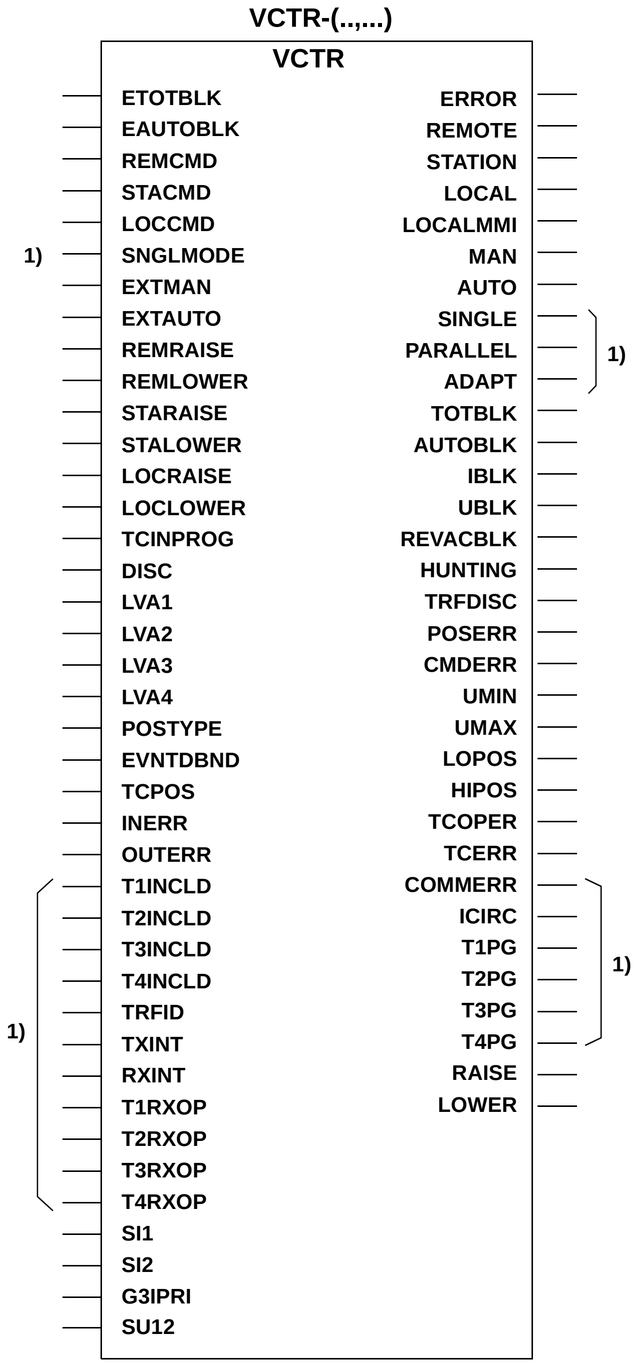
33.4 Function block

For Voltage Control, VCTR, there are two different looks of the function block.
VCTR (function selector set to G3I+G3U)
Two phase currents and corresponding phase to phase voltage used for regulation



1) Only applicable for control of parallel operating transformers

VCTR (function selector set to 2*SI+SU)
Three-phase currents and three-phase voltages used for regulation



1) Only applicable for control of parallel operating transformers

33.5 Input and output signals

Table 99:

In:	Description:
VCTR-ETOTBLK	Total blocking of voltage control, VCTR
VCTR-EAUTOBLK	Blocking of automatic mode, VCTR
VCTR-REMCMD	Enables remote MMI, VCTR
VCTR-STACMD	Enables station MMI, VCTR
VCTR-LOCCMD	Enables local panel switches, VCTR
VCTR-SNGLMODE	Force single control mode, VCTR
VCTR-EXTMAN	Manual control mode, VCTR
VCTR-EXTAUTO	Automatic control mode, VCTR
VCTR-REMRAISE	Manual raise pulse, remote location, VCTR
VCTR-REMLOWER	Manual lower pulse, remote location, VCTR
VCTR-STARAISE	Manual raise pulse, station location, VCTR
VCTR-STALOWER	Manual lower pulse, station location, VCTR
VCTR-LOCRAISE	Manual raise pulse, local location, VCTR
VCTR-LOCLOWER	Manual lower pulse, local location, VCTR
VCTR-TCINPROG	Tap changer in progress signal, VCTR
VCTR-DISC	Disconnected transformer indication, VCTR
VCTR-LVA1	Activation of load voltage adjust. factor 1, VCTR
VCTR-LVA2	Activation of load voltage adjust. factor 2, VCTR
VCTR-LVA3	Activation of load voltage adjust. factor 3, VCTR
VCTR-LVA4	Activation of load voltage adjust. factor 4, VCTR
VCTR-POSTYPE	Tap changer position indication type, VCTR
VCTR-EVNTDBND	Event generation deadband in % of last value, VCTR
VCTR-TCPOS	Tap changer position indication, VCTR
VCTR-INERR	Input module error, VCTR
VCTR-OUTERR	Output module error, VCTR
VCTR-T1INCLD	Transformer T1 included in parallel group, VCTR
VCTR-T2INCLD	Transformer T2 included in parallel group, VCTR
VCTR-T3INCLD	Transformer T3 included in parallel group, VCTR
VCTR-T4INCLD	Transformer T4 included in parallel group, VCTR
VCTR-TRFID	Transformer identity in the parallel group, VCTR
VCTR-TXINT	Send interval, VCTR
VCTR-RXINT	Receive interval, VCTR
VCTR-T1RXOP	Receive block operation for parallel transformer 1, VCTR
VCTR-T2RXOP	Receive block operation for parallel transformer 2, VCTR

Table 99:

In:	Description:
VCTR-T3RXOP	Receive block operation for parallel transformer 3, VCTR
VCTR-T4RXOP	Receive block operation for parallel transformer 4, VCTR
VCTR-SI1	Single phase current 1, VCTR
VCTR-SI2	Single phase current 2, VCTR
VCTR-G3IPRI	Three phase current group primary side, VCTR
VCTR-G3ISEC	Three phase current group secondary side, VCTR
VCTR-SU12	Phase-to-phase voltage, VCTR
VCTR-G3USEC	Three phase voltage group secondary side, VCTR
VCTR-ETOTBLK	Total blocking of voltage control, VCTR
VCTR-EAUTOBLK	Blocking of automatic mode, VCTR
VCTR-REMCMD	Enables remote MMI, VCTR
VCTR-STACMD	Enables station MMI, VCTR
VCTR-LOCCMD	Enables local panel switches, VCTR
VCTR-SNGLMODE	Force single control mode, VCTR
VCTR-EXTMAN	Manual control mode, VCTR
VCTR-EXTAUTO	Automatic control mode, VCTR
VCTR-REMRAISE	Manual raise pulse, remote location, VCTR
VCTR-REMLOWER	Manual lower pulse, remote location, VCTR
VCTR-STARAISE	Manual raise pulse, station location, VCTR
VCTR-STALOWER	Manual lower pulse, station location, VCTR
VCTR-LOCRAISE	Manual raise pulse, local location, VCTR
VCTR-LOCLOWER	Manual lower pulse, local location, VCTR
VCTR-TCINPROG	Tap changer in progress signal, VCTR
VCTR-DISC	Disconnected transformer indication, VCTR
VCTR-LVA1	Activation of load voltage adjust. factor 1, VCTR
VCTR-LVA2	Activation of load voltage adjust. factor 2, VCTR
VCTR-LVA3	Activation of load voltage adjust. factor 3, VCTR
VCTR-LVA4	Activation of load voltage adjust. factor 4, VCTR
VCTR-POSTYPE	Tap changer position indication type, VCTR
VCTR-EVNTDBND	Event generation deadband in % of last value, VCTR
VCTR-TCPOS	Tap changer position indication, VCTR
VCTR-INERR	Input module error, VCTR
VCTR-OUTERR	Output module error, VCTR
VCTR-T1INCLD	Transformer T1 included in parallel group, VCTR
VCTR-T2INCLD	Transformer T2 included in parallel group, VCTR
VCTR-T3INCLD	Transformer T3 included in parallel group, VCTR
VCTR-T4INCLD	Transformer T4 included in parallel group, VCTR

Table 99:

In:	**Description:**
VCTR-TRFID	Transformer identity in the parallel group, VCTR
VCTR-TXINT	Send interval, VCTR
VCTR-RXINT	Receive interval, VCTR
VCTR-T1RXOP	Receive block operation for parallel transformer 1, VCTR
VCTR-T2RXOP	Receive block operation for parallel transformer 2, VCTR
VCTR-T3RXOP	Receive block operation for parallel transformer 3, VCTR
VCTR-T4RXOP	Receive block operation for parallel transformer 4, VCTR
VCTR-SI1	Single phase current 1, VCTR
VCTR-SI2	Single phase current 2, VCTR
VCTR-G3IPRI	Three phase current group primary side, VCTR
VCTR-G3ISEC	Three phase current group secondary side, VCTR
VCTR-SU12	Phase-to-phase voltage, VCTR
VCTR-G3USEC	Three phase voltage group secondary side, VCTR

Out:	**Description:**
VCTR-ERROR	General VCTR function error
VCTR-REMOTE	Remote operation mode, VCTR
VCTR-STATION	Station operation mode, VCTR
VCTR-LOCAL	Local operation mode, VCTR
VCTR-LOCALMMI	Local MMI operation mode, VCTR
VCTR-MAN	Manual control mode, VCTR
VCTR-AUTO	Automatic control mode, VCTR
VCTR-SINGLE	Single control mode, VCTR
VCTR-PARALLEL	Parallel control mode, VCTR
VCTR-ADAPT	Parallel control in adapt mode, VCTR
VCTR-TOTBLK	Voltage control total blocking, VCTR
VCTR-AUTOBLK	Voltage control automatic mode blocking, VCTR
VCTR-IBLK	High current block, total block, VCTR
VCTR-UBLK	Low voltage range block limit, auto mode block, VCTR
VCTR-REVACBLK	OLTC reversed action blocking, auto mode block, VCTR
VCTR-HUNTING	Hunting detection alarm, VCTR
VCTR-TFRDISC	Transformer disconnection, auto mode block, VCTR
VCTR-POSERR	Tap changer position error, VCTR
VCTR-CMDERR	Tap changer command error, VCTR

VCTR-UMIN	Low voltage range limit, lower command block, VCTR
VCTR-UMAX	High voltage range limit, raise command block, VCTR
VCTR-LOPOS	Low tap changer position indication, lower cmd. block, VCTR
VCTR-HIPOS	High tap changer position indication, raise cmd. block, VCTR
VCTR-TCOPER	Tap changer in operation, VCTR
VCTR-TCERR	Tap changer operation error, VCTR
VCTR-COMMERR	Communication error, VCTR
VCTR-ICIRC	Maximum circulating current blocking, VCTR
VCTR-T1PG	Transformer T1 connected to parallel group, VCTR
VCTR-T2PG	Transformer T2 connected to parallel group, VCTR
VCTR-T3PG	Transformer T3 connected to parallel group, VCTR
VCTR-T4PG	Transformer T4 connected to parallel group, VCTR
VCTR-RAISE	Raise voltage command to tap changer, VCTR
VCTR-LOWER	Lower voltage command to tap changer, VCTR

33.6 Setting parameters and ranges

Table 100:

Parameter:	Range:	Description:
Operation	0=Off, 1=On	Operation Voltage Control, Off/On
Uset	85.0 - 120.0	Voltage Control set voltage in % of Ur2
Udeadband	0.5 - 9.0	Set voltage deadband in % of Ur2
Umax	100 - 130	Upper limitation busbar voltage detection in % of Ur2
Umin	70 - 95	Lower limitation busbar voltage detection in % of Ur2
FSDMode	0=Off, 1=Auto, 2=AutoMan	Fast step down function activation mode, Off/Auto/AutoMan
t1Use	0=Const, 1=Inverse	Time characteristics for Time 1, Const/Inverse
t1	1 - 180	Time value in sec. for Time 1
t2Use	0=Const, 1=Inverse	Time characteristics for Time 2, Const/Inverse
t2	1 - 60	Time value in sec. for Time 2

Table 100:

Parameter:	Range:	Description:
tMin	1.0 - 30.0	Minimum operating time in sec.
OperationLDC	0=Off, 1=On	Operation line voltage drop compensation, Off/On
Rline	0.0 - 150.0	Line resistance, primary values, in ohm
Xline	0.0 - 150.0	Line reactance, primary values, in ohm
LVAConst1	-9.0 - 9.0	Constant load voltage adj. factor 1 in % of Ur2
LVAConst2	-9.0 - 9.0	Constant load voltage adj. factor 2 in % of Ur2
LVAConst3	-9.0 - 9.0	Constant load voltage adj. factor 3 in % of Ur2
LVAConst4	-9.0 - 9.0	Constant load voltage adj. factor 4 in % of Ur2
VRAuto	-4.0 - 0.0	Automatic voltage reduction factor in % of Ur2
ExtMMIPrio	0=Priority, 1=NoPriority	External MMI operation priority mode, Priority/NoPriority
TotalBlock	0=Off, 1=On	Total block of the voltage control function, Off/On
AutoBlock	0=Off, 1=On	Automatic mode block of the voltage control function, Off/On
Ublock	50 - 90	Undervoltage block level in % of Ur2
OperationRA	0=Off, 1=On	Operation OLTC reversed action blocking, Off/On
tRevAct	30 - 360	Power system emergency blocking time in sec.
OperationPAR	0=Off, 1=On	Parallel operation, Off/On
Sbase	0.1 - 999.9	Parallel transformer grp. common power base in MVA
T1Xr2	0.1 - 20.0	Transformer 1 reactance, secondary side, in ohm
T2Xr2	0.1 - 20.0	Transformer 2 reactance, secondary side, in ohm
T3Xr2	0.1 - 20.0	Transformer 3 reactance, secondary side, in ohm
T4Xr2	0.1 - 20.0	Transformer 4 reactance, secondary side, in ohm
Comp	0 - 100	Parallell control compensation parameter in %

Table 100:

Parameter:	Range:	Description:
OperationCC	0=Off, 1=On	Operation circulating current block function , Off/On
CircCurrLimit	0.0 - 20000.0	Circulating current block limit in A
LowVoltTap	1 - 64	Tap changer extreme position, lowest voltage
HighVoltTap	1 - 64	Tap changer extreme position, highest voltage
Iblock	0 - 250	The tap changer overcurrent block level in % of Ir1
tPulseDur	0.5 - 5.0	Command output pulse duration time in sec.
tTCTimeout	1 - 10	Tap changer constant timeout time in sec.
DayHuntDetect	0 - 100	Hunting detection alarm, max operations/day
HourHuntDetect	0 - 30	Hunting detection alarm, max operations/hour
CLFactor	1.0 - 3.0	Contact life counter factor
InitCLCounter	0 - 9999999	Initial value for tap changer life counter
SpaResetCLCnt	0=Cancel, 1=Reset	Reset cmd. for tap changer contact lift counter, Cancel/Reset
SpaResetOpCnt	0=Cancel, 1=Reset	Reset cmd. for tap changer no of oper. counter, Cancel/Reset
Ur2	1.0 - 999.9	Rated voltage, secondary side, in kV

33.7 Service report values

Table 101:

Parameter:	Range:	Step:	Description:
ActualUset	0.0 - 1999.9	0.1	Actual set voltage compensated for voltage adj. in kV
BlockCond	0 - 3	1	Status of the voltage ctrl. blocking cond,None/Tot/Auto/Part
BusbarVoltage	0.0 - 1999.9	0.1	Actual busbar voltage in kV
CircCurrent	0.0 - 20000.0	0.1	Actual reactive circulating current in A
CLResetDate	yy-mm-dd hh.mm;ss.sss		SPA presentation of last date of CL reset
ContactLife	0 - 9999999	1	Number of remaining operations for contacts, count(s)
LoadVoltage	0.0 - 1999.9	0.1	Calculated phase-to-phase load point voltage in kV
NoOfOperations	0 - 9999999	1	Total number of operations, count(s)
OCResetDate	yy-mm-dd hh.mm;ss.sss		SPA presentation of last date of op cnt reset
TapPosition	1 - 64	1	Actual tap changer position

Monitoring functionality

34 Event function (EV)

34.1 Summary of application

When using a Substation Automation system, time-tagged events can be continuously sent or polled from the terminal. These events can come from any available signal in the terminal that is connected to the Event function block. The Event function block can also handle double indication, that is normally used to indicate positions of high-voltage apparatus. With this Event function block in the RET 521 terminal, data can be sent to other terminals over the LON bus.

34.2 Summary of function

Both internal logical signals and binary input channels in the terminal can be connected to Event function blocks that provide time-tagged events. The time-tagging of the events that are emerging from internal logical signals have a resolution corresponding to the execution cyclicity of the Event function block. The time-tagging of the events that are emerging from binary input signals have a resolution of 1 ms.

34.3 Description of logic

34.3.1 General

In the RET 521 terminal up to 12 Event function blocks are available. Two of these, number 01 and 02 are executed in a loop with maximum speed. Event functions 03 to 07 are executed in a loop with mediate speed. Event functions 08 to 12 are executed in a loop with lowest speed. Refer to other document describing the execution details.

Each Event function block has 16 connectables corresponding to 16 inputs EVxx-INPUT1 to EVxx-INPUT16. Every input can be given a name with up to 19 characters from the CAP 531 configuration tool.

The inputs can be used as individual events or can be defined as double indication events.

The inputs can be set individually from the Station Monitoring System (SMS) under the Mask-Event function as:

- No events
- OnSet, at
- OnReset, at
- OnChange, at

34.3.2 Double indication

Double indications are used to handle a combination of two inputs at a time, for example, one input for the open and one for the close position of a circuit breaker or disconnector. The double indication consists of an odd and an even input number. When the odd input is defined as a double indication, the next even input is considered to be the other input. The odd inputs has a suppression timer to suppress events at 00 states.

To be used as double indications the odd inputs are individually set from the SMS under the Mask-Event function as:

- Double indication
- Double indication with midposition suppression

Here, the settings of the corresponding even inputs have no meaning.

These states of the inputs generate events. The status is read by the station HMI on the status indication for the odd input:

- 00 generates an intermediate event with the read status 0
- 01 generates an close event with the read status 1
- 10 generates an open event with the read status 2
- 11 generates an undefined event with the read status 3

34.3.3 Communication between terminals

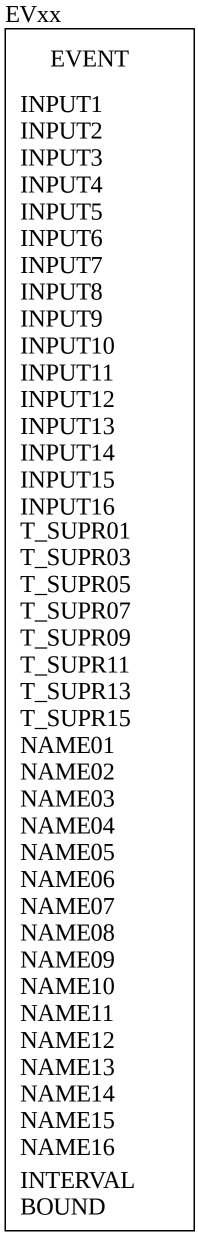
On the Event function block, the BOUND and INTERVAL inputs are available to be used for communication between terminals.

The BOUND input set to 1 means that the output value of the event block is bound to another control terminal on the LON bus. The Event function block is then used to send data over the LON bus to other terminals. The most common use is to transfer interlocking information between different bays. That can be performed by an Event function block used as a send block and with a Multiple Command function block used as a receive block. The configuration of the communication between control terminals is made by the LON Network Tool.

The INTERVAL input is applicable only when the BOUND input is set to 1. The INTERVAL is intended to be used for cyclic sending of data to other terminals via the LON bus with the interval time as set. This cyclic sending of data is used as a backup of the event-driven sending, which is always performed. With cyclic sending of data, the communication can be supervised by a corresponding INTERVAL input on the Multiple Command function block in another terminal connected to the LON bus. This INTERVAL input time is set a little bit longer than the interval time set on the Event function block. With INTERVAL=0, only event-driven sending is performed.

The event-driven sending of data to other control terminals over the LON bus is performed with a resolution corresponding to the execution cyclicity of the Event function block.

34.4 Function block



34.5 Input and output signals

Table 102: Signal list for Event function No. xx

In:	Description:
EVxx-INPUT1	Event input 1 for event block No. xx
EVxx-INPUT2	Event input 2 for event block No. xx
EVxx-INPUT3	Event input 3 for event block No. xx
EVxx-INPUT4	Event input 4 for event block No. xx
EVxx-INPUT5	Event input 5 for event block No. xx
EVxx-INPUT6	Event input 6 for event block No. xx
EVxx-INPUT7	Event input 7 for event block No. xx
EVxx-INPUT8	Event input 8 for event block No. xx
EVxx-INPUT9	Event input 9 for event block No. xx
EVxx-INPUT10	Event input 10 for event block No. xx
EVxx-INPUT11	Event input 11 for event block No. xx
EVxx-INPUT12	Event input 12 for event block No. xx
EVxx-INPUT13	Event input 13 for event block No. xx
EVxx-INPUT14	Event input 14 for event block No. xx
EVxx-INPUT15	Event input 15 for event block No. xx
EVxx-INPUT16	Event input 16 for event block No. xx

34.6 Setting parameters and ranges

Table 103: Setting table for Event function No. xx

Parameter:	Range:	Description:
EventMask1	No Events, OnSet, OnReset, OnChange, Double Ind., Double Ind. with midpos supr	Event mask for input 1, to be set from SMS
EventMask2	No Events, OnSet, OnReset, OnChange	Event mask for input 2, to be set from SMS
EventMask3	No Events, OnSet, OnReset, OnChange, Double Ind., Double Ind. with midpos supr	Event mask for input 3, to be set from SMS
EventMask4	No Events, OnSet, OnReset, OnChange	Event mask for input 4, to be set from SMS
EventMask5	No Events, OnSet, OnReset, OnChange, Double Ind., Double Ind. with midpos supr	Event mask for input 5, to be set from SMS
EventMask6	No Events, OnSet, OnReset, OnChange	Event mask for input 6, to be set from SMS
EventMask7	No Events, OnSet, OnReset, OnChange, Double Ind., Double Ind. with midpos supr	Event mask for input 7, to be set from SMS
EventMask8	No Events, OnSet, OnReset, OnChange	Event mask for input 8, to be set from SMS
EventMask9	No Events, OnSet, OnReset, OnChange, Double Ind., Double Ind. with midpos supr	Event mask for input 9, to be set from SMS
EventMask10	No Events, OnSet, OnReset, OnChange	Event mask for input 10, to be set from SMS
EventMask11	No Events, OnSet, OnReset, OnChange, Double Ind., Double Ind. with midpos supr	Event mask for input 11, to be set from SMS
EventMask12	No Events, OnSet, OnReset, OnChange	Event mask for input 12, to be set from SMS
EventMask13	No Events, OnSet, OnReset, OnChange, Double Ind., Double Ind. with midpos supr	Event mask for input 13, to be set from SMS

Table 103: Setting table for Event function No. xx

Parameter:	Range:	Description:
EventMask14	No Events, OnSet, OnReset, OnChange	Event mask for input 14, to be set from SMS
EventMask15	No Events, OnSet, OnReset, OnChange, Double Ind., Double Ind. with midpos supr	Event mask for input 15, to be set from SMS
EventMask16	No Events, OnSet, OnReset, OnChange	Event mask for input 16, to be set from SMS
EVxx-T_SUPR01	0.000-60.000 s	Suppression time for Input 1, to be set from CAP 531
EVxx-T_SUPR03	0.000-60.000 s	Suppression time for Input 3, to be set from CAP 531
EVxx-T_SUPR05	0.000-60.000 s	Suppression time for Input 5, to be set from CAP 531
EVxx-T_SUPR07	0.000-60.000 s	Suppression time for Input 7, to be set from CAP 531
EVxx-T_SUPR09	0.000-60.000 s	Suppression time for Input 9, to be set from CAP 531
EVxx-T_SUPR11	0.000-60.000 s	Suppression time for Input 11, to be set from CAP 531
EVxx-T_SUPR13	0.000-60.000 s	Suppression time for Input 13, to be set from CAP 531
EVxx-T_SUPR15	0.000-60.000 s	Suppression time for Input 15, to be set from CAP 531
EVxx-NAME01	19 characters string	User name of signal connected to Input 1, to be set from CAP 531
EVxx-NAME02	19 characters string	User name of signal connected to Input 2, to be set from CAP 531
EVxx-NAME03	19 characters string	User name of signal connected to Input 3, to be set from CAP 531
EVxx-NAME04	19 characters string	User name of signal connected to Input 4, to be set from CAP 531
EVxx-NAME05	19 characters string	User name of signal connected to Input 5, to be set from CAP 531
EVxx-NAME06	19 characters string	User name of signal connected to Input 6, to be set from CAP 531
EVxx-NAME07	19 characters string	User name of signal connected to Input 7, to be set from CAP 531
EVxx-NAME08	19 characters string	User name of signal connected to Input 8, to be set from CAP 531

Table 103: Setting table for Event function No. xx

Parameter:	Range:	Description:
EVxx-NAME09	19 characters string	User name of signal connected to Input 9, to be set from CAP 531
EVxx-NAME10	19 characters string	User name of signal connected to Input 10, to be set from CAP 531
EVxx-NAME11	19 characters string	User name of signal connected to Input 11, to be set from CAP 531
EVxx-NAME12	19 characters string	User name of signal connected to Input 12, to be set from CAP 531
EVxx-NAME13	19 characters string	User name of signal connected to Input 13, to be set from CAP 531
EVxx-NAME14	19 characters string	User name of signal connected to Input 14, to be set from CAP 531
EVxx-NAME15	19 characters string	User name of signal connected to Input 15, to be set from CAP 531
EVxx-NAME16	19 characters string	User name of signal connected to Input 16, to be set from CAP 531
EVxx-INTERVAL	0-60 s	Interval time for cyclic sending of data, to be set from CAP 531
EVxx-BOUND	0=Off, 1=On	Connected to other terminals on the network, to be set from CAP 531

35 Disturbance Report

35.1 Summary of application

The Disturbance Report is intended to provide relevant information in case of disturbances. The information is mainly intended for two categories of personal and is sorted accordingly. Operational personal need quick overview for fast decision making, while the relay engineer and maintenance people require more detailed information and can take more time for evaluation and maintenance planning.

The Disturbance Report is a common name for several facilities to supply information on disturbances.

The functions included are:

- General disturbance information
- Indications

- Event recorder
- Trip values
- Disturbance recording

Part of the information is presented on the built-in HMI. All information is accessible via SMS and SCS.

35.2 Information on the built-in HMI

The following information is available for each disturbance, that is stored in the terminal:

- Date and time
- Trig signal
- Indications
- Trip values

35.3 Information retrieved with SMS or SCS

A Disturbance Overview, which is a summary of all the recorded disturbances, is available. The overview contains:

- Disturbance index
- Date and time
- Trig signal, that has activated the recording

Upon selection one of the disturbances more detailed information is available for each disturbance.

The disturbance recording recorded by the disturbance recorder function can be retrieved to a PC and the analogue and digital signals can be visualised on the screen and printed out.

35.4 Summary of function

The Disturbance Report function collects and stores information about disturbances. 48 binary signals and ten analogue signals can be connected to the function. The recording starts when one of the triggers is activated. This means that no report will be generated unless there is a trigger activated. The triggers can be any of the binary inputs or threshold levels on any of the analogue inputs. The recording covers the following time intervals, which form part of the total recording time:

- pre-fault time
- fault time
- post fault time

The function can store up to 10 reports. The reports are stored in a non-volatile cyclic memory and the FIFO principle is employed.

The following functions are included in the disturbance report function:

- General disturbance information

This is a summary of and overview of the recorded disturbances. The content may differ, depending on were it is presented. (Built-in HMI, SMS or SCS)

- Indications

This is a list of signals out of the selected maximum 48, that have been active during the fault time.

- Event recorder

The event recorder records all the status changes among the connected binary signals. The number of events is limited to 150 for each disturbance.

- Trip values

The function calculates the values of currents and voltages before and during fault. The values are presented as phase values with amplitude and argument.

- Disturbance recorder

The disturbance recorder records the analogue and digital channels that are connected to this function. For visualisation the recording has to be transferred to a PC.

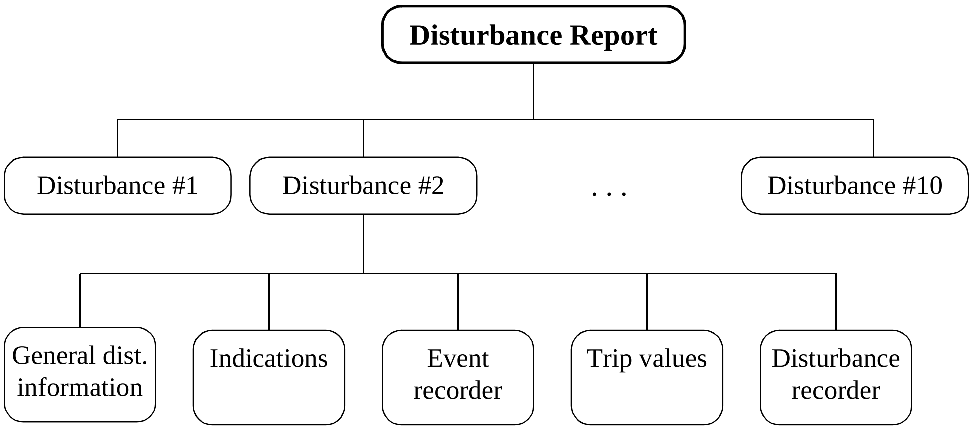


Fig. 89 Structure of the disturbance report function

35.5 Description of logic

35.5.1 Common functions

35.5.1.1 Recording times

A recorded disturbance is divided into three parts, a pre-fault period, a fault period and a post-fault period. The length of the pre-fault and post-fault periods can be configured by the user.

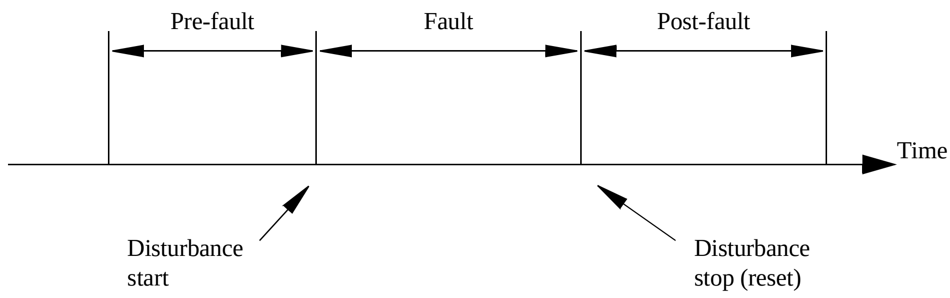


Fig. 90 Periods of a disturbance and their relations.

In addition to the limits of the pre-fault time (tPre) and post-fault time (tPost) the user can specify a limit time (tLim) that defines the maximum length of a disturbance recording from the fault occurrence (trig).Fig. 91 and Fig. 92 show the relations between the time limits for two different values of tLim.

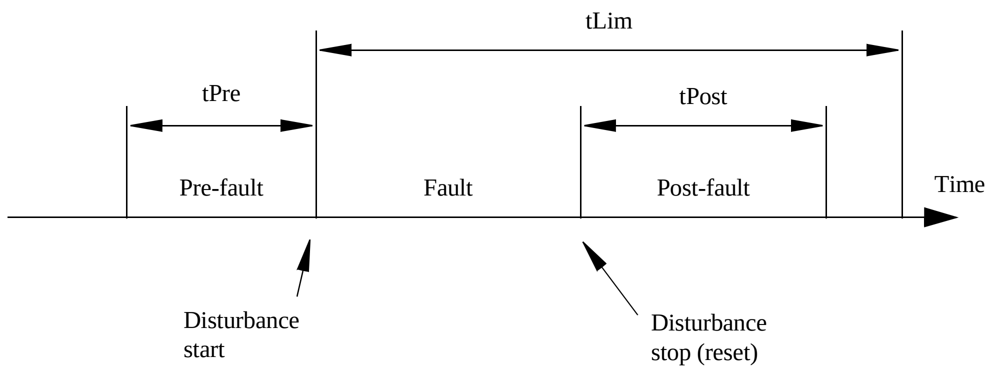


Fig. 91 Recording times relations.

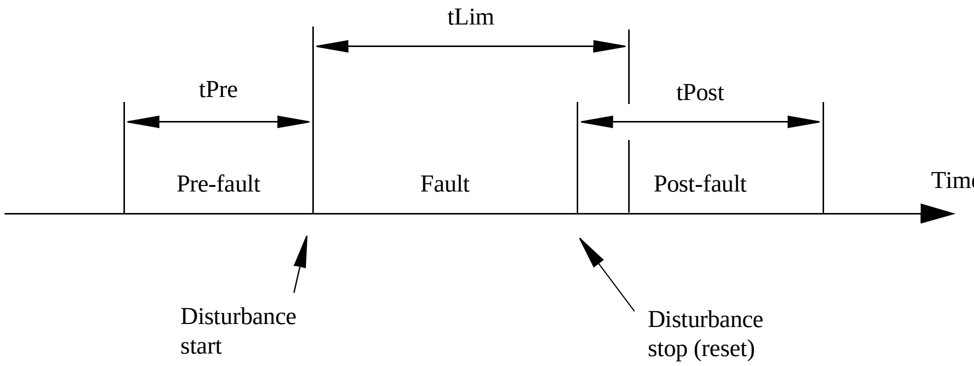


Fig. 92 Recording times relations.

35.5.1.2 Start and stop of recording

A recording of a disturbance can be started by any of the binary input signals or by analogue trig conditions that can be specified by the user. When a disturbance recording is triggered, the pre-fault buffer is locked and the data is stored in the fault buffer for as long as the start condition persists. If the trigger should not reset within an expected time interval, the total recording time is limited by a maximum limit time, tLim. When tLim is reached the active disturbance recording is terminated and the recording continues in a new cyclic buffer. The original trigger and all other triggers that were active when tLim was reached, must first be reset before they can cause a new start condition. Any other trigger, except for the non-reset triggers, can start a new disturbance recording when the current recording is terminated, either by reaching tLim or after a reset of the start condition.

Observe that the disturbance report function can not respond to any new trig condition, during a recording of a disturbance. The whole active disturbance recording must be finished before a new disturbance can be recorded.

However, there is an option (setting parameter PostRetrig) that can be set to allow a new recording to be started during the post-fault period of a recording. In this case the current recording will be terminated when the new trigger is activated. A new recording will start, but without any pre-fault time recording. If this re-trig function during post-fault option is not enabled, a new recording will not start until the post-fault period is terminated (by tPost or tLim).

The start and stop of a recording is time-tagged with date and time with a resolution of 1 ms.

35.5.1.3 Inputs

The disturbance report function can accept up to 48 binary and up to 10 analogue signals.

35.5.1.4 Trig signals

Three types of triggers can be used to start the disturbance report function:

- Binary signal trig
- Analogue signal trig (over and under trig functions)
- Manual trig

35.5.1.5 Binary signal trig

Any of the selected binary input signals can be used to trigger the disturbance report. The trig signals can be selected to trig either on a transition from low to high level or on a transition from high to low level.

35.5.1.6 Analogue signal trig

Analogue signals can only be used, when the disturbance recorder function is installed. Furthermore analogue triggers can only be used for recorded signals.

The analogue input signals can be used to generate trig signals with over and under trig functions. The over trig function compares the value of the analogue signal with a maximum limit value. If the analogue value is above the limit the report function is trigged. In the under trig operation the analogue input value is compared to a minimum limit value and if the signal is below the limit, the report function is trigged. The limits (over and under trig limits) are user configurable for each selected analogue signal. The limits are ratios and are relative a nominal value of the input signal. The nominal values of the input signal are set by the user for each analogue input signal. Every analogue input signal can be used to generate trig signals either using the over function or the under function or both. The analogue trigger functions have an operating time of approximately one cycle.

35.5.1.7 Manual trig

The disturbance report function can also be initiated manually.

35.5.2 Sampling rate

The sampling rate the data storage is 20 samples per cycle, i.e. 1000 Hz for a 50 Hz network and 1200 Hz for a 60 Hz network.

35.5.3 Memory capacity

The memory capacity for the disturbance report function is 10 disturbances. This means that events, indications and trip values for ten latest disturbances are stored in a non-volatile memory. The memory employs the FIFO principle, i.e. when the memory is full, data for the oldest disturbance will be overwritten.

The memory capacity for the disturbance recorder function is dealt with under that function.

35.5.4 Indications

As indications are the binary signals, that were active during the fault time, considered. These signals are listed without any time tagging and stored in a signal list.

35.5.5 Event recorder

All changes of status of the maximum 48 binary input signals are time tagged with date and time with a resolution of 1 ms. The capacity is maximum 150 events for each disturbance.

35.5.6 Trip values

This function calculates the pre-fault and fault values. For calculation of the pre-fault values the first cycle in the recording is used. The calculation of the fault values is based on the cycle immediately following the trig signal. Both pre-fault and fault values are presented as RMS phase values with amplitude and argument.

35.5.7 Disturbance recorder

35.5.7.1 Storage and data format

When a recording is made, the recorded data is stored temporarily in an area for uncompressed data. Data compression is run as a background task.A compression algorithm with 100% recording and upload data accuracy is used. This gives a data compression factor of maximum two times, depending on the shape of the analogue signal wave form. The compression factor for the binary signals depends on how often signal transitions occur and how the signals are grouped when the compression is performed.The compression time is approximately twice the length of the recording. When the compression is completed the data is stored in an other area of the non-volatile memory.

A disturbance recording is stored as two files, a header file and a data file. The header file has information about the following:

- Station name, object name and unit name
- Recording sequence number
- Date and time for the trig of the disturbance
- Pre-fault and fault RMS values
- Signal identifier for the selected binary and analogue signals
- Activated trigger and its value
- Status of analogue inputs including trig functions
- Status of binary input signals
- Recording times
- Sampling rate

The RMS values for currents and voltages during the pre-fault and fault periods are calculated in the terminal.

The data file consists of the compressed data from the recorded analogue and digital signals.

The data format of the header and data files that will be used is the REVAL format, REVAL.HDR and REVAL.DAT. The two files can be retrieved and visualised with RECOM and REVAL.

Since data for one disturbance is collected in different parts of the terminal, all recordings must be erased when parameters are changed.

35.5.7.2 Memory capacity

In the memory area for uncompressed data maximum four recordings with maximum time settings can be stored.

The memory capacity for storage of compressed data is approximately 10 seconds for recordings with full capacity, i.e. 48 binary signals and 10 analogue signals.

35.6 Function block

The following function blocks can be visualised in the CAP/RET 521 configuration tool:

- 1 no block for general functionality
- 3 nos blocks, each for 16 binary inputs
- 10 nos blocks, each for one analogue input

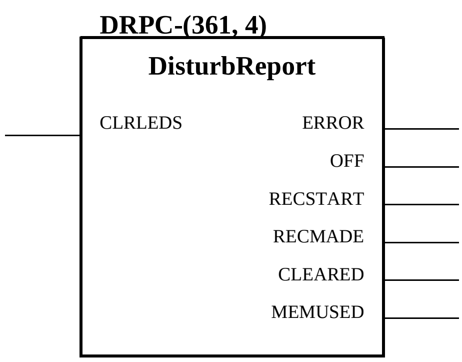


Fig. 93 General function block

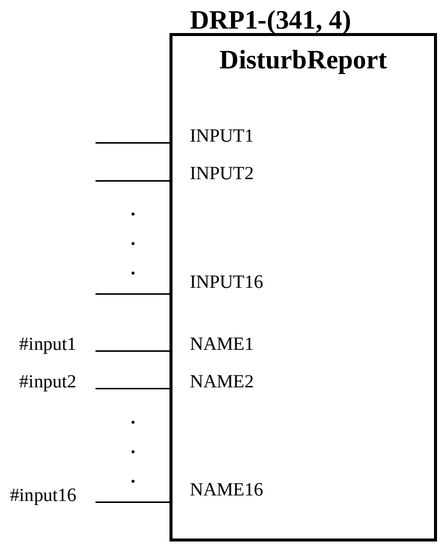


Fig. 94 Function block 1 for binary inputs

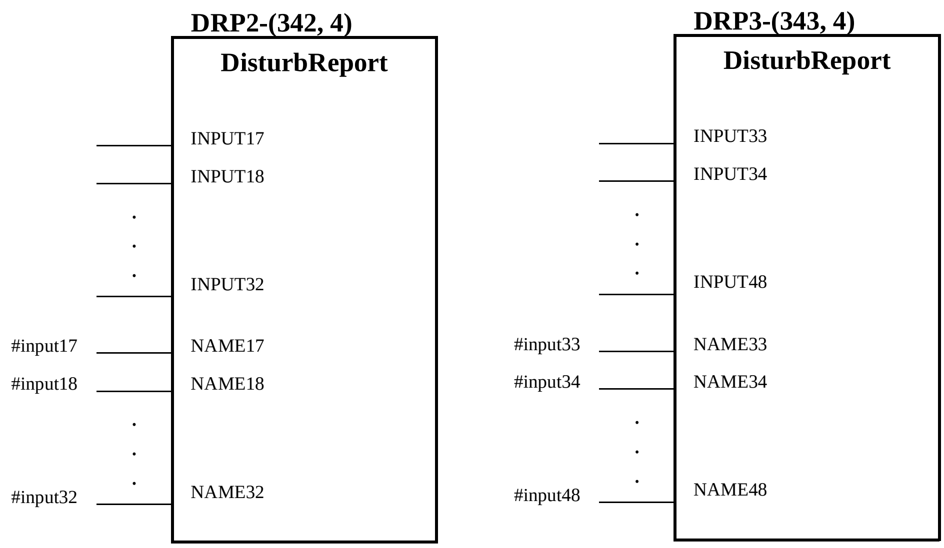


Fig. 95 Function block 2 and 3 for binary inputs

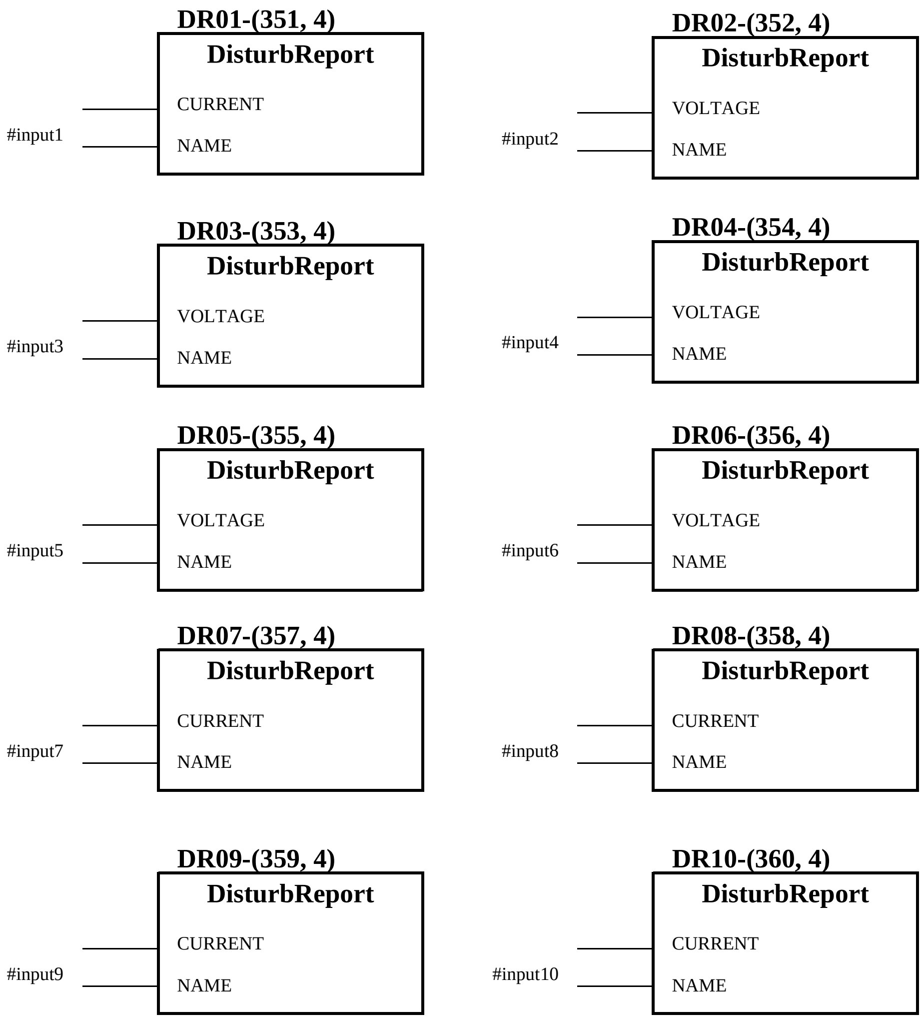


Fig. 96 Function blocks for analogue inputs

35.7 Input and output signals

35.7.1 Input signals

The following signals and parameters are inputs to the disturbance report object. Only the analogue input parameters are specific for the disturbance recorder and the trip values function and are thus only available when any of these options is installed.

- CLRLEDS This binary signal is used to clear the built-in HMI LEDs.
- INPUTx These input signals are used to select the binary input signals that will be recorded. The signals can be any binary signal in the terminal, binary input signals or internally generated within the terminal.
- NAMEx User assigned name of the binary input signal.
- VOLTAGE This input signal is used to select a voltage signal that will be recorded by the function. The selected signal cannot be generated, e.g. a calculated value, in the RET521 terminal and must be connected directly to a voltage input of the terminal.
- CURRENT This input signal is used to select a current signal that will be recorded by the function. The selected signal cannot be generated, e.g. a calculated value, in the RET521 terminal and must be connected directly to a current input of the terminal.
- NAME User assigned name of the analogue input signal.

35.7.2 Output signals

The following signals are output signals of the disturbance report function block.

- OFF Disturbance report operation during normal condition is turned off.
- RECSTART This signal is set when a disturbance recording has been started, i.e. a recording is currently performed.
- RECMADE This output signal is set when a disturbance recording has been completed, i.e. a disturbance has been recorded, compressed and stored to a file in non-volatile memory.
- CLEARED This signal is set when all recorded disturbances in the disturbance report are cleared.
- MEMUSED This output signal is set when the memory usage is over 80% of the available memory assigned to the disturbance recorder function.
- ERROR This output signal is set to indicate an internal error of the disturbance report function.

35.8 Setting parameters and ranges

35.8.1 Description of parameters

35.8.1.1 General

- Operation Defines if the disturbance report function is turned on or off.
- PostRetrig Defines if a new recording can be started during the post-fault period of a recording or not.
- SequenceNo Sequence number of the recorded disturbance.
- tPre Defines the pre-fault recording time, i.e. the length of the recorded time period prior to the start of a disturbance recording.
- tPost Defines the post-fault recording time, i.e. the length of the recorded time period after the trig condition has reset.
- tLim Defines the maximum length of a disturbance. The pre-fault period is not included in this limit.
- SamplingRate Defines the rate used to sample the binary and analogue input signals.
- FreqSource Defines which analogue input signal that should be input to the line frequency caclulation of the trip values function. This signal will also be used as reference when the phase angles are calculated.

Description	Name	Unit	Range	Step	Default
Operation	Operation	0 = Off 1 = On	0 - 1	1	1
Retrig during post fault	PostRetrig	0 = Off 1 = On	0 - 1	1	0
Sequence number	SequenceNo	-	0 - 255	1	0
Pre-fault recording time	tPre	s	0.05 - 0.30	0.01 s	0.05 s
Post-fault recording time	tPost	s	0.1 - 3.0	0.1 s	0.5 s
Limit time	tLim	s	0.5 - 4.0	0.1 s	1.0 s
Sampling rate	Samplin-gRate	Hz	1000/1200	-	1000/ 1200
Line frequency source	FreqSource	-	0 - 10 1)	1	0

1) Function block number for analogue channels (DR01........DR10)

35.8.1.2 Binary signals

- TrigOperation Defines if the binary input signal may trig the disturbance recorder.
- TrigLevel Defines if the binary trig operation will trig on a transition from low to high or on a transition from high to low.
- IndicationMask This parameter defines if the binary signal will be shown on the built-in HMI when the indications are scrolled (auto indications).
- SetLED Defines if the selected binary signal will set the red LED of the built-in HMI when active.

Description	Name	Unit	Range	Step	Default
Trig operation	TrigOperation	0 = Off 1 = On	0 - 1	1	0
Trig level	TrigLevel	0 = Trig on 1 1 = Trig on 0	0 - 1	1	0
HMI indica-tion mask	IndicationMask	0 = Masked 1 = Show	0 - 1	1	0
Set red led	SetLED	0 = Off 1 = On	0 - 1	1	0

35.8.1.3 Analogue signals

- Operation Defines if the connected analogue input signal will be recorded during a disturbance.
- NominalValue Defines the nominal value of the input signal. This value is used to calculate the absolute limits used by the under and over trig functions.
- <TrigOperation Defines if the analogue signal may generate an under trig condition used to start a disturbance recording.
- >TrigOperation Defines if the analogue signal may generate an over trig condition used to start a disturbance recording.
- <TrigLevel Under trig level, relative the rated value of the analogue input signal.
- >TrigLevel Over trig level, relative the rated value of the analogue input signal.

All the binary and analogue settings are set for each selected input signal, i.e. every signal has its own unique settings according to above. The general settings above apply to a single disturbance recording.

Description	Name	Unit	Range	Step	Default
Operation	Operation	0 = Off 1 = On	0 - 1	1	0
Nominal value	NominalValue	kV (U) A (I)	0.0 - 999999.9	0.1	1000
Under trig operation	<TrigOperation	0 = Off 1 = On	0 - 1	1	0
Over trig operation	>TrigOperation	0 = Off 1 = On	0 - 1	1	0
Under trig level	<TrigLevel	%	0 - 200	1%	50%
Over trig level	>TrigLevel	%	0 - 5000	1%	200%

35.9 Service value report

Table 104:

Parameter:	Range:	Step:	Description:
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
<TrigStatus	0 - 1	1	Under trig status, Passive/Active
>TrigStatus	0 - 1	1	Over trig status, Passive/Active

Table 104:

Parameter:	Range:	Step:	Description:
>TrigStatus	0 - 1	1	Over trig status, Passive/Active
>TrigStatus	0 - 1	1	Over trig status, Passive/Active
>TrigStatus	0 - 1	1	Over trig status, Passive/Active
>TrigStatus	0 - 1	1	Over trig status, Passive/Active
>TrigStatus	0 - 1	1	Over trig status, Passive/Active
>TrigStatus	0 - 1	1	Over trig status, Passive/Active
>TrigStatus	0 - 1	1	Over trig status, Passive/Active
>TrigStatus	0 - 1	1	Over trig status, Passive/Active
>TrigStatus	0 - 1	1	Over trig status, Passive/Active
Memory Used	0 - 100		Memory used[a]

a. Rounded up to nearest integer.

36 Remote communication (RC)

36.1 Summary of application

The remote communication can be used for different purposes to enable better access to the information stored in the terminals.

The remote communication can be used with a station monitoring system (SMS) or with computerised substation control system (SCS). Normally, SPA communication is used for SMS and LON communication for SCS. SPA communication is also applied when using the front communication port, but for this purpose, no special Remote communication function is required in the terminal. Only the software in the PC and a special cable for front connection is needed.

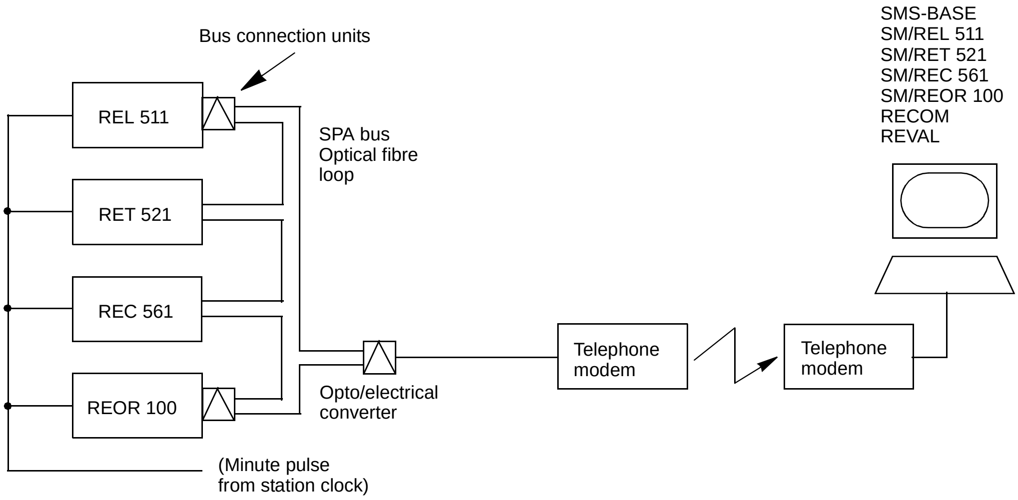


Fig. 97   Example of SPA communication structure

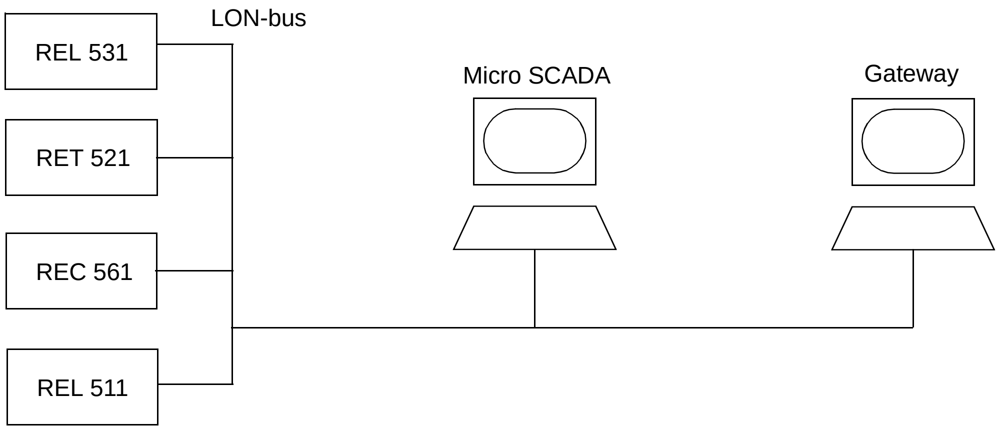


Fig. 98   Example of LON communication structure

36.2 Summary of function

All remote to and from the terminal (including front communication) uses either the SPA bus V 2.4 protocol or the LonTalk protocol.

The remote communication uses optical fibres for transfer of data within a station. The principle of two independent communication ports is used. For this reason, two serial ports for connection of optical fibres are optionally available in the terminal, one for LON communication and one for SPA communication.

36.2.1 SPA operation

The SPA protocol is an ASCII based protocol for serial communication. The communication is based on a master - slave principle, where the terminal is the slave and the PC is the master. Only one master can be applied on each application. A program is needed in the master computer for interpretation of the SPA bus codes and for translation of the settings sent to the terminal. This program is called SMS-BASE. Apart from this program the terminal specific program SM/RET 521 is needed. For configuration CAP 531 and CAP/RET 521 programs are required.

36.2.2 LON operation

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 pier-to-pier protocol where all the devices connected to the network can communicate with each other directly.

36.3 Description of logic

The remote communication uses optical fibres for transfer of data within the station. For this purpose two serial ports for connection of optical fibres are optionally available on the rear of the terminal. One is intended for SPA communication and the other for LON communication. The principle of two independent communication is used.

36.3.1 SPA communication

When communicating locally with a PC in the station using the rear SPA port, the only hardware needed for a station monitoring system is:

- optical fibres
- opto/electrical converter
- PC

When communicating remotely with a PC using the rear SPA port, the same hardware plus a telephone modem is required.

Depending on the functional requirements all or part of the following software packages can be used for SPA communication:

- SMS-BASE, base program. Required when SM/RET 521 or RECOM is used.
- SM/RET 521, terminal specific program for setting and retrieving information.
- CAP 531, base program. Required for CAP/RET521
- CAP/RET 521, terminal specific configuration tool
- RECOM, program for collection of disturbance files. Not required for front communication.
- REVAL, program for visualisation of disturbance data

There are two parameters, that can be set for remote communication. These two are the “slave number” and “baud rate”. These can for obvious reasons only be set on the built-in HMI.

36.3.2 LON communication

The hardware needed for applying LON communication depends on the application, but one very central unit is the LON Star Coupler and optical fibres connecting the star coupler to the terminals.

The LNT, LON Network Tool is used to set the communication parameters. This is a software tool, that is applied as one node on the LON bus.In order to communicate via LON, the terminals need to know which node addresses the other connected terminals have and which network variable selectors should be used. This is organised by the LNT. The node address is transferred to the LNT via the built-in HMI or the LNT can scan the communication network for new nodes.

The speed of the communication is set to default 1,25 Mbits/s. This can be changed by the LNT. If the communication stops, caused by setting of illegal communication parameters or by other disturbance, the parameters can be re-set to default values on the built-in HMI.

36.4 Setting parameters and ranges

36.4.1 SPA communication

Parameter:	Setting range:	Description:
Rear:		
SlaveNo	(1 - 899)	SPA-bus identification number
BaudRate	300, 1200, 2400, 4800, 9600, 19200, 38400 Baud	Communication speed
RemoteChActgrp	Open, Block	Open=Access right to change between active groups (both rear ports)
RemoteChSet	Open, Block	Open=Access right to change any parameter (both rear ports)
Front:		
SlaveNo	(1 - 899)	SPA-bus identification number
BaudRate	300, 1200, 2400, 4800, 9600 Baud	Communication speed

36.4.2 LON communication

There are a number of session timers which can be set via the built-in HMI.These settings are only for advanced users and should only be changed after recommendation from ABB Automation Products AB.

Table 105: Session timers

Parameter	Default value	Description
SessionTmo	20s	Timeout value for the session
RetryTmo	2000 ms	Triggers a retransmission of the message if the message or ACK/NACK is missing when time is out.
IdleAckCycle	5s	Periocity for cyclic idle channel alive transmissions and retransmission of ACK when lost.
BusyAckTmo	300ms	ACK delay time upon recieved message. Sender can bypass the delay by flagging a message for immiedate ACK.
ErrNackCycle	500ms	Periocity value for cyclic NACK transmission during network congestion

The chapter "Design description".

This chapter describes the protection terminal hardware design and each module. This chapter also contains terminal diagrams and technical data.

HW-description RET 521

1 Hardware design

The RET521 follows the 6U Eurocard industry mechanical standard with a passive backplane and a number of slots. The backplane supports two kinds of modules, standard CompactPCI modules and specific ABB Automation Products AB modules based on the CAN bus.

All modules are designed for low power dissipation (no fans), EMC safety (both immunity and emission) and good environmental resistance. That gives high reliability and safe system also under disturbed and rugged conditions.

1.1 Hardware architecture

RET 521 consists of a number of different modules. These modules communicate through the PCI bus or the CAN bus. The PCI bus is used for modules which need extra high transfer rate. Modules with low and medium data rate use the CAN bus.

The local HMI unit communicates directly with the NUM module through two serial channels. Remote HMI is connected via the SPA bus, VDEW-6 bus or the LON bus.

1.2 Hardware modules

The basic configuration of the RET 521 consist of the following modules:

- CBM, Combined Backplane Module. The backplane has 8 slots for CompactPCI modules and 4 slots for specific ABB Automation Products AB modules. One slot is designed for the power supply module.
- AIM, Analog Input Module. CompactPCI module with 10 high performance analogue input channels. The module consists of transformers, analogue to digital converters and a signal processor. Main functions in the software are:
  - time stamping of all values
  - filtering and calibration adjustments of analog inputs
  - self supervision

- NUM, Numerical Module. Main CPU module based on a high performance PowerPC processor. Fits into the specific system slot in the backplane. The module may carry a mezzanine card, according to the PMC (PCI Mezzanine Card) standard, see SLM module. The software system is running under a real time operating system. Main functions in the software are:
  - administration of the CompactPCI bus
  - administration of the CAN bus
  - supervision of all modules included in the rack
  - control error handling
  - control the I/O system
  - handle local HMI
  - handle remote HMI (communication via SPA, VDEW-6 and LON bus)
  - RET521 function execution
- PSM, power supply module. DC/DC converter that support the electronics with +/-12V, +5V and +3,3V. The module can provide up to 50W. Supervision of all voltages are implemented. The module includes one relay output for the “Internal Fail“ signal.
- HMI, human machine interface. Local HMI panel located at the front of the RET 521 terminal.

1.2.1 Optional modules

- SLM, Serial channel and LON channel Module. A mezzanine card for the NUM module, follows the PMC standard. Communication module with two optical interfaces. One for SPA/VDEW-6 bus and one for the LON bus.
- BIM, Binary input module. CAN based module with 16 optical isolated binary inputs. Main functions in the software are:
  - time stamping of all events
  - filtering of binary inputs
  - possibility to have any input as time synchronizing input using galvanic minutepulse
  - pulse counters
  - self supervision
- BOM, Binary output module. CAN based module with 24 relay outputs. 24 single-output relays or 12 freely contacts for “select before execute” output relays. Main functions in the software are:
  - time stamping of all event
  - self supervision

- IOM, Input and output module. CAN based module with 8 optical isolated binary inputs and 12 relay outputs. Main functions in the software are:
  - time stamping of all events
  - filtering of binary inputs
  - possibility to have any input as time synchronizing input using galvanic minutepulse
  - self supervision
- MIM, Milliampere input module. CAN based module with 6 optically isolated low speed analog inputs. All channels are factory calibrated. Main functions in the software are
  - time stamping of all events
  - filtering and calibration adjustments of analog inputs
  - programmable alarm levels
  - self supervision

2 Technical data

Table 1: Electromagnetic compatibility (EMC), immunity tests

Test	Type test values	Reference standards
1 MHz burst disturbance	2,5 kV	IEC 60255-22-1, Class III
Electrostatic discharge	8 kV	IEC 60255-22-2, Class III
Fast transient disturbance	4 kV	IEC 60255-22-4, Class IV
Surge immunity test	2-4 kV, 1,2/50 μs, high energy	IEC 61000-4-5, Class IV
Radiated electromagnetic field disturbance	10 V/m, 26-1000 MHz	EN 61000-4-3, level 3
Conducted electromagnetic field disturbance	10 V/m, 0,15-80 MHz	EN 61000-4-6, level 3

Table 2: Electromagnetic compatibility (EMC), emission tests

Test	Type test values	Reference standards
Electromagnetic emission radiated	30-1000 MHz, class A	EN 55011
Electromagnetic emission conducted	0.15 - 30 Mhz, class A	EN 55081-2

Table 3: Insulation tests

Test	Type test values	Reference standards
Dielectric test All circuits, to earth and other circuits	2,0 kV ac 1 min	IEC 60255-5
Impulse voltage test	5 kV, 1,2/50 μs, 0,5 J	IEC 60255-5
Insulation resistance	> 100 Mohm at 500 V dc	IEC 60255-5

Table 4: Mechanical tests

Test	Type test values	Reference standards
Vibration	Class I	IEC 60255-21-1
Shock and bump	Class I	IEC 60255-21-2
Seismic	Class I	IEC 60255-21-3

Table 5: Connection system

Connector type	Rated voltage	Maximum square area	Maximum load continuous	Maximum load 1 s
Voltage connectors	250 V AC	2,5 mm^2 2 x 1 mm^2	10 A	30 A
Current connectors	250 V AC	4 mm^2	20 A	500 A

Table 6: Additional general data

Operating temperature	-5°C to +55°C
Storage temperature	-40°C to +70°C
Dimensions Width Height Depth	 336 mm (3/4 of 19”) 6U = 266 mm 245 mm

3 Block diagram

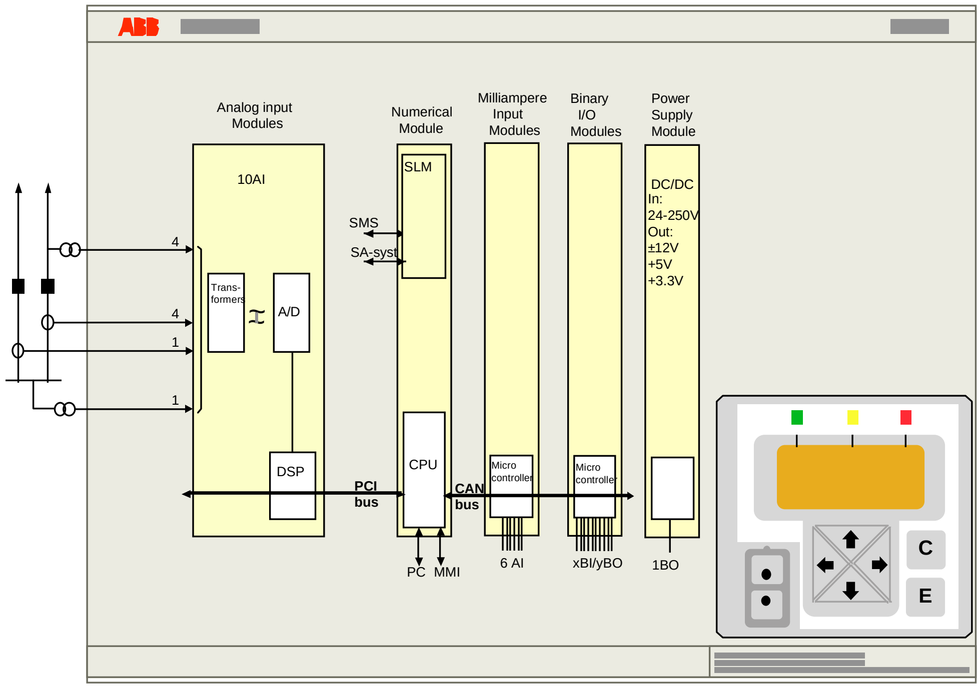


Fig. 1 Internal hardware structure of the RET521 platform

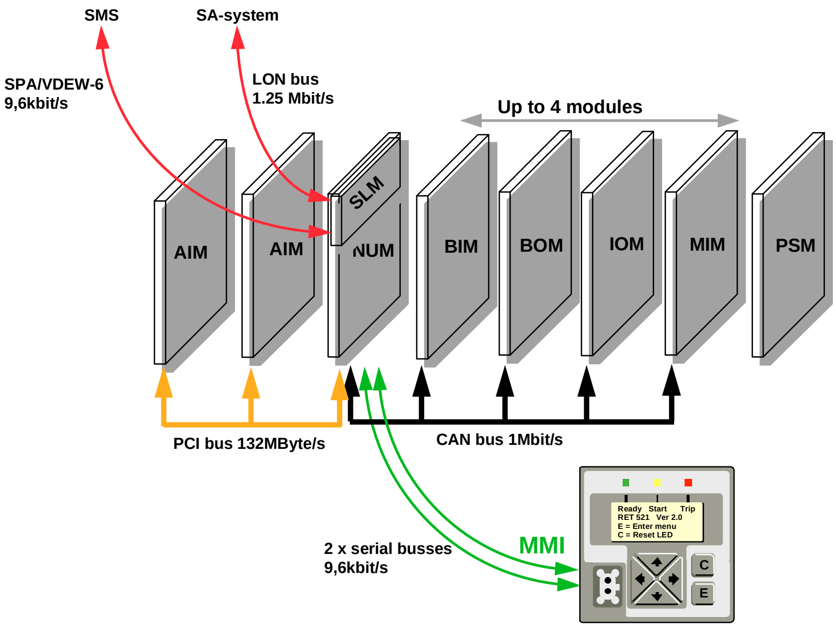
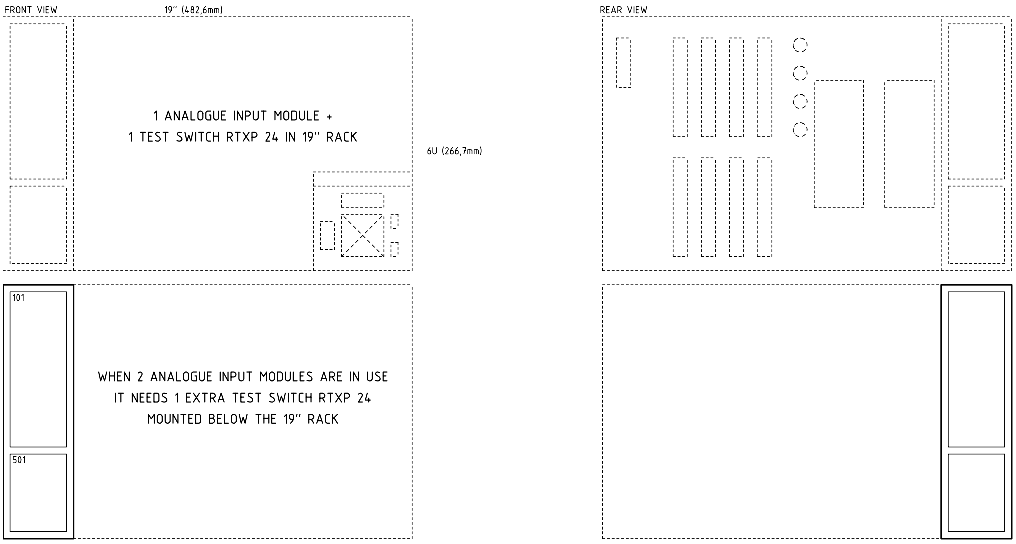


Fig. 2 Internal and external communications busses

4 Terminal diagrams

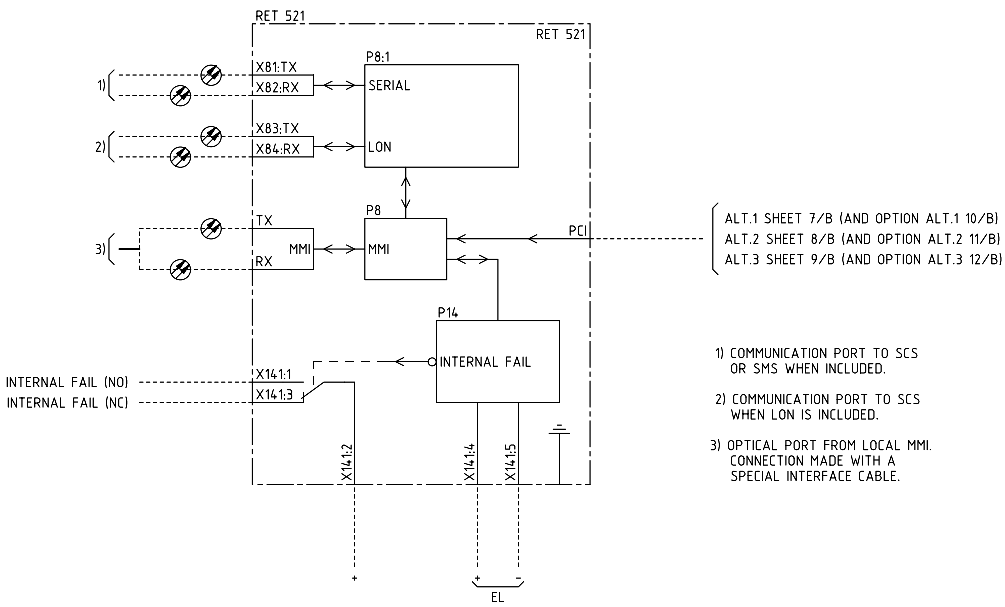
4.1 Hardware and data



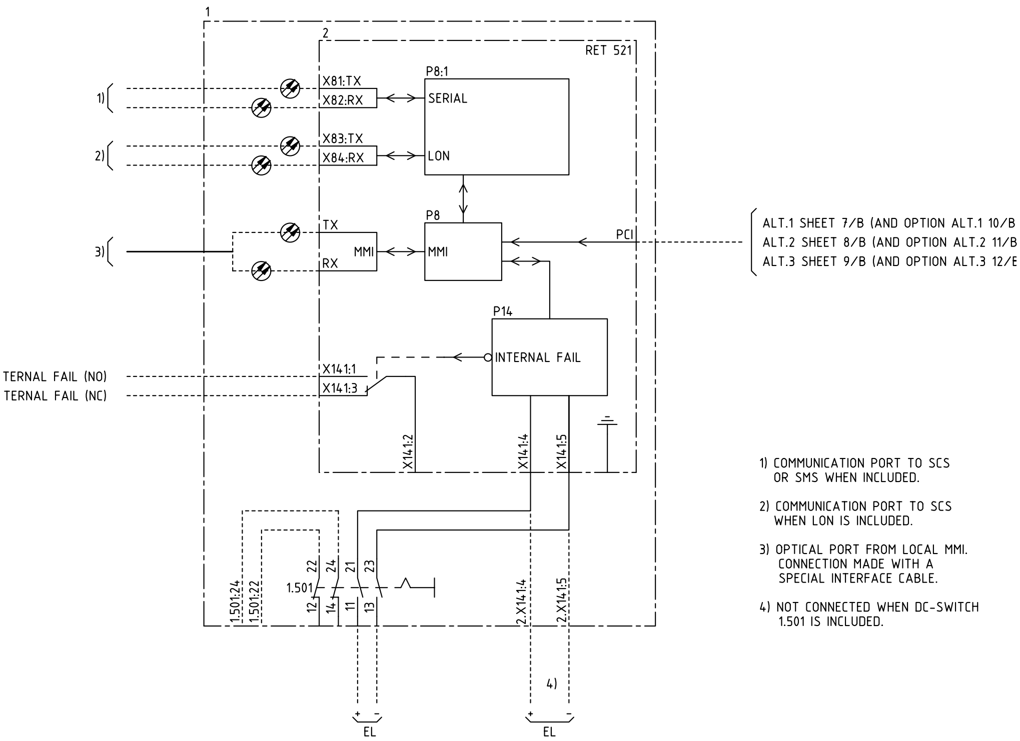
HARDWARE AND DATA

INCLUDED	LOCATION	DESCRIPTION
X	1	TEST SWITCH MODULE
X	1.101	TEST SWITCH RTXP 24
	1.501	DC-SWITCH

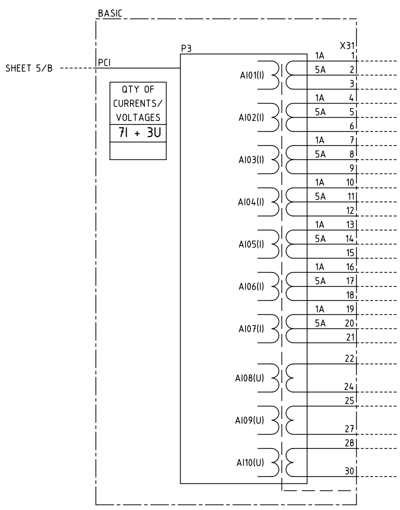
4.2 RET 521 terminal diagram

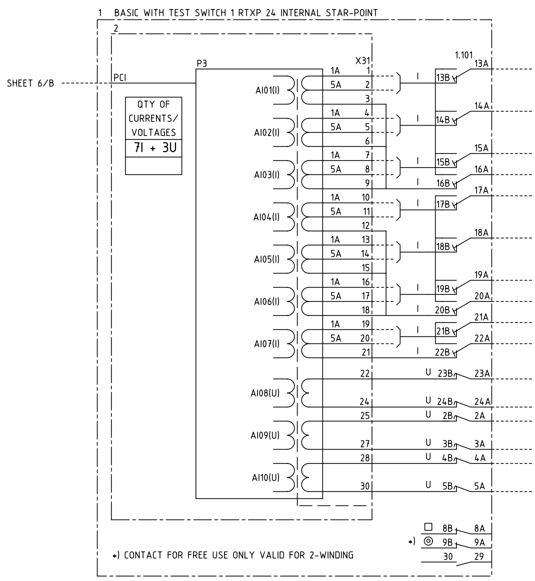


4.3 DC-switch

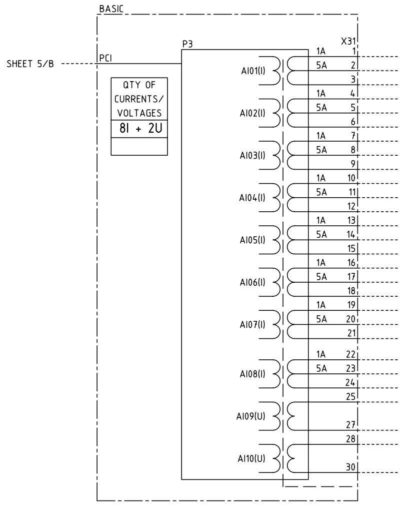


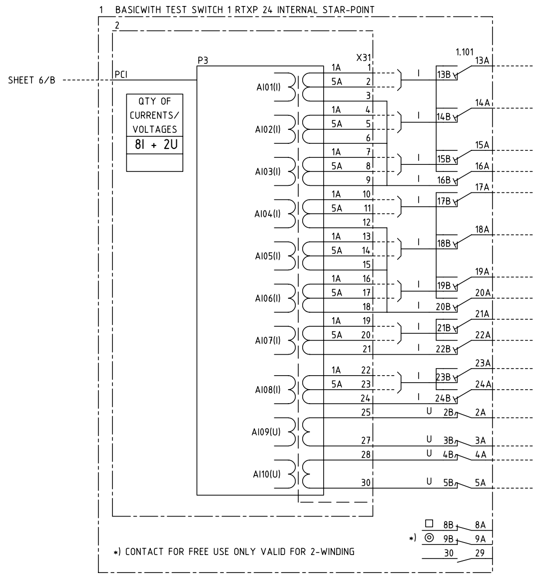
4.4 Analogue input module

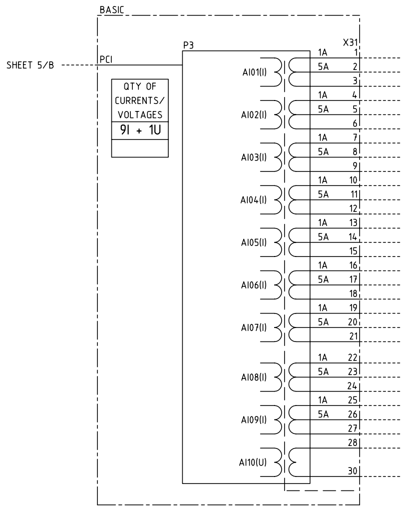


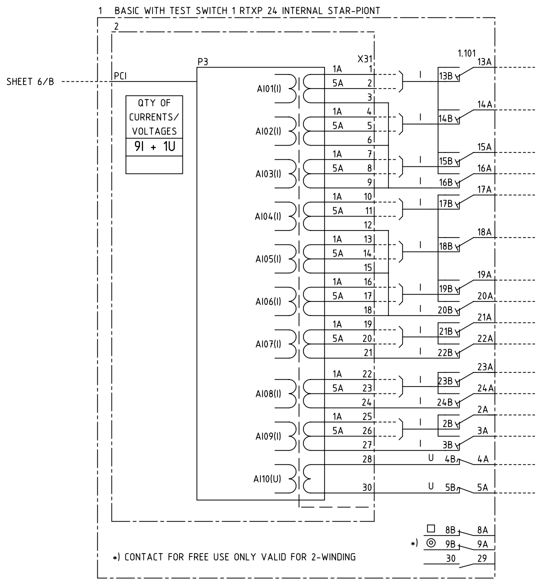


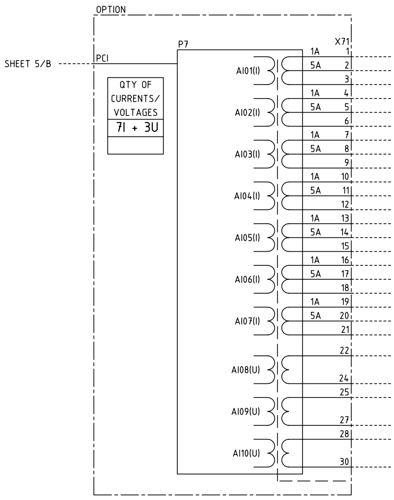
4.5 Analogue input module

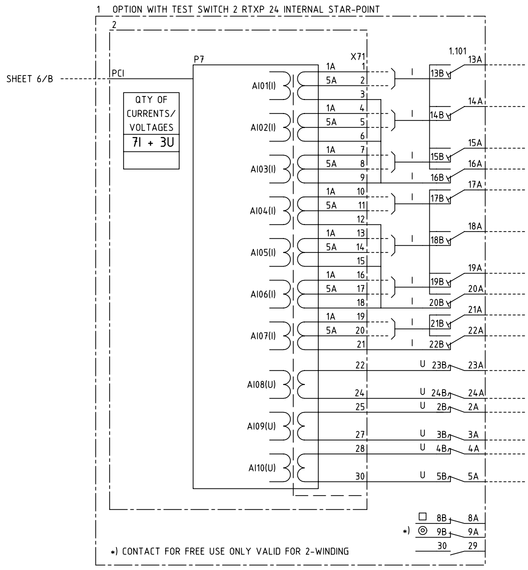


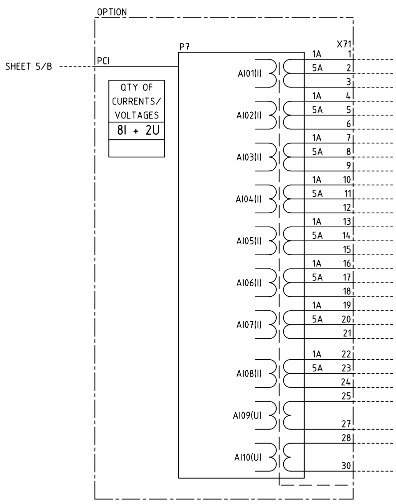


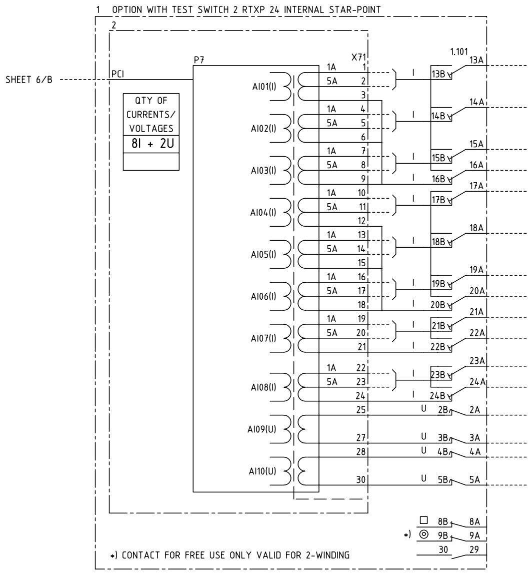


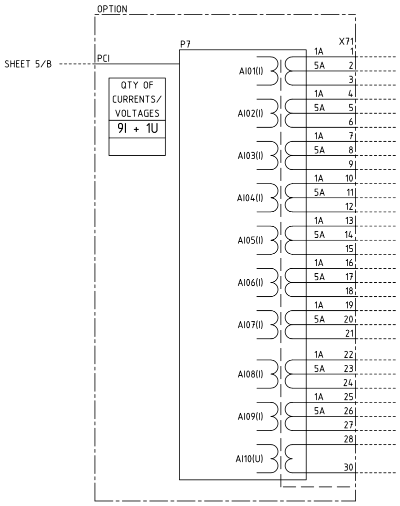


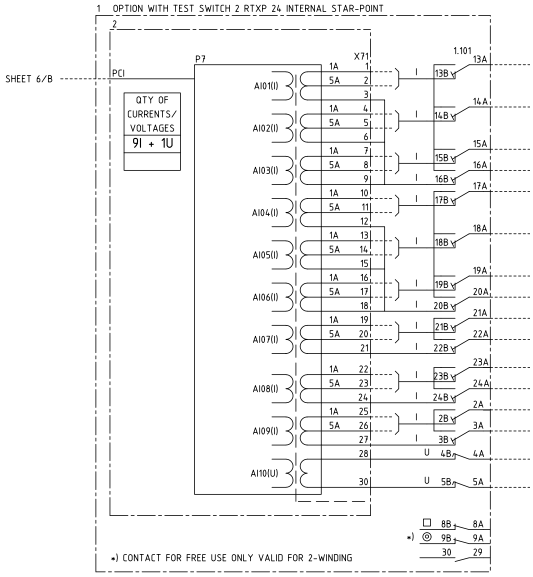




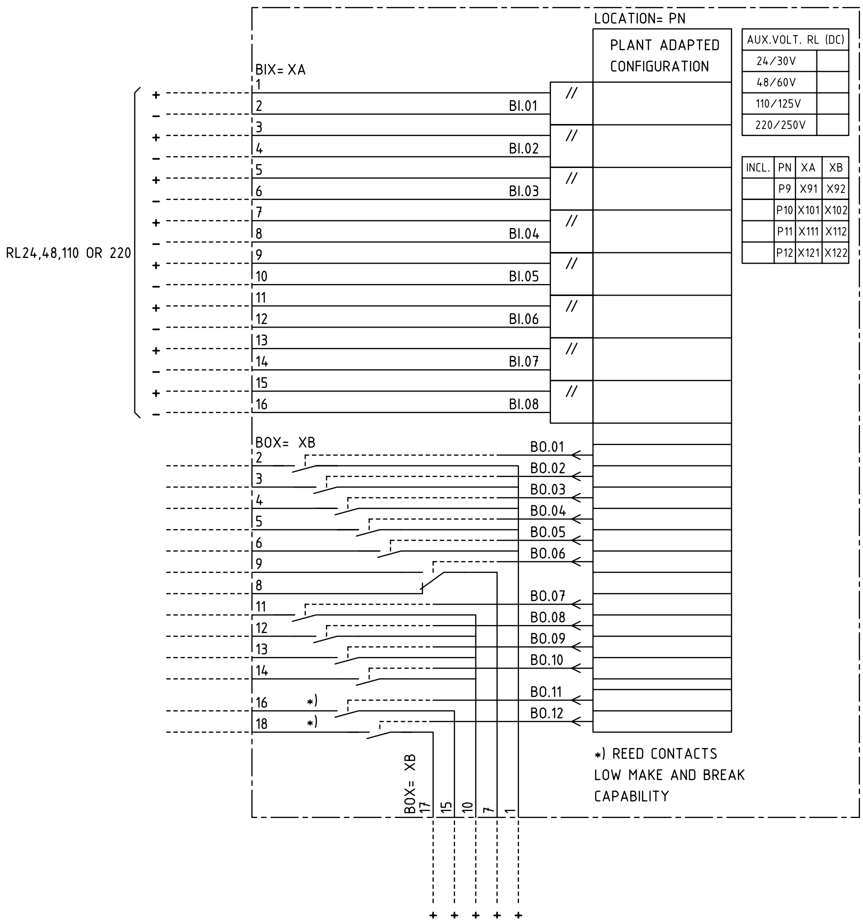




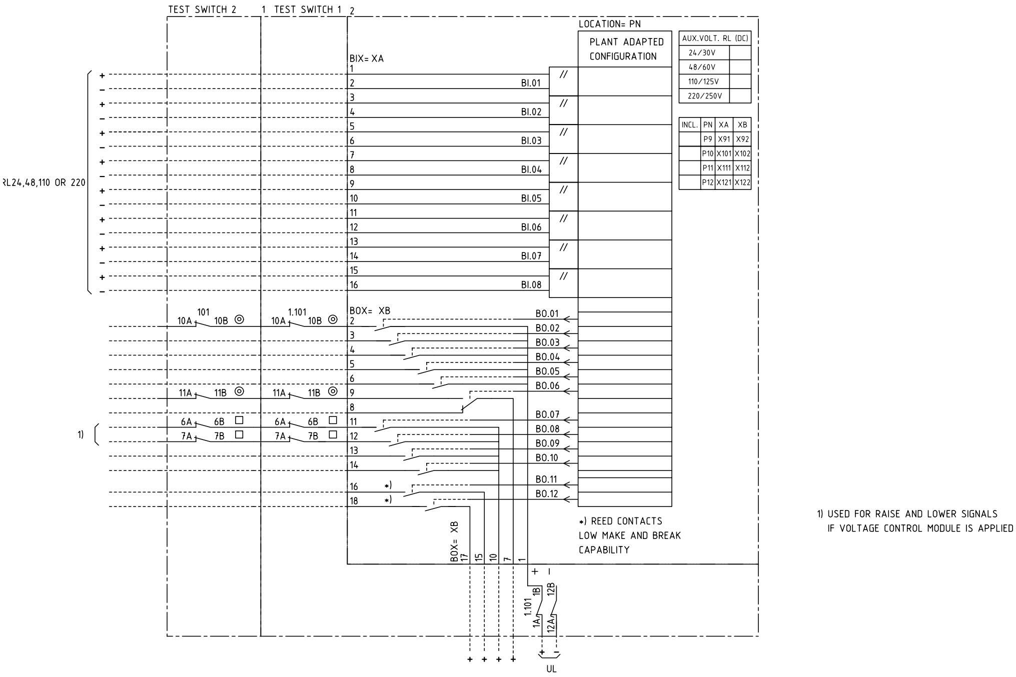




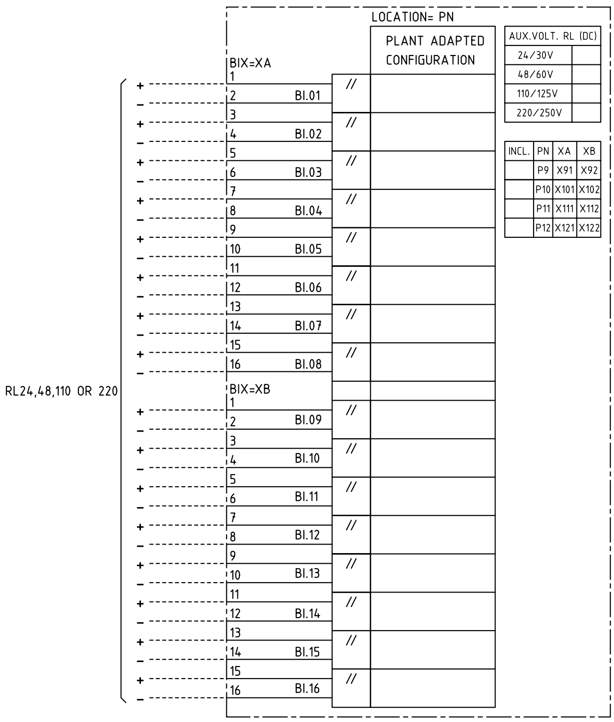
4.6 Binary in/out module



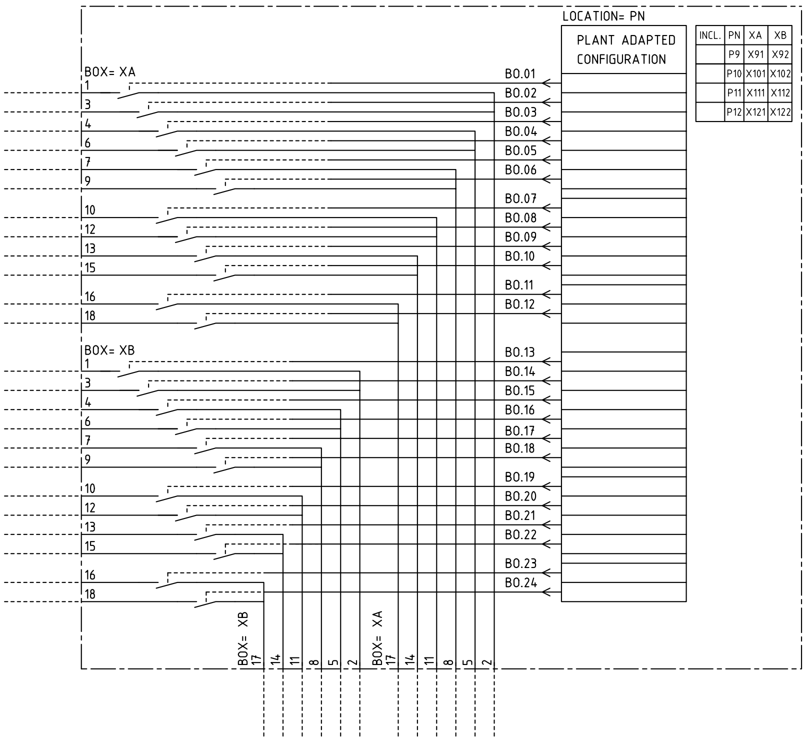
4.7 Binary in/out module with test switch RTXP 24 internal star-point



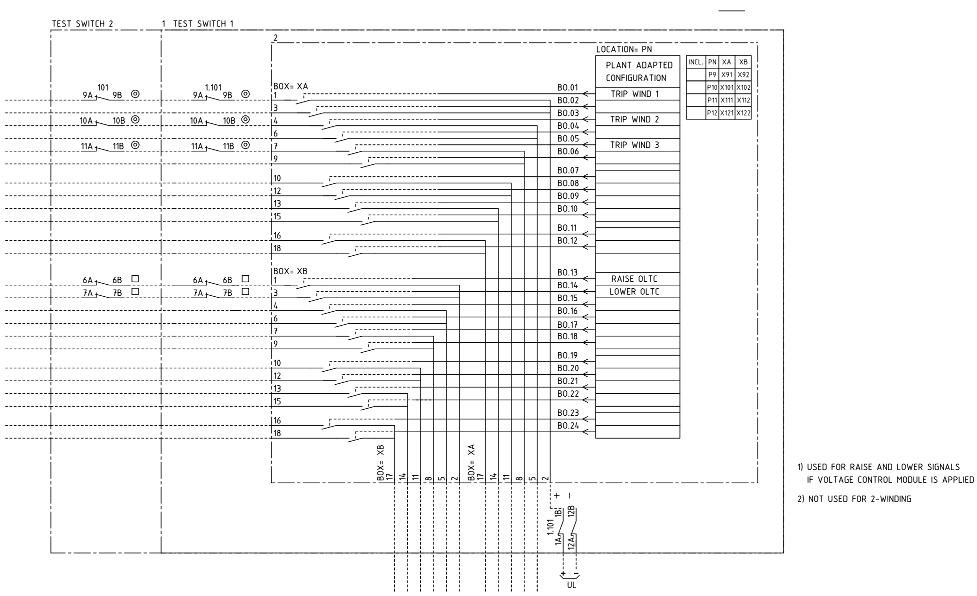
4.8 Binary in 16 module



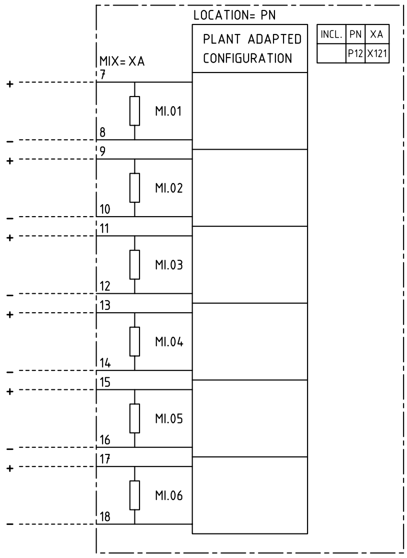
4.9 Binary out module



4.10 Binary out module with test switch RTXP 24 internal star-point



4.11 mA input module



HW-modules

5 Numerical module (NUM)

5.1 Hardware design

The NUM, NUmerical Module is a high performance cpu module based on a 100MHz PowerPC 603e processor. The PowerPC processor was selected because its high floating point performance and low power consumption. The Power PC processor is a superscalar pipelined RISC processor with 16kbyte of code cache and 16 kbyte of data cache.The module is designed to be used in a CompactPCI system slot.

To reduce busloading of the compactPCI bus in the backplane the NUM has one internal PCI bus for internal recourses and the PMC slot and external PCI accesses through the backplane are buffered in a PCI/PCI bridge.

The 32Mbyte of EDODRAM is soldered on the module. The memory accesses are controlled by a processor support chip MPC106 with ECC, which corrects every single bit error and detects every double bit error.

For Boot code there is 512kbyte of bootflash.

The application code and configuration data is stored in 16Mb of flash memory using a flash file system. During power up the application code is moved to and then executed from the DRAM. The code is stored in the flash memory because its nonvolatile and executed in DRAM because of the DRAMs higher performance.

The NUM is equipped with a real time clock and complies with the year 2000 transition.

For identification in production and during field upgrades the NUM is equipped with a IDchip. The IDchip has a singelline interface, a factory programmed unique serialnumber, during production its programmed with article number, hardware version and final test date.

For identification of modules without a local processor there is a signal to the backplane named SYSID, through which the NUM reads their identification data.

The module has two asynchronous serialports connected to the backplane. One for the HMI display and keyboard and one for the HMI optical interface.

For communication with high speed modules ex. analog input modules and high speed serial interfaces the NUM is equipped with a Compact PCI bus. The NUM is the compact PCI system card i.e. it controls busmastering, clockdistribution and receives interrupts.

For communication with lower speed modules e.q. binary in and outputs the NUM is equipped with a CAN bus interface.

The NUM is equip with a PMC slot in which as option a daughtercard may be mounted e.g. an SLM.

5.2 Technical specifications

5.2.1 CompactPCI Compliance

The NUM conforms to the CompactPCI Specification revision 1.0.

5.2.2 Local Resources

Processor	PowerPC 603e at 100 MHz CPU bus frequency 66 MHz
DRAM	32 Mbytes with ECC on-board. Further expansion to 64 Mbytes via two 72-pin SIMM sockets
Flash boot ROM	512 Kbytes or 1 Mbyte in one or two 4 Mbit EPROMs
User Flash	Up to 16 Mbytes of word-wide 5V program Flash
RTC	MS1286 RTC with battery backed NOVRAM
PCI Internal Bus	5V, 32-bit at 33 MHz
PMC Slot	One 5V, 32-bit IEEE P1386.1 compliant slot with front panel I/O. Some signals on the PMC are tracked directly to the user defined signals on the CompactPCI backplane
Serial I/O	Two PC-style COM ports connected to the MMI through the backplane via J1 connector (TTL levels). One port also available via front panel mounted 9-way D-type connector (RS232)
Parallel I/O	Extended Capabilities port conforming to IEEE P1284
Counter/Timers	Two timers in PowerPC 603e chip. Three counters in ISA bridge (UMC 8886). Three independent 16-bit counter/timers in CIO (Z8536) with a resolution of 333ns. Two timers may be linked to form a 32-bit counter/timer
Status LED	One software programmable LED
CAN Interface	One CAN interface conforming to ISO/DIS 11898 and the CAN Specification revision 2.0
IDchip	IDchip containing articlenumber, HWrevision and manufacturingdate

Table 7: Power Requirements

	Typical	Maximum
+3.3 V	1.7A	2.7A
+5 V	0.7A	1.5A
+12 V	10mA	40mA
-12 V	10mA	40mA

Take care when using PMC modules as to how much current they require, especially from the +5V supply.

5.3 Block diagram

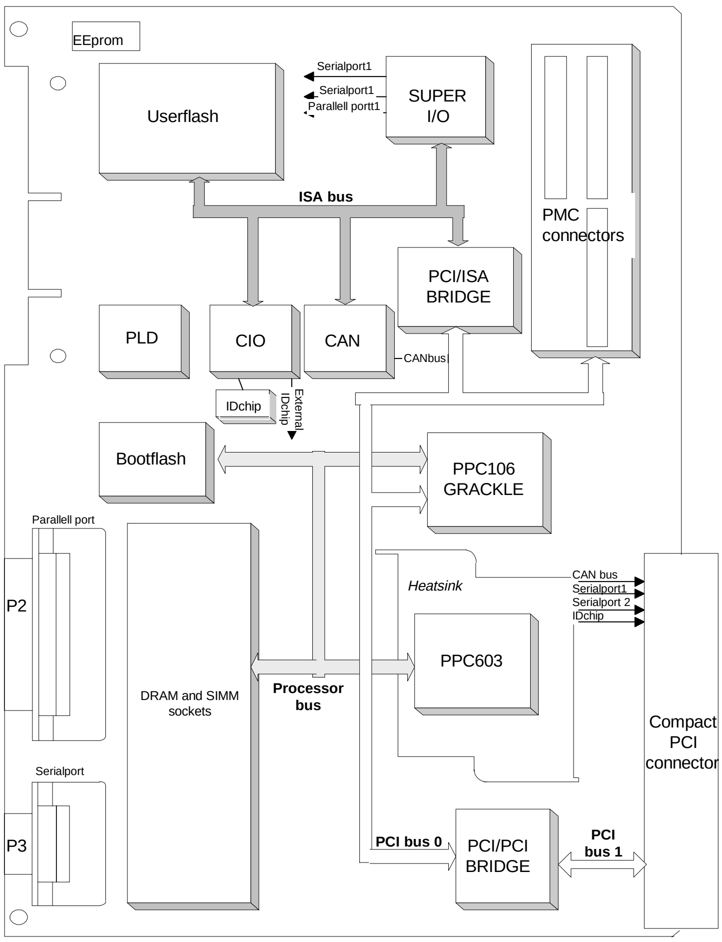


Fig. 3 NUmerical Module blockdiagram

6 Compact backplane module (CBM)

6.1 Hardware design

CBM is a backplane that has 3 CompactPCI connectors and 4connectors for RCAN based ABB boards.For the compact PCI slots a 220pin 2mm Hard Metric connector is used. The RCAN based ABB boards uses a 3 row, 96 pin standard Euro-connector. There is a need for some signals to be present in both connector types. For this purpose some of the User defined part of the CompactPCI connector is used.

The CompactPCI specification gives the possibility for a 3.3V OR 5V signaling in the backplane. The CBM backplane and connected modules must be 5V compatible.

Some pins on the CompactPCI connector is connected to the RCAN bus, to be able to communicate with RCAN based modules.

For identification in production and field upgrades the CBM is equipped with two IDchips with the contents of a factory programmed unique serialnumber, during production its programmed with article number, hardware version and final test date.One contains backplane data and one contains product data.

For the power supply there is a 3 row, 96 pin, Euro-connector.

For powerdegradation early warning there is a signal, ACFail.

If a modules selftest discovers an error it informs other modules through the Internal Fail signal.

6.2 Technical specifications

Table 8: Mounted connectors

Function	Connector identifier
Compact PCI	X3,7,8
RCAN based	X9-12
Power supply	X14
MMI connector	X30

Table 9: The buses in the backplane are connected to the following connectors.

Bus	Connectors
Compact PCI	X3,7,8
RCAN	X3,7,8,9-12,14

Table 9: The buses in the backplane are connected to the following connectors.

Bus	Connectors
MMI display and keyboard interface	X3,7,8,9-12
MMI optical communi-cation interface	X3,7,8,9-12

Table 10: Special signals

Signal	Description	Connector
PRST	System reset	X3,7,8,9-12,14
AC_FAIL_N	Power supply degradation early warning	X3,7,8,9-12,14
INTERNAL_FAIL_M	Module failure broadcast signal	X3,7,8,9-12,14
PPS, MPPS, CMPPS	Timesyncronisation	X3,7,8,9-12,14
SYS_ID	Electronic ID	X3,7,8,9-12,14

Impedance matching: Every signal is impedancematched to 65Ohm +/-10%, calculated for a bare PCB.

6.3 Block diagram

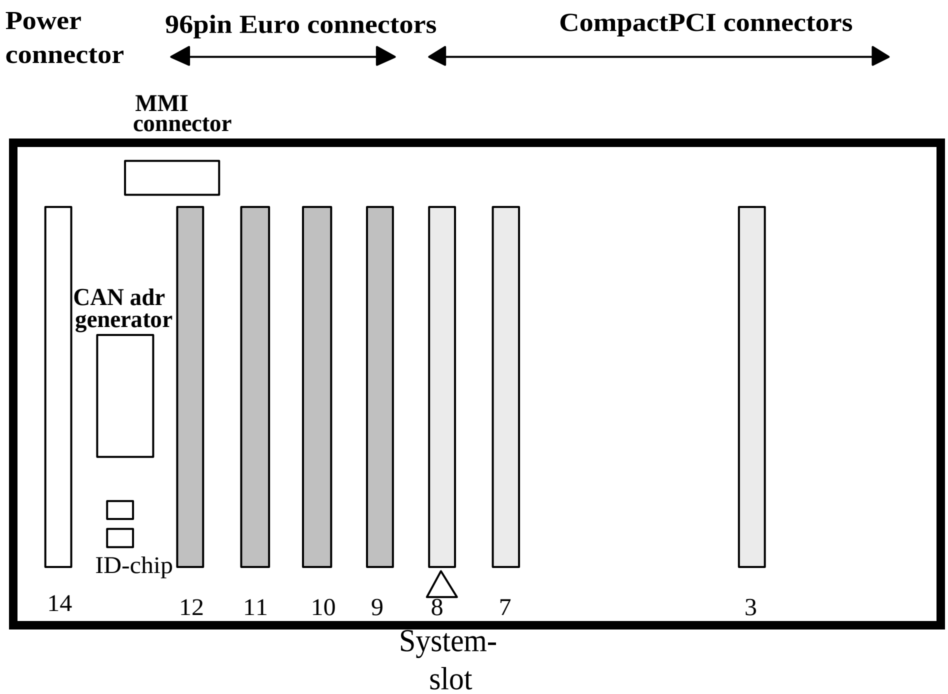


Fig. 4 Connectors on the 3/4 backplane as seen from the connector side

7 Power Supply Module (PSM)

7.1 Hardware design

There are two different types of power supply modules. The Power supplies contains a built-in, self-regulated DC/DC converter that provides full isolation between the terminal and the external battery system.

The first PSM, converts an input voltage range from 24 to 60V, including a ±20% tolerance on the EL voltage.

The second PSM, converts an input voltage range from 110 to 250V, including a ±20% tolerance on the EL voltage.

The output voltages are +3.3, +5, +12 and -12 Volt and the module can provide 50W.

7.2 Block diagram

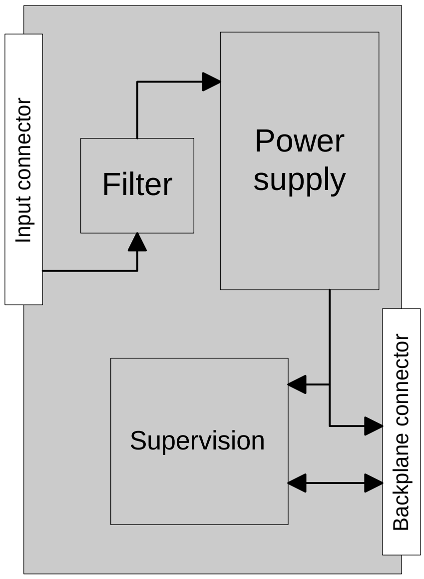


Fig. 5 Block diagram for the PSM.

7.3

8 Analogue input module (AIM)

8.1 Hardware design

The analogue input module (AIM) consists of two connectors for the external connections and two printed board assemblies; transformer board and A/D board.

Current and voltage input transformers are mounted on the transformer board. The transformers form an insulating barrier between the external wiring and the A/D-conversion board, and adapt the values of the measuring quantities to the input circuits of the A/D-conversion board. Maximum ten transformers can be mounted on the transformer board. The design is made for mounting of a current transformer alternatively a voltage transformer in all of the transformer places.

The other printed board assembly is the A/D-conversion board. Over a contact socket strip on the transformer board and a contact pin strip on the A/D board the signals from the transformers are transmitted to input channels of the A/D board. This board is mainly filtering and converting analogue to digital signals. The transmission of data between the A/D board of the analogue input module and the numerical module is done on a backplane board with a CompactPCI bus. The A/D board has ten measuring channels. The channels are equipped with components for current measuring alternatively voltage measuring.

The printed circuit board assemblies and the external connectors are attached with screws to a common mounting plate. The primary windings of the transformers are connected to the external connectors with cables.

Variants of the analogue input module are provided with components for time-synchronization. The time-synchronization components are located on the A/D board. An external synchronization pulse from a synchronization device will be used to get the same time everywhere in the system when the modules are distributed.

8.2 Technical specifications

8.2.1 Transformer board

Toroidal type of transformers are used as current input transformers and EI 38 type of transformers are used as voltage input transformers. The current transformers have windings for both 1A and 5A rated current. The voltage transformers are covering a rated range from 100V to 120V. The process interface of the external connector has screw terminals for maximum one conductor with the area 4mm^2 alternatively two conductors with the area 2,5 mm^2.

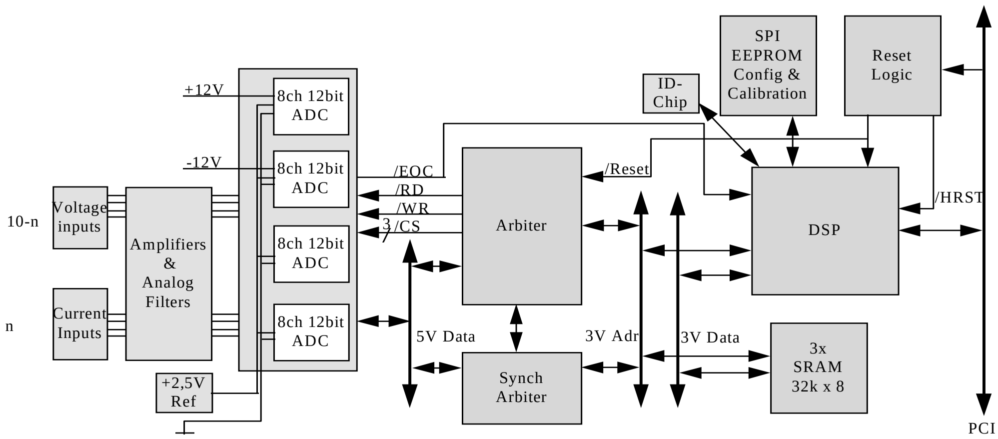
8.2.2 A/D-conversion board

The signals from the transformer board are amplified and filtered with a bandwidth of 10kHz on two ranges for each channel and converted with a resolution of 12 bits. The results, from the conversion on the two ranges, are combined into a single 24bit word and filtered in two cascaded decimation filters programmed into a digital signal processor (DSP).

The numerical filters are of finite impulse response type, giving a linear phase response and appropriate anti aliasing with a cut-off at 2300Hz and 500Hz respectively.

High accuracy is obtained by a calibration process and internal supervision of all vital functions is implemented.

8.3 Block diagram for the A/D-conversion board



9 mA input module (MIM)

9.1 Hardware design

The Milliampere Input Module has six independent analogue channels with separated protection, filtering, reference, A/D-conversion and optical isolation for each input making them galvanic isolated from each other and from the rest of the module.

The differential analogue inputs measure DC and low frequency currents in range of up to +/- 20mA. The A/D converter has a digital filter with selectable filter frequency. All inputs are calibrated separately and stored in a non-volatile memory and the module will self-calibrate if the temperature should start to drift. This module communicates, like the other I/O- modules, with the Main Processing Module via the CAN-bus.

9.2 Technical specifications

Table 11: Energizing quantities, rated values and limits

Quantity:	Rated value:	Nominal range:
mA input module		
input range	± 5, ± 10, ± 20 mA 0-5, 0-10, 0-20, 4-20 mA	± 10 %
input resistance	R_{in} = 194 Ohm	
power consumption		
each mA-board	≤ 4 W	
each mA input	≤ 0,1 W	

9.3 Block diagram

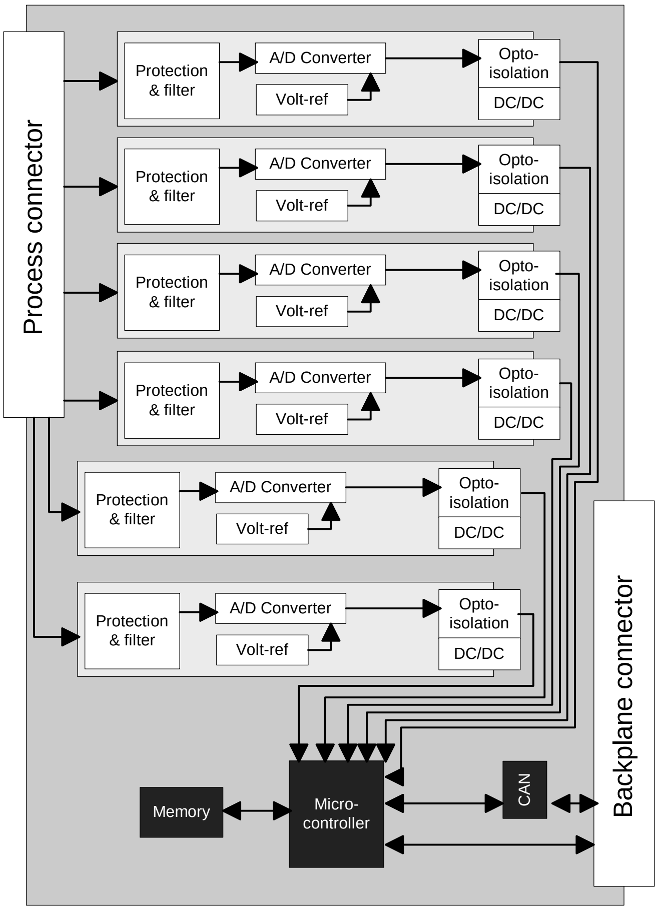


Fig. 6 Block diagram of the Milliampere Input Module

10 Binary input module (BIM)

10.1 Hardware design

In RET521 the number of inputs or outputs can be selected in a variety of combinations. There are no basic I/O configuration of the terminal. Many signals are available for signalling purposes in the terminal, and all are freely programmable. The voltage level of the input modules is selectable at order RL48, 110, or 220 (48/60 V ±20%, 110/125 V ±20% or 220/250 V ±20%). The Binary input module are also available in an RL 24 version (24/30 V ±20%).

The Binary input module contains 16 optical isolated binary inputs. The binary inputs are freely programmable and can be used for the input logical signals to any of the functions. They can also be included in the disturbance recording and event-recording functions. This enables the extensive monitoring and evaluation of operation for the terminal and for all associated electrical circuits. You can select the voltage level of the Binary input modules (RL24, 48, 110, or 220) at order.

Fig. 7 shows the operating characteristics of the binary inputs of the three voltage levels.

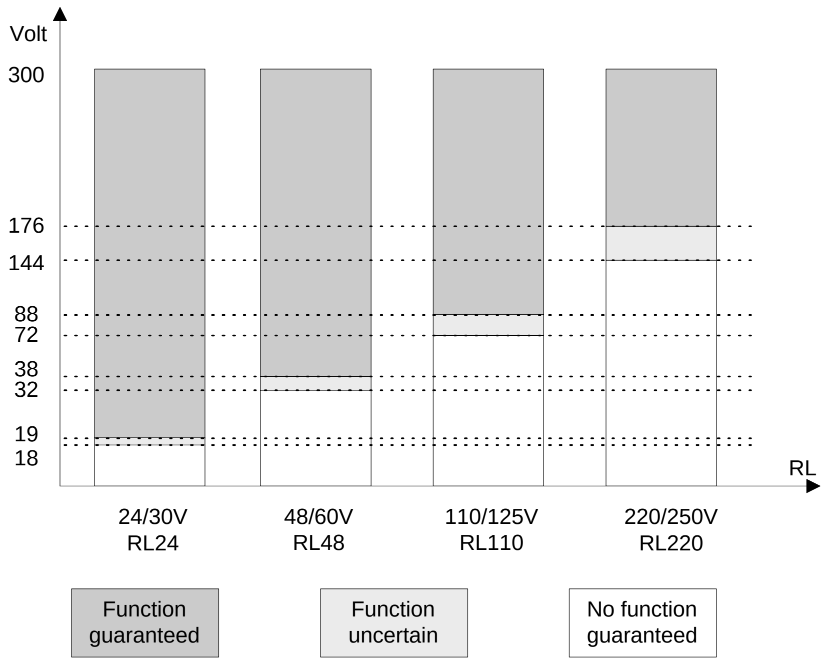


Fig. 7 Voltage dependence for the binary inputs

This module communicates with the NUmerical Module via the CAN-bus on the backplane.

The design of all binary inputs enables the burn off of the oxide of the relay contact connected to the input, despite the low, steady-state power consumption, which is shown in Fig. 8.

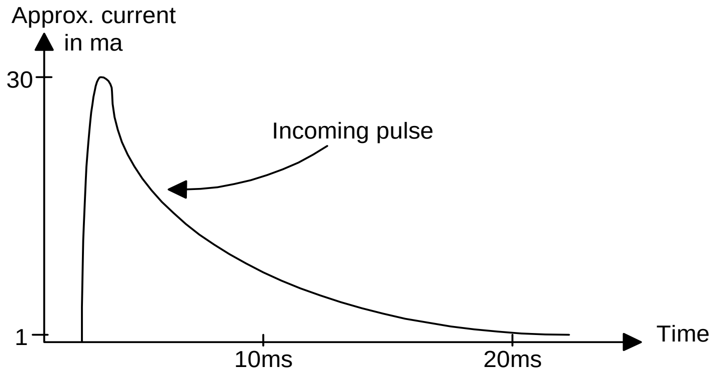


Fig. 8 Current through the relay contact

10.2 Technical specifications

Table 12: Energizing quantities, rated values and limits

Quantity	Rated value	Nominal range
Binary input module		
dc voltage RL	RL24 = (24/30)V	± 20 %
	RL48 = (48/60)V	± 20 %
	RL110 = (110/125)V	± 20 %
	RL220 = (220/250)V	± 20 %
power consumption		
each input-board	≤ 0,5 W	
RL24 = (24/30)V	max. 0,05 W/input	
RL48 = (48/60)V	max. 0,1 W/input	
RL110 = (110/125)V	max. 0,2 W/input	
RL220 = (220/250)V	max. 0,4 W/input	

10.3 Block diagram

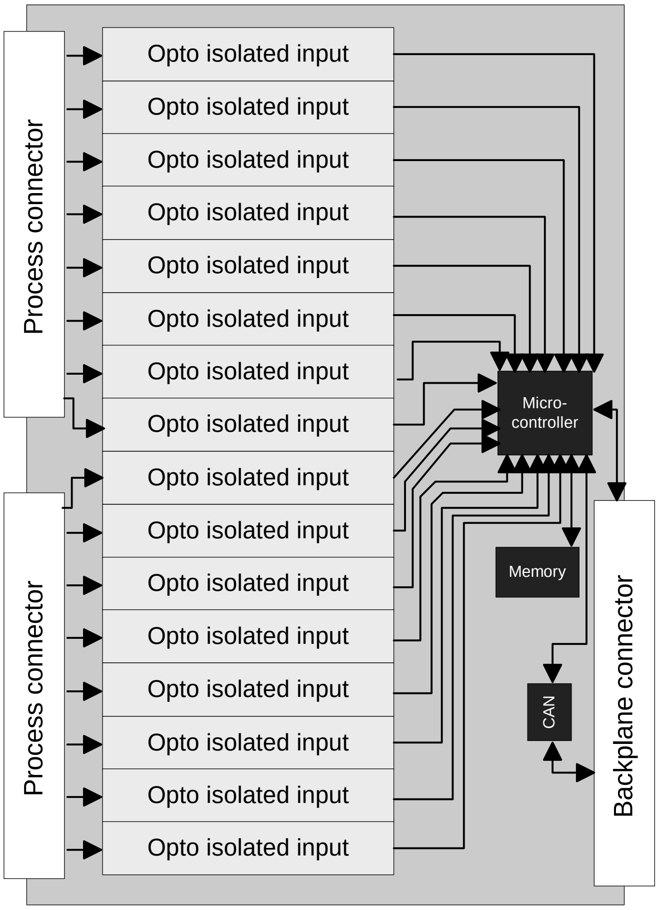


Fig. 9 Block diagram of the Binary input

11 Binary output module (BOM)

11.1 Hardware design

The Binary output module has either 24 single-output relays or 12 command-output relays. They are grouped together as can be seen in the block diagram below. All the output relays have contacts with a high switching capacity (Trip and signal relays)

The voltage level of the output module is selectable at order RL48, 110, or 220 (48/60 V ±20%, 110/125 V ±20% or 220/250 V ±20%).

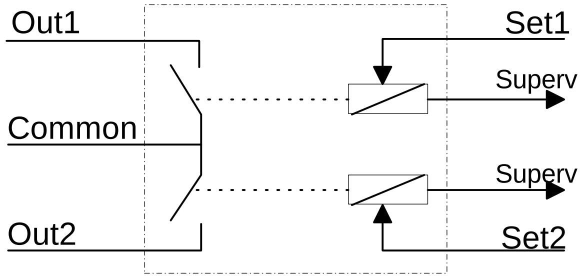


Fig. 10 One of twelve binary output groups

11.2 Technical data

Quantity:	Rated value:	Nominal range:
Binary input module dc voltage RL power consumption each input-board RL24 = (24/30)V RL48 = (48/60)V RL110 = (110/125)V RL220 = (220/250)V	 RL24 = (24/30)V RL48 = (48/60)V RL110 = (110/125)V RL220 = (220/250)V ≤ 0,5 W max. 0,05 W/input max. 0,1 W/input max. 0,2 W/input max. 0,4 W/input	 ± 20 % ± 20 % ± 20 % ± 20 %
Binary output module power consumption each output-board each output relay	 ≤ 1,0 W ≤ 0,25 W	

11.3 Block diagram

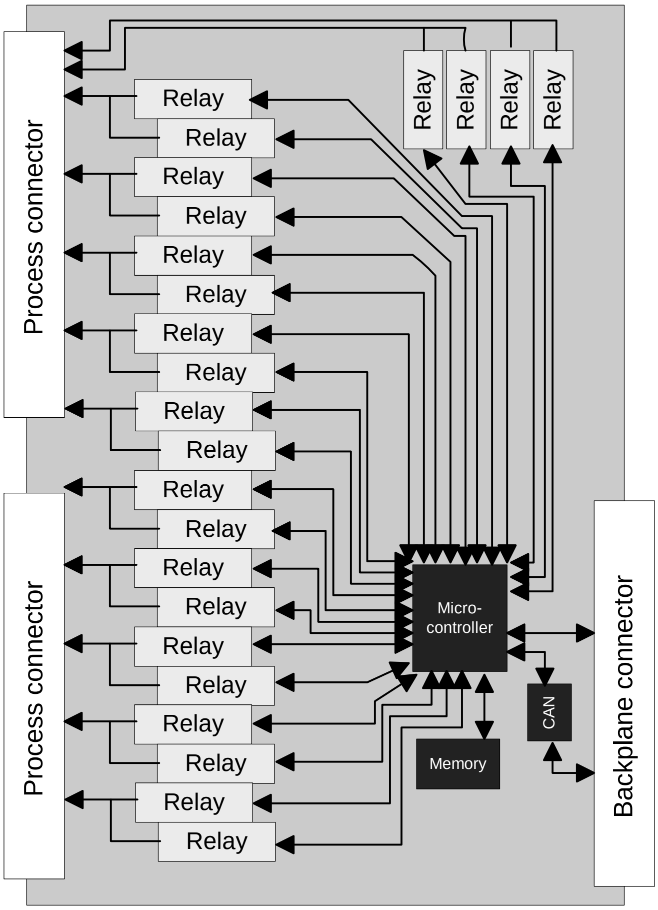


Fig. 11 Block diagram of the Binary Output Module

12 Binary In/Out Module (IOM)

12.1 Hardware design

The Binary in/out module contains eight optical isolated binary inputs and twelve binary output contacts. Ten of the output relays have contacts with a high-switching capacity (Trip and signal relays). The remaining two relays are of reed type and for signalling purpose only. The relays are grouped together as can be seen in the terminal diagram.

12.2 Block diagram

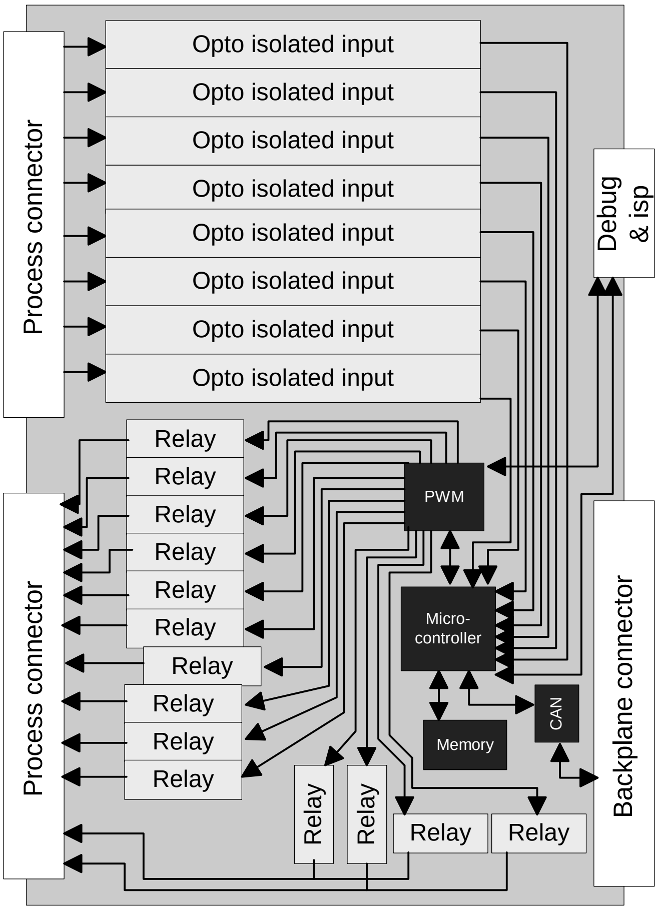


Fig. 12 Block diagram for the binary input/output module

Referenced publications

No applicable publications available.

Customer feedback report

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ABB Automation Products AB
Division Substation Automation
Dept. TMD4
S-721 59 Västerås
Sweden