1MRS755222-MUM

Issued: 1/2005
Version: C/10.8.2005

Diff6T Stabilized three-phase differential protection for transformers

Data subject to change without notice

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1. Introduction

1.1 Features

- Three-phase stabilized differential protection for two-winding power transformers.
- Provides two stages for winding short-circuit and interturn protection: stabilized stage and instantaneous stage.
- Easily adjustable operating characteristic of stabilized stage for different applications.
- The differential and stabilizing currents are calculated for every phase on the basis of the fundamental frequency component of the currents.
- Short operate times at faults occurring in the zone to be protected (internal faults), even with partially saturated current transformers.
- High stability at external faults, also with partially saturated current transformers.
- Blocking based on the ratio of the second harmonic and the fundamental frequency component of the differential current prevents unwanted operations at transformer inrush currents.
- Additional logic to override the second harmonic blocking in a case of switch on to fault.
- Blocking based on the ratio of the fifth harmonic and the fundamental component of the differential current prevents operation in harmless situations of transformer overexcitation - blocking can be eliminated if the ratio of the fifth harmonic and the fundamental component increases at dangerously high overvoltages.
- Separately adjustable instantaneous stage based on instantaneous values of differential currents - instantaneous stage cannot be blocked by the second or fifth harmonic restraint.
- No interposing transformers are needed for the protection of two-winding transformers - numerical vector group matching on HV and LV side.
- Possibility to automatically adapt to the position changes of the tap changer.
- Numerically implemented zero-sequence current elimination in order to eliminate wrong tripping decisions at earth faults occurring outside the protected area.
- Sensitive phase current and phase angle displays facilitate the commissioning and checking of the measurement circuit connection and vector group matching.
- Integrated circuit breaker failure protection.

1.2 Application

This document specifies the functions of the three-phase differential protection for two-winding power transformers and generator-transformer blocks. This function block is used in transformer relays and transformer terminals based on the RED 500 Platform.

3ΔI>

3ΔI>>

Figure 1. Protection diagram symbols of Diff6T

For IEC symbols used in single line diagrams, refer to the manual “Technical Descriptions of Functions, Introduction”, 1MRS750528-MUM

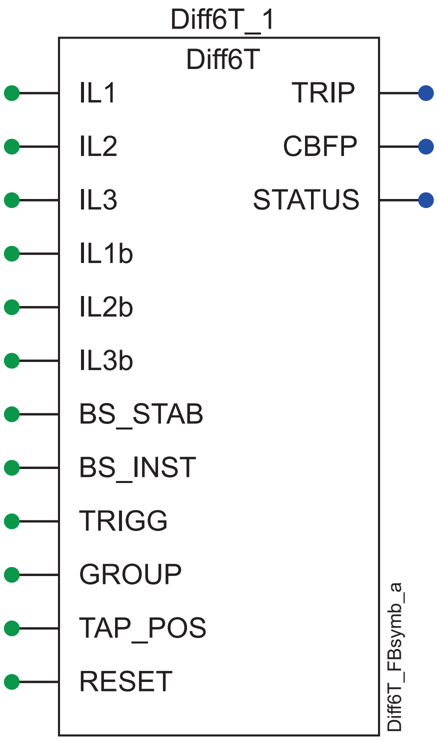

Figure 2. Function block symbol of Diff6T

1.3 Input description

Name	Type	Description
IL1	Analogue channel signal (SINT)	Input for measuring HV side current IL1
IL2	Analogue channel signal (SINT)	Input for measuring HV side current IL2
IL3	Analogue channel signal (SINT)	Input for measuring HV side current IL3
IL1b	Analogue channel signal (SINT)	Input for measuring LV side current IL1b
IL2b	Analogue channel signal (SINT)	Input for measuring LV side current IL2b
IL3b	Analogue channel signal (SINT)	Input for measuring LV side current IL3b
BS_STAB	Digital signal (BOOL, active high)	Blocking signal for stabilized stage
BS_INST	Digital signal (BOOL, active high)	Blocking signal for instantaneous stage
TRIGG	Digital signal (BOOL, pos. edge)	Control signal for triggering the registers
GROUP	Digital signal (BOOL, active high)	Control input for switching between setting group 1 and setting group 2
TAP_POS	Integer signal (SINT)	Present tap position reading
RESET	Reset signal (BOOL, pos. edge)	Input signal for resetting the trip signal and registers of Diff6T

1.4 Output description

Name	Type	Description
TRIP	Digital signal (BOOL, active high)	Trip signal
CBFP	Digital signal (BOOL, active high)	Delayed trip signal for circuit-breaker failure protection (CBFP)
STATUS	Integer signal (WORD)	Coded status output including: trip status, 2. and 5. harmonic blocking status and waveform based blocking status for each phase

2. Description of operation

2.1 Configuration

Phase currents can be measured via conventional current transformers. The measuring devices and signal types for the analogue channels are selected and parameterized in a special dialogue box of the graphic IEC configuration tool. Binary inputs are parameterized in the same programming environment (the number of selectable analogue inputs, binary inputs and outputs depends on the hardware used).

When the analogue channels and binary inputs have been selected and parameterized in the dialogue box, the inputs and outputs of the function block can be configured on a graphic worksheet of the IEC configuration tool. The phase currents IL1, IL2, IL3, IL1b, IL2b and IL3b are connected to the corresponding IL1, IL2, IL3, IL1b, IL2b and IL3b inputs of the function block.

Note! It is not possible to connect the current channels to the current inputs in any other way. E.g. connecting channel IL1 to input IL1b is not possible.

Note! When the function block Diff6T is used, the 2nd harmonic restraint must be selected for the channels connected to the IL_ and IL_b inputs of the function block from the special measurements dialogue box of the configuration tool.

Binary inputs are connected to the Boolean inputs of the function block, and the outputs of the function block are connected to the output signals in the same way.

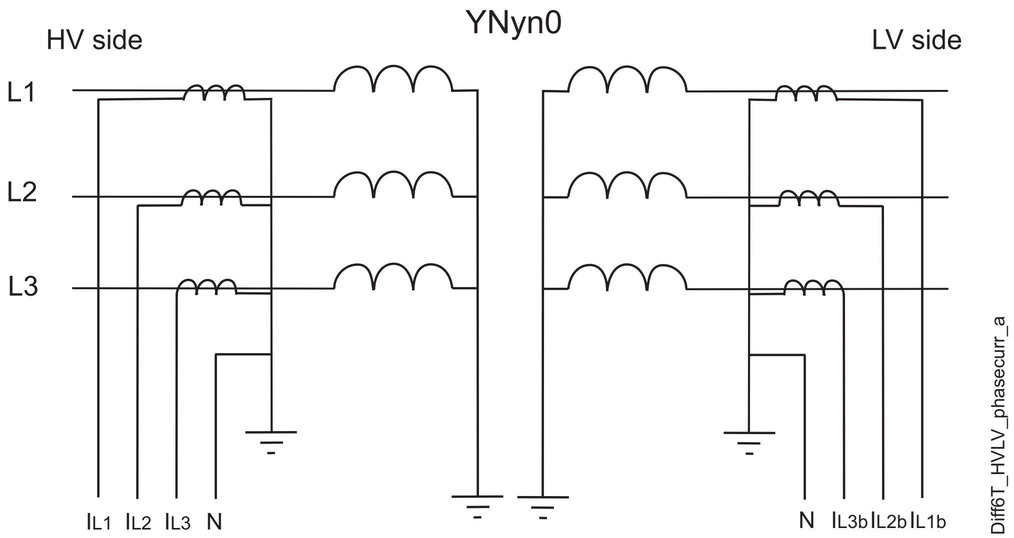

Figure 3. HV side and LV side phase currents

If the automatic tap changer position compensation is to be used, the tap position information is connected to the TAP_POS input of the function block. For details see “Compensation of the tap changer position”.

2.2 Setting the rated frequency of the protected unit

The rated frequency of the relay or the feeder terminal is set via a dialogue box in the configuration tool. The global control parameter Rated frequency of the relay can also be used for reading the rated frequency.

2.3 General

2.3.1 Description of the setting group settings

Basic setting

The Basic setting defines the minimum differential current required for tripping in any circumstances. The Basic setting basically allows for the no-load current of the power transformer and small inaccuracies of the current transformers, but it can also be used to influence the overall level of the operation characteristic. At rated voltage the no-load losses of the power transformer are about 0.2 percent. Should the supply voltage of the power transformer suddenly increase due to operational disturbances, the magnetizing current of the transformer increases as well. In general the magnetic flux density of the transformer is rather high at rated voltage, and a rise in voltage by a few percents will cause the magnetizing current to increase by tens of percents. This should be considered in the Basic setting. (Also see “The operating characteristic”.)

Starting ratio

Variations in the Starting ratio affect the slope of the characteristic, that is, how big change in the differential current, in comparison with the change in the load current, is required for tripping. The Starting ratio should consider CT errors and variations in the transformer tap changer position (if not compensated). Too high a starting ratio should be avoided, because the sensitivity of the protection for detecting interturn faults depends basically on the Starting ratio. Although the coverage area of the Starting ratio is mainly between Turn-point 1 (fixed) and Turn-point 2, it also affects the overall level (offset) of the last slope of the operating characteristic (see “The operating characteristic”).

Turn-point 2

The parameter Turn-point 2 specifies the second turning point (knee point) in the operating characteristic between the coverage areas of the Starting ratio and the last slope with the fixed ratio (see “The operating characteristic”).

Ratio I2f/I1f>

The parameter Ratio I2f/I1f> sets the required percentage level (in comparison to the fundamental component of the differential current) of the second harmonic component of the differential current to activate the second harmonic blocking in the case of a transformer inrush or CT saturation during an external fault.

Ratio I5f/I1f>

The parameter Ratio I5f/I1f> sets the required percentage level (in comparison to the fundamental component of the differential current) of the fifth harmonic component of the differential current to activate the fifth harmonic blocking in the case of transformer overexcitation.

Ratio I5f/I1f>>

The parameter Ratio I5f/I1f>> sets the required percentage level (in comparison to the fundamental component of the differential current) of the fifth harmonic component of the differential current to deactivate (remove) the fifth harmonic blocking in the case of a severe transformer overexcitation, which could damage the transformer.

2. harm. block

The parameter 2. harm. block specifies whether the second harmonic blocking is in use or not. Furthermore, it can be specified whether it is allowed for the internal deblocking logic to remove the second harmonic blocking when the appropriate conditions are met (see “The 2. harmonic deblocking in the case of switch on to a fault”). The possible values are therefore “Not in use” (0), “In use” (1) and “With deblock” (2).

5. harm. block

The 5. harm. block specifies whether the fifth harmonic blocking is in use or not. Furthermore, it can be selected whether it is allowed to remove the blocking if the ratio of the fifth harmonic to fundamental further rises above the limit Ratio I5f/I1f>> (see “Blocking based on the fifth harmonic”). The possible values are therefore “Not in use” (0), “In use” (1) and “With deblock” (2).

2.3.2 Description of the Control settings

Operation mode

The parameter Operation mode can have the values “In use” and “Not in use”. When the parameter is set to “In use”, the protection operates normally. When the parameter is set to “Not in use”, no measured or other output values are shown and no events are sent, although the algorithms of the protection function are still executed normally. In addition to setting all outputs to zero only, a few internal variables are reset. The protection algorithm is therefore aware of the present situation when it is enabled again by setting the parameter Operation mode to “In use”. This means that almost no time is needed to adapt to the current situation and the function is fully functional (and stable).

Group selection

The Group selection is used either to directly select the active setting group (values “Group 1” and “Group 2”) or indirectly (value “GROUP input”). In the case of an indirect setting (value “GROUP input”), the actual active group is selected by the input “GROUP” of the protection function.

Active group

The Active group is actually not a setting. It just monitors the number of the actual active group, which in case of parameter Group selection having value “GROUP input”, would not otherwise be visible.

Trip signal

The Trip signal selects whether the output signal TRIP is latched or not when it becomes activate (possible values “Non-latching” and “Latching”). This does not have any effect on the phase segregated trip indications included in the output STATUS.

Trip pulse

The Trip pulse sets the minimum length to the output signal TRIP in the case it is not latched. This means that when output TRIP becomes active and resets quickly after that (due to that operation criteria are not met anymore) the resetting of the output TRIP is delayed until the time set in the Trip pulse has elapsed.

This setting sets also the length of the output signal CBFP.

CBFP time

The CBFP time sets the delay time, after the TRIP output has become active, to activate the CBFP output, which is used to trip an alternative circuit breaker when the tripping of the first priority circuit breaker has failed.

CT connection

A correct value for the CT connection is determined by the connection polarities of the measuring devices (see “Connection of current transformers”).

The following assumes that the currents are connected to the relay as specified in Figure 8 and Figure 9 in section “Connection of current transformers”.

When the currents are measured so that the CT secondary currents are both flowing from the phase terminal to the ground terminal, the value is to be set to “Type II”. Furthermore, if the currents are measured so that the CT secondary currents are both flowing from the ground terminal to the phase terminal, the value is also “Type II”.

Only if the CT secondary current on one side of the transformer (HV or LV) is flowing from the ground terminal to the phase terminal, and the current on the other side is flowing from the phase terminal to the ground terminal the value shall be set to “Type I”.

HV connection

This parameter specifies the connection of the HV side winding. The correct value is directly available from the data of the protected transformer. Values possible are “Y” (0);“YN” (1);“D” (2); “Z” (3); “ZN” (4).

If the protected object is not a transformer (i.e. it does not need vector group matching) the value for HV connection shall be set to “Y”.

LV connection

This parameter specifies the connection of the LV side winding. The correct value is directly available from the data of the protected transformer. Values possible are “y” (0);“yn” (1);“d” (2); “z” (3); “zn” (4).

If the protected object is not a transformer (i.e. it does not need vector group matching), the value for LV connection shall be set to “y”.

Clock number

A correct value for the Clock number is directly available from the data of the protected transformer. For example, if the transformer vector group is YNd11, then the value for Clock number is “11” (also see Transformer vector group matching”).

If the protected object is not a transformer (i.e. it does not need vector group matching) the value for Clock number is always “0”.

Note! There is no mechanism to inhibit a false combination of the parameters HV connection, LV connection and Clock number. However, all non-supported combinations will result in default matching, (no matching at all) which is Yy0.

Io elimination

With the Io elimination it can be determined whether the zero-sequence current is eliminated from the HV side currents, the LV side currents, or on both sides of the transformer. In most cases the zero-sequence current is eliminated automatically on that side where the vector group matching is done. Setting this parameter to “Not in use” does not change that (also see “Elimination of the zero sequence component of the phase currents”). The possible values are “Not in use” (0); “HV side” (1); “LV side” (2); “HV&LV side” (3).

If the protected object is not a transformer, the value for Io elimination shall be set to “Not in use”.

Min. turns tap

This parameter specifies the tap position number resulting in the minimum effective number of winding turns on the side of the transformer where the tap changer resides. With the aid of this parameter and the parameter Max. turns tap, the tap position compensation algorithm knows in which direction the compensation shall be made (see Figure 4).

This also ensures that if the current tap position information for some reason is corrupted, the automatic tap changer position adaptation does not try to adapt to any unrealistic position values.

Max. turns tap

This parameter specifies the tap position number resulting in the maximum effective number of winding turns on the side of the transformer where the tap changer resides. With the aid of this parameter and the parameter Min. turns tap the tap position compensation algorithm knows in which direction the compensation shall be made (see Figure 4).

This also ensures that if the current tap position information for some reason is corrupted, the automatic tap changer position adaptation does not try to adapt to any unrealistic position values.

Nominal tap

This parameter specifies the tap position number, resulting in nominal voltage (and current).

When the current tap position deviates from this value, the input current values (on the side where the tap changer resides) are scaled to match the currents on the other side. The correct scaling is determined by the number of steps and the direction of the deviation from the nominal tap as well as the percentual change in voltage, which one tap step results in. The percentual value is set in the Tap step % parameter.

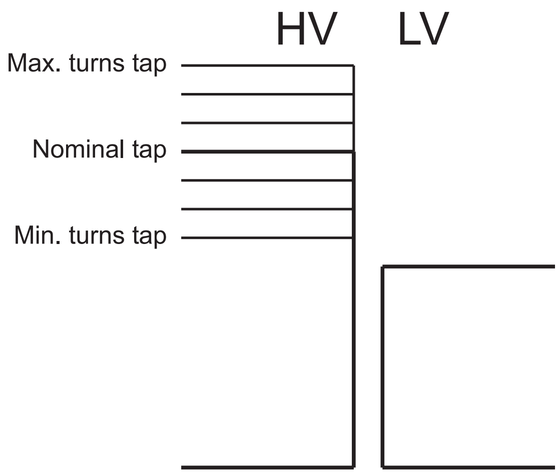

Figure 4. Simplified presentation of the HV and LV windings with demonstration of the settings Max. turns tap, Min. turns tap and Nominal tap.

Tapped winding

This parameter specifies whether the tap changer is connected in the high voltage side winding or in the low voltage side winding. This parameter is also used to enable and disable the automatic adaptation to the tap changer position. The possible values are "Not in use" (0); "HV winding" (1); "LV winding" (2).

Tap step %

The Tap step % specifies how much the voltage changes (in percents) when the tap position changes one step. Also see "Compensation of the tap changer position".

Reset registers

This parameter is only visible in the setting tool and not on the local HMI. Reset registers is actually a command (not setting) which resets all the values in the views "Recorded data X" (where X is 1, 2 or 3).

Test TRIP

The Test TRIP setting is used to activate the test mode for the TRIP output signal. In practice, the test mode means that the TRIP output is activated when Test TRIP is set to "TRUE". When the value is "FALSE" the test mode for the TRIP output is disabled (also see "Test mode").

Test CBFP

The Test CBFP setting is used to activate the test mode for the CBFP output signal. In practice, the test mode means that the CBFP output is activated when Test CBFP is set to "TRUE". When the value is "FALSE" the test mode for the CBFP output is disabled (also see "Test mode").

Event mask 1, Event mask 2, Event mask 3, Event mask 4

These parameters set the event masks for different clients in order to disable the unwanted events so that they will not be visible to the corresponding clients (see “Events ”).

2.4 Operation criteria

2.4.1 Stabilized differential current stage (3∆I>)

Stabilization of the current differential protection is needed since an appearance of a differential current can possibly be due to something else than an actual fault in the transformer (or generator).

In the case of transformer protection, a false differential current can be caused by:

- CT errors,
- varying tap changer positions (if not automatically compensated),
- transformer no-load current,
- transformer inrush currents,
- transformer overexcitation in overvoltage situations,
- transformer overexcitation in underfrequency situations, or
- CT saturation when high currents are passing through the transformer.

A differential current caused by CT errors and tap changer position grows at the same percentual ratio as the load current increases.

In the protection of generators the false differential current can be caused by:

- CT errors and
- CT saturation when high currents are passing through the generator.

High currents passing through the object to be protected may be caused by short circuits outside the protected area, large currents fed by the transformer in motor start-up or transformer inrush situations. Due to these circumstances the operation of the differential relay has been stabilized in respect of the load current. In a stabilized differential relay the differential current required for relay operation is higher, the higher the load current is. The stabilized operation characteristic and the setting ranges are shown in Figure 5.

The operation characteristic of the stabilized stage, 3ΔI>, is determined by Basic setting, Starting ratio and the setting of the second turning point of the operating characteristic curve, Turn-point 2 (the first turning point and the slope of the last part of the characteristic are fixed). The settings are the same for each phase. When the differential current exceeds the operating value determined by the operating characteristic, the differential function “wakes up” (see “The operating characteristic”). If the differential current stays above the operating value continuously for a period defined by the protection algorithms, the trip is activated. Information on the tripped phase(s) is indicated via the coded output STATUS.

The stage can be blocked internally by second or fifth harmonic restraint, or by special algorithms detecting inrush and current transformer saturation at external faults. The stage can be blocked externally using the blocking signal BS_STAB.

The special algorithms are described later in the document (see “The waveform based blocking”).

2.4.2 The positive direction of the currents

Designate the phasors $\bar{I}_1$ and $\bar{I}_2$ of the fundamental frequency currents from the CT secondary on the HV and LV sides of the power transformer. The positive direction of the currents is from the HV side to the LV side (see Figure 5).

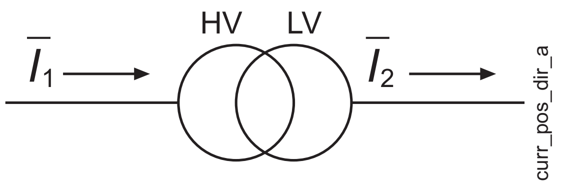

Figure 5. Positive direction of the currents

2.4.3 The differential current

In accordance with Figure 5, the amplitude of the differential current I_d is obtained as follows:

$$I_d = \left|\bar{I}_1 - \bar{I}_2\right| \quad \text{EQ. (1)}$$

In a normal situation there is no fault in the area protected by the differential function. The currents $\bar{I}_1$ and $\bar{I}_2$ are equal and the differential current $I_d = 0$. In practice, however, the differential current deviates from zero in normal situations. In power transformer protection, a differential current is caused by CT inaccuracies, variations in tap changer position (if not compensated), transformer no-load current and instantaneous transformer inrush currents. Increases in the load current cause the differential current caused by the CT inaccuracies and the tap changer position to grow at the same percentual rate.

2.4.4 The stabilizing current

In a stabilized differential relay the differential current required for tripping is higher, the higher the load current is. That is in a normal operation or during external faults. When an internal fault occurs the currents on both sides of the protected object are flowing into the object, which causes the stabilizing current to be considerably smaller. This makes the operation more sensitive during internal faults.

In accordance with Figure 5, the stabilizing current I_b of the relay is obtained as follows:

$$I_b = \frac{\left|\bar{I}_1 + \bar{I}_2\right|}{2} \quad \text{EQ. (2)}$$

2.4.5 The operating characteristic

The operation of the relay is affected by the stabilization as shown graphically by the operating characteristic illustrated in Figure 6.

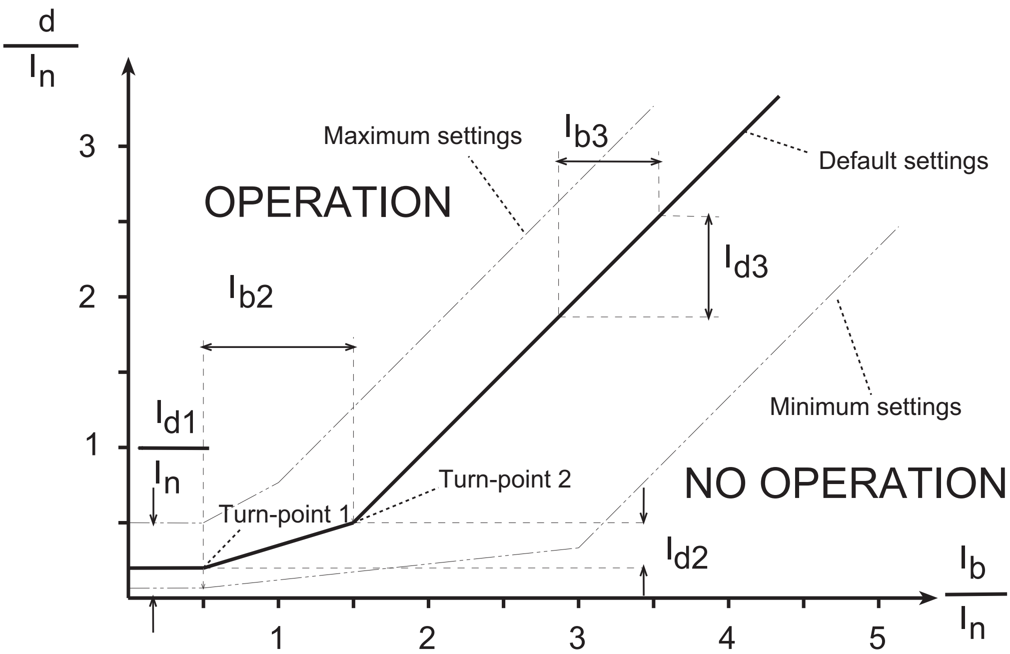

Figure 6. Operation characteristic for stabilized operation of the transformer differential protection function Diff6T

The basic setting of the stabilized stage of the differential function is determined according to Figure 6.

Basic setting = I_{d1}/I_n EQ. (3)

The starting ratio is determined correspondingly:

Starting ratio = I_{d2}/I_{b2} EQ. (4)

The second turning point Turn-point 2 can be set in the range 1.0...3.0.

The slope of operating characteristic curve of the differential function varies in the different parts of the range:

- In part 1 ($0.0 < I_b/I_n <$ Turn-point 1) the differential current required for tripping is constant. The value of the differential current is the same as the basic setting selected for the function. The basic setting basically allows the no-load current of the power transformer and small inaccuracies of the current transformers, but it can also be used to influence the overall level of the operation characteristic. At rated current, the no-load losses of the power transformer are about 0.2 percent. Should the supply voltage of the power transformer suddenly increase due to operational disturbances, the magnetizing current of the transformer will increase as well. In general, the magnetic flux density of the transformer is rather high at rated voltage, and the rise in voltage by a few percents will cause the magnetizing current to increase by tens of percents. This should be considered in the basic setting.
- Part 2, i.e. when Turn-point 1 $< I_b/I_n <$ Turn-point 2, is called the influence area of Starting ratio. In this part, variations in the starting ratio affect the slope of the characteristic, that is, how big the change in the differential current, in comparison with the change in the load current, is required for tripping. The starting ratio should consider CT errors and variations in the transformer tap changer position (if not compensated). A too high starting ratio should be avoided, because the sensitivity of the protection for detecting interturn faults basically depends on the starting ratio.

- At high stabilizing currents, when $I_b/I_n >$ Turn-point 2, the slope of the characteristic is constant (Part 3). The slope is 100%, which means that the increase in the differential current is equal to the corresponding increase in the stabilizing current.

The operation of the differential protection is based on the fundamental frequency components. Operation is accurate and stable: the DC component and harmonics of the current do not cause unwanted operations.

2.4.6 Instantaneous differential current stage (3ΔI>>)

The operation of the instantaneous differential current stage is not stabilized. The instantaneous stage operates when the amplitude of the fundamental frequency component of the differential current exceeds the set operate value Inst.setting, or when the instantaneous value of the differential current exceeds 2.5 x Inst. setting. The internal blocking signals of the differential function do not prevent the operate signal of the instantaneous differential current stage. When required, the operate signal of the stage can be blocked by the external control signal BS_INST.

Should the stabilizing current fall below 30% of the differential current, or the phase angle between the HV side and LV side phase currents exceed 130 degrees after the automatic vector group matching has been made, a fault has most certainly occurred in the area protected by the differential relay. Then the operate value set for the instantaneous stage will be automatically halved and the internal blocking signals of the stabilized stage will be inhibited.

2.4.7 Error checking in the initialization phase

The initialization function checks if:

- The signal types are IL1, IL2, IL3, IL1b, IL2b or IL3b.
- All the required system measurements are on for the connected channels.
- The measuring devices for all channels are CTs.
- The associated task is fast enough (<= 4 times in a fundamental cycle).

2.4.8 Compensation of the tap changer position

The position of the tap changer used for voltage control can be compensated if the position information is provided for the protection function via the input signal “TAP_POS”.

The position value of the tap changer can be brought to the relay as a resistance value, a mA signal or as binary coded. For more information on how the resistance value or the mA signal interface is implemented, refer to the Technical Reference Manual of the relay. For the binary coded interface via the function blocks BCD2INT, GRAY2INT and NAT2INT, refer to the Generic Base Elements function block manual (1MRS752371-MUM).

2.5 Blocking principles

2.5.1 Blocking based on the second harmonic

Transformer magnetizing inrush currents occur when the transformer is energized after a period of de-energization. The inrush current may be many times the rated current and the halving time may be up to several seconds. To the differential relay, inrush current represents differential current, which would cause the relay to operate almost always when the transformer is connected to the network. Typically, the inrush current contains a large amount of second harmonics.

Blocking of the operation of the stabilized stage of the relay at magnetizing inrush current is based on the ratio of the amplitudes of the second harmonic digitally filtered from the differential current and the fundamental frequency (Id2f /Id1f).

The blocking also prevents unwanted operation at recovery and sympathetic magnetizing inrush. At recovery inrush, the magnetizing current of the transformer to be protected increases momentarily when the voltage returns to normal after clearance of a fault outside the protected area. Sympathetic inrush is caused by another transformer, running in parallel with the protected transformer already connected to the network, being energized.

The ratio of the second harmonic to fundamental component can vary considerably between the phases. Especially when the delta compensation is done for an Ynd1 connected transformer and the two phases of the inrush currents are otherwise equal but opposite in phase angle, the subtraction of them in a delta compensation results a very small second harmonic component.

Because of the above some action needs to be taken in order to avoid false tripping of the phase having too low ratio of the second harmonic to fundamental component. One way could be to always block all phases when the second harmonic blocking conditions are fulfilled at least in one phase. The other way is to calculate weighted ratios of the second harmonic to fundamental for each phase using the original ratios of the phases. The latter option is used here.

The ratio to be used for second harmonic blocking is therefore calculated as a weighted average on the basis of the ratios calculated from the differential currents of the three phases. The ratio of the concerned phase is of most weight compared with the ratios of the other two phases (the weighting factors are 4, 1, and 1, where 4 is the factor of the phase concerned). The operation of the stabilized stage on the concerned phase is blocked if the weighted ratio of that phase is above the set blocking limit Id2f/Id1f>, and if blocking is enabled through the parameter 2. harm. block.

Using separate blocking for the individual phases and weighted averages calculated for the separate phases provides a blocking scheme that is stable at connection inrush currents.

If the peak value of the differential current is very high (> 12 p.u.), the limit for the second harmonic blocking is desensitized (in the phase in question) by increasing it proportionally to the peak value of the differential current.

The connection of the power transformer against a fault inside the protected area does not delay the operation of the tripping, because in such a situation the blocking based on the second harmonic of the differential current is prevented by a separate algorithm based on the different waveform and the different rate of change of normal inrush current and inrush current containing fault current. The algorithm does not eliminate the blocking at inrush currents, unless there is a fault in the protected area. The special algorithms used are described in the following (see “The 2. harmonic deblocking in the case of switch on to a fault”).

The second harmonic blocking has a hysteresis to avoid oscillation.

2.5.2 The 2. harmonic deblocking in the case of switch on to a fault

Normally there are low current periods in the differential current during inrush. Also the rate of change of the differential current is very low during these periods. If these features are not present in the differential current, it can be suspected that there is a fault in the transformer.

This feature can also be enabled and disabled via the parameter 2. harm. block.

2.5.3 The waveform based blocking

This algorithm has two parts. Both parts are very similar compared to the above (“The 2. harmonic deblocking in the case of switch on to a fault”), but in this case the criteria for a low current period is different and only the differential current (not derivative) is checked. The first part is intended for external faults while the second is intended for inrush situations.

2.5.4 Blocking based on the fifth harmonic

Inhibition of relay operation in situations of overexcitation is based on the ratio of the fifth harmonic and the fundamental component of the differential current (Id5f/Id1f). The ratio is calculated separately for each phase without weighting factors. Should the ratio exceed the setting value of Ratio I5f/I1f>, and blocking is enabled through the parameter 5. harm. block, the operation of the stabilized stage of the relay in the concerned phase will be blocked.

At dangerous levels of overvoltage, which may cause damage to the transformer, the blocking can be automatically eliminated. Should the ratio of the fifth harmonic and fundamental component of the differential current exceed the parameter Ratio I5f/I1f>>, and the blocking removal is enabled. The enabling and disabling of deblocking feature is also done through the parameter 5. harm. block.

Both the fifth harmonic blocking and the fifth harmonic deblocking have a hysteresis to avoid oscillation.

For further clarification of the limits Ratio I5f/I1f> and Ratio I5f/I1f>> and their hysteresis, see Figure 7.

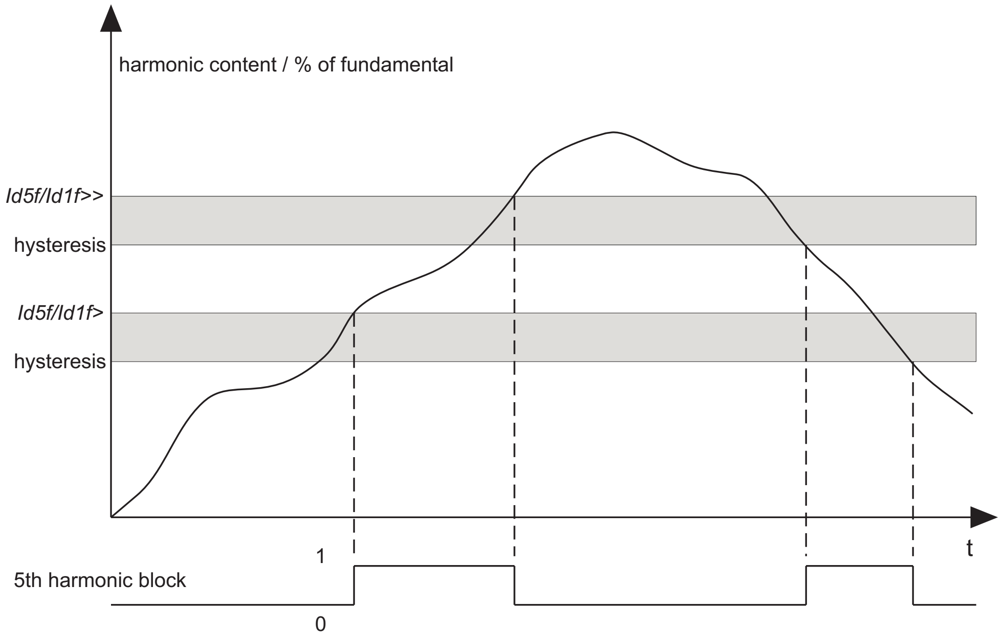

Figure 7. The fifth harmonic blocking limits and the operation when both blocking and deblocking features are enabled via control parameter 5. harm. block

2.5.5 Reset of the blocking signals (deblock)

All the three blocking signals (Waveform, 2. and 5. harmonic) have a counter, which holds the blocking on for a certain time after the blocking conditions have ceased to be fulfilled. Deblocking takes place when those counters have elapsed. This is a “normal” case of deblocking.

The blocking signals can be reset immediately if a very high differential current is measured or if the phase difference (the angle between) of the compared currents is over 130 degrees after the automatic vector group matching has been made. This does not, however, reset the counters holding the blockings, so the blocking signals may return once these conditions are not valid anymore.

2.6 Connection principles

2.6.1 Recommendations for current transformers

The more important the object to be protected, the more attention should be paid to the current transformers. Normally, it is not possible to dimension the current transformers so that they repeat currents with high DC components without saturating when the residual flux of the current transformer is high. The differential protection function block Diff6T operates reliably even though the current transformers are partially saturated. The purpose of the following current transformer recommendations is to secure the stability of the relay at high through currents and the quick and sensitive operation of the relay at faults occurring in the protected area, where the fault currents may be high.

The accuracy class recommended for current transformers to be used with the differential function block Diff6T is 5P, in which the limit of the current error at the rated primary current is 1% and the limit of the phase displacement is 60 minutes. The limit of the composite error at the rated accuracy limit primary current is 5%.

The approximate value of the accuracy limit factor F_a corresponding to the actual CT burden can be calculated on the basis of the rated accuracy limit factor F_n (ALF) at the rated burden, the rated burden S_n, the internal burden S_{in} and the actual burden S_a of the current transformer as follows:

$$F_a = F_n \times \frac{S_{in} + S_n}{S_{in} + S_a} \qquad \text{EQ. (5)}$$

Example 1

In the example the rated burden S_n of the CTs 5P20 is 10 VA, the secondary rated current 5A, the internal resistance $R_{in} = 0.07\ \Omega$ and the accuracy limit factor F_n (ALF) corresponding to the rated burden is 20 (5P20). Thus the internal burden of the current transformer is $S_{in} = (5A)^2 \times 0.07\ \Omega = 1.75$ VA. The input impedance of the relay at a rated current of 5A is < 20 mΩ. If the measurement conductors have a resistance of 0.113 Ω, the actual burden of the current transformer is $S_a = (5A)^2 \times (0.113 + 0.020)\ \Omega = 3.33$ VA. Thus the accuracy limit factor F_a corresponding to the actual burden will be about 46.

The CT burden may grow considerably at the rated current of 5A. At the rated current of 1A the actual burden of the current transformer decreases, while the repeatability simultaneously improves.

At faults occurring in the protected area, the fault currents may be very high compared to the rated currents of the current transformers. Thanks to the instantaneous stage of the differential function block, it is enough that the current transformers are capable of repeating, during the first cycle, the current required for instantaneous tripping.

Thus the current transformers should be able to reproduce the asymmetric fault current without saturating within the next 10 ms after the occurrence of the fault, to secure that the operate times of the relay comply with the times stated in section “Technical Data”.

The accuracy limit factors corresponding to the actual burden of the phase current transformer to be used in differential protection shall fulfill the following requirement:

$$F_a > K_r * I_{kmax} * (T_{dc} * \omega * (1 - e^{-Tm/Tdc}) + 1) \qquad \text{EQ. (6)}$$

where

I_{kmax} is the maximum through-going fault current (in p.u.) at which the protection is not allowed to operate,

T_{dc} is the primary DC time constant related to I_{kmax},

ω is the angular frequency, i.e. 2*π*50 Hz,

T_m is the time-to-saturate, i.e. the duration of the saturation free transformation and

K_r is the remanence factor, 1/(1-r).

The parameter r gives the maximum remanence flux density in the CT core. The value of the parameter r depends on the magnetic material used and on the construction of the CT. For example, the value r = 0.4 means that the remanence flux density may be 40 % of the saturation flux density. The manufacturer of the CT should be contacted when an accurate value for the parameter r is needed. The value r = 0.4 is recommended to be used when an accurate value is not available.

A required minimum time-to-saturate (T_m) in Diff6T is 10 ms.

In the following, two typical cases are considered for the determination of the sufficient accuracy limit factor (F_a):

1. A fault occurring at the substation bus.

The protection must be stable at a fault arising during a normal operating situation. Re-energizing the transformer against a bus fault would lead to very high fault currents and thermal stress, therefore re-energizing is not preferred in this case.

With this assumption the remanence can be neglected.

The maximum through-going fault current I_{kmax} is typically 10 p.u. for a substation main transformer. At a short circuit fault close to the supply transformer, the DC time constant (T_{dc}) of the fault current is almost the same as that of the transformer, the typical value being 100 ms.

The parameters in equation (6) will get the following values:

I_{kmax}	10 (p.u.)
T_{dc}	100 (ms)
ω	100π (Hz)
T_m	10 (ms)
Kr	1

=> $$F_a > K_r * I_{kmax} * (T_{dc} * \omega * (1 - e^{-Tm/Tdc}) + 1) \approx \underline{40} \qquad \text{EQ. (7)}$$

2. Re-energizing against a fault occurring further down in the network.

The protection must be stable also during re-energization against a fault on the line. In this case, existence of remanence is very probable. Let's assume 40%.

On the other hand the fault current is now smaller and since the ratio of the resistance and reactance is greater in this location, having a full DC offset is not possible. Furthermore, the DC time constant (T_{dc}) of the fault current is now smaller, let's assume 50 ms.

Assuming a maximum fault current 30% lower than in the bus fault and a DC offset 90% of the maximum, equation (6) will be written.

The parameters in equation (6) will get the following values:

I_{kmax}	0.7* 10 = 7 (p.u.)
T_{dc}	50 (ms)
ω	100π (Hz)
T_m	10 (ms)
K_r	1/(1-0.4) = 1.6667

=> $F_a > K_r * I_{kmax} * 0.9 * (T_{dc} * \omega * (1 - e^{-Tm/Tdc}) + 1) \approx \underline{40}$ EQ. (8)

If the actual burden of the current transformer (S_a) in equation (5) cannot be reduced low enough to provide a sufficient value for F_a, there are two alternatives to deal with the situation:

1. a current transformer with a higher rated burden S_n can be chosen (which also means a higher rated accuracy limit F_n) or

2. a current transformer with a higher nominal primary current I_{1n} (but the same rated burden) can be chosen.

Example 2

Assuming that the actions according to alternative 2 above is taken in order to improve the actual accuracy limit factor (F_a):

I_{rTR} = 1000 A	(rated secondary current of the transformer)
I_{rCT} = 1500 A	(rated primary current of the CT on the transformer secondary side)
F_n = 30	(rated accuracy limit factor of the CT)
$F_a = (I_{rCT} / I_{rTR}) * F_n$	(actual accuracy limit factor due to oversizing the CT)

Fa = (1500/1000) * 30 = 45

In differential protection it is important that the accuracy limit factors (F_a) of the phase current transformers at both sides correspond with each other, that is, the burdens of the current transformers on both sides should be as equal as possible. Should high inrush or start currents with high DC components pass through the protected object when it is connected to the network, special attention should be paid to the performance and the burdens of the current transformers and to the settings of the function block.

2.6.2 Connection of current transformers

The connections of the primary current transformers are designated as "Type I" and "Type II". In the case that the positive directions of the relay HV and LV side currents are opposite, the setting parameter CT connection is "Type I", see Figure 8. In the case that the positive directions of the relay HV and LV side currents equate, the setting parameter CT connection is "Type II", see Figure 9. The default is "Type I".

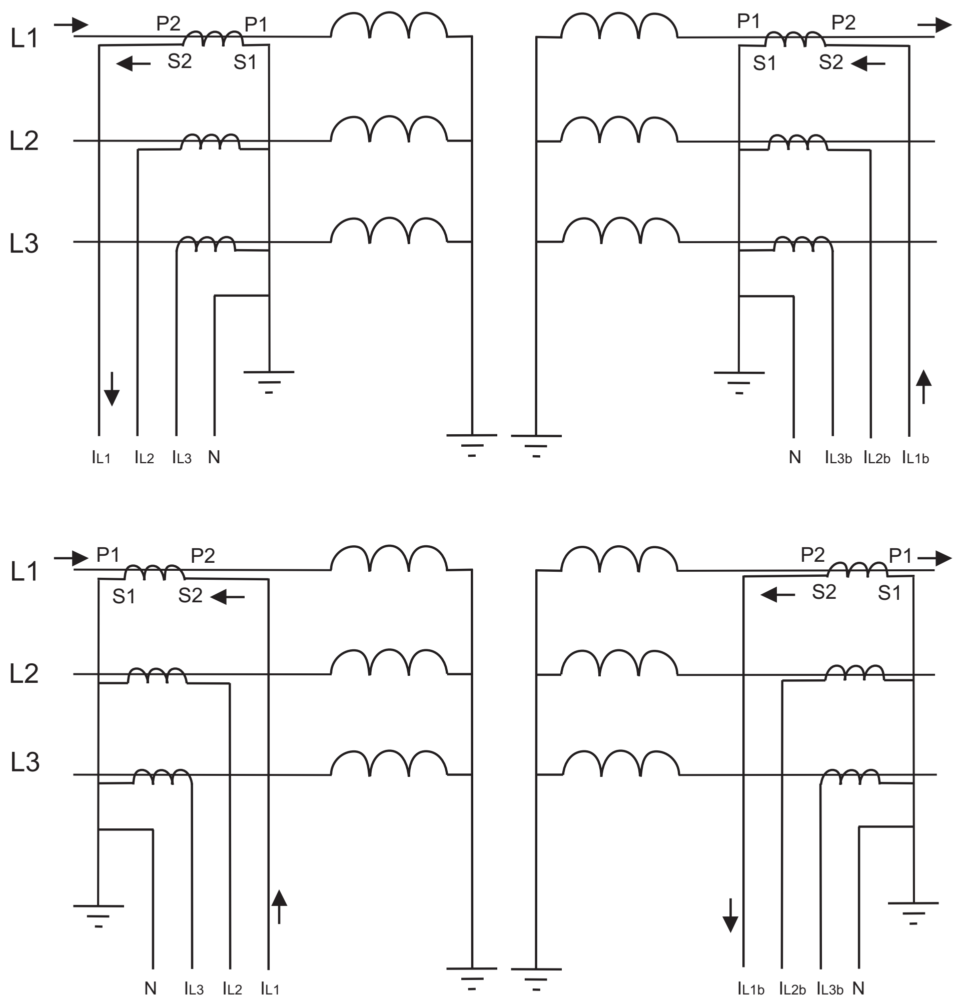

Figure 8. "Type I" connection of current transformers.

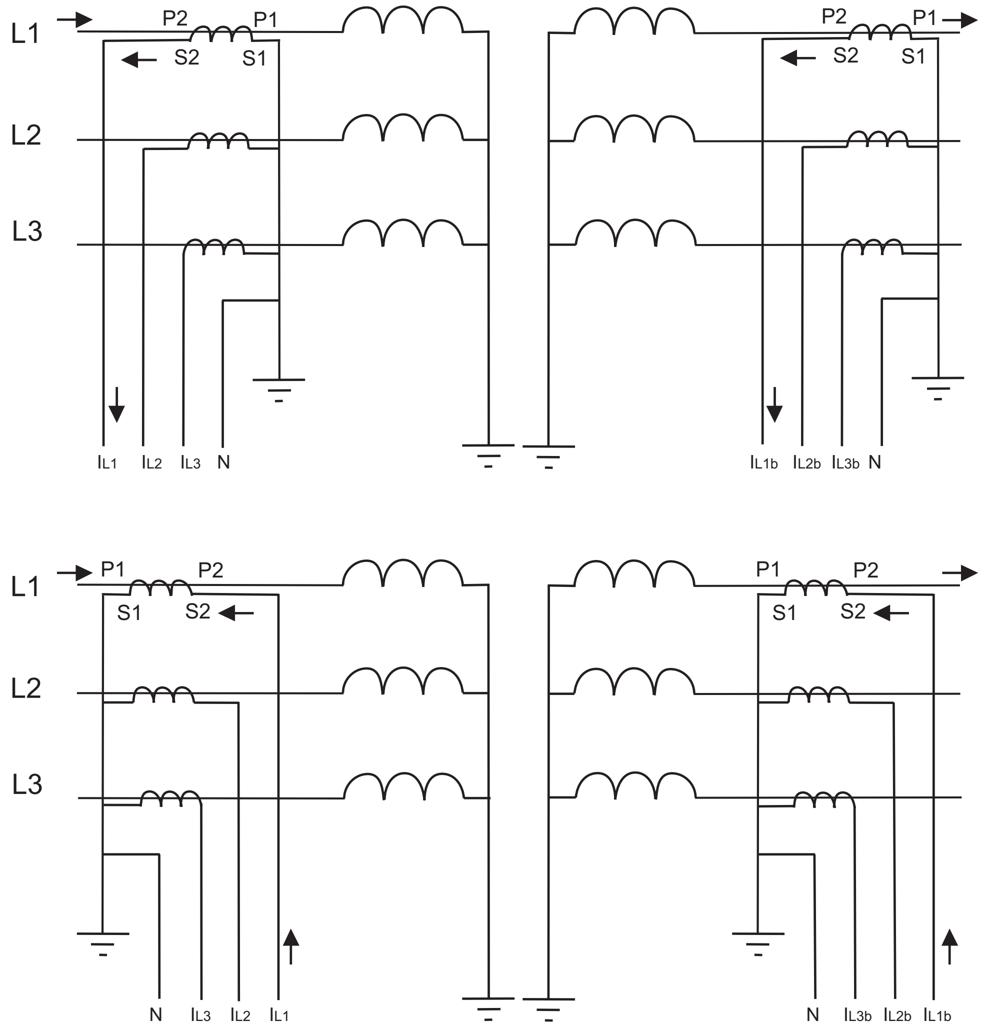

Figure 9. “Type II” connection of current transformers.

2.6.3 Transformer vector group matching

The phase difference of the HV side and LV side currents caused by the vector group of the power transformer is numerically compensated. The matching of the phase difference is based on phase shifting and numerical delta connection inside the relay. The LV connection parameter determines the connections of the phase windings on the LV side (0="y", 1="yn", 2="d", 3="z", 4="zn"). In the same way, the HV connection parameter determines the connection on the HV side (0="Y", 1="YN", 2="D", 3="Z", 4="ZN").

Depending on the vector group, the matching is implemented either on the HV side or the LV side or on both sides, at intervals of 30 °.

When the vector group matching is Yy0, the phase angle of the phase currents connected to the relay does not change. When the vector group matching is Yy6, the phase currents will be turned 180° in the relay.

Example 1.

Vector group matching of a YNd11-connected power transformer on the HV side, CT connection according to Type II.

Settings: HV connection =”YN”, LV connection =”d” and Clock number = “11”. Internally this is compensated as follows; internal HV compensation = “11” and internal LV compensation = “0”.

$$\bar{I}_{L1mHV} = \frac{\bar{I}_{L1} - \bar{I}_{L2}}{\sqrt{3}}$$
$$\bar{I}_{L2mHV} = \frac{\bar{I}_{L2} - \bar{I}_{L3}}{\sqrt{3}} \qquad \text{EQ. (9)}$$
$$\bar{I}_{L3mHV} = \frac{\bar{I}_{L3} - \bar{I}_{L1}}{\sqrt{3}}$$

Example 2.

If the vector group is Yd11and the CT connection according to Type II, the compensation is a little bit different.

Settings: HV connection =”Y”, LV connection =”d” and Clock number = “11”. Internally this is compensated as follows; internal HV compensation = “0” and internal LV compensation = “1”.

$$\bar{I}_{L1mLV} = \frac{\bar{I}_{L1} - \bar{I}_{L3}}{\sqrt{3}}$$
$$\bar{I}_{L2mLV} = \frac{\bar{I}_{L2} - \bar{I}_{L1}}{\sqrt{3}} \qquad \text{EQ. (10)}$$
$$\bar{I}_{L3mLV} = \frac{\bar{I}_{L3} - \bar{I}_{L2}}{\sqrt{3}}$$

In this case, the Wye side currents stay untouched, while the delta side currents are compensated to match the currents actually flowing in the windings.

In this example there is no neutral current on either side of the transformer (assuming there are no earthing transformers installed). In Example 1, however, the compensation is done differently in order to get the HV side neutral current compensated at the same time.

2.6.4 Elimination of the zero sequence component of the phase currents

If the Clock number is 4, 6, 8 or 10, the vector group matching is always done both on the HV and on the LV side. The combination will result in the correct compensation. In this case the zero-sequence component is always removed from both sides automatically. The parameter Io elimination cannot change this.

If the Clock number is 1, 5, 7 or 11, the vector group matching is done on one side only. A possible zero-sequence component of the phase currents at earth faults occurring out of the protection area will be eliminated in the numerically implemented delta connection before the differential current and the stabilizing current are calculated. That is why the vector group matching is almost always made on the wye-connected side of YNd and Dyn connected transformers.

With the Clock number 0 and 6, the zero-sequence component of the phase currents is not eliminated automatically on either side. However, the zero-sequence component on the wye-connected side, earthed at its star point, has to be eliminated by using the Io elimination parameter.

The same parameter has to be used to eliminate the zero-sequence component if there is, for example, an earthing transformer on the delta-connection side of the YNd power transformer in the area to be protected. In this case the vector group matching is normally made on the wye-connected side. On the delta-connected side, elimination of the zero-sequence component has to be separately selected.

By using the Io elimination parameter, the zero-sequence component of the phase currents is calculated and reduced for each phase current as follows:

$$\begin{aligned} \bar{I}_{L1m} &= \bar{I}_{L1} - \frac{1}{3}x(\bar{I}_{L1} + \bar{I}_{L2} + \bar{I}_{L3}) \\ \bar{I}_{L2m} &= \bar{I}_{L2} - \frac{1}{3}x(\bar{I}_{L1} + \bar{I}_{L2} + \bar{I}_{L3}) \\ \bar{I}_{L3m} &= \bar{I}_{L3} - \frac{1}{3}x(\bar{I}_{L1} + \bar{I}_{L2} + \bar{I}_{L3}) \end{aligned} \qquad \text{EQ. (11)}$$

Note! In many cases with earthed neutral of a wye winding it is possible to make the compensation so that the zero-sequence component of the phase currents is automatically eliminated. For example, in a case of an YNd transformer the compensation is done on the HV side to automatically eliminate the zero-sequence component of the phase currents on that side (not existing on the delta side). In those cases explicit elimination is not needed. This is taken into account in Table 1, where the supported transformer vector groups are listed and the need for explicit zero-sequence component elimination is stated.

2.6.5 Matching of various power transformer vector groups

The settings corresponding to the supported power transformer vector groups are listed in the following table:

Table 1. Vector group of the transformer

Vector group of the transformer	HV connection	LV connection	Clock number	Io elimination
Yy0	Y	y	0	Not needed
YNy0	YN	y	0	HV side
YNyn0	YN	yn	0	HV & LV side
Yyn0	Y	yn	0	LV side
Yy2	Y	y	2	Not needed
YNy2	YN	y	2	Not needed
YNyn2	YN	yn	2	Not needed
Yyn2	Y	yn	2	Not needed
Yy4	Y	y	4	Not needed
YNy4	YN	y	4	Not needed
YNyn4	YN	yn	4	Not needed
Yyn4	Y	yn	4	Not needed
Yy6	Y	y	6	Not needed
YNy6	YN	y	6	HV side
YNyn6	YN	yn	6	HV & LV side
Yyn6	Y	yn	6	LV side
Yy8	Y	y	8	Not needed
YNy8	YN	y	8	Not needed
YNyn8	YN	yn	8	Not needed
Yyn8	Y	yn	8	Not needed
Yy10	Y	y	10	Not needed
YNy10	YN	y	10	Not needed
YNyn10	YN	yn	10	Not needed
Yyn10	Y	yn	10	Not needed
Yd1	Y	d	1	Not needed
YNd1	YN	d	1	Not needed
Yd5	Y	d	5	Not needed
YNd5	YN	d	5	Not needed
Yd7	Y	d	7	Not needed
YNd7	YN	d	7	Not needed
Yd11	Y	d	11	Not needed
YNd11	YN	d	11	Not needed
Dd0	D	d	0	Not needed
Dd2	D	d	2	Not needed
Dd4	D	d	4	Not needed
Dd6	D	d	6	Not needed
Dd8	D	d	8	Not needed
Dd10	D	d	10	Not needed
Dy1	D	y	1	Not needed
Dyn1	D	yn	1	Not needed
Dy5	D	y	5	Not needed
Dyn5	D	yn	5	Not needed
Dy7	D	y	7	Not needed
Dyn7	D	yn	7	Not needed

Vector group of the transformer	HV connection	LV connection	Clock number	Io elimination
Dy11	D	y	11	Not needed
Dyn11	D	yn	11	Not needed
Yz1	Y	z	1	Not needed
YNz1	YN	z	1	Not needed
YNzn1	YN	zn	1	LV side
Yzn1	Y	zn	1	Not needed
Yz5	Y	z	5	Not needed
YNz5	YN	z	5	Not needed
YNzn5	YN	zn	5	LV side
Yzn5	Y	zn	5	Not needed
Yz7	Y	z	7	Not needed
YNz7	YN	z	7	Not needed
YNzn7	YN	zn	7	LV side
Yzn7	Y	zn	7	Not needed
Yz11	Y	z	11	Not needed
YNz11	YN	z	11	Not needed
YNzn11	YN	zn	11	LV side
Yzn11	Y	zn	11	Not needed
Zy1	Z	y	1	Not needed
Zyn1	Z	yn	1	Not needed
ZNyn1	ZN	yn	1	HV side
ZNy1	ZN	y	1	Not needed
Zy5	Z	y	5	Not needed
Zyn5	Z	yn	5	Not needed
ZNyn5	ZN	yn	5	HV side
ZNy5	ZN	y	5	Not needed
Zy7	Z	y	7	Not needed
Zyn7	Z	yn	7	Not needed
ZNyn7	ZN	yn	7	HV side
ZNy7	ZN	y	7	Not needed
Zy11	Z	y	11	Not needed
Zyn11	Z	yn	11	Not needed
ZNyn11	ZN	yn	11	HV side
ZNy11	ZN	y	11	Not needed
Dz0	D	z	0	Not needed
Dzn0	D	zn	0	LV side
Dz2	D	z	2	Not needed
Dzn2	D	zn	2	Not needed
Dz4	D	z	4	Not needed
Dzn4	D	zn	4	Not needed
Dz6	D	z	6	Not needed
Dzn6	D	zn	6	LV side
Dz8	D	z	8	Not needed
Dzn8	D	zn	8	Not needed
Dz10	D	z	10	Not needed

Vector group of the transformer	HV connection	LV connection	Clock number	Io elimination
Dzn10	D	zn	10	Not needed
Zd0	Z	d	0	Not needed
ZNd0	ZN	d	0	HV side
Zd2	Z	d	2	Not needed
ZNd2	ZN	d	2	Not needed
Zd4	Z	d	4	Not needed
ZNd4	ZN	d	4	Not needed
Zd6	Z	d	6	Not needed
ZNd6	ZN	d	6	HV side
Zd8	Z	d	8	Not needed
ZNd8	ZN	d	8	Not needed
Zd10	Z	d	10	Not needed
ZNd10	ZN	d	10	Not needed
Zz0	Z	z	0	Not needed
ZNz0	ZN	z	0	HV side
ZNzn0	ZN	zn	0	HV & LV side
Zzn0	Z	zn	0	LV side
Zz2	Z	z	2	Not needed
ZNz2	ZN	z	2	Not needed
ZNzn2	ZN	zn	2	Not needed
Zzn2	Z	zn	2	Not needed
Zz4	Z	z	4	Not needed
ZNz4	ZN	z	4	Not needed
ZNzn4	ZN	zn	4	Not needed
Zzn4	Z	zn	4	Not needed
Zz6	Z	z	6	Not needed
ZNz6	ZN	z	6	HV side
ZNzn6	ZN	zn	6	HV & LV side
Zzn6	Z	zn	6	LV side
Zz8	Z	z	8	Not needed
ZNz8	ZN	z	8	Not needed
ZNzn8	ZN	zn	8	Not needed
Zzn8	Z	zn	8	Not needed
Zz10	Z	z	10	Not needed
ZNz10	ZN	z	10	Not needed
ZNzn10	ZN	zn	10	Not needed
Zzn10	Z	zn	10	Not needed

Measurement CTs can always be wye-connected, whatever the vector group is.

Note! If an earthing transformer is used on the delta side of a Dyn or YNd transformer, Io elimination must be enabled on the delta side.

2.6.6 Commissioning instructions

The correct settings for the connection group compensation (control settings CT connection, HV connection, LV connection and Clock number) can be verified by monitoring the angle values (Angle IL1-IL2, Angle IL2-IL3, Angle IL3-IL1, Angle IL1b-IL2b, Angle IL2b-IL3b, Angle IL3b-IL1b, Angle IL1-IL1b, Angle IL2-IL2b and Angle IL3-IL3b) while injecting current into the transformer. These angle values are calculated from the compensated currents.

When a station service transformer is available, it can be used to provide current into the high voltage side (HV) windings while low voltage side (LV) windings are short-circuited, see Figure 10. This way the current can flow both in HV and LV windings. Other means for providing the commissioning signals can also be used. It should be noted that the currents need to be at least 0.015 p.u. to allow for phase current and angle monitoring.

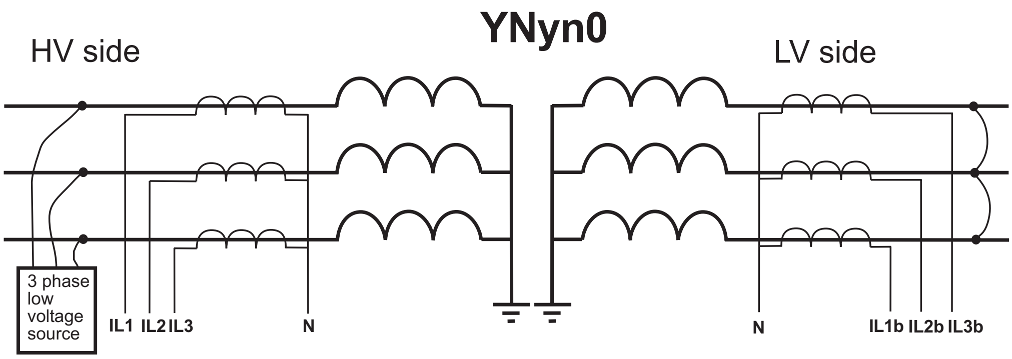

Figure 10. Low voltage test arrangement. The three-phase low voltage source can for example be the station service transformer.

To make sure that the monitored current values are not scaled by the automatic adaptation to the tap changer position, the control setting parameter Tapped winding should be set to value “Not in use”. When only interested on the angle values this is not needed since angle values are not affected by the tap changer position adaptation.

When injecting the currents into the HV winding as described above the angle values Angle IL1-IL2, Angle IL2-IL3, Angle IL3-IL1, Angle IL1b-IL2b, Angle IL2b-IL3b and Angle IL3b-IL1b should show +120.

If this is not the case the phase order may be wrong or the polarity of one current transformer differs from the polarities of the other current transformers on the same side. If the angle values Angle IL1-IL2, Angle IL2-IL3 and Angle IL3-IL1 are shown -120, the phase order is wrong on HV side. If the angle values Angle IL1b-IL2b, Angle IL2b-IL3b and Angle IL3b-IL1b show -120, the phase order is wrong on LV side. If the angle values Angle IL1-IL2, Angle IL2-IL3 and Angle IL3-IL1 do not show the same value (+120) the polarity of one current transformer may be wrong. For example, if the polarity of the current transformer measuring IL2 is wrong, the Angle IL1-IL2 show -60, Angle IL2-IL3 show -60 and Angle IL3-IL1 show +120.

When the phase order is correct and the angle values mentioned above are OK, the angle values Angle IL1-IL1b, Angle IL2-IL2b and Angle IL3-IL3b should show 0. There can be several reasons if this is not the case. If the angle values are +/-180 most probably the value given for CT connection is wrong. If the angle values are something else the value for Clock number can be wrong. Another possibility is that the combination of HV connection and LV connection does not match Clock number. This means that the resulting connection group is not supported.

For example if HV connection is set to "Y", LV connection is set to "y" and Clock number is set to "1" the resulting connection group Yy1 is not supported. Similarly if HV connection is set to "Y", LV connection is set to "d" and Clock number is set to "0" the resulting connection group Yd0 is not supported. All non-supported combinations of the settings HV connection, LV connection and Clock number will result the default connection group compensation that is Yy0.

2.7 Setting groups

Two different groups of setting values, group 1 and group 2, are available for the function block. Switching between the two groups can be done in the following three ways:

1. Locally via the control parameter Group selection of the HMI

2. Over the serial bus with the command V2

3. By means of the input signal GROUP when allowed via the parameter Group selection (i.e. when V2 = 2).

2.8 Test mode

The digital outputs of the function block can be activated with separate control parameters for each output either locally via the HMI or externally via the serial communication. When an output is activated with the test parameter, an event indicating the test is generated.

The protective functions operate normally when the outputs are tested.

2.9 Registers (Recorded Data)

The information required for later fault analysis is recorded when the function block trips or when the recording function is triggered via an external triggering input.

The data of the last three operations (Operation 1...3) are recorded, and the values of the most recent operation always replace the data of the oldest operation. The registers are updated in the following order: Operation 1, Operation 2, Operation 3, Operation 1, Operation 2 and so on.

2.9.1 Date and time

The time stamp indicates the rising edge of the TRIGG signal or the rising edge of the TRIP signal.

2.9.2 Status data

The status data of the input signals BS_STAB and BS_INST (Active or Not active) are recorded at the moment of tripping and triggering.

2.9.3 Currents and phase differences

If the function block trips, the highest differential current value during 50 ms after the rising edge of the TRIP signal is recorded. All the recorded current and phase difference values will originate from that same moment determined by the highest differential current. For external triggering, the current values are recorded at the moment of triggering i.e. on the rising edge of the input signal TRIGG. Consequently, the values of the phase currents IL1, IL2, IL3, IL1b, IL2b, IL3b, the values of the differential currents Id1, Id2, Id3, the values of the stabilizing currents Ib1, Ib2, Ib3 and the phase difference values always originate from the same moment. The current values are recorded as multiples of the rated current In and the phase difference values are recorded in degrees.

2.10 TRIP output

The output signal TRIP may have a non-latching or latching feature. When the latching mode has been selected, the TRIP signal remains active until the output is reset even if the operation criteria have reset. When the non-latching mode has been selected, the TRIP signal remains active until the operation criteria have reset and the time determined by the control parameter Trip pulse has elapsed.

The additional separate indications for each phase included in the output STATUS will always be non-latched (and is not affected by the parameter Trip pulse).

2.11 Delayed trip output CBFP

The stage provides a delayed trip signal CBFP after the TRIP signal unless the fault has disappeared during the set CBFP time delay. In circuit breaker failure protection the CBFP output can be used to operate a circuit breaker upstream from the circuit breaker of the transformer. The control parameter Trip pulse determines also the width of the CBFP output signal.

2.12 STATUS output

The function block has one coded output for a set of infrequently needed data. The STATUS output collects phase-segregated indications of instantaneous trip, stabilized trip, 2. harmonic blocking, 5. harmonic blocking and waveform based blocking. The following figures explain the meaning of the bits.

Table 2. Meaning of the bits in the coded output STATUS.

Bit number	Meaning of the bit
0 (LSB)	Instantaneous stage trip in phase 1
1	Instantaneous stage trip in phase 2
2	Instantaneous stage trip in phase 3
3	Stabilized stage trip in phase 1
4	Stabilized stage trip in phase 2
5	Stabilized stage trip in phase 3
6	Second harmonic block in phase 1
7	Second harmonic block in phase 2
8	Second harmonic block in phase 3
9	Fifth harmonic block in phase 1
10	Fifth harmonic block in phase 2
11	Fifth harmonic block in phase 3
12	Waveform based block in phase 1
13	Waveform based block in phase 2
14 (MSB)	Waveform based block in phase 3

Example: STATUS = 393

Table 3. Example of the bits in the coded output STATUS.

MSB														**LSB**
14	13	12	11	10	9	8	7	6	5	4	3	2	1	0
0	0	0	0	0	0	1	1	0	0	0	1	0	0	1

=> The second harmonic blocking is active in all phases 2, 3 and both stabilized and instantaneous trip have occurred in phase 1.

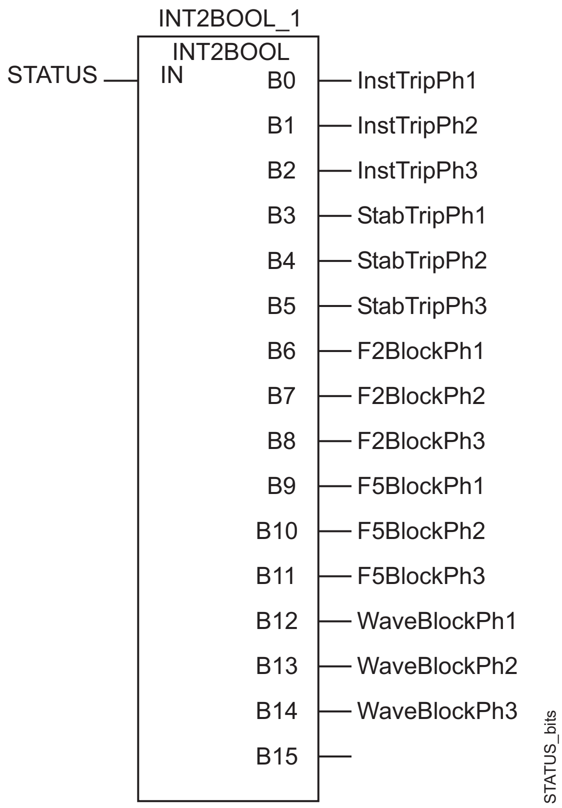

Figure 11. Example of decoding the bits in the coded output STATUS

2.13 Resetting

The TRIP output signal and the registers can be reset via the RESET input, or over the serial bus or the local HMI.

The operation indicators, latched trip signal and recorded data can be reset as follows:

	Operation indicators	Latched trip signal	Registers
RESET input of the function block *		X	X
Parameter F106V013 *		X	X
General parameter F001V011	X		
General parameter F001V012	X	X	
General parameter F001V013	X	X	X
Push-button C	X		
Push-buttons C + E (2 s)	X	X	
Push-buttons C + E (5 s)	X	X	X

* Local reset: resets the latched trip signal or recorded data of the particular function block.

3. Parameters and Events

3.1 General

- Each function block has a specific channel number for serial communication parameters and events. The channel for Diff6T is 106.
- The data direction of the parameters defines the use of each parameter as follows:

Data direction	Description
R, R/M	Read only
W	Write only
R/W	Read and write

- The different event mask parameters (see section “Control Settings”) affect the visibility of events on the HMI or on the serial communication (LON or SPA) as follows:

Event mask 1 (F106V101/102)	SPA / MMI (LON)
Event mask 2 (F106V103/104)	LON
Event mask 3 (F106V105/106)	LON
Event mask 4 (F106V107/108)	LON

For example, if only the events E3, E4 and E5 are to be seen on the HMI of the relay terminal, the event mask value 56 (8 + 16 + 32) is written to the “Event mask 1” parameter (F106V101).

3.2 Setting values

3.2.1 Actual Settings

Parameter	Code	Values	Unit	Default	Data direction	Explanation
Basic setting	S1	5...50	%	20	R	The lowest ratio of the differential and nominal currents to cause a trip.
Starting ratio	S2	10...50	%	30	R	Slope of the second line of the operation characteristics.
Turn-point 2	S3	1.0...3.0	x In	1.5	R	Turn-point between the second and the third line of the operation characteristics.
Inst. setting	S4	5...30	x In	10	R	Trip value of the instantaneous stage.
Ratio I2f/I1f>	S5	7...20	%	15	R	The ratio of the 2. harmonic component to the fundamental component required for blocking.
Ratio I5f/I1f>	S6	10...50	%	35	R	The ratio of the 5. harmonic component to the fundamental component required for blocking.
Ratio I5f/I1f>>	S7	10...50	%	35	R	The ratio of the 5. harmonic component to the fundamental component required to remove the 5. harmonic blocking.
2. harm. block	S8	0…2 [1)]	-	2	R	Selects if the 2. harmonic blocking is allowed and if the deblocking is allowed in case of switch on to a fault.
5. harm. block	S9	0…2 [1)]	-	1	R	Selects if the 5. harmonic blocking is allowed and if the deblocking is allowed in case of a severe overvoltage situation.

[1)] Harm_blk 0 = Not in use; 1 = In use; 2 = With deblock

3.2.2 Setting Group 1

Parameter	Code	Values	Unit	Default	Data direction	Explanation
Basic setting	S41	5...50	%	20	R/W	The lowest ratio of the differential and nominal currents to cause a trip.
Starting ratio	S42	10...50	%	30	R/W	Slope of the second line of the operation characteristics.
Turn-point 2	S43	1.0...3.0	x In	1.5	R/W	Turn-point between the second and the third line of the operation characteristics.
Inst. setting	S44	5...30	x In	10	R/W	Trip value of the instantaneous stage.
Ratio I2f/I1f>	S45	7...20	%	15	R/W	The ratio of the 2. harmonic component to the fundamental component required for blocking.
Ratio I5f/I1f>	S46	10...50	%	35	R/W	The ratio of the 5. harmonic component to the fundamental component required for blocking.
Ratio I5f/I1f>>	S47	10...50	%	35	R/W	The ratio of the 5. harmonic component to the fundamental component required to remove the 5. harmonic blocking.
2. harm. block	S48	0…2 [1)]	-	2	R/W	Selects if the 2. harmonic blocking is allowed and if the deblocking is allowed in case of switch on to a fault.
5. harm. block	S49	0…2 [1)]	-	1	R/W	Selects if the 5. harmonic blocking is allowed and if the deblocking is allowed in case of a severe overvoltage situation.

[1)] Harm_blk 0 = Not in use; 1 = In use; 2 = With deblock

3.2.3 Setting Group 2

Parameter	Code	Values	Unit	Default	Data direction	Explanation
Basic setting	S71	5...50	%	20	R/W	The lowest ratio of the differential and nominal currents to cause a trip.
Starting ratio	S72	10...50	%	30	R/W	Slope of the second line of the operation characteristics.
Turn-point 2	S73	1.0...3.0	x In	1.5	R/W	Turn-point between the second and the third line of the operation characteristics.
Inst. setting	S74	5...30	x In	10	R/W	Trip value of the instantaneous stage.
Ratio I2f/I1f>	S75	7...20	%	15	R/W	The ratio of the 2. harmonic component to the fundamental component required for blocking.
Ratio I5f/I1f>	S76	10...50	%	35	R/W	The ratio of the 5. harmonic component to the fundamental component required for blocking.
Ratio I5f/I1f>>	S77	10...50	%	35	R/W	The ratio of the 5. harmonic component to the fundamental component required to remove the 5. harmonic blocking.
2. harm. block	S78	0…2 [1)]	-	2	R/W	Selects if the 2. harmonic blocking is allowed and if the deblocking is allowed in case of switch on to a fault.
5. harm. block	S79	0…2 [1)]	-	1	R/W	Selects if the 5. harmonic blocking is allowed and if the deblocking is allowed in case of a severe overvoltage situation.

[1)] Harm_blk 0 = Not in use; 1 = In use; 2 = With deblock

3.2.4 Control Settings

Parameter	Code	Values	Unit	Default	Data direction	Explanation
Operation mode	V1	0…1 [1)]	-	1	R/W	Protection block in use or not in use.
Group selection	V2	0…2 [2)]	-	0	R/W	Selection of the active setting group.
Active group	V3	0…1 [3)]	-	0	R/M	Active setting group.
Trip signal	V4	0…1 [4)]	-	0	R/W	Selection of self-holding for TRIP output.
Trip pulse	V5	40...1000	ms	40	R/W	Minimum pulse length of TRIP and CBFP.
CBFP time	V6	100...1000	ms	100	R/W	Operate time of the delayed trip CBFP.
CT connection	V7	0…1 [5)]	-	0	R/W	CT connection type. Determined by the directions of the connected current transformers.
HV connection	V8	0…4 [6)]	-	0	R/W	Connection of the HV side windings. Determined by the transformer vector group (e.g. Dyn11 ->"D").
LV connection	V9	0…4 [7)]	-	0	R/W	Connection of the LV side windings. Determined by the transformer vector group (e.g. Dyn11 ->"yn").
Clock number	V10	0...11	-	0	R/W	Setting the Clock number for vector group compensation (e.g. Dyn11 -> 11).
Io elimination	V11	0…3 [8)]	-	0	R/W	Elimination of the zero-sequence current.
Min. turns tap	V12	-36...36	-	36	R/W	The tap position number results the minimum number of effective winding turns on the transformer where the tap changer is.
Max. turns tap	V14	-36...36	-	0	R/W	The tap position number results the maximum number of effective winding turns on the transformer where the tap changer is.
Nominal tap	V15	-36...36	-	18	R/W	The nominal position of the tap changer resulting in the default transformation ratio of the transformer (as if with no tap changer).
Tapped winding	V16	0…2 [9)]	-	0	R/W	The winding where the tap changer is connected. Also used to enable/disable the automatic compensation of the tap changer position.
Tap step %	V17	0.60...9.00	%	1.50	R/W	The percentage change in voltage corresponding one step of the tap changer.
Reset registers	V13	0…1 [10)]	-	0	W	Resetting of latched trip signal and registers.
Test TRIP	V32	0…1 [11)]	-	0	R/W	Testing of TRIP.
Test CBFP	V33	0…1 [11)]	-	0	R/W	Testing of CBFP.
Event mask 1	V101	0...262143	-	63	R/W	Event mask 1 for event transmission (E0...E17).
Event mask 2	V103	0...262143	-	63	R/W	Event mask 2 for event transmission (E0...E17).
Event mask 3	V105	0...262143	-	63	R/W	Event mask 3 for event transmission (E0...E17).
Event mask 4	V107	0...262143	-	63	R/W	Event mask 4 for event transmission (E0...E17).

[1)] Status 0 = Not in use; 1 = In use
[2)] Group selection 0 = Group 1; 1 = Group 2; 2 = GROUP input
[3)] Active group 0 = Group 1; 1 = Group 2
[4)] Trip signal 0 = Non-latching; 1 = Latching
[5)] Connection type 0 = Type I; 1 = Type II
[6)] HV type 0 = Y; 1 = YN; 2 = D; 3 = Z; 4 = ZN
[7)] LV type 0 = y; 1 = yn; 2 = d; 3 = z; 4 = zn
[8)] IO elimination 0 = Not in use; 1 = HV side; 2 = LV side; 3 = HV&LV side
[9)] Tapped winding 0 = Not in use; 1 = HV winding; 2 = LV winding
[10)] Reset 0 = 0; 1 = Reset
[11)] Test 0 = Do not activate; 1 = Activate

3.3 Measurement values

3.3.1 Input Data

Parameter	Code	Values	Unit	Default	Data direction	Explanation
Current IL1	I1	0.000...60.000	x In	0.000	R/M	Phase current IL1
Current IL2	I2	0.000...60.000	x In	0.000	R/M	Phase current IL2
Current IL3	I3	0.000...60.000	x In	0.000	R/M	Phase current IL3
Current IL1b	I4	0.000...60.000	x In	0.000	R/M	Phase current IL1b
Current IL2b	I5	0.000...60.000	x In	0.000	R/M	Phase current IL2b
Current IL3b	I6	0.000...60.000	x In	0.000	R/M	Phase current IL3b
Current Id1	I7	0.000...60.000	x In	0.000	R/M	Differential current of phase 1
Current Id2	I8	0.000...60.000	x In	0.000	R/M	Differential current of phase 2
Current Id3	I9	0.000...60.000	x In	0.000	R/M	Differential current of phase 3
Current Ib1	I10	0.000...60.000	x In	0.000	R/M	Bias current of phase 1
Current Ib2	I11	0.000...60.000	x In	0.000	R/M	Bias current of phase 2
Current Ib3	I12	0.000...60.000	x In	0.000	R/M	Bias current of phase 3
Id2f/Id1f L1	I13	0.0...100.0	%	0.0	R/M	The ratio of the second harmonic to fundamental in phase 1
Id2f/Id1f L2	I14	0.0...100.0	%	0.0	R/M	The ratio of the second harmonic to fundamental in phase 2
Id2f/Id1f L3	I15	0.0...100.0	%	0.0	R/M	The ratio of the second harmonic to fundamental in phase 3
Angle IL1-IL2	I16	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L1 and L2
Angle IL2-IL3	I17	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L2 and L3
Angle IL3-IL1	I18	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L3 and L1
Angle IL1b-IL2b	I19	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L1b and L2b
Angle IL2b-IL3b	I20	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L2b and L3b
Angle IL3b-IL1b	I21	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L3b and L1b
Angle IL1-IL1b	I22	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L1 and L1b
Angle IL2-IL2b	I23	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L2 and L2b
Angle IL3-IL3b	I24	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L3 and L3b
Input BS_STAB	I25	0…1 [1)]	-	0	R/M	Status of BS_STAB signal
Input BS_INST	I26	0…1 [1)]	-	0	R/M	Status of BS_INST signal
Input GROUP	I27	0…1 [1)]	-	0	R/M	Status of signal for switching between group 1 and 2
Input TAP_POS	I28	-36...36	-	0	R/M	Tap changer position
Input RESET	I29	0…1 [1)]	-	0	R/M	Status of signal for resetting output signals of Diff6T

[1)] Active 0 = Not active; 1 = Active

3.3.2 Output Data

Parameter	Code	Values	Unit	Default	Data direction	Explanation
Output TRIP	O1	0 or 1 [1)]	-	0	R/M	Status of trip signal
Stab. trip	O2	0 or 1 [1)]	-	0	R/M	Status of the trip from stabilized stage
Inst. trip	O3	0 or 1 [1)]	-	0	R/M	Status of the trip instantaneous stage
Output CBFP	O4	0 or 1 [1)]	-	0	R/M	Status of CBFP signal
Output STATUS	O5	0…32767	-	0	R/M	Status enumerator of the Diff6T

[1)] Output 0 = Not active; 1 = Active

3.3.3 Recorded data

3.3.3.1 Recorded Data 1

Parameter	Code	Values	Unit	Default	Data direction	Explanation
Date	V201	YYYY-MM-DD	-	-	R/M	Recording date
Time	V202	hh:mm:ss.000	-	-	R/M	Recording time
Current IL1	V203	0.000...60.000	x In	0.000	R/M	Phase current IL1
Current IL2	V204	0.000...60.000	x In	0.000	R/M	Phase current IL2
Current IL3	V205	0.000...60.000	x In	0.000	R/M	Phase current IL3
Current IL1b	V206	0.000...60.000	x In	0.000	R/M	Phase current IL1b
Current IL2b	V207	0.000...60.000	x In	0.000	R/M	Phase current IL2b
Current IL3b	V208	0.000...60.000	x In	0.000	R/M	Phase current IL3b
Current Id1	V209	0.000...60.000	x In	0.000	R/M	Differential current of phase 1
Current Id2	V210	0.000...60.000	x In	0.000	R/M	Differential current of phase 2
Current Id3	V211	0.000...60.000	x In	0.000	R/M	Differential current of phase 3
Current Ib1	V212	0.000...60.000	x In	0.000	R/M	Bias current of phase 1
Current Ib2	V213	0.000...60.000	x In	0.000	R/M	Bias current of phase 2
Current Ib3	V214	0.000...60.000	x In	0.000	R/M	Bias current of phase 3
Angle IL1-IL2	V215	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L1 and L2
Angle IL2-IL3	V216	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L2 and L3
Angle IL3-IL1	V217	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L3 and L1
Angle IL1b-IL2b	V218	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L1b and L2b
Angle IL2b-IL3b	V219	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L2b and L3b
Angle IL3b-IL1b	V220	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L3b and L1b
Angle IL1-IL1b	V221	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L1 and L1b
Angle IL2-IL2b	V222	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L2 and L2b
Angle IL3-IL3b	V223	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L3 and L3b
Tripped phases	V224	0…7 [1)]	-	0	R/M	Trip status indicating the phases issuing the trip
Input BS_STAB	V225	0…1 [2)]	-	0	R/M	Status of BS_STAB input
Input BS_INST	V226	0…1 [2)]	-	0	R/M	Status of BS_INST input
Input TAP_POS	V227	-36...36	-	0	R/M	Tap changer position
Active group	V228	0…1 [3)]	-	0	R/M	Active setting group
Reg. reason	V229	0…3 [4)]	-	0	R/M	Reason for registration (TRIP >, TRIP >> or TRIGG)

[1)] Active phase: 0 = Not active; 1 = Phase L1; 2 = Phase L2; 3 = Phases L1&L2; 4 = Phase L3; 5 = Phases L3&L1; 6 = Phases L2&L3; 7 = Phases L1&L2&L3
[2)] Active: 0 = Not active; 1 = Active
[2)] Active group: 0 = Group 1; 1 = Group 2
[4)] Registration reason: 0 = Not active; 1= TRIP >; 2 = TRIP >>; 3 = TRIGG

3.3.3.2 Recorded Data 2

Parameter	Code	Values	Unit	Default	Data direction	Explanation
Date	V301	YYYY-MM-DD	-	-	R/M	Recording date
Time	V302	hh:mm:ss.000	-	-	R/M	Recording time
Current IL1	V303	0.000...60.000	x In	0.000	R/M	Phase current IL1
Current IL2	V304	0.000...60.000	x In	0.000	R/M	Phase current IL2
Current IL3	V305	0.000...60.000	x In	0.000	R/M	Phase current IL3
Current IL1b	V306	0.000...60.000	x In	0.000	R/M	Phase current IL1b
Current IL2b	V307	0.000...60.000	x In	0.000	R/M	Phase current IL2b
Current IL3b	V308	0.000...60.000	x In	0.000	R/M	Phase current IL3b
Current Id1	V309	0.000...60.000	x In	0.000	R/M	Differential current of phase 1
Current Id2	V310	0.000...60.000	x In	0.000	R/M	Differential current of phase 2
Current Id3	V311	0.000...60.000	x In	0.000	R/M	Differential current of phase 3
Current Ib1	V312	0.000...60.000	x In	0.000	R/M	Bias current of phase 1
Current Ib2	V313	0.000...60.000	x In	0.000	R/M	Bias current of phase 2
Current Ib3	V314	0.000...60.000	x In	0.000	R/M	Bias current of phase 3
Angle IL1-IL2	V315	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L1 and L2
Angle IL2-IL3	V316	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L2 and L3
Angle IL3-IL1	V317	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L3 and L1
Angle IL1b-IL2b	V318	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L1b and L2b
Angle IL2b-IL3b	V319	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L2b and L3b
Angle IL3b-IL1b	V320	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L3b and L1b
Angle IL1-IL1b	V321	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L1 and L1b
Angle IL2-IL2b	V322	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L2 and L2b
Angle IL3-IL3b	V323	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L3 and L3b
Tripped phases	V324	0…7 [1)]	-	0	R/M	Trip status indicating the phases issuing the trip
Input BS_STAB	V325	0…1 [2)]	-	0	R/M	Status of BS_STAB input
Input BS_INST	V326	0…1 [2)]	-	0	R/M	Status of BS_INST input
Input TAP_POS	V327	-36...36	-	0	R/M	Tap changer position
Active group	V328	0…1 [3)]	-	0	R/M	Active setting group
Reg. reason	V329	0…3 [4)]	-	0	R/M	Reason for registration (TRIP >, TRIP >> or TRIGG)

[1)] Active phase 0 = Not active; 1 = Phase L1; 2 = Phase L2; 3 = Phases L1&L2; 4 = Phase L3; 5 = Phases L3&L1; 6 = Phases L2&L3; 7 = Phases L1&L2&L3
[2)] Active 0 = Not active; 1 = Active
[2)] Active group 0 = Group 1; 1 = Group 2
[4)] Registration reason 0 = Not active; 1= TRIP >; 2 = TRIP >>; 3 = TRIGG

3.3.3.3 Recorded Data 3

Parameter	Code	Values	Unit	Default	Data direction	Explanation
Date	V401	YYYY-MM-DD	-	-	R/M	Recording date
Time	V402	hh:mm:ss.000	-	-	R/M	Recording time
Current IL1	V403	0.000...60.000	x In	0.000	R/M	Phase current IL1
Current IL2	V404	0.000...60.000	x In	0.000	R/M	Phase current IL2
Current IL3	V405	0.000...60.000	x In	0.000	R/M	Phase current IL3
Current IL1b	V406	0.000...60.000	x In	0.000	R/M	Phase current IL1b
Current IL2b	V407	0.000...60.000	x In	0.000	R/M	Phase current IL2b
Current IL3b	V408	0.000...60.000	x In	0.000	R/M	Phase current IL3b
Current Id1	V409	0.000...60.000	x In	0.000	R/M	Differential current of phase 1
Current Id2	V410	0.000...60.000	x In	0.000	R/M	Differential current of phase 2
Current Id3	V411	0.000...60.000	x In	0.000	R/M	Differential current of phase 3
Current Ib1	V412	0.000...60.000	x In	0.000	R/M	Bias current of phase 1
Current Ib2	V413	0.000...60.000	x In	0.000	R/M	Bias current of phase 2
Current Ib3	V414	0.000...60.000	x In	0.000	R/M	Bias current of phase 3
Angle IL1-IL2	V415	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L1 and L2
Angle IL2-IL3	V416	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L2 and L3
Angle IL3-IL1	V417	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L3 and L1
Angle IL1b-IL2b	V418	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L1b and L2b
Angle IL2b-IL3b	V419	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L2b and L3b
Angle IL3b-IL1b	V420	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L3b and L1b
Angle IL1-IL1b	V421	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L1 and L1b
Angle IL2-IL2b	V422	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L2 and L2b
Angle IL3-IL3b	V423	-180.0...180.0	°	0.0	R/M	Phase difference of the currents L3 and L3b
Tripped phases	V424	0…7 [1)]	-	0	R/M	Trip status indicating the phases issuing the trip
Input BS_STAB	V425	0…1 [2)]	-	0	R/M	Status of BS_STAB input
Input BS_INST	V426	0…1 [2)]	-	0	R/M	Status of BS_INST input
Input TAP_POS	V427	-36...36	-	0	R/M	Tap changer position
Active group	V428	0…1 [3)]	-	0	R/M	Active setting group
Reg. reason	V429	0…3 [4)]	-	0	R/M	Reason for registration (TRIP >, TRIP >> or TRIGG)

[1)] Active phase 0 = Not active; 1 = Phase L1; 2 = Phase L2; 3 = Phases L1&L2; 4 = Phase L3; 5 = Phases L3&L1; 6 = Phases L2&L3; 7 = Phases L1&L2&L3
[2)] Active 0 = Not active; 1 = Active
[2)] Active group 0 = Group 1; 1 = Group 2
[4)] Registration reason 0 = Not active; 1= TRIP >; 2 = TRIP >>; 3 = TRIGG

3.3.4 Events

Code	Weighting coefficient	Default mask	Event reason	Event state
E0	1	1	TRIP signal of 3d I> stage	Reset
E1	2	1	TRIP signal of 3d I> stage	Activated
E2	4	1	TRIP signal of 3d I>> stage	Reset
E3	8	1	TRIP signal of 3d I>> stage	Activated
E4	16	1	CBFP signal 3d I> or 3d I>>	Reset
E5	32	1	CBFP signal 3d I> or 3d I>>	Activated
E6	64	0	I2f/I1f> blocking	Reset
E7	128	0	I2f/I1f> blocking	Activated
E8	256	0	I5f/I1f> blocking	Reset
E9	512	0	I5f/I1f> blocking	Activated
E10	1024	0	Waveform blocking	Reset
E11	2048	0	Waveform blocking	Activated
E12	4096	0	BS_STAB signal of 3d I> stage	Reset
E13	8192	0	BS_STAB signal of 3d I> stage	Activated
E14	16384	0	BS_INST signal of 3d I>> stage	Reset
E15	32768	0	BS_INST signal of 3d I>> stage	Activated
E16	65536	0	Test mode of 3d I> and 3d I>>	Off
E17	131072	0	Test mode of 3d I> and 3d I>>	On

4. Technical Data

Operation accuracies	At the frequency range f/f_n = 0.95...1.05 Phase difference measurement: ± 4° Operation of stabilized stage: ± 4% of set value or ± 2% x I_n Operation of instantaneous stage: ± 4% of set value or ± 2% x I_n
Trip time	Injected currents > 2.0 x operating current: f/f_n = 0.95...1.05 internal time < 35 ms total time1) < 45 ms
Reset time	60...1020 ms (depends on the minimum pulse width set for the TRIP output)
Reset ratio	Typ. 0.98 (range 0.90...0.98)
Retardation time	Total retardation time when the current or voltage drops below the operate value1) < 40 ms
Configuration data	Task execution interval (Relay Configuration Tool): 5 ms at the rated frequency f_n = 50 Hz

[1)] Includes the delay of the heavy-duty output relay