Analysis of Fundamental Differences in Transformer 87T Differential Protection

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I INTRODUCTION

When protection requirements dictate the use of multivendor equipment to avoid common mode of failures, utility protection engineers may believe for the transformer differential protection function (87T) that the same best practice application rules and setting guidelines will apply equally to all.

Faced with two 87T protection functions to set, one from vendor A and the other from vendor B, the utility protection engineer may believe that both need to be set the same way, as both need to comply to a common set of settings rules. For instance, applying a perceived common rule that dictates which transformer side should be used by the 87T function as the phase reference side.

This paper explains that there is not just one set of rules that apply to all. For any through-fault (external fault) or load condition, so long as the 87T function is properly set and there is no CT saturation, the calculated differential currents will be zero irrespective of which transformer side has been assigned as the phase reference for the calculation. However, depending on the method of restraint current calculation, the choice of phase reference side plays a significant role, as the calculated restraint currents depend on the assigned phase reference side. Whereas the calculation of the differential currents imposes no firm requirement on the choice of the phase reference side, the method of calculation of the restraint currents does.

The choice of phase reference side also impacts how the 87T function operates. For example, in accordance with utility policy, a utility has installed two microprocessor-based transformer protection relays from two different vendors, as system A and system B, to protect a Delta-wye (Dy) transformer. The 87T function in each relay was set in accordance with the vendor recommendations (one with the Delta-side as the phase reference, the other with the wye-side as the phase reference). While in service, the transformer experiences an internal single-phase fault. The 87T function in each relay operates, but the relay with the Delta-side as phase reference indicates operation of the 87T function in two phases, whereas the other relay with the wye-side as phase reference indicates 87T operation in all three phases. This paper explains that both 87T functions operated correctly, and that the difference in operation was due to the transformer side that was selected as the phase reference.

II OVERVIEW OF TRANSFORMER DIFFERENTIAL PROTECTION (87T)

Differential protection is based on summing the currents from all sides of the protected object. The primary currents are fed to the relays via CTs, and it is these CTs that form the zone boundaries of the differential protection zone. For no internal fault, the sum of the currents is zero, i.e. the currents entering and leaving the zone of protection are equal, whereas for an internal fault, the sum is non-zero, i.e. the currents entering and leaving are no longer equal. This non-zero sum represents the zone differential current.

When a transformer is the protected object, it is true to say that the differential measurement principle is based on the sum of power from all sides being zero, as the sum of currents will only be zero after all compensations have been performed. Differential protection of transformers therefore presents additional challenges, including:

- mismatch in magnitude between currents due to the voltage transformation (turns ratio of the windings and their connection)
- phase angle shift between currents due to different types of winding connections
- zero-sequence currents that cannot be transformed across the transformer, and so only flow on one side.

Due to the current magnitude mismatch, the primary currents entering and leaving the transformer are not equal, even under normal balanced load conditions. The traditional way to overcome this was with the selection of CT ratios and relay taps. The phase shift across the transformer was compensated for by the way in which the CT secondaries were connected to the relay. Take for example Wye-delta (Yd) and Delta-wye (Dy) type transformers, where the standard practice was to select the delta-side as the phase reference side for the 87T protection by wye-connecting the CT secondaries on that side to the relay. The CT secondaries on the transformer wye-side were then connected in the same delta connection, DAB or

DAC, as the transformer delta-winding connection. This delta connection of the wye-side CT secondaries served two purposes, one of these being to align the phase of the wye-side currents with the phase of the delta-side currents, allowing the currents to then be summed phase-wise. The second was to form a trap for zero-sequence currents which could flow on the wye-side, but not on the delta-side of the transformer.

Modern microprocessor-based relays perform this compensation mathematically within the 87T function. All CT secondaries can therefore be wye-connected to the protection relay, as the delta-connection of the CT secondaries to the relay on the wye-side of Dy or Yd transformers is no longer necessary. The mathematical compensation takes care of the magnitude mismatch, the phase angle shift, and the subtraction of zero-sequence currents as required. For the phase angle shift compensation, a reference side must be assigned. The reference side is the side to which the currents from all other sides are aligned, whilst its own currents undergo no shift in phase, i.e. are not rotated.

Figure 1 shows a typical two-slope 87T characteristic for a standard two- or three-winding transformer. To make the 87T function as sensitive and stable as possible, a restrained differential characteristic is used. To get operation with such a characteristic requires that the differential current be greater than a certain percentage of the current through the transformer. This stabilizes the 87T function under through fault conditions while still permitting good basic sensitivity.

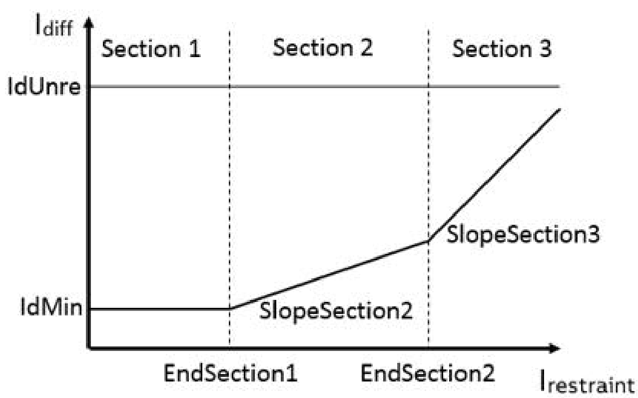

Figure 1: Typical characteristic for transformer 87T protection

The differential and restraint quantities are calculated from the measured currents. The way these values are calculated can vary depending on the design of the 87T function. The restraint quantity is a measure of through current level. It is an indicator of how high the currents are, i.e. an indicator of how difficult the conditions are under which the CTs are operating, as the higher the currents, the more difficult the conditions, and the higher the probability that the calculated differential currents may have a false component, primarily due to CT saturation.

If the calculated values of differential and restraint currents, which are calculated for each phase, plot above the characteristic, the 87T function operates, whereas if the point plots below the characteristic, the 87T function restrains.

III PRE MICROPROCESSOR-BASED RELAYING

The belief that the same best practice application rules and settings guidelines always apply appear justified for the older generations of relaying technology (pre microprocessor-based). Take again, for example, Dy and Yd type power transformers, where the standard practice was to select the delta-connected side as the phase reference for the 87T protection (delta-side CT secondaries wye-connected to the 87T relay).

<u>Example 1</u>
Dyn1 (= DABY) transformer; 100MVA
High-side = winding 1 (W1) = 230kV
Low-side = winding 2 (W2) = 115kV
W1 Irated = 251.0A; W2 Irated = 502.0A
W1 CT ratio: 300/5; W2 CT ratio: 1000/5

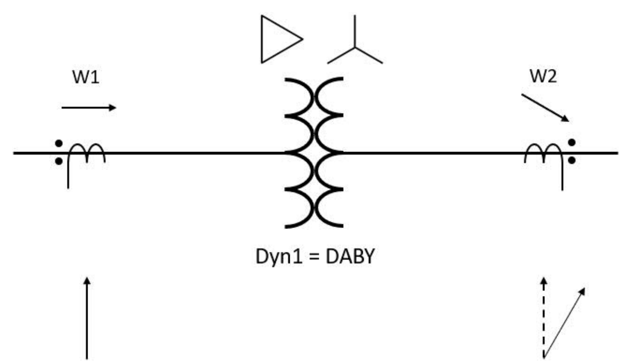

Figure 2(a): Dyn1 transformer showing W1 to W2 phase shift

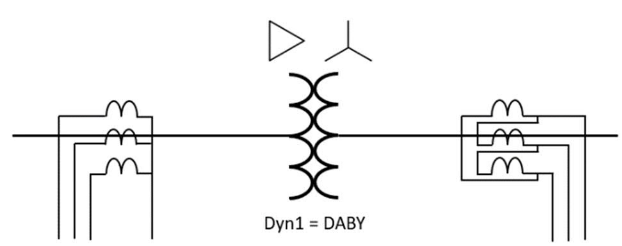

Figure 2(b): Dyn1 transformer showing W1 and W2 CT secondary connections

The W1 delta-side is the phase reference. The W2 wye-side currents need to be rotated anti-clockwise +30° to align with the delta-side phase reference currents. This is achieved using the same delta-connection (DAB) of the W2 wye-side CT secondaries as the transformer delta-winding.

Example 2

YNd11 (= YDAB) transformer; 100MVA

High-side = winding 1 (W1) = 230kV

Low-side = winding 2 (W2) = 115kV

W1 Irated = 251.0A; W2 Irated = 502.0A

W1 CT ratio: 500/5; W2 CT ratio: 600/5

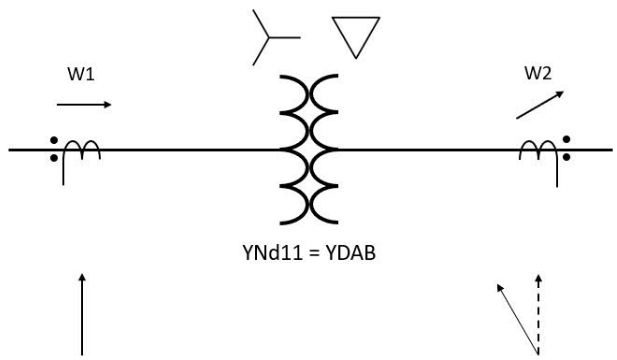

Figure 3(a): YNd11 transformer showing W1 to W2 phase shift

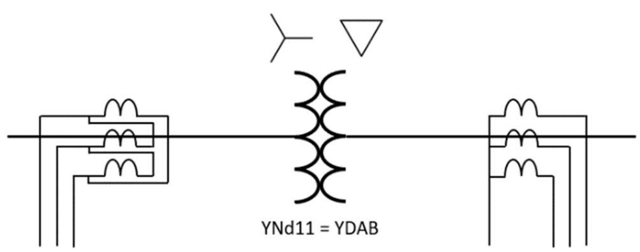

Figure 3(b): YNd11 transformer showing W1 and W2 CT secondary connections

The W2 delta-side is the phase reference. The W1 wye-side currents need to be rotated anti-clockwise +30° to align with the delta-side phase reference currents. This is achieved using the same delta-connection (DAB) of the W1 wye-side CT secondaries as the transformer delta-winding.

For both Examples 1 and 2, the differential currents are calculated for balanced load as well as different external fault types on the W2-side. See Appendix A for details. The delta-side of the transformer is always the phase reference, as the delta-side CT secondaries are wye-connected to the 87T relay.

For all cases studied, the calculated differential currents are zero. Also, it can be clearly seen that the delta-side is the phase reference, as the CT secondary currents on this side connected to the 87T relay have the same phase angle as the primary currents. As all differential currents are zero for all cases, this confirms that having the delta-side as the phase reference for the 87T protection function provides a correctly operating solution for the measurement of differential current.

IV MICROPROCESSOR-BASED RELAYING

Calculation of the differential currents

Two-winding power transformer

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = A * \begin{bmatrix} IA\_W1 \\ IB\_W1 \\ IC\_W1 \end{bmatrix} + \frac{V_{rated\_W2}}{V_{rated\_W1}} * B * \begin{bmatrix} IA\_W2 \\ IB\_W2 \\ IC\_W2 \end{bmatrix}$$

Three-winding power transformer

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = A * \begin{bmatrix} IA\_W1 \\ IB\_W1 \\ IC\_W1 \end{bmatrix} + \frac{V_{rated\_W2}}{V_{rated\_W1}} * B * \begin{bmatrix} IA\_W2 \\ IB\_W2 \\ IC\_W2 \end{bmatrix} + \frac{V_{rated\_W3}}{V_{rated\_W1}} * C * \begin{bmatrix} IA\_W3 \\ IB\_W3 \\ IC\_W3 \end{bmatrix}$$

where:
- ID_A, ID_B, ID_C are the calculated differential currents in, respectively, phase A, B, C
- IA, IB, IC are the actual primary phase currents in each winding
- A, B, C are 3x3 matrices for, respectively, winding 1 (W1), winding 2 (W2), and winding 3 (W3)

The actual A, B, and C matrix elements depend on:
- winding connection type, i.e. wye or delta
- transformer vector group, i.e. Dyn1 (D = DAB), YNd1 (d = DAC), etc., which introduces a phase shift between currents in multiples of 30°
- zero-sequence current elimination set On or Off

Consider a two-winding power transformer:

$$A * \begin{bmatrix} IA\_W1 \\ IB\_W1 \\ IC\_W1 \end{bmatrix} = \begin{bmatrix} DCCA\_W1 \\ DCCB\_W1 \\ DCCC\_W1 \end{bmatrix}$$

and

$$\frac{V_{rated\_W2}}{V_{rated\_W1}} * B * \begin{bmatrix} IA\_W2 \\ IB\_W2 \\ IC\_W2 \end{bmatrix} = \begin{bmatrix} DCCA\_W2 \\ DCCB\_W2 \\ DCCC\_W2 \end{bmatrix}$$

where:
- DCCA_W1 represents the Differential Current Contribution from W1 to the phase A differential current calculation, etc. These differential current contributions are also commonly termed the compensated currents in the differential current calculation.

$|ID\_A| = |DCCA\_W1 + DCCA\_W2|$

$|ID\_B| = |DCCB\_W1 + DCCB\_W2|$

$|ID\_C| = |DCCC\_W1 + DCCC\_W2|$

<u>Calculation of the restraint currents</u>

Looking at several 87T functions from various vendors, the restraint currents are calculated in different ways. Here are three methods commonly found:

Method 1:

$$|I_{restraint}\_A| = |I_{restraint}\_B| = |I_{restraint}\_C|$$
$$= MAX(|DCCA\_W1|, |DCCB\_W1|, |DCCC\_W1|, |DCCA\_W2|, |DCCB\_W2|, |DCCC\_W2|)$$

Method 2:

$|I_{restraint}\_A| = |DCCA\_W1| + |DCCA\_W2|$

$|I_{restraint}\_B| = |DCCB\_W1| + |DCCB\_W2|$

$|I_{restraint}\_C| = |DCCC\_W1| + |DCCC\_W2|$

Method 3:

$|I_{restraint}\_A| = ½(|DCCA\_W1| + |DCCA\_W2|)$

$|I_{restraint}\_B| = ½(|DCCB\_W1| + |DCCB\_W2|)$

$|I_{restraint}\_C| = ½(|DCCC\_W1| + |DCCC\_W2|)$

Settings entered by the settings engineer determine the matrices to be used in the matrix equation to calculate on-line the differential and restraint currents. The chosen phase reference side for the 87T function determines which matrices will be used in the matrix equation, and hence what the calculated restraint currents will be and what the calculated differential currents will be for an internal fault.

<u>Principles behind the 87T function</u>

The common characteristic for all types of three-phase power transformers is that they introduce a phase angle shift Θ between the W1- and W2-side no-load voltages. Furthermore, strict rules only exist for the phase angle shift between the sequence components of the no-load voltage on the two sides of the transformer, and not for the individual phase voltages on the two sides of the transformer.

The following holds true for the positive-, negative- and zero-sequence no-load voltage components:
- if the W1 positive-sequence no-load voltage component (VPS_W1) leads the W2 positive-sequence no-load voltage component (VPS_W2) by angle Θ; then
- the W1 negative-sequence no-load voltage component (VNS_W1) will lag the W2 negative-sequence no-load voltage component (VNS_W2) by angle Θ; and
- the W1 zero-sequence no-load voltage component (VZS_W1) will be exactly in phase with the W2 zero-sequence no-load voltage component (VZS_W2) when the zero-sequence no-load voltage component can be transferred across the transformer.

As soon as the power transformer is loaded, this voltage relationship will no longer be valid, due to the voltage drop across the power transformer's impedance. However, the same phase angle relationship will be valid for the sequence components of the current, which flow into W1 and out from W2.

Therefore, the following holds true for the sequence current components:
- if the W1 positive-sequence current component (IPS_W1) leads the W2 positive-sequence current component (IPS_W2) by angle Θ (the same angle Θ as for the positive-sequence no-load voltage component); then
- the W1 negative-sequence current component (INS_W1) will lag the W2 negative-sequence current component (INS_W2) by angle Θ; and
- the W1 zero-sequence current component (IZS_W1) will be exactly in phase with the W2 zero-sequence current component (IZS_W2) when the zero-sequence current component can be transferred across the transformer.

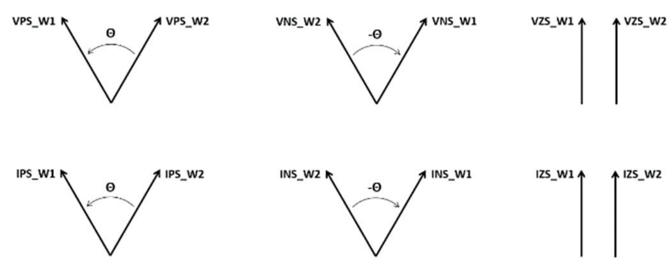

Figure 4: Phasor diagrams showing the W1 to W2 angular relationship across a power transformer for the positive-, negative- and zero-sequence no-load voltage and current components

For the analysis to follow, it can be taken that the current magnitude compensation of the phase currents from the two power transformer sides has been performed. Hence, only the procedure for phase angle shift compensation will be presented.

The sequence differential currents can be calculated using the following equations:

$ID\_PS = IPS\_W1 + e^{j\Theta} * IPS\_W2$

$ID\_NS = INS\_W1 + e^{-j\Theta} * INS\_W2$

$ID\_ZS = IZS\_W1 + IZS\_W2$

By applying the relationship between phase and sequence quantities the following equation can be written for the phase differential currents:

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = A * \begin{bmatrix} ID\_ZS \\ ID\_PS \\ ID\_NS \end{bmatrix}$$

where

$$A = \begin{bmatrix} 1 & 1 & 1 \\ 1 & a^2 & a \\ 1 & a & a^2 \end{bmatrix}$$

and where

$$a = e^{j120}$$
$$a^2 = e^{-j120}$$

From the above, the following equation can be obtained:

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = A * \begin{bmatrix} IZS\_W1 \\ IPS\_W1 \\ INS\_W1 \end{bmatrix} + A * \begin{bmatrix} 1 & 0 & 0 \\ 0 & e^{j\Theta} & 0 \\ 0 & 0 & e^{-j\Theta} \end{bmatrix} * \begin{bmatrix} IZS\_W2 \\ IPS\_W2 \\ INS\_W2 \end{bmatrix}$$

Again, by applying the relationship between phase and sequence quantities the following equation can be obtained:

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \begin{bmatrix} IA\_W1 \\ IB\_W1 \\ IC\_W1 \end{bmatrix} + A * \begin{bmatrix} 1 & 0 & 0 \\ 0 & e^{j\Theta} & 0 \\ 0 & 0 & e^{-j\Theta} \end{bmatrix} * A^{-1} * \begin{bmatrix} IA\_W2 \\ IB\_W2 \\ IC\_W2 \end{bmatrix}$$

where

$$A^{-1} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix}$$

Defining M(Θ) as:

$$M(\Theta) = A * \begin{bmatrix} 1 & 0 & 0 \\ 0 & e^{j\Theta} & 0 \\ 0 & 0 & e^{-j\Theta} \end{bmatrix} * A^{-1}$$

gives

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \begin{bmatrix} IA\_W1 \\ IB\_W1 \\ IC\_W1 \end{bmatrix} + M(\Theta) * \begin{bmatrix} IA\_W2 \\ IB\_W2 \\ IC\_W2 \end{bmatrix}$$

M(Θ) as a function of Θ can be written as:

$$M(\Theta) = \frac{1}{3} \begin{bmatrix} 1+2*\cos(\Theta) & 1+2*\cos(\Theta+120°) & 1+2*\cos(\Theta-120°) \\ 1+2*\cos(\Theta-120°) & 1+2*\cos(\Theta) & 1+2*\cos(\Theta+120°) \\ 1+2*\cos(\Theta+120°) & 1+2*\cos(\Theta-120°) & 1+2*\cos(\Theta) \end{bmatrix}$$

M(0°) is the unit matrix:

$$\begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix}$$

It can be assigned to the power transformer side that is taken as the reference side for phase angle compensation. The equation derived above can then be re-written as:

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = M(0°) * \begin{bmatrix} IA\_W1 \\ IB\_W1 \\ IC\_W1 \end{bmatrix} + M(\Theta) * \begin{bmatrix} IA\_W2 \\ IB\_W2 \\ IC\_W2 \end{bmatrix}$$

Θ is the angle by which the W2 positive-sequence no-load voltage component must be rotated to align with the W1 positive-sequence no-load voltage component. Angle Θ has a positive value when rotation is in the anti-clockwise direction.

Note that it is equally possible to select W2 as the reference side for the phase angle compensation. In this case a negative value for angle Θ is applied to W1.

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = M(-\Theta) * \begin{bmatrix} IA\_W1 \\ IB\_W1 \\ IC\_W1 \end{bmatrix} + M(0°) * \begin{bmatrix} IA\_W2 \\ IB\_W2 \\ IC\_W2 \end{bmatrix}$$

The M(Θ) matrix doesn't subtract the zero-sequence current. Therefore, it's possible to define a new matrix M0(Θ), which simultaneously performs the phase angle shift compensation and subtracts the zero sequence current.

$$M0(\Theta) = M(\Theta) - \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & 1 & 1 \\ 1 & 1 & 1 \end{bmatrix}$$

M0(Θ) as a function of Θ can be written as:

$$M0(\Theta) = \frac{2}{3} \begin{bmatrix} \cos(\Theta) & \cos(\Theta+120°) & \cos(\Theta-120°) \\ \cos(\Theta-120°) & \cos(\Theta) & \cos(\Theta+120°) \\ \cos(\Theta+120°) & \cos(\Theta-120°) & \cos(\Theta) \end{bmatrix}$$

Thus, it's possible to select matrix M(Θ) to perform the phase angle shift compensation only or, when required, to select the matrix M0(Θ) to perform the phase angle shift compensation as well as to remove the zero sequence currents.

V DIFFERENTIAL AND RESTRAINT CURRENT CALCULATION, A COMPARATIVE ANALYSIS

Three examples are used. Examples 3 and 4 are, respectively, for the same transformer as in Examples 1 and 2. Example 5 is for an autotransformer. For each example the differential and restraint currents are calculated for different external fault types on the W2-side.

For the purposes of this paper, in the examples that follow, only standard phase-to-bushing connections are considered. Good to note here is that a power transformer's rating plate is only valid for positive-sequence quantities applied in the same sequence as the bushing markings.

Example 3
Dyn1 (= DABY) transformer; 100MVA
W1/W2 = 230kV/115kV
W1 Irated = 251.0A; W2 Irated = 502.0A

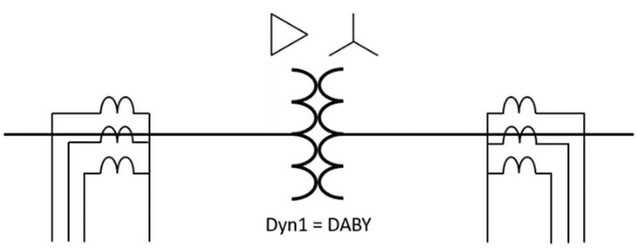

Figure 5: Dyn1 transformer with wye-connected CTs on both Delta- and wye-sides

W1 Delta-side as the phase reference

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = M(0°) * \begin{bmatrix} IA\_W1 \\ IB\_W1 \\ IC\_W1 \end{bmatrix} + \frac{115}{230} * M0(30°) * \begin{bmatrix} IA\_W2 \\ IB\_W2 \\ IC\_W2 \end{bmatrix}$$

$$M(0°) = \begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix}$$

$$M0(30°) = \begin{bmatrix} 0.577 & -0.577 & 0.000 \\ 0.000 & 0.577 & -0.577 \\ -0.577 & 0.000 & 0.577 \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix}$$

The M0(30°) matrix does the same as the old method of delta-connecting the CT secondaries on the transformer wye-side.

To align with the W1 Delta-side phase reference currents the W2 wye-side currents must be rotated anti-clockwise +30°.

W2 wye-side as the phase reference

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = M(-30°) * \begin{bmatrix} IA\_W1 \\ IB\_W1 \\ IC\_W1 \end{bmatrix} + \frac{115}{230} * M0(0°) * \begin{bmatrix} IA\_W2 \\ IB\_W2 \\ IC\_W2 \end{bmatrix}$$

$$M(-30°) = \begin{bmatrix} 0.911 & 0.333 & -0.244 \\ -0.244 & 0.911 & 0.333 \\ 0.333 & -0.244 & 0.911 \end{bmatrix}$$

$$M0(0°) = \begin{bmatrix} 0.667 & -0.333 & -0.333 \\ -0.333 & 0.667 & -0.333 \\ -0.333 & 0.667 & -0.333 \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix}$$

To align with the W2 wye-side phase reference currents the W1 Delta-side currents must be rotated clockwise -30°.

As the phase currents IA_W1, IB_W1 and IC_W1 have no zero-sequence component (transformer Delta-side), applying M0(-30°) would yield the same result as applying M(-30°).

$$M0(-30°) = \begin{bmatrix} 0.577 & 0.000 & -0.577 \\ -0.577 & 0.577 & 0.000 \\ 0.000 & -0.577 & 0.577 \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix}$$

Example 4
YNd11 (= YDAB) transformer; 100MVA
W1/W2 = 230kV/115kV
W1 Irated = 251.0A; W2 Irated = 502.0A

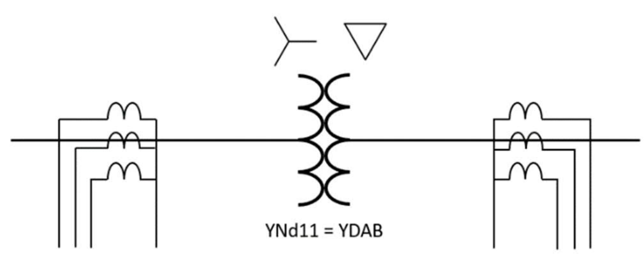

Figure 6: YNd11 transformer with wye-connected CTs on both Wye- and delta-sides

W2 delta-side as the phase reference

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = M0(30°) * \begin{bmatrix} IA\_W1 \\ IB\_W1 \\ IC\_W1 \end{bmatrix} + \frac{115}{230} * M(0°) * \begin{bmatrix} IA\_W2 \\ IB\_W2 \\ IC\_W2 \end{bmatrix}$$

$$M0(30°) = \begin{bmatrix} 0.577 & -0.577 & 0.000 \\ 0.000 & 0.577 & -0.577 \\ -0.577 & 0.000 & 0.577 \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix}$$

$$M(0°) = \begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix}$$

As in the previous Example 3, the M0(30°) matrix does the same as the old method of delta-connecting the CT secondaries on the transformer Wye-side.

To align with the W2 delta-side phase reference currents the W1 Wye-side currents must be rotated anti-clockwise +30°

W1 Wye-side as the phase reference

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = M0(0°) * \begin{bmatrix} IA\_W1 \\ IB\_W1 \\ IC\_W1 \end{bmatrix} + \frac{115}{230} * M(-30°) * \begin{bmatrix} IA\_W2 \\ IB\_W2 \\ IC\_W2 \end{bmatrix}$$

$$M0(0°) = \begin{bmatrix} 0.667 & -0.333 & -0.333 \\ -0.333 & 0.667 & -0.333 \\ -0.333 & 0.667 & -0.333 \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix}$$

$$M(-30°) = \begin{bmatrix} 0.911 & 0.333 & -0.244 \\ -0.244 & 0.911 & 0.333 \\ 0.333 & -0.244 & 0.911 \end{bmatrix}$$

To align with the W1 Wye-side phase reference currents the W2 delta-side currents must be rotated clockwise -30°.

Again, as the phase currents IA_W2, IB_W2 and IC_W2 have no zero-sequence component (transformer delta-side), applying M0(-30°) would yield the same result as applying M(-30°).

$$M0(-30°) = \begin{bmatrix} 0.577 & 0.000 & -0.577 \\ -0.577 & 0.577 & 0.000 \\ 0.000 & -0.577 & 0.577 \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix}$$

Example 5

Autotransformer, no delta tertiary (YNyn0 transformer)
100MVA; W1/W2 = 230kV/115kV
W1 Irated = 251.0A; W2 Irated = 502.0A

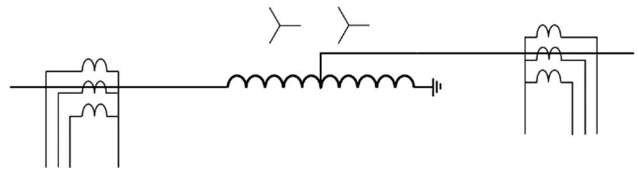

Figure 7: Autotransformer with wye-connected CTs on both sides

Using the M0(0°) matrix

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = M0(0°) * \begin{bmatrix} IA\_W1 \\ IB\_W1 \\ IC\_W1 \end{bmatrix} + \frac{115}{230} * M0(0°) * \begin{bmatrix} IA\_W2 \\ IB\_W2 \\ IC\_W2 \end{bmatrix}$$

$$M0(0°) = \begin{bmatrix} 0.667 & -0.333 & -0.333 \\ -0.333 & 0.667 & -0.333 \\ -0.333 & 0.667 & -0.333 \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix}$$

Using the M0(-30°) matrix

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = M0(-30°) * \begin{bmatrix} IA\_W1 \\ IB\_W1 \\ IC\_W1 \end{bmatrix} + \frac{115}{230} * M0(-30°) * \begin{bmatrix} IA\_W2 \\ IB\_W2 \\ IC\_W2 \end{bmatrix}$$

$$M0(-30°) = \begin{bmatrix} 0.577 & 0.000 & -0.577 \\ -0.577 & 0.577 & 0.000 \\ 0.000 & -0.577 & 0.577 \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix}$$

Discussion and analysis, calculation of differential currents

There are, in reality, an infinite number of ways to calculate the differential currents for a three-phase power transformer, as any arbitrary angle can be defined as the phase reference, with the currents from all windings then being rotated to align with the selected phase reference. This can be explained further by looking at Example 3 for the W2-side external three-phase fault. The Delta-side IA_W1 current has ∠-60° and the wye-side IA_W2 current has ∠-90°. Choosing the Delta-side as the phase reference, the Delta-side currents would receive no phase angle rotation, whereas the wye-side currents need to be rotated +30° anti-clockwise. Therefore, the chosen matrices would be M(0°) for the Delta-side, and M0(30°) for the wye-side (M0 for the wye-side as zero-sequence subtraction must be applied). However, it would be equally possible to select the matrix M(1°) for the Delta-side, and M0(31°) for the wye-side, or M(10°) and M0(40°), or M(11°) and M0(41°), etc. This of course is mathematically possible but has no real practical meaning. In practice, typically, for an n-sided transformer, n possibilities arise whereby any one of the n sides can be selected as the phase reference. Take for example a two-winding transformer (n = 2):

- one approach would be to take the W1-side as the phase reference side (with 0° phase angle shift).

- the second approach would be to take the W2-side as the phase reference side (with 0° phase angle shift).

It is with the selection of the phase reference side that the settings engineer comes across the following settings rule differences:

- if a delta-winding exists, select the (first) delta-side as the phase reference side – then select the appropriate matrices to rotate the currents from all other sides to align with the phase reference delta-side (the selected delta-side currents undergo no (0°) phase angle shift).
- if no delta-winding exists, select …..

or

- if a wye-winding exists, select the (first) wye-side as the phase reference side – then select the appropriate matrices to rotate the currents from all other sides to align with the phase reference wye-side.
  Example:
  - Wye-delta transformer → select the W1 Wye-side as the phase reference side (with 0° phase angle shift)
  - Delta-wye transformer → select the W2 wye-side as the phase reference side (with 0° phase angle shift)
- if no wye-winding exists, select …..

For Examples 3, 4 and 5, the differential currents are calculated for different external fault types on the W2-side, using one winding as the phase reference for the calculation, then the other. See Appendix B for details.

For all cases, the differential currents for all phases, for all external fault types, are zero, irrespective of whether the delta- or wye-side is taken as the phase reference (the used matrices in the matrix equation depend on which side is assigned as the phase reference). In fact, it can be stated that for the calculation of the differential currents, for any through-fault (external fault) or load condition, the calculated differential currents will always be zero irrespective of which transformer side is assigned as the phase reference, so long as the 87T function is properly set and there is no CT saturation.

Matrix selection comes into play more for internal faults because most of them are single-phase faults and the calculated differential currents will be different for different matrix selections. Therefore, the differences in the calculated differential currents resulting from matrix selection will only be seen for internal faults or for external faults followed by CT saturation.

For Delta-wye (Dy) or Wye-delta (Yd) transformers, taking the delta-side as the phase reference mimics how the traditional (pre microprocessor-based relaying) 87T differential protection schemes were engineered. For an internal single-phase fault in the winding on limb A of the magnetic core, equally large differential currents will be calculated in two phases (phase A and also phase B or C, depending on the delta connection), when assigning the delta-side as the phase reference, and the 87T function would operate in both phases. The calculated differential currents would not correspond to one physical limb of the protected transformer. A clear indication of the faulted limb is therefore lost. However, in practice, this might not be of great importance as the tank would anyway need to be opened to inspect the transformer.

When taking the wye-side as the phase reference (only available in microprocessor-based relays) the calculated differential currents correspond to a higher degree to the limb with the fault. This is even true when the subtraction of zero-sequence currents is enabled. Enabling the subtraction of zero-sequence currents is often required, and is always required on the wye-side for all types of Dy and Yd transformers. When the subtraction of zero-sequence currents is enabled, all three phases can operate due to the applied matrix that mixes all three phases on the wye-side. Even so, by taking the wye-side as the phase reference, the biggest differential current would appear in phase A for an internal single-phase fault in the winding on limb A, clearly indicating the actual faulted limb.

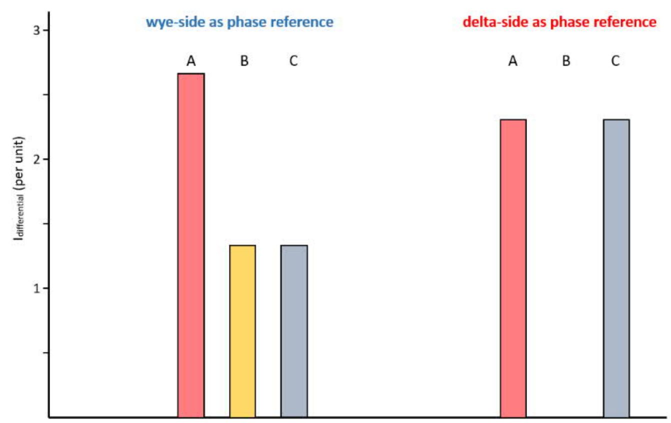

Figure 8: Differential currents for an internal single-phase fault in the winding on limb A

From Figure 8 it can be clearly seen why the differential protection would operate in all three phases when the wye-side is selected as the phase reference, but in only two phases for the same internal fault when the delta-side is selected as the phase reference. It can also be seen that a slightly larger magnitude of differential current is calculated for an internal single-phase fault when using the wye-side as the phase reference. The ratio of the differential currents is:

$$\text{wye-reference : delta-reference} = \frac{2}{3} : \frac{1}{\sqrt{3}} = 0.667 : 0.577$$

i.e. when the wye-side is selected as the phase reference, the differential current calculated for the phase on the limb with the fault is 1.155 times larger than the differential currents calculated for the same fault when the delta-side is selected as the phase reference. This translates to a slightly increased sensitivity for internal single-phase faults.

Therefore, for microprocessor-based differential protection with all CT secondaries wye-connected, some benefits can be realized when selecting the wye-side as the phase reference, like more definite indication of the actual limb of the magnetic core where the fault occurred as well as slightly increased sensitivity for internal single-phase faults. A typical guideline to follow could be:

- select the first wye-connected winding as the phase reference winding (with 0° phase angle shift)
- select the first delta-connected winding as the phase reference winding only for transformers without any wye-connected windings.

However, the above recommendation doesn't consider how the restraint currents are calculated, and how this may impact the selection of the phase reference side.

A point to note is that applying the M0(Θ) matrix (i.e. enabling zero-sequence subtraction) reduces the sensitivity of the differential protection. The sole reason for subtracting the zero-sequence currents is to ensure stability for external faults. Consider again the external phase-ground (A) fault on the W2-side of the Dyn1 transformer of Example 3. With zero-sequence subtraction enabled for the wye-winding, the calculated differential current in all phases is zero (with either the Delta-side or the wye-side selected as the phase reference). With zero sequence subtraction disabled for the wye-winding, the calculated differential current in all phases is 334.7A (with either the Delta-side or the wye-side selected as the phase reference), which would definitely cause unwanted operation of the differential function for the external fault.

Were it not necessary to enable zero-sequence subtraction to ensure external fault stability, electing not to enable it would have benefits for internal single-phase faults. Such benefits would include increased magnitude in the calculated differential current (i.e. increased sensitivity) for the same fault versus what would be calculated with zero-sequence subtraction enabled, and no need for the mixing of the measured phase currents, giving a much clearer indication of the limb with the fault, as the differential function would operate in just the phase on the limb with the fault.

The recording from an actual event is now used to illustrate the points made above. The details of the in-service transformer that experienced this event are as follows:

Autotransformer YNyn0(d) – d-winding is not used
150MVA; W1/W2/W3 = 220kV/115kV/(10.5kV)
W1 Irated = 394A; W2 Irated = 753A
W1 CT ratio: 600/1; W2 CT ratio: 750/1
W1 secondary base current = 0.656A
W2 secondary base current = 1.004A

This transformer is protected with a 2-winding 87T function. It has an OLTC, which is ignored for this analysis.

The event comprised an external W2-side three-phase fault that evolved to an internal C-phase fault when the external fault was cleared.

Figure 9 shows the W1 220kV-side currents. Figure 9(a) the current waveforms, and Figure 9(b) the RMS currents. Notice the transition point where the external three-phase fault cleared, and the internal C-phase fault started.

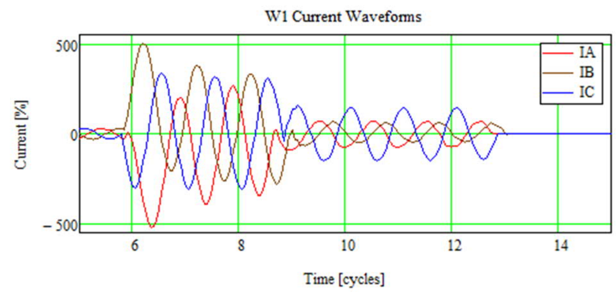

Figure 9(a)

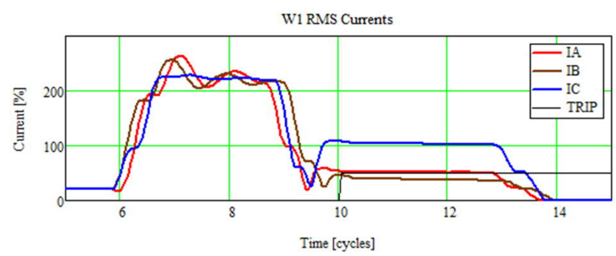

Figure 9(b)

Figure 10 shows the W2 115kV-side currents. Figure 10(a) the current waveforms, and Figure 10(b) the RMS currents.

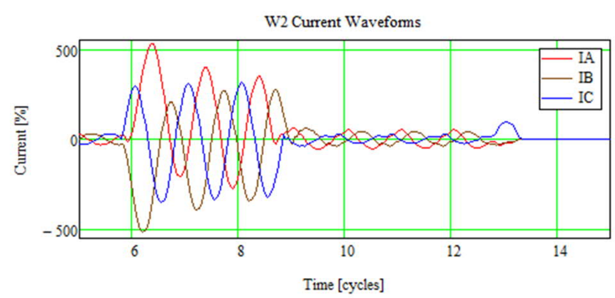

Figure 10(a)

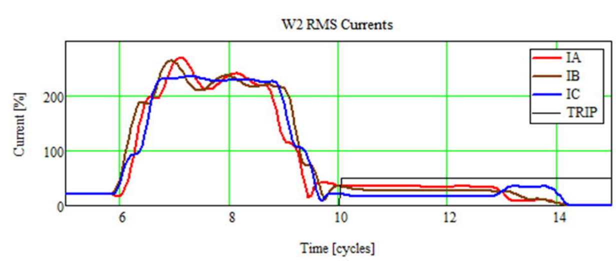

Figure 10(b)

A computer software for engineering calculations is now used to calculate the differential currents from the recorded phase currents during the internal C-phase fault. The objective is to use different matrix selections to show how matrix selection impacts the calculated differential currents.

Figure 11 shows the calculated differential currents when the M0(30°) matrix is used on both the W1- and W2-sides (i.e. as if a side with a delta-winding were being selected as the phase reference).

$$M0(30°) = \begin{bmatrix} 0.577 & -0.577 & 0.000 \\ 0.000 & 0.577 & -0.577 \\ -0.577 & 0.000 & 0.577 \end{bmatrix}$$

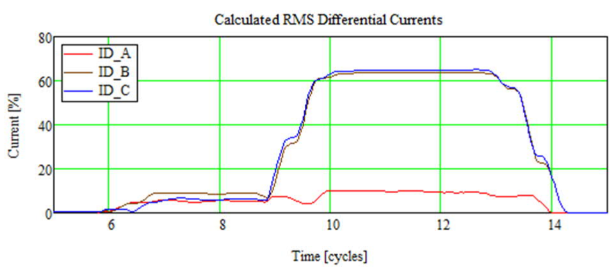

Figure 11: Calculated differential currents when using the M0(30°) matrix

Note the two equal differential currents calculated for phase C (the faulted phase) and phase B. The differential function would operate in these two phases, and give target indication showing this operation. There would be no clear indication of the limb in which this fault has occurred.

Figure 12 shows the calculated differential currents when the M0(-30°) matrix is used on both the W1- and W2-sides (again as if a side with a delta-winding were being selected as the phase reference).

$$M0(-30°) = \begin{bmatrix} 0.577 & 0.000 & -0.577 \\ -0.577 & 0.577 & 0.000 \\ 0.000 & -0.577 & 0.577 \end{bmatrix}$$

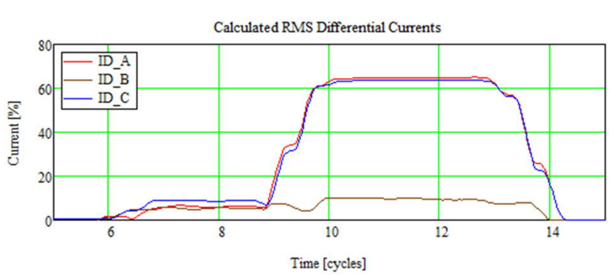

Figure 12: Calculated differential currents when using the M0(-30°) matrix

Note again the two equal differential currents calculated for phase C (the faulted phase) and this time phase A. Selecting the M0(-30°) matrix instead of the M0(30°) matrix just swops the unfaulted phase in which the equal differential current is calculated. The differential function would operate now in Phases C and A, and give target indication showing this operation. Again, there would be no clear indication of the limb in which this fault has occurred.

Figure 13 shows the calculated differential currents when the M0(0°) matrix is used on both the W1- and W2-sides (i.e. making the (first) side with a wye-winding the phase reference). The M0(0°) matrix subtracts the zero sequence-currents.

$$M0(0°) = \begin{bmatrix} 0.667 & -0.333 & -0.333 \\ -0.333 & 0.667 & -0.333 \\ -0.333 & 0.667 & -0.333 \end{bmatrix}$$

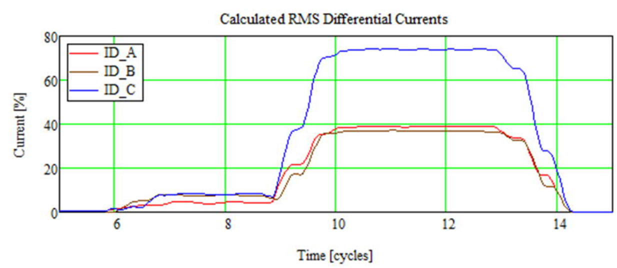

Figure 13: Calculated differential currents when using the M0(0°)matrix

In this case the differential current calculated for phase C is clearly the largest, and so gives clear indication of the limb in which this fault has occurred. Comparing Figure 13 with Figures 11 and 12, the phase C differential current in Figure 13 is 1.15 times larger than the differential currents calculated in the two phases in Figures 11 and 12.

Note that when using the M0(0°) matrix the differential function would most likely operate in all three phases, and give target indication showing this operation.

Figure 14 shows the calculated differential currents when the M(0°) matrix is used on both the W1- and W2-sides (again making the (first) side with a wye-winding the phase reference).The M(0°) matrix does not subtract the zero-sequence currents.

$$M(0°) = \begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix}$$

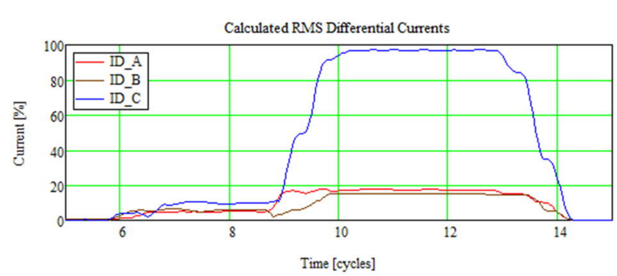

Figure 14: Calculated differential currents when using the M(0°) matrix

In this case the differential current calculated for phase C is again clearly the largest, but where Figure 14 differs from Figure 13 is that in Figure 14:

- the differential current calculated for phase C is larger, thereby increasing the sensitivity, and
- the differential currents calculated for phases A and B are now very small.

If it were possible to use the M(0°) matrix, this would be very beneficial for internal single-phase faults as the differential function would operate only in the faulted phase, give target indication showing this operation, and so give clear indication of the limb in which this fault has occurred just by the target indication. However, the major disadvantage, unfortunately, is that using the M(0°) matrix in this application would make the differential protection highly susceptible to misoperation for external faults.

Discussion and analysis, calculation of restraint currents

For the same Examples 3, 4 and 5 from before, the restraint currents are calculated using Methods 1 and 2 for different external fault types on the W2-side, using first one winding as the phase reference for the calculation, then the other.

Method 1 for calculation of restraint currents:

$$
\begin{aligned}
|I_{restraint}\_A| = |I_{restraint}\_B| = |I_{restraint}\_C| &= \mathrm{MAX}(|DCCA\_W1|, |DCCB\_W1|, |DCCC\_W1|, \\
&\quad |DCCA\_W2|, |DCCB\_W2|, |DCCC\_W2|)
\end{aligned}
$$

Method 2 for calculation of restraint currents:

$$|I_{restraint}\_A| = |DCCA\_W1| + |DCCA\_W2|$$

$$|I_{restraint}\_B| = |DCCB\_W1| + |DCCB\_W2|$$

$$|I_{restraint}\_C| = |DCCC\_W1| + |DCCC\_W2|$$

Example 3

Dyn1 (= DABY) transformer

External phase-phase (BC) 115kV W2-side fault – W1 Delta-side as the phase reference

Method 1	Method 2
$\lvert I_{restraint}\_A\rvert$ = 1,004.1A = 4.00 per unit	$\lvert I_{restraint}\_A\rvert$ = 1,004.1A = 4.00 per unit
$\lvert I_{restraint}\_B\rvert$ = 1,004.1A = 4.00 per unit	$\lvert I_{restraint}\_B\rvert$ = 2,008.2A = 8.00 per unit
$\lvert I_{restraint}\_C\rvert$ = 1,004.1A = 4.00 per unit	$\lvert I_{restraint}\_C\rvert$ = 1,004.1A = 4.00 per unit

Same external phase-phase (BC) 115kV W2-side fault – W2 wye-side as the phase reference

Method 1	Method 2
$\lvert I_{restraint}\_A\rvert$ = 869.6A = 3.46 per unit	$\lvert I_{restraint}\_A\rvert$ = 0.0A = 0.00 per unit
$\lvert I_{restraint}\_B\rvert$ = 869.6A = 3.46 per unit	$\lvert I_{restraint}\_B\rvert$ = 1,739.1A = 6.93 per unit
$\lvert I_{restraint}\_C\rvert$ = 869.6A = 3.46 per unit	$\lvert I_{restraint}\_C\rvert$ = 1,739.1A = 6.93 per unit

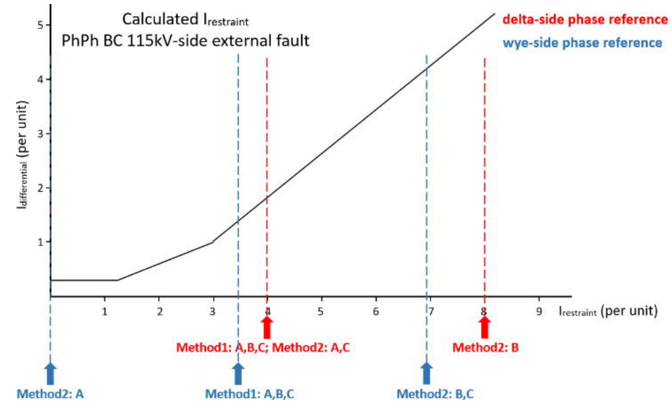

Figure 15: Method 1 versus Method 2 restraint current calculation for an external W2-side phase-phase (BC) fault

With the Delta-side as the phase reference:

$$
\begin{aligned}
ID\_A &= IA + \frac{115}{230} * \frac{1}{\sqrt{3}} * (IA - IB) \\
&= DCCA\_W1 + DCCA\_W2
\end{aligned}
$$

With the wye-side as the phase reference:

$$
\begin{aligned}
ID\_A &= \frac{1}{\sqrt{3}} * (IA - IC) + \frac{115}{230} * \frac{1}{3} * (2IA - IB - IC) \\
&= DCCA\_W1 + DCCA\_W2
\end{aligned}
$$

Method 2 calculates the phase A restraint current as follows:

$$|I_{restraint}\_A| = |DCCA\_W1| + |DCCA\_W2|$$

With the wye-side as the phase reference the W1 A phase compensated current contains W1 A and C phase currents. Both are fault currents that are exactly equal in magnitude and phase angle when calculated theoretically. The W2 A phase compensated current contains W2 A, B and C phase currents. The W2 B and C phase currents are fault currents that are exactly equal in magnitude and have exactly opposite phase angle when calculated theoretically. The W2 A phase current is not a fault current, and is equal to zero when calculated theoretically, ignoring load current. See Appendix B.

When calculating the W1 A phase compensated current, the W1 A and C phase currents cancel each other out. Likewise, when calculating the W2 A phase compensated current, the W2 B and C phase currents cancel each other out. However, due to some CT saturation or other error, a differential current could be calculated for phase A, which would also have a very small calculated restraint current when using Method 2.

Therefore, using the wye-side as the phase reference when using Method 2 for calculating the restraint currents introduces a possibility for misoperation for external phase-phase faults. To overcome this, when using Method 2 for calculating the restraint currents, the Delta-side should be selected as the phase reference. This guarantees adequate restraint against misoperation due to some CT or other error, thereby ensuring stability for such external phase-phase faults.

When it comes to ensuring through-fault stability for external phase-phase faults, using Method 1 for calculating the restraint currents places no prerequisite on which side should be selected as the phase reference. Either the wye- or Delta-side could be selected as the phase reference as adequate restraint current to ensure through phase-phase fault stability would be calculated for both selections.

External phase-ground (A) 115kV W2-side fault – <u>W1 Delta-side as the phase reference</u>

Method 1	Method 2
$\lvert I_{restraint}\_A \rvert$ = 579.7A = 2.31 per unit	$\lvert I_{restraint}\_A \rvert$ = 1,159.4A = 4.62 per unit
$\lvert I_{restraint}\_B \rvert$ = 579.7A = 2.31 per unit	$\lvert I_{restraint}\_B \rvert$ = 0.0A = 0.00 per unit
$\lvert I_{restraint}\_C \rvert$ = 579.7A = 2.31 per unit	$\lvert I_{restraint}\_C \rvert$ = 1,159.4A = 4.62 per unit

Same external phase-ground (A) 115kV W2-side fault – <u>W2 wye-side as the phase reference</u>

Method 1	Method 2
$\lvert I_{restraint}\_A \rvert$ = 669.4A = 2.67 per unit	$\lvert I_{restraint}\_A \rvert$ = 1,338.8A = 5.33 per unit
$\lvert I_{restraint}\_B \rvert$ = 669.4A = 2.67 per unit	$\lvert I_{restraint}\_B \rvert$ = 669.4A = 2.67 per unit
$\lvert I_{restraint}\_C \rvert$ = 669.4A = 2.67 per unit	$\lvert I_{restraint}\_C \rvert$ = 669.4A = 2.67 per unit

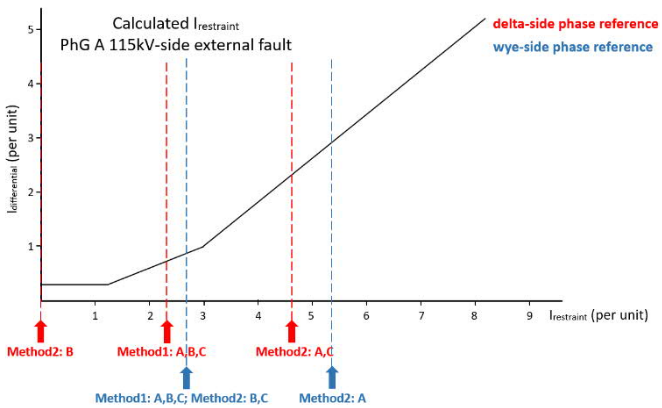

Figure 16: Method 1 versus Method 2 restraint current calculation for an external W2-side phase-ground (A) fault

With the Delta-side as the phase reference:

$$\text{ID\_B} = \text{IB} + \frac{115}{230} * \frac{1}{\sqrt{3}} * (\text{IB - IC})$$
$$= \text{DCCB\_W1} + \text{DCCB\_W2}$$

With the wye-side as the phase reference:

$$\text{ID\_B} = \frac{1}{\sqrt{3}} * (\text{IB - IA}) + \frac{115}{230} * \frac{1}{3} * (\text{2IB - IA - IC})$$
$$= \text{DCCB\_W1} + \text{DCCB\_W2}$$

Method 2 calculates the phase B restraint current as follows:

$$\lvert I_{restraint}\text{\_B} \rvert = \lvert \text{DCCB\_W1} \rvert + \lvert \text{DCCB\_W2} \rvert$$

With the Delta-side as the phase reference the W1 B phase compensated current contains only W1 B phase current, which is not a fault current, and is equal to zero when calculated theoretically, ignoring load current. The W2 B phase compensated current contains W2 B and C phase currents, which are also not fault currents, and so are equal to zero when calculated theoretically, ignoring load current. See Appendix B.

Although the calculated restraint current for phase B is very small, theoretically zero, the likelihood that some differential current, small but enough to cause a misoperation, would be calculated for phase B due to some CT saturation or other error is small, as no fault currents are included in the phase B compensated currents for the differential calculation.

Therefore, for restraint currents calculated using Method 2, it could be argued that the Delta-side could (still) be selected as the phase reference side without a high probability of introducing a possibility for misoperation for external phase-ground faults.

As with the external phase-phase faults, when it comes to ensuring through-fault stability for external phase-ground faults, using Method 1 for calculating the restraint currents places no prerequisite on which side should be selected as the phase reference. Either the wye- or Delta-side could be selected as the phase reference as adequate restraint current to ensure through phase-ground fault stability would be calculated for both selections. In fact, by selecting the wye-side as the phase reference, a slightly higher stability is ensured.

Consider again the internal single-phase winding fault in limb A of the transformer with differential currents as shown in Figure 8. Figure 17 shows these differential currents plotted against the restraint currents calculated using both Methods 1 and 2. In Figure 17, M1A means Method 1, phase A, and is shown next to the plotted point of the calculated phase A differential current versus the calculated phase A restraint current using Method 1. Similarly for the other points.

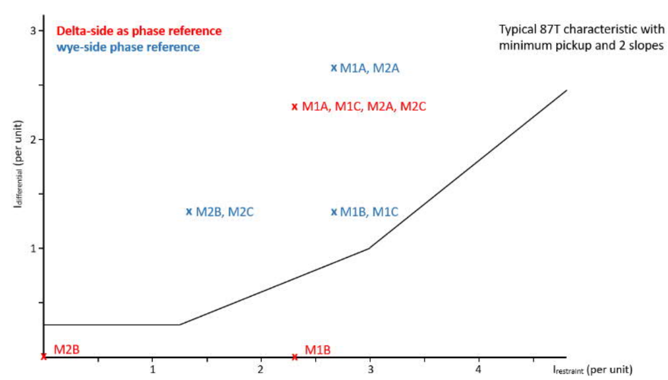

Figure 17: Typical differential-restraint current plot for internal single-phase fault in limb A showing Method 1 versus Method 2 of restraint current calculation

From Figure 17 it can be seen that whether Method 1 or Method 2 is used for the restraint current calculation, the differential protection would operate in all three phases when the wye-side is selected as the phase reference, but in only two phases for the same internal fault when the Delta-side is selected as the phase reference.

Example 4
YNd11 (= YDAB) transformer

External phase-phase (BC) 115kV W2-side fault – W2 delta-side as the phase reference

Method 1	Method 2
$\lvert I_{restraint}\_A \rvert$ = 869.6A = 3.46 per unit	$\lvert I_{restraint}\_A \rvert$ = 0.0A = 0.00 per unit
$\lvert I_{restraint}\_B \rvert$ = 869.6A = 3.46 per unit	$\lvert I_{restraint}\_B \rvert$ = 1,739.1A = 6.93 per unit
$\lvert I_{restraint}\_C \rvert$ = 869.6A = 3.46 per unit	$\lvert I_{restraint}\_C \rvert$ = 1,739.1A = 6.93 per unit

Same external phase-phase (BC) 115kV W2-side fault – W1 Wye-side as the phase reference

Method 1	Method 2
$\lvert I_{restraint}\_A \rvert$ = 1,004.1A = 4.00 per unit	$\lvert I_{restraint}\_A \rvert$ = 1,004.1A = 4.00 per unit
$\lvert I_{restraint}\_B \rvert$ = 1,004.1A = 4.00 per unit	$\lvert I_{restraint}\_B \rvert$ = 1,004.1A = 4.00 per unit
$\lvert I_{restraint}\_C \rvert$ = 1,004.1A = 4.00 per unit	$\lvert I_{restraint}\_C \rvert$ = 2,008.2A = 8.00 per unit

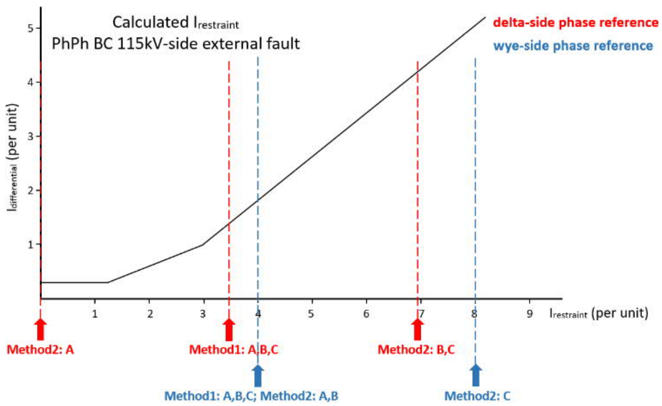

Figure 18: Method 1 versus Method 2 restraint current calculation for an external W2-side phase-phase (BC) fault

With the delta-side as the phase reference:

$$ID\_A = \frac{1}{\sqrt{3}} * (IA - IB) + \frac{115}{230} * IA$$
$$= DCCA\_W1 + DCCA\_W2$$

With the Wye-side as the phase reference:

$$ID\_A = \frac{1}{3} * (2IA - IB - IC) + \frac{115}{230} * \frac{1}{\sqrt{3}} * (IA - IC)$$
$$= DCCA\_W1 + DCCA\_W2$$

Method 2 calculates the phase A restraint current as follows:

$$\lvert I_{restraint}\_A \rvert = \lvert DCCA\_W1 \rvert + \lvert DCCA\_W2 \rvert$$

With the delta-side as the phase reference the W1 A phase compensated current contains W1 A and B phase currents. Both are fault currents that are exactly equal in magnitude and phase angle when calculated theoretically. The W2 A phase compensated current contains only W2 A phase current, which is not a fault current, and is equal to zero when calculated theoretically, ignoring load current. See Appendix B.

When calculating the W1 A phase compensated current, the W1 A and B phase currents cancel each other out. However, due to some CT saturation or other error, a differential current could be calculated for phase A, which would also have a very small calculated restraint current when using Method 2.

Therefore, using the delta-side as the phase reference when using Method 2 for calculating the restraint currents introduces a possibility for misoperation for external phase-phase faults. To overcome this, when using Method 2 for calculating the restraint currents, it appears that the Wye-side should rather be selected as the phase reference. This would guarantee adequate restraint against misoperation due to some CT or other error, thereby ensuring stability for such external phase-phase faults.

When it comes to ensuring through-fault stability for external phase-phase faults, using Method 1 for calculating the restraint currents places no prerequisite on which side should be selected as the phase reference. Either the Wye- or delta-side could be selected as the phase reference as adequate restraint current to ensure through phase-phase fault stability would be calculated for both selections. In fact, by selecting the Wye-side as the phase reference, a slightly higher stability is ensured.

Example 5
Autotransformer, no delta tertiary (YNyn0 transformer)

External phase-phase (BC) 115kV W2-side fault – M0(-30°) matrix (i.e. as if a side with a delta-winding were being selected as the phase reference)

Method 1	Method 2
$\lvert I_{restraint}\_A \rvert$ = 1,004.1A = 4.00 per unit	$\lvert I_{restraint}\_A \rvert$ = 1,004.1A = 4.00 per unit
$\lvert I_{restraint}\_B \rvert$ = 1,004.1A = 4.00 per unit	$\lvert I_{restraint}\_B \rvert$ = 1,004.1A = 4.00 per unit
$\lvert I_{restraint}\_C \rvert$ = 1,004.1A = 4.00 per unit	$\lvert I_{restraint}\_C \rvert$ = 2,008.2A = 8.00 per unit

Same external phase-phase (BC) 115kV W2-side fault – M0(0°) matrix (i.e. making the (first) side with a wye-winding the phase reference)

Method 1	Method 2
$\lvert I_{restraint}\_A \rvert$ = 869.6A = 3.46 per unit	$\lvert I_{restraint}\_A \rvert$ = 0.0A = 0.00 per unit
$\lvert I_{restraint}\_B \rvert$ = 869.6A = 3.46 per unit	$\lvert I_{restraint}\_B \rvert$ = 1,739.1A = 6.93 per unit
$\lvert I_{restraint}\_C \rvert$ = 869.6A = 3.46 per unit	$\lvert I_{restraint}\_C \rvert$ = 1,739.1A = 6.93 per unit

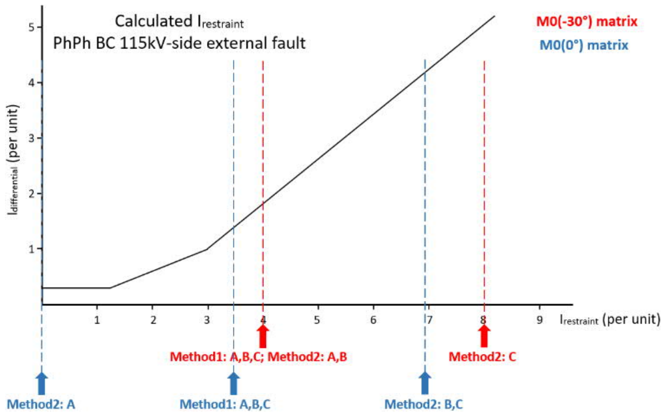

Figure 19: Method 1 versus Method 2 restraint current calculation for an external W2-side phase-phase (BC) fault

With the M0(-30°) matrix:

$$ID\_A = \frac{1}{\sqrt{3}} * (IA - IC) + \frac{115}{230} * \frac{1}{\sqrt{3}} * (IA - IC)$$

$$= DCCA\_W1 + DCCA\_W2$$

With the M0(0°) matrix:

$$ID\_A = \frac{1}{3} * (2IA - IB - IC) + \frac{115}{230} * \frac{1}{3} * (2IA - IB - IC)$$

$$= DCCA\_W1 + DCCA\_W2$$

Method 2 calculates the phase A restraint current as follows:

$$|I_{restraint}\_A| = |DCCA\_W1| + |DCCA\_W2|$$

With the M0(0°) matrix the W1 A phase compensated current contains W1 A, B and C phase currents. The W1 B and C phase currents are fault currents that are exactly equal in magnitude and have exactly opposite phase angle when calculated theoretically. The W1 A phase current is not a fault current, and is equal to zero when calculated theoretically, ignoring load current. Likewise, the W2 A phase compensated current contains W2 A, B and C phase currents. The W2 B and C phase currents are fault currents that are exactly equal in magnitude and have exactly opposite phase angle when calculated theoretically. The W2 A phase current is not a fault current, and is equal to zero when calculated theoretically, ignoring load current. See Appendix B.

When calculating the W1 A phase compensated current, the W1 B and C phase currents cancel each other out. Likewise, when calculating the W2 A phase compensated current, the W2 B and C phase currents cancel each other out. However, due to some CT saturation or other error, a differential current could be calculated for phase A, which would also have a very small calculated restraint current when using Method 2.

Therefore, using the M0(0°) matrix when using Method 2 for calculating the restraint currents introduces a possibility for misoperation for external phase-phase faults. To overcome this, when using Method 2 for calculating the restraint currents, the M0(-30°) matrix should be selected. Note that it would also be okay to select the M0(30°) matrix. Selection of either one of these two matrices would guarantee adequate restraint against misoperation due to some CT or other error, thereby ensuring stability for such external phase-phase faults.

When it comes to ensuring through-fault stability for external phase-phase faults, using Method 1 for calculating the restraint currents places no prerequisite on which matrix should be selected. Either the M0(0°), the M0(-30°) or the M0(30°) matrix could be selected, as adequate restraint current to ensure through phase-phase fault stability would be calculated for all selections.

Selecting the M0(0°) matrix is the same as selecting the first side with a wye-winding (W1) as the phase reference. As the transformer is YNyn, the same matrix as for W1 applies also to W2.

External phase-ground (A) 115kV W2-side fault – <u>M0(-30°) matrix</u>

Method 1	Method 2
$\lvert I_{restraint}\_A\rvert$ = 579.7A = 2.31 per unit	$\lvert I_{restraint}\_A\rvert$ = 1,159.4A = 4.62 per unit
$\lvert I_{restraint}\_B\rvert$ = 579.7A = 2.31 per unit	$\lvert I_{restraint}\_B\rvert$ = 1,159.4A = 4.62 per unit
$\lvert I_{restraint}\_C\rvert$ = 579.7A = 2.31 per unit	$\lvert I_{restraint}\_C\rvert$ = 0.0A = 0.00 per unit

Same external phase-ground (A) 115kV W2-side fault – <u>M0(0°) matrix</u>

Method 1	Method 2
$\lvert I_{restraint}\_A\rvert$ = 669.4A = 2.67 per unit	$\lvert I_{restraint}\_A\rvert$ = 1,338.8A = 5.33 per unit
$\lvert I_{restraint}\_B\rvert$ = 669.4A = 2.67 per unit	$\lvert I_{restraint}\_B\rvert$ = 669.4A = 2.67 per unit
$\lvert I_{restraint}\_C\rvert$ = 669.4A = 2.67 per unit	$\lvert I_{restraint}\_C\rvert$ = 669.4A = 2.67 per unit

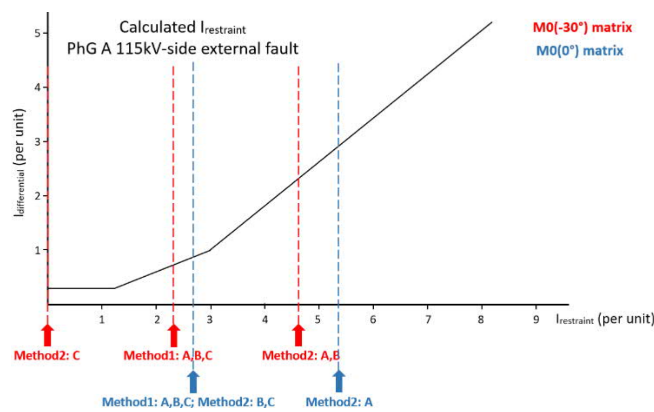

Figure 20: Method 1 versus Method 2 restraint current calculation for an external W2-side phase-ground (A) fault

With the M0(-30°) matrix:

$$ID\_C = \frac{1}{\sqrt{3}} * (IC - IB) + \frac{115}{230} * \frac{1}{\sqrt{3}} * (IC - IB)$$

$$= DCCC\_W1 + DCCC\_W2$$

With the M0(0°) matrix:

$$ID\_C = \frac{1}{3} * (2IC - IA - IB) + \frac{115}{230} * \frac{1}{3} * (2IC - IA - IB)$$

$$= DCCC\_W1 + DCCC\_W2$$

Method 2 calculates the phase C restraint current as follows:

$$|I_{restraint}\_C| = |DCCC\_W1| + |DCCC\_W2|$$

With M0(-30°) as the used matrix, the W1 C phase compensated current contains W1 B and C phase currents, neither of which are fault currents, with both equal to zero when calculated theoretically, ignoring load current. Similarly, the W2 C phase compensated current contains W2 B and C phase currents, neither of which are fault currents, with both equal to zero when calculated theoretically, ignoring load current. See Appendix B.

Although the calculated restraint current for phase C is very small, theoretically zero, the likelihood that some differential current, small but enough to cause a misoperation, would be calculated for phase C due to some CT saturation or other error is small, as no fault currents are included in the phase C compensated currents for the differential calculation.

Therefore, for restraint currents calculated using Method 2, it could be argued that the M0(-30°) matrix could (still) be selected without a high probability of introducing a possibility for misoperation for external phase-ground faults. Note that it would also be okay to select the M0(30°) matrix with a similar result.

As with the external phase-phase faults, when it comes to ensuring through-fault stability for external phase-ground faults, using Method 1 for calculating the restraint currents places no prerequisite on which matrix should be selected. Either the M0(0°), the M0(-30°) or the M0(30°) matrix could be selected, as adequate restraint current to ensure through phase-ground fault stability would be calculated for all selections. In fact, by selecting the M0(0°) matrix, a slightly higher stability is ensured.

VI CONCLUSIONS

It has been shown in this paper that it is not best practice to apply one common set of setting rules to all microprocessor-based relay 87T transformer differential functions. Each 87T function will have its own setting rules that should be followed to provide optimum performance (e.g. ensuring adequate restraint for external faults). Each 87T function's setting rules align with how it has been designed, and in particular with how it calculates its restraint currents. Therefore these rules are not common, and so are not applicable equally in all instances. Knowing and understanding these underlying rules is the first step towards developing optimum 87T function settings.

How the restraint currents are calculated does impact the transformer side that can be selected as the phase reference. It is imperative that with the selected phase reference adequate restraint currents will always be calculated so that a small amount of false differential current (e.g. due to CT saturation) will not cause the 87T function to unwantedly operate for an external fault.

Aside from the impact imposed by the method of the restraint current calculation, it would otherwise be okay for the differential current calculation for Dy and Yd transformers that either the wye- or the delta-side be the phase reference. Matrix selection (phase reference selection) comes into play more for internal faults. Most of them are single-phase faults and the calculated differential currents would be different for different matrix selections. Being able to select the wye-side as the phase reference would give a slight improvement in sensitivity, as well as a clearer indication of the actual limb of the magnetic core in which the fault had occurred.

The method of restraint current calculation is also important when it comes to comparing operating characteristics, if this is to be done on a fair basis. It is simply not the same if the calculated restraint currents are 100% or 200% for the same through-load conditions. For this reason, it may not be best practice to adopt and apply standard slope settings to different 87T functions. Again, these should be based on the guidelines from the manufacturer of each 87T function.

APPENDIX A – CALCULATION OF DIFFERENTIAL CURRENTS FOR EXAMPLES 1 AND 2

For all fault calculations, the following conditions apply:
- 1pu voltage
- no pre-fault load
- source impedance = 0
- transformer positive-, negative- and zero-sequence reactances, as applicable, = 0.25pu

Note: as the through load flow is W1 to W2, and the faults are external on the W2 115kV-side, the direction for the W1 currents is “to object” (the transformer), whereas the direction for the W2 currents is “from object”. For this reason, the W2 currents are phase shifted by 180°.

Example 1
Dyn1 (= DABY) transformer

Balanced rated load current

W1 tap scaling factor: 4.18
W2 tap scaling factor: 4.35

IA_W1 = 251.0∠0°A_{pri} = 4.18∠0°A_{sec} = 1.00∠0°A_{pu}
IB_W1 = 251.0∠-120°A_{pri} = 4.18∠-120°A_{sec} = 1.00∠-120°A_{pu}
IC_W1 = 251.0∠120°A_{pri} = 4.18∠120°A_{sec} = 1.00∠120°A_{pu}

IA_W2 = 502.0∠150°A_{pri} = 4.35∠180°A_{sec} = 1.00∠180°A_{pu}
IB_W2 = 502.0 ∠30°A_{pri} = 4.35∠60°A_{sec} = 1.00∠60°A_{pu}
IC_W2 = 502.0 ∠-90°A_{pri} = 4.35∠-60°A_{sec} = 1.00∠-60°A_{pu}

External phase-phase (BC) 115kV W2-side fault

W1 tap scaling factor: 4.18
W2 tap scaling factor: 4.35

IA_W1 = 502.0∠0°A_{pri} = 8.37∠0°A_{sec} = 2.00∠0°A_{pu}
IB_W1 = 1,004.1∠180°A_{pri} = 16.73∠180°A_{sec} = 4.00∠180°A_{pu}
IC_W1 = 502.0∠0°A_{pri} = 8.37∠0°A_{sec} = 2.00∠0°A_{pu}

IA_W2 = 0.0A_{pri} = 8.70∠180°A_{sec} = 2.00∠180°A_{pu}
IB_W2 = 1,739.1∠0°A_{pri} = 17.39∠0°A_{sec} = 4.00∠0°A_{pu}
IC_W2 = 1,739.1∠180°A_{pri} = 8.70∠180°A_{sec} = 2.00∠180°A_{pu}

External phase-ground (A) 115kV W2-side fault

W1 tap scaling factor: 4.18
W2 tap scaling factor: 4.35

IA_W1 = 579.7∠-90°A_{pri} = 9.66∠-90°A_{sec} = 2.31∠-90°A_{pu}
IB_W1 = 0.0A_{pri} = 0.00A_{sec} = 0.00A_{pu}
IC_W1 = 579.7∠90°A_{pri} = 9.66∠90°A_{sec} = 2.31∠90°A_{pu}

IA_W2 = 2,008.2∠ 90°A_{pri} = 10.04∠90°A_{sec} = 2.31∠90°A_{pu}
IB_W2 = 0.0A_{pri} = 0.00A_{sec} = 0.00A_{pu}
IC_W2 = 0.0A_{pri} = 10.04∠-90°A_{sec} = 2.31∠-90°A_{pu}

Example 2
YNd11 (= YDAB) transformer

Balanced rated load current

W1 tap scaling factor: 4.35
W2 tap scaling factor: 4.18

IA_W1 = 251.0∠0°A_{pri} = 4.35∠30°A_{sec} = 1.00∠30°A_{pu}
IB_W1 = 251.0∠-120°A_{pri} = 4.35∠-90°A_{sec} = 1.00∠-90°A_{pu}
IC_W1 = 251.0∠120°A_{pri} = 4.35∠150°A_{sec} = 1.00∠150°A_{pu}

IA_W2 = 502.0∠-150°A_{pri} = 4.18∠-150°A_{sec} = 1.00∠-150°A_{pu}
IB_W2 = 502.0 ∠90°A_{pri} = 4.18∠90°A_{sec} = 1.00∠90°A_{pu}
IC_W2 = 502.0 ∠-30°A_{pri} = 4.18∠-30°A_{sec} = 1.00∠-30°A_{pu}

External phase-phase (BC) 115kV W2-side fault

W1 tap scaling factor: 4.35
W2 tap scaling factor: 4.18

IA_W1 = 502.0∠180°A_{pri} = 0.0A_{sec} = 0.00A_{pu}
IB_W1 = 502.0∠180°A_{pri} = 15.06∠180°A_{sec} = 3.46∠180°A_{pu}
IC_W1 = 1,004.1∠0°A_{pri} = 15.06∠0°A_{sec} = 3.46∠0°A_{pu}

IA_W2 = 0.0A_{pri} = 0.0A_{sec} = 0.00A_{pu}
IB_W2 = 1,739.1∠0°A_{pri} = 14.49∠0°A_{sec} = 3.46∠0°A_{pu}
IC_W2 = 1,739.1∠180°A_{pri} = 14.49∠180°A_{sec} = 3.46∠180°A_{pu}

APPENDIX B – CALCULATION OF DIFFERENTIAL CURRENTS FOR EXAMPLES 3, 4 AND 5

For all fault calculations, the following conditions apply:

- 1pu voltage
- no pre-fault load
- source impedance = 0
- transformer positive-, negative- and zero-sequence reactances, as applicable, = 0.25pu

Note: as the faults are external on the W2 115kV-side, the direction for the W1 currents is "to object" (the transformer), whereas the direction for the W2 currents is "from object". For this reason, the W2 currents in the matrix equations following are phase shifted by 180° from those calculated.

For each case the calculated compensated currents are shown for each side. The per phase differential currents are calculated by summing these compensated currents. Furthermore, the magnitudes of these compensated currents are used by the different methods to calculate the per phase restraint currents.

<u>Example 3</u>

Dyn1 (= DABY) transformer

<u>External three-phase fault on the W2 115kV-side</u>

The calculated W1 and W2 fault currents are as follows:

$IA\_W1 = 1,004.1\angle{-60°}A_{pri}$	$IA\_W2 = 2,008.2\angle{-90°}A_{pri}$
$IB\_W1 = 1,004.1\angle{180°}A_{pri}$	$IB\_W2 = 2,008.2\angle{150°}A_{pri}$
$IC\_W1 = 1,004.1\angle{60°}A_{pri}$	$IC\_W2 = 2,008.2\angle{30°}A_{pri}$

W1 Delta-side as the phase reference:

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \underbrace{\begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix} * \begin{bmatrix} 1,004.1\angle{-60°} \\ 1,004.1\angle{180°} \\ 1,004.1\angle{60°} \end{bmatrix}}_{\begin{bmatrix} 1,004.1\angle{-60°} \\ 1,004.1\angle{180°} \\ 1,004.1\angle{60°} \end{bmatrix}} + \underbrace{\frac{115}{230} * \frac{1}{\sqrt{3}} \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} * \begin{bmatrix} 2,008.2\angle{90°} \\ 2,008.2\angle{-30°} \\ 2,008.2\angle{-150°} \end{bmatrix}}_{\begin{bmatrix} 1,004.1\angle{120°} \\ 1,004.1\angle{0°} \\ 1,004.1\angle{-120°} \end{bmatrix}}$$

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \begin{bmatrix} 0.0 \\ 0.0 \\ 0.0 \end{bmatrix}$$

W2 wye-side as the phase reference:

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \underbrace{\frac{1}{\sqrt{3}} \begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix} * \begin{bmatrix} 1,004.1\angle{-60°} \\ 1,004.1\angle{180°} \\ 1,004.1\angle{60°} \end{bmatrix}}_{\begin{bmatrix} 1,004.1\angle{-90°} \\ 1,004.1\angle{150°} \\ 1,004.1\angle{30°} \end{bmatrix}} + \underbrace{\frac{115}{230} * \frac{1}{3} \begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix} * \begin{bmatrix} 2,008.2\angle{90°} \\ 2,008.2\angle{-30°} \\ 2,008.2\angle{-150°} \end{bmatrix}}_{\begin{bmatrix} 1,004.1\angle{90°} \\ 1,004.1\angle{-30°} \\ 1,004.1\angle{-150°} \end{bmatrix}}$$

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \begin{bmatrix} 0.0 \\ 0.0 \\ 0.0 \end{bmatrix}$$

<u>External phase-phase (BC) fault on the W2 115kV-side</u>

The calculated W1 and W2 fault currents are as follows:

$IA\_W1 = 502.0\angle{0°}A_{pri}$	$IA\_W2 = 0.0$
$IB\_W1 = 1,004.1\angle{180°}A_{pri}$	$IB\_W2 = 1,739.1\angle{180°}A_{pri}$
$IC\_W1 = 502.0\angle{0°}A_{pri}$	$IC\_W2 = 1,739.1\angle{0°}A_{pri}$

W1 Delta-side as the phase reference:

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \underbrace{\begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix} * \begin{bmatrix} 502.0\angle{0°} \\ 1,004.1\angle{180°} \\ 502.0\angle{0°} \end{bmatrix}}_{\begin{bmatrix} 502.0\angle{0°} \\ 1,004.1\angle{180°} \\ 502.0\angle{0°} \end{bmatrix}} + \underbrace{\frac{115}{230} * \frac{1}{\sqrt{3}} \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} * \begin{bmatrix} 0.0 \\ 1,739.1\angle{0°} \\ 1,739.1\angle{180°} \end{bmatrix}}_{\begin{bmatrix} 502.0\angle{180°} \\ 1,004.1\angle{0°} \\ 502.0\angle{180°} \end{bmatrix}}$$

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \begin{bmatrix} 0.0 \\ 0.0 \\ 0.0 \end{bmatrix}$$

W2 wye-side as the phase reference:

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \underbrace{\frac{1}{\sqrt{3}} \begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix} * \begin{bmatrix} 502.0\angle{0°} \\ 1,004.1\angle{180°} \\ 502.0\angle{0°} \end{bmatrix}}_{\begin{bmatrix} 0.0 \\ 869.6\angle{180°} \\ 869.6\angle{0°} \end{bmatrix}} + \underbrace{\frac{115}{230} * \frac{1}{3} \begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix} * \begin{bmatrix} 0.0 \\ 1,739.1\angle{0°} \\ 1,739.1\angle{180°} \end{bmatrix}}_{\begin{bmatrix} 0.0 \\ 869.6\angle{0°} \\ 869.6\angle{180°} \end{bmatrix}}$$

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \begin{bmatrix} 0.0 \\ 0.0 \\ 0.0 \end{bmatrix}$$

<u>External phase-ground (A) fault on the W2 115kV-side</u>

The calculated W1 and W2 fault currents are as follows:

$IA\_W1 = 579.7\angle{-90°}A_{pri}$	$IA\_W2 = 2,008.2\angle{-90°}A_{pri}$
$IB\_W1 = 0.0$	$IB\_W2 = 0.0$
$IC\_W1 = 579.7\angle{90°}A_{pri}$	$IC\_W2 = 0.0$

W1 Delta-side as the phase reference:

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \underbrace{\begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix} * \begin{bmatrix} 579.7\angle{-90°} \\ 0.0 \\ 579.7\angle{90°} \end{bmatrix}}_{\begin{bmatrix} 579.7\angle{-90°} \\ 0.0 \\ 579.7\angle{90°} \end{bmatrix}} + \underbrace{\frac{115}{230} * \frac{1}{\sqrt{3}} \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} * \begin{bmatrix} 2,008.2\angle{90°} \\ 0.0 \\ 0.0 \end{bmatrix}}_{\begin{bmatrix} 579.7\angle{90°} \\ 0.0 \\ 579.7\angle{-90°} \end{bmatrix}}$$

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \begin{bmatrix} 0.0 \\ 0.0 \\ 0.0 \end{bmatrix}$$

W2 wye-side as the phase reference:

$$\begin{bmatrix} \text{ID\_A} \\ \text{ID\_B} \\ \text{ID\_C} \end{bmatrix} = \underbrace{\frac{1}{\sqrt{3}}\begin{bmatrix}1&0&-1\\-1&1&0\\0&-1&1\end{bmatrix} * \begin{bmatrix}579.7\angle -90^\circ\\0.0\\579.7\angle 90^\circ\end{bmatrix}}_{\begin{bmatrix}669.4\angle -90^\circ\\334.7\angle 90^\circ\\334.7\angle 90^\circ\end{bmatrix}} + \underbrace{\frac{115}{230} * \frac{1}{3}\begin{bmatrix}2&-1&-1\\-1&2&-1\\-1&-1&2\end{bmatrix} * \begin{bmatrix}2{,}008.2\angle 90^\circ\\0.0\\0.0\end{bmatrix}}_{\begin{bmatrix}669.4\angle 90^\circ\\334.7\angle -90^\circ\\334.7\angle -90^\circ\end{bmatrix}}$$

$$\begin{bmatrix} \text{ID\_A} \\ \text{ID\_B} \\ \text{ID\_C} \end{bmatrix} = \begin{bmatrix}0.0\\0.0\\0.0\end{bmatrix}$$

<u>Example 4</u>
YNd11 (=YDAB) transformer

<u>External three-phase fault on the W2 115kV-side</u>

The calculated W1 and W2 fault currents are as follows:

$IA\_W1 = 1{,}004.1\angle -120^\circ A_{pri}$	$IA\_W2 = 2{,}008.2\angle -90^\circ A_{pri}$
$IB\_W1 = 1{,}004.1\angle 120^\circ A_{pri}$	$IB\_W2 = 2{,}008.2\angle 150^\circ A_{pri}$
$IC\_W1 = 1{,}004.1\angle 0^\circ A_{pri}$	$IC\_W2 = 2{,}008.2\angle 30^\circ A_{pri}$

W2 delta-side as the phase reference:

$$\begin{bmatrix} \text{ID\_A} \\ \text{ID\_B} \\ \text{ID\_C} \end{bmatrix} = \underbrace{\frac{1}{\sqrt{3}}\begin{bmatrix}1&-1&0\\0&1&-1\\-1&0&1\end{bmatrix} * \begin{bmatrix}1{,}004.1\angle -120^\circ\\1{,}004.1\angle 120^\circ\\1{,}004.1\angle 0^\circ\end{bmatrix}}_{\begin{bmatrix}1{,}004.1\angle -90^\circ\\1{,}004.1\angle 150^\circ\\1{,}004.1\angle 30^\circ\end{bmatrix}} + \underbrace{\frac{115}{230} * \begin{bmatrix}1&0&0\\0&1&0\\0&0&1\end{bmatrix} * \begin{bmatrix}2{,}008.2\angle 90^\circ\\2{,}008.2\angle -30^\circ\\2{,}008.2\angle -150^\circ\end{bmatrix}}_{\begin{bmatrix}1{,}004.1\angle 90^\circ\\1{,}004.1\angle -30^\circ\\1{,}004.1\angle -150^\circ\end{bmatrix}}$$

$$\begin{bmatrix} \text{ID\_A} \\ \text{ID\_B} \\ \text{ID\_C} \end{bmatrix} = \begin{bmatrix}0.0\\0.0\\0.0\end{bmatrix}$$

W1 Wye-side as the phase reference:

$$\begin{bmatrix} \text{ID\_A} \\ \text{ID\_B} \\ \text{ID\_C} \end{bmatrix} = \underbrace{\frac{1}{3}\begin{bmatrix}2&-1&-1\\-1&2&-1\\-1&-1&2\end{bmatrix} * \begin{bmatrix}1{,}004.1\angle -120^\circ\\1{,}004.1\angle 120^\circ\\1{,}004.1\angle 0^\circ\end{bmatrix}}_{\begin{bmatrix}1{,}004.1\angle -60^\circ\\1{,}004.1\angle 180^\circ\\1{,}004.1\angle 60^\circ\end{bmatrix}} + \underbrace{\frac{115}{230} * \frac{1}{\sqrt{3}}\begin{bmatrix}1&0&-1\\-1&1&0\\0&-1&1\end{bmatrix} * \begin{bmatrix}2{,}008.2\angle 90^\circ\\2{,}008.2\angle -30^\circ\\2{,}008.2\angle -150^\circ\end{bmatrix}}_{\begin{bmatrix}1{,}004.1\angle 120^\circ\\1{,}004.1\angle 0^\circ\\1{,}004.1\angle -120^\circ\end{bmatrix}}$$

$$\begin{bmatrix} \text{ID\_A} \\ \text{ID\_B} \\ \text{ID\_C} \end{bmatrix} = \begin{bmatrix}0.0\\0.0\\0.0\end{bmatrix}$$

<u>External phase-phase (BC) fault on the W2 115kV-side</u>

The calculated W1 and W2 fault currents are as follows:

$IA\_W1 = 502.0\angle 180^\circ A_{pri}$	$IA\_W2 = 0.0$
$IB\_W1 = 502.0\angle 180^\circ A_{pri}$	$IB\_W2 = 1{,}739.1\angle 180^\circ A_{pri}$
$IC\_W1 = 1{,}004.1\angle 0^\circ A_{pri}$	$IC\_W2 = 1{,}739.1\angle 0^\circ A_{pri}$

W2 delta-side as the phase reference:

$$\begin{bmatrix} \text{ID\_A} \\ \text{ID\_B} \\ \text{ID\_C} \end{bmatrix} = \underbrace{\frac{1}{\sqrt{3}}\begin{bmatrix}1&-1&0\\0&1&-1\\-1&0&1\end{bmatrix} * \begin{bmatrix}502.0\angle 180^\circ\\502.0\angle 180^\circ\\1{,}004.1\angle 0^\circ\end{bmatrix}}_{\begin{bmatrix}0.0\\869.6\angle 180^\circ\\869.6\angle 0^\circ\end{bmatrix}} + \underbrace{\frac{115}{230} * \begin{bmatrix}1&0&0\\0&1&0\\0&0&1\end{bmatrix} * \begin{bmatrix}0.0\\1{,}739.1\angle 0^\circ\\1{,}739.1\angle 180^\circ\end{bmatrix}}_{\begin{bmatrix}0.0\\869.6\angle 0^\circ\\869.6\angle 180^\circ\end{bmatrix}}$$

$$\begin{bmatrix} \text{ID\_A} \\ \text{ID\_B} \\ \text{ID\_C} \end{bmatrix} = \begin{bmatrix}0.0\\0.0\\0.0\end{bmatrix}$$

W1 Wye-side as the phase reference:

$$\begin{bmatrix} \text{ID\_A} \\ \text{ID\_B} \\ \text{ID\_C} \end{bmatrix} = \underbrace{\frac{1}{3}\begin{bmatrix}2&-1&-1\\-1&2&-1\\-1&-1&2\end{bmatrix} * \begin{bmatrix}502.0\angle 180^\circ\\502.0\angle 180^\circ\\1{,}004.1\angle 0^\circ\end{bmatrix}}_{\begin{bmatrix}502.0\angle 180^\circ\\502.0\angle 180^\circ\\1{,}004.1\angle 0^\circ\end{bmatrix}} + \underbrace{\frac{115}{230} * \frac{1}{\sqrt{3}}\begin{bmatrix}1&0&-1\\-1&1&0\\0&-1&1\end{bmatrix} * \begin{bmatrix}0.0\\1{,}739.1\angle 0^\circ\\1{,}739.1\angle 180^\circ\end{bmatrix}}_{\begin{bmatrix}502.0\angle 0^\circ\\502.0\angle 0^\circ\\1{,}004.1\angle 180^\circ\end{bmatrix}}$$

$$\begin{bmatrix} \text{ID\_A} \\ \text{ID\_B} \\ \text{ID\_C} \end{bmatrix} = \begin{bmatrix}0.0\\0.0\\0.0\end{bmatrix}$$

<u>Example 5</u>
Autotransformer, no delta tertiary (YNyn0 transformer)

<u>External three-phase fault on the W2 115kV-side</u>

The calculated W1 and W2 fault currents are as follows:

$IA\_W1 = 1{,}004.1\angle -90^\circ A_{pri}$	$IA\_W2 = 2{,}008.2\angle -90^\circ A_{pri}$
$IB\_W1 = 1{,}004.1\angle 150^\circ A_{pri}$	$IB\_W2 = 2{,}008.2\angle 150^\circ A_{pri}$
$IC\_W1 = 1{,}004.1\angle 30^\circ A_{pri}$	$IC\_W2 = 2{,}008.2\angle 30^\circ A_{pri}$

M0(-30°) matrix:

$$\begin{bmatrix} \text{ID\_A} \\ \text{ID\_B} \\ \text{ID\_C} \end{bmatrix} = \underbrace{\frac{1}{\sqrt{3}}\begin{bmatrix}1&0&-1\\-1&1&0\\0&-1&1\end{bmatrix} * \begin{bmatrix}1{,}004.1\angle -90^\circ\\1{,}004.1\angle 150^\circ\\1{,}004.1\angle 30^\circ\end{bmatrix}}_{\begin{bmatrix}1{,}004.1\angle -120^\circ\\1{,}004.1\angle 120^\circ\\1{,}004.1\angle 0^\circ\end{bmatrix}} + \underbrace{\frac{115}{230} * \frac{1}{\sqrt{3}}\begin{bmatrix}1&0&-1\\-1&1&0\\0&-1&1\end{bmatrix} * \begin{bmatrix}2{,}008.2\angle 90^\circ\\2{,}008.2\angle -30^\circ\\2{,}008.2\angle -150^\circ\end{bmatrix}}_{\begin{bmatrix}1{,}004.1\angle 60^\circ\\1{,}004.1\angle -60^\circ\\1{,}004.1\angle 180^\circ\end{bmatrix}}$$

$$\begin{bmatrix} \text{ID\_A} \\ \text{ID\_B} \\ \text{ID\_C} \end{bmatrix} = \begin{bmatrix}0.0\\0.0\\0.0\end{bmatrix}$$

Note: alternatively, the M0(30°) matrix could have been used.

$$= \frac{1}{\sqrt{3}}\begin{bmatrix}1&-1&0\\0&1&-1\\-1&0&1\end{bmatrix}$$

The compensated currents will have different angles, and for some of the faults (BC, A) the compensated currents ‘switch’ between phases, but otherwise the end result is the same.

M0(0°) matrix:

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \underbrace{\frac{1}{3}\begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix} * \begin{bmatrix} 1{,}004.1\angle{-90°} \\ 1{,}004.1\angle 150° \\ 1{,}004.1\angle 30° \end{bmatrix}}_{\begin{bmatrix} 1{,}004.1\angle{-90°} \\ 1{,}004.1\angle 150° \\ 1{,}004.1\angle 30° \end{bmatrix}} + \underbrace{\frac{115}{230} * \frac{1}{3}\begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix} * \begin{bmatrix} 2{,}008.2\angle 90° \\ 2{,}008.2\angle{-30°} \\ 2{,}008.2\angle{-150°} \end{bmatrix}}_{\begin{bmatrix} 1{,}004.1\angle 90° \\ 1{,}004.1\angle{-30°} \\ 1{,}004.1\angle{-150°} \end{bmatrix}}$$

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \begin{bmatrix} 0.0 \\ 0.0 \\ 0.0 \end{bmatrix}$$

<u>External phase-phase (BC) fault on the W2 115kV-side</u>

The calculated W1 and W2 fault currents are as follows:

IA_W1 = 0.0	IA_W2 = 0.0
IB_W1 = $869.6\angle 180° A_{pri}$	IB_W2 = $1{,}739.1\angle 180° A_{pri}$
IC_W1 = $869.6\angle 0° A_{pri}$	IC_W2 = $1{,}739.1\angle 0° A_{pri}$

M0(-30°) matrix:

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \underbrace{\frac{1}{\sqrt{3}}\begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix} * \begin{bmatrix} 0.0 \\ 869.6\angle 180° \\ 869.6\angle 0° \end{bmatrix}}_{\begin{bmatrix} 502.0\angle 180° \\ 502.0\angle 180° \\ 1{,}004.1\angle 0° \end{bmatrix}} + \underbrace{\frac{115}{230} * \frac{1}{\sqrt{3}}\begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix} * \begin{bmatrix} 0.0 \\ 1739.1\angle 0° \\ 1739.1\angle 180° \end{bmatrix}}_{\begin{bmatrix} 502.0\angle 0° \\ 502.0\angle 0° \\ 1{,}004.1\angle 180° \end{bmatrix}}$$

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \begin{bmatrix} 0.0 \\ 0.0 \\ 0.0 \end{bmatrix}$$

M0(0°) matrix:

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \underbrace{\frac{1}{3}\begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix} * \begin{bmatrix} 0.0 \\ 869.6\angle 180° \\ 869.6\angle 0° \end{bmatrix}}_{\begin{bmatrix} 0.0 \\ 869.6\angle 180° \\ 869.6\angle 0° \end{bmatrix}} + \underbrace{\frac{115}{230} * \frac{1}{3}\begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix} * \begin{bmatrix} 0.0 \\ 1739.1\angle 0° \\ 1739.1\angle 180° \end{bmatrix}}_{\begin{bmatrix} 0.0 \\ 869.6\angle 0° \\ 869.6\angle 180° \end{bmatrix}}$$

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \begin{bmatrix} 0.0 \\ 0.0 \\ 0.0 \end{bmatrix}$$

<u>External phase-ground (A) fault on the W2 115kV-side</u>

The calculated W1 and W2 fault currents are as follows:

IA_W1 = $1{,}004.1\angle{-90°} A_{pri}$	IA_W2 = $2{,}008.2\angle{-90°} A_{pri}$
IB_W1 = 0.0	IB_W2 = 0.0
IC_W1 = 0.0	IC_W2 = 0.0

M0(-30°) matrix:

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \underbrace{\frac{1}{\sqrt{3}}\begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix} * \begin{bmatrix} 1{,}004.1\angle{-90°} \\ 0.0 \\ 0.0 \end{bmatrix}}_{\begin{bmatrix} 579.7\angle{-90°} \\ 579.7\angle 90° \\ 0.0 \end{bmatrix}} + \underbrace{\frac{115}{230} * \frac{1}{\sqrt{3}}\begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix} * \begin{bmatrix} 2{,}008.2\angle 90° \\ 0.0 \\ 0.0 \end{bmatrix}}_{\begin{bmatrix} 579.7\angle 90° \\ 579.7\angle{-90°} \\ 0.0 \end{bmatrix}}$$

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \begin{bmatrix} 0.0 \\ 0.0 \\ 0.0 \end{bmatrix}$$

M0(0°) matrix

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \underbrace{\frac{1}{3}\begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix} * \begin{bmatrix} 1{,}004.1\angle{-90°} \\ 0.0 \\ 0.0 \end{bmatrix}}_{\begin{bmatrix} 669.4\angle{-90°} \\ 334.7\angle 90° \\ 334.7\angle 90° \end{bmatrix}} + \underbrace{\frac{115}{230} * \frac{1}{3}\begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix} * \begin{bmatrix} 2{,}008.2\angle 90° \\ 0.0 \\ 0.0 \end{bmatrix}}_{\begin{bmatrix} 669.4\angle 90° \\ 334.7\angle{-90°} \\ 334.7\angle{-90°} \end{bmatrix}}$$

$$\begin{bmatrix} ID\_A \\ ID\_B \\ ID\_C \end{bmatrix} = \begin{bmatrix} 0.0 \\ 0.0 \\ 0.0 \end{bmatrix}$$

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