SA2008-000355 rev. -

Universal Testing Method for

Power Transformer Differential Protection

Secondary Injection for Transformer Differential Protection

1 Introduction

Differential protection for standard power transformers has been used for decades. It is based on ampere-turn-balance of all windings mounted on the same magnetic core lag. In order to correctly apply transformer differential protection the following compensations shall be provided:

- current magnitude difference on different sides of the protected transformer (i.e. current magnitude compensation);
- power transformer phase angle shift compensation; and
- zero sequence current compensation (i.e. zero sequence current elimination)

With modern numerical transformer differential relays all above compensations are provided in the relay software. Thus, it can be quite tricky to test a numerical transformer differential relay by secondary injection in order to verify that the relay is set properly to protect transformer in a particular application.

Thus, a new standardized testing methodology for transformer differential protection relay from any manufacturer will be presented.

2 Basic Power Transformer Theory

Typical voltage and current definitions used for three-phase power transformers are shown in Figure 1.

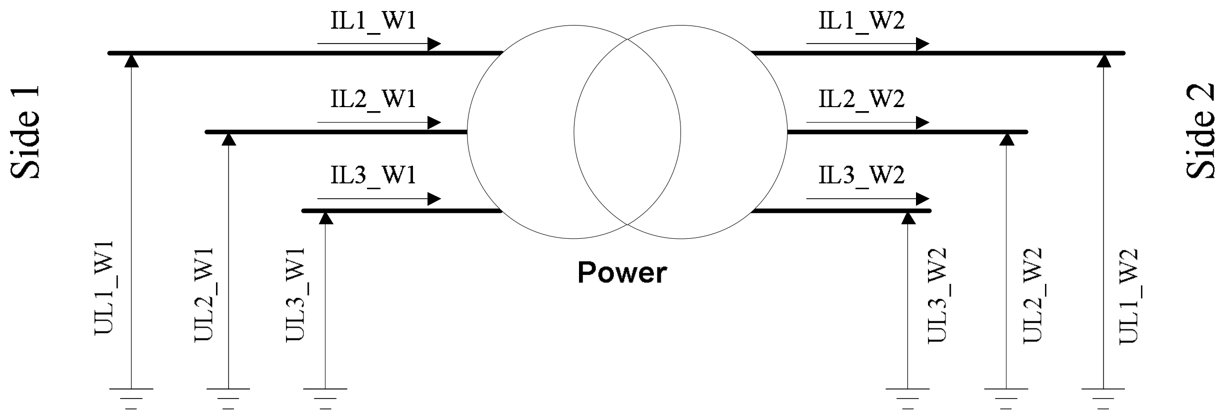


Figure 1: Typical voltage and current reference direction for a transformer

The standard three-phase power transformers introduce a fixed phase angle shift Θ of n*30º (n=0, 1, 2, …, 11) between its winding 1 and winding 2 side no-load voltages, as shown in Figure 2.

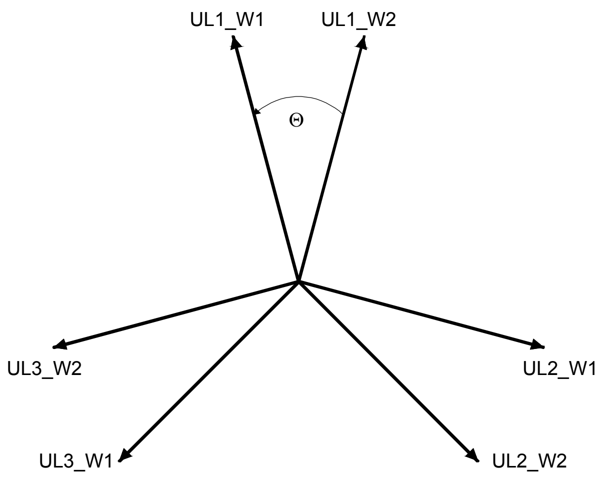


Figure 2: Phasor diagram for individual phase no-load voltages

As shown in reference [1], strict rules only exist for the phase angle shift between sequence components of the no-load voltages from the two sides of the power transformer (see Figure 3), but not for individual phase voltages from the two sides of the power transformer.

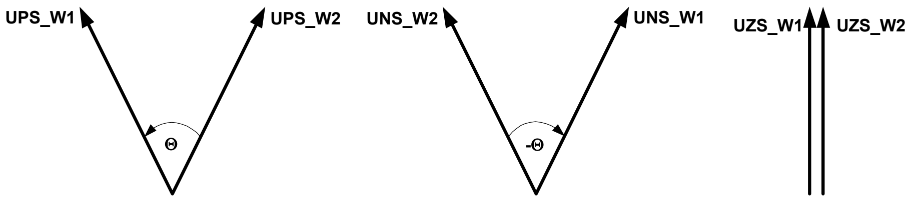


Figure 3: Phasor diagram for no-load positive, negative & zero sequence voltages components from the two sides of the power transformers

As shown in Figure 3 the following will hold true for the positive, negative & zero sequence no-load voltage components:

- the positive sequence no-load voltage component from winding 1 (UPS_W1) will lead the positive sequence no-load voltage component from winding 2 (UPS_W2) by angle Θ;
- the negative sequence no-load voltage component from winding 1 (UNS_W1) will lag the negative sequence no-load voltage component from winding 2 (UNS_W2) by angle Θ; and
- the zero sequence no-load voltage component from winding 1 (UZS_W1) will be exactly in phase with the zero sequence no-load voltage component from winding 2 (UZS_W2), when the zero sequence no-load voltage components are at all transferred across the power transformer.

However, as soon as the power transformer is loaded, this voltage relationship will not longer be valid, due to the voltage drop across the power transformer impedance.

However it can be shown that the same phase angle relationship, as shown in Figure 3, will be valid for sequence current components [1], as shown in Figure 4, which flow into the power transformer on winding 1 side and flow out from the power transformer on winding 2 side (see Figure 1 for current reference directions).

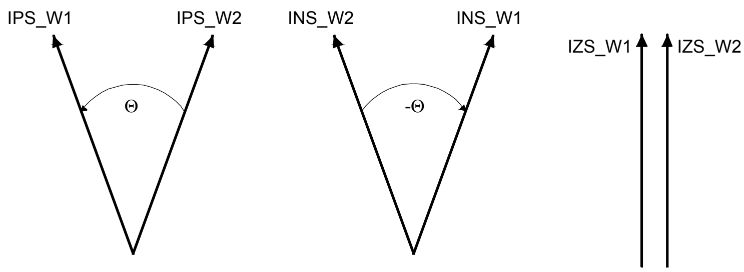


Figure 4: Phasor diagram for positive, negative & zero sequence current components from the two sides of the power transformers

As shown in Figure 4, the following will hold true for the sequence current components from the two power transformer sides:

- the positive sequence current component from winding 1 (IPS_W1) will lead the positive sequence current component from winding 2 (IPS_W2) by angle Θ (the same relationship as for the positive sequence no-load voltage components);
- the negative sequence current component from winding 1 (INS_W1) will lag the negative sequence current component from winding 2 (INS_W2) by angle Θ (the same relationship as for the negative sequence no-load voltage components); and
- the zero sequence current component from winding 1 (IZS_W1) will be exactly in phase with the zero sequence current component from winding 2 (IZS_W2), when the zero sequence current components are at all transferred across the transformer (the same relationship as for the zero sequence no-load voltage components).

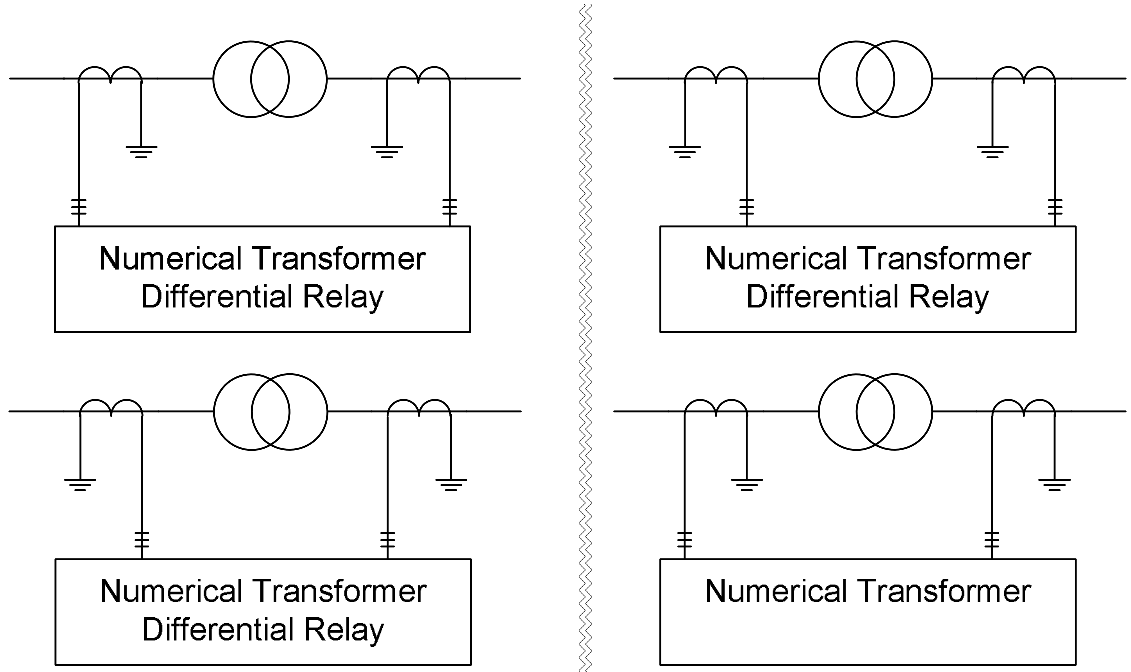
These properties can be used to test the numerical differential protection of any manufacturer as described further in this document. Namely, if testing is based on injecting only one sequence current component at the time on both CT inputs of the transformer differential protection, simple testing procedures can be derived, which are more intuitive, less complex and straightforward than existing phase-wise testing procedures.

3 Basis for the New Testing Principle

During secondary testing of numerical transformer differential relays, the appropriate secondary currents (i.e. with correct magnitude and phase angle) shall be injected to the differential relay in order to test its suitability for the particular application. In order to inject appropriate currents, care must be taken regarding protected power transformer rating data and main CT connections which are used for this particular installation.

Typically star/wye connected main CTs are used; however in some countries delta connected main CTs are applied. The star connected main CTs will be mostly described in this document, but one testing example with delta connected main CTs will be also provided.

When CTs are star connected it is possible to connect them to the differential relay in one of the four possible ways, as shown in Figure 5.



Phase angle shift between currents from the two CTs secondary sides is (Θ +180^{o}) degrees.

a)

Phase angle shift between currents from the two CTs secondary sides is Θ degrees.

b)

Figure 5: Possible CT arrangements for star/wye connected main CTs

It can be shown that for differential relay only two different types of CT connections are possible, regarding the phase angle shift between the main CT secondary currents, as shown in Figure 5a and 5b respectively.

In case of the first connection type (i.e. both main CTs stared either inside or outside), as shown in Figure 5a, the following will be true for the phase angle shift between sequence current components on the two CT secondary sides:

- the positive sequence current component from CT input for winding 1 side will lead the positive sequence current component from CT input for winding 2 side by angle (180º +Θ);

- the negative sequence current component from CT input for winding 1 side will lag the negative sequence current component from CT input for winding 2 side by angle (180º +Θ); and
- the zero sequence current component from CT input for winding 1 side will be exactly in contra-phase (i.e. 180º apart) with the zero sequence current component from CT input for winding 2 side, when zero sequence current components are at all transferred across the protected power transformer.

Note that secondary CT currents, for such main CT connections as shown in Figure 5a, will always have additional 180º phase angle difference from the primary currents. This additional 180º phase angle shift is caused by main CT secondary connections (i.e. when both main CTs are stared either inside or outside).

In case of the second connection type (i.e. one main CTs stared inside and the other main CT stared outside), as shown in Figure 5b, the following will be true for the phase angle shift between sequence current components on the two CT secondary sides:

- the positive sequence current component from CT input for winding 1 side will lead the positive sequence current component from CT input for winding 2 side by angle Θ;
- the negative sequence current component from CT input for winding 1 side will lag the negative sequence current component from CT input for winding 2 side by angle Θ; and
- the zero sequence current component from CT input for winding 1 side will be exactly in phase (i.e. 0º apart) with the zero sequence current component from CT input for winding 2 side, when zero sequence current components are at all transferred across the protected power transformer.

Note that secondary CT currents, for such main CT connections as shown in Figure 5b, have exactly the same phase angle relationship as the primary currents from the two power transformer sides (see Figure 4).

Once the phase angle relationship between the two CT secondary currents is known, only the current magnitudes are required for the secondary injection. Magnitude compensation for the differential protection has been shown in [2, 3]. The base currents (i.e. 100% current) on each power transformer side are calculated by using the maximum rated apparent power of the all power transformer windings in accordance with the following equation:

$$I_{Base\_Wi} = \frac{S_{rMax}}{\sqrt{3} \cdot U_{rWi}}$$

where:

- IBase_Wi is winding i base current in primary amperes
- SrMax is the maximum rated apparent power of the all power transformer windings
- UrWi is winding i rated phase-to-phase no-load voltage

When the base current on the CT secondary sides are known, then the following procedure can be used to inject stable and operating conditions into the differential relay:

- Inject ONLY the positive sequence current component with 100% magnitude on both sides of the protected transformer, with the phase angle shift depending on the main CT connections as described after Figure 5 (e.g. W2 positive sequence current shall leg the W1 positive sequence current by angle Θ or (180º+Θ)). The differential relay shall be stable. The bias current shall be 100% and all three differential currents shall be negligible (i.e. theoretically equal to 0%). Rotate the positive sequence current component only on one side of the protected power transformer by 180º. Due to this current inversion the differential relay shall trip in all three phases. All three differential currents shall be 200%.

- Inject ONLY the negative sequence current component with 100% magnitude on both sides of the protected transformer, with the phase angle shift depending on the main CT connections as described after Figure 5 (e.g. W2 negative sequence current shall lead the W1 negative sequence current by angle Θ or (180º+Θ)). The differential relay shall be stable. The bias current shall be 100% and all three differential currents shall be negligible (i.e. theoretically equal to 0%). Rotate the negative sequence current component on only one side of the transformer by 180º. Due to this current inversion the differential relay shall trip in all three phases. All three differential currents shall be 200%.

- If the zero sequence currents are properly transferred across the power transformer (what is seldom the case), inject ONLY the zero sequence current component with 100% magnitude on both sides of the protected transformer, with the phase angle shift depending on the main CT connections as described after Figure 5 (e.g. W2 zero sequence current shall either in phase or contra-phase with the W1 zero sequence current). The differential relay shall be stable. The bias current shall be 100% and all three differential currents shall be negligible (i.e. theoretically equal to 0%).

- If the zero sequence currents are NOT properly transferred across the power transformer (e.g. transformer with vector group Yd5), inject ONLY the zero sequence current component with 100% magnitude on one side of the protected transformer at the time. When injection is performed on the side where the zero sequence currents are eliminated, the differential relay shall not trip and all three differential currents shall be negligible (i.e. theoretically equal to 0%). When injection is performed on the side where the zero sequence currents are NOT eliminated the differential relay shall trip and all three differential currents shall have value of approximately 100%.

By performing this test it is verified that the differential protection will be stable for all symmetrical and non-symmetrical external faults and through-load conditions. It as well confirms that the differential relay will trip for internal faults. By slight modification of the presented testing method the complete operating characteristic of the numerical differential relay can be tested in the similar way.

It shall be noted that exactly the same testing method can be applied on traditional, analogue transformer differential protection schemes with interposing CTs. The only prerequisite is that the currents are injected into the primary windings of the interposing CTs and not directly into the differential relay. By doing so, the complete differential protection scheme consisting of interposing CTs and the analogue differential relay are verified.

4 Example with all main CTs star connected

One example of such transformer differential protection testing will be presented. All relevant data to test any applied differential protection can be found on Figure 6.

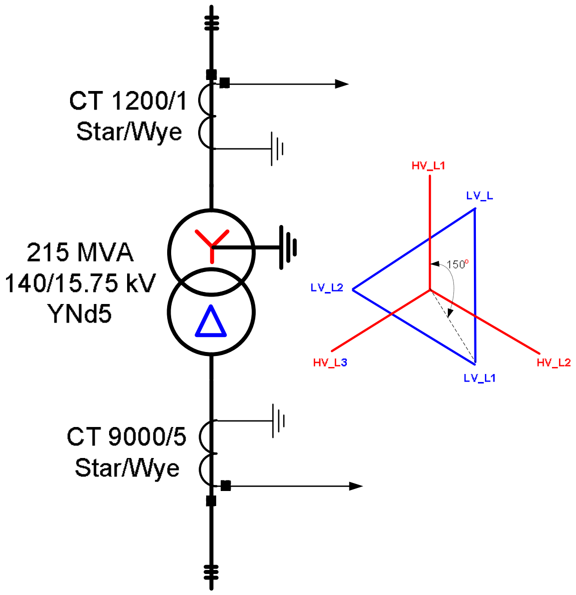


Figure 6: Practical Example with star connected main CTs

The maximum power (i.e. base power) for this transformer is 215MVA, and against this value, the base primary currents and base currents on the CT secondary side are calculated as shown in Table 1.

Table 1: Base current calculations for the YNd5 transformer

	Primary Base Current	Base current on CT secondary side (i.e. 100%)
W1, 140kV-Star	$\frac{215MVA}{\sqrt{3}\cdot 140kV} = 886.6A$	$\frac{886.6}{1200/1} = 0.739A$
W2, 15.75kV-Delta	$\frac{215MVA}{\sqrt{3}\cdot 15.75kV} = 7881.3A$	$\frac{7881.3}{9000/5} = 4.379A$

4.1 Injection with Positive Sequence Current Components

In order to inject the stable condition with positive sequence current the following secondary currents shall be injected into the differential relay. The required injection currents are shown in Table 2.

Table 2: Stable condition with 100% positive sequence component only on both sides

Injected currents into 140kV CT input	Injected currents into 15.75kV CT input
$IL1 = 0.739A\lfloor 0^0$	$IL1 = 4.379A\lfloor 210^0 + 180^0 = 4.379A\lfloor 30^0$ *
$IL2 = 0.739A\lfloor 240^0$	$IL2 = 4.379A\lfloor 90^0 + 180^0 = 4.379A\lfloor 270^0$ *
$IL3 = 0.739A\lfloor 120^0$	$IL3 = 4.379A\lfloor -30^0 + 180^0 = 4.379A\lfloor 150^0$ *

* Rule Θ+180° applied due to CT connections shown in Figure 6

The differential relay shall be stable. The bias current shall be 100% and all three differential currents shall be negligible (i.e. theoretically equal to 0%).

In order to check tripping with the positive sequence current components invert the positive sequence current on winding two side by 180º. The required injection currents are shown in Table 3.

Table 3: Trip condition with 100% positive sequence component only on both sides

Injected currents into 140kV CT input	Injected currents into 15.75kV CT input
$IL1 = 0.739A\lfloor 0^0$	$IL1 = 4.379A\lfloor 210^0$
$IL2 = 0.739A\lfloor 240^0$	$IL2 = 4.379A\lfloor 90^0$
$IL3 = 0.739A\lfloor 120^0$	$IL3 = 4.379A\lfloor 330^0$

The differential relay shall trip in all three phases. All three differential currents shall be 200%.

4.2 Injection with Negative Sequence Current Components

In order to inject the stable condition with negative sequence current the following secondary currents shall be injected into the differential relay. The required injection currents are shown in Table 4. Note that the following two steps shall be performed in order to perform this injection:

- phase angles shall just be swapped between the two sides (i.e. angles for 140kV side from Table 2 are now assigned to currents from 15,75kV side and vice versa)
- phase angles values shall be exchanged between phases L2 and L3 on both sides of the transformer in order to create the negative sequence currents.

Table 4: Stable condition with 100% negative sequence component only on both sides

Injected currents into 140kV CT input	Injected currents into 15.75kV CT input
$IL1 = 0.739A\lfloor 30^0$	$IL1 = 4.379A\lfloor 0^0$
$IL2 = 0.739A\lfloor 150^0$	$IL2 = 4.379A\lfloor 120^0$
$IL3 = 0.739A\lfloor 270^0$	$IL3 = 4.379A\lfloor 240^0$

The differential relay shall be stable. The bias current shall be 100% and all three differential currents shall be negligible (i.e. theoretically equal to 0%).

In order to check tripping with the negative sequence current components invert the negative sequence current on winding two side by 180º. The required injection currents are shown in Table 5.

Table 5: Trip condition with 100% negative sequence component only on both sides

Injected currents into 140kV CT input	Injected currents into 15.75kV CT input
$IL1 = 0.739A\lfloor 30^0$	$IL1 = 4.379A\lfloor 180^0$
$IL2 = 0.739A\lfloor 150^0$	$IL2 = 4.379A\lfloor 300^0$
$IL3 = 0.739A\lfloor 270^0$	$IL3 = 4.379A\lfloor 60^0$

The differential relay shall trip in all three phases. All three differential currents shall be 200% in all phases.

4.3 Injection with Zero Sequence Current Component

Zero sequence currents are not transferred across this transformer. Thus, two separate injections shall be performed with zero sequence current only injected on side at the time.

The required injection currents to test behavior of the differential relay from the 140kV side are shown in Table 6.

Table 6: Zero sequence component testing from 140kV side

Injected currents into 140kV CT input	Injected currents into 15.75kV CT input
$IL1 = 0.739A\lfloor 0^0$	$IL1 = 0.0A\lfloor 0^0$
$IL2 = 0.739A\lfloor 0^0$	$IL2 = 0.0A\lfloor 0^0$

$IL3 = 0.739A\angle 0^0$	$IL3 = 0.0A\angle 0^0$

The zero sequence currents must be eliminated on 140kV side. Thus, the differential relay shall be stable. All three differential currents shall be negligible (i.e. theoretically equal to 0%).

The required injection currents to test behavior of the differential relay from the 15,75kV side are shown in Table 7.

Table 7: Zero sequence component testing from 15,75kV side

Injected currents into 140kV CT input	Injected currents into 15.75kV CT input
$IL1 = 0.0A\angle 0^0$	$IL1 = 4.379A\angle 0^0$
$IL2 = 0.0A\angle 0^0$	$IL2 = 4.379A\angle 0^0$
$IL3 = 0.0A\angle 0^0$	$IL3 = 4.379A\angle 0^0$

The zero sequence currents elimination is not critical on 15.75kV side. Depending on the relay design it might happen that differential relay is either stable (e.g. all three differential currents equal to zero), when a zero sequence current is eliminated, or it will trip, when a zero sequence current is not eliminated on 15.75kV side (e.g. all three differential currents equal to 100%).

Once all of these tests are successfully performed the differential relay is properly set and configured in order to protect this particular transformer in this installation.

5 Example with delta connected main CTs

One example of such transformer differential protection testing will be presented. All relevant data to test any applied differential protection can be found on Figure 7.

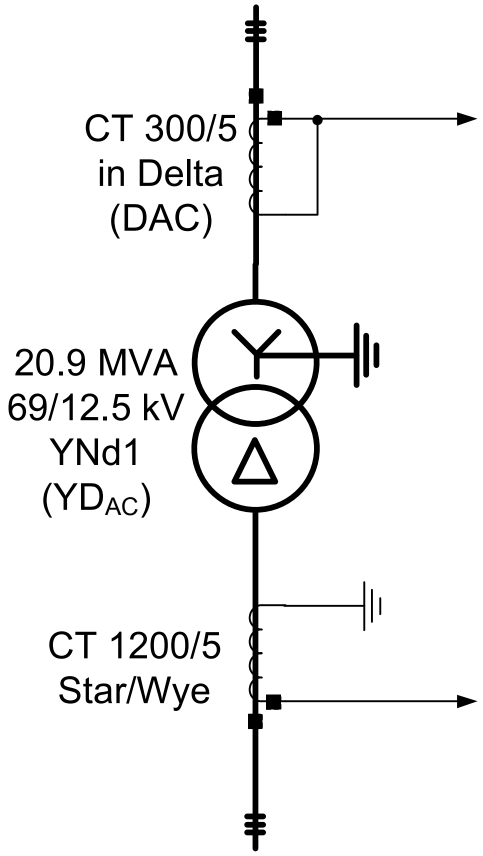


Figure 7: Practical Example with delta connected main CTs

The maximum power (i.e. base power) for this transformer is 20.9MVA, and against this value, the base primary currents and base currents on the CT secondary side are calculated as shown in Table 8. Note the influence of the delta connected main CTs for calculation of the CT secondary side base current on 69kV (i.e. $\sqrt{3}$ factor!).

Table 8: Base current calculations for the YNd1 transformer

	Primary Base Current	Base current on CT secondary side (i.e. 100%)
W1, 69kV-Star	$\frac{20.9MVA}{\sqrt{3}\cdot 69kV} = 174.9A$	$\sqrt{3}\cdot\frac{174.9}{300/5} = 5.045A$
W2, 12.5kV-Delta	$\frac{20.9MVA}{\sqrt{3}\cdot 12.5kV} = 965.3A$	$\frac{965.3}{1200/5} = 4.022A$

5.1 Injection with Positive Sequence Current Components

When the transformer vector group compensation is performed by connected main CTs in delta on the star/way winding sides of the protected transformer, the achieved phase angle shift between the CT secondary current is 180º. Thus, in order to inject the stable condition with positive sequence current the following secondary currents shall be injected into the differential relay. The required injection currents are shown in Table 9.

Table 9: Stable condition with 100% positive sequence component only on both sides

Injected currents into 69kV CT input	Injected currents into 12.5kV CT input
$IL1 = 5.045A\underline{\vert 0^0}$	$IL1 = 4.022A\underline{\vert 180^0}$
$IL2 = 5.045A\underline{\vert 240^0}$	$IL2 = 4.022A\underline{\vert 60^0}$
$IL3 = 5.045A\underline{\vert 120^0}$	$IL3 = 4.022A\underline{\vert 300^0}$

The differential relay shall be stable. The bias current shall be 100% and all three differential currents shall be negligible (i.e. theoretically equal to 0%).

In order to check tripping with the positive sequence current components invert the positive sequence current on winding two side by 180º. The required injection currents are shown in Table 10.

Table 10: Trip condition with 100% positive sequence component only on both sides

Injected currents into 69kV CT input	Injected currents into 12.5kV CT input
$IL1 = 5.045A\underline{\vert 0^0}$	$IL1 = 4.022A\underline{\vert 0^0}$
$IL2 = 5.045A\underline{\vert 240^0}$	$IL2 = 4.022A\underline{\vert 240^0}$
$IL3 = 5.045A\underline{\vert 120^0}$	$IL3 = 4.022A\underline{\vert 120^0}$

The differential relay shall trip in all three phases. All three differential currents shall be 200%.

5.2 Injection with Negative Sequence Current Components

In order to inject the stable condition with negative sequence current the following secondary currents shall be injected into the differential relay. The required injection currents are shown in Table 11. Note that the following two steps shall be performed in order to perform this injection:

- phase angles shall just be swapped between the two sides (i.e. angles for 69kV side from Table 2 are now assigned to currents from 15,75kV side and vice versa)

- phase angles values shall be exchanged between phases L2 and L3 on both sides of the transformer in order to create the negative sequence currents.

Table 11: Stable condition with 100% negative sequence component only on both sides

Injected currents into 69kV CT input	Injected currents into 12.5kV CT input
$IL1 = 5.045A\underline{\|180^0}$	$IL1 = 4.022A\underline{\|0^0}$
$IL2 = 5.045A\underline{\|300^0}$	$IL2 = 4.022A\underline{\|120^0}$
$IL3 = 5.045A\underline{\|60^0}$	$IL3 = 4.022A\underline{\|240^0}$

The differential relay shall be stable. The bias current shall be 100% and all three differential currents shall be negligible (i.e. theoretically equal to 0%).

In order to check tripping with the negative sequence current components invert the negative sequence current for example on winding one side by 180º. The required injection currents are shown in Table 12.

Table 12: Trip condition with 100% negative sequence component only on both sides

Injected currents into 69kV CT input	Injected currents into 12.5kV CT input
$IL1 = 5.045A\underline{\|0^0}$	$IL1 = 4.022A\underline{\|0^0}$
$IL2 = 5.045A\underline{\|120^0}$	$IL2 = 4.022A\underline{\|120^0}$
$IL3 = 5.045A\underline{\|240^0}$	$IL3 = 4.022A\underline{\|240^0}$

The differential relay shall trip in all three phases. All three differential currents shall be 200% in all phases.

5.3 Injection with Zero Sequence Current Component

Zero sequence currents are not transferred across this transformer. The main CT delta connection on the 69kV sides stops the flow of the zero sequence currents on that side. Thus, it is only necessary to inject the zero sequence current on 12.5kV side only. The required injection currents to test behavior of the differential relay from the 12.5kV side are shown in Table 13.

Table 13: Zero sequence component testing from 12.5kV side

Injected currents into 69kV CT input	Injected currents into 12.5kV CT input
$IL1 = 0.0A\underline{\|0^0}$	$IL1 = 4.022A\underline{\|0^0}$

$IL2 = 0.0A\underline{\lvert 0^0}$	$IL2 = 4.022A\underline{\lvert 0^0}$
$IL3 = 0.0A\underline{\lvert 0^0}$	$IL3 = 4.022A\underline{\lvert 0^0}$

The zero sequence currents elimination is not critical on 12.5kV side. Depending on the relay design it might happen that differential relay is either stable (e.g. all three differential currents equal to zero), when a zero sequence current is eliminated, or it will trip, when a zero sequence current is not eliminated on 12.5kV side (e.g. all three differential currents equal to 100%).

Once all of these tests are successfully performed the differential relay is properly set and configured in order to protect this particular transformer in this installation.

6 Summary and conclusions

The proposed method can be effectively used for testing of any numerical, three-phase power transformer differential protection regardless its make.

It is well known fact that fault currents for any type of external or internal faults can be represented by the positive, negative and zero sequence current components. Thus, by performing these tests in a sequence-wise fashion it is verified that the differential protection will be stable for all symmetrical and non-symmetrical external faults and through-load conditions. These tests as well confirm that the differential relay will operate (i.e. trip) for any internal fault.

By using this method it is possible to test the differential protection for an n-winding transformer by testing in between two windings at a time. However, note that the SrMax value shall ALWAYS be used for the base current calculations on all sides of the protected power transformer. It is sufficient to test winding 1 side against all other windings (one at the time) in order to verify proper operation of the relay for all operating conditions.

It shall be noted that exactly the same testing method can be applied on traditional, analogue transformer differential protection schemes utilizing all star connected main CTs and interposing CTs to perform magnitude and phase angle compensation. The only prerequisite is that the currents are injected into the primary windings of the interposing CTs and not directly into the differential relay. By doing so, the complete differential protection scheme consisting of interposing CTs and the analogue differential relay are verified.

The only drawback of this method is that a test set with six current generators is required. However this is typically not a limitation with modern secondary test equipment.

7 References

[1] Electrical Transmission and Distribution Reference Book, 4th edition, Westinghouse Electric Corporation, East Pittsburgh, PA 1950, pp. 44–60.

[2] Z. Gajić, “Differential Protection Solution for Arbitrary Phase Shifting Transformer”, International Conference on Relay Protection and Substation Automation of Modern EHV Power Systems, Moscow – Cheboksary, Russia, September 2007.

[3] ABB Document 1MRK 504 086-UEN, "Technical reference manual, Transformer Protection IED RET 670", Product version: 1.1, ABB Power Technologies AB, Västerås, Sweden, Issued: March 2007.