PREVENTING TRANSFORMER MIS-OPERATIONS DURING EXTERNAL FAULTS

Authors:

Rene Aguilar, Megger, Odessa, Texas 77645

Joe Perez P.E., SynchroGrid, College Station, Texas 77802

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PREVENTING TRANSFORMER MIS-OPERATIONS FOR EXTERNAL FAULTS

Rene Aguilar, Megger, Odessa, Texas rene.aguilar@megger.com
Joe Perez P.E., SynchroGrid, College Station, Texas jperez@synchrogrid.com

Introduction:

Transformer protection relays have evolved from the simple electromechanical (EM) to the more advanced and complex microprocessor type relays. As microprocessor relays became more advanced, so did the test methods required for its verification. However, a lot of the testing personnel are still using the same testing methods as they did with the old relays. These traditional test methods can result in inaccurate test results and incorrect validation of modern microprocessor transformer protective relays resulting in a mis-operation. A significant difference is that most electromechanical transformer differential relays were tested using single phase test methods. This presents a problem when trying to test real time events such as external faults due to the limitation presented by single phase testing. This paper will describe the benefits of using modern test methods for relay verification during external faults.

Transformer Differential Protection Overview:

Current differential protective devices are used in the industry to protect primary assets such as transformers, generators, motors, and busses. The differential function is based on Kirchhoff current rule that states all current going in must equal all the current going out. The protection of power transformers can be challenging to the protection engineers due to the differential current errors found in CTs, changes in loading, and different transformer impedances, etc.

Traditional Differential Schemes

Figure 1 below shows a traditional transformer differential scheme using electromechanical relays.

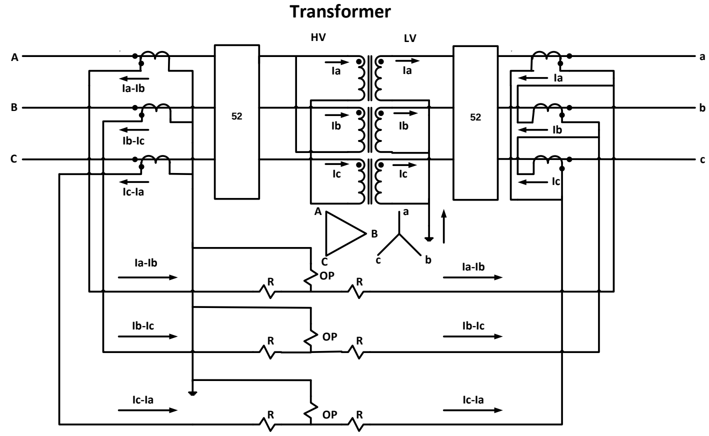


Figure 1: Traditional Electromechanical Relay Wiring

These types of differential relays compare the currents coming in from the high and low side of the transformer and determine if a fault is present within the zone of protection. However, there are several factors that can affect the difference in the currents the relay sees which can result in mis-operations. These factors are CT mismatch errors, phase shift and zero sequence current due to transformer Delta-Wye transformation. In addition, when these factors are present, the differential relays might operate either due to a slight increase in load or during an external fault.

CT mismatch errors are inherent in electromechanical relays. There errors are caused by difference in voltage levels which required different current transformer and results in different operating characteristics [4]. If the mismatch error is too large, it can cause the differential relay to mis-operate. In order to solve this mis-match error during steady state conditions or external faults the electromechanical relays use a slope percent differential characteristic as shown in Figure 2. Notice that if the percent current difference is higher than the operating characteristic, the relay would trip.

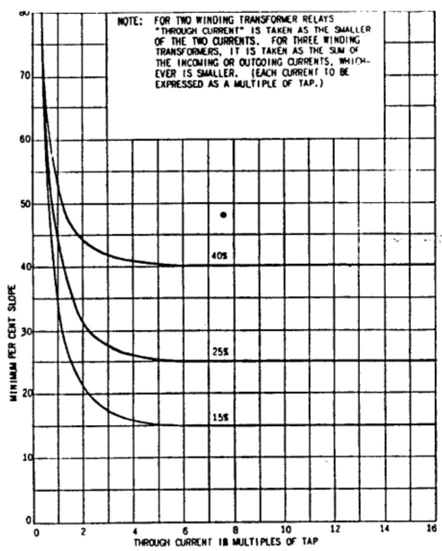


Figure 2: Slope Characteristic of Electromechanical Relays

The phase shifting of the transformer and its respective vector group is another factor that can cause differential errors. The vector group provides the amount of phase shift that will occur when the current goes from the primary to secondary side of the transformer. Figure 3 below shows the phase shift for a Dy1 transformer.

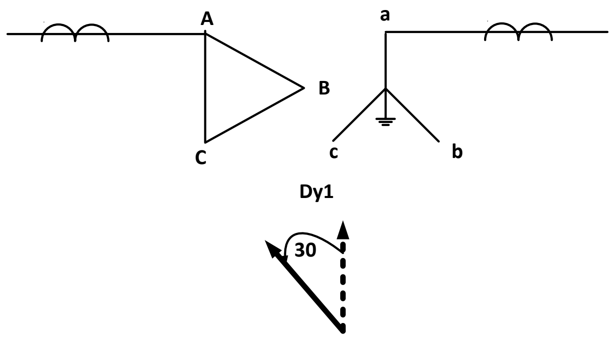


Figure 3: Phase Shift Across Dy1 Transformer

According to the IEEE Std C57.12.00, the primary side of the transformer will always lead the secondary side by 30 degrees [5]. If the CT connections on both sides of the transformers are connected Wye, then the relay will see a difference in phase current and it will operate. In order to compensate for the 30 degree phase shift, the current transformers in the Wye side of the transformers must be connected in delta. This is shown above in figure 1. Notice that the currents flowing into the relay inputs are now equivalent.

Another benefit of connecting the current transformers in delta is to block the zero sequence current. During external faults, a zero sequence current flows through the neutral of the transformer which then returns through the phase currents. The delta connected CTs act as a zero sequence trap and the relay will not see the additional zero sequence current.

These can mathematically be explained using symmetrical components. This is shown below:

$$\begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & \propto^2 & \propto \\ 1 & \propto & \propto^2 \end{bmatrix} \begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} I_a = I_0 + \ I_1 + I_2$$

$$I_b = I_0 + \propto^2 \ I_1 + \propto I_2$$

The sequence currents the relay will see on the primary and secondary current inputs are shown in equations below.

$$IWPA = I_a - I_b = (I_0 - I_0) + I_1(1 - \propto) + I_2(1 - \propto^2)$$

$$IWSA = I_a = I_0 + \ I_1 + I_2$$

Notice from the equations above how the zero sequence current is eliminated by delta connection

In summary, Most of the factors explained above that can cause mis-operations were corrected by physical means. However, this is not the case when using modern differential protective relays.

Modern Differential Schemes

With new microprocessor relays, the CT mismatch errors, zero sequence current, phase shift are handled by using complex algorithms within the device. Figure 4 below shows a differential scheme using modern microprocessor relays. Notice that the CTs are wye connected on both sides of the transformers.

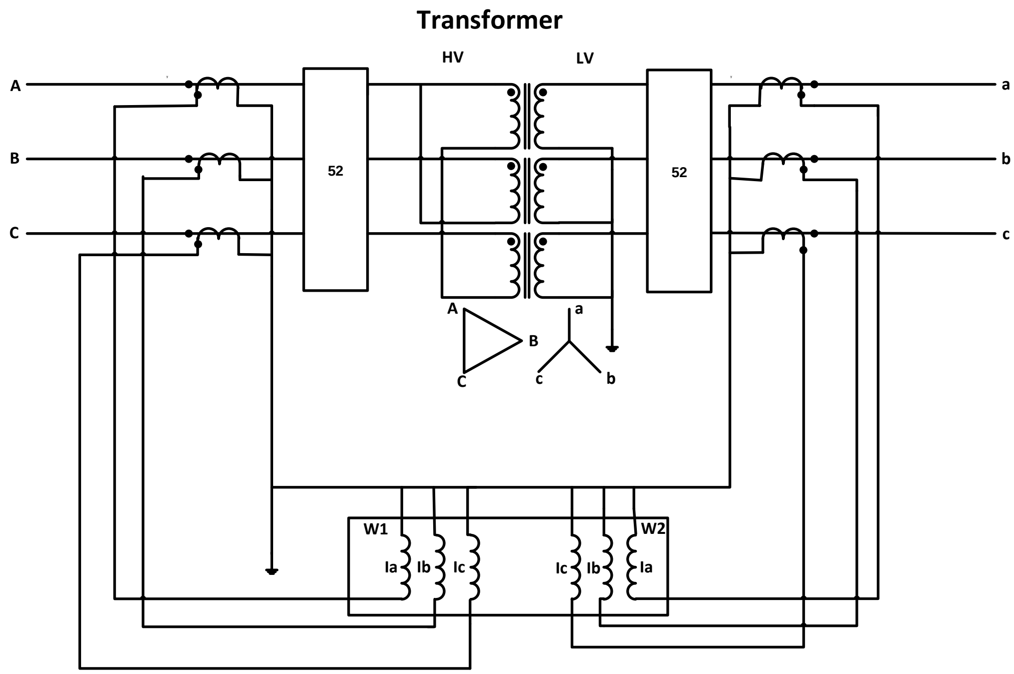


Figure 4: Wiring diagram for Differential Scheme Using Microprocessor Relay

Microprocessor relays completely eliminate the CT mismatch error due to the infinite selection of taps. This was not the case with the electromechanical since it had a finite selection of taps.

In addition, the microprocessor relays automatically correct for the phase shift angle due to the delta-wye voltage transformation across the transformer. These relays compensate the currents by using mathematical matrices that represent either a delta or wye connected CTs with its corresponding phase shift [1]. The following matrices are used to correct the phase shift across the Dy1 transformer. Since, the primary side of the transformer is delta connected no compensation is required and will use the identity matrix shown below:

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

The secondary side of the transformer is wye connected. As a result the currents will need to be compensated. This is done by using the current matrix below:

$$CTC(1) = \frac{1}{\sqrt{3}} \times \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix}$$

Using these two matrices the relay will compute the following compensated currents:

$$\begin{bmatrix} W1A_{COMP} \\ W1B_{COMP} \\ W1C_{COMP} \end{bmatrix} = \begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 1 & 0 \end{bmatrix} \times \begin{bmatrix} Ia \\ Ib \\ Ic \end{bmatrix}$$

$$\begin{bmatrix} W2A_{COMP} \\ W2B_{COMP} \\ W2C_{COMP} \end{bmatrix} = \frac{1}{\sqrt{3}} \times \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} \times \begin{bmatrix} Ia \\ Ib \\ Ic \end{bmatrix}$$

After the currents above have gone through matrix calculation, the currents will represent delta currents, and the zero sequence current will be eliminated. The relay will use these compensated currents to compute the restraint and operate quantities by using the percent differential slope characteristics as shown in figure 5.

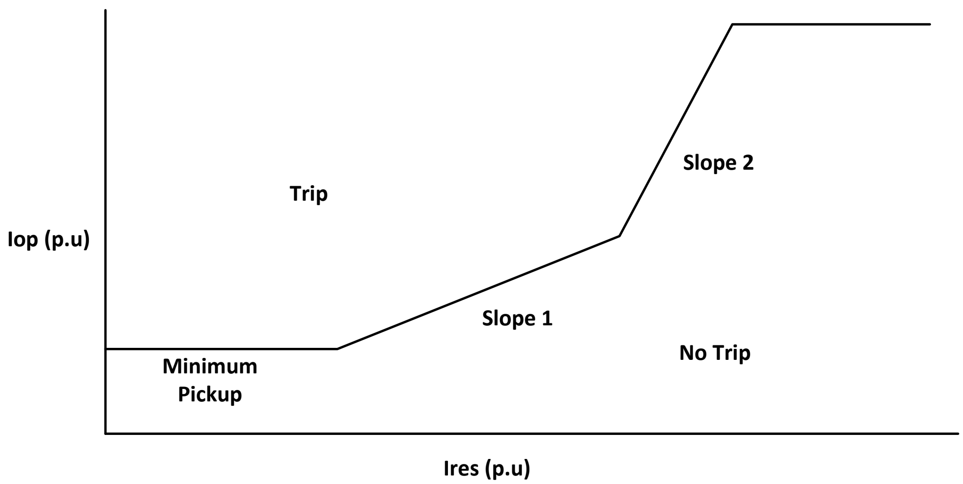


Figure 5: Operating Characteristic of a Modern Differential Relay

The restraint and operate quantities are computed by the relay as follows:

$$I_{OPERATE(PU)} = \frac{I_{Winding1}\angle\Theta_{Winding1}}{Tap_{HV}} + \frac{I_{Winding2}\angle\Theta_{Winding2}}{Tap_{LV}}$$

$$I_{RESTRAINT(PU)} = k \times \left(\frac{\left|I_{Winding1}\angle\Theta_{Winding1}\right|}{Tap_{HV}} + \frac{\left|I_{Winding2}\angle\Theta_{Winding2}\right|}{Tap_{LV}} \right)$$

The value of k represents the biased current factor. This varies based on manufacturers but the most common values for k are:

$$k = 1, .5, min, max$$

The relay compares the ratio of operate and restraint current and if the ratio falls above the characteristic, the relay will trip.

These new improvements to differential protective relays present a challenge when trying to verify its operation. When testing electromechanical relays, the connections of the CTs did not play a role on the verification of the relay. This is not the case with microprocessor relays which require new and improved test methods to verify the operation of the protective relay.

Common Test Methods:

Today, single phase test methods are still used for verification of numerical transformer protection devices. These methods are a carryover from testing the old electromechanical relays that were primarily single phase relays. A single phase test would only require two single phase current sources in order to verify the relays operating characteristics. Using these tests, the tester could verify the devices minimum pickup, slope characteristic, and some form of harmonic restraint. These single phase tests primarily verified the operation of the protective device in case of internal faults, but it did not address external faults.

The slope test verified the operating characteristic of the differential relay. This test required two current sources to be injected into the differential relay phase inputs.

As mentioned above, the CT mismatch errors, zero sequence current, transformer phase shift were not considered when testing electromechanical relays. However, this is not true when using single phase test methods to test modern differential relays.

Recall that most modern differential relays internally compensate the currents it sees based on the transformer vector group. If these compensation factors are not applied correctly, the relay can produce erroneous results. For example, in order to test the slope characteristic of the microprocessor relay using the single phase method, one would have to inject one current on the primary side relay input and the other current on the secondary side relay input. By using this test method, the relay will calculate the following currents:

$$\begin{bmatrix} W1A_{COMP} \\ W1B_{COMP} \\ W1C_{COMP} \end{bmatrix} = \begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 1 & 0 \end{bmatrix} \times \begin{bmatrix} Ia \\ Ib \\ Ic \end{bmatrix} = \begin{bmatrix} I \\ 0 \\ 0 \end{bmatrix}$$

$$\begin{bmatrix} W2A_{COMP} \\ W2B_{COMP} \\ W2C_{COMP} \end{bmatrix} = \frac{1}{\sqrt{3}} \times \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} \times \begin{bmatrix} Ia \\ Ib \\ Ic \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} I \\ 0 \\ -I \end{bmatrix}$$

Notice that the C phase of the relay is seeing a differential current due to vector compensation. In order to test the differential element with the single phase test method would require the isolation of the indivual phase differential elements. If the isolation is not possible this could lead to incorrect results and cause the relay to fail the tests.

Single phase test methods will not help prove the microprocessor relay's correct operation for external faults. The inadequacy of single phase test methods to verify the correct operation of modern differential relays requires the use of modern test methods. This is especially important when verifying the correct operation of the relay for external faults.

Improved Modern Test Methods:

New improvements in differential protective devices require new test methods in order to verify their correct operation. Using the traditional single phase test methods does not verify the entire differential scheme. In contrast, using improve test methods can provide the tester valuable information regarding the status of the differential scheme. By using new test methods for microprocessor relays, one can simulate true system conditions during external and internal faults that can lead to detecting settings or wiring issues. The improved test methods are primarily multi-phase which requires the use of multiple current sources. For example, a two winding differential scheme would require the use of six current sources. The test quantities are either calculated or simulated using steady state or real time simulator models.

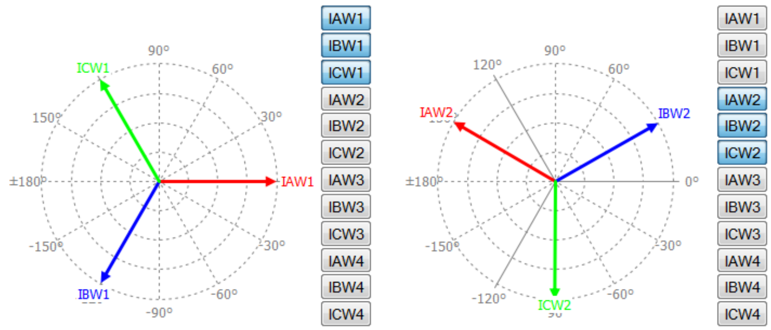
Steady State Methods

Steady state or metering tests are used to verify the correct phasing, polarity, compensation factors, etc of the relay. The test current values for metering tests are calculated based on the configuration of the transformer, and CT ratios. The test quantities are applied as to simulate a steady state condition on the transformer. Table 1 below shows test values in order to simulate a steady state condition.

Phase	Injected Currents			
	W1		**W2**	
	RMS(A)	Degrees	RMS(A)	Degrees
A-N	6.24	0	4.32	210
B-N	6.24	120	4.32	330
C-N	6.24	240	4.32	90

Table 1: State Sequencer Through Fault

Using these values and the metering capabilities of the relay, the current magnitudes, phase angles, and the restraint and operate quantities can be easily be verified. In traditional schemes this verification was done when the transformer was lightly loaded and sufficient current was available in order to determine that the wiring was correct. With microprocessor relays, this test can be executed even if no load is on the transformer. Figure 6 below shows the metered values for a steady state simulation.



	Operate Currents			Restraint Currents		
	IOP1	IOP2	IOP3	IRT1	IRT2	IRT3
I (Mult. of Tap)	0.01	0.00	0.02	1.00	1.00	1.01
	Second Harmonic Currents			Fifth Harmonic Currents		
	I1F2	I2F2	I3F2	I1F5	I2F5	I3F5
I (Mult. of Tap)	0.00	0.00	0.00	0.00	0.00	0.00

Figure 6: Metering Test Values

Notice from the metered equations above, that the compensation is being done correctly. The test is applying one per unit into each winding which results in zero operate current and full restraint current. This test has shown the relay settings are correct and that the relay is correctly compensating.

Through Faults Tests

The relay also needs to be tested for its correct operation due to external faults. The type of fault which is of most concern is the phase to ground fault but other types of faults should also be considered. The following sections will demonstrate how to compute external fault test values for phase to ground, phase to phase and three phase faults. Figure 7 shows the system one line that will be used to calculate the test values.

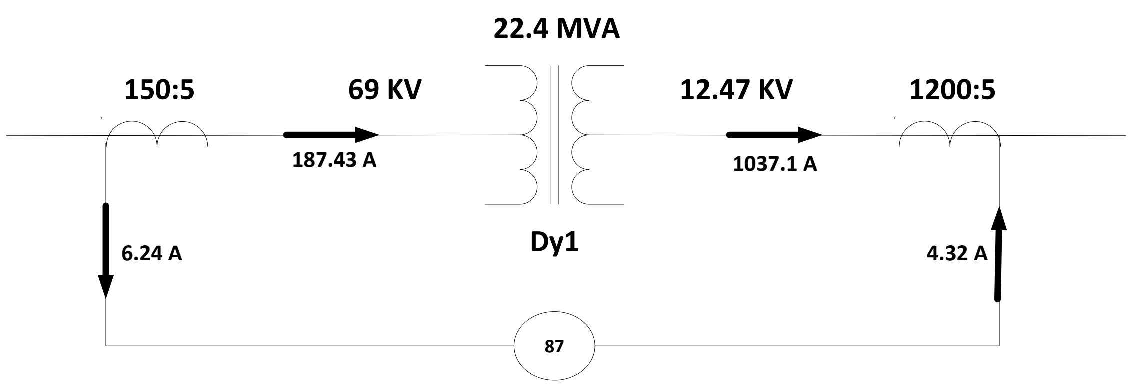


Figure 7: Transformer Configuration

Calculating Test Values for Three Phase through Faults:
The three phase fault values for a through fault for a Dy1 transformer is shown below:

$$Transformer$$

$$MVA = 22.4 \quad KV_{High} = 69 \quad KV_{Low} = 12.47$$

$$Curent\ Transformers$$

$$CTR_{High} = 30{:}1 \quad CTR_{Low} = 240{:}1$$

The nominal rated currents are:

$$Irated_{HV} = \frac{MVA}{\sqrt{3} \times KV_{P-P(HV)}} = \frac{22.4 \times 10^3}{\sqrt{3} \times 69} = 187.65\ Amps$$

$$Irated_{LV} = \frac{MVA}{\sqrt{3} \times KV_{P-P(LV)}} = \frac{22.4 \times 10^3}{\sqrt{3} \times 12.47} = 1038.3\ Amps$$

The computed tap values are:

$$Tap_{HV} = \frac{Irated_{HV}}{CTR_{HV}} = \frac{187.65}{30} = 6.25$$

$$Tap_{LV} = \frac{Irated_{LV}}{CTR_{LV}} = \frac{1038.3}{240} = 4.32$$

The currents phase angles have to be determined from the vector group of the transformer. Our transformer falls under vector group one resulting in a 30 degree lag phase shift. We will use the delta side as the reference for the compensation factors. As a result, these winding currents will not require compensation. These currents will only use the identity matrix.

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

The winding two currents have to be corrected for the phase shift and magnitude. The winding two currents will be compensated using the following matrix:

$$CTC(1) = \frac{1}{\sqrt{3}} \times \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix}$$

The test currents would have to be injected as to emulate the transformer vector group. This would require the winding two currents to be adjusted by the 30 degrees. It is important when applying the test currents to understand what the phase convention of the test set is. Some test sets will apply the currents using a lagging system while others use a leading system. Table 2 below shows the test values that represent a 200% external three phase fault through the transformer.

Phase	Injected Currents			
	W1		W2	
	RMS(A)	Degrees	RMS(A)	Degrees
A-N	12.495 375.85	0 0	8.643 2074.2	210 210
B-N	12.495 375.85	120 120	8.643 2074.2	330 330
C-N	12.495 375.85	240 240	8.643 2074.2	90 90

Table 2: Three Phase External Fault at 200% (Lagging System)

If we insert these test currents into restraint and operate equations, it will yield the following quantities:

$$\begin{bmatrix} W1A_{COMP} \\ W1B_{COMP} \\ W1C_{COMP} \end{bmatrix} = \begin{bmatrix} 12.495\angle 0° \\ 12.495\angle 120° \\ 12.495\angle 240° \end{bmatrix}$$

$$\begin{bmatrix} W2A_{COMP} \\ W2B_{COMP} \\ W2C_{COMP} \end{bmatrix} = \begin{bmatrix} \frac{1}{\sqrt{3}}(8.64\angle 210° - 8.64\angle 330°) \\ \frac{1}{\sqrt{3}}(8.64\angle 330° - 8.64\angle 90°) \\ \frac{1}{\sqrt{3}}(8.64\angle 90° - 8.64\angle 210°) \end{bmatrix} = \begin{bmatrix} \frac{1}{\sqrt{3}}(8.64 \times \sqrt{3}\angle 180° \\ \frac{1}{\sqrt{3}}(8.64 \times \sqrt{3}\angle 300° \\ \frac{1}{\sqrt{3}}(8.64 \times \sqrt{3}\angle 60° \end{bmatrix}$$

$$I_{OPERATE(PU)} = \frac{12.495\angle 0°}{6.24} + \frac{8.64\angle 180°}{4.32} = 2\angle 0° + 2\angle 180° = 0$$

$$I_{RESTRAINT(PU)} = \frac{\frac{|12.495\angle 0°|}{6.24} + \frac{|8.64\angle 180°|}{4.32}}{2} = \frac{2+2}{2} = 2\ p.u$$

The relay should restrain and not operate for this simulation as the operate current is zero. The restraint quantity is correct and it is at 200% which corresponds to the value that was simulated.

Calculating Test Values for Phase to Phase External Faults

Although phase to phase faults do not contain much zero sequence current, it is important to check that the relay does not operate during through faults. In order to compute the test quantities for this type fault, it is important to understand the behavior of the currents on both sides of the transformer. Figure 8 below shows the currents flowing through the transformer during an external phase to phase fault.

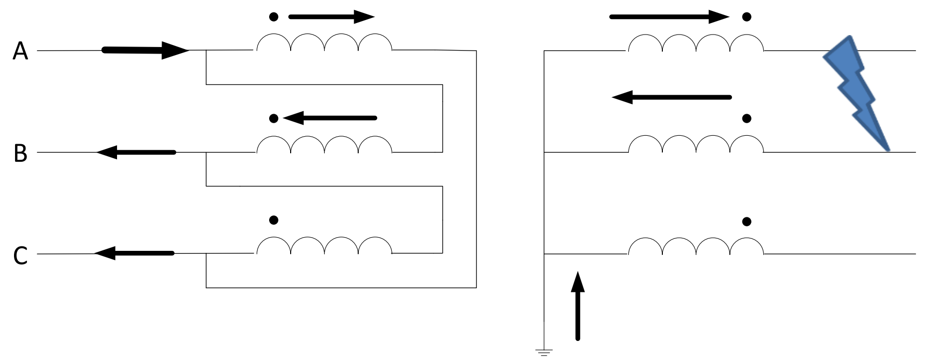


Figure 8: A Phase to B Phase External Fault

During an external phase to phase fault, the transformer sees three currents on the delta side as shown above [2]. In order to simulate this condition, five current sources are required. The currents simulated can be approximated by the following:

$$I_{Secondary} = I_F$$

$$I_{Delta} = \frac{I_F}{\sqrt{3}}$$

$$I_{Primary} = I_{Delta} \times 2$$

Using the equations above the following test values simulate an A phase to B phase external fault of 200%.

$$\begin{bmatrix} IAW1 \\ IBW1 \\ ICW1 \end{bmatrix} = \begin{matrix} 14.43\angle 0° \\ 7.205\angle 180° \\ 7.205\angle 180° \end{matrix} \qquad \begin{bmatrix} IAW2 \\ IBW2 \\ ICW2 \end{bmatrix} = \begin{matrix} 8.64\angle 180° \\ 8.64\angle 0° \\ 0\angle 180° \end{matrix}$$

Using equations 1 and 2 the operate and restraint quantities are

$$\begin{bmatrix} IAW2_{COMP} \\ IBW2_{COMP} \\ ICW2_{COMP} \end{bmatrix} = \begin{bmatrix} \frac{1}{\sqrt{3}}(8.64\angle 180° - 8.64\angle 0°) \\ \frac{1}{\sqrt{3}}(8.64\angle 0° - 0\angle 90°) \\ \frac{1}{\sqrt{3}}(0\angle 90° - 8.64\angle 180°) \end{bmatrix} = \begin{bmatrix} \frac{1}{\sqrt{3}}(17.28\angle 180°) \\ \frac{1}{\sqrt{3}}8.64 \\ \frac{1}{\sqrt{3}}(8.64) \end{bmatrix} = \begin{bmatrix} 9.98\angle 180° \\ 4.99 \\ 4.99 \end{bmatrix}$$

$$I_{OPERATE(PU)\_1} = \frac{14.43\angle 0°}{6.24} + \frac{9.98\angle 180°}{4.32} = 2.31\angle 0° + 2.31\angle 180° = 0$$

$$I_{RESTRAINT(PU)\_1} = \frac{\frac{|12.495\angle 0°|}{6.24} + \frac{|9.98\angle 180°|}{4.32}}{2} = \frac{2.31 + 2.31}{2} = 2.31\ p.u$$

For this fault the relay does not operate as shown in figure 8b below. This same process can be repeated for the restraint and operate quantities of the other phases and similar results would be obtained as shown below.

	Operate Currents			Restraint Currents		
	IOP1	IOP2	IOP3	IRT1	IRT2	IRT3
I (Mult. of Tap)	0.31	0.85	1.17	2.16	1.58	0.58
	Second Harmonic Currents			Fifth Harmonic Currents		
	I1F2	I2F2	I3F2	I1F5	I2F5	I3F5
I (Mult. of Tap)	0.01	0.01	0.01	0.00	0.00	0.00

Figure 8a: Simulated External A to B fault of 200% (No Compensation=Trip)

	Operate Currents			Restraint Currents		
	IOP1	IOP2	IOP3	IRT1	IRT2	IRT3
I (Mult. of Tap)	0.01	0.00	0.01	2.31	1.15	1.16
	Second Harmonic Currents			Fifth Harmonic Currents		
	I1F2	I2F2	I3F2	I1F5	I2F5	I3F5
I (Mult. of Tap)	0.01	0.00	0.00	0.00	0.00	0.00

Figure 8b: Simulated External A Phase to B Phase fault of 200% (Compensated=No Trip)

Calculating Test Values for Phase to Ground External Faults

External phase to ground faults are of concern due to the zero sequence current that flow through the grounded wye of the transformer. The high side of the transformer does not see this current as it circulates in the delta winding. This causes an unbalance to the currents the relay is seeing and if not corrected will cause a misoperation. The relay needs to be able to correctly remove this additional zero sequence current.

During an external phase to ground fault, the transformer sees the following current distributions:

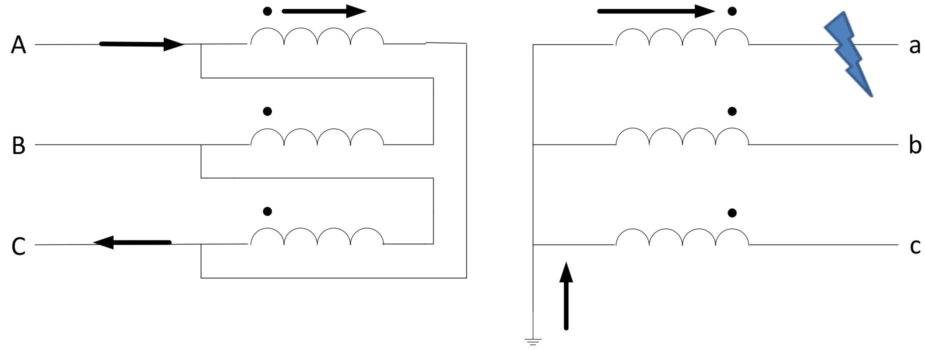


Figure 9: A-G External Fault for a DABY Transformer

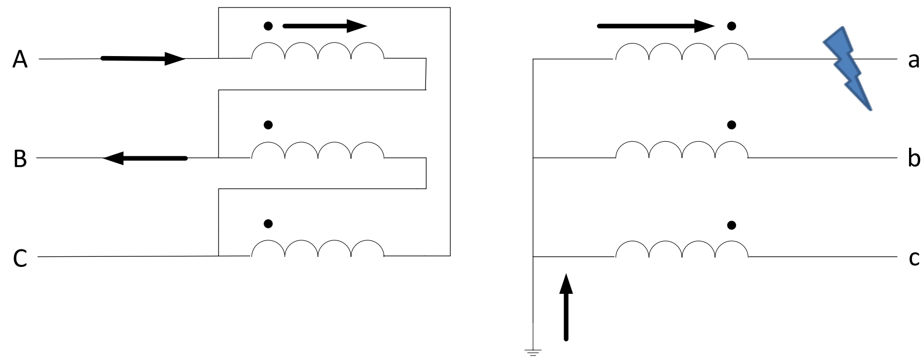


Figure 10: A-G External Fault for a DABY Transformer

Notice that a phase to ground fault on the wye side appears as a phase to phase fault on the delta side of the transformer. This valuable information can be used to analyze misoperation of differential protective relays.

The current contributions can be calculated using the following equations:

$$I_{Secondary} = I_F$$

$$I_{Delta} = \frac{I_F}{\sqrt{3}}$$

$$I_{Primary} = I_{Delta}$$

With no zero sequence correction and the CTs Wye connected the following currents would flow into the relay [3].

$$\begin{bmatrix} IAW1 \\ IBW1 \\ ICW1 \end{bmatrix} = \begin{bmatrix} \frac{I_F}{\sqrt{3}} \\ 0 \\ \frac{I_F}{\sqrt{3}}\angle 180° \end{bmatrix} \qquad \begin{bmatrix} IAW2 \\ IBW2 \\ ICW2 \end{bmatrix} = \begin{bmatrix} I_F\angle 180° \\ 0\angle 180° \\ 0\angle 180° \end{bmatrix}$$

$$I_{OPERATE(PU)} = \frac{I_F\angle 0°}{\sqrt{3} \times Tap_{Hv}} + \frac{I_F\angle 180°}{Tap_{Lv}} = \frac{1}{\sqrt{3}}\angle 0° + 1\angle 180° = .42\ pu$$

$$I_{RESTRAINT(PU)} = \frac{\frac{|I_F\angle 0°|}{\sqrt{3} \times Tap_{Hv}} + \frac{|I_F\angle 180°|}{Tap_{Lv}}}{2} = \frac{\frac{1}{\sqrt{3}} + 1}{2} = .7886\ p.u$$

This would result in a mis-operation of the relay.

Now, let's take the zero sequence compensation into account. This would result in the relay restraining and not tripping due to the external ground fault. Since the high voltage side is delta connected, it does not require any form of compensation. The winding two currents are compensated as follows:

$$\begin{bmatrix} W2A_{COMP} \\ W2B_{COMP} \\ W2C_{COMP} \end{bmatrix} = \begin{bmatrix} \frac{1}{\sqrt{3}}(I_F\angle 180° - 0°) \\ \frac{1}{\sqrt{3}}(0 - 0) \\ \frac{1}{\sqrt{3}}(0 - I_F\angle 180°) \end{bmatrix} = \begin{bmatrix} \frac{1}{\sqrt{3}}(I_F\angle 180° \\ 0 \\ \frac{1}{\sqrt{3}}(I_F\angle 0°) \end{bmatrix}$$

$$I_{OPERATE(PU)} = \frac{I_F\angle 0°}{\sqrt{3} \times Tap_{Hv}} + \frac{I_F\angle 180°}{\sqrt{3} \times Tap_{Lv}} = \frac{1}{\sqrt{3}}\angle 0° + \frac{1}{\sqrt{3}}\angle 180° = 0\ pu$$

$$I_{RESTRAINT(PU)} = \frac{\frac{|I_F\angle 0°|}{\sqrt{3} \times Tap_{Hv}} + \frac{|I_F\angle 180°|}{\sqrt{3} \times Tap_{Lv}}}{2} = \frac{\frac{1}{\sqrt{3}} + \frac{1}{\sqrt{3}}}{2} = .5773\ p.u$$

Based on the calculations above, the relay will restraint correctly and will not operate due to the external ground fault. The relay will still operate for internal ground faults even if the zero sequence current is not accounted for as it will operate on the positive and negative sequence currents.

The following test values are computed using the equations above which simulate an A phase to ground external fault of 200%.

$$\begin{bmatrix} IAW1 \\ IBW1 \\ ICW1 \end{bmatrix} = \begin{matrix} 7.205\angle 0° \\ 0\angle 180° \\ 7.205\angle 180° \end{matrix} \qquad \begin{bmatrix} IAW2 \\ IBW2 \\ ICW2 \end{bmatrix} = \begin{matrix} 8.64\angle 180° \\ 0\angle 180° \\ 0\angle 180° \end{matrix}$$

The metered values from the relay prove its correct operation for an external phase to ground fault.

	Operate Currents			Restraint Currents		
	IOP1	IOP2	IOP3	IRT1	IRT2	IRT3
I (Mult. of Tap)	0.85	0.00	1.16	1.58	0.00	0.58
	Second Harmonic Currents			Fifth Harmonic Currents		
	I1F2	I2F2	I3F2	I1F5	I2F5	I3F5
I (Mult. of Tap)	0.01	0.00	0.01	0.00	0.00	0.00

Figure 11a: Simulated external A to G fault of 200% (No Compensation=Trip)

	Operate Currents			Restraint Currents		
	IOP1	IOP2	IOP3	IRT1	IRT2	IRT3
I (Mult. of Tap)	0.00	0.00	0.01	1.16	0.00	1.16
	Second Harmonic Currents			Fifth Harmonic Currents		
	I1F2	I2F2	I3F2	I1F5	I2F5	I3F5
I (Mult. of Tap)	0.00	0.00	0.00	0.00	0.00	0.00

Figure 11b: Simulated External A -G Fault of 200% (Compensation=No Trip)

Cases Studies

Use of Test Methods to Verify Wiring and Relay Stability

For this case study, the transformer is connected delta on the 138 kV side and is connected to winding one of the relay. The low voltage side is connected grounded-wye with a voltage of 13.8 kV and a tertiary that has a voltage of 4.16 kV and is also connected grounded-wye. The transformer configuration is DYn11Yn11 and is rated for 15 MVA.

As load was increased the engineers noticed an unlikely increase in operate current during normal load conditions which raised a concern but was not addressed. This concern was addressed during an external fault which resulted in the differential operation. An investigation was launched as to determine what had caused the relay to trip. With the transformer only carrying about 50% of its capacity a waveform capture was triggered. Figure 12 and 13 below show the captured waveforms and the corresponding phasor diagrams..

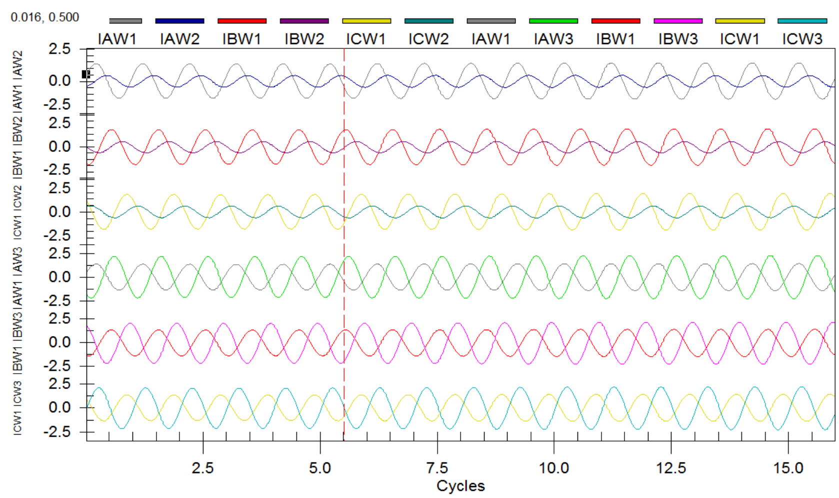


Figure 12: Captured Waveforms from Relay

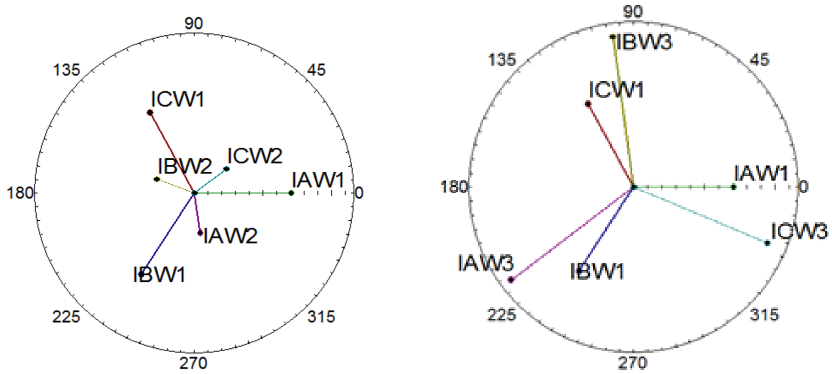


Figure 13: Phasor Diagram of Currents with Respect to W1

The phasor diagram above shows the system currents seen by the relay before compensation is applied. The relationship between the high side and low side currents should be approximately 180 degrees plus the 30 degree phase shift. Notice that the W1 and W3 currents above appear to have this relationship. However, the W2 currents do not have this phase relationship. Taking these currents and applying the vector compensation will yield the currents shown below in figure 14.

The compensated currents should have a phase relationship of approximately 180 degrees. The currents shown below in figure 14a do not have this phase relationship and results in the higher operate currents. However, the currents shown in figure 14b have the correct phase relationship.

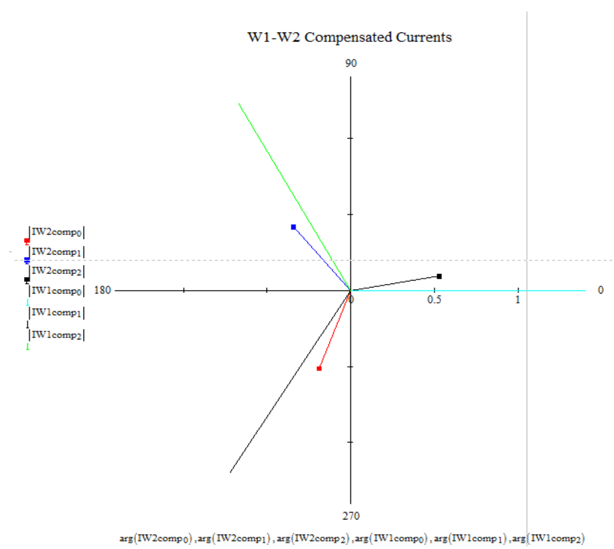


Figure 14a: Phasor Diagram of Compensated Currents for W1 and W2

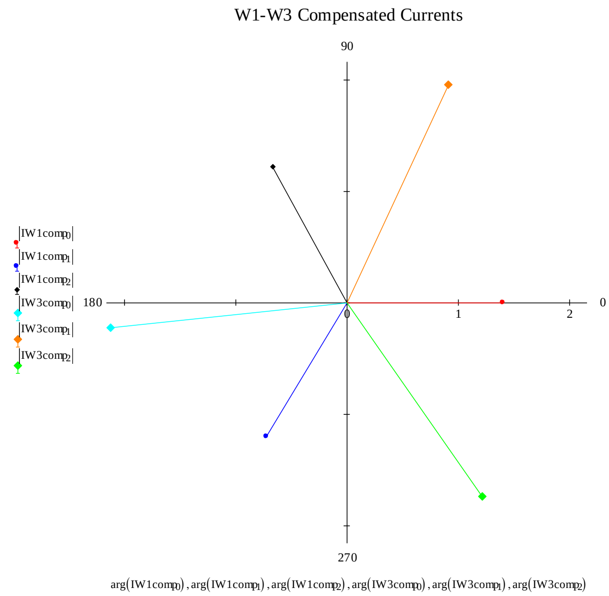


Figure 14b: Phasor Diagram of Compensated Currents for W1 and W3

Figure 15 below shows the restraint and operate quantities plotted on the differential slope characteristic. Although the differential current is located in the non-operating zone, the operate quantity is high.

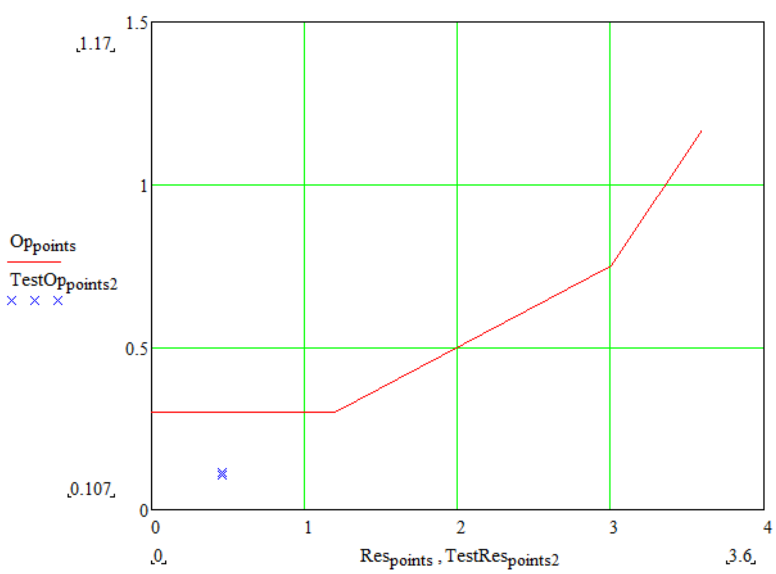


Figure 15: Plot of Differential Quantities on Slope Characteristic

Looking at the phasor diagrams above and observing the phase relationships points to a possible wiring problem with the W2 currents. It appears that the phases have been rolled and the polarity inverted. This information was passed to the field personnel for further investigation. Upon inspecting the current connections revealed a wiring issue on W2 currents. The inputs to the relay on winding two should have been ABC but it was connected BCA and with the polarity inverted. Once the wiring was corrected, another waveform capture was triggered. The following figures show the phasor diagram and differential characteristic after the fix.

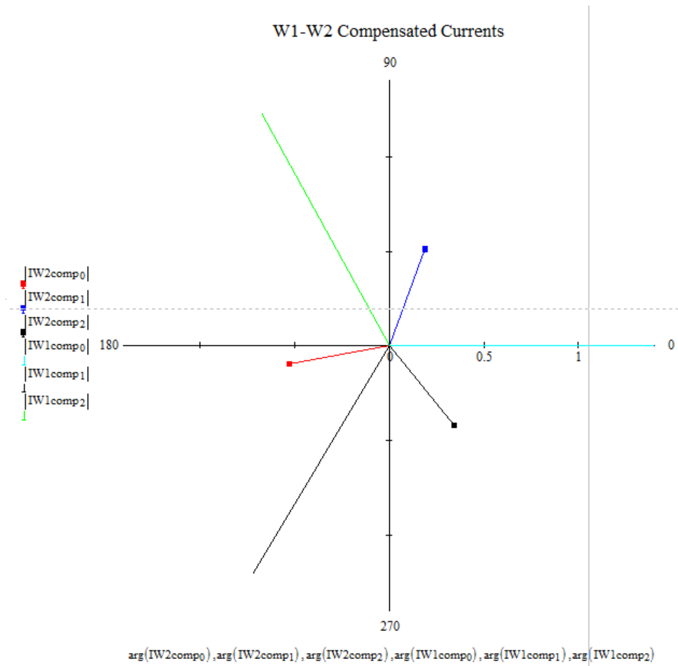


Figure 16: Phasor Diagram After Wiring Issue Corrected

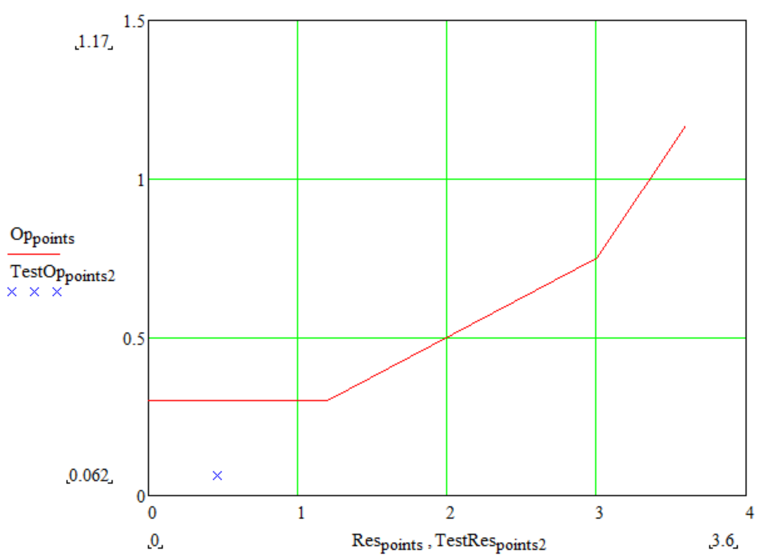


Figure 17: Plot of Differential Quantities on Slope Characteristic (wiring corrected)

The traditional tests performed on the relay could not have detected this problem. These tests completely isolate the relay from all the wiring. This would require either a primary or secondary injection test in order to verify the phasing is correct. A secondary test was selected to verify the correction and that the phasing on the relay was correct.

This transformer is connected in a DACY and the following test quantities will simulate an external three phase and single phase fault of 200% on the low voltage side of the transformer as well as the tertiary.

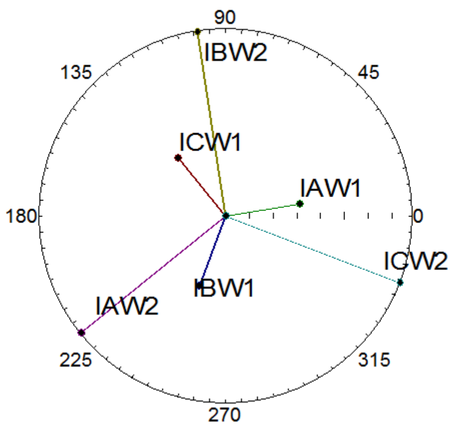
Three Phase Test Values

$$\begin{bmatrix} IAW1 \\ IBW1 \\ ICW1 \end{bmatrix} = \begin{matrix} 6.28\angle 0° \\ 6.28\angle 120° \\ 6.28\angle 240° \end{matrix} \qquad \begin{bmatrix} IAW2 \\ IBW2 \\ ICW2 \end{bmatrix} = \begin{matrix} 15.68\angle 150° \\ 15.68\angle 270° \\ 15.68\angle 30° \end{matrix}$$

Phase to Ground Test Values

$$\begin{bmatrix} IAW1 \\ IBW1 \\ ICW1 \end{bmatrix} = \begin{matrix} 3.62\angle 0° \\ 3.62\angle 180° \\ 0\angle 180° \end{matrix} \qquad \begin{bmatrix} IAW2 \\ IBW2 \\ ICW2 \end{bmatrix} = \begin{matrix} 15.68\angle 180° \\ 0\angle 180° \\ 0\angle 180° \end{matrix}$$

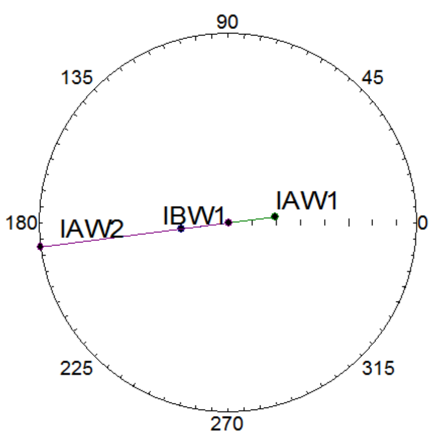
During the fault, the fault currents were monitored and the following information was received from the relay. The differential quantities display an operate current of zero and full restraint.



	Operate Currents			Restraint Currents		
	IOP1	IOP2	IOP3	IRT1	IRT2	IRT3
I (Mult. of Tap)	0.01	0.02	0.02	2.00	2.00	2.00

	Second Harmonic Currents			Fifth Harmonic Currents		
	I1F2	I2F2	I3F2	I1F5	I2F5	I3F5
I (Mult. of Tap)	0.01	0.01	0.00	0.00	0.00	0.00

Figure 18: Relay Differential Quantities for Simulated 3 Phase Fault on W1-W2



	Operate Currents			Restraint Currents		
	IOP1	IOP2	IOP3	IRT1	IRT2	IRT3
I (Mult. of Tap)	0.00	0.00	0.00	1.16	1.16	0.00

	Second Harmonic Currents			Fifth Harmonic Currents		
	I1F2	I2F2	I3F2	I1F5	I2F5	I3F5
I (Mult. of Tap)	0.00	0.00	0.00	0.00	0.00	0.00

Figure 19: Relay Differential Quantities for Simulated A-G fault on W1-W2

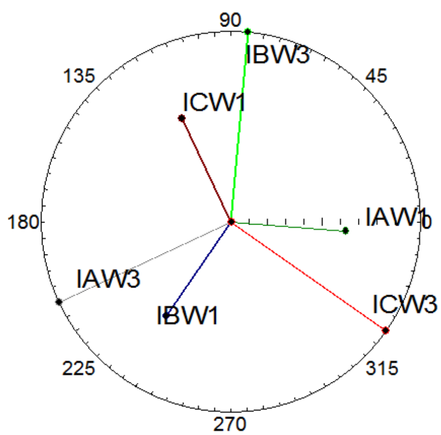
A similar fault was simulated on the tertiary. The following test values were used:

Three Phase Test Values

$$\begin{bmatrix} IAW1 \\ IBW1 \\ ICW1 \end{bmatrix} = \begin{matrix} 6.28\angle 0° \\ 6.28\angle 120° \\ 6.28\angle 240° \end{matrix} \qquad \begin{bmatrix} IAW3 \\ IBW3 \\ ICW3 \end{bmatrix} = \begin{matrix} 10.4\angle 150° \\ 10.4\angle 270° \\ 10.4\angle 30° \end{matrix}$$

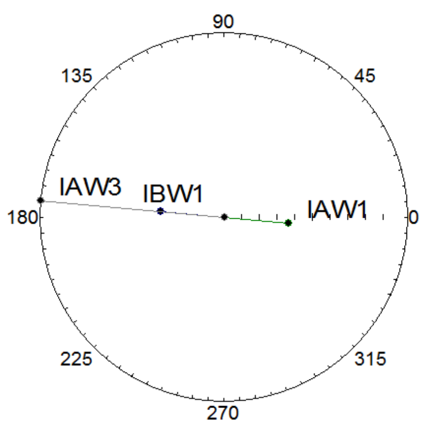
Phase to Ground Test Values

$$\begin{bmatrix} IAW1 \\ IBW1 \\ ICW1 \end{bmatrix} = \begin{matrix} 3.63\angle 0° \\ 3.63\angle 180° \\ 0\angle 180° \end{matrix} \qquad \begin{bmatrix} IAW3 \\ IBW3 \\ ICW3 \end{bmatrix} = \begin{matrix} 10.4\angle 180° \\ 0\angle 180° \\ 0\angle 180° \end{matrix}$$



	Operate Currents			Restraint Currents		
	IOP1	IOP2	IOP3	IRT1	IRT2	IRT3
I (Mult. of Tap)	0.02	0.01	0.02	2.01	2.00	2.01
	Second Harmonic Currents			**Fifth Harmonic Currents**		
	I1F2	I2F2	I3F2	I1F5	I2F5	I3F5
I (Mult. of Tap)	0.01	0.01	0.01	0.01	0.00	0.01

Figure 20: Relay Differential Quantities for Simulated 3 Phase Fault on W1-W3



	Operate Currents			Restraint Currents		
	IOP1	IOP2	IOP3	IRT1	IRT2	IRT3
I (Mult. of Tap)	0.00	0.00	0.00	1.16	1.16	0.00
	Second Harmonic Currents			**Fifth Harmonic Currents**		
	I1F2	I2F2	I3F2	I1F5	I2F5	I3F5
I (Mult. of Tap)	0.01	0.00	0.00	0.00	0.00	0.00

Figure 21: Relay Differential Quantities for Simulated A-G Fault On W1-W3

These tests have verified the stability of the relay for external faults. This ensures that the wiring modification was indeed correct.

Conclusion

These new test methods are a new tool that can be used to verify the stability of differential relays for external faults. By simulating real time events, one can discovered errors that were not possible using single phase test methods. As a result, it is encouraged that new microprocessor relays be tested as close to real system events as possible.

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[1] Mark Lanier, "Determining the Correct Connection Compensation in the SEL-387E Relay," Application Note AG2006-01, Schweitzer Engineering Laboratories.

[2] Atineza. Ed, Cooper. M, " Verifying Transformer Differential Compensation Settings," Schweitzer Engineering Laboratories.

[3] Costello. D, " Lessons Learned Through Commissioning and Analyzing Data from Transformer Differential Installations," Schweitzer Engineering Laboratories.

[4] Blackburn. L, Applied Protective Relaying, Westinghouse Electric Corporation, 1982.

[5] IEEE Standard C12.51, "General Requirements for Liquid-Immerse Distribution, Power Regulating Transformers," 2000.

Biography:

Rene Aguilar received his B.S. in Electrical Engineering from the University of Texas at Austin. He has extensive experience in the testing and commissioning of electrical schemes as well as performing power system studies. In 2005, he joined Megger as an Application Engineer in the technical support group. He currently holds the title of Senior Application Engineer and was the team leader in the relay technical support group. He is in charge with developing custom applications for numerical protection relays. He is currently testing and developing the IEC 61850 implementation on the Megger products as well as multi-vendor device applications of IEC 61850. He is a member of the IEEE and an active member of Power System Relay Committee PSRC.

Joe Perez received his B.S. degree in Electrical Engineering from Texas A&M University in 2003. After college, he worked as a field engineer installing and commissioning medium voltage switchgears, AC and DC drives, and control houses. In 2004, Joe joined the utility world as a transmission engineer for TMPA. He gained close experience with system protection design, fault analysis and how to face blackouts of a transmission system. He also was in charge of transmission system planning studies such as power flow and contingency analysis. In 2007, Joe decided to move to the relay manufacturing side and joined ERLPhase Power Technologies, previously known as NXTPhase. At ERL, he gained extensive experience in relay protection algorithms for line distance, transformer and bus differential relays.

In 2012, Joe Perez established SynchroGrid LLC to provide electric utilities with simplified power system protection design, analysis, applications, and research. Joe is the author and many relay application notes and has presented technical papers at WPRC, Texas A&M and Georgia Tech Relay Conferences. Joe is a registered professional engineer in the state of Texas and a member of PSRC, IEEE, and PES. Joe resides in the Bryan/College Station area. He can be contacted at jperez@synchrogrid.com.