Beyond the Nameplate – Selecting Transformer Compensation Settings for Secure Differential Protection

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***Abstract*—Microprocessor-based transformer differential relays offer fast and dependable protection for transformer faults while remaining secure for through faults. Differential elements in microprocessor-based relays compensate for the transformer winding connections internally based on the compensation settings provided by the user. Transformer differential settings are often misunderstood, and incorrect settings can lead to undesired operations. Relays use compensation settings to compensate for transformer and current transformer (CT) connections. Understanding transformer winding construction, phase-to-bushing terminal connections, and CT connections is crucial to the correct selection of transformer compensation matrices.**

This paper presents simple rules, based on fundamentals, for the correct selection of compensation settings and their application to several real-world installations. It discusses how different compensation settings (matrices) affect the differential elements and uses a real-world event to show how incorrect compensation settings can result in misoperation, even under load conditions. By analyzing two events from differential relay operations, the paper further shows that some compensation pairs, although valid in terms of producing a balanced differential current, could compromise the security of the differential element due to insufficient restraining current for certain external fault types with CT saturation. For both events, following the rules presented in the paper improved the security of the differential element and avoided the misoperations.

I. Introduction

Transformer differential protection, while a simple concept, is often misunderstood. Having a transformer in the zone of protection offers many challenges to the relay setting engineer. These challenges include current magnitude mismatch, transformer phase angle shift, zero-sequence current removal, unequal current transformer (CT) performance, and inrush during energization [1] [2] [3]. This paper focuses on how to properly set microprocessor-based relays to compensate for the phase shift across the transformer in order to ensure secure transformer differential protection.

A common misconception is that the only thing required to correctly set transformer compensation settings in a microprocessor-based relay is the nameplate of the transformer. This paper proves that the nameplate alone is not enough. Other factors, such as phase-to-bushing connections and CT connections, also come into play and can change the required compensation settings.

II. Overview of Transformer Differential Protection

Current differential protection for transformers is a highly selective form of protection based on the theory of ampere-turn balance. Transformer compensation matrices are developed from fundamentals to satisfy ampere-turn balance on each core leg of a transformer [4]. Although not entirely accurate in terms of ampere-turn balance, Kirchhoff's current law (KCL) can be used to simply explain transformer differential protection. The current entering the zone of protection must equal the current leaving the zone of protection, otherwise there must be another path (such as a fault) inside the zone for current to flow through. A current differential protection scheme is very selective and fast because its zone is determined by the location of the CTs, and no coordination with external devices is necessary. These schemes are commonly used to protect transformers, buses, and other important power system equipment.

A. Percentage-Restrained Differential

In a percentage-restrained differential relay, CTs from both sides of the protected equipment are brought into the relay, and the measured currents are used to calculate operate and restraint values, as shown in Fig. 1. The way these values are calculated can vary depending on relay design, but the operate quantity is a measure of difference current into the zone while the restraint quantity is a measure of through current through the zone. The operate and restraint values are calculated for each phase.

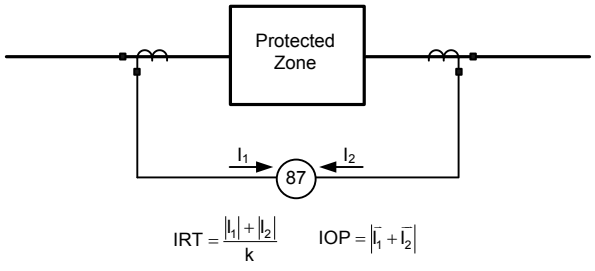

Fig. 1. Operate and restraint calculations for a percentage-restrained differential relay

To understand how different values of operate and restraint quantities are calculated, we look at both an external and an internal fault. An external fault is shown in Fig. 2a. Assuming a CT ratio of 1:1, we can see that the relay calculates a restraint current of 5 and an operate current of 0 for this fault. An internal fault is shown in Fig. 2b. Because the current flow changes directions through the right CT, the relay calculates a restraint current of 5 and an operate current of 10 for this fault.

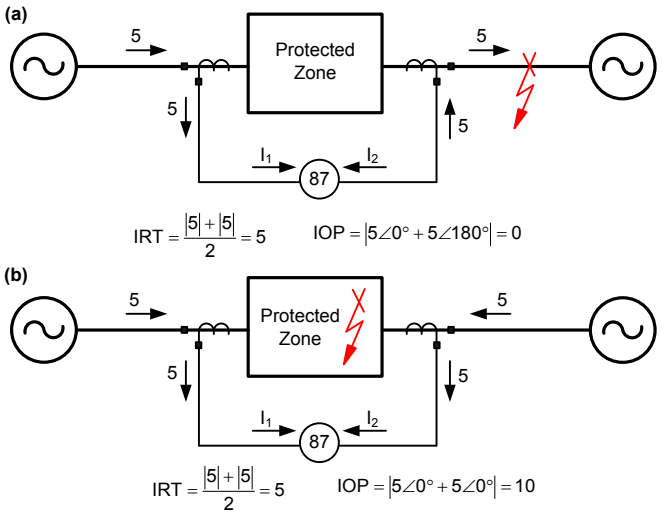

Fig. 2. Operate and restraint values for an external (a) and an internal (b) fault

The operate and restraint values are then used to plot a point on a percentage-restrained differential characteristic, as shown in Fig. 3. The percentage-restrained characteristic is made up of a minimum operate current and a slope value, which can be set in the relay. Relay designs can have single slopes, dual slopes, or adaptive slopes, but the idea behind them is the same. If the calculated values of operate and restraint cause the point to fall above the line, then the relay operates. If the point falls below the line, the relay restrains.

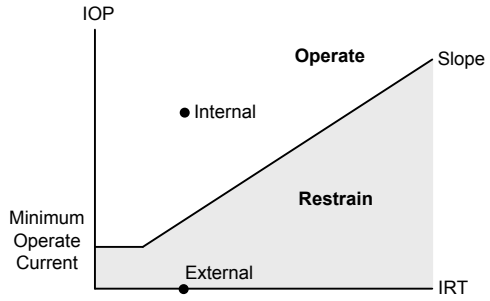

Fig. 3. Single-slope percentage-restrained differential characteristic

In Fig. 3, notice that the values the relay calculated for the example external fault fall within the restrain region, while the values calculated for the example internal fault fall within the operate region. The sloped line allows the relay to be more sensitive for low values of through current and more secure for higher values of current where CT saturation is possible. For more information on percentage-restrained differential characteristics, refer to [5].

B. Transformer Compensation

The concept of current differential protection is simple, but it is made more complicated when the zone of protection includes a transformer. The turns ratio and winding connections of a transformer make it so that the current entering the transformer is not the same as the current leaving the transformer, even under normal conditions. Traditionally, CT ratios and electromechanical relay tap settings were used to compensate for the difference in current magnitude across the transformer. Similarly, CT connections were used to compensate for the phase shift across the transformer. For example, a delta-wye transformer would have wye-connected CTs on the delta side and delta-connected CTs, with the same type of delta connection as the transformer delta, on the wye side in order to counteract the phase shift created by the transformer on the system.

Although this method has historically been adequate to balance the currents on either side of the transformer, there are many disadvantages to connecting CTs in delta. The wiring of delta-connected CTs is a bit more involved and difficult to troubleshoot. Delta-connected CTs also increase the burden for certain fault types compared with wye-connected CTs, and they are therefore more likely to cause CT saturation [6]. Delta-connected CTs also block zero-sequence currents and do not provide the relay with the exact phase current measurements that are seen on the system. This makes it difficult to coordinate backup overcurrent elements that use these CT measurements with downstream devices.

Modern microprocessor-based relays implement this compensation mathematically, internal to the relay. When using these relays, it is recommended to connect all CTs in wye and compensate for the transformer phase shift using compensation settings within the relay.

The way a microprocessor-based relay compensates for the differences in magnitude and angle across a transformer is simple. It is assumed that the CT ratios will still do the majority of the work in making the current magnitudes similar on either side. The relay then measures the current phasors from the CTs and applies a tap scaling factor to each winding measurement in order to make up for other differences in magnitudes and to get both winding currents on the same base. Tap settings correspond to how much secondary current the relay will see on each winding for full through-load conditions. Tap settings are calculated as shown in (1) for each winding, where kV_{WDG} is the line-to-line voltage of the winding, and C is 1 for wye-connected CTs and $\sqrt{3}$ for delta-connected CTs.

$$TAP = \frac{MVA \bullet 1,000 \bullet C}{\sqrt{3} \bullet kV_{WDG} \bullet CTR} \quad (1)$$

As the equation shows, the tap settings take into account the transformer ratio, any CT ratio (CTR) mismatch, and any $\sqrt{3}$ magnitude differences due to delta-connected CTs. After the relay scales each winding input by the corresponding tap setting, it applies a compensation matrix to compensate for the phase shift across the transformer. Compensation matrices are

discussed in the following subsection. After applying the compensation matrix, the per-unit compensated currents on each winding should have the same magnitude and be 180 degrees out of phase for normal through-load conditions. Note that the 180-degree difference is due to the common practice of wiring transformer differential CTs so they both look away from or both look into the zone of protection (with polarities opposite to each other). The relay then uses these compensated currents to calculate the operate and restraint values described previously. Fig. 4 shows an example of how a transformer current differential relay compensates the currents it measures on each winding by magnitude and angle to make up for the shift across the transformer.

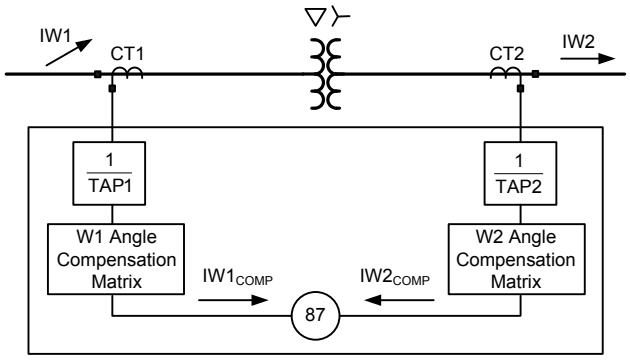

Fig. 4. Relay compensation of magnitude and angle

C. Compensation Matrices

Using different transformer winding and phase connections, it is possible to create power transformers with phase shifts equal to any multiple of 30 degrees, from 0 to 360. All phase shifts are created with some form of delta, wye, or zig-zag winding configuration. As such, any modern transformer differential relay designed for global use should be able to compensate for all common configurations.

Historically, compensation for the phase shift across a transformer was done physically using wye, delta, or double-delta external CT connections. Microprocessor-based transformer compensation works by applying matrices that mathematically duplicate the phase shift created by wiring external CTs in these configurations.

Appendix A shows all of the matrices that can be applied by a relay to compensate for transformer phase shifts. Table IX (in Appendix A) includes matrices that mimic wye-connected CTs, delta-connected CTs, and double-delta-connected CTs. Most relay manufacturers do not provide all of these matrices as available compensation settings. This is especially true for the even-numbered rows, where the same phase shift compensation can be achieved by applying either a wye or double-delta matrix. The main difference between the two is that the wye matrices do not remove zero-sequence current, whereas the double-delta matrices do.

A microprocessor-based relay may include 13 compensation matrices, where Matrix 0 mimics wye-connected CTs with no phase shift and no zero-sequence removal, all of the odd matrices (Matrix 1, 3, … 11) mimic delta-connected CTs with zero-sequence removal and various degrees of phase shift, and all of the even matrices (Matrix 2, 4, … 12) mimic double-delta connected CTs with zero-sequence removal and various degrees of phase shift [7] [8] [9]. The matrices are generally named according to the phase shift they compensate. Matrix 1 compensates for a 30-degree phase shift, Matrix 2 compensates for a 60-degree shift, and so on. As noted in Appendix A, the compensation is done in the positive (counterclockwise) direction when the relay sees ABC phase sequence and in the negative (clockwise) direction when the relay sees ACB phase sequence.

One question that may arise when looking at the compensation matrix options in this relay is the difference between selecting Matrix 0 and Matrix 12. Neither matrix rotates the phasors, but Matrix 12 (along with all other nonzero matrices) removes zero-sequence currents, whereas Matrix 0 is the identity matrix and does not remove zero-sequence currents. Recall that the goal of selecting correct compensation matrices is to satisfy the ampere-turn balance for a healthy transformer [4].

In electromechanical installations, this was done by wiring CTs in the opposite configuration of the transformer winding (for example, wire CTs in wye on the delta side of the transformer, and wire CTs in delta on the wye side of the transformer.) In order to mimic that installation in a microprocessor-based relay with wye-connected CTs, Matrix 0 (the wye matrix) should always be selected for the delta winding of a delta-wye transformer. This results in a nonzero matrix being selected for the wye side of the transformer, which is very important. A nonzero matrix should always be selected for a wye winding with wye-connected CTs. This is because, for an external ground fault on the wye side, no zero-sequence current flows through the CTs on the delta side due to the delta zero-sequence trap. However, zero-sequence current can flow up through the neutral of the wye side of the transformer to the fault and be seen in the wye-connected CTs. This is shown in Fig. 5. The relay will then see zero-sequence current on one side of the transformer but not the other, which can cause an unbalance in the currents within the differential element. Selecting a nonzero matrix for the wye side of the transformer ensures that this zero-sequence current is removed and balances the differential.

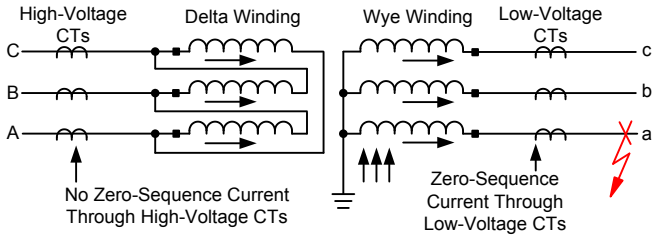

Fig. 5. Zero-sequence current through delta-wye transformer with wye CTs

The selected compensation matrices are applied to the relay phase currents as shown in (2). Note that it is assumed that the phase currents have already been divided by the relay tap setting to correct for magnitude and are now per-unit currents.

$$\begin{bmatrix} \text{Ia}_{\text{compensated}} \\ \text{Ib}_{\text{compensated}} \\ \text{Ic}_{\text{compensated}} \end{bmatrix} = [\text{Compensation Matrix}] \bullet \begin{bmatrix} \text{Ia} \\ \text{Ib} \\ \text{Ic} \end{bmatrix} \quad (2)$$

It is possible to derive how each matrix provides the indicated phase shift by applying the matrix to a balanced set of three-phase currents. For example, Matrix 1 is defined by (3) and provides a phase shift of 1 • 30 = 30 degrees.

$$\text{Matrix 1} = \frac{1}{\sqrt{3}} \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} \quad (3)$$

The function of Matrix 1 can be verified by applying it to a set of three phase currents.

$$\begin{bmatrix} \text{Ia}_{\text{compensated}} \\ \text{Ib}_{\text{compensated}} \\ \text{Ic}_{\text{compensated}} \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} \bullet \begin{bmatrix} \text{Ia} \\ \text{Ib} \\ \text{Ic} \end{bmatrix} \quad (4)$$

$$\begin{bmatrix} \text{Ia}_{\text{compensated}} \\ \text{Ib}_{\text{compensated}} \\ \text{Ic}_{\text{compensated}} \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} (1 \bullet \text{Ia}) + (-1 \bullet \text{Ib}) + (0 \bullet \text{Ic}) \\ (0 \bullet \text{Ia}) + (1 \bullet \text{Ib}) + (-1 \bullet \text{Ic}) \\ (-1 \bullet \text{Ia}) + (0 \bullet \text{Ib}) + (1 \bullet \text{Ic}) \end{bmatrix} \quad (5)$$

$$\begin{bmatrix} \text{Ia}_{\text{compensated}} \\ \text{Ib}_{\text{compensated}} \\ \text{Ic}_{\text{compensated}} \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} \text{Ia} - \text{Ib} \\ \text{Ib} - \text{Ic} \\ \text{Ic} - \text{Ia} \end{bmatrix} \quad (6)$$

Next, balanced per-unit currents of ABC phase sequence are applied.

$$\begin{bmatrix} \text{Ia}_{\text{compensated}} \\ \text{Ib}_{\text{compensated}} \\ \text{Ic}_{\text{compensated}} \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} (1\angle 0^\circ) - (1\angle -120^\circ) \\ (1\angle -120^\circ) - (1\angle 120^\circ) \\ (1\angle 120^\circ) - (1\angle 0^\circ) \end{bmatrix} \quad (7)$$

$$\begin{bmatrix} \text{Ia}_{\text{compensated}} \\ \text{Ib}_{\text{compensated}} \\ \text{Ic}_{\text{compensated}} \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} \sqrt{3}\angle 30^\circ \\ \sqrt{3}\angle -90^\circ \\ \sqrt{3}\angle 150^\circ \end{bmatrix} \quad (8)$$

$$\begin{bmatrix} \text{Ia}_{\text{compensated}} \\ \text{Ib}_{\text{compensated}} \\ \text{Ic}_{\text{compensated}} \end{bmatrix} = \begin{bmatrix} 1\angle 30^\circ \\ 1\angle -90^\circ \\ 1\angle 150^\circ \end{bmatrix} \quad (9)$$

The balanced currents have each been shifted by +30 degrees without any change to their magnitude. Note that the matrix includes a division by $\sqrt{3}$ to counteract the magnitude increase caused by the subtraction of two phasors of equal magnitude separated by 120 degrees. If we applied balanced per-unit currents of ACB phase sequence, Matrix 1 would provide a shift of –30 degrees. Note that in either case, the direction of the phase shift is defined by the positive-sequence current. In addition, the direction of the phase shift for the negative-sequence current is opposite to that of the positive-sequence current.

III. Using the Nameplate to Set the Relay

A common method of selecting compensation settings in a transformer current differential relay is directly using the phase shift indicated on the nameplate of the transformer. This practice, although common, unfortunately can result in incorrect operation of the differential element. This is because the phase shift given on the nameplate of a transformer makes two very important assumptions:

- The system has an ABC phase sequence.
- The phase-to-bushing connections are ABC. In other words, A-phase on the system is connected to the H1 and X1 bushings of the transformer, B-phase on the system is connected to the H2 and X2 bushings of the transformer, and C-phase on the system is connected to the H3 and X3 bushings of the transformer.

Assuming both of these conditions are true, the phase shift given on the nameplate should indicate the phase shift performed by the transformer. However, the nameplate still does not take into account the external factors that can change the phase shift that the relay sees, such as the following:

- CTs connections (delta or wye).
- CT polarity direction.
- System phase to relay current input connections. (Does A-phase on the system go to A-phase on the relay?)

All of these factors affect the phase shift that the relay sees and must be taken into account, even for standard installations. The main point is that in order to properly select compensation settings, the entire installation must be considered, not just the nameplate of the transformer.

IV. Deriving the Phase Shift

The rules for determining correct compensation settings are described in Section V. The first step in doing this is to determine the phase shift between the positive-sequence currents that the relay sees across the transformer. Once the phase shift is determined, compensation settings can be selected to counteract that shift.

The example in this section shows how to derive the phase shift for an installation of the step-down delta-wye distribution transformer shown in Fig. 23 in Appendix B. Both sets of CTs are connected in wye, with differential polarity. The delta side of the transformer corresponds to the Winding 1 inputs on the relay, while the wye side of the transformer corresponds to the Winding 2 inputs on the relay. If the system has ABC phase sequence and the phase-to-bushing connections are standard, then we know that the phase shift across this transformer is equal to what is given on the nameplate (the high side leads the low side by 30 degrees). If the CT connections are standard (CTs connected in wye with differential polarity, A-phase on the system is connected to A-phase on the relay, and so on), then this phase shift can be used to directly determine the compensation settings of the relay. The derivation for this standard case is shown in Example 1 of Appendix C. In this section, we derive the phase shift for the

same transformer when installed with nonstandard connections.

The first step to deriving the phase shift across a transformer installation is knowing how the transformer itself, specifically the delta winding, is constructed. In the United States, there are two common ways to refer to the wiring of a delta winding: DAB (A minus B, B minus C, and C minus A) or DAC (A minus C, C minus B, and B minus A). DAB means that the polarity of A-phase is connected to the nonpolarity of B-phase with standard phase-to-bushing connections. Because it is possible to connect a transformer with nonstandard phase-to-bushing connections, what this really means is that the polarity of the winding on Core Leg 1 (normally A-phase) is connected to the nonpolarity of the winding on Core Leg 2 (normally B-phase). Similarly, a DAC connection means that the polarity of the winding on Core Leg 1 (normally A-phase) is connected to the nonpolarity of the winding on Core Leg 3 (normally C-phase). Most transformer manufacturers do not specify polarity sides of transformer windings, but the polarity side is typically the side connected to the bushing.

Fig. 6 shows the difference in connections between a DAB (Fig. 6a) and a DAC (Fig. 6b) winding. Because the transformer in Fig. 23 is a DABY transformer, its delta winding will look like Fig. 6a. Drawing the physical connections of the transformer correctly is the first step in deriving the phase shift across the installation. No matter how the phases land on the bushings or how the system phase sequence changes, these internal connections will not change.

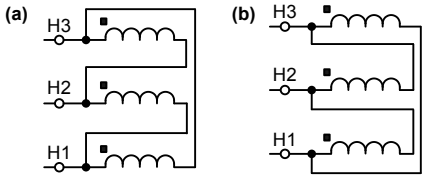

Fig. 6. DAB-connected (a) and DAC-connected (b) delta windings

In international markets, it is also common to represent the transformer winding connections in vector group notation. See [10] for an explanation of this notation. Using this notation, the transformer in Fig. 23 can be represented as Dyn1. Simply, the first capital letter designates the high-voltage side and its connection, the following lowercase letter designates the low-voltage side and its connection, *n* is added if the neutral point is brought out, and the number at the end indicates the number of 30-degree increments by which low-side currents lag the high-side currents for ABC system phase sequence. For ACB system phase sequence, it indicates the number of 30-degree increments by which low-side currents lead the high-side currents.

Once we draw how the transformer is physically constructed, we need to draw how the system phases land on the bushings. Consider Fig. 7, where the transformer is not installed with standard phase-to-bushing connections. This transformer is connected to the system in such a way that A-phase on the system goes to H3 and X3 on the transformer, B-phase on the system goes to H2 and X2 on the transformer, and C-phase on the system goes to H1 and X1 on the transformer.

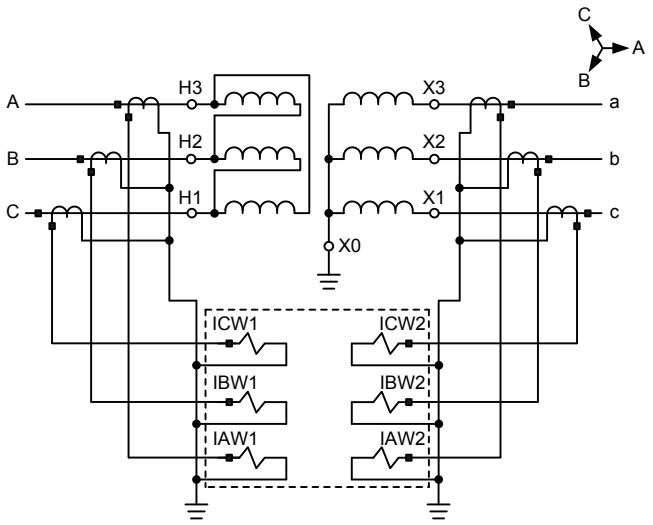

Fig. 7. Transformer, CT, and relay connections for a nonstandard case

Once we have the drawing in Fig. 7, we can easily trace through the transformer connection to derive the phase shift between currents on either side. First, assuming current flow through the transformer from the delta side to the wye side, we label the currents going through the wye side with their direction and phase based on the phase-to-bushing connections, as shown in Fig. 8. Next, we know that the individual phase windings inside the transformer (before the delta or wye connections) are magnetically coupled to each other, and if we assume (for simplicity) a transformer ratio of 1:1, the current through one is the same as the current through the other. Knowing this, we can label the currents inside the delta winding the same as the currents on the wye side.

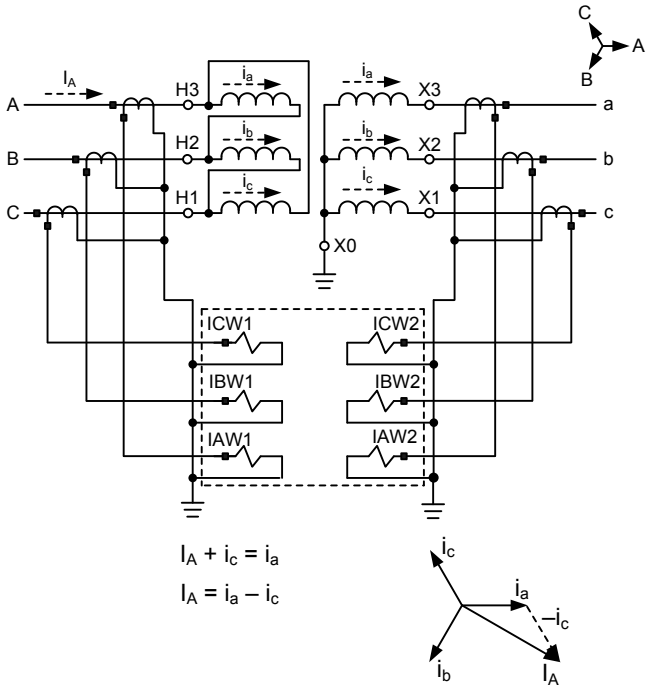

Fig. 8. Deriving the phase shift across the transformer for a nonstandard case

Next, we choose a high-side terminal (for example, H3) and label the current coming into the delta connection on that phase (in this example, I_A). Then, we write a KCL equation at node H3 to derive the current coming into the delta winding (I_A) in terms of the other currents entering (i_c) and leaving (i_a) the node. The derivation of this KCL equation for the delta-side A-phase current is shown at the bottom of Fig. 8. The final equation should result in a delta-side current in terms of a difference in wye-side currents.

We plot the wye-side currents using the phase sequence of the system and use graphical phasor subtraction to derive where the delta-side currents plot with respect to the corresponding wye-side currents. In this example, we can see that the delta-side current (I_A) is $\sqrt{3}$ times larger and lags the wye-side current (i_a) by 30 degrees on the system. This can be done for all three phases, and the results are shown in Fig. 9. Note that the result shows that the high side lags the low side by 30 degrees, while the nameplate states that the high side leads the low side by 30 degrees. Remember that the phase shift given on the nameplate assumes two things: an ABC system phase sequence and standard phase-to-bushing connections. Due to the phase-to-bushings connections in this example, the actual phase shift performed by the transformer does not match the phase shift given on the nameplate.

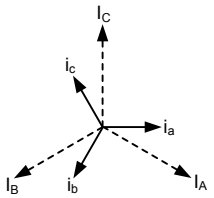

Fig. 9. Phase currents on the system for a nonstandard case

A shortcut that can be used to determine whether the phase shift given on the nameplate is accurate, or if the opposite phase shift is being performed by the transformer, is given in [11]. We know that the actual phase shift is dependent on system phase sequence and phase-to-bushing connections. When the system phase sequence matches the order of the phase-to-bushing connections, the nameplate on the transformer accurately represents the phase shift being performed. When they are opposite, the nameplate's mirror image represents the actual phase shift. Table I (derived from [11]) allows us to easily determine whether to use the nameplate or the mirror image of the nameplate to determine the phase shift across a transformer installation without having to trace through the transformer connections.

TABLE I
NAMEPLATE PHASE SHIFT TRUTH TABLE

System Phase Sequence	Phase-to-Bushing Connection Order	Nameplate or Mirror Image of Nameplate
ABC	ABC, BCA, or CAB	Nameplate
ABC	ACB, CBA, or BAC	Mirror image
ACB	ABC, BCA, or CAB	Mirror image
ACB	ACB, CBA, or BAC	Nameplate

Once the current phasors on either side of the transformer are known, we need to determine what the phasors look like at the relay inputs after the CTs have been taken into consideration. When CTs are connected in delta, there will be a 30-degree shift, depending on whether they are connected in DAB or DAC. When CTs are connected in wye, there will not be a 30-degree shift. The polarity of the CTs must also be taken into account. For this example, the CTs are connected in wye and have differential polarity. The opposite polarity means that one set of three-phase currents (on one side of the transformer) will shift 180 degrees out of phase when they pass through the CTs. Finally, we take into account the CT-to-relay connections. Here, the relay is wired in the standard way, meaning that A-phase on the system is connected to A-phase on the relay, and so on. After taking these factors into account, the phasors seen at the relay will look like Fig. 10. These are the final phasors that will be used when determining the compensation settings.

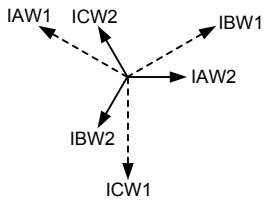

Fig. 10. Phase currents at the relay for a nonstandard case

This example proves that changing the phase-to-bushing connections of a transformer installation can change the phase shift from what is indicated on the nameplate. Changing the phase sequence or CT connections can also result in a different phase shift, as shown in Examples 2 and 3 of Appendix C. Appendix C also contains additional examples of how to derive the phase shift and compensation settings for other transformer types and connections.

V. SELECTING THE CORRECT COMPENSATION MATRICES

The goal in selecting compensation matrices in the relay is to make it so that after the compensation matrices are applied to the current phasors that the relay measures, the resultant compensated per-unit phasors of the high-voltage side (Winding 1) and the low-voltage side (Winding 2) of the transformer are 180 degrees apart. This ensures that under ideal through-load conditions, the operate quantity that the relay calculates is 0.

As described in Section I, Subsection C, we can think of each compensation matrix as a shift of a certain multiple of 30 degrees. For example, Matrix 1 shifts the currents one multiple of 30 degrees, Matrix 2 shifts the currents two multiples of 30 degrees (or 60 degrees), and so on. The shift is done in the counterclockwise direction when the relay sees an ABC phase sequence and the clockwise direction when the relay sees an ACB phase sequence.

A. Rules for Selecting Correct Compensation Matrices

A common misconception in the past has been that any winding can be chosen as a reference and the other winding rotated with compensation settings so the resulting phasors after compensation are 180 degrees out of phase. Rare cases (shown in Section VI) have proven that the reference cannot be arbitrarily chosen, and doing so can lead to a misoperation of the differential element. Rules for correctly selecting compensation matrices are as follows:

1. Look beyond the nameplate. Derive the phase shift of the installation that the relay sees, taking into account transformer construction, phase-to-bushing connections, system phase sequence, and CT connections. This will result in a phasor diagram like Fig. 10.
2. If a delta winding exists and is wired into the relay, choose it as your reference. Select Matrix 0 for the compensation of the delta winding, and select the appropriate matrix for the compensation of the wye winding(s).
3. If a delta winding does not exist, select Matrix 11 for the compensation of one of the wye windings, and select the appropriate matrix for the compensation of the other wye winding(s).
4. Avoid using even-numbered matrices when possible. Refer to the following subsection when Rules 1–3 result in an even-numbered matrix.

We now use these rules to determine the compensation settings for the example in Section IV. Rule 1 tells us to derive the phase shift of the installation as seen by the relay, which we did in Section IV (given in Fig. 10).

Rule 2 tells us what to do when a delta winding exists, which it does in this case. Because Winding 1 is a delta winding, we know that we need to select it as our reference and choose Matrix 0 for that winding. In order to make Winding 2 180 degrees out of phase with Winding 1, we need to rotate it 11 multiples of 30 degrees in the counterclockwise direction. (Recall that we rotate counterclockwise because the phase sequence seen by the relay is ABC.) This results in a compensation pair of (0, 11) for (Winding 1, Winding 2). This also satisfies Rule 4 because we avoid using even-numbered matrices. Section VII explains the downsides of using even-numbered matrices. Compensation settings for other example installations are given in Appendix C.

B. Special Cases

The rules in the previous subsection cover the vast majority of transformer installations. This subsection covers other special cases that you may encounter, such as the following:

1. In retrofit applications, where compensation is done external to the relay with CT wiring, use Matrix 0 for all windings, or turn compensation off in the relay entirely.
2. If there is a ground source, such as a zig-zag grounding transformer within the differential zone of a delta winding, select Matrix 12 for that winding. This is the only case where an even-numbered matrix is recommended.
3. If there is more than one delta winding present, and the phase shift between the delta windings is zero, Matrix 0 should be selected for all of the delta windings. If the phase shift between the delta windings is not zero, then the CTs on all of the delta windings should be connected in such a way that the phase shift between them is made to be zero, and Matrix 0 should be selected for all of the delta windings.
4. If following the rules in the previous subsection results in an even-numbered matrix that is not desired, one option is to rewire the CT-to-relay connections so that an odd-numbered matrix can be applied.

C. Confirming the Correct Compensation Matrices

Even if great care is used in selecting compensation settings, it is critical that proper commissioning be performed in order to detect wiring errors, rolled phases, or incorrectly entered settings. Manufacturers' commissioning worksheets are an excellent place to start when commissioning a transformer differential installation. These commissioning worksheets lead users through the checks presented in this subsection. Although these checks will not detect the issue presented in Section VII, they will detect the vast majority of common problems with transformer differential installations.

First, verify correct system phasors by applying load current to the transformer and verifying that the magnitudes and angles of currents measured by the relay match expectations. Common reasons for currents not matching expectations include reversed CT polarity, rolled CT wiring, and rolled phases in the transformer primary connections.

Next, verify that the selected compensation matrices compensate these currents correctly. Some relays allow you to meter secondary measured currents, but not the currents after compensation is applied. In those cases, tools are available that can be used to apply compensation matrices to measured winding currents and to ensure that the resulting compensated currents are 180 degrees out of phase from each other.

Finally, verifying correct differential quantities (operate and restraint current) can work as a final check to ensure that the differential element is set correctly. In an ideal system, the operating current should be 0 and the restraint current should be 1 or 2 per unit (pu) (depending on the relay restraint philosophy) at the rated MVA and voltage of the transformer. In real systems, CT error, relay error, winding tap position, and transformer magnetization current can all combine to result in a small amount of operating current. Verify that the currents are close to what is expected, and that the mismatch (ratio of operate to restraint current) is less than 10 percent. If this ratio is higher than expected, it is likely that there is an error in CT wiring, CT tap settings, or relay compensation settings.

$$\frac{\text{IOP}}{\text{IRT}} < 10\% \tag{10}$$

VI. Example of Incorrect Compensation Settings

To illustrate the importance of knowing the details about the complete installation of a transformer differential relay, consider an example where an engineer only used the nameplate of a 30 MVA DABY distribution transformer, rated 69 kV delta to 12.47 kV wye, to set the compensation settings. Fig. 11 includes the phase-to-bushing connections, where A-phase on the system is connected to H1 and X1, C-phase is connected to H2 and X2, and B-phase is connected to H3 and X3. The CT connections are standard.

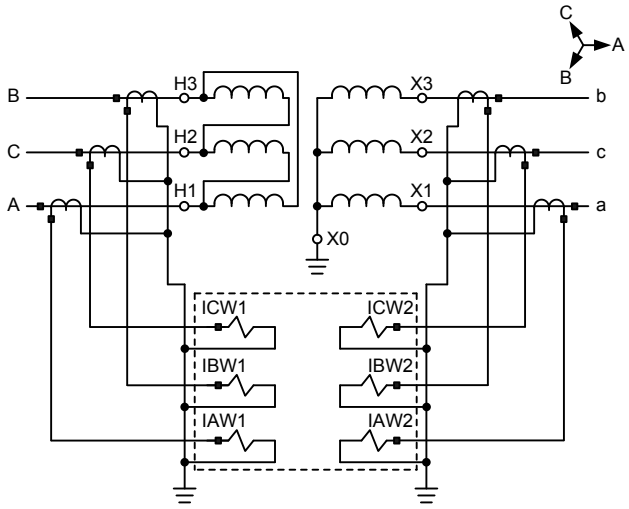

Fig. 11. DABY transformer with nonstandard phase-to-bushing connections

The utility installed a new transformer and was slowly transferring feeder load onto it. After a week, an undesired operation occurred, and the utility decided to raise the minimum operate current setting from 0.2 pu to 0.25 pu. Another week later, the transformer differential relay tripped again. The utility engineer contacted the relay manufacturer application engineer and provided the event report shown in Fig. 12. The event report shows that the relay tripped on 87R, the restrained current differential element.

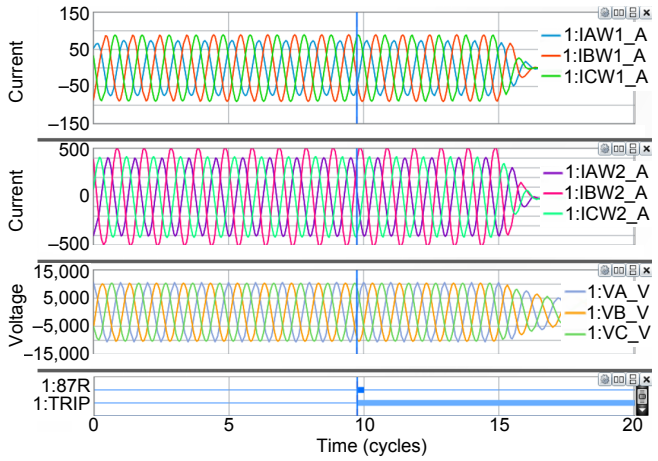

Fig. 12. Winding currents show feeder load during trip

After reviewing the event reports from the second operation, the application engineer suspected an incorrect winding compensation matrix selection. In Fig. 13, operate current in all three differential elements is elevated above the 10 percent mismatch rule of thumb given in (10).

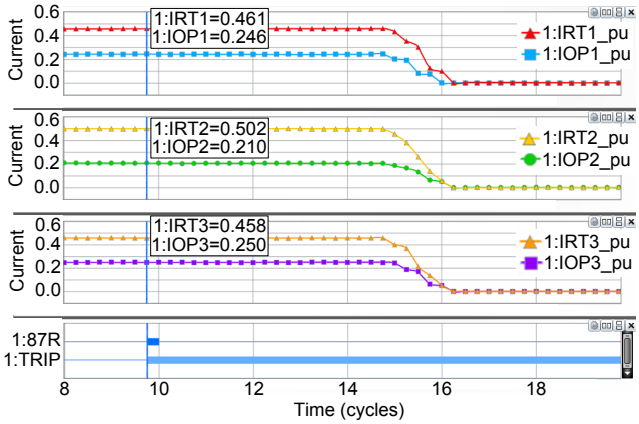

Fig. 13. Elevated operate current throughout event

While this could be a wiring error, the fact that it occurs in all three elements points to the more likely cause being a settings error. In this case, the utility engineer selected a compensation pair of (0, 1)—expected settings for standard connections for a DABY transformer, as shown in Example 1 of Appendix C. However, the system phase-to-bushing connections are actually wired as shown in Fig. 11. If we use the same procedure described in Section IV to trace through the transformer connections and derive the phase shift as seen by the relay, we get the phasors shown in Fig. 14a and Fig. 14b.

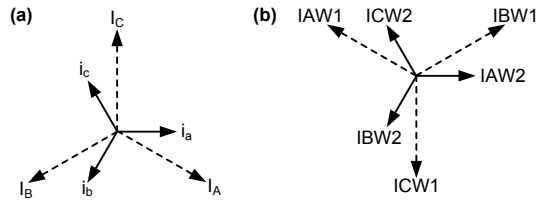

Fig. 14. Phase currents on the system (a) and at the relay (b) for nonstandard phase-to-bushing connections

Using the rules described in Section V, correct matrix compensation settings for this installation would be (0, 11). These settings would cause the relay to remain secure for external faults and through load, with near zero operate current.

VII. New Rules Add Security

Section V explains how to select correct compensation matrices. The rules state to select the delta winding as a reference (select Matrix 0) and rotate the other winding in increments of 30 degrees to be 180 degrees out of phase with the reference, as measured by the relay. They also mention that arbitrarily selecting the reference winding can lead to compensation pairs that pose security risks under certain rare conditions. This section shows two events where arbitrary selection of the reference winding caused relay misoperations.

The misoperations described in this section were due to how Matrix 12 (and all of the double-delta matrices in Appendix A) combine currents to perform their phase shift. When these matrices are exposed to a fault where two of the phase currents are similar in magnitude and 180 degrees out of phase with each other, the math these matrices perform causes the faulted phase currents to cancel out in one of the differential elements. This cancellation drastically reduces the compensated current values along with the resulting restraint current that the relay calculates. With reduced restraint current, a small amount of CT error can be enough operate current to cause a trip.

A. Case I: DABY Transformer With External A-Phase-to-B-Phase Fault

Consider a DABY transformer with ABC phase sequence and standard phase-to-bushing and CT connections. The transformer ratings are 22 MVA and 72 kV delta (Winding 1) to 13 kV grounded-wye (Winding 2). The relay is set with CTR1 = 40, CTR2 = 240, TAP1 = 4.48, TAP2 = 4.12, minimum operate current = 0.3, Slope 1 = 25%, Slope 2 = 70%, and k = 1. As discussed in Example 1 of Appendix C, the engineer should select compensation pair (0, 1) for this installation. In this particular case, the relay setting engineer used Winding 2 as the reference and selected compensation pair (11, 12).

An external fault occurred on the power system, as shown in Fig. 15. The fault started as an A-phase-to-B-phase fault on the wye side of the transformer and evolved into a three-phase fault. An A-phase-to-B-phase fault on the low side of a delta-wye transformer should appear on the high side with an A-phase current equal to and 180 degrees out of phase with the sum of the B-phase and C-phase currents. For an external fault, the relay should remain secure for this operation. In this particular event, though, the relay tripped.

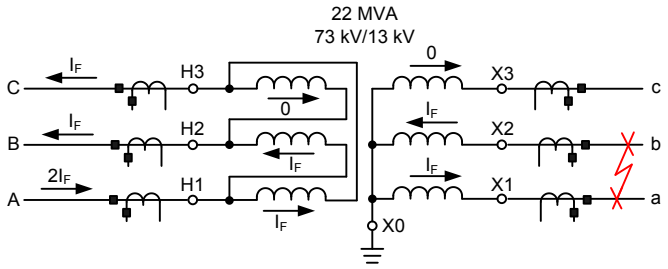

Fig. 15. A-phase-to-B-phase fault on wye side of a DABY transformer

Fig. 16 shows that the relay tripped during the phase-to-phase portion of the external fault. The filtered event data show that due to CT saturation, the fault current magnitude for the phases involved in the fault are not equal—about a 7 percent mismatch exists. With the dual percentage-differential slope, however, the relay should remain secure.

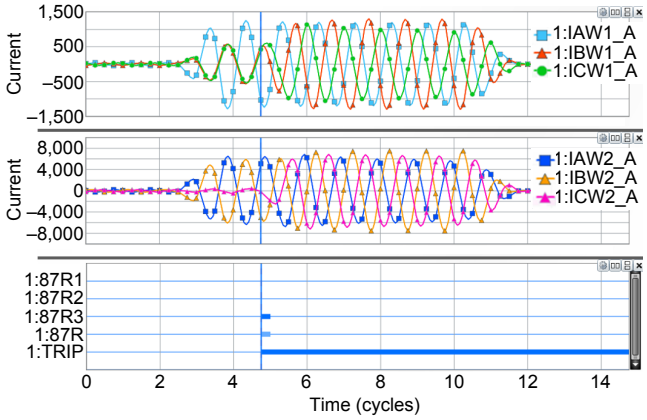

Fig. 16. Differential Element 3 operates for external fault

Knowing how the relay calculates compensated currents (see Fig. 4), we can use software analytic tools to calculate the compensated currents as well as operate and restraint currents at the time of the trip. These compensated currents are shown in Table II.

Table II
Compensated Currents With Compensation Set to (11, 12)

Input	Currents Measured by Relay (A primary)	Compensated Currents (pu of tap)
IAW1	912 ∠0°	4.21 ∠–1.4°
IBW1	414 ∠–175°	4.27 ∠–178°
ICW1	395∠175°	0.23∠74.8°
IAW2	4,620 ∠178°	4.66 ∠179°
IBW2	4,320 ∠2°	4.38 ∠1.43°
ICW2	323 ∠–35.9°	0.36 ∠–39.2°

Now, we look at how the relay calculates the C-phase compensated currents for this fault. Equation (11) shows how Matrix 11 is applied to the Winding 1 currents, resulting in the Winding 1 compensated currents. The specific equation for C-phase compensated current is shown in (12).

$$\begin{bmatrix} IAW1C \\ IBW1C \\ ICW1C \end{bmatrix} = \frac{1}{CTR1 \bullet TAP1} \bullet \frac{1}{\sqrt{3}} \bullet \begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix} \bullet \begin{bmatrix} IAW1 \\ IBW1 \\ ICW1 \end{bmatrix} \quad (11)$$

$$ICW1C = \frac{1}{CTR1 \bullet TAP1} \bullet \frac{1}{\sqrt{3}} \bullet (-IBW1 + ICW1) \quad (12)$$

The Winding 1 C-phase compensated current contains only Winding 1 B-phase and C-phase currents. The currents measured by the relay from Table II are very similar in magnitude and phase angle, but CT error keeps them from being exactly the same. This difference results in a small amount of compensated current for Winding 1 C-phase.

Similarly, (13) shows how Matrix 12 is applied to the Winding 2 currents, resulting in Winding 2 compensated currents. The specific equation for C-phase compensated current is shown in (15).

$$\begin{bmatrix} IAW2C \\ IBW2C \\ ICW2C \end{bmatrix} = \frac{1}{CTR2 \bullet TAP2} \bullet \frac{1}{3} \bullet \begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix} \bullet \begin{bmatrix} IAW2 \\ IBW2 \\ ICW2 \end{bmatrix} \quad (13)$$

$$ICW2C = \frac{1}{CTR2 \bullet TAP2} \bullet \frac{1}{3} \bullet \left(-IAW2 + -IBW2 + 2 \bullet ICW2\right) \quad (14)$$

Because Table II shows that IAW2 is almost equal in magnitude but opposite in direction compared with IBW2, ICW2C can be simplified to only include ICW2 current—in this case, load current.

Next, we can calculate operate and restraint current using the equations shown in Fig. 1. In this particular relay, k = 1. The results are shown in Table III. These values match the operate and restraint values from the relay differential event report shown in Fig. 17. The blue vertical line in Fig. 17 corresponds to the blue vertical line in Fig. 16.

TABLE III
OPERATE AND RESTRAINT CURRENTS WITH COMPENSATION SET TO (11, 12)

Differential Characteristic Current	Differential Element 1	Differential Element 2	Differential Element 3
IOP (pu)	0.452	0.115	0.337
IRT (pu)	8.868	8.650	0.584
IOP/IRT (%)	5.1	1.3	57.7

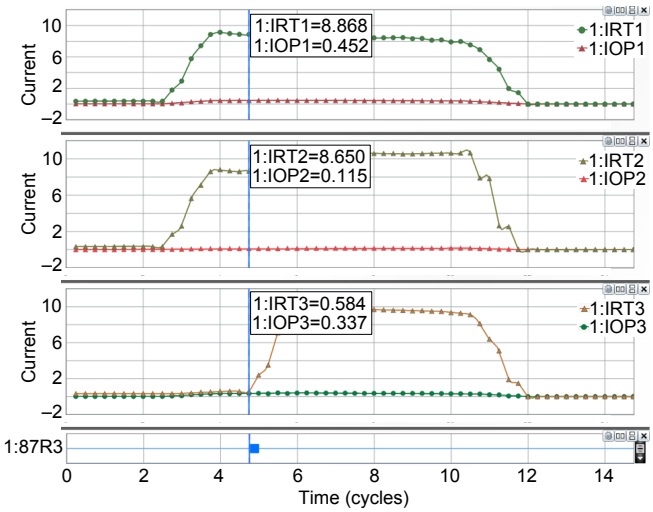

Fig. 17. Plotting operate and restraint currents with original matrices

As shown in Table III, the magnitude of restraint current in Element 3 (correlating to C-phase) is very small compared with the other two elements. The corresponding operate current is also small but above the minimum operate current required to allow an operation. With these values, Element 3, which operates based on IOP3/IRT3, plots at 57.7 percent (above the slope setting of 25 percent) and trips the relay.

The reason the restraint current in Element 3 is so small is because of how Matrix 12 (and all of the double-delta matrices in Appendix A) combine the phase currents for this specific fault type. Recall that the restraint current in Element 3 is a combination of the C-phase compensated currents from Winding 1 and Winding 2. Equation (12) shows that for this phase-to-phase fault, the only resulting compensated current from Winding 1 is due to the difference in CT performance. Equation (15) shows that the combination of currents performed by Matrix 12 causes the fault current contribution to be completely removed from the compensated current on Winding 2, leaving only load current. These two values are both very small and add up to a very small restraint value, causing the relay security to suffer. When the restraint current is so small, a small amount of CT error can lead to a misoperation. In this case, the difference current from uneven CT saturation was only 7 percent. We expect a slope setting of 25 percent to easily restrain an error current of 7 percent.

In Fig. 17, it is interesting to see that when the fault changed from phase-to-phase on the low side of the transformer to three-phase, the restraint current increased. However, the additional security did not help because the relay had already operated.

Now consider compensation pair (0, 1), which provides the same 30-degree compensation between Winding 1 and Winding 2 and would be obtained by following the rules in Section V. The compensated currents using these matrices are shown in Table IV.

TABLE IV
COMPENSATED CURRENTS WITH COMPENSATION SET TO (0, 1)

Input	Currents Measured by Relay (A primary)	Compensated Currents (A secondary pu of tap)
IAW1	912 ∠0°	5.09 ∠0°
IBW1	414 ∠–175°	2.31 ∠–175°
ICW1	395 ∠175°	2.21 ∠175°
IAW2	4,620 ∠178°	5.22 ∠180°
IBW2	4,320 ∠2°	2.38 ∠4.68°
ICW2	323 ∠–35.9°	2.86 ∠–3.97°

Equation (16) shows how Matrix 0 is applied to the Winding 1 currents, and the specific C-phase compensated current equation is shown in (17). Winding 1 C-phase compensated current only includes current from C-phase Winding 1, resulting in a larger value than in Table II.

$$\begin{bmatrix} \text{IAW1C} \\ \text{IBW1C} \\ \text{ICW1C} \end{bmatrix} = \frac{1}{\text{CTR1} \bullet \text{TAP1}} \bullet \begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix} \bullet \begin{bmatrix} \text{IAW1} \\ \text{IBW1} \\ \text{ICW1} \end{bmatrix} \quad (15)$$

$$\text{ICW1C} = \frac{1}{\text{CTR1} \bullet \text{TAP1}} \bullet (\text{ICW1}) \quad (16)$$

Equation (18) shows how Matrix 1 is applied to the Winding 2 currents, and the specific C-phase compensated current equation is shown in (19). Winding 2 C-phase compensated currents now include both fault current (IAW2) and load current (ICW2), resulting in a much larger Winding 2 C-phase compensated current.

$$\begin{bmatrix} \text{IAW2C} \\ \text{IBW2C} \\ \text{ICW2C} \end{bmatrix} = \frac{1}{\text{CTR2} \bullet \text{TAP2}} \bullet \frac{1}{\sqrt{3}} \bullet \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} \bullet \begin{bmatrix} \text{IAW2} \\ \text{IBW2} \\ \text{ICW2} \end{bmatrix} \quad (17)$$

$$\text{ICW2C} = \frac{1}{\text{CTR2} \bullet \text{TAP2}} \bullet \frac{1}{\sqrt{3}} \bullet (-\text{IAW2} + \text{ICW2}) \quad (18)$$

The operate and restraint currents calculated from these new compensated currents are shown in Table V and plotted in Fig. 18. The restraint current for Element 3 is much higher than in Table III. Fig. 18 shows that the restraint current increases as soon as the fault occurs and would have kept the relay secure for this fault.

TABLE V
OPERATE AND RESTRAINT CURRENTS WITH COMPENSATION SET TO (0, 1)

Differential Characteristic Current	Differential Element 1	Differential Element 2	Differential Element 3
IOP (pu)	0.131	0.068	0.652
IRT (pu)	10.307	4.687	5.062
IOP/IRT (%)	1.3	1.5	12.9

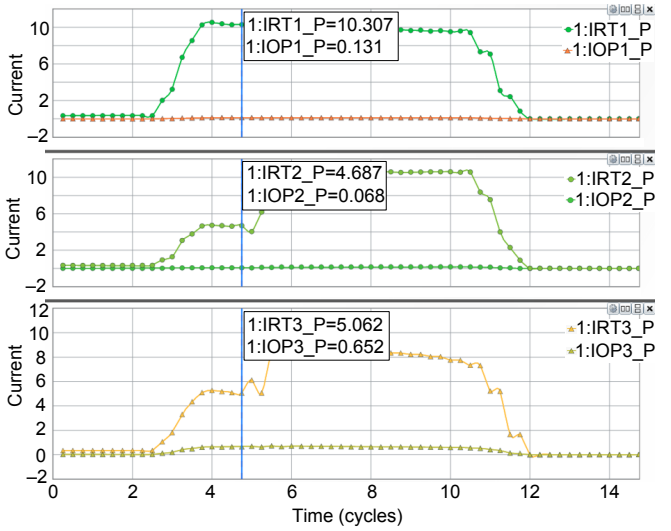

Fig. 18. Plotting operate and restraint currents with correct matrices

Based on Table V, we can calculate where each differential element plots on the slope characteristic with minimum operate current = 0.3, Slope 1 = 25%, and Slope 2 = 70%. Fig. 19 compares the original compensation with the correct compensation (derived from the rules in Section V, which are based on fundamental principles) for each of the three percentage-restrained differential elements. It also shows the trip characteristic based on the relay settings. It is evident from Fig. 19 that correct compensation settings derived using the rules in Section V cause the element to properly restrain, and security is improved.

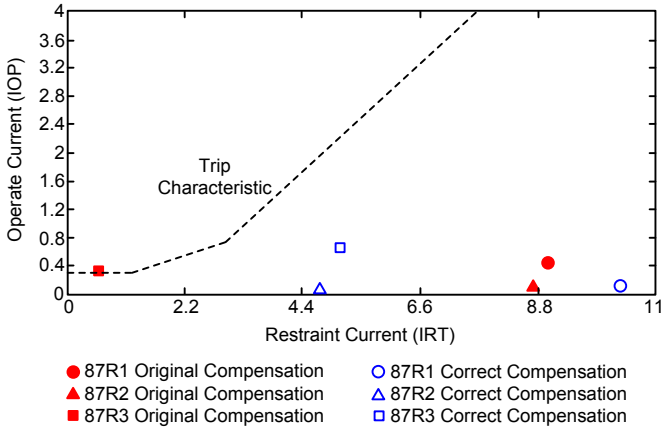

Fig. 19. Relay trip characteristic and matrix selection comparison for A-phase-to-B-phase external fault

B. Case II: Autotransformer With External A-Phase-to-B-Phase Fault

Consider a 100 MVA, 230 kV/115 kV autotransformer with standard connections. The relay is set with CTR1 = 60, CTR2 = 120, TAP1 = 4.18, TAP2 = 4.18, minimum operate current = 0.3, Slope 1 = 25%, Slope 2 = 50%, and k = 1. The winding arrangement in an autotransformer results in a phase shift of 0 degrees between the primary and secondary windings. Per the rules in Section V, with the delta tertiary not being brought into the relay (and therefore not being a part of the differential calculation), the correct compensation settings for this application are (11, 11). What could happen if the relay setting engineer used compensation pair (12, 12) was modeled using real-time digital simulation.

An autotransformer on a radial system feeding a load equal to 20 percent of the transformer full-load amperes (FLA) rating was used as the model system. An external A-phase-to-B-phase fault was placed on the power system as shown in Fig. 20.

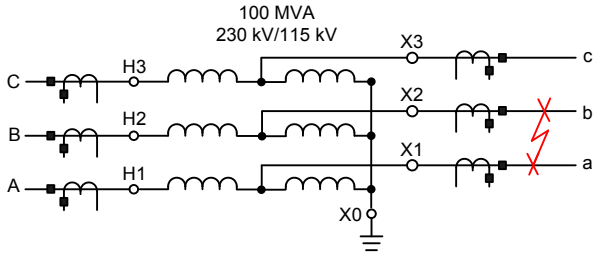

Fig. 20. A-phase-to-B-phase external fault on the low-voltage side of the autotransformer

Fig. 21 shows that the relay tripped for the external phase-to-phase fault. Similar to Case I, the filtered event data show that due to CT saturation on Winding 1, the fault current magnitude for the phases involved in the fault are not equal—about a 12 percent mismatch exists.

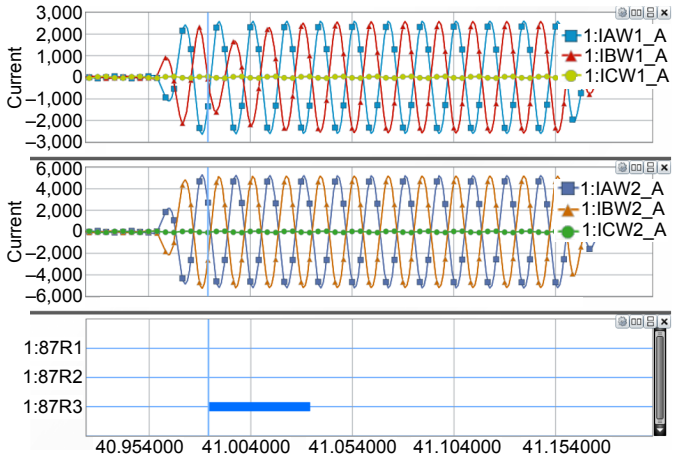

Fig. 21. Differential Element 3 operates for external fault

Similar analysis to Case I was carried out. The compensated currents on Winding 1 using the compensation pairs (12, 12) and (11, 11) were calculated and are presented in Table VI. Table VI shows that A-phase and B-phase compensated currents have significant magnitude for both compensation pairs, which provides adequate restraint when combined with Winding 2 values. However, the C-phase compensated current when using (12, 12) is much lower in magnitude than the C-phase compensated current when using (11, 11).

TABLE VI
COMPENSATED CURRENTS WITH COMPENSATION PAIR (12, 12) AND (1, 1)

Input	Currents Measured by Relay (A primary)	Compensated Currents for Pair (12, 12) (A secondary pu of tap)	Compensated Currents for Pair (11, 11) (pu of tap)
IAW1	1,910 ∠0°	7.05 ∠9.16°	4.46 ∠–0.5°
IBW1	1,640 ∠–148°	6.62 ∠–160°	7.85 ∠–165°
ICW1	33.8 ∠151°	1.41 ∠123°	3.73 ∠32.8°

Now, we look at (20) and (21) to understand this difference between the compensated C-phase currents. Equation (20) shows how the C-phase compensated current is calculated using (12, 12), and (21) shows how the C-phase compensated current is calculated using (11, 11). Equation (20) shows that when Matrix 12 is applied, the resulting ICW1C is the difference current in the faulted phases (–IAW1 + –IBW1) summed with ICW1 current—in this case, a very light load current. On the other hand, (21) shows that when Matrix 11 is applied, the resulting ICW1C includes both fault current (–IBW1) and load current (ICW1), resulting in a much larger value.

$$ICW1C = \frac{1}{CTR1 \bullet TAP1} \bullet \frac{1}{3} \bullet \left(-IAW1 + -IBW1 + 2 \bullet ICW1\right) \quad (19)$$

$$ICW1C = \frac{1}{CTR1 \bullet TAP1} \bullet \frac{1}{\sqrt{3}} \bullet \left(-IBW1 + ICW1\right) \quad (20)$$

What is important to understand is how these resulting compensated currents impact the operate and restraint currents for this external fault. The operate and restraint currents using the equations shown in Fig. 1, with k = 1, were calculated for the compensation pairs (12, 12) and (11, 11) and are presented in Table VII and Table VIII, respectively. These values were also plotted on the percentage-restrained trip characteristic based on the relay settings and are presented in Fig. 22. It is evident from Fig. 22 that the restraint current in Element 3 (C-phase) for the compensation pair (12, 12) is very small, and a small amount of false operate current was enough to cause the element to trip for an external fault. On the other hand, the restraint current in Element 3 (C-phase) for the compensation pair (11, 11) is adequately high to properly secure the element in the presence of false operate current. This analysis again proves that the compensation settings derived using the rules in Section V cause the element to properly restrain, and security is improved.

TABLE VII
OPERATE AND RESTRAINT CURRENTS WITH COMPENSATION SET TO (12, 12)

Differential Characteristic Current	Differential Element 1	Differential Element 2	Differential Element 3
IOP (pu)	1.32	2.64	1.31
IRT (pu)	14.71	14.19	1.51
IOP/IRT (%)	9	18	87

TABLE VIII
OPERATE AND RESTRAINT CURRENTS WITH COMPENSATION SET TO (11, 11)

Differential Characteristic Current	Differential Element 1	Differential Element 2	Differential Element 3
IOP (pu)	0.00	2.29	2.28
IRT (pu)	8.93	16.65	8.06
IOP/IRT (%)	0	14	28

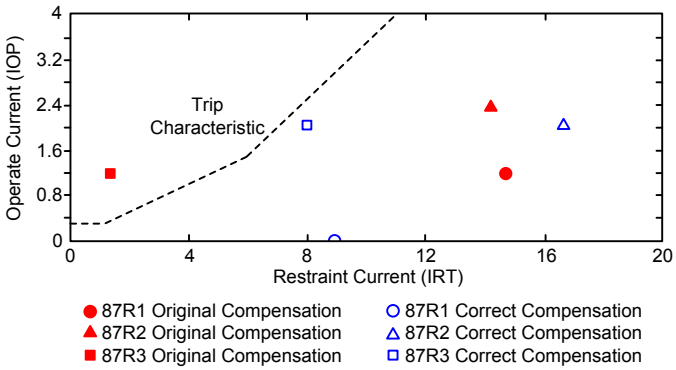

Fig. 22. Relay trip characteristic and matrix selection comparison for A-phase-to-B-phase external fault

VIII. CONCLUSION

This paper presents four simple rules (based on fundamental principles) that should be followed in order to select correct compensation matrices for the secure application of transformer differential relays. The first rule is that the engineer needs to look beyond the nameplate to determine the phase shift that a relay sees across a transformer installation. The transformer construction, system phase sequence, phase-to-bushing connections, and CT connections all influence the phase shift that the relay sees.

Once the phase shift is known, selecting the correct compensation settings is simple. In general, the delta winding, when available, should always be selected as the reference winding and assigned Matrix 0. The wye winding should be assigned an odd matrix that brings the currents the relay sees to be 180 degrees out of phase with the delta winding. Examples of how to apply these rules to several real-world installations are given in Appendix C.

The events shown in this paper prove that even-numbered matrices should be avoided whenever possible because they can result in a loss of restraint current and reduce the security of the differential elements when CT saturation occurs during an external phase-to-phase fault. That being said, it is important to understand the likelihood of seeing a misoperation like this. The possibility of CT saturation during transformer through faults is low due to transformers having high reactance and microprocessor-based relays having very low burden. However, CT saturation can still occur when fault currents have high dc offset, CTs are selected improperly, or applications use dual-breaker terminations where the fault current entering and exiting the dual-breaker terminal is not limited by the transformer reactance. Despite the low occurrence of misoperations attributed to uneven CT saturation during external phase-to-phase faults, it is important to apply correct compensation settings using the rules in this paper to avoid these operations.

IX. Appendix A

This appendix shows the various matrices used for compensating winding currents in transformer differential relays. Table IX is taken from [1], but this version includes corrections to the wye matrices that will be changed in the next revision of the standard. Matrices that are labeled with a number (Matrix *n*) are available as compensation settings in a microprocessor-based relay [7] [8] [9]. In Table IX, "cw" is clockwise and "ccw" is counterclockwise.

TABLE IX
COMPENSATING DIFFERENTIAL CURRENTS FOR NUMERICAL RELAYS

Row	Degree Shift That Would be Cancelled		Wye	Delta	Double-Delta
0	ABC, 0 • 30º cw	0º	Matrix 0 $= \begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix}$		Matrix 12 $= \frac{1}{3}\begin{bmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{bmatrix}$
	ACB, 0 • 30º ccw	0º			
1	ABC, 1 • 30º cw	30º		Matrix 1 $= \frac{1}{\sqrt{3}}\begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix}$	
	ACB, 1 • 30º ccw	330º			
2	ABC, 2 • 30º cw	60º	$1\begin{bmatrix} 0 & -1 & 0 \\ 0 & 0 & -1 \\ -1 & 0 & 0 \end{bmatrix}$		Matrix 2 $= \frac{1}{3}\begin{bmatrix} 1 & -2 & 1 \\ 1 & 1 & -2 \\ -2 & 1 & 1 \end{bmatrix}$
	ACB, 2 • 30º ccw	300º			
3	ABC, 3 • 30º cw	90º		Matrix 3 $= \frac{1}{\sqrt{3}}\begin{bmatrix} 0 & -1 & 1 \\ 1 & 0 & -1 \\ -1 & 1 & 0 \end{bmatrix}$	
	ACB, 3 • 30º ccw	270º			
4	ABC, 4 • 30º cw	120º	$1\begin{bmatrix} 0 & 0 & 1 \\ 1 & 0 & 0 \\ 0 & 1 & 0 \end{bmatrix}$		Matrix 4 $= \frac{1}{3}\begin{bmatrix} -1 & -1 & 2 \\ 2 & -1 & -1 \\ -1 & 2 & -1 \end{bmatrix}$
	ACB, 4 • 30º ccw	240º			
5	ABC, 5 • 30º cw	150º		Matrix 5 $= \frac{1}{\sqrt{3}}\begin{bmatrix} -1 & 0 & 1 \\ 1 & -1 & 0 \\ 0 & 1 & -1 \end{bmatrix}$	
	ACB, 5 • 30º ccw	210º			
6	ABC, 6 • 30º cw	180º	$1\begin{bmatrix} -1 & 0 & 0 \\ 0 & -1 & 0 \\ 0 & 0 & -1 \end{bmatrix}$		Matrix 6 $= \frac{1}{3}\begin{bmatrix} -2 & 1 & 1 \\ 1 & -2 & 1 \\ 1 & 1 & -2 \end{bmatrix}$
	ACB, 6 • 30º ccw	180º			
7	ABC, 7 • 30º cw	210º		Matrix 7 $= \frac{1}{\sqrt{3}}\begin{bmatrix} -1 & 1 & 0 \\ 0 & -1 & 1 \\ 1 & 0 & -1 \end{bmatrix}$	
	ACB, 7 • 30º ccw	150º			
8	ABC, 8 • 30º cw	240º	$1\begin{bmatrix} 0 & 1 & 0 \\ 0 & 0 & 1 \\ 1 & 0 & 0 \end{bmatrix}$		Matrix 8 $= \frac{1}{3}\begin{bmatrix} -1 & 2 & -1 \\ -1 & -1 & 2 \\ 2 & -1 & -1 \end{bmatrix}$
	ACB, 8 • 30º ccw	120º			
9	ABC, 9 • 30º cw	270º		Matrix 9 $= \frac{1}{\sqrt{3}}\begin{bmatrix} 0 & 1 & -1 \\ -1 & 0 & 1 \\ 1 & -1 & 0 \end{bmatrix}$	
	ACB, 9 • 30º ccw	90º			
10	ABC, 10 • 30º cw	300º	$1\begin{bmatrix} 0 & 0 & -1 \\ -1 & 0 & 0 \\ 0 & -1 & 0 \end{bmatrix}$		Matrix 10 $= \frac{1}{3}\begin{bmatrix} 1 & 1 & -2 \\ -2 & 1 & 1 \\ 1 & -2 & 1 \end{bmatrix}$
	ACB, 10 • 30º ccw	60º			
11	ABC, 11 • 30º cw	330º		Matrix 11 $= \frac{1}{\sqrt{3}}\begin{bmatrix} 1 & 0 & -1 \\ -1 & 1 & 0 \\ 0 & -1 & 1 \end{bmatrix}$	
	ACB, 11 • 30º ccw	30º			

X. Appendix B

The nameplate of a DABY transformer is shown in Fig. 23.

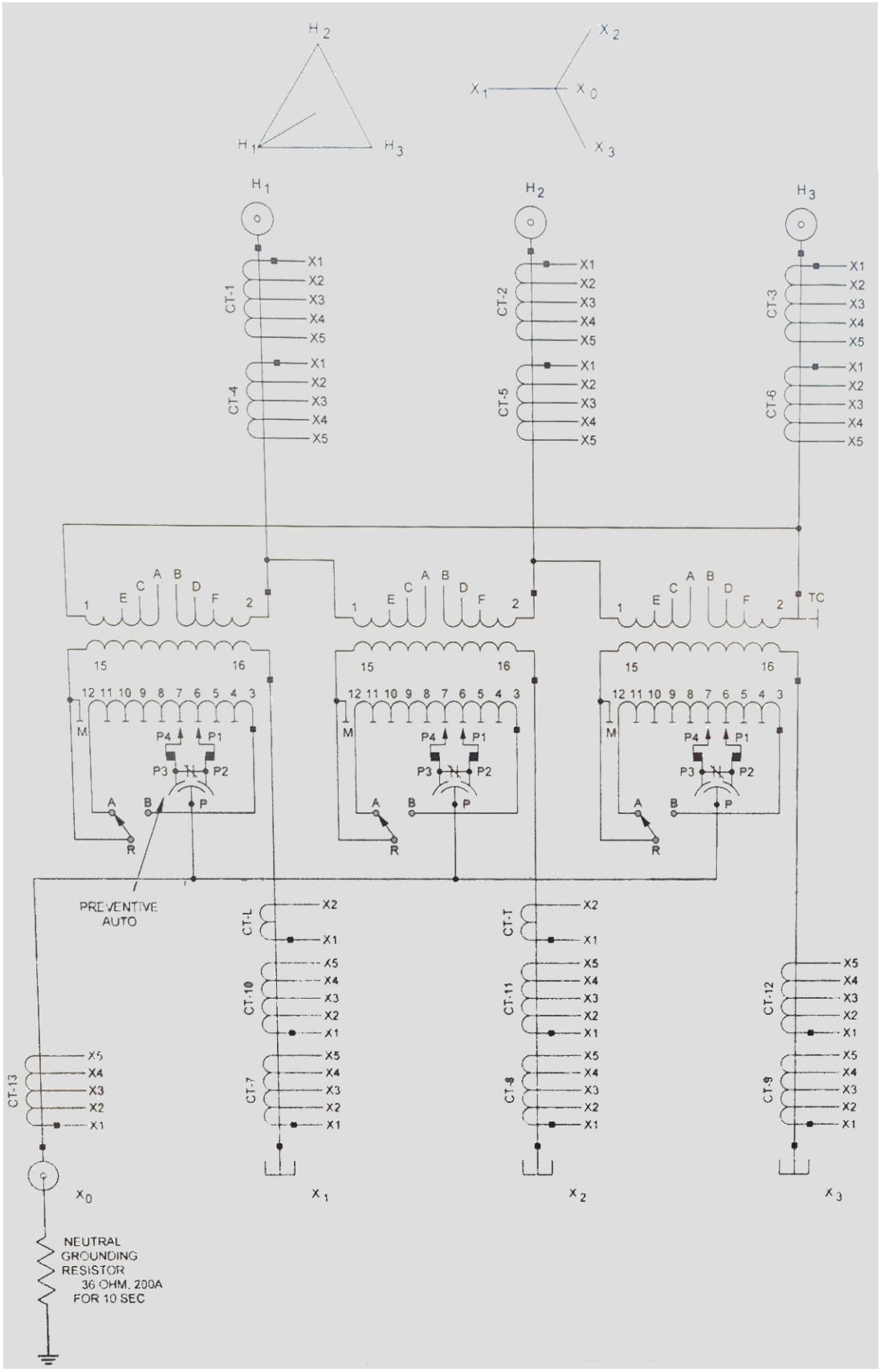

Fig. 23. Nameplate of a DABY transformer

XI. Appendix C

A. Example 1: DABY Transformer, ABC System Phase Sequence, Standard Phase-to-Bushing Connections, and Standard CT Connections

In this example, the transformer in Appendix B is connected on a system with ABC system phase sequence, standard phase-to-bushing connections, and standard CT connections. This is shown in Fig. 24. We can use the procedure detailed in Section IV to trace through the transformer connection and derive the phase shift between currents on either side. The result is shown at the bottom of Fig. 24.

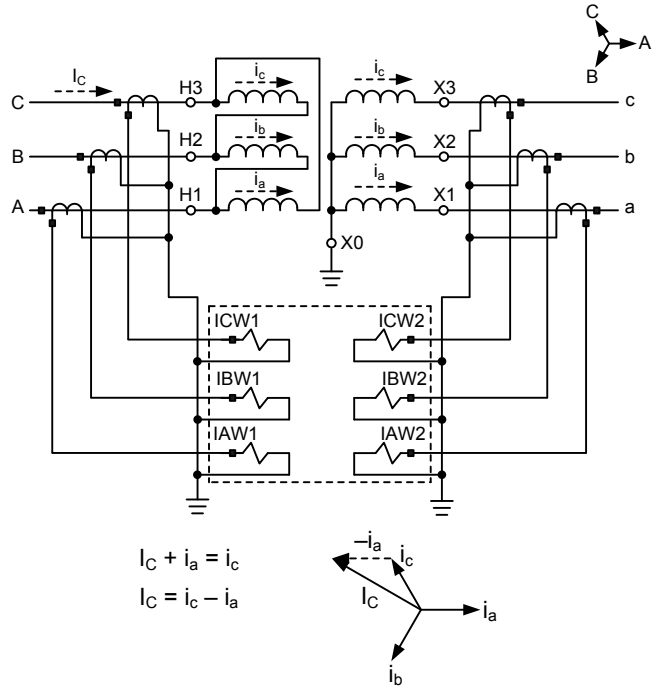

Fig. 24. Deriving the phase shift across the transformer for Example 1

In this example, we can see that the delta-side current (I_C) is $\sqrt{3}$ times larger and leads the wye-side current (i_c) by 30 degrees on the system. This can be done for all three phases, and the results are shown in Fig. 25a. For this example (with ABC phase sequence, standard phase-to-bushing connections, and standard CT connections), the phasors in Fig. 25a could be drawn directly from the nameplate.

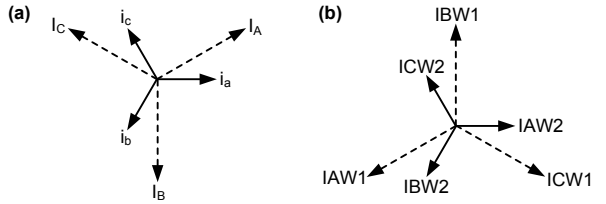

Fig. 25. Phase currents for Example 1 on the system (a) and at the relay (b)

Next, we need to determine what the phasors look like at the relay inputs after the CTs have been taken into consideration. With standard CT connections, the phasors seen at the relay will look like Fig. 25b.

Now that we have derived the phase shift of the installation that the relay sees, we can apply the remainder of the rules in Section V to determine the compensation settings for this example. Because Winding 1 is a delta winding, Rule 2 tells us that we must select it as our reference and choose Matrix 0 for that winding. In order to make Winding 2 180 degrees out of phase with Winding 1, we need to rotate it one multiple of 30 degrees in the counterclockwise direction. (Recall that we are rotating counterclockwise because the phase sequence seen by the relay is ABC.) This results in a compensation pair of (0, 1).

B. Example 2: DABY Transformer, ACB System Phase Sequence, Standard Phase-to-Bushing Connections, and Standard CT Connections

This example is similar to Example 1, but with ACB system phase sequence instead of ABC. The current flow through the transformer and the resulting equations are the same as in Example 1, but due to the ACB system phase sequence, the resulting phase shift across the transformer is different, as shown in Fig. 26.

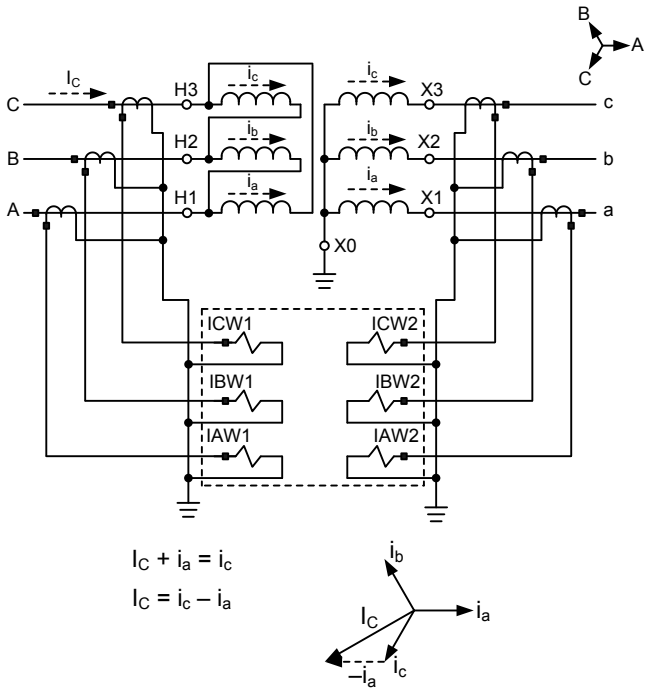

Fig. 26. Deriving the phase shift across the transformer for Example 2

In this example, we can see that the delta-side current (I_C) is $\sqrt{3}$ times larger and lags the wye-side current (i_c) by 30 degrees on the system, which is in the opposite direction of Example 1. This is shown in Fig. 27a. Next, we need to determine what the phasors look like at the relay inputs after the CTs have been taken into consideration. With standard CT connections, the phasors seen at the relay will look like Fig. 27b.

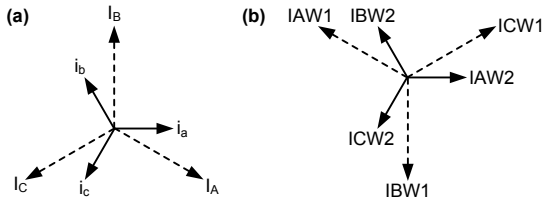

Fig. 27. Phase currents for Example 2 on the system (a) and at the relay (b)

Now that we have derived the phase shift of the installation that the relay sees, we can apply the remainder of the rules in Section V to determine the compensation settings for this example. Because Winding 1 is a delta winding, Rule 2 tells us that we must select it as our reference and choose Matrix 0 for that winding. In order to make Winding 2 180 degrees out of phase with Winding 1, we need to rotate it one multiple of 30 degrees in the clockwise direction. (Recall that we are rotating clockwise because the phase sequence seen by the relay is ACB.) This results in a compensation pair of (0, 1). Note that the compensation settings are the same as in Example 1. Because the matrices perform the phase shift in the opposite direction when the phase sequence changes, a change in phase sequence alone will not change the resulting compensation settings required for the installation.

C. Example 3: DABY Transformer, ABC System Phase Sequence, Nonstandard Phase-to-Bushing Connections, and Nonstandard CT Connections

Due to the realities of substation construction and how phases transfer from transmission lines to buswork, the phase-to-bushing connections on a transformer might not be standard. When this happens, the engineer is faced with a choice on how to wire the relay. It is always recommended to match the system phases with the corresponding labeled current input on the relay. That is, A-phase on the system should always be connected to the A-phase current inputs on the relay, and the same with B-phase and C-phase. However, in order to standardize their drawings, some utilities choose to wire the relay the same way every time, without regard to the actual system phases. This means they always wire A-phase on the relay to the H1 and X1 terminal CTs, B-phase on the relay to the H2 and X2 terminal CTs, and C-phase on the relay to the H3 and X3 terminal CTs.

Fig. 28 shows how the phase-to-bushing and CT-to-relay connections might be wired in one of these cases. Keep in mind that the practice of not matching the system phases to the relay phases is not recommended. Doing this adds complication to the settings and can cause confusion when relay targets and event reports are analyzed because the relay phase labels do not match the actual system phases. These connections can also be found in mobile transformer installations, where the phase-to-bushing connections can change between installations but the wiring between the CTs and the relay remains unchanged. Reference [12] describes how to set a relay to protect a mobile DABY transformer.

Tracing through the transformer connection, as described in Section IV, results in the phase shift shown at the bottom of Fig. 28.

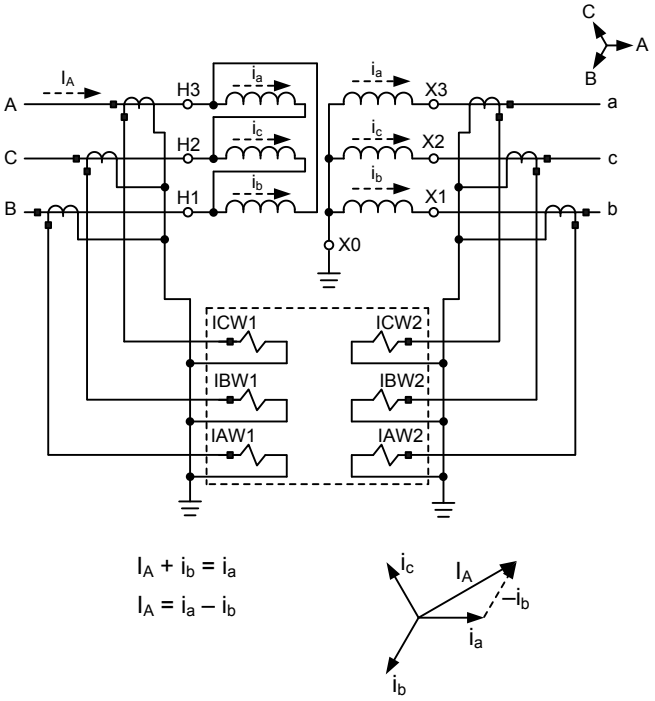

Fig. 28. Deriving the phase shift across the transformer for Example 3

In this example, we can see that the delta-side current (I_A) is $\sqrt{3}$ times larger and leads the wye-side current (i_b) by 30 degrees on the system. Because the engineer maintained the phase sequence order when making the phase-to-bushing connections, the phase shift given on the nameplate of the transformer is maintained. This can be done for all three phases, and the results are shown in Fig. 29a. Note that if we use the shortcut in Table I, the system phase sequence (ABC) matches the order of the phase-to-bushing connections (BCA). This means that the nameplate phase shift is correct and can be used.

Next, we need to determine what the phasors look like at the relay inputs after the CTs have been taken into consideration. For this example, the CTs are connected in wye and have differential polarity. However, we need to take into account the fact that the CTs are wired to the incorrect phases on the relay. In this configuration, what is A-phase on the system is actually C-phase on the relay, what is C-phase on the system is actually B-phase on the relay, and what is B-phase on the system is actually A-phase on the relay. Taking this into account, the phasors seen at the relay will look like Fig. 29b.

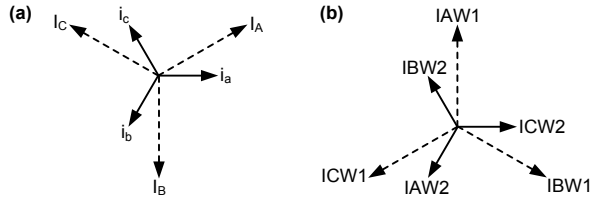

Fig. 29. Phase currents for Example 3 on the system (a) and at the relay (b)

Now that we have derived the phase shift of the installation that the relay sees, we can apply the remainder of the rules in Section V to determine the compensation settings for this example. Because Winding 1 is a delta winding, Rule 2 tells us that we must select it as our reference and choose Matrix 0 for that winding. In order to make Winding 2 180 degrees out of phase with Winding 1, we need to rotate it one multiple of 30 degrees in the counterclockwise direction. (Recall that we are rotating counterclockwise because the phase sequence seen by the relay is ABC.) This results in a compensation pair of (0, 1).

D. Example 4: DACY Transformer, ABC System Phase Sequence, Standard Phase-to-Bushing Connections, and Nonstandard CT Connections

In this example, a DACY transformer is connected on a system with ABC system phase sequence, standard phase-to-bushing connections, and nonstandard CT connections. The CTs are connected in wye, with load polarity instead of differential polarity. This is shown in Fig. 30. Tracing through the transformer connection, as described in Section IV, results in the phase shift shown at the bottom of Fig. 30.

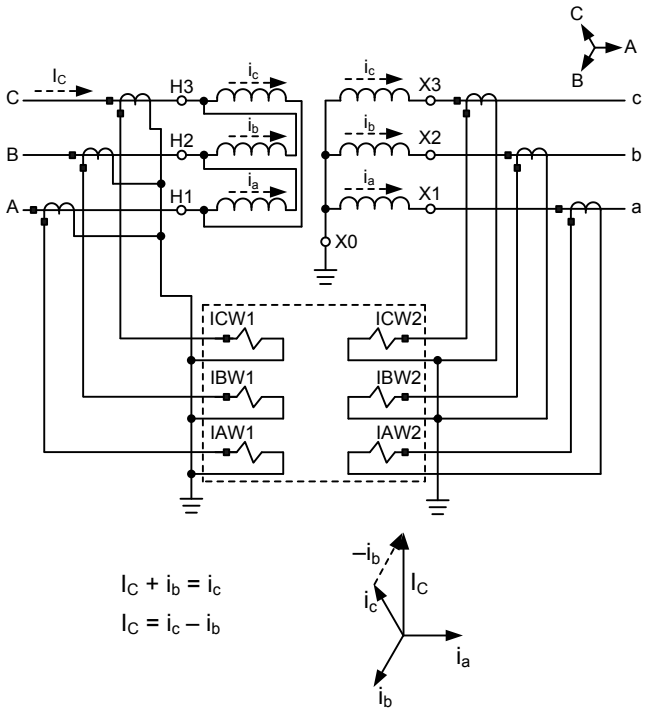

Fig. 30. Deriving the phase shift across the transformer for Example 4

In this example, we can see that the delta-side current (I_C) is $\sqrt{3}$ times larger and lags the wye-side current (i_c) by 30 degrees on the system. This can be done for all three phases, and the results are shown in Fig. 31a.

Next, we need to determine what the phasors look like at the relay inputs after the CTs have been taken into consideration. Although CTs in standard transformer installations have differential polarity, where the CTs face each other, load polarity can be found in some applications where a CT is being used for feeder protection as well as transformer protection. Because the CTs in this installation have load polarity, neither of the winding currents get flipped by 180 degrees before being brought into the relay. Therefore, the phasors seen at the relay will look like Fig. 31b.

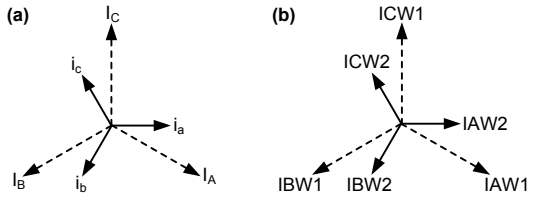

Fig. 31. Phase currents for Example 4 on the system (a) and at the relay (b)

Now that we have derived the phase shift of the installation that the relay sees, we can apply the remainder of the rules in Section V to determine the compensation settings for this example. Because Winding 1 is a delta winding, Rule 2 tells us that we must select it as our reference and choose Matrix 0 for that winding. In order to make Winding 2 180 degrees out of phase with Winding 1, we need to rotate it five multiples of 30 degrees in the counterclockwise direction. (Recall that we are rotating counterclockwise because the phase sequence seen by the relay is ABC.) This results in a compensation pair of (0, 5).

E. Example 5: Autotransformer, ABC System Phase Sequence, Standard Phase-to-Bushing Connections, and Standard CT Connections

In this example, a wye-wye autotransformer is connected on a system with ABC system phase sequence, standard phase-to-bushing connections, and standard CT connections. The delta tertiary exists but is buried and not brought out to the relay. This is shown in Fig. 32. Tracing through the transformer connection, as described in Section IV, results in the phase shift shown at the bottom of Fig. 32.

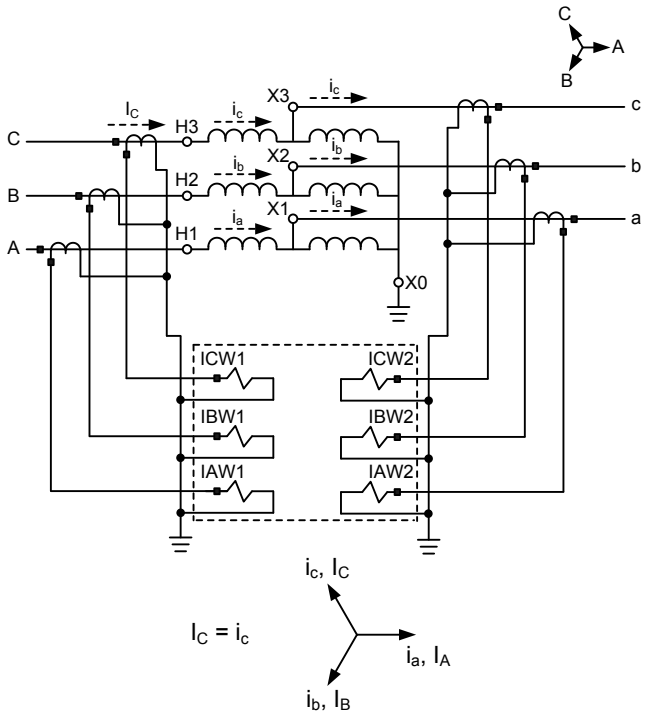

Fig. 32. Deriving the phase shift across the transformer for Example 5

In this example, we can see that the high-side currents are in phase with the low-side currents on the system, as shown in Fig. 33a.

Fig. 33. Phase currents for Example 5 on the system (a) and at the relay (b)

Next, we need to determine what the phasors look like at the relay inputs after the CTs have been taken into consideration. For this example, with standard CT connections, the phasors seen at the relay will look like Fig. 33b.

Now that we have derived the phase shift of the installation that the relay sees, we can apply the remainder of the rules in Section V to determine the compensation settings for this example. Rule 2 tells us that if there is no delta winding connected to the relay, which is the case here, we must select Matrix 11 for one of the wye windings and select the appropriate odd matrix for the compensation of the other wye winding. Therefore, we can select Matrix 11 for either Winding 1 or Winding 2. If we select Matrix 11 for Winding 1, this will shift the Winding 1 phasors 11 multiples of 30 degrees in the counterclockwise direction. In order to keep Winding 2 180 degrees out of phase with Winding 1, we must also shift Winding 2 by 11 multiples of 30 degrees in the counterclockwise direction. This results in a compensation pair of (11, 11).

Autotransformers usually have a low-voltage tertiary winding that lags the high- and medium-voltage windings by 30 degrees. If the delta tertiary winding is brought into the relay as part of the differential, we select Matrix 0 for that winding per the rules in Section V. Assuming standard connections, analysis similar to the previous examples leads to selecting Matrix 11 for both high- and medium-voltage windings.

F. Example 6: DABY Transformer with Zig-Zag Grounding Transformer Within the Differential Zone on the Delta Side, ABC System Phase Sequence, Standard Phase-to-Bushing Connections, and Standard CT Connections

This example is the same as Example 1, but with a zig-zag grounding transformer on the delta side of the DABY transformer. Zig-zag transformers are typically used for grounding purposes and act as a source of zero-sequence current. If the zig-zag transformer is located outside of the differential zone on the delta side, it can be ignored, and the compensation settings will remain the same as in Example 1. The same is true if the zig-zag transformer is present on the wye side, be it inside or outside the differential zone. If the zig-zag transformer is within the differential zone on the delta side, as shown in Fig. 34, then it has to be accounted for when determining proper compensation settings.

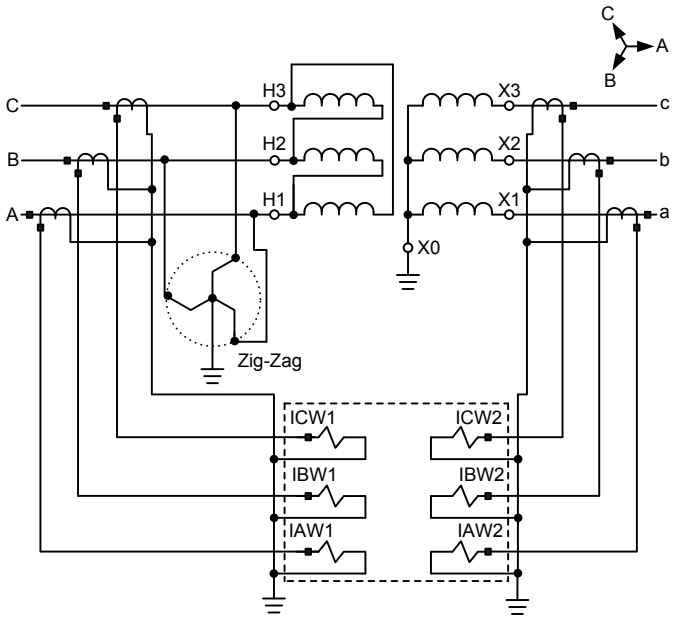

Fig. 34. DABY transformer with zig-zag grounding transformer within the differential zone on delta side

Fig. 35a shows the one-line diagram of a radial system with the source connected to the wye side of the transformer shown in Fig. 34 and an external A-phase-to-ground fault on the delta side of the transformer. Fig. 35b shows the corresponding sequence diagram for this fault. From the positive-sequence network, it can be observed that both Winding 1 and Winding 2 CTs see equal amounts of positive-sequence current. Likewise, from the negative-sequence network, it can be observed that both Winding 1 and Winding 2 CTs see equal amounts of negative-sequence current. However, from the zero-sequence network, it can be observed that only the Winding 1 CT sees the zero-sequence current while the Winding 2 CT does not see any. Hence, for proper current balance of the differential element, the zero-sequence current on Winding 1 (delta side) should be filtered out. This is done by selecting a nonzero compensation matrix for the delta winding of the transformer.

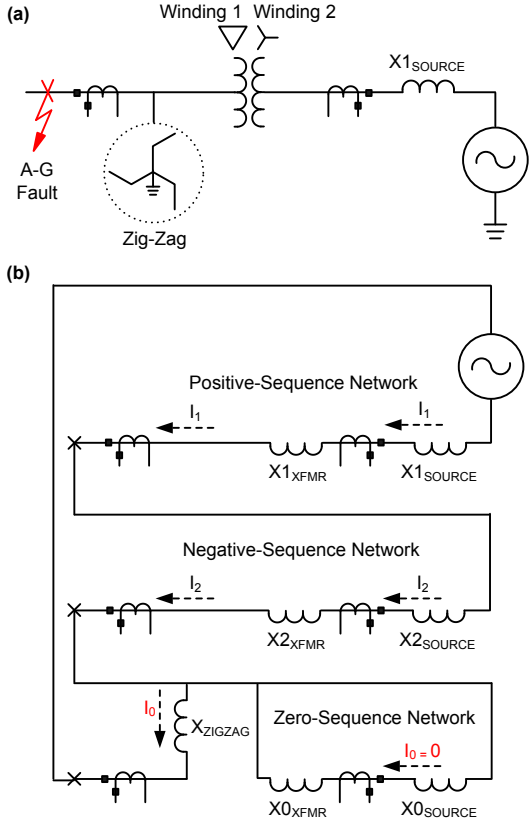

Fig. 35. One-line (a) and sequence diagram (b) for an A-phase-to-ground (A-G) fault external to a DABY transformer with a ground source

The currents and phasor diagrams shown in Fig. 24 and Fig. 25 of Example 1 hold true for this example as well. The resulting compensation pair in Example 1 is (0, 1). This compensation pair will bring Winding 2 currents as seen by the relay 180 degrees out of phase with Winding 1. However, recall the explanation in the previous paragraph as well as the rules for special cases in Section V, which tell us that we need to remove zero-sequence current from the delta side of the transformer when there is a ground source on the delta side within the zone of protection. To do this, we choose Matrix 12 instead of Matrix 0 for Winding 1. Matrix 12 removes the zero-sequence currents on the delta side while keeping the phase shift the same as Matrix 0. This results in a compensation pair of (12, 1).

G. Example 7: Atypical Wye-Delta Transformer, ABC System Phase Sequence, Standard Phase-to-Bushing Connections, and Standard CT Connections

In this example, the atypical wye-delta transformer shown in Fig. 36 is connected to a system with ABC system phase sequence, standard phase-to-bushing connections, and standard CT connections. This system is shown in Fig. 37. Tracing through the transformer connection, as described in Section IV, results in the phase shift shown at the bottom of Fig. 37, which matches the nameplate in Fig. 36. Although the wye winding is the high-voltage winding in this case and drawn on the left side in Fig. 37, the procedure of tracing currents to determine the phase shift is still the same, with currents flowing through the transformer from the delta side to the wye side.

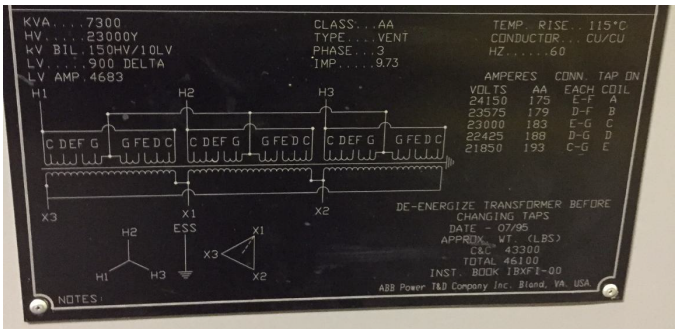

Fig. 36. Nameplate of an atypical wye-delta transformer

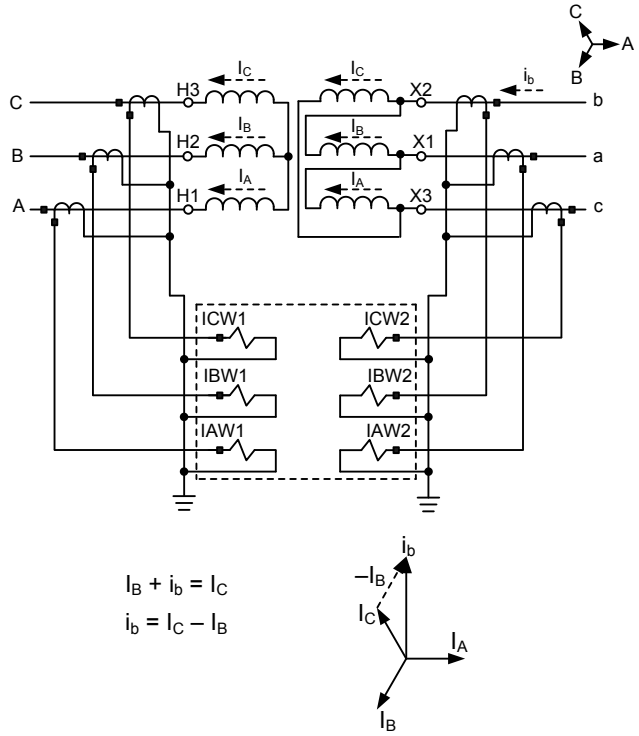

Fig. 37. Deriving the phase shift across the transformer for Example 7

In this example, we can see that the delta-side current (i_b) is $\sqrt{3}$ times larger and lags the wye-side current (I_B) by 150 degrees on the system. This can be done for all three phases, and the results are shown in Fig. 38a.

Next, we need to determine what the phasors look like at the relay inputs after the CTs have been taken into consideration. With standard CT connections, the phasors seen at the relay will look like Fig. 38b.

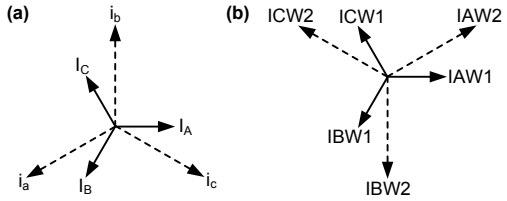

Fig. 38. Phase currents for Example 7 on the system (a) and at the relay (b)

Now that we have derived the phase shift of the installation that the relay sees, we can apply the remainder of the rules in Section V to determine the compensation settings for this example. Because Winding 2 is a delta winding, Rule 2 tells us that we must select it as our reference and choose Matrix 0 for that winding. In order to make Winding 1 180 degrees out of phase with Winding 2, we need to rotate it seven multiples of 30 degrees in the counterclockwise direction. (Recall that we are rotating counterclockwise because the phase sequence seen by the relay is ABC.) This results in a compensation pair of (7, 0).

Table X summarizes all seven examples and the resulting compensation setting pairs.

TABLE X
COMPENSATION SETTINGS FOR EXAMPLES 1 TO 5

Example	Phase Sequence	Connections			Settings
		Transformer	Phase-to-Bushing	CT	
1	ABC	DABY	Standard	Standard	0, 1
2	ACB	DABY	Standard	Standard	0, 1
3	ABC	DABY	Nonstandard	Nonstandard	0, 1
4	ABC	DACY	Standard	Nonstandard	0, 5
5	ABC	Wye-wye autotransformer	Standard	Standard	11, 11
6	ABC	DABY with zig-zag	Standard	Standard	12, 1
7	ABC	Atypical wye-delta	Standard	Standard	7, 0

XII. REFERENCES

[1] IEEE Standard C37.91-2008, IEEE Guide for Protecting Power Transformers.

[2] K. Behrendt, N. Fischer, and C. Labuschagne, "Considerations for Using Harmonic Blocking and Harmonic Restraint Techniques on Transformer Differential Relays," proceedings of the 33rd Annual Western Protective Relay Conference, Spokane, WA, October 2006.

[3] H. J. Altuve, N. Fischer, G. Benmouyal, and D. Finney, "Sizing Current Transformers for Line Protection Applications," proceedings of the 66th Annual Conference for Protective Relay Engineers, College Station, TX, April 2013.

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XIII. BIOGRAPHIES

Barker Edwards is a relay design and commissioning engineer and project engineer with PowerServices, Inc. and has over 46 years of experience in the field of electrical engineering. He has obtained extensive electric power utility experience in the areas of testing, maintenance, and troubleshooting of relay systems and substation equipment. His years of experience with Progress Energy, Southeastern Transformer, and PowerServices have included commissioning substations, utility controls, and industrial controls.

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Ariana Hargrave earned her B.S.E.E., magna cum laude, from St. Mary's University in San Antonio, TX, in 2007. She graduated with a Master's of Engineering in electrical engineering from Texas A&M University in 2009, specializing in power systems. Ariana joined Schweitzer Engineering Laboratories, Inc. in 2009 and works as a protection application engineer in Fair Oaks Ranch, Texas. She is a registered professional engineer in the state of Texas and has been an IEEE member for 13 years.

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