Stop the Epidemic!
Transformer Protection Misoperations

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Stop the Epidemic! Transformer Protection Misoperations

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***Abstract*—While modern transformer protective relays allow more flexibility and features compared to electromechanical relays, these features often introduce complexities in verifying that protection is configured properly. Setting and commissioning transformer relays continues to challenge the industry, and undesired operations occur too often. To help stop the epidemic of unexpected transformer relay operations, more comprehensive tools are needed to simplify the verification of relay installations.**

This paper explores common transformer commissioning issues and details how to use the comprehensive differential current report generated by numerical transformer relays to find and correct common problems and inoculate users against unexpected transformer trips.

I. Introduction

While the title of this paper may seem trendy given the impact of the recent global pandemic, it actually was inspired by a conversation among colleagues in 2015. We were evaluating a number of transformer relay misoperations, and someone exclaimed that there was an epidemic of misoperations. That conversation stuck with one of the authors and inspired the concept for this paper years later.

The principle of differential relaying counts on the fact that all currents at the boundary of the zone of protection should sum to zero. This is pretty straightforward for differential zones that are galvanically connected such as electrical buses, reactors, and rotating machine stator zones. Kirchhoff's current law (KCL) is conceptually easy to apply to sum the currents around the differential zone; however, the need to sum to zero leaves differential schemes very susceptible to error in any measurement. The scheme is prone to security failures (i.e., tripping when it should not) for errors in magnitude, angle, polarity, or phasing of the (sometimes many) individual zone boundary measurements that must be summed to form the differential current. Once set up correctly, differential schemes can be very secure.

Compared to KCL-type differential zones as used for buses, reactors, and stators, transformer differential schemes work on the principle of Ampere-Turn Balance (ATB). The differential relays are configured to sum the ampere-turns around core leg loops in the transformer magnetic circuit [1]. This requires the currents at each zone boundary to be normalized relative to each other. Normalizing currents across a transformer requires two types of compensation. Current transformer ratios (CTRs) and TAP (scaling factor) compensation account for the mismatch of current magnitudes across the transformer. Matrix compensation accounts for the difference in phase shift and zero-sequence currents across the transformer. When these two types of compensation are applied properly, a transformer differential relay measures negligible operate current under normal, steady-state operating conditions.

Electromechanical differential relays required connecting the current transformers (CTs) properly in wye or delta external to the relay to get the currents entering and exiting the relay to be 180 degrees out of phase before summing the currents in the differential element. Care had to be taken to ensure that zero-sequence current was properly removed when the transformer windings provided a path for zero-sequence current to flow. In special cases, auxiliary CTs were required to build zero-sequence traps. Magnitude mismatch was accommodated by selecting CT ratios to match the high- and low-side currents as closely as possible while properly accounting for the $\sqrt{3}$ factor introduced by connecting CTs in delta. Differential relays were constructed with TAPs in the restraint winding inputs that allowed fine tuning the magnitude compensation to reduce the differential operate current.

Modern transformer relays use settings and internal calculations to normalize zone boundary currents for a variety of power transformer and CT configurations. The flexibility of compensation settings in modern relays allows the CT circuits to be simply connected in wye regardless of the configuration of the transformer. All compensation is then performed internally based on settings. This has been a boon to the industry and made CT circuits simpler and easier to design, wire, and verify. While the CT circuits are simpler, setting and commissioning transformer relays continues to challenge the industry and undesired operations occur too often. To help stop the epidemic of unexpected transformer relay operations, more comprehensive tools are needed to simplify the verification of transformer differential installations.

When a transformer is first loaded, in-service tests are performed to verify transformer differential relay wiring and configuration. This is an important last chance to verify that everything is correct between the actual primary power system and the secondary relaying system with actual power flowing through the zone of protection. When electromechanical relays are used, angle compensation is performed externally to the relay. Magnitude compensation is performed both externally (CTR selection) and internally (TAP compensation). Operate current can easily be read by inserting a probe in series with the operate coil to determine if there are issues that may require investigation. While this is a quick check, it is not always conclusive because it does not account for the TAP compensation that occurs in the differential element circuitry. Angle compensation and wiring errors can be easily identified by reading the magnitude and angle of current in each of the restraint inputs of the relay.

Today, many relays with internal compensation only report the currents coming into the relay (before compensation), making it more difficult to find compensation problems. The typical substitute for jacking into the operate circuit is a metering report that tells the commissioning engineer the calculated operate and restraint current magnitudes after compensation. Similar to directly reading the current in the operate coil of an electromechanical differential relay, this metering report is used to prompt further investigation if excessive operate current is observed. However, identifying the source of this error can be one of the most challenging aspects of commissioning.

This paper explores common transformer commissioning issues and details methods to verify the mathematical compensation that occurs between the currents entering the relay and the differential element calculating operate and restraint quantities. The paper illustrates the value of a comprehensive differential current report generated by the relay. This report makes it easy to find and correct common problems and inoculate users against unexpected transformer trips.

II. Review of Fundamentals

In a percentage-restrained differential application, CTs from all sides of the protected equipment provide the measured currents to the relay, which are then used to calculate operate and restraint values as shown in Fig. 1. Equation (1) shows one typical method for quantifying these measurements [2]. The operate quantity is a measure of the sum of currents into the zone while the restraint quantity is a measure of total or average current through the zone.

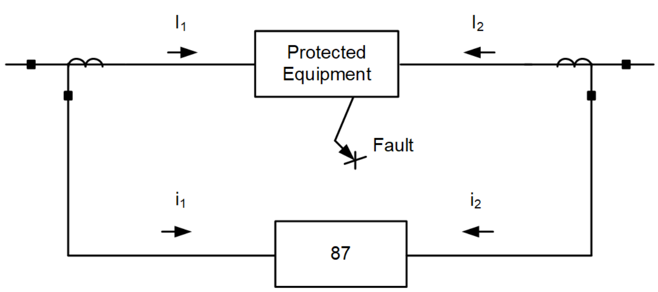


Fig. 1 Current differential protection

$$I_{OP} = \left| \vec{i}_{w1} + \vec{i}_{w2} \right|$$
$$I_{RT} = k \bullet \left(\left| \vec{i}_{w1} \right| + \left| \vec{i}_{w2} \right| \right) \quad (1)$$

where:

I_{OP} = Operate current.

I_{RT} = Restraint current.

k = Scaling factor.

When k is equal to 0.5, (1) yields the average current through the zone. Scaling factor k can be other values as well.

The operate and restraint values calculated in (1) are then used to plot a point on a percentage-restrained differential characteristic. Fig. 2 shows an example of a simple single-slope restraint characteristic [3]. The percentage-restrained differential characteristic is comprised of a minimum operate current and a slope value, which is a percentage ratio of the operate-to-restraint current. For example, in a simple single-slope differential element, if the operating point is in the operate region of the characteristic, i.e, $I_{OP} > \frac{\text{Slope (\%)}}{100} \bullet I_{RT}$, and I_{OP} is greater than the minimum operate current, the relay operates. If the point falls in the restrain region, the relay restrains [3]. I_{OP} should be close to zero under normal operating conditions.

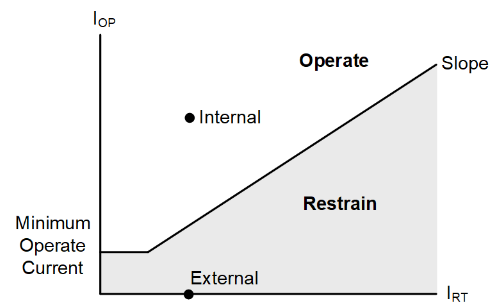


Fig. 2 Percentage restrained differential characteristic [3]

If one tries to apply the percentage-restrained differential characteristic directly to a transformer, I_{OP} will not be zero even under normal conditions. The turns ratio and winding connections of a transformer make it so that the current entering and leaving the transformer does not sum to zero without proper compensation. The relationship between the currents of different windings of a transformer is given by the ATB equations. Reference [1] extensively covers ATB. To retain the focus on differential relay misoperations, we will not cover ATB here. Proper compensation of current magnitude and phase is a must before applying percentage-restrained differential to a transformer.

In electromechanical relays, the compensation of transformer currents was achieved using CT ratios, CT connections, and TAP settings in the relays. In microprocessor relays, this compensation can be done numerically inside the relay without modifying CT connections, as shown in Fig. 3 [1] [3].

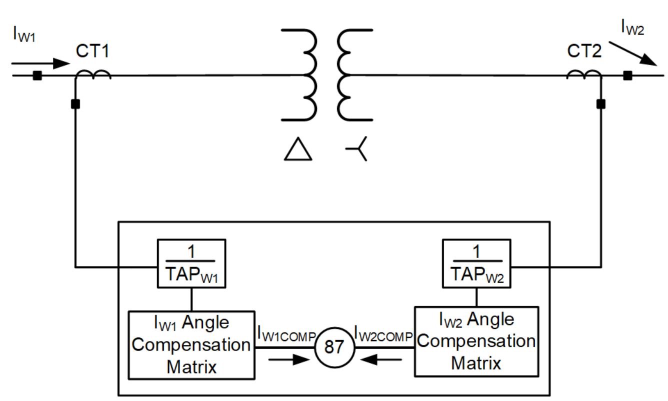


Fig. 3 Relay compensation of current magnitudes and angles

To understand how compensation works, let us look at an example of a DABY (Dyn1) transformer, as shown in Fig. 4.

The notation DAB is a shorthand way of saying, "delta with an IA-IB connection." In a standard DABY transformer, the low-voltage (LV) side currents lag the high-voltage (HV) side currents by 30 degrees. The magnitude of the LV side currents is equal to turns ratio times the magnitude of HV side currents. We must compensate for this difference in magnitude and angle before calculating operate and restraint quantities.

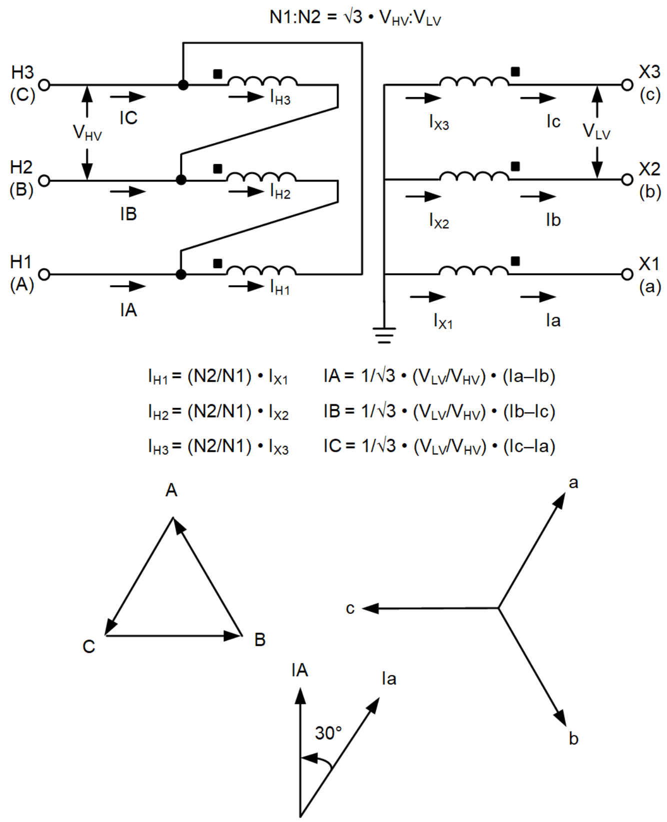


Fig. 4 Currents across a standard DABY transformer

The magnitude mismatch can be compensated to some extent by selecting the nearest matching CT ratio, i.e., $CTR_{LV} = \frac{V_{HV}}{V_{LV}} \cdot CTR_{HV}$. Any remaining magnitude difference that cannot be removed with standard CT ratios can be compensated using a magnitude compensation setting in the relay called TAP (shown in Fig. 3). TAP compensation brings all the differential zone CT currents to a common per-unit system by dividing them with the TAP value; TAP value for each CT can be calculated as shown in (2):

$$TAP = \frac{MVA \cdot 1000 \cdot CTCON}{\sqrt{3} \cdot VTERM \cdot CTR} \qquad (2)$$

where:

MVA = Common MVA base for all in zone transformer windings.

VTERM = Rated line-line transformer voltage on CT side.

CTR = Current transformer ratio.

CTCON = 1 for wye-connected CT and √3 for delta-connected CT.

Phase angle compensation can be performed two ways for a microprocessor relay:

1. Externally to the relay by using a wye-connected CT on the HV (delta) side, and a DAB-connected CT on the LV (wye) side. This is the only option available for electromechanical relays.
2. Internally to the relay by applying a compensation matrix on measured currents. Matrix compensation mathematically mimics the CTs connected in delta or wye [4].

Equation (3) shows how the HV and LV side measured currents are multiplied by compensation matrices M_{HV} and M_{LV} to obtain compensated currents ($I[\Phi]_C$, where Φ = A, B, C and a, b, c):

$$\begin{bmatrix} IA_C \\ IB_C \\ IC_C \end{bmatrix} = [M_{HV}] \cdot \begin{bmatrix} IA \\ IB \\ IC \end{bmatrix}$$
$$\begin{bmatrix} Ia_C \\ Ib_C \\ Ic_C \end{bmatrix} = [M_{LV}] \cdot \begin{bmatrix} Ia \\ Ib \\ Ic \end{bmatrix} \qquad (3)$$

where for the standard DABY transformer:

$$[M_{HV}] = \begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix}$$

$$[M_{LV}] = \frac{1}{\sqrt{3}} \cdot \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix}$$

Matrix M_{HV} provides no phase shift to the HV currents, which is similar to a wye-connected CT. Matrix M_{LV} provides a phase shift of +30 degrees to the LV side currents, mimicking a CT connected in DAB. In addition to adjusting the phase angle, matrix M_{LV} also removes zero-sequence quantities from the wye-side currents. Appendix A shows how multiplying the measured currents by matrix M_{LV} results in a phase shift of 30 degrees and removal of zero sequence.

Removing zero sequence from the LV side of the transformer is required because the wye connection is grounded and provides a path for zero-sequence currents to flow in the event of an external ground fault, as shown in Fig. 5. The zero-sequence current will not flow through the CTs on the delta side. If this zero-sequence current is not removed from the wye-side CT measurements, it will appear as a false operating current to the differential relay and cause the relay to misoperate.

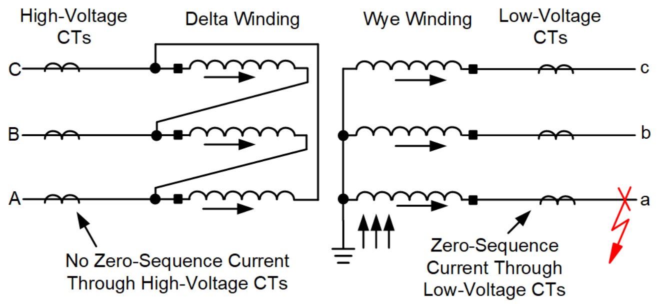


Fig. 5 Zero-sequence current through DABY transformer with wye CTs

The matrices M_{LV} and M_{HV} we selected here are unique to the DABY transformer and CT connections shown in Fig. 5. IEEE C37.91 defines phase shifts in multiples of 30 degrees, starting from 0 degrees to 360 degrees, for a total of 12 possible phase shifts [4]. Matrix compensation in microprocessor relays must be carefully, correctly selected to compensate for this phase shift along with zero-sequence removal. Most modern microprocessor-based relays include 13 compensation matrices; where Matrix 0 behaves like a wye-connected CT, it does not provide any phase shift nor does it remove zero sequence. The odd matrices (Matrix 1, 3, … 11) behave like delta-connected CTs; they will remove zero-sequence current and correct for any phase shift that is an odd multiple of 30 degrees. The even matrices (Matrix 2, 4, … 12) behave like double-delta-connected CTs, removing zero-sequence current and correcting for any phase shift that is an even multiple of 30 degrees [4]. How to select correct compensation matrices for a given transformer connection is discussed in [3].

III. Commissioning Fundamentals

The process of commissioning a protection system involves running tests that verify the design, settings, and system installation. Many different errors can result in protection system misoperations. Protection misoperations can consist of security failures (e.g., the relay trips when a fault in the protected zone is not present) or dependability failures (e.g., the relay fails to trip when a fault in the protected zone is present). Flaws in the protection system that cause either type of failure can often go undetected until the right set of circumstances occur and expose the flaw. Fortunately, with differential relaying, the stringent requirement that every current signal must sum with the others to nearly zero means that most errors will expose themselves as security failures sooner rather than later.

Another fortunate aspect of differential relaying is that it only requires current. The focus of this discussion is on verifying current circuits all the way to the differential element inside the relay.

A. Overlapping Tests

Often, overlapping tests are used to verify a complete instrument transformer circuit. By overlapping tests, we mean portions of the circuit are verified individually such that when all tests are complete, the entire circuit has been tested. For example, the substation apparatus technicians may be responsible for testing the transformers and breaker apparatus for proper polarity and ratio of the CTs installed inside the apparatus. The line of handoff between work groups might be the field-side terminal blocks in the apparatus. The relay technicians then verify the rest of the current circuit by using a test set to push current from the terminal blocks inside the apparatus control cabinet (to verify continuity, phasing, and CT polarity) through the field cables, through any intermediate junction boxes and termination cabinets, to the relay panels, and then through the panel wiring to the relays.

In such a test, errors can be missed at the discontinuities of tests and handoffs between work groups. Plus, with differential schemes, testing each circuit individually may miss an issue when the currents are summed between different circuits.

B. Primary Injection Testing

Primary injection testing involves injecting a test signal into the primary conductors and detecting that it properly appears at the relay. This provides assurance that any errors are found at the handoff point between overlapping tests. This test helps detect errors that may otherwise be missed. Two typical tests are described here: one using a battery and another using a three-phase source of test current of sufficient capacity to provide adequate signals for measurement.

These tests often require that safety grounds be temporarily removed from the primary conductors during testing. For this reason, proper caution and procedures should be followed in conducting these tests.

1) DC Kick Test

One form of primary injection test is the "kick test," also known as the "DC pulse test" [5]. This test has the advantage that the test source is a low-capacity lantern battery and therefore easily portable and accessible. A high dc current is not required nor desired, so a high-capacity battery such as a car battery should not be used.

The test works on Faraday's law of electromagnetic induction. By causing a change in current in the primary conductor of the CT, the resulting changing magnetic flux induces a voltage in the magnetically coupled secondary conductor of the CT. If the changing current is a positive step change (close the circuit), a positive voltage pulse appears in the secondary during the rise time of the primary dc current and results in a positive pulse of current at the relay. When the dc current is interrupted, causing a negative step change in dc current, a negative pulse of voltage appears in the secondary circuit and results in a negative pulse of current at the relay. Care should be taken to use a low-current battery and keep the switch-closed duration short to prevent magnetizing the transformer and CT cores.

A milliammeter with a D'Arsonval movement is used to sense the up kick and the down kick of making and breaking the battery circuit, hence the name kick test. A meter that is null center (i.e., can freely move either direction to show both the up and down kick) is recommended. One downside of this test is that, while the required test apparatus is minimal (a battery, some long leads, and a knife switch), electromechanical meters may not be readily available on the jobsite because the workhorse in the industry today is digital multimeters.

When planning these tests, it is important to determine how to connect the battery and short circuits such that there is a low-impedance path for currents to flow through the primary conductor of the CT. In the case of CTs buried inside the tank of a transformer, the same laws of induction apply to the dc pulse currents as to the normal ac currents. If all other windings on the same core leg are open-circuited, that open circuit will be reflected to the winding that you wish to kick through and the current pulse in the secondary circuit will be very weak. This is especially a concern when "kicking" a ground CT. The rules of zero-sequence current flow must be observed.

See Fig. 6 for a kick test of the X0 bushing CT of a delta-wye distribution transformer. Fig. 6 (a) shows connecting the battery to all three phases of the wye windings. This allows the primary kick currents to easily circulate in the delta, giving a good signal in the secondary. Fig. 6 (b) shows connecting the battery to only one phase of the wye windings. In this case, the kick currents still flow freely because the safety ground shorts the primary winding of the one phase being kicked through.

This test proves continuity, phasing, and polarity of the CT circuit. It does not prove ratio. A separate test is required to verify ratio. Because the numerical relay will not read the current pulses, this test is not useful for verifying the compensation that happens between the relay CT inputs and the differential element.

2) Three-Phase Primary Injection Tests (Through-Fault Tests)

The most thorough pre-energization test and the one most easily interpreted by commissioning personnel is the three-phase primary injection test. In this test, the phase leads at one terminal of the differential zone are short-circuited on the buswork outside of the differential CTs and a relatively LV three-phase source is connected to the other terminal of the differential zone. The reader is recommended to consult [6]. Reference [6] provides a thorough discussion of how to conduct three-phase primary injection tests. The following is a very high-level summary of this test.

The three-phase voltage applied is calculated to be great enough to drive some fraction of rated current through the leakage reactance of the transformer.

For example, let us assume a 138 kV–34.5 kV transformer with 7 percent base impedance. The CT ratios were chosen to give 3 A secondary at transformer-rated current. We would like to have no less than 0.25 A current in the CT secondary circuits in a 5 A nominal relay to verify magnitude and angle of the currents. Accuracy for loading less than this level could be affected by other errors and lead to inconclusive readings.

In this case, 0.25 A secondary is 8.3 percent of 3 A. We would require a three-phase source of 34.5 kV • 7% • 8.3% = 201V_{LL} to drive the desired minimum current through the transformer leakage impedance when the transformer is short-circuited on the 138 kV side. The MVA rating of the three-phase test source would need to be sized based on the primary amperes required. Greater test currents than the minimum of 0.25 A are desirable to detect the relatively low-magnitude errors caused by a CT on the wrong ratio. Using a 480 V test source, we would expect to see around 0.6 A secondary provided to the relay in this example.

When balanced three-phase ac current is flowing in the primary conductors at each of the zone boundaries, the relay properly measures and compensates the currents, providing a realistic representation of what the relay will do when placed in service. Any wiring errors and/or compensation setting errors can be resolved in advance. For steps on how to verify proper wiring and compensation, refer to Section IV.

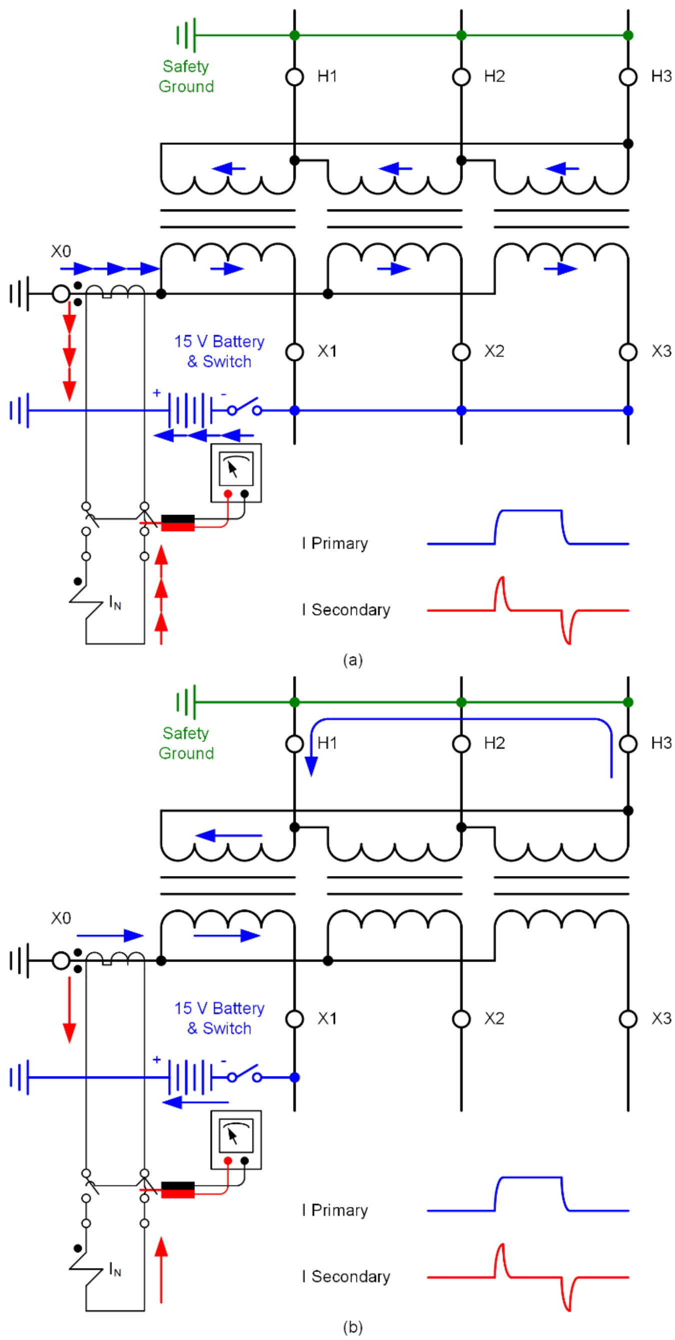


Fig. 6 Example ground CT kick test

Often, ground CTs cannot be verified during load checks because the load flow has very little unbalance. Schemes such as restricted earth fault (REF) are dependent on the polarity of the current from the ground CT relative to the residual current in the zone boundary CTs. AC primary injection testing easily allows verification of these circuits. The test source and the shorting jumpers can be reconfigured to cause zero-sequence current flow in the appropriate CTs for the purpose of verifying that the REF element restrains for a simulated external ground fault condition. The proper configuration of internal zero-sequence compensation can also be verified in this way.

The ac primary injection test is especially useful when it is not possible to ensure that adequate load flow will be available at all zone boundary CTs when the transformer is first placed in service and load checks on all circuits cannot be completed at that time. This is often the case. With this test, the commissioning crew is confident that the differential protection scheme is properly connected and currents are compensated correctly.

C. In-Service Readings

Unless three-phase primary injection tests are completed as described in the previous section, the first time that any significant current flows in the primary conductors and transformer windings is during first loading. This is *the* most important test for verifying everything from wiring to relay configuration. If possible, the startup procedure should follow a sequence to load differential restraint inputs one pair at a time. For example, consider the transformer installation shown in Fig. 7. The transformer is an autotransformer with dual breaker terminals on the high side, a single low-side breaker, and a tertiary breaker connecting a shunt reactor.

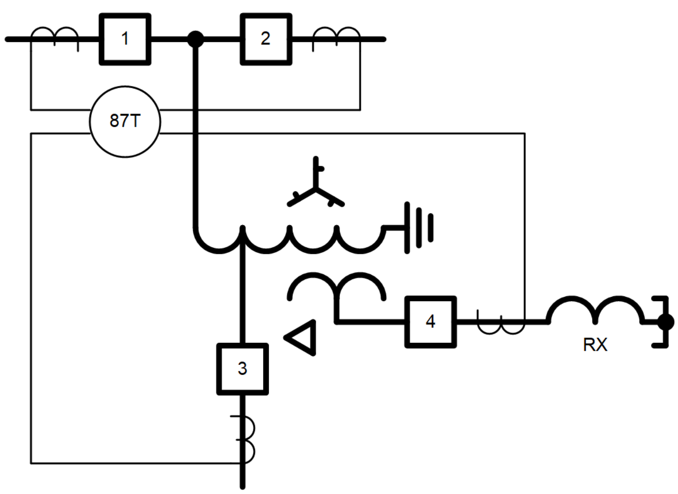


Fig. 7 Example in-service readings plan

The transformer is initially energized by closing Breaker 1. Once the transformer has been successfully energized, we are assured that the transformer is not faulted. At this point, any errors in wiring and/or compensation not found during initial testing cannot cause a trip. A differential relay with only one terminal closed is nothing more than a sensitive overcurrent relay. There is no current flowing in any other restraint input that can generate restraint or create false differential current due to wiring or compensation errors.

Next, we might close Breaker 2. However, this may only close an additional path through the complex bus arrangement and the current division through the bus cannot be easily predicted. For this reason, it is not assured that sufficient load will flow through this pair of inputs to get adequate readings. A better choice is to close Breaker 3 or Breaker 4 to pick up load through the differential zone. Let us assume that Breaker 3 is closed for the first load check. Once the compensated currents for that pair of restraint inputs are verified, Breaker 2 can be closed and Breaker 1 opened to verify Breaker 2 against Breaker 3. At this point, three of the four inputs are verified.

Finally, Breaker 4 is closed. This one can be confusing because the load flow from Breaker 2 to Breaker 3 will likely be a high power factor load while the current in Breaker 4 will be purely reactive. This significant difference in power factor of the load may be confusing when evaluating the angles between the various current inputs. A better sequence might have been to close Breaker 4 to pick up the reactor load and verify it against Breaker 1. The current flow in both breakers is reactive current and, after compensation, will be 180 degrees out of phase with each other. Then, open Breaker 4 and close Breaker 3 to verify it against Breaker 1. In this case, the currents are normal load flow currents with the same power factor. Finally, close Breaker 2 and open Breaker 1 to verify Breaker 2 against Breaker 3.

Often, only part of the installation is placed in service during construction. For example, in Fig. 7 the outage sequence requires that the new transformer be placed in service while Breaker 2 and the bus work associated with that side of the substation are still under construction. When Breaker 2 is ready to be placed in service, it is now necessary to repeat taking in-service readings to ensure that the differential element remains balanced with sufficient current in the Breaker 2 CT circuits. If three-phase primary injection testing was accomplished to verify all circuits in advance, the inability to load all inputs when the transformer is placed in service is not a concern.

It is important to realize that any schemes that rely on ground CT current, such as REF, cannot easily be verified with first loading checks. When such schemes are used, it is recommended to use one of the two primary injection tests to verify polarity of the ground CTs before placing the transformer in service. If these tests are not completed, it may be prudent to leave the REF element in non-tripping monitoring mode until the configuration of the element can be checked by reviewing oscillographic recordings from the first external ground fault on the power system. If that is the plan, be sure to configure the relay to trigger a recording when an external ground fault occurs.

D. Trip on First Loading

It is important to understand that the transformer protection installation should be fully verified via commissioning tests before first energization and first loading. We should not proceed with energizing circuits until we are sure that everything is fully verified and expect that no errors will be found. But, despite our best efforts, some errors can still exist. In many cases, these are errors in configuration of internal compensation. Often, the relay is tested based on the settings provided. If the settings are not correct for the application, the error may only be revealed during first loading with actual power flow through the zone of protection. This section discusses planning for and responding to the case of trip on first loading because of an error not detected by the previous tests.

When taking first loading readings, it is desirable to calculate in advance the amount of load that must be picked up to achieve at least 0.25 A in a 5 A nominal relay. It is also desirable to calculate in advance the load flow required to reach the minimum pickup setting of the differential element. If possible, we would like to arrange to have enough load to obtain adequate magnitude and angle readings, yet low enough to not trip the transformer and allow us time to take readings and evaluate them. Once everything is verified, the transformer can be released to operations for full use.

Equations (4) and (5) can be used to calculate the minimum loading required to get adequate signals and the loading required to exceed the minimum pickup of the differential element. Equation (4) should be calculated for each CT input on the differential zone and the largest result should be used:

$$MVA_{MIN} = 0.25A \bullet CTR \bullet kV \bullet \sqrt{3} \bullet 1000 \quad (4)$$

where:

MVA_{MIN} is the MVA required to obtain at least 0.25 A of load flow to verify compensated magnitude and angle.

CTR and kV are the CT ratio and voltage rating used to calculate the TAP compensation factor for each of the inputs.

$$MVA_{O87P} = MVA_{TAP} \bullet O87P \quad (5)$$

where:

MVA_{O87P} is the MVA required to exceed the minimum pickup.

MVA_{TAP} is the MVA value used to calculate TAP compensation factors.

O87P is the differential element minimum pickup in per unit of TAP.

Ideally, the load used for the first loading test would fall somewhere between MVA_{MIN} and MVA_{O87P}. However, often the amount of load that will be picked up by closing the load breaker is not easily controlled. If there is a wiring or compensation error, the differential relay can trip the transformer immediately upon closing in the breaker that picks up load through the differential zone. Some personnel may be tempted to block the differential protection until the differential circuits are verified. Generally, this should not be done when first energizing the transformer. We would like to have this important protection in service until we are sure that the transformer is unfaulted. Remember that wiring and compensation errors can only cause a trip due to load flow through the zone.

The consequences of tripping a transformer upon picking up load are also generally not significant. Tripping an energized (healthy) transformer upon first loading only indicates that there is an error in the CT wiring or the compensation settings. It does not indicate that the transformer is faulty. Further, the load being picked up is either being served by parallel circuits, or the load was on outage prior to the moment of closing the load breaker. The undesired trip of the transformer at this point does not make either matter worse. For many engineers, going to the expense of using three-phase primary injection testing to avoid this scenario is not considered necessary.

Some personnel may choose to block or desensitize the differential element upon the second attempt to pick up load to facilitate taking readings to determine the source of the error. These changes may be considered acceptable if the transformer has redundant protection during the short duration that the problematic differential element is blocked or desensitized. Often, we have a second fast and sensitive protection scheme, such as a combination of high-set instantaneous overcurrent and sudden pressure relaying or a redundant differential scheme, protecting the transformer.

IV. Errors and Analysis

Due to the inherent complexity of transformer relay installations, there are many ways that mistakes can be made. Some of the most common errors are related to CT wiring, shown in Fig. 8; the CT can be wired to an incorrect TAP, the CT can be wired with incorrect polarity, and the CT phases can be swapped when wired to the relay.

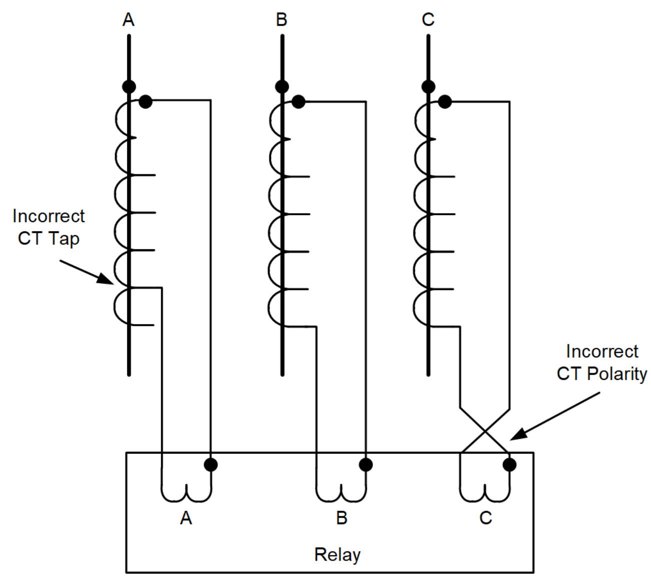


Fig. 8 Common CT wiring errors in transformer differential relay installations [7]

Common errors unrelated to CT wiring include incorrectly compensating for phase angle differences, failing to properly remove zero-sequence currents from grounded wye windings, and incorrect TAP settings due to the difference in power ratings between windings.

All of these errors must be identified and corrected for the currents comprising the differential to sum to near zero and the transformer differential relay to operate correctly. While correcting the mistakes is more straightforward, identifying what is wrong in the first place can be a challenge.

There are various techniques that can be used to identify each of these common errors. These techniques can be performed during commissioning or after a fault using fault data from the relay event report. Commissioning spreadsheets can also be created to lead you through many of these checks and automate calculations and phasor plots. The commissioning spreadsheet in Appendix B shows one such example.

A. Swapped Phases

Current metering data can be used to identify when two phases have been swapped when connected to the relay. Many times, simply plotting these values on a polar graph and comparing them to what is expected will be enough to reveal the error. Reference [7] shows how a simple negative-sequence current calculation for each winding can also be used to identify swapped phases. If negative-sequence current is greater than positive-sequence current on any of the windings during balanced conditions, suspect that phases have been swapped. If the negative-sequence current is greater than the positive-sequence current on all of the windings, it is also possible that the phase sequence setting in the relay is incorrect (i.e., ACB instead of ABC).

$$I_1 > I_2 \text{ (Pass)}$$
$$I_2 > I_1 \text{ (Fail)}$$

B. Incorrect CT Polarity

Current metering data can also be used to identify errors in CT polarity. Incorrect polarity on a single CT can be identified using the angular relationship between balanced phases. For a system with an ABC phase sequence, the angular relationship is as shown in Table I (with IA held at a reference of 0 degrees) [7].

TABLE I
PHASE ANGLE RELATIONSHIPS FOR CT POLARITY ERRORS

Condition	A-Phase	B-Phase	C-Phase
Correct Polarity	IA ∠ 0	IB ∠ –120	IC ∠ 120
Incorrect Polarity on A-Phase	IA ∠ 0	IB ∠ 60	IC ∠ –60
Incorrect Polarity on B-Phase	IA ∠ 0	IB ∠ 60	IC ∠ 120
Incorrect Polarity on C-Phase	IA ∠ 0	IB ∠ –120	IC ∠ –60

It is also possible that an entire set of CTs on one side of the transformer is wired in reverse polarity. Wiring transformer differential CTs in differential polarity (i.e., polarity of all CTs facing away from the transformer) as shown in Fig. 1 is most common. However, it is acceptable to wire the CTs in load-flow polarity (polarity of both CTs facing the same direction) as long as the phase angle difference is accounted for in compensation settings. To detect incorrect polarity on an entire set of CTs, plot the phasors for both windings and compare the phase relationship to what is expected. The phasors that a relay measures using wye-connected CTs in load polarity will have the same relationship as the transformer produces on the primary system. For a DABY (Dyn1) transformer, the wye-side phasors will lag the delta-side phasors by 30 degrees. If the CTs are connected in differential polarity, the extra 180-degree shift due to the CT polarity will result in the low-side currents leading the high-side currents by 150 degrees.

C. Incorrect CT TAP Position (One CT)

A single incorrectly tapped CT will cause unbalance in the load reading that does not exist in the system. This error can be identified by comparing the ratio of positive- and negative-sequence current of each winding to each other. If the ratio of the positive-sequence current to the negative-sequence current on one winding is not the same as the other transformer winding(s), suspect a single incorrectly tapped CT. Whichever side has the higher negative-sequence current is likely the side with the incorrectly tapped CT.

$$\frac{I_{1\_HV}}{I_{2\_HV}} = \frac{I_{1\_LV}}{I_{2\_LV}} \text{ (Pass)}$$
$$\frac{I_{1\_HV}}{I_{2\_HV}} \neq \frac{I_{1\_LV}}{I_{2\_LV}} \text{ (Fail)}$$

D. Incorrect TAP Settings, CT Ratio, or CT TAP Position (All Three CTs)

Several sources of errors can cause magnitude mismatch on the relay across all three compensated phases. These are:

1. The CT ratio used in calculating TAP is different from the actual CT ratio in use. This could be due to a difference between the drawings and the settings file. It could also be caused by the wiring diagram not matching the schematics, or an installation error where the CT is tapped incorrectly.
2. The TAP settings are entered in the wrong order (the high-side TAP is entered as the low-side TAP, and vice versa).
3. The TAP settings are calculated using a different MVA for one winding. This problem can manifest when tertiary windings are brought into the differential relay. Tertiary windings are sometimes rated at a much lower MVA capacity compared to other transformer windings, which makes it tempting to use the nameplate MVA rating for the tertiary when calculating TAP for that winding. Although this will produce the rated current for this winding, it will not accurately represent the transformer's current ratio. Because a differential relay works on a common per-unit system, the same MVA value must be used across all windings. See [8] for further considerations when choosing a common MVA.

To detect Error 2 or Error 3, first check to see if the relay is automatically calculating the TAP settings. Many modern microprocessor-based relays automatically calculate TAP when the MVA for the transformer is set in the relay. The TAP calculation follows (2), using the set MVA as the common base and the rated voltage levels and CT ratio settings. Assuming those parameters are set correctly, this automatic calculation eliminates Error 2 and Error 3 in modern relays.

If the MVA setting in the relay is set to OFF, the TAP settings must be manually calculated and entered into the relay, making the chance for error greater. If this is the case, use (2) to verify that the TAP calculations are correct for the installation and that a common MVA base is being used for each winding. Section V.B gives an example of how this is done.

There are several methods that can be used to identify the most common error, Error 1.

1) Comparison to Load Data on Another Device

One method of checking for Error 1 involves a load check. Here, metered load current is taken from a device external to the transformer differential relay. These load data serve as a reference because it cannot be assumed that the relay being commissioned is correctly installed. If the reference current magnitudes do not match the measured currents on all the phases of a winding, suspect that Error 1 exists. This is the most accurate method to detect Error 1. The next two methods discussed are approximations; their accuracy will be reduced due to load imbalance and losses in the transformer.

2) Calculate Expected Currents Based on Transformer Ratio

If load check data are not available, [7] shows how you can identify Error 1 using the fact that the HV/LV ratio of the transformer is inversely related to the current ratio. This method is useful when looking at an event report after a transformer relay misoperation. We can multiply the measured HV current on each phase by the transformer ratio to calculate the expected LV current on each phase, as shown in (6). Be sure to use the voltage ratings for the actual transformer TAP positions at the time the readings were taken in (6). These values can be compared to the measured LV currents on each phase. If the expected currents do not match the measured currents on all the phases of a winding, suspect Error 1.

$$I_{LV\_Expected} = \frac{V_{HV}}{V_{LV}} I_{HV\_Measured} \tag{6}$$

$$I_{LV\_Expected} = I_{LV\_Measured} \text{ (Pass)}$$

$$I_{LV\_Expected} \neq I_{LV\_Measured} \text{ (Fail)}$$

For multi-winding transformers, such as transformers with a loaded tertiary, the method in (7) should be used. Using two windings as reference, the expected currents on the third winding can be calculated. Equation (7) normalizes the tertiary (T) and LV current measurements to calculate the expected HV current. Summing the currents of a multi-winding transformer requires using magnitude and angle information. When normalizing the windings for a multi-winding transformer, all measured currents should have their angle shifted to align with the terminal they are being normalized to.

$$I_{HV\_Expected} = \left| \frac{V_{LV}}{V_{HV}} \overline{I}_{LV\_Measured} + \frac{V_{TV}}{V_{HV}} \overline{I}_{TV\_Measured} \right| \tag{7}$$

3) Compare Power In to Power Out

Another method of identifying Error 1 when load check data are not available is to perform a calculation to prove that power into the transformer equals power out of the transformer [9]. Prefault data from a relay event report can be used to calculate power in (P_{in}) and power out (P_{out}) using (8) and (9):

$$P_{in} = \sqrt{3} \bullet I_{wdg1} \bullet CTR_{wdg1} \bullet kV_{wdg1} \tag{8}$$

$$P_{out} = \sqrt{3} \bullet I_{wdg2} \bullet CTR_{wdg2} \bullet kV_{wdg2} \tag{9}$$

where:

I_{wdg1} = Current in secondary amperes on Winding 1
I_{wdg2} = Current in secondary amperes on Winding 2
CTR_{wdg1} = CT ratio for Winding 1
CTR_{wdg2} = CT ratio for Winding 2
kV_{wdg1} = Nominal kV rating of Winding 1
kV_{wdg2} = Nominal kV rating of Winding 2

$$P_{in} = P_{out} \text{ (Pass)}$$

$$P_{in} \neq P_{out} \text{ (Fail)}$$

Because a transformer is a constant power device, P_{in} should equal P_{out}. If they are not equal, we can suspect that one set of CTs is tapped incorrectly. Note that this method assumes all three phases on a given winding are reading similar current magnitudes (the load is balanced).

If the source of error is an incorrectly tapped CT, we can attempt to identify which CT is incorrect. This is done by first assuming P_{in} to be correct and solving for the CT ratio on Winding 2 that would make $P_{out} = P_{in}$. Then, we can assume P_{out} to be correct and solve for the CT ratio on Winding 1 that would make $P_{in} = P_{out}$. If one of these answers results in a ratio that corresponds to an available CT TAP, it is possible that is the error.

E. Incorrect Phase Angle Compensation Settings

Section II described how phase angle compensation is done in microprocessor relays using compensation settings. These angle compensation settings are a common source of error and, by extension, cause transformer relay misoperations. Determining errors in compensation settings is made especially difficult because as we saw in Section II, a transformer differential relay does not operate directly on the currents it measures at its terminals. Instead, it first compensates these currents in magnitude and angle and uses these compensated currents to calculate operate and restraint quantities. Many microprocessor-based relays only report the currents measured at the terminals, making it difficult to know what these compensated currents are and how the relay is using them to calculate operate and restraint quantities.

Many tools can be used to manually calculate compensated currents. Spreadsheets like the one shown in Appendix B can be created to take in metering data from the relay and apply the necessary matrix compensation defined by the relay settings. The tool in [10] does the same thing using an event report from the relay, which can be triggered either during commissioning or downloaded after a trip. The output of these tools is the compensated currents in magnitude and angle. These currents can then be used to verify phase angle compensation settings and calculate operate and restraint values.

Some modern microprocessor-based relays include differential metering reports that show the compensated currents after magnitude and angle compensation. Appendix C shows an example of this type of differential report. Having this report built into the relay is a strong advantage, as it saves time having to manually calculate these values using the tools described.

Once the compensated currents are available, a simple analysis can show us whether the angle compensation settings are correct. The goal of angle compensation is for the compensated currents entering the transformer to cancel the currents leaving the transformer during load or external fault conditions. A properly configured transformer differential relay will produce near zero operating current when measuring load current.

If all previous checks in Section IV.A–IV.D do not detect any issues and operating current is still present during normal conditions, suspect an error in the angle compensation settings. If angle-compensated current data are available through metering, the source of this error can be easily identified. If the matrix-compensated currents (magnitude and angle) obtained from the source terminals do not equal the matrix-compensated currents from the load terminals, suspect a phase angle compensation calculation error.

F. Failure to Properly Remove Zero-Sequence Current

As described in Section II, if any transformer winding(s) is neutrally grounded, zero-sequence current must be removed from all grounded windings. Failure to remove zero-sequence current will produce false operating current during an external fault involving ground. Identifying zero-sequence compensation errors using load current can be difficult because the load imbalance will likely not be large enough to produce any meaningful ground current. If differential metering is available, a zero-sequence compensation error can be identified by monitoring the operate current while simulating a phase-to-ground fault using the three-phase primary injection test method described in Section III. When proper zero-sequence compensation settings are used, external faults should produce the same negligible operate current that is measured during perfectly balanced load conditions. If injection testing is not possible, settings should be verified again while commissioning so that all grounded windings have matrix compensation removing zero-sequence current.

V. Case Studies

The following two case studies demonstrate how to troubleshoot errors with transformer differential relay installations. In both cases, the transformer was successfully energized for the first time and operators were slowly transferring load onto it when the transformer relay tripped. This sequence of events generally indicates an issue with the differential configuration and not an actual transformer fault, which would have manifested during energization. Of course, the event report should be downloaded and examined to rule out the unlikely scenario of a fault occurrence simultaneous with picking up load.

In Case A, the minimum pickup setting (O87P) was desensitized, the transformer re-energized, and then load switched back in. The comprehensive differential metering report shown in Fig. 10 was then collected and used to troubleshoot the false operating current. In Case B, the relay's recorded event report is used to troubleshoot. Both cases use the techniques discussed in Section IV.A–IV.E to identify the source of the error.

A. Case A: Commissioning Example Using Metering Data

In this example, the phase-to-bushing connections are standard (A-phase is connected to H1 and X1, B-phase is connected to H2 and X2, and C-phase is connected to H3 and X3), the CTs are connected in wye with differential polarity, the CT-to-relay connections are standard (the A-phase CT is connected to the A-phase current input on the relay, the B-phase CT is connected to the B-phase current input on the relay, and the C-phase CT is connected to the C-phase current input on the relay), and the system phase sequence is ABC. Fig. 9 shows an autotransformer with a loaded delta-connected tertiary winding. The delta winding, Winding W, is chosen as the reference and S, T, and U currents are compensated by 30 degrees using Matrix 11 compensation.

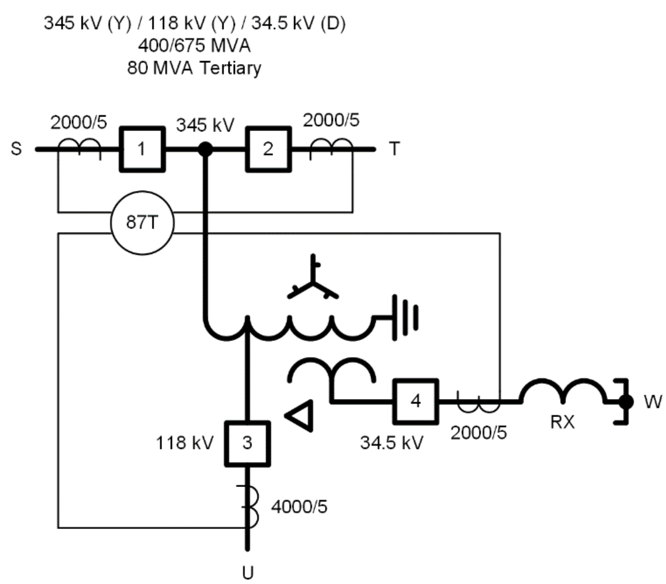


Fig. 9 Autotransformer with delta-connected tertiary winding

A differential metering report provided by the relay is used to verify settings and connections for loaded conditions with all four breakers closed. The metering data, shown in Fig. 10, report 0.42 pu of false operate current on all three phases. The techniques discussed in Section IV.A–IV.E will be used to identify the source of the reported error.

```
Operate Currents (per unit)          Restraint Currents (per unit)
IOPA       IOPB       IOPC           IRTA       IRTB       IRTC
 0.42       0.42       0.42           1.22       1.21       1.21
Tap and Matrix Compensation:                          Reference Terminal = S
                   Terminal Currents            Tap Comp.        Matrix Comp.
Phase A      (A,pri)    (A,sec)     (DEG)     (per unit)     (per unit)     (DEG)
 IAS         275.68      0.69        0.00         0.24          0.24      -29.90
 IAT         376.05      0.94     -149.19         0.33          0.33     -179.10
 IAU         495.73      0.62       98.89         0.15          0.15       69.02
 IAW         653.97      1.63      -12.58         0.49          0.49      -12.58
Phase B
 IBS         275.64      0.69     -119.89         0.24          0.24     -149.95
 IBT         376.62      0.94       90.91         0.33          0.33       60.88
 IBU         495.08      0.62      -20.93         0.15          0.15      -51.04
 IBW         653.72      1.63     -132.47         0.49          0.49     -132.47
Phase C
 ICS         275.62      0.69      120.19         0.24          0.24       90.15
 ICT         376.38      0.94      -28.98         0.33          0.33      -59.05
 ICU         495.62      0.62     -140.86         0.15          0.15     -170.88
 ICW         653.90      1.63      107.67         0.49          0.49      107.67

Compensation Settings:
CTCONS: Y        TAPS:    2.82     TSCTC: 11
CTCONT: Y        TAPT:    2.82     TTCTC: 11
CTCONU: Y        TAPU:    4.13     TUCTC: 11
CTCONW: Y        TAPW:    3.35     TWCTC:  0
```

Fig. 10 Failing comprehensive differential metering report

The CT polarity and any possible phase swap can be ruled out as the source of error by examining the angular relationship of the terminal currents shown in Fig. 10, or using the graphical representation shown in Fig. 11. The phases on all terminals maintain a 120-degree separation with an ABC phase sequence, ruling out an obvious CT polarity issue or phase swapping.

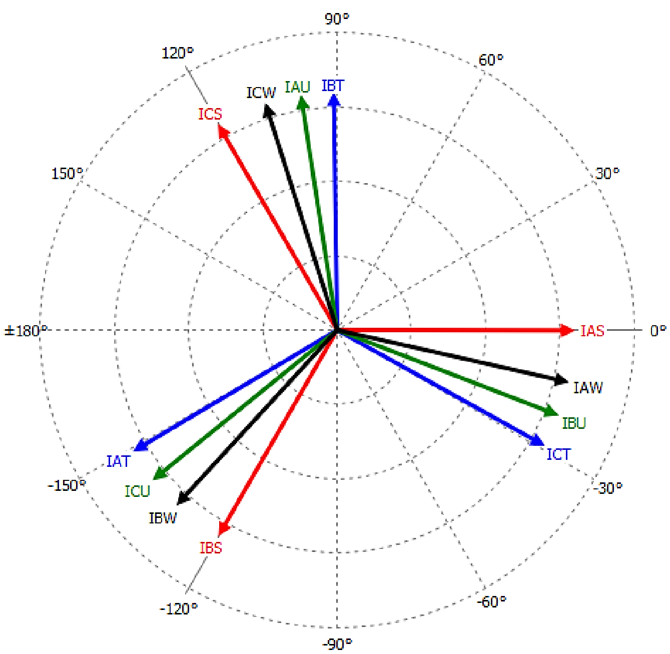


Fig. 11 Phasor metering data for S, T, U, and W terminals

As discussed in Section IV.B, collecting metered sequence component currents is another quick method to identify a possible phase swap. The metering data captured in Fig. 12 show the secondary currents on Terminal T are almost purely positive sequence. All the other terminals meter a similar relationship of I_1 versus I_2, ruling out the possibility of a single incorrectly tapped CT as described in Section IV.C.

```
Fundamental Meter: Winding T
                 Phase Currents                        Sequence Currents
              IA         IB         IC            I1         3I2        3I0
MAG(A,pri)  376.13     376.60     376.32       376.35       0.78       1.52
ANG(deg)   -149.29      90.82     -29.09      -149.19     138.17      84.82
```

Fig. 12 Metering sequence currents

Next, we can check for incorrect TAP settings, CT ratios, or CT TAP position (all three CTs) as described in Section IV.D. Error 1 in Section IV.D can be verified using (7). The HV current entering the transformer should be the vector sum of Terminals S and T, equal to approximately 198 A.

$$\begin{aligned} IA_{HV\_Measured} &= 275.7\angle 0° + 376\angle -149.2° \\ &= 198.3\angle -103.8° A \end{aligned}$$

Normalizing the measured tertiary current and LV current to the HV side of the transformer and taking their sum should give the total HV current expected. Because the tertiary winding in this example is lagging the HV winding, 30 degrees are added to the phase angle of the tertiary winding to bring it into alignment with the measured HV current.

$$\begin{aligned} IA_{HV\_Expected} = \frac{118}{345} 495.7\angle 98.9° + \frac{34.5}{345} 654\angle \\ \left(-12.6° + 30°\right) = 190.6\angle 79° A \end{aligned}$$

The measured HV current magnitude is approximately equal to the current expected using (6), indicating that a CT TAP position error is unlikely. Looking at the phase relationship of the summed HV currents ($IA_{HV\_Measured}$) and the summed/normalized LV and tertiary currents ($IA_{HV\_Expected}$), there are approximately 180 degrees of phase shift. This is as expected for CTs wired with differential polarity and further verifies correct CT polarity is being used throughout.

Error 2 and Error 3 in Section IV.D are not common in microprocessor-based relays. However, the automatic calculation of TAP settings was not used in this installation (MVA = OFF). We can check for Error 2 and Error 3 using the comprehensive differential metering report. TAP and matrix compensation settings remain as the likely sources of error.

For a properly configured system, compensated currents entering the differential zone should equal compensated currents leaving the zone. Again, for this example, the HV terminal is supplying currents to the tertiary and LV terminals. Converting the summed A-phase currents ($IA_{HV\_Measured}$) to secondary, and dividing by the set TAP value for the HV terminals, gives a per-unit TAP-compensated value of 198.3/400/2.82 = 0.18 pu. Summing the compensated currents of Terminals U and W should equal 0.18 pu.

$$\left| IA_{HV\_PU} \right| = \left| \overline{IAU_{PU}} + \overline{IAW_{PU}} \right| \text{ (Pass)}$$

$$0.18 \neq 0.53 = \left| 0.15\angle 69° + 0.49\angle -12.6° \right| \text{ (Fail)}$$

Visual inspection of the compensated angles shows that the angles of Terminals S, T, and U were adjusted by 30 degrees, as expected to account for the delta winding on Terminal W. With all other sources of error investigated, an error in the TAP compensation is the most likely cause of error.

The equation to calculate TAP is given in (2). We can see that the TAP for each terminal was incorrectly calculated using the rated MVA for each winding.

$$TAPS = TAPT = \frac{675 \bullet 1000}{\sqrt{3} \bullet 345 \bullet 2000/5} = 2.82$$

$$\text{TAPU} = \frac{675 \bullet 1000}{\sqrt{3} \bullet 118 \bullet 4000 / 5} = 4.13$$

$$\text{TAPW} = \frac{80 \bullet 1000}{\sqrt{3} \bullet 34.5 \bullet 2000 / 5} = 3.35$$

Calculating the TAP with a common MVA will correctly convert the terminal quantities into a per-unit equivalent. For this system, 675 MVA was used as the common MVA.

$$\text{TAPS} = \text{TAPT} = \frac{675 \bullet 1000}{\sqrt{3} \bullet 345 \bullet 2000 / 5} = 2.82$$

$$\text{TAPU} = \frac{675 \bullet 1000}{\sqrt{3} \bullet 118 \bullet 4000 / 5} = 4.13$$

$$\text{TAPW} = \frac{675 \bullet 1000}{\sqrt{3} \bullet 34.5 \bullet 2000 / 5} = 28.24$$

As shown in Fig. 13, with the new TAP settings the compensated current is now summing to near zero as expected. In each phase loop, the summed currents of Terminals S and T cancel the summed currents of Terminals U and W to create near-zero operate current, indicating appropriate compensation.

```
Operate Currents (per unit)          Restraint Currents (per unit)
IOPA       IOPB       IOPC           IRTA       IRTB       IRTC
 0.01       0.01       0.01           0.79       0.78       0.78
Tap and Matrix Compensation:                        Reference Terminal = S
                  Terminal Currents              Tap Comp.      Matrix Comp.
Phase A      (A,pri)    (A,sec)     (DEG)       (per unit)   (per unit)    (DEG)
 IAS         275.58      0.69        0.00         0.24         0.24       -29.91
 IAT         376.15      0.94     -149.19         0.33         0.33      -179.09
 IAU         495.63      0.62       98.91         0.15         0.15        69.02
 IAW         653.99      1.63      -12.57         0.06         0.06       -12.57
Phase B
 IBS         275.56      0.69     -119.88         0.24         0.24      -149.94
 IBT         376.62      0.94       90.92         0.33         0.33        60.88
 IBU         494.75      0.62      -20.91         0.15         0.15       -51.03
 IBW         653.73      1.63     -132.46         0.06         0.06      -132.46
Phase C
 ICS         275.66      0.69      120.19         0.24         0.24        90.16
 ICT         376.28      0.94      -28.98         0.33         0.33       -59.05
 ICU         495.80      0.62     -140.87         0.15         0.15      -170.86
 ICW         653.97      1.63      107.67         0.06         0.06       107.67

Compensation Settings:
CTCONS: Y      TAPS:   2.82    TSCTC: 11
CTCONT: Y      TAPT:   2.82    TTCTC: 11
CTCONU: Y      TAPU:   4.13    TUCTC: 11
CTCONW: Y      TAPW:  28.24    TWCTC:  0
```

Fig. 13 Operating currents are close to zero after correcting the TAP setting error

B. Case B: Field Event Example Using Post-Fault Analysis

This example shows how the methods in Section IV were used to identify a problem with a transformer installation after an incorrect trip. Fig. 14 shows the installation of a 30 MVA DABY (Dyn1) distribution transformer, rated 69 kV delta to 12.47 kV wye. Note that the phase-to-bushing connections are not standard, with A-phase on the system connecting to H1 and X1, C-phase on the system connecting to H2 and X2, and B-phase on the system connecting to H3 and X3. The CTs are connected in wye with differential polarity, the CT-to-relay connections are standard, and the system phase sequence is ABC. Winding 1 of the relay is connected to the 69 kV delta side of the transformer, and Winding 2 of the relay is connected to the 12.47 kV wye side of the transformer. The relay was set with compensation settings of Matrix 0 (delta side) and Matrix 1 (wye side).

Fig. 15 shows a polar plot of the filtered event report recorded by the transformer relay when it tripped. Fig. 16 shows the magnitude of the operate and restraint currents recorded by the relay. Notice that on all three phases in Fig. 16, operate current is not near zero. This indicates that there is a problem somewhere in the installation.

When a transformer relay trips for load or an external fault, we can use the pre-trigger values from the filtered event report to check for the errors detailed in Section IV.

The first check is for swapped phases (Section IV.A). The calculated positive- and negative-sequence currents for Winding 1 and Winding 2 are shown in Fig. 17. Notice that the positive-sequence quantities are much larger than the negative-sequence quantities on both windings, so swapped phases is not expected to be the problem.

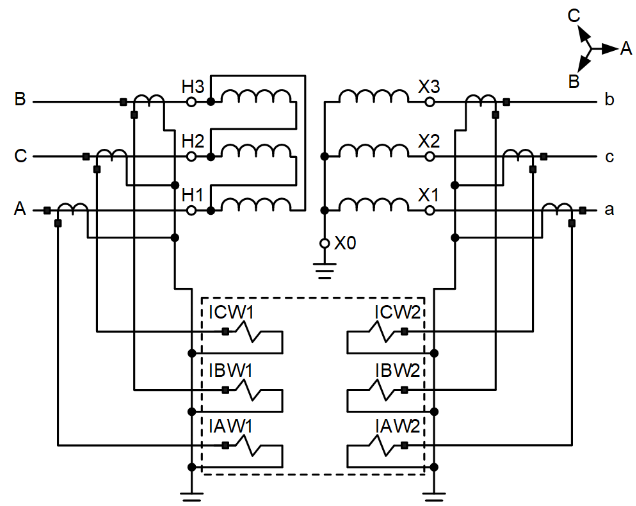


Fig. 14 Three-line diagram of transformer relay installation [3]

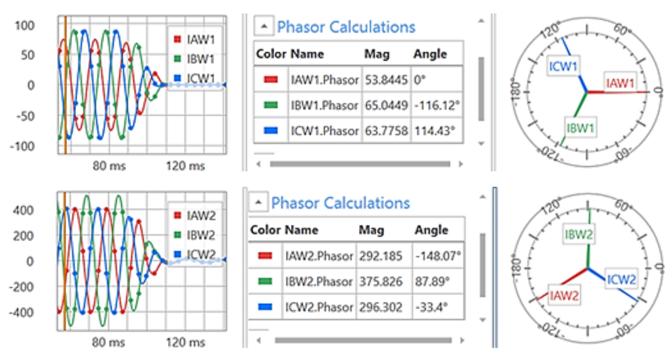


Fig. 15 Filtered event report from relay trip

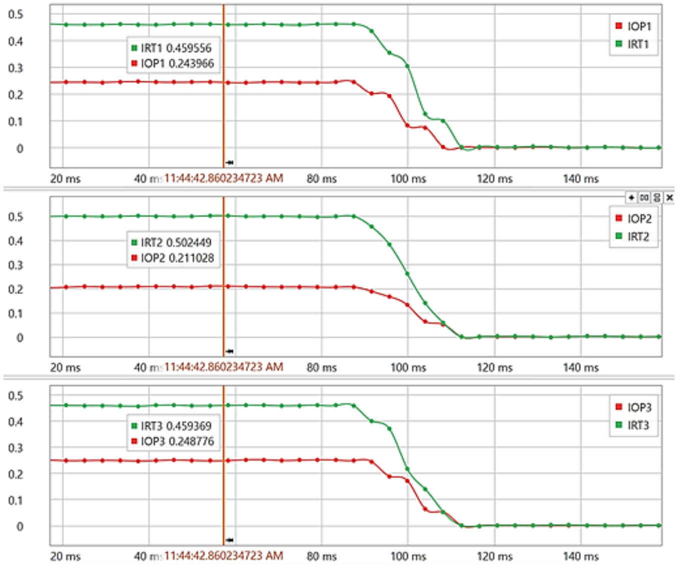


Fig. 16 Differential event report from relay trip showing operate currents not close to zero

Name	Mag	Angle
POS_SEQ_W1	60.7414	-0.56°
NEG_SEQ_W1	6.54316	173.81°
POS_SEQ_W2	321.204	-151.28°
NEG_SEQ_W2	35.2124	-33.64°

Fig. 17 Positive- and negative-sequence quantities for Winding 1 and Winding 2

The second check is for incorrect CT polarity (Section IV.B). We can detect incorrect CT polarity by looking at the phase angle relationships between the phases. Table I shows how we can detect incorrect polarity on a single CT by looking at the phase angle relationships between the phases. Fig. 18 shows the phase angle relationships for Winding 1 and Winding 2 for this event. Note that each polar graph was plotted separately with A-phase as reference (IAWI and IAW2 are both plotted at 0 degrees). These phase relationships match the relationships for correct polarity in Table I.

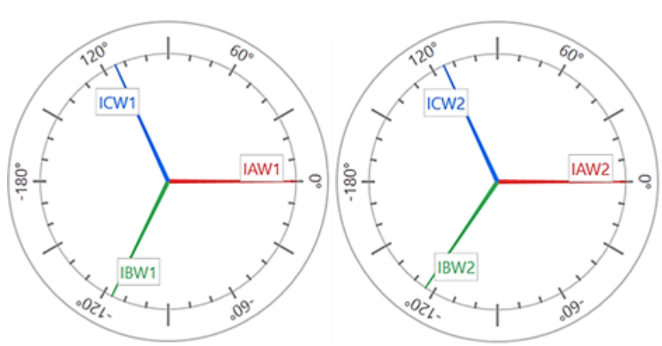


Fig. 18 Phase angle relationships on Winding 1 (left) and Winding 2 (right)

To detect incorrect polarity on an entire set of CTs, we can plot the phasors of both windings with a common reference (IAW1, for example). These phasors are shown on the right side of Fig. 15. We can compare this phase relationship to the relationship we expect for the given installation. Based on the non-standard phase-to-bushing connections, the low-side currents (Winding 2) should lead the high-side currents (Winding 1) by 30 degrees on the system. Because the CTs are connected in differential polarity, the extra 180-degree shift due to the CT polarity results in the low side lagging the high side by 150 degrees. This derivation is described in more detail in [3]. We can see that the phasors in Fig. 15 match the phase shift that we expect for the installation. Therefore, we do not suspect incorrect CT polarity to be the problem.

The third check is for an incorrect CT TAP position on a single CT (Section IV.C). To perform this check, we can compare the ratios of positive- to negative-sequence current across the transformer as shown in the following calculations, using the values from Fig. 17:

$$\frac{I_{1\_HV}}{I_{2\_HV}} = \frac{I_{1\_LV}}{I_{2\_LV}}$$

$$\frac{60.74}{6.54} \approx \frac{321.20}{35.21}$$

$$9.29 \approx 9.12$$

Because the ratios match, we do not suspect an incorrect CT TAP position on a single CT.

The fourth check is for incorrect TAP settings, CT ratio, or TAP position on all three CTs (Section IV.D). We will skip checking for Error 2 and Error 3 in Section IV.D because the engineer let the relay automatically calculate TAP settings based on a common MVA setting. In addition, this relay does not have metering reports that provide the compensated currents after TAP scaling. We will instead check for the most common error, Error 1.

Section IV.D gives several methods to check for Error 1. We will use Method 2 because there are no externally metered load data available. Applying (6) for each phase, we calculate:

$$IA_{LV_{Expected}} = \frac{69}{12.47} \bullet 53.84 = 297.91 \text{ A}$$

$$IB_{LV_{Expected}} = \frac{69}{12.47} \bullet 65.04 = 359.88 \text{ A}$$

These expected values are similar to the measured Winding 2 currents in Fig. 15 for A and B phases. There is some error in C-phase, which could be explained by the fact that this is a distribution application with unbalanced load.

The final check is for incorrect compensation settings (Section IV.E). To see if the compensation settings are correct, we need to start with the currents from Fig. 15, which are the primary currents measured by the relay. We then need to apply the compensation settings in the relay to these measured currents to determine the compensated currents, as described in Section II.

The compensation settings used in this example are Matrix 0 and Matrix 1. These matrices are shown here:

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

Section II shows how to apply these matrices to the measured currents to obtain the compensated currents. Applying (3) to this example, we get:

$$\begin{bmatrix} \text{IAW1C} \\ \text{IBW1C} \\ \text{ICW1C} \end{bmatrix} = \frac{1}{\text{CTR1} \bullet \text{TAP1}} \bullet [\text{Matrix } 0] \bullet \begin{bmatrix} \text{IAW1} \\ \text{IBW1} \\ \text{ICW1} \end{bmatrix}$$

$$\begin{bmatrix} \text{IAW1C} \\ \text{IBW1C} \\ \text{ICW1C} \end{bmatrix} = \frac{1}{80 \bullet 3.14} \bullet \begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix} \bullet \begin{bmatrix} 53.84\angle 0 \\ 65.04\angle -116 \\ 63.78\angle 114.43 \end{bmatrix}$$

$$\begin{bmatrix} \text{IAW1C} \\ \text{IBW1C} \\ \text{ICW1C} \end{bmatrix} = \begin{bmatrix} 0.21\angle 0 \\ 0.26\angle -116 \\ 0.25\angle 114 \end{bmatrix}$$

$$\begin{bmatrix} \text{IAW2C} \\ \text{IBW2C} \\ \text{ICW2C} \end{bmatrix} = \frac{1}{\text{CTR2} \bullet \text{TAP2}} \bullet [\text{Matrix } 1] \bullet \begin{bmatrix} \text{IAW2} \\ \text{IBW2} \\ \text{ICW2} \end{bmatrix}$$

$$\begin{bmatrix} \text{IAW2C} \\ \text{IBW2C} \\ \text{ICW2C} \end{bmatrix} = \frac{1}{400 \bullet 3.48} \bullet \frac{1}{\sqrt{3}} \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} \bullet \begin{bmatrix} 292.19\angle -148 \\ 375.83\angle 88 \\ 296.30\angle -33 \end{bmatrix}$$

$$\begin{bmatrix} \text{IAW2C} \\ \text{IBW2C} \\ \text{ICW2C} \end{bmatrix} = \begin{bmatrix} 0.25\angle -116 \\ 0.24\angle 113 \\ 0.21\angle 0 \end{bmatrix}$$

We can now use these compensated currents to calculate the operate and restraint currents for each phase. Applying (3) from Section II, where this relay has a constant k = 2, we calculate:

$$\text{IOP}_\text{A} = |\text{IAW1C} + \text{IAW2C}| = 0.24$$

$$\text{IOP}_\text{B} = |\text{IBW1C} + \text{IBW2C}| = 0.21$$

$$\text{IOP}_\text{C} = |\text{ICW1C} + \text{ICW2C}| = 0.25$$

$$\text{IRT}_\text{A} = \frac{|\text{IAW1C}| + |\text{IAW2C}|}{2} = 0.46$$

$$\text{IRT}_\text{B} = \frac{|\text{IBW1C}| + |\text{IBW2C}|}{2} = 0.50$$

$$\text{IRT}_\text{C} = \frac{|\text{ICW1C}| + |\text{ICW2C}|}{2} = 0.46$$

These calculations can require significant effort to perform. Tools such as [10] are available to automatically apply compensation settings and plot the compensated currents. Fig. 19 shows the results using the tool described in [10] to plot the compensated currents after the compensation settings of Matrix 0 (delta side) and Matrix 1 (wye side) are applied.

We can then check these compensated currents to ensure they balance each other (i.e., the two windings are 180 degrees out of phase with each other). Reviewing the results of our calculations, we can see that the A-phase current on Winding 1 (IAW1C) is not 180 degrees out of phase with the A-phase current on Winding 2 (IAW2C) as we would expect. The same is true for the B and C phases. These phase errors result in operate currents that are not close to zero and point to a problem with the compensation settings. When applying the rules for setting compensation matrices in [3] to this installation, we found that the compensation settings selected were incorrect. The correct compensation settings for this installation are Matrix 0 (delta side) and Matrix 11 (wye side).

As you can see, the need for compensated current information (not just the currents measured at the relay terminals) is necessary to identify phase angle compensation setting errors. Performing all of the previous calculations manually can be enough of a burden to deter some engineers and technicians from performing these checks at all. Instead of requiring the user to perform manual calculations, newer microprocessor-based relays provide the same data in a comprehensive differential metering report. This report can be run during commissioning to catch mistakes before they result in misoperations. To show what this report looks like, we played the event from this case study into a relay that supported comprehensive differential metering reports. The report from that relay is shown in Fig. 20. Note that "Terminal S" is Winding 1, and "Terminal T" is Winding 2.

The first thing we notice in the report in Fig. 20 is the existence of operate current. This signifies that there is a problem with the installation that must be investigated. If there is not enough load, the error might not be enough to cause a trip. However, it still needs to be corrected because when load increases or a through fault occurs, the relay may misoperate.

Next, we can look at the TAP and Matrix Compensation section of the report. This section gives us the measured terminal currents (the same as those obtained from the filtered event report in Fig. 15). The checks in Section IV.A–IV.C should all be performed with these values. Next, the report gives the currents after they are compensated by TAP scaling. If these numbers are not all similar, suspect a TAP issue as detailed in Section IV.D. Finally, the report gives the currents after phase angle compensation. These numbers should all balance across the windings. In other words, for a two-terminal installation, they should be equal and 180 degrees apart. In a multi-terminal installation, the sum of all the "input" terminals of the transformer should equal the sum of all the "output" terminals. If these expectations are not reflected in the report, suspect an issue with matrix compensation (Section IV.E).

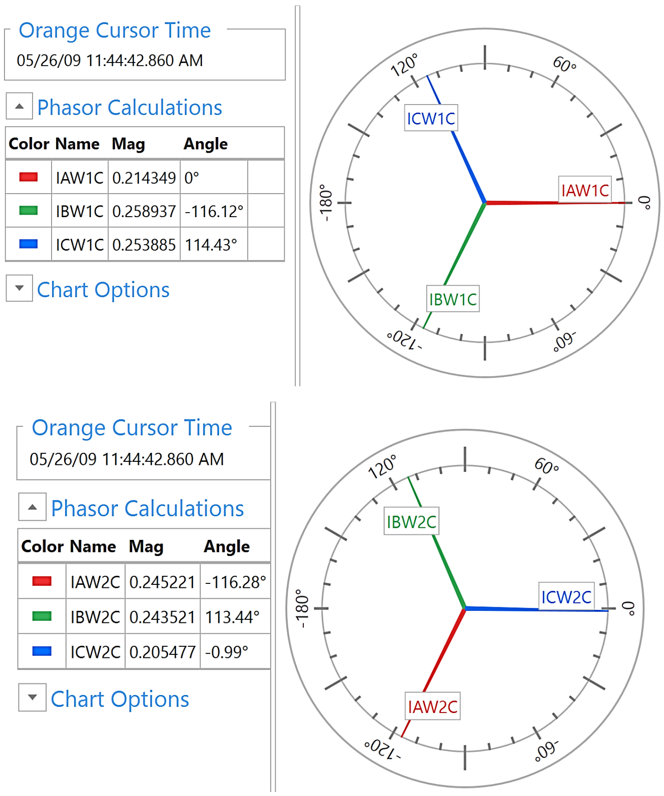


Fig. 19 Compensated currents on Winding 1 (top) and Winding 2 (bottom) after compensation settings (0, 1)

```
Operate Currents (per unit)          Restraint Currents (per unit)
IOPA       IOPB       IOPC           IRTA       IRTB       IRTC
 0.23       0.23       0.23           0.44       0.49       0.46

Tap and Matrix Compensation:                          Reference Terminal = S
                      Terminal Currents            Tap Comp.        Matrix Comp.
Phase A        (A,pri)      (A,sec)      (DEG)    (per unit)    (per unit)    (DEG)
 IAS            51.80        0.65        0.00       0.21          0.21         0.00
 IAT           283.86        0.71     -150.00       0.20          0.23      -115.69
Phase B
 IBS            63.24        0.79     -120.17       0.25          0.25      -120.17
 IBT           364.12        0.91       90.38       0.26          0.24       117.12
Phase C
 ICS            63.69        0.80      120.31       0.25          0.25       120.31
 ICT           295.08        0.74      -29.15       0.21          0.21        -0.20

Compensation Settings:
CTCONS: Y       TAPS:   3.14     TSCTC:  0
CTCONT: Y       TAPT:   3.47     TTCTC:  1
```

Fig. 20 Comprehensive differential metering report with compensation settings (0, 1)

Fig. 21 shows the comprehensive differential metering report after the compensation settings were changed to (0, 11). We can now see that the operate currents are near zero on all three phases. The currents after compensation are now balanced—equal in magnitude and 180 degrees apart. This is what we would expect for a correct installation.

The comprehensive commissioning report serves as a one-stop shop for all the data you need to perform the commissioning checks outlined in this paper. The compensated currents, as well as the calculated operate and restraint currents, are all provided without the user needing to retrieve any event records, perform any manual calculations, or use any external tools.

```
Operate Currents (per unit)          Restraint Currents (per unit)
IOPA       IOPB       IOPC           IRTA       IRTB       IRTC
 0.00       0.03       0.02           0.41       0.49       0.49
Tap and Matrix Compensation:                          Reference Terminal = S
                      Terminal Currents            Tap Comp.        Matrix Comp.
Phase A        (A,pri)      (A,sec)      (DEG)    (per unit)    (per unit)    (DEG)
 IAS            51.52        0.64        0.00       0.21          0.21         0.00
 IAT           285.53        0.71     -149.74       0.21          0.21       179.95
Phase B
 IBS            63.37        0.79     -120.01       0.25          0.25      -120.01
 IBT           363.07        0.91       90.78       0.26          0.23        64.51
Phase C
 ICS            63.55        0.79      120.72       0.25          0.25       120.72
 ICT           294.44        0.74      -29.34       0.21          0.24       -62.72

Compensation Settings:
CTCONS: Y       TAPS:   3.14     TSCTC:  0
CTCONT: Y       TAPT:   3.47     TTCTC: 11
```

Fig. 21 Comprehensive differential metering report after compensation settings changed to (0, 11)

VI. Conclusion

Transformer relay installations can be complicated and there are many ways that mistakes can be made. Some of the most common errors are related to CT wiring: the CT can be wired to an incorrect TAP, the CT can be wired with incorrect polarity, and the CT phases can be swapped when wired to the relay. Other errors unrelated to wiring can also be made, such as incorrectly compensating for phase angle differences, failing to properly remove zero-sequence currents from grounded wye windings, and incorrect TAP settings due to the difference in power ratings between windings.

All of these errors must be identified and corrected for the currents comprising the differential to sum to near zero and the transformer differential relay to operate correctly. While correcting the mistakes is more straightforward, identifying what is wrong in the first place can be a challenge.

This paper shows various techniques that can be used to identify each of these common errors. These techniques can be performed during commissioning or after a fault using pre-fault data from the relay event report. A relay with comprehensive differential metering reports is extremely valuable when performing these checks during commissioning because it provides current values before and after compensation. This single report provides everything you need to know to work through necessary commissioning checks and stop the epidemic of transformer relay misoperations.

VII. Appendix A

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

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

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

$$\begin{bmatrix} Ia_{compensated} \\ Ib_{compensated} \\ Ic_{compensated} \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} 1 & -1 & 0 \\ 0 & 1 & -1 \\ -1 & 0 & 1 \end{bmatrix} \bullet \begin{bmatrix} Ia \\ Ib \\ Ic \end{bmatrix}$$

$$\begin{bmatrix} Ia_{compensated} \\ Ib_{compensated} \\ Ic_{compensated} \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} (1 \bullet Ia) + (-1 \bullet Ib) + (0 \bullet Ic) \\ (0 \bullet Ia) + (1 \bullet Ib) + (-1 \bullet Ic) \\ (-1 \bullet Ia) + (0 \bullet Ib) + (1 \bullet Ic) \end{bmatrix}$$

$$\begin{bmatrix} Ia_{compensated} \\ Ib_{compensated} \\ Ic_{compensated} \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} Ia - Ib \\ Ib - Ic \\ Ic - Ia \end{bmatrix}$$

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

$$\begin{bmatrix} Ia_{compensated} \\ Ib_{compensated} \\ Ic_{compensated} \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} (1\angle 0°) - (1\angle -120°) \\ (1\angle -120°) - (1\angle 120°) \\ (1\angle 120°) - (1\angle 0°) \end{bmatrix}$$

$$\begin{bmatrix} Ia_{compensated} \\ Ib_{compensated} \\ Ic_{compensated} \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} \sqrt{3}\angle 30° \\ \sqrt{3}\angle -90° \\ \sqrt{3}\angle 150° \end{bmatrix}$$

$$\begin{bmatrix} Ia_{compensated} \\ Ib_{compensated} \\ Ic_{compensated} \end{bmatrix} = \begin{bmatrix} 1\angle 30° \\ 1\angle -90° \\ 1\angle 150° \end{bmatrix}$$

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.

Matrix 1 also removes zero-sequence current. To see how this works, we can write Ia, Ib, and Ic in terms of their symmetrical components:

$$Ia = I_1 + I_2 + I_0$$

$$Ib = \alpha^2 I_1 + \alpha I_2 + I_0$$

$$Ic = \alpha I_1 + \alpha^2 I_2 + I_0$$

We can now write (5) in terms of symmetrical components:

$$\begin{bmatrix} Ia_{compensated} \\ Ib_{compensated} \\ Ic_{compensated} \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} (I_1 + I_2 + I_0) - (\alpha^2 I_1 + \alpha I_2 + I_0) \\ (\alpha^2 I_1 + \alpha I_2 + I_0) - (\alpha I_1 + \alpha^2 I_2 + I_0) \\ (\alpha I_1 + \alpha^2 I_2 + I_0) - (I_1 + I_2 + I_0) \end{bmatrix}$$

Rearranging terms, we get:

$$\begin{bmatrix} Ia_{compensated} \\ Ib_{compensated} \\ Ic_{compensated} \end{bmatrix} = \frac{1}{\sqrt{3}} \begin{bmatrix} (1 - \alpha^2) I_1 + (1 - \alpha) I_2 + (I_0 - I_0) \\ (\alpha 2 - \alpha) I_1 + (\alpha - \alpha^2) I_2 + (I_0 - I_0) \\ (\alpha - 1) I_1 + (\alpha^2 - 1) I_2 + (I_0 - I_0) \end{bmatrix}$$

Notice that the zero-sequence components cancel to zero for all three compensated currents.

VIII. Appendix B

Fig. 22 shows an example of a transformer commissioning spreadsheet. This spreadsheet is based on the worksheet found in [11].

Commissioning Test Work Sheet

Date:	
Location:	
Comments:	

Relay Settings

Phase Sequence (SHO G)	PHROT	ABC						
SHO								
Relay Identification	RID	XFMR 1						
Terminal Identification	TID	STATION A						
	Winding 1		Winding 2		Winding 3		Winding 4	
Current Transformer Connection	W1CT	Y	W2CT	Y	W3CT	Y	W4CT	Y
Current Transformer Ratio	CTR1	120	CTR2	240	CTR3	400	CTR4	400
Transformer MVA	MVA	100.0						
Connection Compensation	W1CTC	11	W2CTC	11	W3CTC	0	W4CTC	NA
Nominal LL Voltage (kV)	VWDG1	230.00	VWDG2	138.00	VWDG3	13.80	VWDG4	NA
Tap Calculation	TAP1	2.09	TAP2	1.74	TAP3	10.46	TAP4	NA
Relay Differential Settings	O87P	0.3	SLP1	25	SLP2	50	IRS	3.0
	U87P	10.0						

Metered Load (Data Taken from Independent Metering Source)

Enter NA if winding input not in use.

	Winding 1		Winding 2		Winding 3		Winding 4	
Megawatts	MW1	44.0	MW2	44	MW3	0	MW4	NA
MegaVARs	MVAR1	2.3	MVAR2	2.3	MVAR3	0	MVAR4	NA
Comments on Source of Metered Data:								
Calculated MVA	MVA1	44.1	MVA2	44.1	MVA3	0.0	MVA4	NA
$MVAn = \sqrt{MWn^2 + MVARn^2}$								

Calculated Relay Amps

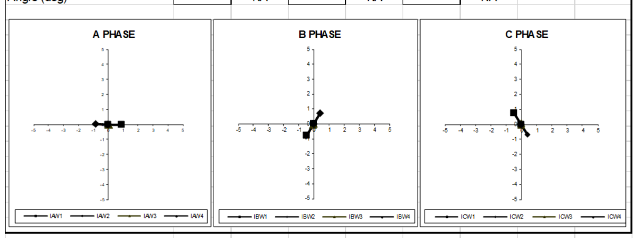
Calculated Amps Primary	$I1_{PRI}$	110.6	$I2_{PRI}$	184.3	$I3_{PRI}$	0.0	$I4_{PRI}$	NA
$In_{PRI} = \frac{MVAn * 1000}{\sqrt{3} * VWDGn}$								
Calculated Amps Secondary	$I1_{SEC}$	0.9	$I2_{SEC}$	0.8	$I3_{SEC}$	0.0	$I4_{SEC}$	NA

$IF\_WnCT{=}Y, In_{SEC} = \frac{In_{PRI}}{CTRn}$ $\quad IF\_WnCT{=}D, In_{SEC} = \frac{In_{PRI} * \sqrt{3}}{CTRn}$

W3 Current too low for reliable angle reading

Magnitude, Angle, and Phase Rotation Check (MET SEC<Enter> Command)

Winding 1	IAW1		IBW1		ICW1		3I2W1	
	Read	Expected	Read	Expected	Read	Expected	Read	Expected
I (A, Sec)	0.91	0.9	0.92	0.9	0.89	0.9	0.04	0.00
Angle (deg)	0	0	-119	-120	120	120		
Winding 2	**IAW2**		**IBW2**		**ICW2**		**3I2W2**	
	Read	Expected	Read	Expected	Read	Expected	Read	Expected
I (A, Sec)	0.81	0.8	0.82	0.8	0.79	0.8	0.05	0.00
Angle (deg)	179	180	60	60	-61	-60		
Winding 3	**IAW3**		**IBW3**		**ICW3**		**3I2W3**	
	Read	Expected	Read	Expected	Read	Expected	Read	Expected
I (A, Sec)	0.06	0.0	0.06	0.0	0.06	0.0	0.00	0.00
Angle (deg)	-27	Too Low	-148	Too Low	86	Too Low		
Winding 4	**IAW4**		**IBW4**		**ICW4**		**3I2W4**	
	Read	Expected	Read	Expected	Read	Expected	Read	Expected
I (A, Sec)		NA		NA		NA		NA
Angle (deg)		NA		NA		NA		



Differential Check (MET DIF<Enter> Command)

	Operate Currents			Restraint Currents		
	IOP1	IOP2	IOP3	IRT1	IRT2	IRT3
I (Mult. Of Tap)	0.01	0.01	0.02	0.29	0.29	0.29
Mismatch Calculation	MM1	MM2	MM3			
$MMn = \left(\frac{IOPn}{IRTn}\right) * 100$	3%	3%	7%			

Fig. 22 Example transformer relay commissioning spreadsheet

IX. Appendix C

Fig. 23 is an example of a comprehensive differential metering report available in some microprocessor-based transformer differential relays. The report has four parts.

Part 1 includes the standard differential element metering information, including calculated operate (IOPp) and calculated restraint (IRTp) values. It also reports harmonic values as a percentage of fundamental values for the operate current in each differential element.

```
Part 1
=>>MET DIF A

Operate Currents (per unit)        Restraint Currents (per unit)
IOPA      IOPB      IOPC           IRTA      IRTB      IRTC
 0.01      0.01      0.01           0.74      0.74      0.74

2nd Harmonic Currents (percentage of IOPA, IOPB, IOPC)
IOPAF2    IOPBF2    IOPCF2
 0.00      0.00      0.00

4th Harmonic Currents (percentage of IOPA, IOPB, IOPC)
IOPAF4    IOPBF4    IOPCF4
 0.00      0.00      0.00

5th Harmonic Currents (percentage of IOPA, IOPB, IOPC)
IOPAF5    IOPBF5    IOPCF5
 0.00      0.00      0.00
```

```
Part 2
Enabled Windings:  S, T, U, W

Tap and Matrix Compensation:                           Reference Terminal = S
                    Terminal Currents            Tap Comp.        Matrix Comp.
Phase A      (A,pri)     (A,sec)     (DEG)    (per unit)    (per unit)    (DEG)
 IAS         282.14       0.35        0.00       0.25          0.25      -29.89
 IAT         358.71       0.45     -155.30       0.32          0.32      174.79
 IAU         391.71       0.98      103.56       0.12          0.12       73.68
 IAW         653.77       0.82      -16.46       0.06          0.06      -16.46
Phase B
 IBS         282.51       0.35     -119.86       0.25          0.25     -149.91
 IBT         359.72       0.45       84.84       0.32          0.32       54.81
 IBU         391.55       0.98      -16.26       0.12          0.12      -46.36
 IBW         653.54       0.82     -136.36       0.06          0.06     -136.36
Phase C
 ICS         282.43       0.35      120.25       0.25          0.25       90.19
 ICT         359.39       0.45      -35.05       0.32          0.32      -65.12
 ICU         391.71       0.98     -136.19       0.12          0.12     -166.22
 ICW         653.61       0.82      103.79       0.06          0.06      103.79
```

```
Part 3
Compensation Settings:
CTCONS: Y      TAPS:   1.41     TSCTC: 11
CTCONT: Y      TAPT:   1.41     TTCTC: 11
CTCONU: Y      TAPU:   8.26     TUCTC: 11
CTCONW: Y      TAPW:  14.12     TWCTC:  0
```

```
Part 4
Relay Word Bits:
P87A    P87B    P87C    87RA    87RB    87RC    87R     87T_M
0       0       0       0       0       0       0       0

87UA    87UB    87UC    87U     87T_SF  87T_SFA 87T_SFB 87T_SFC
0       0       0       0       0       0       0       0

87ABK2  87BBK2  87CBK2  87XBK2  87ABK5  87BBK5  87CBK5  87QB
0       0       0       0       0       0       0       0
```

Fig. 23 Example comprehensive differential metering report

Part 2 gives the values in each restraint input. Reading from left to right, we see the current magnitude displayed in primary amperes. The secondary magnitude and angle are displayed next. This is the actual current measured by the relay. Next, the secondary current is divided by the TAP compensation factor to convert it to per unit of TAP. Finally, the magnitude-normalized currents are multiplied by the phase and zero-sequence compensation matrix to display the magnitude and angle of the fully compensated restraint current. These are the currents used to sum to obtain IOP for each phase-differential element. The magnitudes of these currents are summed to form the IRT for each phase differential element.

Part 3 provides the critical compensation settings used in Part 2. All information required to get from the left side of Part 2 to the right side of Part 2 is provided. Finally, Part 4 provides status of critical differential element outputs.

This comprehensive listing of information allows the user to easily verify the differential installation. This record can be captured during first loading and kept as a comprehensive record that the transformer differential installation was correct when first placed in service.

X. References

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XI. Biographies

Michael J. Thompson received his B.S., magna cum laude, from Bradley University in 1981 and an M.B.A. from Eastern Illinois University in 1991. Upon graduating, he served nearly 15 years at Central Illinois Public Service (now AMEREN). Prior to joining Schweitzer Engineering Laboratories, Inc. (SEL) in 2001, he worked at Basler Electric. He is presently a Fellow Engineer at SEL Engineering Services, Inc. He is a senior member of the IEEE, Officer of the IEEE PES Power System Relaying and Control Committee, past chairman of the Substation Protection Subcommittee of the PSRC and received the Standards Medallion from the IEEE Standards Association in 2016. Michael is a registered professional engineer in six jurisdictions, was a contributor to the reference book, *Modern Solutions for the Protection Control and Monitoring of Electric Power Systems*, has published numerous technical papers and magazine articles, and holds three patents associated with power system protection and control.

Ariana Hargrave earned her B.S.E.E., magna cum laude, from St. Mary's University in San Antonio, Texas, 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. (SEL) in 2009 and works as a senior protection application engineer in Fair Oaks Ranch, Texas. She has published over 30 application guides and technical papers and was honored to receive the Walter A. Elmore

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