Work Smarter, Not Harder: Using Software Tools to Diagnose REF Installation Errors

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***Abstract*—Restricted earth fault (REF) protection is a necessary, but often underused, element for protecting transformers. Many engineers are hesitant to apply REF protection due to fear of misoperations and extended outages caused by wiring or settings errors. To encourage adoption of REF protection, this paper presents an algorithm that automatically detects and diagnoses REF field installation errors. The algorithm can use load data with sufficient unbalance to identify errors before they result in misoperations. It can also use data from an external ground fault after a misoperation has occurred to quickly identify errors and reduce outage time. The paper shows how the algorithm was implemented as a software tool and provides six examples of how it was used to find errors in different field installations.**

I. Introduction

Misoperations of the restricted earth fault (REF) element due to wiring or settings errors continue to be a widespread problem for the industry. One utility reported eleven REF misoperations in a span of six years [1]. An REF misoperation in Manhattan made the news when it plunged the city into darkness and caused 72,000 customers to lose power for about five hours [2] [3]. Fear of such misoperations has caused many engineers to avoid applying REF protection altogether, leaving their transformers vulnerable to internal ground faults that cannot be detected by the phase differential element (87R) alone [4].

The wiring and settings errors that can cause the REF element to misoperate can be detected through primary injection testing, but this type of testing is not always practical or feasible [5]. If primary injection testing cannot be performed, it is possible to use an event report triggered by the relay to diagnose REF installation errors. This event report can be triggered during load (if sufficient unbalance exists) or during an external ground fault. An experienced engineer must analyze the data in the event report to determine if the installation is correct or has errors. If errors exist, further analysis must be performed to identify the exact wiring or setting errors and determine the solution.

The analysis required for in-service commissioning checks can take significant time and effort when performed manually. Relays from different vintages and manufacturers can have different names and units for signals and settings. Digging through instruction manuals to identify these differences can be tedious, especially for an organization that uses several different types of transformer relays. Furthermore, manual analysis is prone to human errors, which can lead to an incorrect diagnosis.

This paper shows how an algorithm was developed to automate the in-service commissioning checks used to detect REF field installation errors. This algorithm allows users to work smarter, not harder by speeding up analysis, removing the chance for human error, and eliminating the need to understand the specifics of a given installation every time. Applying this algorithm to an event report during unbalanced load conditions will tell engineers if the installation is correct or identify any errors before they result in a misoperation. Applying this algorithm to an event report after the REF element misoperates during an external fault will quickly inform engineers of the error that caused the misoperation and reduce outage time.

This paper first reviews the basics of how an REF element works and what types of field installation errors can cause it to misoperate. It then discusses the existing methods that are used to find these errors as well as their limitations. Next, it explains how the algorithm that automatically detects field installation errors works and how it was implemented as a software tool. Finally, it shows six examples of how the tool has been used to accurately find errors in different field installations.

II. Background

An REF element is used to detect ground faults on grounded wye transformer windings. The name restricted comes from the element zone of protection being restricted to the area between the ground CT and the phase CTs on the terminal side of the wye winding, as shown in Fig. 1.

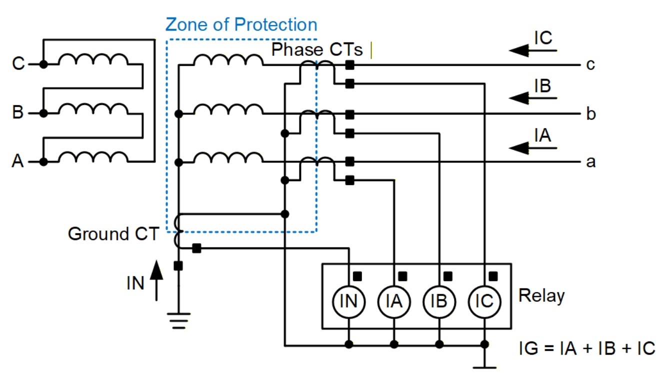

Fig. 1. REF element zone of protection.

REF protection can be applied using low-impedance schemes (ground differential elements and current-polarized directional overcurrent elements) and high-impedance differential schemes [6] [7]. This paper focuses on the current-polarized directional overcurrent REF element. This section explains how the element works, how installation errors can affect its operation, and how errors can be detected during testing.

A. How REF Works

The REF element uses the ground CT to measure current at the neutral end of the wye winding (IN) and one or more sets of three-phase, wye-connected phase CTs to calculate residual current at the terminal side of the wye winding (IG). The CTs, or combination of CTs, used for calculating the IG current are defined by a setting in the relay (WYE_TERMS). The REF element does not require the IN and IG CTs to have the same ratio (CTRN and CTR) or same nominal rating (INOM_N and INOM). To compensate for any differences, the logic scales both currents to per-unit values on a common base, as shown in Fig. 2.

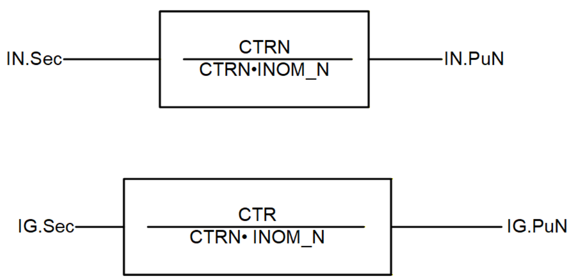

Fig. 2. Scaling IN and IG to per-unit values on the neutral base.

The per-unit currents are then used in the REF logic shown in Fig. 3. The element is enabled when the magnitude of the per-unit neutral current (IN.PuN) is greater than the pickup (IN.PICKUP), indicating that a ground fault exists somewhere on the system on the wye side of the transformer. To determine if the fault is internal or external to the zone of protection, the element checks if IG current is greater than IG.PICKUP (typically 80 percent of IN.PICKUP).

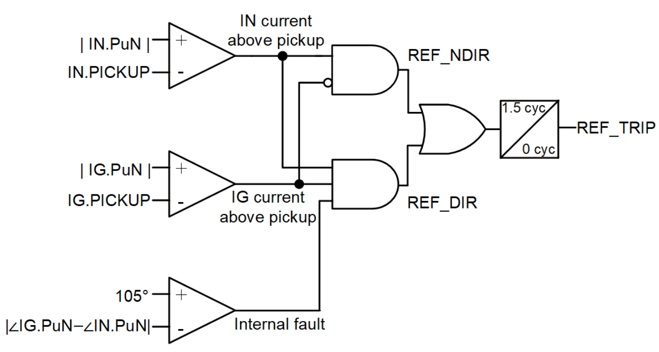

Fig. 3. Logic for a current-polarized directional overcurrent REF element.

If IG current is not above its pickup, the fault is declared as internal to the zone of protection, the nondirectional path (REF_NDIR) asserts, and the REF element operates. The nondirectional path is required to cover internal fault cases when the wye-side breaker is open or when there is no ground source on the wye side of the transformer.

If IG current is above its pickup, the element compares the angles between the IN and IG currents. This angle check can be understood using Fig. 4. With CTs wired in differential polarity, the relay should ideally measure IN and IG to be 180 degrees out of phase for an external ground fault and in phase for most internal ground faults. (For autotransformers, the relationship between IN and IG currents may be different during internal ground faults closer to the terminal side of the winding [8].) The logic in modern REF elements declares an internal fault and asserts the directional path (REF_DIR) when the angle difference between IN and IG is less than 105 degrees (as seen in Fig. 5).

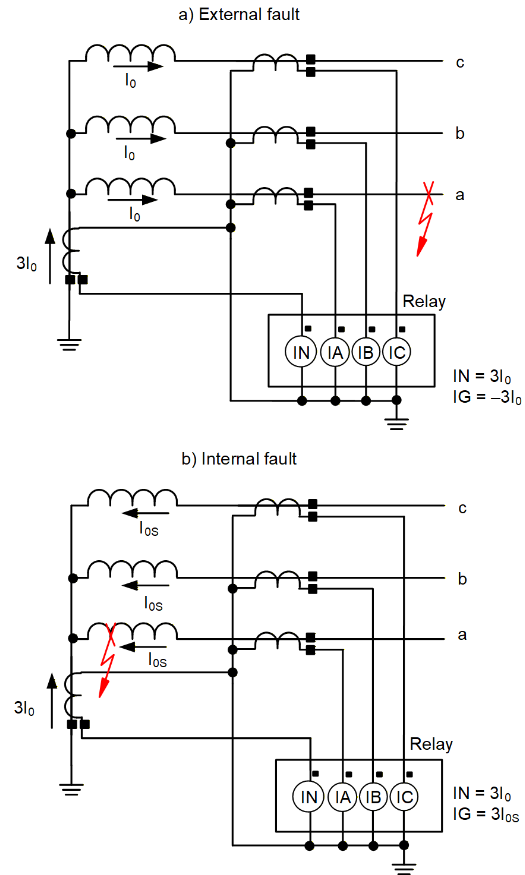

Fig. 4. Ground fault current flow in the wye winding for a) external and b) internal faults [4].

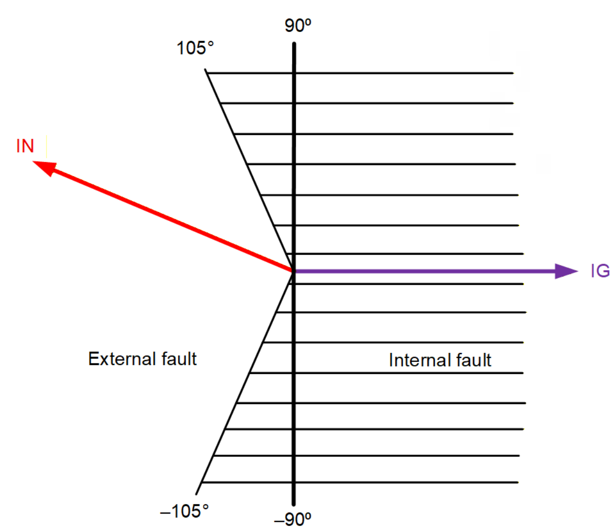

Fig. 5. REF element angle check.

B. Types of REF Installation Errors

The proper operation of the REF element is contingent on correct values of IN and IG currents. Unfortunately, wiring and settings errors can compromise these currents and can cause the REF element to misoperate—either incorrectly operating for an external ground fault or not operating for an internal ground fault. These errors can include the following:

1) Inverted CT polarity (IN or IG CTs)

The REF element expects IN and IG CTs to be connected in differential polarity. If the polarity of one of the CTs is inverted, a misoperation can occur. It is also possible that the CTs on the primary system are connected in differential polarity, but a polarity inversion occurs at the relay terminals or due to a setting in the relay. An inverted neutral CT is one of the most common causes of REF misoperations.

2) Wiring error in IG CTs

The REF element expects the IG CTs to be connected in wye. If the CTs are mistakenly connected in delta, or they are connected in wye but the neutral connection is missing, the relay will not measure any IG current during an external ground fault and the element will misoperate.

3) Incorrect CT ratio/tap position (IN or IG CTs)

The REF element expects the IN and IG CT ratios in the relay settings to match the actual ratios in the field. If this is not true, the IN or IG currents may fall below their respective pickups, causing the element to misoperate.

4) Incorrect WYE_TERMS setting

The REF element expects the WYE_TERMS setting to be set to the terminal(s) on the relay that are connected to the wye winding of the transformer. If this is not true, the element will use the wrong phase currents to calculate the IG current and will misoperate during an external ground fault.

C. Detecting REF Installation Errors

The best way to find REF installation errors before they result in a misoperation is by performing primary injection tests. If those tests are not possible (usually due to company practices or equipment requirements), a DC kick test can be performed, but this test is limited in that it can only detect the inverted CT error described in Section II.B.1. More details about these tests can be found in [4].

Another way to find REF installation errors is to analyze relay event report data. If enough unbalance exists on the system during normal load conditions (over 5 percent of nominal current on the IN and IG current inputs), an event report can be triggered during load and used for analysis. The event report can be triggered manually or when a low-set neutral overcurrent element asserts. If there is not enough unbalance on the system during normal load conditions, it is necessary to wait for an external unbalanced fault to occur downstream of the transformer and download the event report generated by the relay. Although this is one of the most common ways that REF installation errors are discovered, it is not ideal, as the REF element may misoperate before the error can be detected.

Once an event report is obtained, the engineer performing the analysis must have the expertise to know how to analyze the data to determine if the installation is correct or if errors exist.

The first step to this analysis involves understanding the data in the event report, which presents the following challenges, all of which vary depending on the relay model and manufacturer:

- Understanding which current signal names and settings names the REF element is using.
- Understanding if the calculated ground current is reported by the relay in the event report or if it must be calculated manually.
- Understanding the units of the currents reported in the event report (e.g., primary amperes vs. secondary amperes).

The second step is converting the currents in the event report to per-unit values, as shown in Fig. 2. To do this, the engineer must know the CT ratio settings for the phase and neutral CTs and the nominal ratings of the phase and neutral CT inputs.

The final step is analyzing and comparing the magnitudes and angles of the per-unit currents to confirm a correct installation or determine the root cause of an incorrect installation. Some errors, such as inverted polarity, are easier to identify than others.

III. Algorithm to Automatically Identify REF Installation Errors

The manual analysis to detect REF installation errors described in Section II.C requires expertise, can take significant time and effort, and is prone to human error. When working with relays from different vintages and manufacturers, it takes time to search through instruction manuals and identify the names and units for every current signal and necessary relay setting. The circumstances get more challenging when an outage has occurred and the engineer is under pressure to get the lights back on.

Instead of manual analysis, using an algorithm to provide automated analysis allows users to quickly apply the same process every time without the fear of human error. There is also no need for the user to be intimately familiar with the design and operation of multiple relays. Any differences between the relays, such as signal names, settings names, and units, are programmed in the algorithm once and applied automatically. As far as a user is concerned, all these differences are handled under the hood. There is also no need for the user to be an expert in analyzing REF element misoperations. The process used to identify errors is programmed once and handled behind the scenes.

This section explains an algorithm that was developed to automatically detect REF field installation errors. It describes how the algorithm works and how it can be implemented.

A. Description

The algorithm performs two main functions: determining if an REF installation is correct or not, and, if not, determining what the problem is. The ability of the algorithm to validate a correct installation gives users confidence that the REF element is set correctly, the CTs are wired correctly, and the element will operate for an internal ground fault and restrain for an external ground fault. If the algorithm cannot verify that the installation is correct, it attempts to diagnose the problem and guide the user to root cause. The algorithm can detect all the common REF installation errors described in Section II.B.

Fig. 6 shows the logic for the algorithm. The outputs visible to the user are shown in bold and are described in the sections that follow.

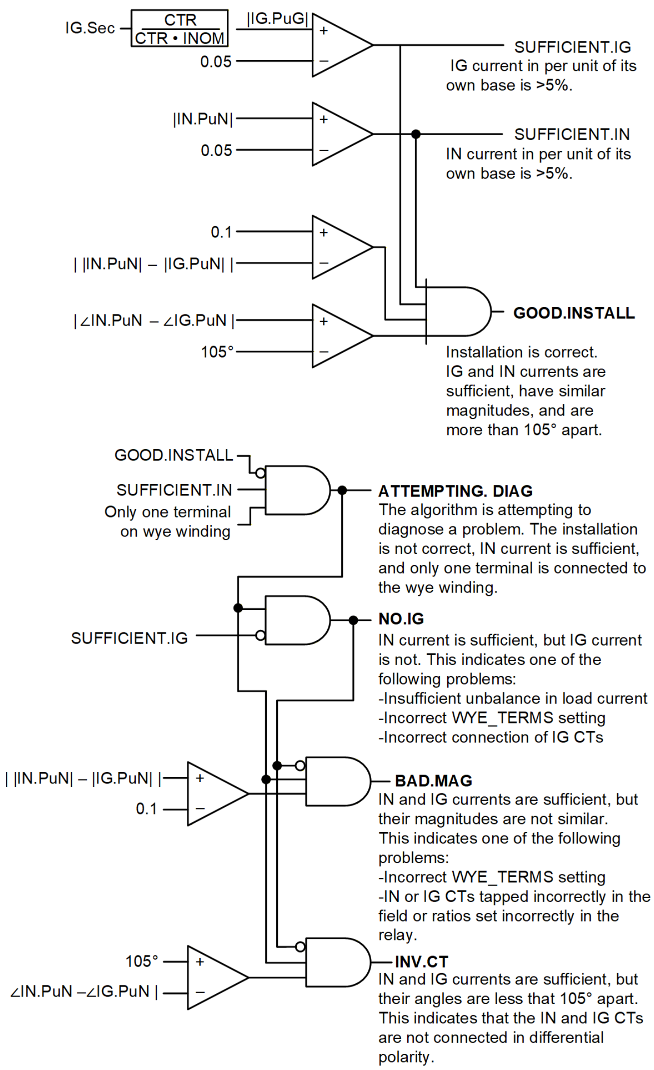

Fig. 6. Logic to automatically detect REF field installation errors.

1) *GOOD.INSTALL*

The logic for GOOD.INSTALL determines if the installation is correct or not. It asserts when all the following are true:

- The magnitude of the IG current in per unit of its own base (the nominal current of the phase CTs) is above 0.05 pu. When this is true, SUFFICIENT.IG asserts. This ensures that enough current exists on the IG CTs that the magnitude and angle of the IG current measurement can be trusted.
- The magnitude of the IN current in per unit of its own base is above 0.05 pu. When this is true, SUFFICIENT.IN asserts. This ensures that enough current exists on the IN CT that the magnitude and angle of the IN current measurement can be trusted.
- The magnitude difference between IN and IG currents (with both values in per unit of the neutral base) is less than 10 percent. This confirms that the IN and IG currents are approximately equal in magnitude, which is expected for a correct installation during an external ground fault or unbalanced load.
- The angle difference between the IN and IG currents is greater than 105 degrees. This confirms that the IN and IG currents are out of phase with each other (ideally 180 degrees apart), which is expected for a correct installation during an external ground fault or unbalanced load.

The assertion of GOOD.INSTALL tells the user that the algorithm was able to confirm that the REF installation is correct. If GOOD.INSTALL is asserted, no other outputs will be asserted. For events triggered during load on a correct installation, it is possible that GOOD.INSTALL may not assert if the IN and IG currents are not above 0.05 pu.

2) *ATTEMPTING.DIAG*

The logic for ATTEMPTING.DIAG determines if necessary conditions are met that enable the algorithm to diagnose the error. It asserts when all the following are true:

- The installation has not been verified as correct (GOOD.INSTALL deasserted).
- The magnitude of the IN current in per unit of its own base is above 0.05 pu (SUFFICIENT.IN asserted). This is the only current magnitude requirement; IG current does not also have to be above 0.05 pu to determine the problem.
- There is only one terminal connected to the wye winding of the transformer. This condition checks the WYE_TERMS setting to confirm if the IG current is being calculated based on only one terminal or more than one terminal. Although the algorithm is able to confirm a correct installation when WYE_TERMS includes more than one terminal (see Fig. 6), it is only able to correctly identify a problem when WYE_TERMS includes only one terminal.

The assertion of ATTEMPTING.DIAG tells the user that the above conditions necessary to diagnose an incorrect REF installation have been met. If ATTEMPTING.DIAG is asserted, the user should check the rest of the outputs to determine the problem.

3) *NO.IG*

The logic for NO.IG detects errors that result in no current measured by the IG CTs. It asserts when all the following are true:

- A diagnosis is being attempted (ATTEMPTING.DIAG asserted).
- The magnitude of the IG current in per unit of its own base is below 0.05 pu (SUFFICIENT.IG deasserted).

The assertion of NO.IG tells the user that the error could be due to the reasons listed below. The user should investigate each reason in the given order to determine the problem.

- The current has insufficient unbalance (less than 0.05 pu). This can be confirmed by looking at the calculated ground current on another device that is measuring the current on the wye side of the transformer. If the unbalance is confirmed to be insufficient, the user must wait for an event with sufficient unbalance to validate their installation.
- The WYE_TERMS setting in the relay is incorrect. The setting must be set to the relay terminal(s) connected to the wye winding of the transformer.
- The connection of the IG CTs is incorrect. This could include the CTs being wired in a delta connection instead of a wye connection. It could also include the CTs being wired in a wye connection with the neutral connection missing. This can be confirmed by inspecting the wiring of the IG CTs and fixing any errors.

4) BAD.MAG

The logic for BAD.MAG detects errors that result in a magnitude mismatch between the per-unit values of IN and IG currents. It asserts when all the following are true:

- The error is not due to a missing IG current condition (NO.IG deasserted). This also ensures that the magnitude of IG current is above 0.05 pu on its own base.
- A diagnosis is being attempted (ATTEMPTING.DIAG asserted). This also ensures that the magnitude of IN current is above 0.05 pu on its own base.
- The magnitude difference between IN and IG currents (with both values in per unit of the neutral base) is greater than 10 percent. Equal magnitudes are expected for a correct installation during an external ground fault or unbalanced load.

The assertion of BAD.MAG tells the user that the error could be due to the following reasons. The user should investigate each reason in the given order to determine the problem.

- The WYE_TERMS setting in the relay is incorrect. The setting must be set to the relay terminal(s) connected to the wye winding of the transformer.
- The IN or IG CTs are tapped incorrectly in the field or the IN and IG CT ratios are set incorrectly in the relay. The wiring of the IN and IG CTs must be tapped at ratios that match the settings in the relay.

5) INV.CT

The logic for INV.CT determines if the IN and IG CTs are not connected in differential polarity. It asserts when all the following are true:

- The error is not due to a missing IG current condition (NO.IG deasserted). This also ensures that the magnitude of IG current is above 0.05 pu on its own base.
- A diagnosis is being attempted (ATTEMPTING.DIAG asserted). This also ensures that the magnitude of IN current is above 0.05 pu on its own base.
- The angle difference between the IN and IG currents is less than 105 degrees. These two currents are expected to be 180 degrees out of phase for a correct installation during an external ground fault or unbalanced load.

This error can be confirmed by inspecting the wiring of the CTs and any polarity reversal settings that may exist in the relay.

B. Implementation

The algorithm described in Section III.A can be implemented in several ways. One method is programming the algorithm in relay firmware or relay logic. Doing this allows the algorithm to run automatically under certain conditions (for example, when IN current is above 0.05 pu during an external fault or load) without any input from the user. The relay can then alarm on the front panel or to SCADA if it detects a problem.

Another option is creating a software tool that applies the algorithm to event report data triggered by the transformer relay. The tool needs to be capable of importing relay event report data, running the algorithm described in Section III.A, and displaying results.

To support users of both modern and legacy generations of transformer relays, the authors elected to implement the algorithm as a software tool. The tool was developed using commercially available event analysis software [9] and made available in [10]. The tool requires an event report triggered either during unbalanced load or an unbalanced external fault. In addition to detecting REF installation errors, the tool also plots charts that help the user understand the operation of the REF element by visualizing the IN and IG currents and the relationship between them. The application of the tool is explained in more detail in Section IV.

IV. Application Examples

This section shows how the tool explained in Section III was used to analyze six different REF field installations. In all cases, the tool was able to inform the user within minutes if the installation was correct or had errors. If errors existed, the tool identified them correctly—even in events where multiple errors existed simultaneously.

A. Tool Confirms Correct Installation

A 28 MVA 115/13.2 kV delta-wye transformer is protected by a transformer relay with three REF elements (REF1, REF2, and REF3) and 5 A nominal current inputs. The wye winding is protected by the REF2 element. A simplified one-line diagram is shown in Fig. 7.

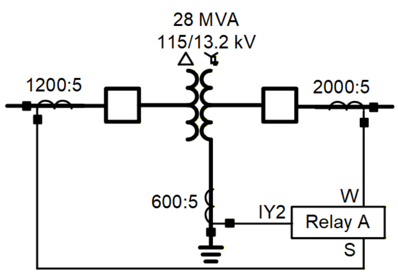

Fig. 7. Example A system one-line diagram.

The relay recorded an event report during system unbalance conditions, which provided an opportunity to apply the software tool and verify the REF installation. The process of applying the tool is described in the following steps.

1. The event report is opened in the event analysis software and the software tool is imported.
2. The five user settings shown in Table I are configured. These settings allow the tool to choose the correct signals and settings for analysis. Settings RELAY_TYPE and REF_ELEMENT must be manually entered by the user and the remaining settings can generally be left at their default values. When WYE_TERMS is left at the default value of AUTO, the tool pulls the value from the relay settings saved in the event report. The values of the user settings for this event are shown in Table I.

TABLE I
EXAMPLE A USER SETTINGS

User Setting	Value	Description
RELAY_TYPE	RELAY A	Relay model.
REF_ELEMENT	2	REF element to be analyzed. When set to 2, the tool automatically uses the IY2 current as IN current and the REF2 element pickup as IN.PICKUP.
WYE_TERMS	AUTO	Terminals used to calculate IG current. AUTO is equivalent to Terminal W in this event.
INOM_N	5	Nominal current rating of the relay neutral CT input terminal in amperes.
INOM	5	Nominal current rating of the terminal(s) used to calculate the IG current in amperes.

3. The IN current chart (see Fig. 8) generated by the tool is analyzed to identify the window of time when the IN current is high. The orange cursor is positioned in the middle of that window to define when the tool runs the algorithm. In this event, the orange cursor was positioned in the middle of the window when IN current increased for about 2 cycles above the standing unbalance current.
4. The algorithm outputs are viewed in the Algorithm Digital Chart. For this event, GOOD.INSTALL was asserted, confirming that the REF installation was correct.
5. (Optional): The additional charts generated by the tool (see Fig. 8) are analyzed to understand the outputs of the algorithm as well as the REF element. These additional charts show the following:
   - The IG Current Chart shows the A-, B-, and C-phase currents used by the relay to calculate the IG current based on the WYE_TERMS setting.
   - The IN Pickup Chart compares the magnitude of the IN current (equivalent to IN.PuN) against IN.PICKUP.
   - The IG Pickup Chart compares the magnitude of the IG current (equivalent to IG.PuN) against IG.PICKUP.
   - The Angle Check Chart plots the IN and IG current phasors (magnitude and angle of IN.PuN and IG.PuN). If both IN and IG current magnitudes are above their respective pickups, the chart also plots the ±105 degree thresholds as grey lines that define the boundary between internal and external faults.
   - The Relay Digital Chart shows the relay-generated outputs of the REF element and the trip logic.
   - The Algorithm Digital Chart shows the outputs generated by the algorithm.

In this event, the magnitude of both IN and IG currents were sufficient (above 0.05 per unit). They also had the same magnitude and were 180 degrees out of phase. Therefore, the algorithm declared the REF installation to be correct. The REF2 element did not operate because the magnitude of the IN current was below IN.PICKUP.

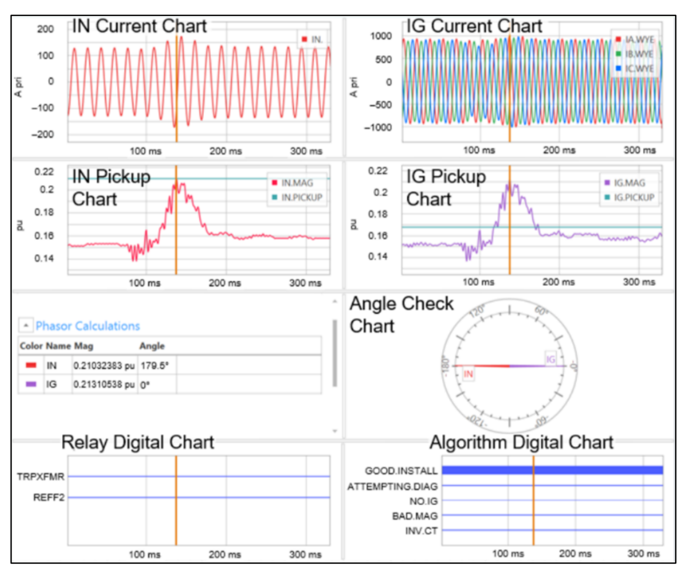

Fig. 8. Tool confirms correct installation during system unbalance.

B. *Tool Detects Inverted CT*

A 22 MVA 138/12.47 kV delta-wye transformer is protected by a transformer relay with three REF elements (REF1, REF2, and REF3) and 5 A nominal current inputs. The wye winding is protected by the REF1 element. A simplified one-line diagram of how the scheme was supposed to be wired is shown in Fig. 9.

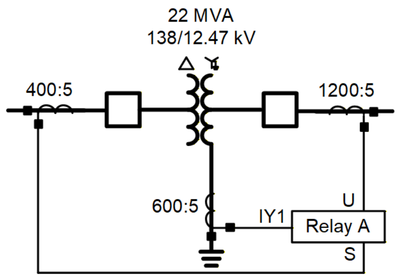

Fig. 9. Example B system one-line diagram.

The relay tripped and recorded an event report when the REF1 element operated during an external C-G fault. The process outlined in Section IV.A was used to apply the tool to the event report and determine the root cause of the misoperation. The user settings are shown in Table II.

TABLE II
EXAMPLE B USER SETTINGS

User Setting	Value	Description
RELAY_TYPE	RELAY A	Relay model.
REF_ELEMENT	1	REF element to be analyzed. When set to 1, the tool automatically uses the IY1 current as IN current and the REF1 element pickup as IN.PICKUP.
WYE_TERMS	AUTO	Terminals used to calculate IG current. AUTO is equivalent to Terminal U in this event.
INOM_N	5	Nominal current rating of the relay neutral CT input terminal in amperes.
INOM_G	5	Nominal current rating of the terminal(s) used to calculate the IG current in amperes.

The outputs of the algorithm are shown in Fig. 10. These outputs show that the algorithm did not detect a correct installation, attempted to diagnose the problem, and found the error to be an inverted CT. Field inspection later confirmed that the externally-mounted CT on the transformer neutral was installed with polarity opposite to what is shown in Fig. 9.

Further analysis of the charts can help explain the INV.CT decision by the algorithm. Both IN and IG currents have the same magnitude, which is expected for an external fault. However, the two currents are in phase instead of 180 degrees out of phase. As a result, the algorithm declares the error to be an inverted CT.

Finally, the charts in Fig. 10 can be used to help explain how the installation error resulted in the operation of the REF element. When the IN current exceeded IN.PICKUP during the C-G fault, the REF element was enabled. Because IG current was above IG.PICKUP, the REF element performed an angle check to determine if the fault was internal or external to the zone of protection. Because the two currents have similar phase angles, the REF1 element asserted, and the relay issued a trip.

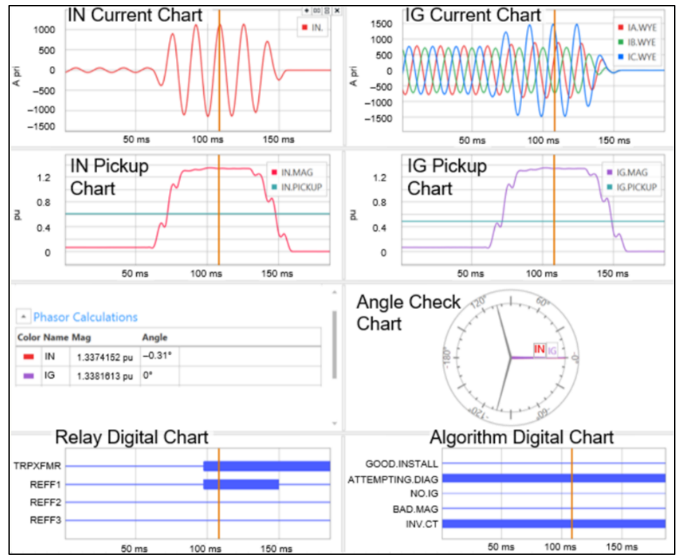

Fig. 10. Tool detects inverted CT during external ground fault.

C. *Tool Detects Incorrect WYE_TERMS Setting*

A 225 MVA 138/13.8/34.5 kV wye-delta-wye transformer is protected by a transformer relay with three REF elements (REF1, REF2, and REF3) and 5 A nominal current inputs. The 138 kV wye winding is protected by the REF1 element, and the 34.5 kV wye winding is protected by the REF2 element. A simplified one-line diagram is shown in Fig. 11.

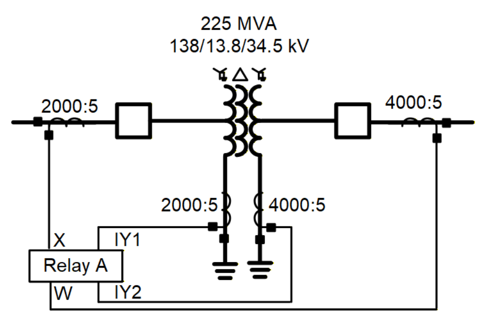

Fig. 11. Example C simplified one-line diagram.

The relay tripped and recorded an event report when the REF1 element operated during an external ground fault on the 138 kV system. The process outlined in Section IV.A was used to apply the tool to the event report and determine the root cause of the misoperation. The user settings are shown in Table III.

TABLE III
EXAMPLE C USER SETTINGS

User Setting	Value	Description
RELAY_TYPE	RELAY A	Relay model.
REF_ELEMENT	1	REF element to be analyzed. When set to 1, the tool automatically uses the IY1 current as IN current and the REF1 element pickup as IN.PICKUP.
WYE_TERMS	AUTO	Terminals used to calculate IG current. AUTO is equivalent to Terminal W in this event.
INOM_N	5	Nominal current rating of the relay neutral CT input terminal in amperes.
INOM_G	5	Nominal current rating of the terminal(s) used to calculate the IG current in amperes.

The outputs of the algorithm are shown in Fig. 12. These outputs show that the algorithm did not detect a correct installation, attempted to diagnose the problem, and found the error to be NO.IG. Working through the list described in Section III.A.3, the error was found to be an incorrect WYE_TERMS setting. The setting was set to Terminal W in the relay, but Fig. 11 shows that WYE_TERMS should have been set to Terminal X.

Further analysis of the charts can help explain the NO.IG decision by the algorithm. Both IN and IG currents should have the same magnitude during an external fault. Because IN current was above IN.PICKUP but IG current was near zero (Terminal W did not measure any current, as there are no ground sources on the 34.5 kV side), the algorithm declared the error to be a NO.IG condition.

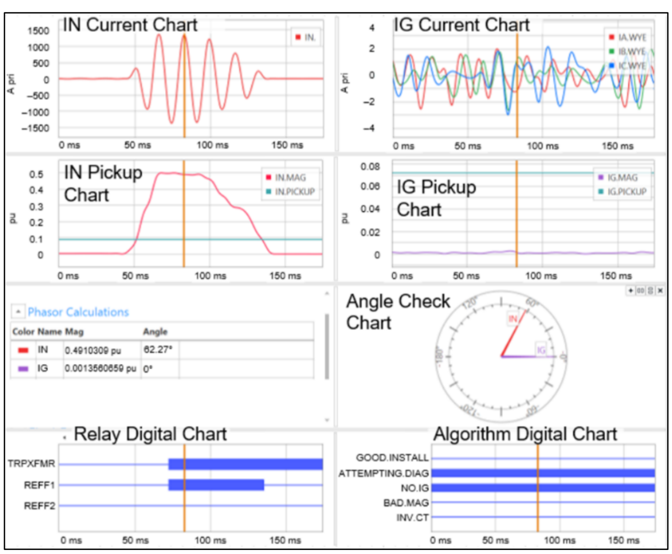

Fig. 12. Tool detects missing IG current.

The tool also allows the user to see the behavior of the algorithm with a corrected WYE_TERMS setting. In this event, when the WYE_TERMS setting is changed from AUTO to Terminal X, the IG current magnitude is now equal to the IN current magnitude and the two currents are 180 degrees out of phase. As a result, the algorithm asserts GOOD.INSTALL and the NO.IG output is deasserted. This is shown in Fig. 13.

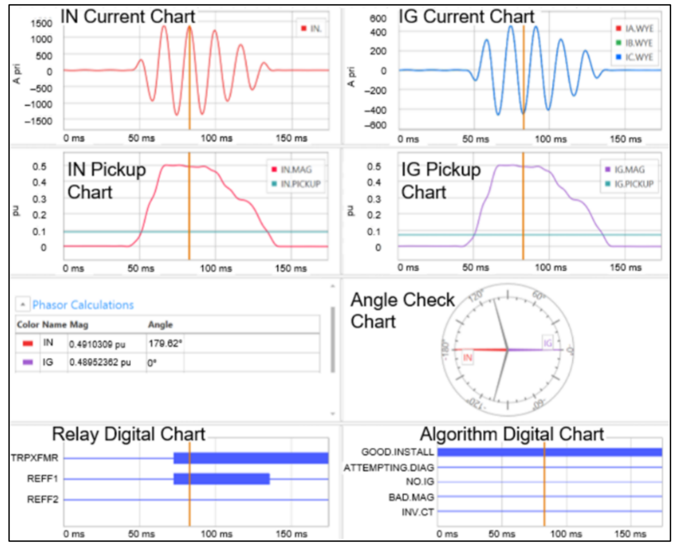

Fig. 13. Tool confirms correct installation after WYE_TERMS setting is corrected.

Finally, the charts in Fig. 12 can be used to help explain how the installation error resulted in the operation of the REF element. When the IN current exceeded the IN.PICKUP during the fault, the REF element was enabled. Because IG current was below IG.PICKUP, the REF1 element declared an internal fault and the relay issued a trip.

D. Tool Detects Multiple Errors (Incorrect CT Tap and Inverted CT)

A 120 MVA 345/13.8/13.8 kV wye-delta-delta transformer is protected by a transformer relay with three REF elements (REF1, REF2, and REF3) and 5 A nominal current inputs. The wye winding is protected by the REF1 element. A simplified one-line diagram of how the scheme was supposed to be wired is shown in Fig. 14.

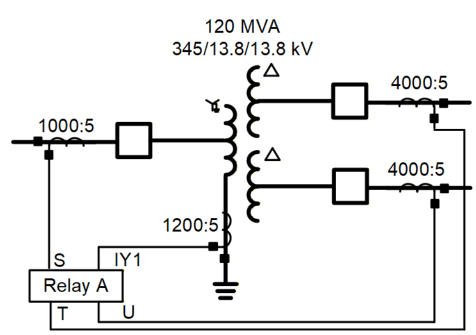

Fig. 14. Example D simplified one-line diagram.

The relay tripped and recorded an event report when the REF1 element operated during an external ground fault on the 345 kV system. The process outlined in Section IV.A was used to apply the tool to the event report and determine the root cause of the misoperation. The user settings are shown in Table IV.

TABLE IV
EXAMPLE D USER SETTINGS

User Setting	Value	Description
RELAY_TYPE	RELAY A	Relay model.
REF_ELEMENT	1	REF element to be analyzed. When set to 1, the tool automatically uses the IY1 current as IN current and the REF1 element pickup as IN.PICKUP.
WYE_TERMS	AUTO	Terminals used to calculate IG current. AUTO is equivalent to Terminal S in this event.
INOM_N	5	Nominal current rating of the relay neutral CT input terminal in amperes.
INOM_G	5	Nominal current rating of the terminal(s) used to calculate the IG current in amperes.

The outputs of the algorithm are shown in Fig. 15. These outputs show that the algorithm did not detect a correct installation, attempted to diagnose the problem, and found two errors: a magnitude mismatch between IN and IG and an inverted CT.

Further analysis of the charts can help explain the BAD.MAG and INV.CT decisions by the algorithm. The difference between the IN and IG current magnitudes is more than 10 percent. Furthermore, the two currents are similar in phase instead of 180 degrees out of phase. As a result, the algorithm declared the errors to be BAD.MAG and INV.CT.

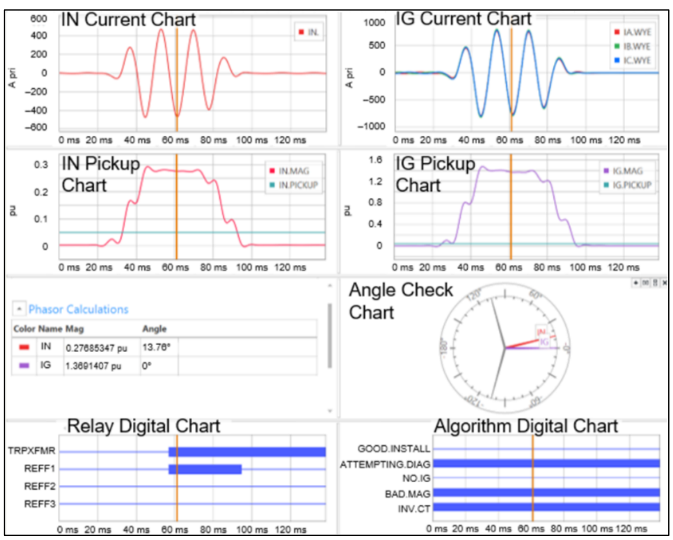

Fig. 15. Tool catches two errors.

Finally, the charts in Fig. 15 can be used to help explain how the installation errors resulted in the operation of the REF element. When the IN current exceeded IN.PICKUP during the fault, the REF element was enabled. Because IG current was above IG.PICKUP, the REF element performed an angle check to determine if the fault was internal or external to the zone of protection. Because the two currents have similar phase angles, the REF1 element asserted, and the relay issued a trip.

E. Tool Detects Multiple Errors (Incorrect WYE_TERMS Setting and Inverted CT)

A 20 MVA 138/13 kV delta-wye transformer is protected by a transformer relay with one REF element and 5 A nominal current inputs. The wye winding is protected by the REF1 element. A simplified one-line diagram of how the scheme was supposed to be wired is shown in Fig. 16.

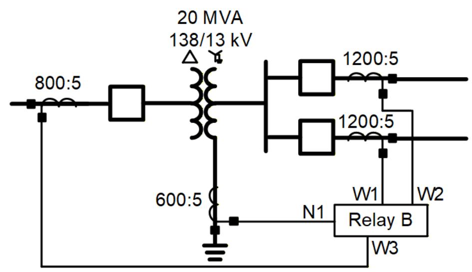

Fig. 16. Example E simplified one-line diagram.

The relay tripped and recorded an event report when the REF1 element operated during an external ground fault on feeder F1. The process outlined in Section IV.A was used to apply the tool to the event report and determine the root cause of the misoperation. The user settings are shown in Table V.

TABLE V
EXAMPLE E USER SETTINGS

User Setting	Value	Description
RELAY_TYPE	RELAY B	Relay model.
REF_ELEMENT	1	REF element to be analyzed. When set to 1, the tool automatically uses the N1 current as the IN current and the REF1 element pickup as IN.PICKUP.
WYE_TERMS	AUTO	Terminals used to calculate IG current. AUTO is equivalent to Terminal W2 in this event.
INOM_N	5	Nominal current rating of the relay neutral CT input terminal in amperes.
INOM_G	5	Nominal current rating of the terminal(s) used to calculate the IG current in amperes.

The outputs of the algorithm are shown in Fig. 17. These outputs show that the algorithm did not detect a correct installation, attempted to diagnose the problem, and found the error to be NO.IG. Working through the list described in Section III.A.3, the error was found to be an incorrect WYE_TERMS setting. The setting was set to Terminal W2 in the relay. The one-line diagram shown in Fig. 16 shows that WYE_TERMS should be set to a combination of Terminal W1 and Terminal W2.

Further analysis of the charts can help explain the NO.IG decision by the algorithm. Both IN and IG currents should have the same magnitude during an external fault. Because the IN current exceeded IN.PICKUP but the IG current was near zero, the algorithm declared the error to be a NO.IG condition.

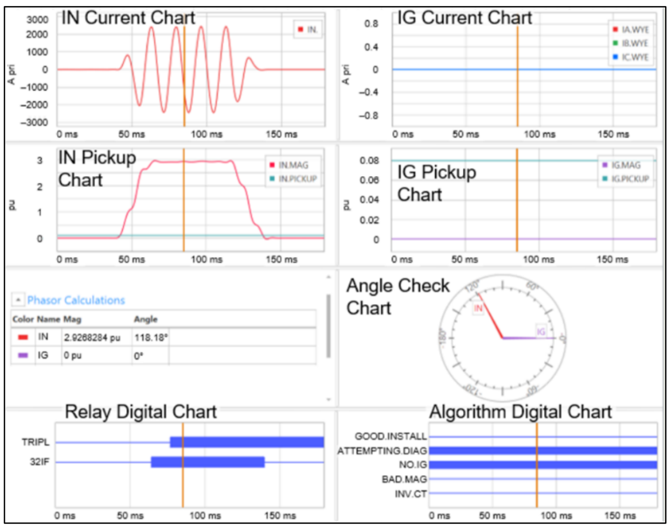

Fig. 17. Tool detects missing IG current.

The tool also allows the user to see the behavior of the algorithm with a corrected WYE_TERMS setting. Fig. 18 shows the outputs of the algorithm when the WYE_TERMS setting is changed from AUTO to a combination of Terminal W1 and Terminal W2. The algorithm still does not declare a correct installation, but it cannot attempt diagnosis due to WYE_TERMS having multiple terminals.

A quick analysis of the charts can help explain why the algorithm did not detect a correct installation. With the corrected WYE_TERMS setting, IG and IN currents now have the same magnitude, which is expected for an external fault, but are in phase instead of 180 degrees out of phase. This indicates that one of the CTs has inverted polarity, causing the algorithm to not assert GOOD.INSTALL.

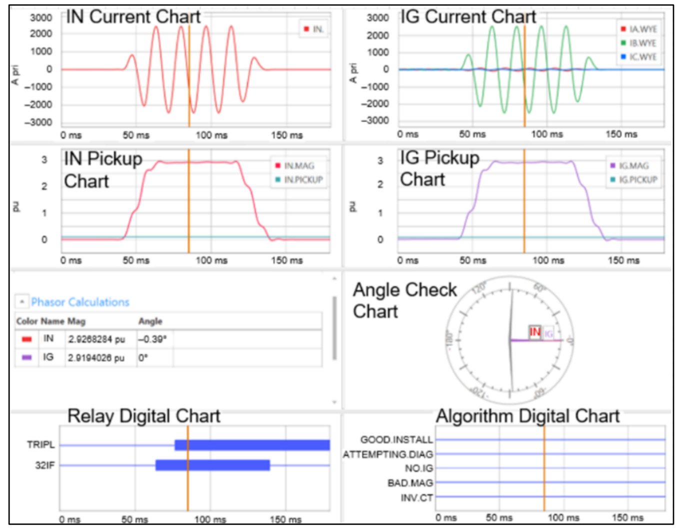

Fig. 18. After the WYE_TERMS setting is corrected, the tool still does not declare a correct installation.

Finally, the charts in Fig. 17 can be used to help explain how the installation errors resulted in the operation of the REF element. When the IN current exceeded IN.PICKUP during the fault, the REF element was enabled. Because IG current was below IG.PICKUP, the REF1 element declared an internal fault and the relay issued a trip.

F. Tool Detects Wiring Error of IG CTs

A 67 MVA 138/13.8 kV delta-wye transformer is protected by a transformer relay with two REF elements (REF1 and REF2) and 5 A nominal current inputs. The wye winding is protected by the REF2 element. A simplified one-line diagram is shown in Fig. 19.

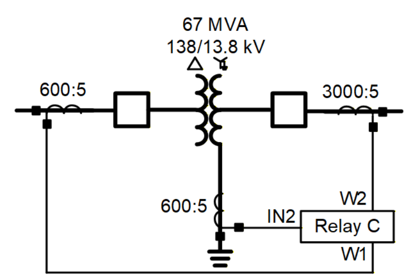

Fig. 19. Example F simplified one-line diagram.

The relay tripped and recorded an event report when the REF2 element operated during an external ground fault. The process outlined in Section IV.A was used to apply the tool to the event report and determine the root cause of the misoperation. The user settings are shown in Table VI.

TABLE VI
EXAMPLE F USER SETTINGS

User Setting	Value	Description
RELAY_TYPE	RELAY C	Relay model.
REF_ELEMENT	2	REF element to be analyzed. When set to 2, the tool automatically uses the IN2 current as IN current and the REF2 element pickup as IN.PICKUP.
WYE_TERMS	AUTO	Terminals used to calculate IG current. AUTO is equivalent Terminal W2 in this event.
INOM_N	5	Nominal current rating of the relay neutral CT input terminal in amperes.
INOM_G	5	Nominal current rating of the terminal(s) used to calculate the IG current in amperes.

The outputs of the algorithm are shown in Fig. 20. These outputs show that the algorithm did not detect a correct installation, attempted to diagnose the problem, and found the error to be NO.IG. Working through the list described in Section III.A.3, the error was found to be a missing neutral connection on the wye-connected IG CTs.

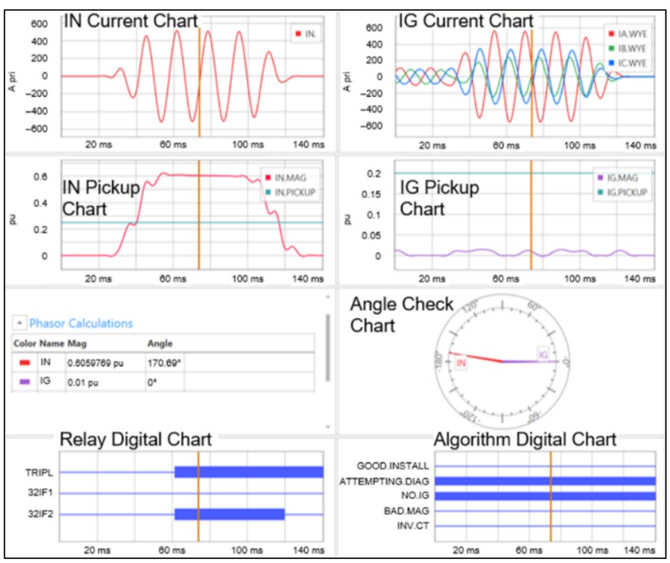

Fig. 20. Tool detects missing IG current.

Further analysis of the charts can help explain the NO.IG decision by the algorithm. Both IN and IG currents should have the same magnitude during an external fault. Because IN current exceeded IN.PICKUP but IG current was near zero, the algorithm declared the error to be a NO.IG condition.

The IB.WYE and IC.WYE currents in Fig. 20 are half as large and 180 degrees out of phase with the IA.WYE current. This relationship is characteristic of a missing or disconnected neutral wire on a set of wye-connected IG CTs and can be understood using Fig. 21 for an A-G fault. Take note of the neutral wire that connects the common point of the wye-connected CTs to the common point of the wye connection at the phase CT inputs. If this wire is missing or not connected, the fault current on Phase A is forced to come back through the IB and IC current inputs in the relay to complete the Phase A secondary circuit. As a result, the relay measures IB and IC currents to be half as large and 180 degrees out of phase with the IA current. Because of this relationship, IG current (which is a calculated sum of all three phase currents) calculates to zero.

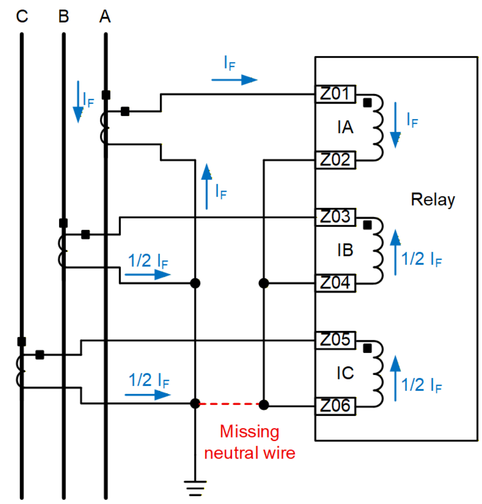

Fig. 21. Three-line drawing of a set of wye-connected IG CTs with missing neutral wire (assuming a CT ratio of 1:1).

Finally, the charts in Fig. 20 can be used to help explain how the installation error resulted in the operation of the REF element. When the IN current exceeded IN.PICKUP during the fault, the REF element was enabled. Because IG current was below IG.PICKUP, the REF1 element declared an internal fault and the relay issued a trip.

V. CONCLUSION

Wiring and settings errors in REF installations continue to plague the industry by causing misoperations and extended outages. These errors can only be caught in commissioning using primary injection testing, which is not always feasible. As a result, these errors often stay hidden until a misoperation occurs and causes an outage. Understanding the data from a misoperation and getting to root cause takes time and is prone to human error due to differences between relay models, such as the names and units of signals and settings.

This paper presents an algorithm that was developed to automatically detect and diagnose all common REF field installation errors. The algorithm works with many different relay models and can be used either after a misoperation has occurred or during unbalanced load conditions. The paper shows how the algorithm was implemented as a software tool and provides six examples of how it was used to find errors in different field installations. The authors believe that this software tool will increase the industry's confidence in the REF element by reducing the number and length of misoperations due to installation errors.

Analysis techniques like the ones described in this paper are usually methodical—making them ideal candidates for automating the identification of field installation errors in many types of protection schemes. The upfront effort needed to create these algorithms is significant, but once completed, the algorithms can be used by engineers countless times over. This expedites analysis, ensures consistency, and removes the chance for human error.

Even more importantly, automated algorithms that detect field installation errors can prevent misoperations and help improve power system reliability. Every misoperation that can be avoided is a win for the industry. Even when a misoperation occurs, automated algorithms help reduce outage time by quickly identifying the installation error. Every minute that engineers can save during root cause analysis saves a minute of outage time for customers.

In an effort to create a more reliable power system, the authors call upon relay manufacturers, users, and standards organizations to create and support the development of algorithms that detect field installation errors. These algorithms can be implemented as software tools and shared across the industry. They can also be implemented in relay firmware, as having the relay report installation errors during commissioning avoids an outage all together.

VI. References

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VII. Biographies

Swagata Das earned her B.Tech degree from SRM University in Chennai, India, in 2009. She graduated with her MSE and PhD degrees in electrical engineering from the University of Texas at Austin in 2011 and 2015, respectively. Swagata joined Schweitzer Engineering Laboratories, Inc. (SEL) in 2015 and works as a senior protection application engineer in Boerne, Texas. She has published more than 25 application guides and technical papers and received the Walter A. Elmore Best Paper Award from the Georgia Institute of Technology Protective Relaying Conference in 2017 and 2023. In 2022, she published her first book, *Fault Location on Transmission and Distribution Lines, Principles and Applications*, which is available in over 300 libraries worldwide. She is an active contributor to IEEE PSRC standards, a senior IEEE member, and a registered professional engineer in the state of Texas.

Ariana Hargrave earned her BSEE, magna cum laude, from St. Mary's University in San Antonio, Texas, in 2007. She graduated with a Master 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 spent 16 years as a protection application engineer in Boerne, Texas. In 2025, she transferred to the Research & Development division of SEL where she now works as a principal engineer. She has published more than 40 application guides and technical papers and authored the chapter on system protection in the book *Women in Power: Research and Development Advances in Electric Power Systems*. Ariana was honored to receive the Walter A. Elmore Best Paper Award from the Georgia Institute of Technology Protective Relaying Conference in 2017, 2018, and 2023. She is a senior IEEE member and a registered professional engineer in the state of Texas.

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