PRS Phase II Misoperations White Paper

Prepared by:
MRO Protective Relay Subcommittee

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Table of Contents

Preface

Midwest Reliability Organization's Vision is to: "***Maintain and improve the quality of life through a highly reliable regional bulk power system.***"

Midwest Reliability Organization (MRO) operates as a cross-border Regional Entity and is headquartered in Saint Paul, Minnesota. The MRO Region covers roughly one million square miles spanning the provinces of Saskatchewan and Manitoba, and all or parts of the states of Illinois, Iowa, Minnesota, Michigan, Montana, Nebraska, North Dakota, South Dakota and Wisconsin. The region includes more than 130 organizations that are involved in the production and delivery of electricity to more than 20 million people. These organizations include municipal utilities, cooperatives, investor-owned utilities, transmission system operators, a federal power marketing agency, Canadian Crown Corporations, and independent power producers.

MRO's primary responsibilities are to: ensure compliance with mandatory reliability standards by entities who own, operate, or use the interconnected, international Bulk Power System; conduct assessments of the grid's ability to meet electricity demand in the region; and analyze regional system events.

Introduction

Background

In 2016, the MRO Protective Relay Subcommittee (PRS) published the white paper Protection Systems Misoperations. The white paper was part of the MRO PRS misoperation reduction project to support NERC's goal of reducing the rate of misoperations. The white paper focused on misoperations associated with the three most common causes identified by the NERC Protection Systems Misoperations Task Force with special emphasis placed on misoperations of over current elements. The underlying assumption was that an overall reduction in the misoperation rate would result in an improvement in overall Bulk Electric System (BES) Reliability. At MRO we believe that this assumption has some validity. However, the reduction efforts should be focused on improving BES reliability, as opposed to merely improving a performance statistic. Not all misoperations have equal impact on BES Reliability.

Analysis of misoperations and their role in system disturbances reveals that certain classes of misoperations have a more severe impact on BES reliability than others. Two types of misoperations are observed to have the most egregious impacts on reliability: misoperations associated with bus differential relays and misoperations associated with breaker failure relays. These high impact misoperations are the subject of this Phase II white paper.

The reliability impact of unintended operations of either type are quite similar, and highly dependent on bus configuration. The impact of failure to operate is dependent on fault location. With bus differential relays the location is always on the bus. The fault must be cleared at all remote sources. In nearly all cases, the remote sources will respond to the fault. Clearing is generally delayed, and outages are extensive and prolonged. In the case of failure to operate of a breaker failure relay, the fault in general is not on the bus. As the fault moves away from a local bus, the required remote clearing becomes more problematic. Delays in clearing increase, and in some cases coverage may not exist.

Since many of the issues with bus differential relays are common to all types of differential relays, this white paper also discusses misoperations associated with generator and transformer differential relays. Most misoperations of these differential relays involve errors in the way currents are processed by the relay. These may be due to setting errors, design errors, wiring errors, and other causes, but in most cases they can be identified by observing the behavior of load current in the differential scheme at the time of installation. Commissioning practices for differential relays are also included in the paper. Stronger commissioning practices would have prevented many observed differential relay misoperations from ever occurring.

Target Audience

This technical paper is intended for all personnel whose work relates to the design, installation, testing and maintenance of BES protection system equipment.

Chapter One: Breaker Failure Relaying

Breaker Failure Relaying

There is a strong movement towards redundancy of Protection Systems for increased dependability. Where they exist, these redundant protection systems operate a non-redundant set of circuit breakers. Redundancy of circuit breakers is far from common. Since breakers do fail on occasion, breaker failure relaying schemes are often the last line of defense against system faults. Restrictions placed on the loadability of remote back-up relays by NERC Standard PRC-023 increase the dependency on reliable breaker failure protection.

Breaker Failure Misoperation Review

Breaker failure schemes have been identified as critical schemes with significant impacts to the bulk electric system when they operate incorrectly or fail to operate when needed.

The MRO Protective Relay Subcommittee has reviewed misoperation submissions from 2010 through the first quarter of 2016 and identified those misoperations that were attributed to breaker failure relay issues. Four additional misoperation events involving the use of 52a contacts supervising breaker failure schemes are also included later in 2016. The review found that breaker failure misoperations accounted for 47 submissions during this time period. The breaker failure misoperations were broken down by general NERC cause codes as shown below in Table 1. The top three ranked causes are related to logic errors, design errors, and as left personnel errors. In addition, there were some misoperations attributed specifically to relay malfunctions and DC system errors. It should be noted that many misoperation submissions did not always provide the root cause of the misoperation.

Errors	Count:	Percent:
Logic Errors	11	23.4%
Design Errors	11	23.4%
As-left Personnel Errors	10	21.3%
Relay Failures/malfunctions	6	12.8%
DC System	5	10.6%
Incorrect Settings	2	4.3%
AC System	1	2.1%
Other Explainable	1	2.1%
Total	**47**	**100%**

Table 1: Breaker Failure Misoperations per Cause Code

The breaker failure misoperation data was also broken down by looking at the specifics of the issue with the breaker failure scheme that was available from the submissions. The top three identified issues using this method are shown below in Table 2. This identification method indicates the most common issue for breaker failure misoperations could be attributed to inappropriate initiation. The inappropriate initiations were due to numerous and different NERC cause codes. In addition, the breaker failure relay settings logic errors and design/application errors not directly related to the initiation part of the scheme were also noted. To a lesser extent transients and wiring or prints related errors were also identified in Table 2.

Inappropriate initiation	**24**
Logic errors	8
Design errors	5
As-left personnel error	4
Relay failures/malfunctions	3
DC system	2
Other/Explainable	1
Incorrect settings	1
Relay Settings-Logic Error	**5**
As-left personnel error	2
Logic errors	2
Incorrect settings	1
Design/Application Error	**5**
Design errors	5
Transient Error	**4**
DC system	3
Relay failures/malfunctions	1
Wiring/Prints Error	**3**
AC system	1
Design errors	1
As-left personnel error	1
Coordination/Time Delay Error	**2**
Relay failures/malfunctions	1
As-left personnel error	1
Temporary/Testing Error	**2**
Logic errors	1
As-left personnel error	1
Relay Malfunction (replaced or recalibrate)	**1**
Relay failures/malfunctions	1
Relay Firmware Issue	**1**
As-left personnel error	1
Grand Total	**47**

Table 2: Breaker Failure Misoperations- Specific Causes

In order to help minimize breaker failure misoperations the protective relay subcommittee review team elected to document some considerations and observations related to implementing breaker failure schemes based on the misoperation data that was observed. The focus areas are noted below.

A. Purpose of Breaker Failure Schemes
B. Inappropriate Breaker Failure Initiation (and general logic errors)
    1. Logic Errors
    2. Design/Wiring Errors

3. As-left Errors
4. Auxiliary breaker contact supervision in BFI

A. Purpose of Breaker Failure Schemes

Breaker Failure Protection (BFP) is the protection that is specifically relied upon to take appropriate action to clear a fault when the breaker that is normally expected to clear the fault fails to do so for any reason. BFP is designed to operate when the protective relaying scheme initiates a circuit breaker trip and that breaker does not correctly interrupt the fault.

Breaker failure can be caused by a variety of situations, as noted below:

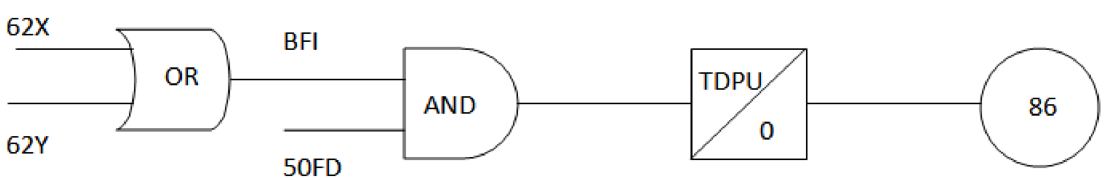
- *Failure to Trip*
  In failure to trip situations, the breaker contacts do not open after the trip circuit has been energized by the protective scheme. This could be caused by an open or short in the trip circuit wiring or in the trip coil. It could also be the result of a mechanical problem in the breaker that prevents the contacts from opening.

- *Failure to Clear*
  In these scenarios the breaker contacts open, but the arc is not extinguished and current continues to flow. This could be caused by mechanical problems (incomplete opening), or dielectric problems (such as contaminated oil or loss of vacuum). Failure to clear is significantly different from failure to trip in that the breaker auxiliary contacts (52a and 52b) will change state indicating breaker opening. Because of this, an auxiliary contact position may not be a reliable indicator of a satisfactory breaker opening.

The purpose of breaker failure protection is to ensure that faults are cleared in a time frame consistent with:

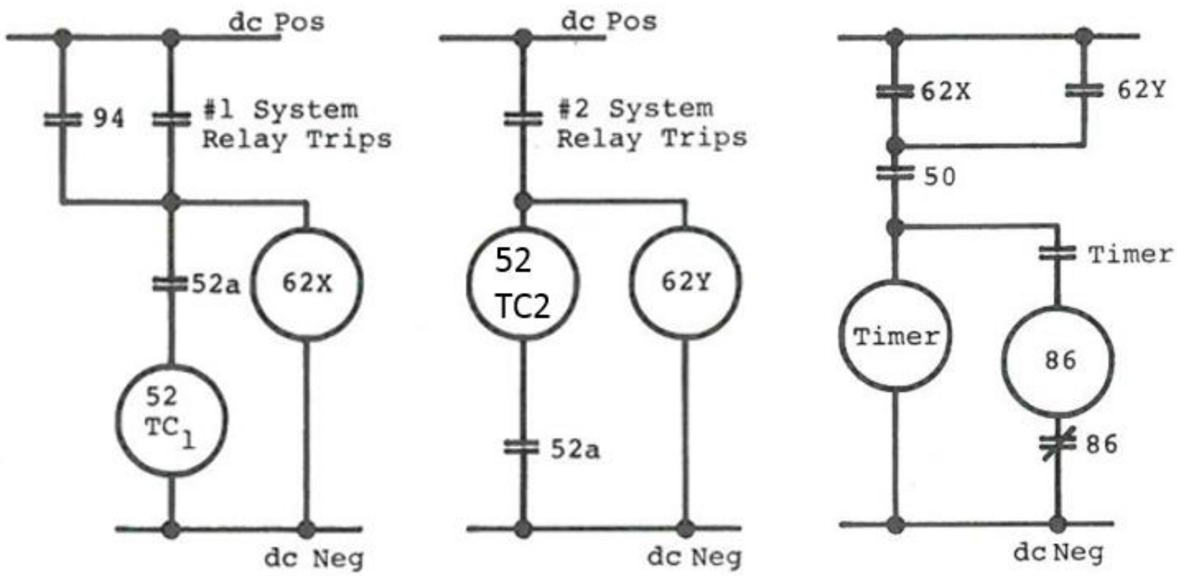
- Enhancing system stability
- Limiting equipment damage
- Improving coordination of overlapping protection schemes and to
- Improving quality of supply by minimizing the duration of power system voltage dips

The logic for a simple breaker failure protection schemes are shown below. This logic is sufficient for the large majority of applied breakers.



Scheme 1: Breaker Failure Protection Logics in Microprocessor Based Relays

62X – Protection System 1 operated
62Y – Protection System 2 operated
BFI – Breaker Failure Initiation
50FD – Individual Breaker Current Fault Detector



Scheme 2: Breaker Failure Protection Scheme in Electromechanical Based Relays

62X – Protection System 1 operated
62Y – Protection System 2 operated
50 – Current Fault Detector

In these schemes, all protection systems that issue trip commands to a given breaker are inputs to an OR logic gate. The output of this gate is combined with a circuit breaker current detector in an AND gate. The output of the AND gate drives a timer with a user set pickup time and zero dropout time. If the timer times out, it operates a lockout relay which performs the breaker failure tripping requirements for the failed breaker. Key properties of this scheme are:

- Only protection systems are used to initiate breaker failure timing
- If there are no protection system inputs **or** no circuit breaker current is detected, the input to the timer is removed
- The timer drops out with zero delay

The pickup time of the timer is set by the user. It must be short enough to ensure that faults are cleared in a time frame that is specified above, but long enough to allow the breaker to operate according to the manufacturer's specified operating time. Normally, a security margin is added to the breaker's nominal operating time. This simple logic will cover most requirements for response to failed breakers. For variations on this scheme to address specific or unusual applications refer to IEEE Standard C37-119, Guide for Breaker Failure Protection of Power Circuit Breakers.

B. Inappropriate Breaker Failure Initiation (and general logic errors)

The MRO protection misoperation statistics show that 51% (24 out of 47) of the breaker failure protection misoperations are caused by Inappropriate Breaker Failure Initiation. The data indicated that approximately 54% of the 24 misoperations identified as inappropriate initiations were caused by incorrectly standing breaker failure initiate signals resulting in breaker failure trips when load current or through fault current exceeded the breaker failure fault detector threshold. Causes for these incorrect standing initiate signals were split equally between logic errors (relay programming), design errors, as left personnel errors (such as wiring, relay programming or temporary jumpers) and relay malfunctions.

In addition, 25% of the misoperations identified as inappropriate initiation were due to general errors in the breaker failure initiate logic such as incorrect logic in normal/alternate breaker transfer bus schemes, incorrectly including communication check back status in the initiate scheme, and incorrectly including supervisory breaker open commands in the initiate scheme.

Finally, another 12% of the misoperations identified as inappropriate initiation were due to DC system cable failures and a low gas pressure status incorrectly wired to initiate and bypass the breaker failure timing.

It should be noted that there were five additional relay settings logic errors identified in Table 2 that are not directly associated with inappropriate initiation issues. These logic errors were related to incorrect breaker failure output programming, incorrect CT current assignments, and incorrect settings being left in the relaying likely by field personnel. These identified issues all resulted in the breaker failure scheme misoperating.

Therefore, a large percentage of the misoperations can be attributed to four main reasons:

1. Logic Errors
2. Design/Wiring Errors
3. As-left Errors
4. Use of breaker auxiliary contacts

Following are some recommended considerations to reduce the errors in each of these four categories.

1. Logic Errors

Review of the protection misoperation statistics for the MRO region indicate that a large percentage of breaker failure misoperations were caused by applying incorrect logic.

- It is important to verify settings logic for all contacts that assert a breaker failure initiate input. It is extremely critical that these contacts unlatch after the fault has been removed (or when a breaker failure lockout is reset) from the system. If not, upon restoring the system the breaker failure scheme may operate causing a misoperation. One example observed involved the misapplication of dropout timers not being supervised by overcurrent elements. This caused timing to continue, even though the fault had cleared.

- Only protection system trips should initiate breaker failure relaying. Protection systems operate for fault conditions, which are required to clear as quickly as possible. This is the primary purpose of breaker failure relaying. It is not advised to initiate breaker failure for SCADA or local control trip commands. Typically, these control functions would be used during routine switching or maintenance activities in which high speed operating of the equipment is not important. Note: if a fault was experienced during the control activity, the protection systems would still operate as designed and breaker failure relaying would still be activated.

- Other logic setting mistakes have occurred around the use of the fault current detector. Specifically, the over current level the detector is set at, has caused misoperations. When misoperation occurs it is usually because the level is set too high preventing the scheme from operating. The settings value needs to be set low enough to pick up for all fault conditions. Certain outages can reduce the system strength resulting in much lower fault current during an event than otherwise expected. Other times a fault might have high impedance resulting in much lower fault current being produced. Another issue to watch out for is the detection of fault current for a far reaching element in which sources of infeed at remote bus might make fault current detection difficult. This is another reason to ensure the detection level is low enough to detect all faults.

- Certain relays have multiple sets of current transformer (CT) inputs. This allows the system protection engineer to apply one relay to perform breaker failure relaying across multiple breakers. This introduces the potential to apply incorrect breaker failure settings to the unintended set of CT inputs. Extra caution must be applied when designing breaker failure schemes in these cases.

- In other cases, high speed reclosing has caused breaker failure misoperations due to the reclose attempt occurring within the time interval of breaker failure relaying. These misoperations related to reclosing only occur when the initiating contacts have unsupervised delay on drop out timers set on them. Again it is recommended to have these contacts drop out when the fault has been cleared. Note: if lockout relays are initiating breaker failure, typically this issue does not occur because the lockout prevents closing the circuit breaker back in. Having to reset the lockout ensures the contact is dropped out of the breaker failure initiate scheme.

Many of these issues could be mitigated with peer reviews of the settings, design and drawings. Consideration should also be given to implementing the use of standard setting design and setting templates.

Another way to reduce standing BFI issues is to program the relay to generate an alarm to the SCADA system or to a relay display to indicate if there is a sustained breaker failure initiate input present. This should catch some of the unwanted breaker failure initiate conditions before they cause a breaker failure protection misoperation.

2. Design/Wiring Errors

In addition to the recommendations above consideration should also be given to implementing more thorough commissioning methods. Thorough commissioning methods help identify and correct wiring errors. Consideration should be given to implementing the use of standard commissioning procedure templates that can be customized as needed for specific designs and substation locations.

3. As-left Errors

As left personnel errors (such as wiring, relay programming or temporary jumpers) can also be addressed with using improved commissioning practices. Human performance tools should also be implemented such as detailed field personnel work plans that provide methods to minimize the chance of errors. These techniques can include tagging, work zone identification, and barrier kits to improve panel wiring work and tracking of temporary jumpers and temporary relay settings.

Also, there should be a process so that final as-left settings and as-received settings are reviewed by engineering.

4. Use of Breaker Auxiliary Contacts

Table 2 indicates five misoperation submissions were due to Design/Application Errors. The majority of these submissions were related to the use of auxiliary contacts in breaker failure schemes. In these cases, data indicated the schemes failed to operate due to issues with the use of auxiliary contacts. In addition, these schemes likely did not require the use of auxiliary contacts.

Individual breaker current detectors should always be used whenever possible in the breaker failure protection logic. For cases where no or little fault current is present such as the turn-to-turn fault protection element in generator protection, a breaker auxiliary contact can be used in the breaker failure protection logic. However, due to the possibility of an unreliable breaker auxiliary contact, such as a stuck phase on the breaker main contact while the breaker auxiliary contact indicates the breaker is in open condition, some special considerations may need to be taken into account when using the auxiliary contact in the breaker failure scheme.

Figure 1 below shows one example of breaker failure protection logic using breaker auxiliary contact. This example places more emphasis on scheme dependability.

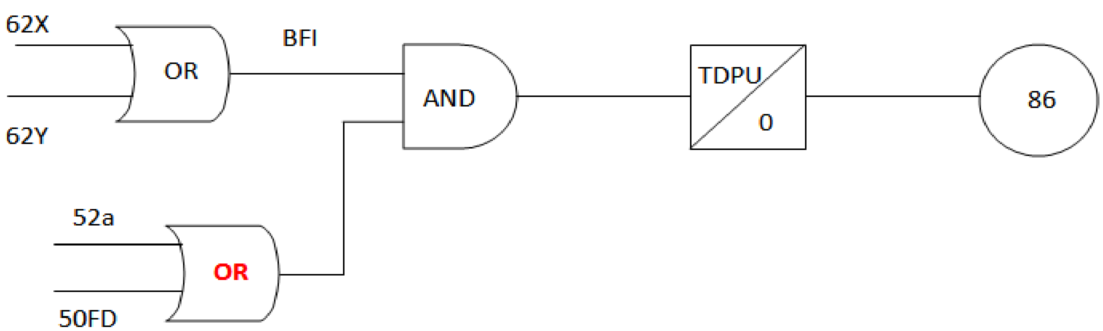


Figure 1: Breaker failure Logic Using 52a Contact OR with Current Detector

Figure 2 below shows another example of breaker failure protection logic using breaker auxiliary contact. This example places more emphasis on scheme security.

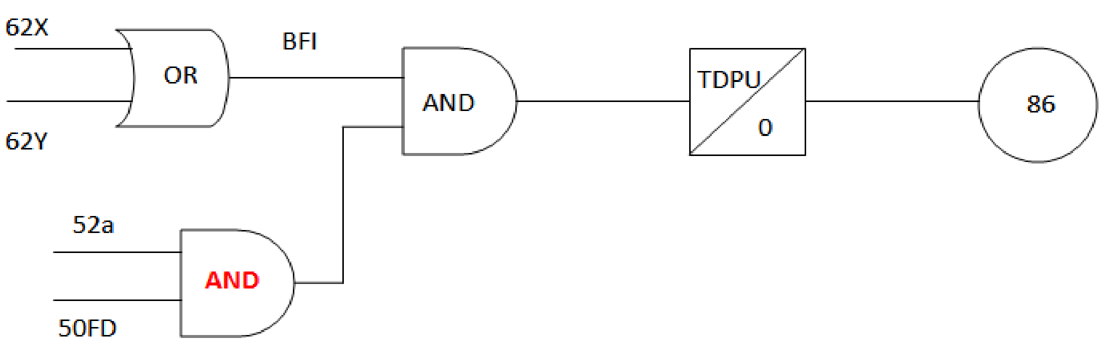


Figure 2: Breaker failure Logic Using 52a Contact AND with Current Detector

If a breaker auxiliary contact must be used in the breaker failure protection scheme, the security and dependability of the scheme must be carefully weighed for a specific application to determine which scheme to use. Additional periodic maintenance testing for proper function and timing should also be considered.

The configuration depicted in Figure 2, where a 52a contact is used to supervise breaker failure relaying, is occasionally encountered in MRO, and elsewhere in NERC. Its use is usually defended as a technique to provide increased security against false operation of the breaker failure scheme. It can provide this increased security ONLY WHEN THE BREAKER IS OPEN. When the breaker is closed, no additional security is obtained. Far more important, this type of supervision prevents operation when certain types of breaker failures occur during faults. These failures exist when breakers fail to interrupt fault currents or restrikes occur. This type of failure is particularly damaging when it occurs for faults on a line connected to a bus with multiple sources. The necessary remote clearing can be delayed, sequential, or nonexistent. The negative aspects of this configuration are discussed in a NERC Lesson Learned [10], and a NERC System Protection and Control Subcommittee paper [11].

Transient Issues

Review of the protection misoperation statistics for the MRO region indicate that a subset of breaker failure protection system misoperations caused by Inappropriate Breaker Failure Initiation are due to transients or surges on the breaker failure initiation inputs.

The presence of transient voltages and currents in the low-voltage direct-current circuits of protection and control systems is well researched and documented. A few resources concerning the origin and mitigation of these transients are listed in the reference section: [1], [4], and [13]. These transients may originate in the low-voltage protection and control circuits or in the high voltage power system and then be coupled into the dc protection and control circuits through common electrical connections, such as "ground" circuits, current transformers, and potential transformers, or through their associated electric and magnetic fields. Transients can be generated in the high voltage power system by capacitor switching, bus de-energization, transmission line switching, capacitively coupled voltage transformer (CCVT) transients, unequal pole closing of power circuit breakers, fault occurrence, fault clearing, line reactor de-energization, load tap changing, or series capacitor gap flashing and re-insertion. Transients can be generated in the low-voltage control system by dc coil interruption, dc circuit energization, dc system grounds, or current transformer saturation due to large primary currents, poor current transformer quality, or excessive secondary burden.

The inadvertent operation of critical protection system inputs such as direct trip or direct transfer trip (DTT) initiation inputs will result in incorrect trips. The inadvertent operation of breaker failure initiation input can result in an incorrect breaker failure operation if the duration of the transient exceeds the breaker failure timer setting and the load current is above the setting of the breaker failure overcurrent fault detector. Some breaker failure protection systems have used a feature that will "seal-in" the breaker failure initiate signal until the overcurrent fault detector drops out. Even a relatively brief transient on the initiate input of these systems can result in an incorrect breaker failure operation.

Mitigation or Suppression Techniques

Good protection and control system design practices can suppress the generation of transients or mitigate their undesirable effects. Suppression is preferred since it avoids the additional control circuit complexity associated with mitigation measures. These practices include:

- Physical separation: Keeping electrically noisy circuits physically separated from control circuits will significantly reduce the magnitude of induced transients. Low energy level control circuits should be grouped together in cable ducts and located as far as possible from power circuits. Cable ducts should be run perpendicular to high voltage buses to minimize coupling.

- Electrical separation: Minimizing common mode interaction between segments of a control system by the use of isolation transformers. High frequency transients can be blocked by the use of inductance as in the use of chokes.

- Increasing energy required to operate relay inputs: Increasing the voltage or energy level required to operate an auxiliary relay or the input of a solid state or microprocessor relay will reduce the probability of a surge or transient causing an inadvertent operation. Solid state or microprocessor protective relay digital inputs are often more sensitive than older electromechanical auxiliary relay inputs, increasing their susceptibility to operation by transients. The energy level required to operate a digital input can be increased by paralleling a resistor with the input. This method has been used to successfully eliminate digital input operations due to transients as shown on the left in Figure 3 where a 15 kilo-ohm, 7-watt resistor is connected in parallel with a breaker failure initiate input.

- Buffering of relay inputs: Another method of de-sensitizing digital relay inputs is to buffer the input using Zener diodes and a resistor-capacitor network.

- Increasing the pickup time delay of the protection system input: As shown in Figure 3, the digital inputs of protection systems often include an adjustable "debounce" timer that can be used to reduce the probability of input noise causing a false initiate signal. If the pickup (PU) delay is set longer that the duration of the transient an incorrect breaker failure operation can be avoided. Selecting the appropriate time delay with any degree of certainty would require measurement of the transient waveform or the duration of the actual pickup time during the transient. Figure 4 illustrates an implementation of this mitigation technique that does not increase the total breaker failure clearing time. If the total desired breaker failure clearing time is two times FCpu this scheme utilizes the FCpu time twice before a breaker failure condition is asserted. The first timer is used as an input pickup delay timer to ride through transients at the input and the second is used to provide the desired total breaker failure time. Once started, the second timer can only be reset by the current detector (50FT) dropping out, indicating that the protected circuit breaker has opened.

- Utilize breaker failure "re-trip" function: Modern protection systems provide the option of enabling breaker "re-trip" logic that will immediately send a trip signal to the alternate trip coil (or both trip coils) before the breaker failure timer expires. This feature remains susceptible to operating for transients but reduces the severity of an incorrect operation since only one circuit breaker will trip. The consequences of a false breaker failure operation depend upon the type of high voltage bus configuration used in a substation. An incorrect breaker failure operation in a main bus - transfer bus scheme will result in the loss of all transmission connected to the bus, making the use of re-trip logic more attractive. Re-trip logic adds complexity to the breaker failure scheme and adding it to existing schemes will require additional wiring and/or protection system programming.

- Utilize interposing auxiliary relays on the breaker failure initiate input: Utilizing an interposing relay that requires a much higher operating energy than a sensitive relay digital input will reduce the probability of incorrect operations due to surges and transients. Adding this to breaker failure schemes will also increase cost and complexity and the operating time of the interposing relay must be considered when setting the breaker failure timer.

- Parallel clamping: Placing a Zener diode in parallel with a coil, as shown in the right section of Figure 3, will eliminate the surge generated by interruption of the coil current. A varistor may be used instead if the additional drop-out delay caused by the Zener is undesirable.

- Suppression by correct cable routing: The supply and return conductors of a circuit connecting equipment in the switchyard and equipment in the control building should always be routed within the same cable to minimize electromagnetically induced signals. Routing the supply and return conductors in different cables creates a large electromagnetic flux loop and significant coupling to electrically noisy circuits in the switchyard.

- Suppression by using twisted pair signal leads: Routing the supply and return conductors of a circuit in a twisted pair cable will minimize the effect of electromagnetic coupling to adjacent noisy circuits.

- Suppression by using shielded signal leads: Routing the supply and return conductors of a circuit within the same shielded cable will minimize the effect of electrostatic coupling to adjacent noisy circuits.

- Utilize fiber optic control circuits: Since fiber optic media are immune to electromagnetic and electrostatic interference they are ideally suited for use as control circuits in the electrically noisy environment of an electric power substation. Utilizing IEC61850 "GOOSE" messaging between protective relays for signals such as breaker failure initiate will eliminate any interference by electrical transients or surges.

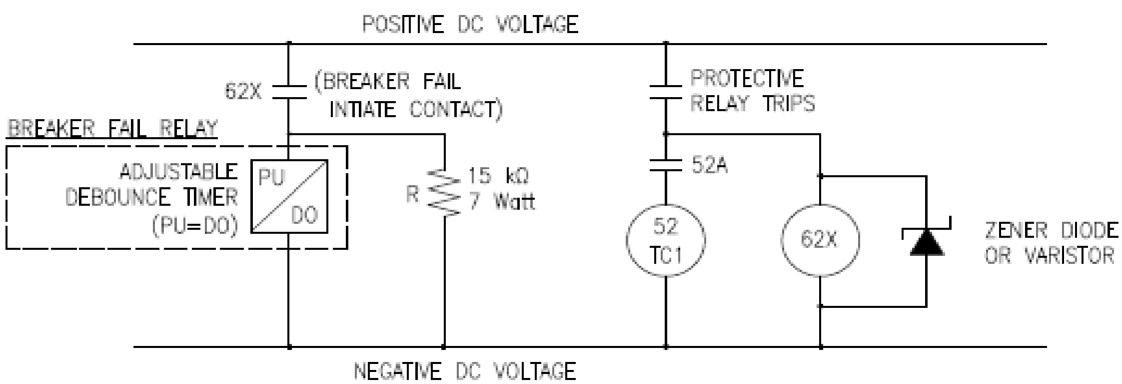


Figure 3: Breaker Failure Scheme with Adjustable Timer

Custom Breaker Failure Scheme (Fault Current)

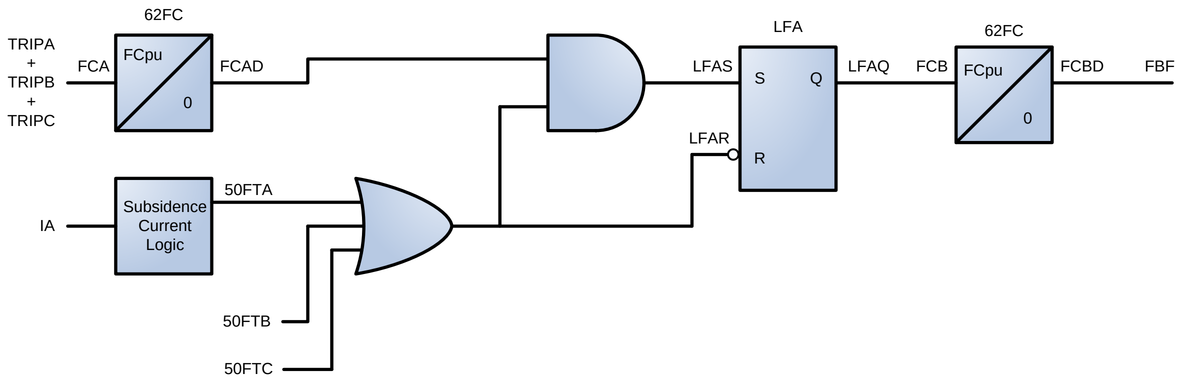
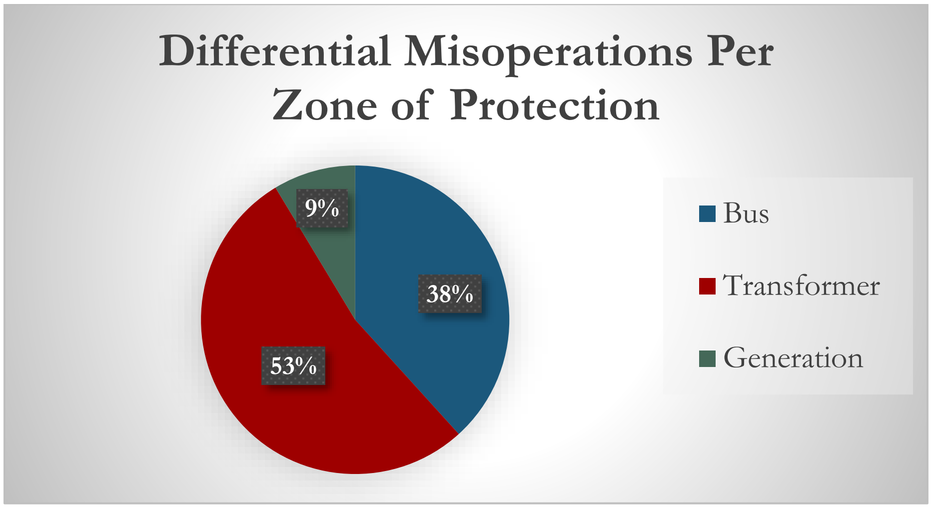


Figure 4: Customized Breaker Failure Scheme

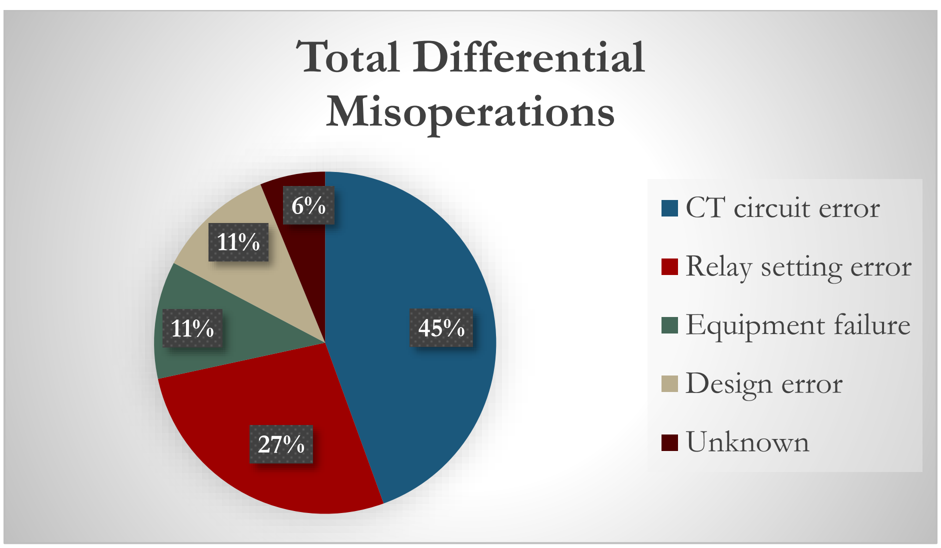
Chapter Two: Differential Relay Applications

Differential Protection Misoperation Review

Current differential protection is commonly utilized across the industry to provide protection for generators, transformers, and network buses. This section discusses practices available to help reduce the probability of transformer, bus, and generator current differential misoperations.

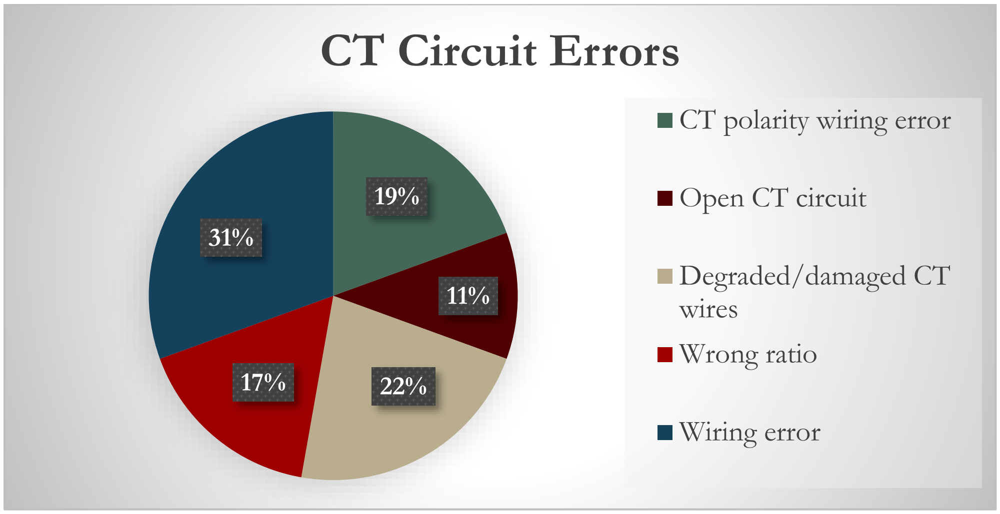


Review of MRO misoperation data revealed only 9% of all current differential misoperations were associated with generator protection schemes, for which 85% were associated with CT circuit errors. Therefore, the majority of this discussion will focus on transformer and bus misoperation reduction opportunities. Given their similarities, the transformer and bus CT circuit considerations presented are also relevant to generator protection CT circuits.



CT Circuit Considerations for Reducing the Probability of a Differential Misoperation

Whether protecting a generator, transformer, or bus, proper CT circuit design and CT performance are critical to the reliability and security of a differential protection scheme. As illustrated below, there were several sources of CT circuit errors.



Review of the CT circuit related misoperations revealed 95% of the root causes could have originated during the design process. Even the degraded CT wire misoperations could have potentially been avoided if asset renewal programs included control cable replacement during relay or equipment asset renewal projects.

Opportunities to reduce misoperations can be pursued by following some recommended practices. The first of these practices is performing a fault study to ensure the available fault current does not saturate the CTs in the differential circuit. It may be beneficial to include planned Network upgrades to capture the effects of future increases in fault duty when selecting CT ratios. If relay and metering class CTs are mixed in a differential protection scheme, the fault current could saturate the metering class CT and result in a misoperation. Typically, only relay class CTs should be used for differential protection. IEEE Standard C37.110 presents a comprehensive treatment of the theory and application of CTs to assist the relay application engineer in the correct selection and application of CTs for protective relaying purposes.

When connecting the CTs in a differential circuit, using a lead size different than the balance of the control wiring can help readily identify a differential circuit during construction and future maintenance activities. For example, use of #12 conductors for DC and potential circuits, and a separate four conductor #10 control cable for CT circuits provides the benefits of not only differentiating the CT circuit from the other circuits, but also provides the benefits of reduced CT burden. Consistent wire color code for phasing A, B, C, or (1, 2, 3) and neutral can also help reduce the probability of wiring errors.

During design, compare the AC schematic and wiring diagrams, and mark each portion (e.g. yellow line the schematics) to ensure the leads are physically configured to create the circuits shown on the schematic. Personnel should verify breaker position relative to tying to the even CTs or the odd CTs, dictated by the physical orientation of the breaker on the foundation, such that the physical design matches the electrical design. After the AC schematics have been verified against the wiring diagram, the AC schematics should be verified for proper CT polarity connectivity. Assume a three phase external fault occurs on the primary network within the protected zone, then trace the CT secondary currents through all the associated CTs and verify proper polarity connectivity. Be especially cautious if there is a combination of Delta and Wye connected CTs due to the magnitude and angle differences introduced. The preceding steps are used to help identify AC schematic design errors that could result in wiring diagram design errors. Wiring errors were a contributing factor in approximately one third of differential misoperations. Given the need to sometimes wire CTs in a manner that is not necessarily straight forward, the paper *"Unconventional CT and VT Connections and How to Get Them Right"*, from the IEEE Transactions on Industry Applications Volume 41, Number 2, March / April 2005, p. 514 - 519, provides excellent insight to the considerations necessary to ensure proper CT installation.

The following design considerations offer opportunities to reduce misoperations when applying tapped multi-ratio CTs.

- Changing CT ratios late in the design process or during the construction phase of a project can result in wiring errors. Minimizing the variety of CT ratios used at equipment, such as breakers and transformers, can also aid in reducing wiring errors. Performing fault studies early in the design process to determine the required CT ratios provides an opportunity to reduce design changes during a project, reduce the variety of CT ratios used, and therefore reduce the chances of a misoperation due to CT wiring errors.

- Documenting tapped CT ratios on multiple drawings can introduce a records management risk. Inaccurate information on drawings often contributes to CT wiring errors. It is a good practice to limit the duplication of CT ratios on multiple drawings. When duplication of information occurs, consider the use of CAD software that automatically updates multiple instances of the same information to address this issue.

- The saturation capability of a CT (e.g. C800) applies to the full winding ratio only. If a tap is used on a multi-ratio CT, the voltage capability of the CT is reduced. The voltage capability is proportional to the ratio between the tap being used and the full winding ratio. This should be taken into account when evaluating CT saturation in differential protection schemes.

- High impedance differential schemes have several design issues related to the use of tapped multi-ratio CTs. Matched CT ratios are preferred in high impedance differential schemes. For high impedance relays, it is also preferred that the full winding ratio be used for all CTs. Where taps are used on multi-ratio CTs, the high burden of the relay can result in a large voltage across the unused full CT winding. This occurs during fault conditions due to autotransformer action. This voltage can exceed the insulation capability of the CT and the connected equipment. For this reason, it is recommended that the unused full CT winding not be left open circuited in a high impedance differential scheme.

- In general, to obtain the highest CT capability and performance, the highest CT ratio permissible based on sensitivity requirements should be used for differential protection schemes. IEEE C37.110 "Guide for the Application of Current Transformers used for Protective Relaying Purposes" [6] is a good resource to assist the protection engineer in the correct application of CTs used for protective relaying.

Monitoring of Current Transformer Failure

A CT is an essential part of a power system. Typically, a CT is a piece of equipment considered to be non-problematic, but significant consequences can be experienced when one fails. When a CT fails, protection systems can be rendered ineffective or they can misoperate, leading to unwanted outages. In an extreme case, a CT failure can be catastrophic, which can lead to equipment damage and a significant hazardous to personnel.

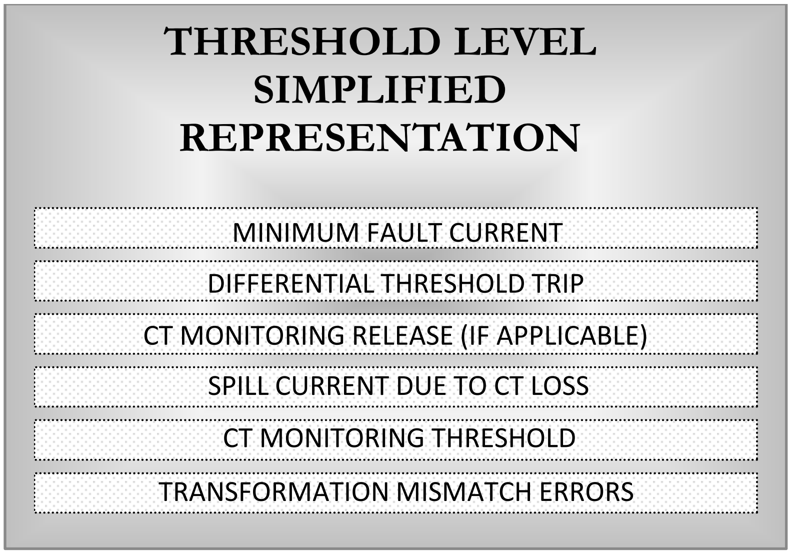
Modern numerical relay systems can be set to provide an alarm if a CT measuring point is lost (due to failure, being short-circuited, or open-circuited), indicating a CT needs to be serviced while still providing protection. Due to the possible severity associated with losing a CT, this alarm should not only be localized, but be provided to the Control Center as a high priority alarm. This monitoring alarm can be applied on differential protection where a sensitive setting is not required, and if properly designed the health of the CT circuit can be established. Applying this monitoring function may be difficult and should be utilized where high fault currents are experienced. For equipment that requires sensitive protective settings, the monitoring function may not be beneficial given it would have to be set higher than the protective settings. Although if sensitivity can be relaxed, this monitoring function can be utilized to alarm for low levels of measured differential current, allowing system operation to continue and avoid mal operation of the differential protection.

The CT monitoring function can be set to detect measurement of a low level differential current for the expected loss of a CT current input. This function should only be used if a defined level can be distinguished between the expected low level current caused by loss of a CT and fault current on the protected equipment. Setting of this function should be above transformation/mismatch errors and below the setting threshold of the differential protection. The monitoring function can give an alarm for complete loss of a CT current input or can possibly be phase selective. If this alarm is not applied properly, it can become a nuisance alarm, leading to it being ignored or disabled. This monitoring function may give an alarm at system start-up or during normal system operation.

Another possible monitoring function that can be available is an open-circuited CT (broken wire) condition. This function gives indication when an open CT is experienced on any phase of the CT circuit during normal system operation. It monitors interruptions on the secondary circuit of the CT, where the interruption would induce a spill current. The open-circuited CT monitoring function inspects the transient behavior of all phase currents. It checks the plausibility of the instantaneous current values and determines if the values correspond to what’s expected. If an instantaneous value does not correspond to an expected value or decays quickly and/or abruptly drops out, with the other phase current continuing to flow, this condition would be alarmed. This monitoring function will give an alarm only during normal system operation and not at system start-up.

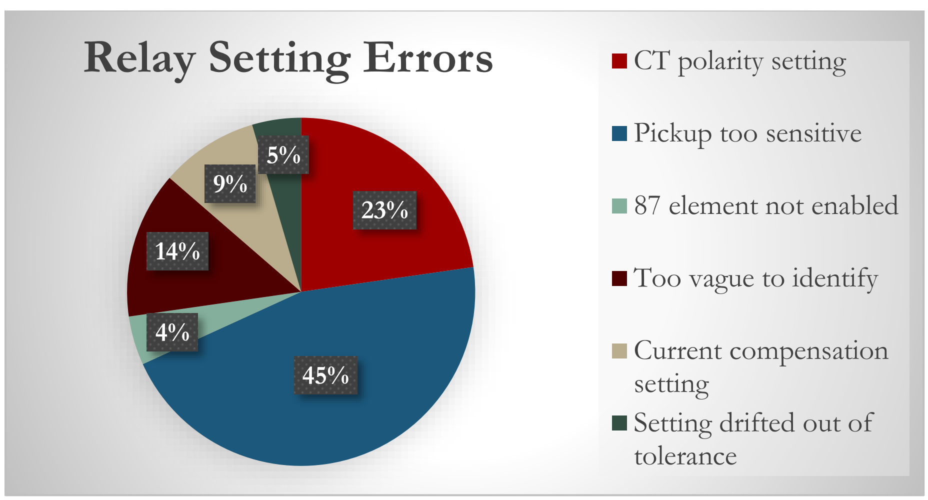
Depending on the relay manufacturer, it may be necessary to verify that the CT monitoring scheme does not adversely affect (disable) the differential protection function.

The progression of the CT differential current level versus relay pickup levels should follow a coordinated progression. Low level CT differential mismatch errors should not result in alarms. Should the loss of a CT current occur, the CT monitoring scheme should assert and provide SCADA alarm indication. If sensitivity studies allow, the differential trip element should not assert for a loss of CT input. Some relays can disable the protection function for a CT low level differential mismatch alarm, but it may be necessary to ensure the relay will enable the protection function if a differential threshold indicative of a fault is exceeded. Given the CT differential current level is load sensitive, an effective CT monitoring scheme can be difficult to achieve.



Relay Setting Considerations for Reducing the Probability of a Differential Misoperation

Methods available to reduce the probability of a relay setting error misoperation are about as diverse as the root cause of the setting errors. An independent peer review of proposed settings is undoubtedly one of the most beneficial methods available to reduce relay setting errors that result in a misoperation. Standard relay setting development documents that establish non-varying settings where possible can help the review process as well as ensure a well thought out setting is applied consistently when possible.



Category	Bus	Transformer	Generator	Sub-Category Totals	Sub-Category
Relay setting error					
	5	0	0	5	CT polarity setting
	2	8	0	10	Pickup too sensitive
	1	0	0	1	87 element not enabled
	1	2	0	3	Too vague to identify
	0	2	0	2	Current compensation setting
	0	0	1	1	Setting drifted out of tolerance
Subtotals =	9	12	1	22	

1. Generator Protection Considerations

The only generator differential relay setting misoperation was due to an electromechanical relay that drifted out of tolerance, which was replaced shortly thereafter per a relay asset renewal project. Whether relay maintenance practices could have prevented the misoperation is unknown, but it does highlight the potential benefits of a proactive asset renewal program that might otherwise go unappreciated.

2. Bus Protection Considerations

The bus differential relay setting misoperations were due to either a high impedance differential pickup setting set too sensitive, or an incorrect CT polarity setting associated with a microprocessor relay. The high impedance pickup set too sensitive misoperations did not provide enough detail to make specific suggestions for improvement. Although it may be an infrequent occurrence, when bus lightning arrestors exist within a differential zone protected by a static (solid state) high impedance differential relay, the relay performance should be verified against the arrestor performance. As previously indicated, improper CT polarity setting misoperations were associated with microprocessor based relays. An independent peer review of relay settings prior to their being issued for construction could identify such setting errors. The CT verification practices recommended earlier in this paper could also help reduce the probability of these misoperations.

3. Transformer Protection Considerations

Given the electrical transients associated with the performance of a transformer and the complexity of the associated relay settings, it is no surprise that 53% of all differential scheme misoperations originated from transformer protection schemes. The source of the incorrect settings varied, originating from restricted ground fault, negative sequence, instantaneous overcurrent, inadequate second harmonic restraint, and current angle compensation settings. Of these misoperations, four occurred during energization, and six were the result of through faults. Energization transient misoperations tended to be associated with negative sequence differential sensitivity, instantaneous overcurrent pickup, or inadequate second harmonic restraint. Through fault misoperations tended to be associated with ground or negative sequence differential element sensitivity. Review of the transformer misoperations reveals the protection engineer must understand the transformer's real world transient performance when setting transformer protective elements, and reevaluate settings when network changes occur that affect local transient performance. Walter Elmore's paper "How to Ensure Improper Transformer Protection Operation" provides excellent insight to some of the challenges associated with the proper connection and application of a transformer differential scheme. [2]

Transformer restricted earth fault (REF) protection is intended to provide sensitive protection for ground faults near the neutral point of grounded wye windings. REF elements compare the sum of the zero sequence current at the terminals of a wye connected winding to the zero sequence current in the associated winding's neutral. Given the zero sequence current at the terminals of the wye winding is achieved by the summation of three phase currents, saturation of one phase CT can result in a false zero sequence current. This situation can be most significant for two breaker transformer terminals, where the maximum external fault current is not limited to the transformer through fault current and the fault type does not provide true zero sequence current (i.e. phase-phase or three phase faults). If transformer REF protection is provided, it must be verified to not trip during a through fault condition.

The paper "Analysis of an Autotransformer Restricted Earth Fault Application," [3] provides insight to the special considerations necessary when applying REF protection on a grounded wye winding. Verification of REF protection performance during commissioning may be difficult or impossible. Therefore, it may be beneficial to implement the REF protection without enabling the associated trip logic such that scheme performance can be verified during faults external to the protected transformer.

Negative sequence differential protection is intended to provide sensitive protection for transformer turn-to-turn faults, especially during heavy load conditions which can reduce the sensitivity of phase differential elements. As with most differential protective elements, security can be more challenging to achieve than sensitivity. The paper "Negative Sequence Differential Protection – Principles, Sensitivity, and Security", explains the principles of negative sequence differential protection, and identifies considerations necessary when developing negative sequence differential protection. Similar to REF protection, it may be beneficial to implement the negative sequence differential protection without enabling the associated trip logic such that scheme performance can be verified during faults external to the protected transformer.

The second-harmonic content of the transformer differential currents have traditionally been utilized by the differential protective elements to block or to increase restraint during inrush conditions. Newer transformers with core designs that produce fewer losses, as well as some older transformers under certain conditions, may produce less second harmonics in their magnetizing currents during energization. Transformer differential second harmonic restraint settings must take into account the inrush performance characteristics of the specific transformer being protected. The paper "Low Second-Harmonic Content in Transformer Inrush Currents – Analysis and Practical Solutions for Protection Security," [5] provides insight to the special considerations necessary when developing differential second harmonic restraint settings.

If a microprocessor based transformer differential relay utilizes a CT current phase angle compensation correction setting, care should be taken to ensure the setting is consistent with the transformer windings being protected. Peer review should scrutinize this setting, which should include verification of the transformer windings relative to the CT configuration and wiring. There may be benefit to verifying the current phase angle compensation setting during field testing by providing the relay an out of zone fault, which should only require the injection of one high side and one low side current into the relay.

Transformer protection complexities and current transformer behavior during system faults can present the protection engineer with unique challenges. The IEEE Standard C37.91 "Guide for

Protecting Power Transformers” [8] provides a good discussion of how to properly apply relays and other devices to protect transformers used in transmission and distribution systems.

Chapter Three: Commissioning Practices to Reduce Misoperations

The MRO Protective Relay Subcommittee reviewed misoperation submissions from 2010 to first quarter 2016 that were attributed to differential relays. A vast majority of these misoperations could have been prevented with detailed commissioning and testing practices by on-site personnel. The primary commissioning activity to prevent most of the differential misoperations is a load check. This chapter provides guidance for how to perform a load check that would prevent many of the differential misoperations. When following these commissioning procedures, make sure that the construction schedule is not compressed to the point that resources are not provided adequate time to properly commission the protection schemes. In addition, ensure that system configuration will provide sufficient load current on the day of commissioning. This paper will also step through some relay setting, AC circuitry, and DC circuitry checks that can be performed to resolve potential problems before a load check.

Design Checks Prior to Field Commissioning a Differential Relay

While most of the MRO differential relay misoperations would have been prevented with load checks, a sizable amount could have been prevented by doing the following design checks to the relay.

1. **CT Ratio and Polarity Verification**

- Improper CT ratios are a common problem. Two checks that must be done:
  - Verify the CT ratio in the relay settings matches the CT Ratio in the schematics.
  - Verify the CT ratio was wired correctly to match the schematic and relay settings.

- CT Polarity Verification: Wrong CT polarity is a common problem. A possible cause could be a wiring or setting error. Two checks that must be done:
  - Verify the CT polarity setting in the relay (if available), matches the polarity in the schematics.
  - Verify the CT polarity was wired correctly to match the schematic and relay settings.

- Review the schematics and settings to ensure all outputs that are used are properly programmed.
- Ensure all windings used in differential protection are enabled.

2. **Other Settings Checks**

- Winding Compensation: Winding compensation settings are used to align phase current and remove zero sequence. Improper winding compensation settings will cause a misoperation. Some checks that can be performed prior to the load check:
  - Verify the winding compensation settings installed in the relay match the transformer configuration, such as verifying the correct settings are used to remove zero sequence. (Settings notes or a table from settings engineer would be helpful).
  - Also pay attention to how the transformer connects to the bus. A replacement transformer could have H1, H2 and H3 in a different order. This could cause the replacement transformer to be ACB instead of ABC, which would require different compensation settings.
- Compare as-left settings to as-received settings and report any differences to Engineering.

Commissioning AC circuitry

Prior to placing a differential protection system into service, each AC component should be checked thoroughly, including the circuitry, to ensure proper signals will be delivered to the relay. This will help identify any component defects, wiring deficiencies, drawing discrepancies or other installation problems. Performing proper commissioning activities prior to placing equipment into service will help reduce unwanted operations. The following is a list of checks and tests on the AC components that should be considered during commission activities:

1. **Checks**
   - Verify orientation of components installed matches design documents. For example, verify the utilized CTs match the intended design based on the orientation of the breaker.
   - Verify the CT being used in the protection scheme is the intended component and is properly phased.
   - Verify multi-ratio CTs are tapped at ratios matching the design documents.
   - Verify CT winding (delta, wye) configuration matches the design intent. One example, check to ensure all configurations are the same in a bus differential application. Another example, one might need to check the configurations are different in some transformer applications to cancel phase shifts across the transformer.
   - Verify the CT secondary wiring has only a single ground point.

2. **Tests**
   - Turns ratio test should be performed at all taps of each CT and the result compared to the manufacture's published ratios.
   - Polarity checks ensuring the polarity of the CT matches the design documents and shop drawings.
   - Perform a CT Saturation test and compare the results to the manufacturer's published curves.
   - An insulation test of each CT should be performed to ensure proper dielectric strength.
   - Perform an insulation test of the secondary wiring checking the dielectric integrity of the cable. This test will find defects in the jacket that may have occurred during the manufacturing process or during installation.
   - Verify that there is one and only one ground on the CT secondary circuit.
   - Injecting current into the CT secondary wiring to check proper wiring between the CT terminations and the relay. This can be done by placing a known current magnitude in the conductor and then verifying that the expected value is received at the relay. The location of the current injection should be done as close the CT itself as possible.
   - A Primary current injection test can be performed to verify the AC circuit: CT ratio, CT polarity and wiring to the relay. The current magnitude must be large enough to allow for accurate measurements to be taken. Measurements can be verified at the relay by using the meter function in microprocessor relays or phase angle meters in electromechanical schemes.
   - Demagnetize all CTs following all tests.

Commissioning DC circuitry

Similar to AC circuits the DC portion of differential protection should be commissioned to ensure that everything will operate as expected. This will help identify any component defects, wiring deficiencies, drawing discrepancies or other installation problems. The following is a list of checks and tests on the DC system that should be considered during commission activities:

- Verify that all devices needed to clear a fault in the zone of the differential relay are tripped. Also verify that closing circuits are appropriately blocked by the lockout relay.
- Perform a full point-to-point wiring check from relay terminal through breaker trip coils in breaker cabinet. Confirm that the device cabinet wiring matches the most recent shop drawings provided by the manufacturer.
- Verify that the proper relay output operates the lockout relay. Verify all relay outputs that are used for other protective functions (i.e., breaker failure initiates, etc.). Also, if the relay has polarity sensitive outputs, verify that they are wired properly.
- Do a complete function check on each lockout contact to verify that the proper breaker is tripped or action initiated by the contact. Also verify that the test switches are wired properly
- Confirm all internal relay logic and that all trip and alarm outputs are properly enabled and that they are on the relay terminals indicated on the confirmed DC Schematics.
- If there is lockout relay coil monitoring, verify that it is functioning properly.
- Verify that all alarm outputs properly annunciate in the substation and alarm properly in the energy management system.

Load Check during Commissioning

Upon energizing facilities being protected by newly installed or modified differential protection, load checks should be performed to ensure the system has been installed correctly. Completing load checks will help identify errors such as a mismatch between wiring and the relay settings. Each of the following should be evaluated with the relay's measured values when applicable.

- Phasor currents:
    - Current magnitudes are nearly balanced.
    - A secondary relay metering the same circuit can be used as a comparison for current magnitude.
    - Phase rotation is to match the utility's standard phase rotation and near 120 degrees between each phase.
    - When performing a load check, all current inputs of the relay being used need to be load checked to ensure that they meet these criteria.

- Power factor:
    - Verify power factor is at an acceptable level.

- Differential current:
    - While not always possible at time of commissioning, substantial restraint current should be seen by the differential relay. When current magnitude is too low, this should be reevaluated at the time current magnitudes are an acceptable level. A typical minimum acceptable load check magnitude would be 0.5 – 1.0-amp secondary current.
    - A nearly zero operate current should be observed. This value should be below the minimum I_{op} setting threshold.

Examples of Load Checking Typical Schemes

1. Low Impedance Bus Differential Example

When performing a load check of a low impedance bus differential relay, the first measurement that should be evaluated is the magnitude of differential current, or the vector sum of the normalized currents from each CT input. When there is no internal fault, this value should be nearly zero. Depending on the relay type, how these secondary currents are verified will be different. When commissioning a microprocessor bus differential relay, each of these current magnitudes and angles can be observed through the relay manufacturer's HMI or through issuing a command to the relay in order to display these values. For microprocessor relays, these currents will be displayed as their primary value. When commissioning an electromechanical low impedance bus differential relay, each of these currents will need to be measured using a clamp on tester or inserting a current probe into the relays current test jack, to read each individual CT input. Each of these currents will be secondary values and can be reflected to the primary side using the CT ratio.

From here, current magnitude and angle from each of the CT inputs into the relay should be individually verified. First it should be confirmed that the current magnitudes measured for each phase of an input are nearly equal. This should be confirmed for each three phase input into the relay. Additionally, it should be verified that phase rotation for each of the current inputs match each other.

When a redundant bus differential protection exists, the vector current of the input being verified should be compared to the corresponding current input in the redundant relays. These should match in both magnitude and angle. When these current magnitudes do not match, the CT ratio should be used to reflect currents to the primary side and compared. In microprocessor relays these primary values are displayed through the relays manufacturer's HMI and a variance may be due to CTR setting error. This should be checked for each of the three phase inputs.

As an additional check, the vector currents for each of these inputs into the bus relay could be compared to its corresponding line or transformer relay to ensure the conditions of equal magnitude with angles 180 degrees apart are satisfied.

While not always present at time of commissioning, substantial restraint current should be seen by the differential relay. When secondary current magnitude is below the relay's input sensitivity level, a load check should be performed at the time current magnitudes are at an acceptable level.

2. High Impedance Bus Differential Example

One main difference between a high and low impedance bus differential relay is that when using a high impedance relay, the CT for all circuits within the bus's zone of protection will be paralleled together into one point and then connected to one high impedance relay input. This differs from when using a low impedance relay, where the CT for each of these circuits is wired to an individual low impedance relay current input.

When performing a load check of a high impedance bus differential, voltage across the operating coils should be measured to be near zero. If the voltage reads exactly zero, a check for shorted CTs should be made. When there is a substantial voltage present across the operating coil, the most common causes are that all of these CTs are not tapped at the same ratio or at least one of the CTs is not paralleled.

An additional method for commissioning would be to individually short and then isolate each one of the CTs at a time and then observe the voltage across the input. For this method, a backup bus protection scheme would need to be in service and the trip test switches to the relay being tested opened prior to this check.

Another way to verify the current signals is to use a clamp-on current meter to measure the magnitude and angle of each of the current circuits. The sum of the currents on each should add up to zero or a very low value.

3. Transformer Differential Example

When performing a load check of transformer differential relaying, the first measurement that should be evaluated is the magnitude of differential current, or the vector sum of the normalized currents from each CT input. When CT wiring is correct, this value should be near zero. When commissioning a microprocessor transformer differential relay, each of these current magnitudes and angles can be observed through the relay manufacturer's HMI or through issuing a command to the relay in order to display these values. For microprocessor relays, these currents will be displayed as their primary value. When commissioning an electromechanical transformer differential relay, each of these currents will need to be measured using a clamp on tester to read each individual CT input. Each of these currents will be secondary values and can be reflected to the primary side using the CTR.

From here, current magnitude and angle from each of the CT inputs into the relay should be individually verified. First it should be confirmed that the current magnitudes measured for each phase of an input are nearly equal. This should be confirmed for each three phase input into the relay. Additionally, it should be verified that phase rotation for each of the current inputs match each other.

4. Generator Differential Example

When performing a load check of generator differential relaying, the first measurement that should be evaluated is the magnitude of differential current, or the vector sum of the normalized currents from each CT input. When CT wiring is correct, this value should be near zero. To avoid unnecessary tripping, bring the unit up to an output level below the relay pickup and verify CT currents before ramping up to full output.

When commissioning a microprocessor generator differential relay, each of these current magnitudes and angles can be observed through the relay manufacturer's HMI or through issuing a command to the relay in order to display these values. For microprocessor relays, these currents will be displayed as their primary value. When commissioning an electromechanical generator differential relay, each of these currents will need to be measured using a clamp on tester to read each individual CT input. Each of these currents will be secondary values and can be reflected to the primary side using the CTR.

From here, current magnitude and angle from each of the CT inputs into the relay should be individually verified. First it should be confirmed that the current magnitudes measured for each phase of an input are nearly equal. This should be confirmed for each three phase input into the relay. Additionally, it should be verified that phase rotation for each of the current inputs match each other.

Concluding Remarks

This paper is focused on preventing the types of Protection System misoperations that are most consistently observed during the Event Analysis process, as significantly exacerbating the severity of an event. Specifically, breaker failure and bus differential schemes are discussed. The impact of unnecessary operations of these systems is highly dependent on bus configuration. The failure to operate of either scheme always results in extensive tripping (or worse, failure to clear a fault) regardless of bus configuration. Reducing misoperations associated with these Protection Systems would significantly reduce the number of events rising to the levels calling for NERC Event Analysis.

The chapter on differential relays also includes transformer and generator relays, as the cause of misoperations is often similar to that of bus differential relays. Since so many misoperations of differential relays could have been prevented by more thorough commissioning, a chapter on commissioning differential relays is included. Many of the concepts presented in that chapter are applicable to commissioning Protection Systems in general. This is particularly true of the caveat, "ensure that the construction schedule is not compressed to the point that resources are not providing adequate time to properly commission the protection schemes."

Finally, readers of this paper are encouraged to make use of the materials listed in the References section.

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