Electromechanical Differential Relays Misoperation and Investigation

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Abstract— **In November 2017, an industrial site had a full blackout due to both of its main electromechanical differential relays operating due to a downstream ground fault. Due to system complexity, as well as lack of commissioning during a tie breaker installation, a mistake was introduced into the protection system. This paper describes the investigation into the nuisance trips and how proper commissioning could have prevented this issue.**

I. Introduction

Transformer differential protection (ANSI 87) is one of the most common protection methods for large power transformers due to its outstanding speed and accuracy. However, given the complexity of this method when applied on Delta – Wye Grounded transformers, mistakes made during the design and/or installation phases might not be detected promptly, and ***eventually*** cause an undesired operation (it could take months or years!). This paper analyzes the transformer differential protection scheme of two 25 MVA, 138 / 12.47 kV transformers feeding a Main – Tie – Main scheme, and how the improper installation and commissioning of a tie breaker caused a full outage at an industrial facility.

II. Differential Protection

The discussion of differential protection starts with one of the most basic electrical laws: Kirchhoff's Current Law (KCL). The KCL law states that the "algebraic sum of the currents entering a node (or a closed boundary) is zero" [1]. In other words, the amount of current that enters an electrical node must equal the amount of current that exits the node. In the case that these currents are unequal, an unintended path for current flow is present. Figure 1 shows a basic KCL representation.

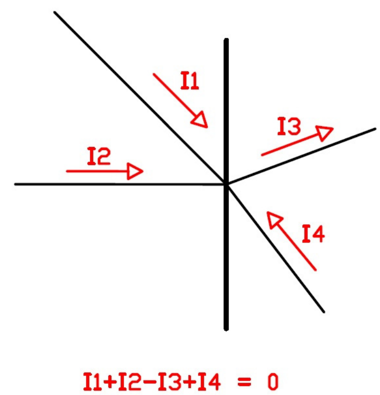

Fig. 1. Kirchoff's current law (KCL)

Differential relays apply KCL to protect electrical apparatuses (e.g. bus, transformer, line, etc.) through the use of current transformers (CTs), which must be installed at each connection point to obtain the total current summation. In order to perform the summation, each set of CTs must be brought into a protective device. A more modern approach allows for the current values to be transmitted between relays using fiber optics (outside of the scope of this paper).

It must be noted that in these systems the CT polarity plays an important role: the CTs must be installed and wired so that the total current summation adds up to zero on load and external faults. This is only possible if CTs at each end of the apparatus have opposite polarity and their resulting currents into the relay are 180° out of phase. For a more thorough explanation of current flow and CT polarity, refer to Rangel [2]. Figure 2 shows a typical bus differential protection scheme.

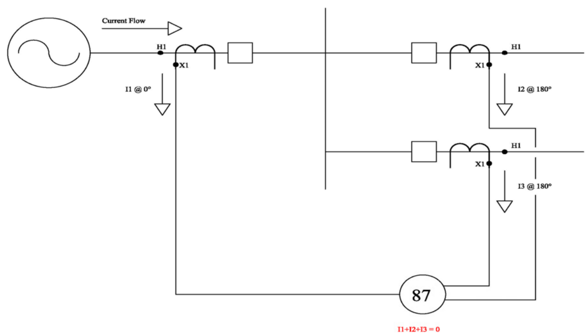

Fig. 2. Bus differential protection scheme

III. Transformer Differential Protection using Electromechanical Relays

Transformer differential protection was originally performed using electromechanical relays (it is now available with digital relays as well), and a large number of these devices are still in service today. These relays require a set of currents at each side of the transformer (known as restraint currents) to undergo physical summation (known as operate current) to determine the fault location (i.e. internal or external) using a percentage characteristic method. For a detailed explanation of this method, refer to the ABB HU and HU-1 Instruction Manual [3]. Figure 3 shows the restraint and operate currents in a differential electromechanical relay.

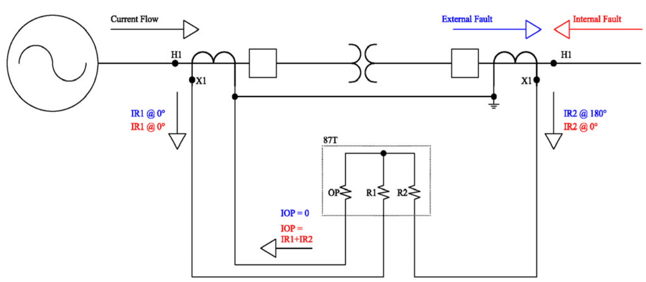

Fig 3. Differential protection using an electromechanical relay (simplified)

One of the biggest challenges in transformer differential protection is the delta – wye grounded transformer configuration, which is very typical. In this configuration, the delta-side windings are connected with one of the sides of a given winding (i.e. polarity side) to the opposite side of an adjacent winding (i.e. non-polarity side). With this connection type, the currents entering the delta side of the transformer are considered to be phase to phase, while the currents exiting the wye grounded side of the transformer are considered to be phase to ground (all 3 windings are grounded on one side). This configuration creates a 30-degree phase shift between the low and the high-voltage currents, which must be considered to properly apply transformer differential protection. Figure 4 shows the phase angle relationship between the delta and the wye-grounded primary currents (A-phase shown only). For a more detailed analysis, refer to Amberg and Rangel [4].

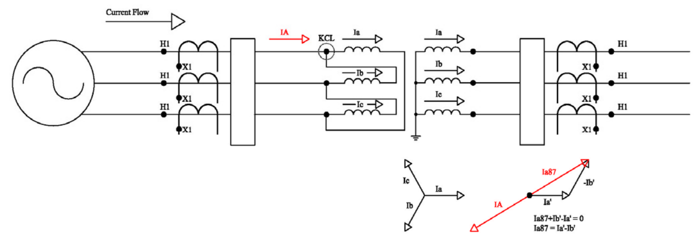

Fig. 4. 30-degree shift on a Delta – Wye grounded transformer

IV. Current Compensation and Electromechanical Relays

In the previous section, a 30-degree phase shift between both sides of the transformer was described; to cancel the secondary currents out (and satisfy KCL), this shift must be addressed. To address this issue, the CTs on the delta side must be wye-grounded connected, while the CTs on the wye-grounded side must be delta connected. This CT delta configuration creates phase to phase secondary currents, and therefore rotates their phase angles by 30 degrees; with this final shift, both sets of secondary currents will have a phase angle difference of 180 degrees.

Note: Proper tap selection must be considered in transformer differential protection. However, in this particular system TAP1 and TAP2 were properly selected and they did not contribute to the misoperation, therefore they will not be further discussed.

Figure 5 shows the proper CT configuration to be used on transformer differential protection with electromechanical relays. Due to the opposing CT polarity, both restraint currents entering the relay are 180 degrees apart from each other.

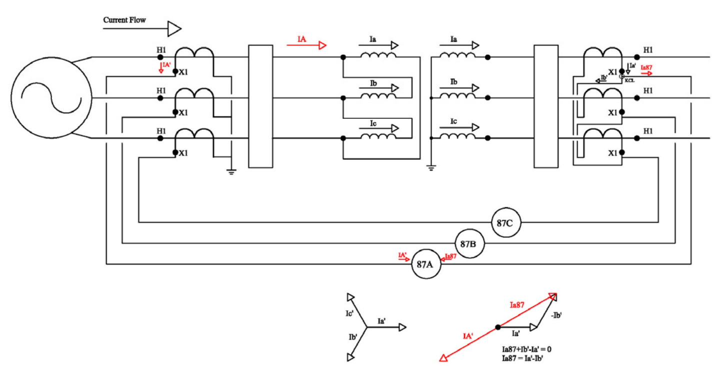

Fig. 5. Delta-connected secondary CTs

V. Existing Power System

The system discussed in this paper consists of two incoming 138 kV transmission lines feeding a 138 kV breaker each. Each breaker then feeds a 25 MVA, 138 kV / 12.47 kV transformer. On the low-voltage side, each transformer feeds a 12.47 kV breaker, which then feeds a 12.47 kV bus (identified as bus A and bus B). Each bus provides power to three different feeders (identified as 1, 2, and 3 on bus A and 4, 5, and 6 on bus B). A connection between bus A and bus B exists through a tie breaker connected to both buses.

As far as instrumentation goes, the CTs on the high-voltage side of the transformer are wye-grounded connected (CT ratio of 100:5), while the CTs on the low-voltage side of the transformer are delta connected (CT ratio of 1200:5). Since the 12.47 kV buses are part of the differential scheme (per design), the CTs at the load side of each feeder, as well as one set of CTs from the tie breaker must be connected to the 87T relays (every set connected in delta and paralleled). Figure 6 shows a simplified one-line diagram of the system.

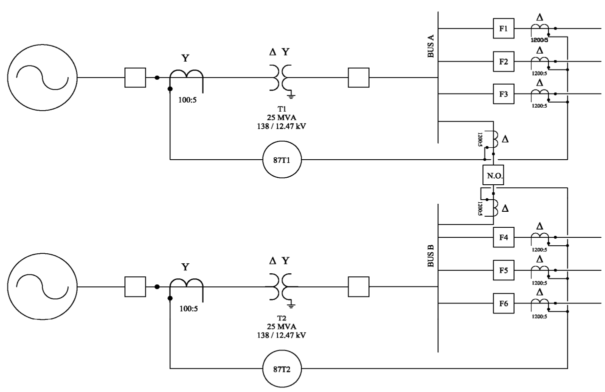

Fig. 6. One-line diagram, existing power system (simplified)

VI. Phase to Ground Fault

A C-phase to ground fault happened downstream of Feeder 5 on 11/29/2017. A digital relay had recently been installed to protect feeder 5, and an event report was generated during the fault. The event report shows that the fault lasted in the system approximately 3 cycles, and it had a maximum current value of approximately 2,400 A_{RMS}. During this fault, both differential protection relays (87T1 and 87T2) tripped and a full blackout was experienced at this facility (both 138 kV breakers opened). Figure 7 shows the oscillography generated by the feeder 5 relay during the ground fault.

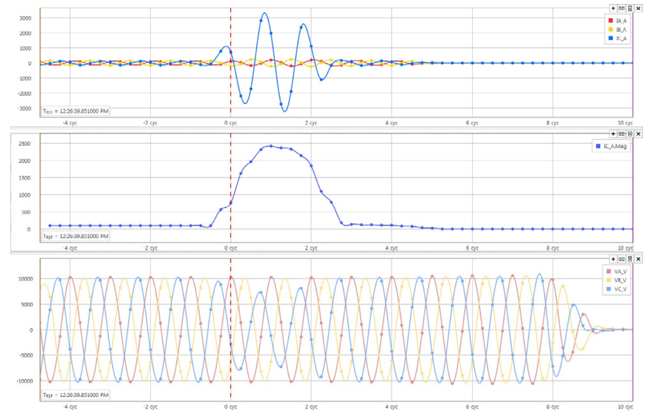

Fig. 7. C-phase to ground fault on Feeder 5, 11/29/2017

VII. Troubleshooting

Once site personnel identified the ground fault downstream of Feeder 5, they determined that both 87 relays had misoperated and requested the assistance of a third-party testing company to investigate the reason for these misoperations. The relay flags had been cleared, the lockout relays had been reset, the 138 kV breaker on the A side was closed (the system became partially energized), and loading was kept to a minimum until the root cause was determined.

The half of the system that was re-energized had a very small amount of load, therefore performing troubleshooting/commissioning was very difficult. Also, because the 87T1 relay is electromechanical, it was not possible to obtain all of the restraint currents at once (a digital relay is able to capture these currents through a triggered event report). It was then determined to troubleshoot the other half of the system that was still de-energized and isolated.

In order to verify the restraint currents flowing into 87T2, it was planned to inject current from the feeder breaker CT terminal blocks back into the relay. Given that the CT burden is much higher than the wiring and the relay inputs, it was not necessary to lift the wires prior to testing. One Amp (balanced) was injected at each polarity connection point at the Feeder 5 breaker CT terminal blocks (ST2X-1, ST4X-1, ST6X-1) and current measurements were taken with a digital clamp meter at a) the field wiring exiting the breaker and b) the restraint channel at 87T2. The measured currents were a) 1 Amp (expected) and b) 0.6 Amps (unexpected). Figure 8 shows a simplified schematic of the current testing performed at Feeder 5 and the 87T2 relay (A-phase measured values shown only).

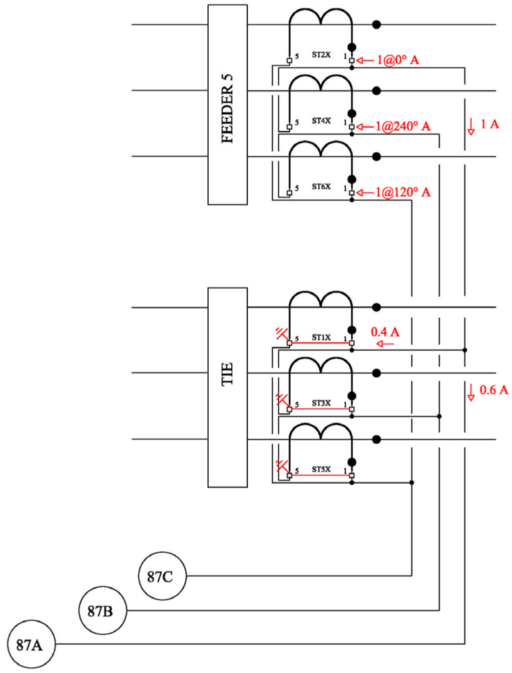

Fig. 8. Current testing at Feeder 5 breaker (simplified)

According to KCL, there are 0.4 Amps flowing in an "unknown" path. Site personnel mentioned that due to aging, the tie breaker had been replaced months ago, **it was not put in service** (i.e. the breaker would remain open and the isolating switches opened up), but connections were made to put it in service if needed. It was also mentioned that the 87T relays had nuisance tripped in the past, and these events started to happen shortly after this breaker's installation. A visual inspection was performed at the tie breaker's wiring cabinet and it was noticed that shorting screws had been installed at the CT shorting blocks connected to the 87T relays (see Figure 9). Using the digital clamp meter, it was verified that the "missing" 0.4 Amps were flowing into this unintended path. Since the CTs are delta-connected, their windings were shorted and a current path through this short was created (see Figure 8), which would then create an outstanding operate current; this operate current would become high enough during an external fault, and the 87T relays would declare (erroneously!) an internal fault and trip.

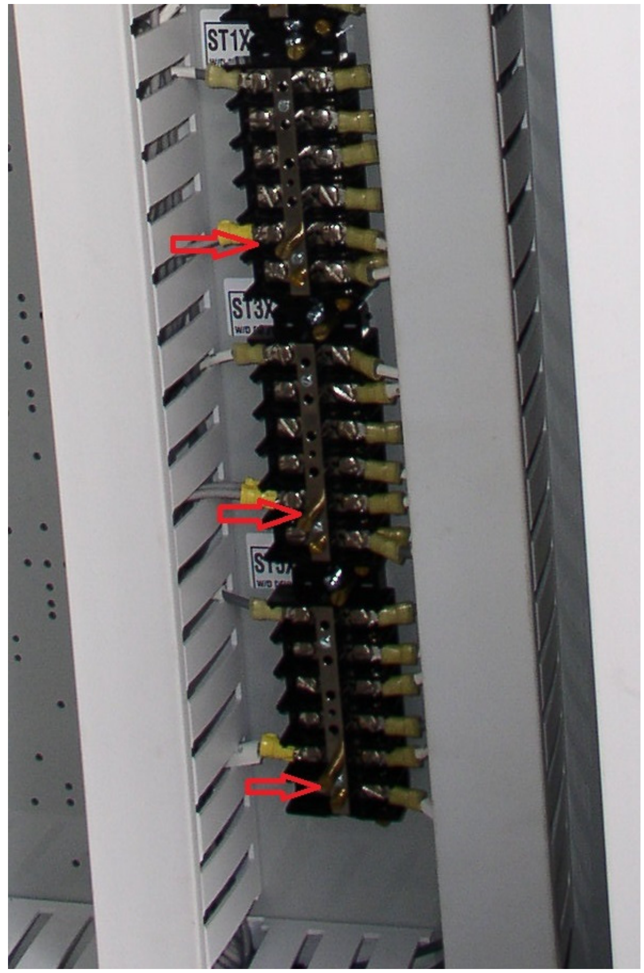

Fig. 9. Tie breaker CT terminal blocks, shorting screws are inserted

VIII. Lessons Learned

A few lessons were learned from these misoperations:

- When replacing substation apparatuses, individual components that are part of the specific apparatus might have an effect on the system. In the case of outdoor breakers, **the included current transformers must be fully tested and commissioned** prior to re-energizing the system to ensure proper operation.

- The use of electromechanical differential relays on a delta – wye grounded transformer adds complexity due to the CT delta connection on the wye grounded side of the power transformer. These **delta-connected CTs must never be shorted** as the non-polarity side of one phase is always connected to the polarity side of another phase.

- Whenever CTs are introduced into a system but they are not to be used, they can be connected wye-grounded and shorted out (they must never be left open). However, **a connection into a protection system means that CTs are actually in service** and therefore need to be properly installed and tested.

- **Protection systems** (in this case the differential relays) **must be re-commissioned anytime they are modified**. One simple check is to meter the operate current (upon loading the power transformer); for electromechanical relays, a digital clamp meter can be used, while for digital relays a meter command should suffice. The mismatch between operate and restraint currents must be low (according to relay manufacturer specifications).

IX. Conclusion

The process of replacing substation apparatuses due to aging and/or limitations is very common, and all of the new instrumentation devices introduced into the system (e.g. CTs) must be fully tested and commissioned to ensure proper operation. Without proper testing and commissioning, mistakes can go undetected and eventually cause misoperations.

X. References

[1] Alexander, C. and Sadiku, M. *Fundamentals of Electric Circuits*, 3rd Edition. The McGraw- Hill Companies, Inc., 2007.

[2] Rangel, A. "What Is So Negative about Negative Sequence? Part 2." *NETA World*, Summer 2018.

[3] ABB, Inc. *Type HU and HU-1 Transformer Differential Relays Instruction Manual*, 1999.

[4] Amberg, A. and Rangel, A. *Tutorial on Symmetrical Components*, 1st Edition (ebook). Schweitzer Engineering Laboratories, Inc. Accessed March 7, 2016 at *https://cdn.selinc.com/assets/Literature/Publications/White%20Papers/LWP0010-01_TutorialSymmetrical-Pt1_AR_20130422.pdf*.

XI. Biographies

Alex Rangel is a protection and controls engineer for Saber Power Field Services, LLC. Alex is a NETA Level 4 certified, has been an IEEE member for 11 years, and has been a registered professional engineer in the state of Texas since 2014. He holds a BS in electrical engineering and an MS in engineering from The University of Texas at Austin.