

Enhancing Power Transformer Differential Protection to Improve Security and Dependability

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Abstract—Current differential principle is a well-known principle used for protection of transformers, motors, generators, buses, and any other type of power equipment with input and output current measurements. Further, the principle is used in developing percent differential protection, which can be programmed to the desired sensitivity for detecting in-zone faults and security during external faults. This protection dependability is usually achieved by modeling a differential-restraining characteristic with two regions, operating and nonoperating, and tracking the real differential restraint ratio during faults. Some external faults with high dc offset and high X/R system time constant would easily saturate the installed current transformers (CTs), which in return would cause high differential/restraint ratio above the preset characteristic into the operating region. In such cases, the differential protection would operate and cause unwanted transformer trip. This paper focuses on some enhancements applied to the differential principle of the main differential protection; it also defines guidance on how to setup the protection for better sensitivity and security. The paper is supported by fault cases, showing the improved security and dependability during internal/external faults with and without CT saturation.

Index Terms—Breakpoint, current transformer (CT) saturation, differential protection(87), differential/restraint trajectory, external fault, internal fault, phasor, slope.

I. INTRODUCTION

THE POWER transformer is one of the most expensive components in the electric power system, and as such it needs to be properly protected during internal faults. Transformers experience many transient faults that can saturate the winding current transformers (CTs) used by the differential protection. Saturated CT during through-faults can lead to unwanted differential protection operation and trip the transformer breakers.

II. HISTORY OF THE DIFFERENTIAL PROTECTION

Towards the end of the 19th century [1], some engineers in Germany developed the differential protection principle that compares two dc voltage phases with the neutral phase, where

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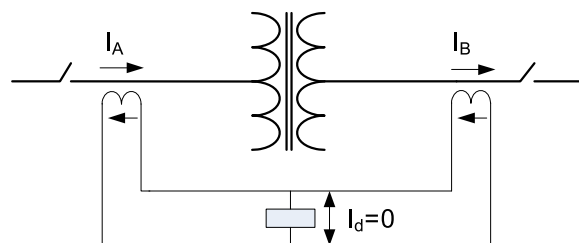


Fig. 1. First attempt to apply differential protection to a transformer.

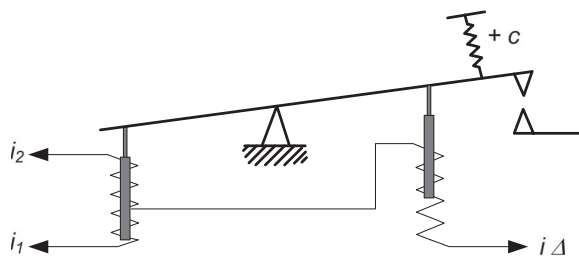


Fig. 2. First percent differential protection.

a beam relay with two coils is balanced as long as both voltages were equal. This was followed by many other attempts to compare currents from a three-phase system during symmetrical conditions.

In 1904, Merz and Price first patented the differential protection based on a comparison of the currents measured at both sides of power system component. Two CTs were installed on both sides of the equipment. The secondary windings of the current transformers were connected such that during normal operation, the vector sum of the currents would be zero.

A single differential relay was used to trip both sides to protect the power transformer. The disadvantage of this system was that when the current transformers were operating under a no-load condition, the circuit would experience a high voltage. A bridge circuit was used to measure the current difference between both CTs, as shown in Fig. 1.

The first percent differential protection [1] was invented in 1929 by McColl, who added a restraining winding to avoid false tripping. He assembled the protection using two electromagnets which would move an arm of balance, as depicted in Fig. 2. One electromagnet uses the geometrical sum of currents for restraining (biased relay), and the other one uses the geometrical difference for tripping. As a result, the tripping current proportional to the through-fault current had to be larger to cause a trip, hence the name “percent differential.”

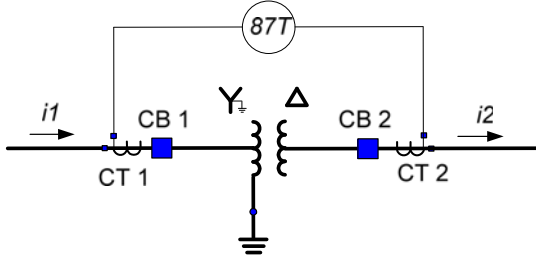


Fig. 3. Simple diagram of percent differential protection applied to transformer.

During that time, however, the current differential principle could only be developed to a certain level, as all discoveries were based on arranging currents, using interposing CTs for currents scaling, phase shifts, and relays with electromagnetic coils.

Later, differential principle was implemented for detection of fault in any equipment with measurable input and output currents. The major difference between old and today's differential relay can be found in the way of processing the currents by the protective devices. Today's devices use internal magnitude and angle compensation rather than using external interposing CTs. In additions, modern differential relays perform dc filtering, signal digitization, and calculate the restraining current based on the programmed equations. These relays apply preprogrammed differential/restraint characteristics and algorithms with integrated security and dependability.

III. TRANSFORMER DIFFERENTIAL PROTECTION (87T)

Nowadays the transformer differential protection resides in microprocessor based relays, which perform signal processing, filtering, currents compensation, and computation of differential and restraint currents. The protection is offered with certain level of sensitivity, security, and dependability during faults. Some algorithms use simple characteristic to distinguish between external and internal faults, while others are more complex, [5], [6], and involve more protection principles. In general, the more complex algorithms provide better security during external faults by tolerating current transformer saturation and inhibiting the protection to operate. By doing so, the relay manufacturers provide the user with a wide range of CT selection, to allow the protection to work with even smaller and low rated CTs that can easily saturate.

The protective device providing transformer differential protection is usually connected to the current transformers from both transformer windings, as depicted in Fig. 3. They perform the following major computations.

A. CT Mismatch and Scaling of Currents

Since the transformer's primary job is to either step-down or step-up voltages, in most of the cases, the phase-to-phase voltages for each transformer winding are different. The different winding voltages lead to different winding currents that are reversely proportional to the voltage ratio. Since currents

measured at both windings are different in magnitude, CTs installed on both sides are also different in ratings, class accuracy, knee-point saturation voltage, primary current rating, etc. As a rule of thumb, a satisfactory performance of C-class CTs selected for transformer differential protection can be obtained if the voltage formed by multiplying the maximum symmetrical CT secondary current during internal fault and the total CT secondary burden is less than half of the C-class voltage rating of that CT [4]. This allows some room for dc offset (asymmetry) and remanence before the CT saturates. A more accurate rule to avoid CT saturation for the maximum asymmetrical external fault current requires CTs with C voltage rating of $(1+X/R)$ times the burden voltage appearing for the maximum symmetrical external fault [4].

The magnitudes of the winding currents measured by the protective device are usually very different from each other, and if summed together would result in the nonzero differential current. Therefore, scaling of the currents to a common base is needed. Some devices calculate the CT mismatch by programming a tap for each winding current [6], while other devices automatically calculate the CT mismatch based on transformer ratings [3].

When tap selection method is used, it is important to make the ratio between the taps to be reversely proportional to the ratio of the nominal currents from the transformer windings. Using tap method, winding 1 and winding 2 currents at the secondary of the current transformer can be calculate as

$$I_S(w1) = \frac{I(w1)_N \cdot CT(w1)_{sec}}{CT(w1)_{prim}} \quad (1)$$

$$I_S(w2) = \frac{I(w2)_N \cdot CT(w2)_{sec}}{CT(w2)_{prim}}. \quad (2)$$

Mismatch between winding 1 and 2 currents can be calculate as

$$M_{CT} = \frac{I_S(w1)}{I_S(w2)} \quad (3)$$

where

$CT(w1)_{sec}, CT(w2)_{sec}$	rated CT secondary currents of winding 1 and winding 2 CTs;
$CT(w1)_{prim}, CT(w2)_{prim}$	rated primary currents of winding 1 and winding 2 CTs;
M_{CT}	mismatch between winding currents and winding CTs.
$I(w1)_N, I(w2)_N$	are defined by

$$I(w1)_N = \frac{MVA}{V_{ph-ph}(w1) \cdot \sqrt{3}} \quad (4)$$

$$I(w2)_N = \frac{MVA}{V_{ph-ph}(w2) \cdot \sqrt{3}}. \quad (5)$$

The method resembles the selection of taps for electromechanical relays and has some disadvantages.

- 1) The tap selection is based on discrete values, and the exact matching of currents depends on the resolution of the tap values.

- 2) Tap values with low resolution would introduce constant error that can be seen as a small differential current during normal loading conditions.

Once the M_{CT} mismatch is computed, the relay engineer needs to find a pair of taps (one per winding) from the ones available on the relay, and make the same ratio M_{Taps} , or make the closest possible ratio to the one from the winding secondary currents. Calculation of the new mismatch in percentage is then performed based on

$$M_{Relay} = \frac{M_{CT} - M_{Taps}}{M_{Taps}}, \% \quad (6)$$

As mentioned, other protective devices calculate CT mismatch automatically and perform the scaling without the need of tap calculation [2], [3]. These devices calculate scaling factors (SFs) very accurately and apply them to the corresponding winding currents. For these devices, one of the windings is selected as a reference and the SFs are computed based on that reference using (7) and (8). For example, if winding 1 is selected as a magnitude reference winding, then the SF for each winding is calculated as follows:

$$SF(w1) = \frac{V_{ph-ph}(w1) \cdot CT(w1)_{prim}}{V_{ph-ph}(w1) \cdot CT(w1)_{prim}} = 1 \quad (7)$$

$$SF(w2) = \frac{V_{ph-ph}(w2) \cdot CT(w2)_{prim}}{V_{ph-ph}(w1) \cdot CT(w1)_{prim}} \quad (8)$$

Further, the device multiplies the current measured from each winding by the corresponding SF, and the currents become equal in magnitude.

B. Transformer Phase Shift Compensation

The windings wound on each leg of a three-phase transformer can be connected in a number of ways to satisfy the application of the transformer in the power system. Some windings are connected in "Star" (Wye connection), Zig-Zag, with the start point either grounded or ungrounded, while others are connected in Delta to provide ground insulation. Phase shift is encountered when the connection arrangement of the windings is different, for example, primary winding connected in Delta and secondary winding connected in Wye.

In the past, the phase shift compensation has been compensated externally by connecting the secondary circuits from the CTs installed on the Wye winding in Delta, and the CTs from the Delta winding in Wye. This way the phase shift compensation is performed by the Delta CTs from the Wye winding. The advantages of using this method are external compensation of transformer phase shift and elimination of zero-sequence current. The disadvantage of this method is that some other protective functions from the relay will need to use the same Delta connected CTs. Thus pickup settings need to be higher than Wye connected CTs by the square root of three.

In modern relays, the external phase shift compensation is not so common, since the new digital relays, [2] and [3], automatically perform internal phase shift compensation while all CTs are connected in Wye. When all transformer CTs are connected in Wye, the currents introduced to the relay terminals

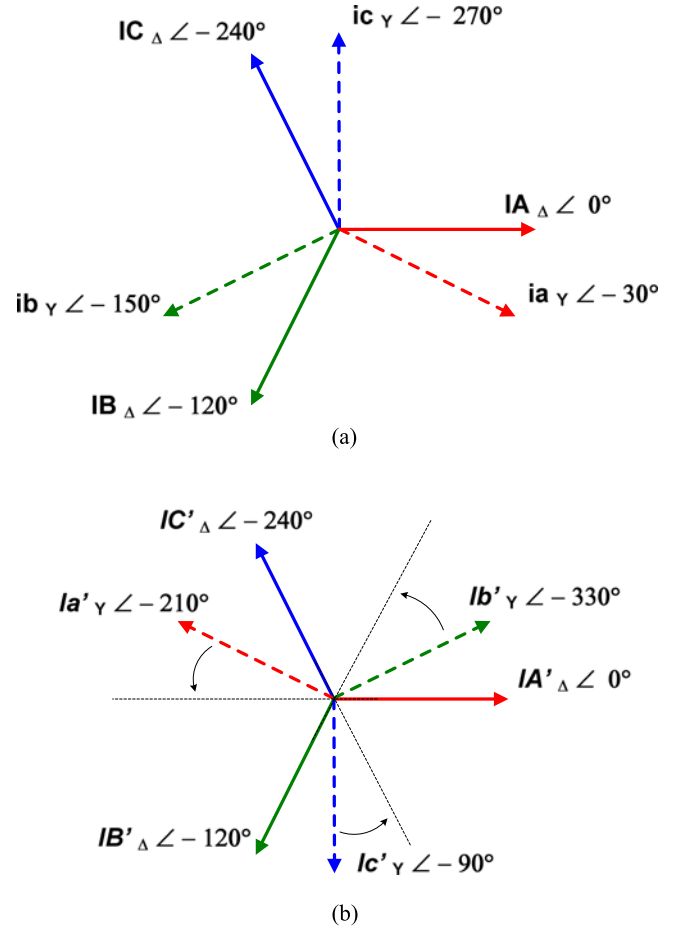


Fig. 4. (a) 30° phase shift between primary and secondary currents of Y/Δ transformer. (b) CT secondary currents and phase shift compensation applied by the relay.

replicate the transformer phase shift, i.e., 30°, 60°, 120°, etc., with the addition of 180° incurring from the mirrored polarity of the CTs with respect to the transformer. These relays measure the shifted winding currents and apply a set of equations. For example, following set of equations can be used to compensate the 30° phase shift between Wye and delta windings currents

$$\left. \begin{aligned} \overrightarrow{ia_{Y\ comp}} &= \frac{\overrightarrow{ia_Y} - \overrightarrow{ib_Y}}{\sqrt{3}} \\ \overrightarrow{ib_{Y\ comp}} &= \frac{\overrightarrow{ib_Y} - \overrightarrow{ic_Y}}{\sqrt{3}} \\ \overrightarrow{ic_{Y\ comp}} &= \frac{\overrightarrow{ic_Y} - \overrightarrow{ia_Y}}{\sqrt{3}} \end{aligned} \right\} \quad (9)$$

The phase compensated Wye currents are then compared with the Delta phase reference currents. With the applied phase compensation and encountering the mirrored CT polarities with respect to the transformer, the relay sees the both windings currents 180° out of phase.

Fig. 4(a) and (b) shows phase current phasors to illustrate the phase compensation performed by the relay.

The applied set of equations depends on the type of transformer group selected on the relay. The standard phase shifts seen on conventional type power transformers are in multiples of 30° , and many transformer differential relays provide a preset table for selection of the transformer type. This preset table contains combinations of Wye, Delta, and Zig-Zag windings for two and three winding transformers. Some relays provide high resolution when programming the transformer phase shift angle and are capable to perform compensation even for transformers with nonstandard phase shifts [3].

IV. DIFFERENTIAL/RESTRAINT CHARACTERISTIC

The current differential protection uses magnitude and phase shift compensated currents to form differential and restraint currents, and compare their ratio against preset characteristic. The characteristic reflects the desired sensitivity for detecting internal faults as well as the desired security during external faults. Depending on the protective device, the characteristic can have a different shape. Some characteristics include single slope as shown in Fig. 5(a), while others have two slopes as shown in Fig. 5(b)–(d). Differential characteristic, Fig. 5(d), includes a smooth cubic spline curve connecting the cross-point between slope (S)1/breakpoint (BP)1 with the cross-point of S2/BP2.

Regardless of the type of characteristics, the main purpose of the differential characteristic is to compare the differential/restraint (I_d/I_r) ratio detected in real time against the ratio defined by the characteristic.

The differential current is the vector sum of the compensated input currents of the windings and can be calculated using

$$I_d = i(w1)_{\text{comp}} + i(w2)_{\text{comp}} \quad (10)$$

where

$i(w1)_{\text{comp}}$ is the winding 1 compensated current;

$i(w2)_{\text{comp}}$ is the winding 2 compensated current.

While the computation of differential current is always the same, computation of the restraint current can be defined by one of following equations:

“average” method

$$I_r = \frac{|i(w1)_{\text{comp}}| + |i(w2)_{\text{comp}}|}{2}; \quad (11)$$

“sum” method

$$I_r = |i(w1)_{\text{comp}}| + |i(w2)_{\text{comp}}|; \quad (12)$$

“scaled Sum” method

$$I_r = \frac{1}{n} \left(|i(w1)_{\text{comp}}| + |i(w2)_{\text{comp}}| \right); \quad (13)$$

“geometrical Average” method

$$I_r = \sqrt[n]{|i(w1)_{\text{comp}}| \cdot |i(w2)_{\text{comp}}|}; \quad (14)$$

“maximum” method

$$I_r = \max \left(|i(w1)_{\text{comp}}|, |i(w2)_{\text{comp}}| \right). \quad (15)$$

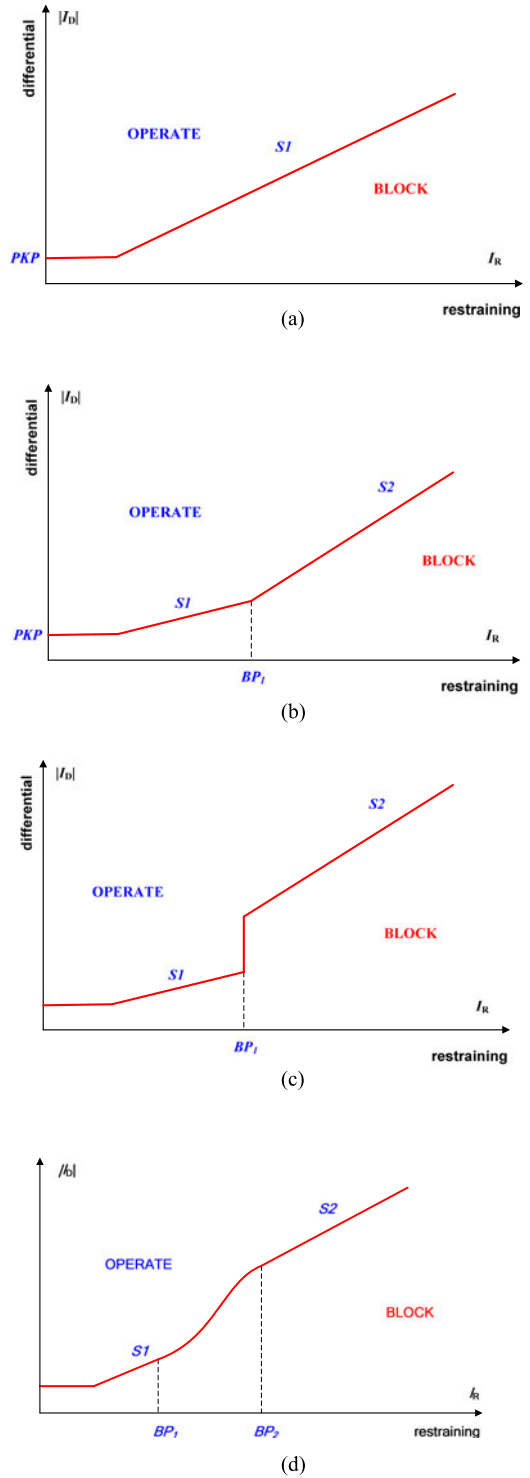


Fig. 5. Common diff./restr. characteristic shapes. (a) Single slope. (b) Two slopes, one breakpoint. (c) Two slopes, one breakpoint. Slopes projected from 0. (d) Two slopes, two breakpoints with smooth curve between slopes.

V. INTERNAL AND EXTERNAL FAULTS

Power transformers experience all types of power system faults, Fig. 6, which are generally defined as internal and external faults. Internal faults include faults in the transformer windings, tank, insulation, bushings, tap changer, and all other

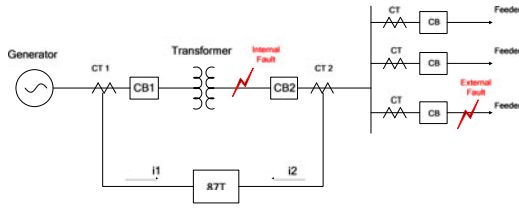


Fig. 6. Transformer zone of 87T protection.

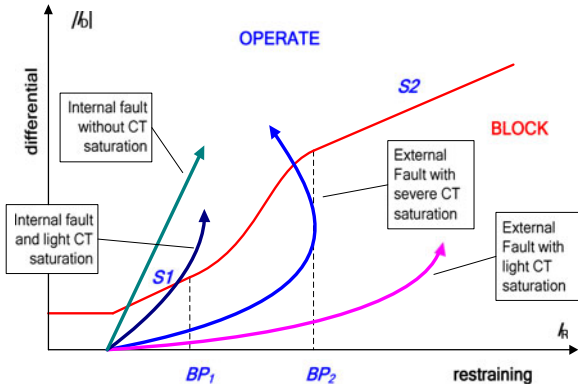


Fig. 7. Differential/restraint trajectories during internal and external faults with and without CT saturation.

components in the zone between the current transformers. The transformers also experience all types of transients caused by faults outside the transformer differential zone. Some of these external faults would occur close to the transformer location, while others would be far from it.

With respect to the 87T protection, the common signature during fault condition is the sudden increase of currents. Depending on the number of power sources connected to the transformer, the fault currents during internal fault can be either from one winding only, or from the other winding/windings as well. During external faults, the increase of currents is always observed from both windings CTs. The currents compensated by the relay during external fault may not be always identical in magnitude and opposite by phase, as in many cases these currents are distorted due to CT saturation. High magnitude fault currents with full offset and long dc time constant tend to easily saturate the CTs. High burden impedance connected at the CT secondary terminals makes the CT saturation even worse. If such current distortion is not accounted during programming of the transformer percent differential protection, an unwanted operation may occur. Fig. 7 shows patterns of internal and external faults with and without CT saturation.

From Fig. 7, the first trajectory (far right) reflects the differential/restraint currents ratio during an external fault with light CT saturation with the highest point falling into the safe no-operation region below slope 2. The second trajectory (second from right) reflects external fault with severe CT saturation. In this case, the distortion caused by the CT saturation leads to a ratio that exceeds characteristic with the highest point falling into the operating region. In such a case, the 87T protection would produce unwanted trip. The third trajectory (third from

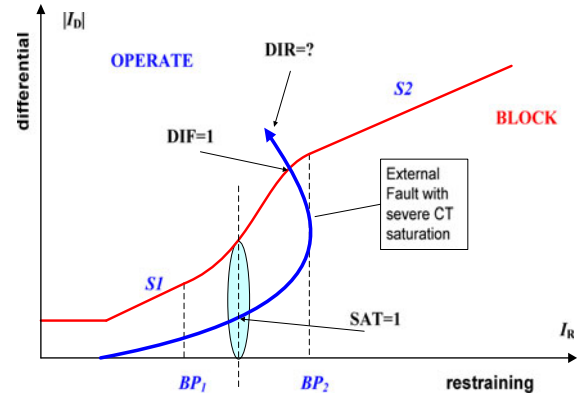


Fig. 8. Logic flags during external fault.

right), reflects light CT saturation during an internal fault. The fourth trajectory is a straight line (first on the left) and reflects the case of internal fault without CT saturation. This straight line describes 1:1 ratio between differential and restraint current. This is so, because in this example, the differential current is computed as a vector sum of the currents from both sides of the transformer using (16), and the restraint current is computed as the maximum of both currents using (17). With zero current from winding 2 CT during the fault and no CT saturation of winding 1 CT, the I_D/I_R ratio would be equal 100% using (18)

$$I_d = i(w1)_{comp} + i(w2)_{comp} = i(w1)_{comp} \quad (16)$$

$$I_r = \max \left(\left| i(w1)_{comp} \right|, \left| i(w2)_{comp} \right| \right) = i(w1)_{comp} \quad (17)$$

$$\frac{I_d}{I_r} = \frac{i(w1)_{comp}}{i(w1)_{comp}}, \% = 100\%. \quad (18)$$

VI. SECURING THE PROTECTION DURING EXTERNAL FAULTS

The enhancement of the protection consists of two parts [5]: the first part is associated with detection of an external fault, and the second part is related to checking the directions on the perphase basis from both windings. The directional check is performed if the actual differential/restraint ratio falls into the operation region above the characteristic. The directional check would then confirm if the fault is external or internal. If the detection confirms external fault, the 87T protection is inhibited from operation.

A. Detection of External Fault

The detection of an external faults is performed by comparing the “maximum of” restraint current against a threshold (see Fig. 8) computed as an average breakpoint between the values of the user-programmed BP1 and BP2. At the same time, the differential/restraint ratio during the fault is computed if it falls below an average slope based on user-programmed S1 and S2 values. The point of the average slope and the average breakpoint appears in the middle of the smooth intermediate curve (see Fig. 8). Flag saturation (SAT) is generated and retained for a period of time to allow for the fault trajectory to develop

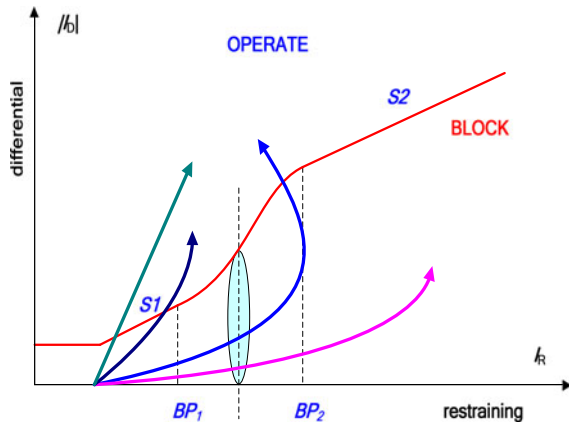


Fig. 9. Differential/restraint trajectories with external fault detection.

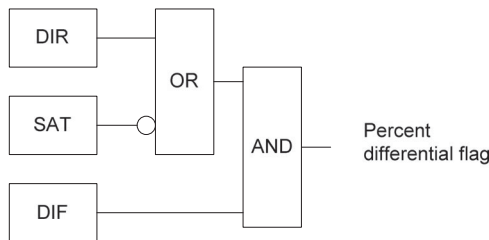


Fig. 10. 87T security logic.

completely, i.e., either cross the characteristic into the operating region or stay in the safe nonoperation zone. The directional check is performed only after initiation of SAT flag, and only if the trajectory crosses the characteristic into the operating region.

B. Directional Flag

The value of the directional (DIR) flag (see Fig. 9) determines whether the fault is internal or external in nature [5]. DIR flag equal zero indicates an external fault (angle difference between the winding compensated currents bigger than 90°), and flag equal 1 indicates an internal fault (angle difference less than 90°).

Considering the I_D/I_R trajectories of Fig. 7, it can be seen that applying the external fault detection condition (see Fig. 9) trajectories of the both external faults would trigger SAT flag. However, the directional check will be performed only for the case of external fault and severe CT saturation at the point of crossing into the operating region (second from right).

The relay applies a simple logic (see Fig. 11) involving the generated flags: differential flag (DIF), SAT flag, and DIR flag.

The two trajectories of Fig. 7 related to internal fault would not trigger SAT flag, and the protection would not need to check DIR flag in terms to produce operation and trip. Following the logic of Fig. 10 during internal faults, the I_D/I_R trajectory goes straight into the operating region producing only DIF flag. Since no saturation condition is generated, and the DIR flag is not checked, the fault is cleared fast without any additional time. On the other hand, during an external fault, the signature

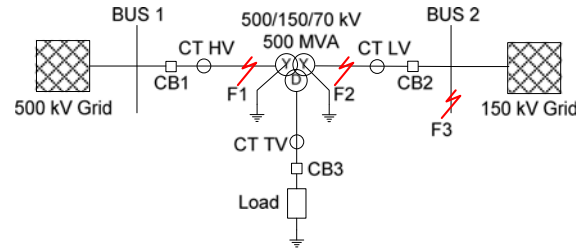


Fig. 11. Power system test model.

of the I_D/I_R trajectory is to move to the right from the normal condition and cross the saturation detection line. The SAT flag is triggered high, and the protection will wait for the DIR flag. In case, the I_D/I_R trajectory goes above the characteristic into the operating area, the algorithm checks the angle difference between the currents and defines the value of the DIR flag. A DIR flag equal to zero indicates an external fault. It is worth mentioning here that during CT saturation, the angle difference between the saturated and the nonsaturated currents remains bigger than 90° . The DIR flag would change from 0 to 1, in cases of evolving fault, i.e., from external to internal.

C. Art of Defining the Characteristic

The values of the pickup level, S1, S2, BP1, and BP2 shall be carefully defined to optimize the response of the 87T protection during internal and external faults. For this purpose, the data from the power transformer nameplate, CT saturation characteristics, burden, as well as minimum and maximum fault currents, and X/R of the system are needed. The target for the protection engineer is to set the slopes and the breakpoints and achieve the desired sensitivity during internal faults, as well as the desired security during external faults. Finding the maximum fault current including the X/R of the system that would not cause CT saturation would help to program BP1. Finding the lowest fault current including X/R of the system that would cause the worst CT to saturate and output secondary current with at least half-cycle saturation free time, would help in programming breakpoint 2. The selection of slope 1 would correspond to the differential currents that would be seen for through currents (restraint) with magnitudes less than breakpoint 1, while the selection of slope 2 value is associated with the degree of CT saturation during external faults.

VII. REAL-TIME DIGITAL SIMULATION

Dynamic testing using real-time digital simulation (RTDS) [7] was performed to check the differential protection security and dependability after the implementation of the enhancement. The performed tests included applying internal, external, and evolving faults. The evolving faults included: external to internal, internal to internal, external to external, and internal to external.

The RTDS model, as shown in Fig. 11, consists of Delta/Wye power transformer supplied by two power sources, one connected on each side. The tests were performed for various system conditions and fault types such as three phase (ABC, ABC-g),

TABLE I

Case #	Fault Type	Fault Location	CT1 Burden (ohms)	CT2 Burden (ohms)	Operating Time (sec)	
					Relay without EDP	Relay with EDP
1	A-g	F1	15	4	0.01164	0.0168
2	BC	F1	15	4	0.012	0.01872
3	ABC	F1	15	4	0.01212	0.0168
4	A-g	F1	15	4	0.01176	0.01656
5	A-g	F3	0	15	0	0
6	BC	F3	0	15	0.03804	0
7	ABC	F3	0	15	0.0222	0
8	A-g	F3	0	15	0	0
9	A-g	F3	0	13	0	0
10	BC	F3	0	13	0.01992	0
11	ABC	F3	0	13	0.021	0
12	A-g	F3	0	13	0	0
13	A-g	F3	0	10	0	0
14	A-g	F3	0	8	0	0
15	BC	F3	0	14	0.01944	0
16	BC	F3	0	12	0.0192	0
17	BC	F3	0	10	0.01884	0
18	BC	F3	0	8	0.01956	0
19	BC	F3	0	7	0.23508	0
20	BC	F3	0	6	0.2874	0
21	BC	F3	0	5	0.23508	0
22	BC	F3	0	4	0.2364	0
23	BC	F3	0	20	0.01788	0
24	ABC	F3	0	20	0.02136	0
25	ABC	F3	0	18	0.0198	0
26	ABC	F3	0	16	0.0396	0
27	ABC	F3	0	14	0.02196	0
28	ABC	F3	0	12	0.06648	0
29	ABC	F3	0	10	0.02184	0
30	BC	F3	0	9	0.02088	0
31	BC	F3	0	8	0.06876	0
32	BC	F3	0	7	0.02724	0
33	BC	F3	0	6	0.23688	0
34	BC	F3	0	5	0.285	0

phase to phase (AB, BC, CA), two phase to ground (AB-g, BC-g, CA-g), and phase to ground (A-g, B-g, C-g). In order to simulate high and low fault current magnitudes, each fault type was applied at different fault location (F1, F2, F3), varying fault resistance (low and high), CT saturation (light to severe) level, and transformer loading (60%, 100%, 130%, and 150%).

Table I shows performance comparison between two relays with and without enhanced differential protection (EDP). As it can be seen during internal faults (case#1–4) both relays properly operate, and trip within 50 Hz power cycle. However, during external faults, the relay without EDP falsely trips in the events of external BC and ABC faults with CT saturation (case#6, 7, 10, 11, 15–34), while the relay with EDP remains secure and does not trip for all these cases.

Fig. 12 shows the CT primary and secondary current of Phase B during external BC fault with severe, moderate, and light saturation, and Fig. 13 shows the trajectory of phase B I_D/I_R ratio corresponding to the degree of CT saturation. In the case of severe CT saturation, it can be seen in Fig. 12(a) that CT saturates in the first quarter of the first power cycle, resulting in the high false differential current while the increase of the restraint current is not significant (solid line from Fig. 14). In the

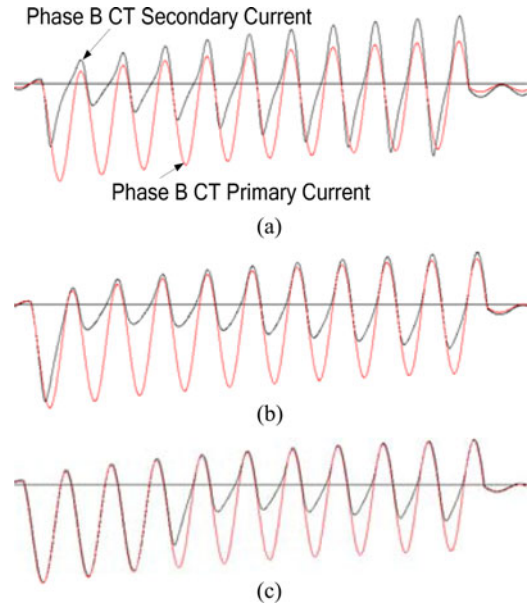


Fig. 12. Signatures of Phase B current at CT secondary and primary sides for an external BC fault with (a) severe, (b) moderate, and (c) light CT saturation.

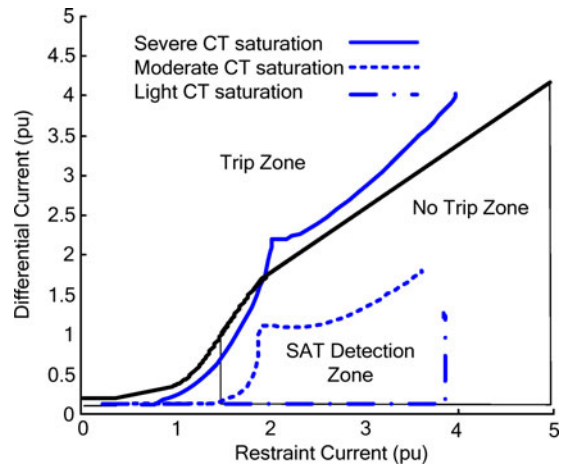


Fig. 13. Phase B differential/restraint trajectories during an external BC fault with severe, moderate and light CT saturation.

moderate CT saturation case, the CT saturates in the first quarter of the second power cycle, resulting in significant increase of restraint current [see (Fig. 12(b))]. Fig. 12(c) shows phase B current with light CT saturation that starts in the first quarter of the fourth power cycle, resulting in even bigger restraint current.

During external faults with CT saturation, the typical differential characteristic slope setting will help prevent operation of the differential protection, but only up to certain degree. During severe CT saturation conditions, the false differential current is much significant, while the increase of restraint current is not that significant, and can result in protection mal-operation (solid line in Fig. 13). In such conditions, if only the differential/restraint characteristic was set as a trip/no-trip criteria, the severe CT saturation would cause operation during the fault.

In this case, the additional CT saturation detection technique and the directional check helped to secure the protection against

operating on external fault. The trajectories from Fig. 12(b) and (c) corresponding to moderate and light CT saturations during external faults do not exceed the characteristic and do not require directional checks, as shown in Fig. 13.

VIII. CONCLUSION

The transformer percent differential protection is not reliable enough during external fault, if the differential/restraint characteristic is the only one criteria providing security. The saturation of CTs during external faults could lead to cases of dangerously high differential/restraint ratios crossing the characteristic into the operating region and causing unwanted trip. The help of early CT saturation detection, as well as directionality check are vital for the protection to provide additional security during external faults. Careful analysis of the system including the power transformer, and current transformers, is needed to set the protection for optimum performance.

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