ADAPTIVE FEATURES OF NUMERICAL DIFFERENTIAL RELAYS

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Abstract

The paper presents a fact that it is now possible to design a numerical transformer differential protection with better performance than the previous analog or electromechanical generations of transformer differential relays.
For transformer differential protection applications, it is extremely important to build-in good security since an unwanted operation might result in severe consequences for the power utility as well as for the complete power-system. On the other hand, the protection must be highly dependable as well. Failure to operate or even slow operation of the differential relay, in case of an actual internal fault, can have serious consequences. These two requirements are contradictory to each other and it is a very challenging task for relay manufacturers to meet both of these requirements.
The modern transformer differential protection demonstrates more adaptive features that give the possibility to combine security and dependability of the protection scheme.
This paper will present how adaptive features of the differential relay increase the sensitivity and dependability of the differential protection scheme.
This is supported by results from testing on a power system model as well as recordings from actual installations.

1. Determination of differential (operate) and restrain currents

During normal operation of the transformer, the sum of the ampere-turns of the all windings placed on the same transformer magnetic core leg must be equal to the magnetomotive force (MMF) required to set up the working flux in the transformer core. Because of the very small air gap in the transformer core, the MMF is negligible. So the sum of the ampere-turns of the all windings placed on the same transformer leg should be equal to zero during the normal operating condition of the power transformer.
This method of forming the differential (operate) currents is straight forward . By applying this concept, both current magnitudes and the phase shifts differences between all involved currents are taken care at the same time.
For determination of the differential (operate) currents, a two winding transformer will be considered, refer to Figure 1. The same concept may be applied for any transformer connection and for any number of windings.

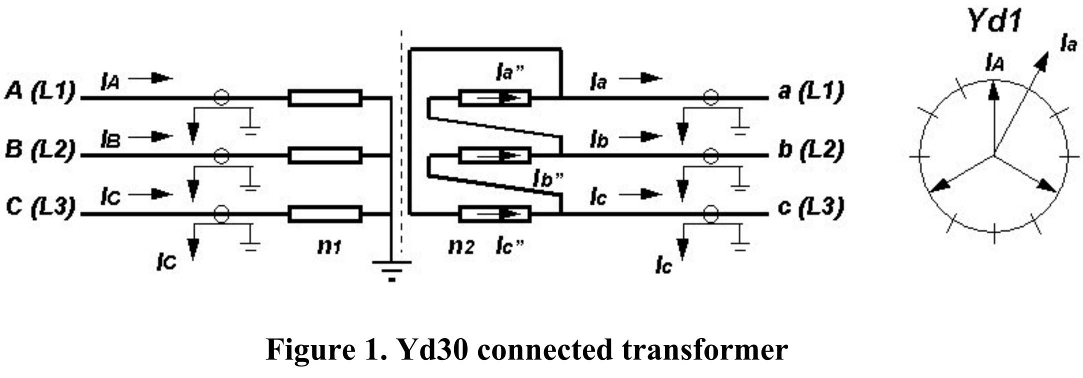

Figure 1. Yd30 connected transformer

$I_a^{"} * n_2 = I_A * n_1$ equality of Ampere-turns on power transformer, phase **a**
$I_c^{"} * n_2 = I_C * n_1$ equality of Ampere-turns on power transformer, phase **c**

$I_a^{"} = I_A * \frac{n_1}{n_2}$ currents which can't be measured can be expressed as functions of the terminal currents that are measured

$I_c^{"} = I_C * \frac{n_1}{n_2}$

$$I_a = I_a^{"} - I_c^{"} = (I_A - I_C) * (\frac{n_1}{n_2})$$

$$I_{diff\_a} = I_a * (\frac{n_2}{n_1}) - (I_A - I_C) \qquad (1)$$

Expression (1) represents the differential current on the phase **A** and referred to the power transformer primary side.
In a similar way it is possible to derive the expressions for the differential currents on the phase **b** and **c** as:

$$I_{diff\_b} = I_b * (\frac{n_2}{n_1}) - (I_B - I_A) \qquad (2)$$

$$I_{diff\_c} = I_c * (\frac{n_2}{n_1}) - (I_C - I_B) \qquad (3)$$

The turns ratio $\frac{n_1}{n_2}$ is usually obtained via rated voltages. From Figure 1, turns ratio is:
$\frac{(U_{r1} / \sqrt{3})}{U_{r2}}$ where U_{r1} and U_{r2} are rated voltages for the transformer windings.

Expressions (1), (2) and (3) rewritten in the compact form are as:

$$\begin{bmatrix} I_{diff\_a} \\ I_{diff\_b} \\ I_{diff\_c} \end{bmatrix} = \begin{bmatrix} \sqrt{3}C & 0 & 0 & -1 & 0 & 1 \\ 0 & \sqrt{3}C & 0 & 1 & -1 & 0 \\ 0 & 0 & \sqrt{3}C & 0 & 1 & -1 \end{bmatrix} \times \begin{bmatrix} I_a \\ I_b \\ I_c \\ I_A \\ I_B \\ I_C \end{bmatrix} \qquad (4)$$

or $i_d = M * i$ (5)

In expression (4), factor C is:

$$C = (\frac{U_{r2}}{U_{r1}}) * (\frac{n_{CTL}}{n_{CTH}}) \quad (6)$$

n_{CTH} and n_{CTL} represents the current transformer's ratio at high and low voltage sides.

I_a, I_b, I_c, I_A, I_B and I_C are secondary currents at the low and high voltage transformer sides.

Matrix M in the (5) depends on the type of transformer connection, CT ratio's and rated voltages.

It is also obvious from (5) that matrix M is not constant and is the function of the turn-ratio. Hence for a transformer with a tap changer, matrix M is not constant!

For this particular example the restraint current will be calculated as the relatively highest current of the six measured currents.

2. Adaptive Functions

Adaptive relaying has been defined in a CIGRE report as follows: "Adaptive protection is a protection philosophy which permits and seeks to make adjustments in various protection functions automatically in order to make them more attuned to prevailing power system conditions".

2.1 Adaptive compensation for the tap changer

Assume an On Load Tap Changer (OLTC) is installed on the protected transformer. When the OLTC moves from one position to another, amplitude mismatch in the equation (5) and false differential current will occur. Normally, the range of an OLTC might be around ± 15% of rated voltage, so a contribution of around 15% to differential current may occur.

As we can see from Figure 2, two sources of the false differential current and some margin will increase the slope and minimum operating current of the percentage differential characteristic of the non-adaptive relay.

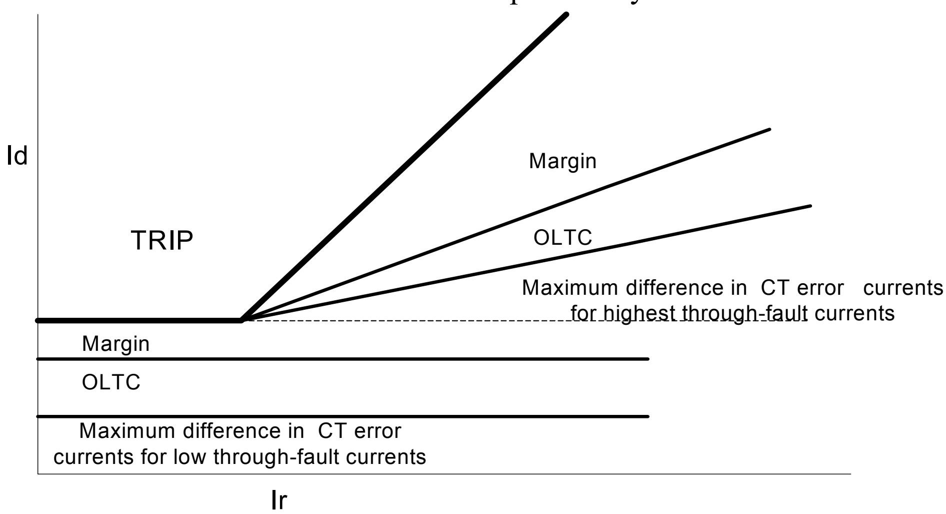

Figure 2: Percentage differential relay characteristic

From (6), the actual value of C for an arbitrary OLTC position **k** is:

$$C_{(k)} = \frac{U_{r2}(1+k\Delta)}{U_{r1}} \frac{n_{CTL}}{n_{CTH}} \tag{7}$$

where Δ is tap changer step size.

In the adaptive differential protection function, the tap changer position is measured and used in the equation (7) for a simple linear compensation.
In order to make a compensation for the variable factor C in (7), the following OLTC data is required as a setting values:

- total number of taps
- rated tap number
- minimum tap voltage
- maximum tap voltage

All these data are readily available on the power transformer nameplate. The actual tap position may be transmitted to the relay as an analog value (transducer output) or as a digital value (BCD coded signal).
Because of the adaptive calculation of the differential current, it is possible to considerably increase the sensitivity and improve possibility to detect inter-turn faults in the transformer.
To prevent an unwanted operation of the differential relay when tap changer position reading is lost during normal operation, the differential protection function will automatically increase its minimum operating value to 30%. Hence it will not issue a trip signal until the calculated differential current is above this limit.

2.2. Adaptive inrush blocking

2.2.1. Inrush phenomenon

Any abrupt increase of the power transformer terminal voltage will result in the transient current much larger then transformer rated current. This transient current is generally called inrush current.
Typical transient (inrush) currents are caused by:

- energizing of the power transformer,
- voltage recovery after clearance of heavy short circuit somewhere else in the power system (recovery inrush),
- energizing of another power transformer in the station which is connected in parallel with transformer which was already in operation (sympathetic inrush),
- evolving faults,
- out-of –phase synchronization of a connected generator.

Inrush phenomenon is not a fault condition, and therefore does not necessitate the operation of differential protection, which, on the contrary, must remain stable during the inrush transient condition.
Some records of the inrush currents furnished for reference are:

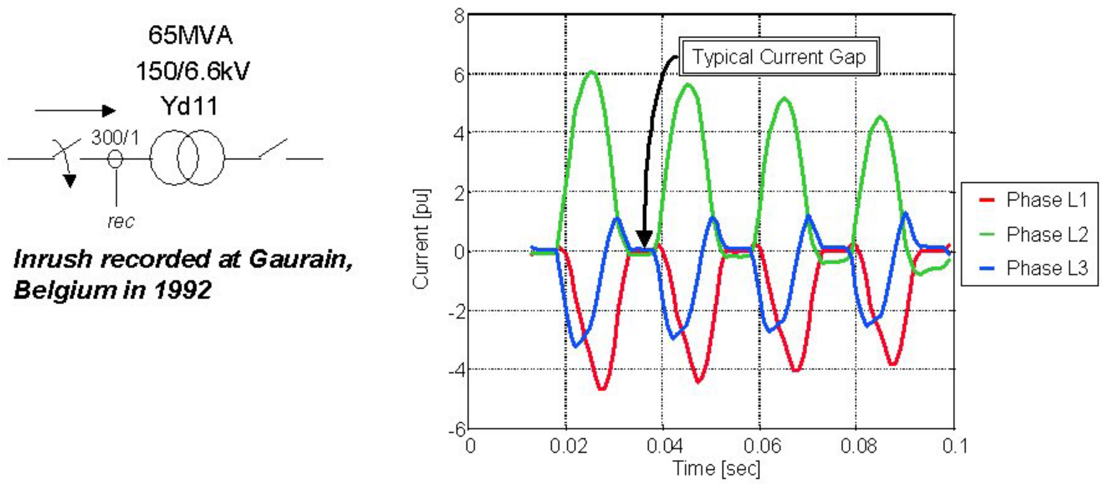

Figure 3: Initial inrush current during energizing the power transformer

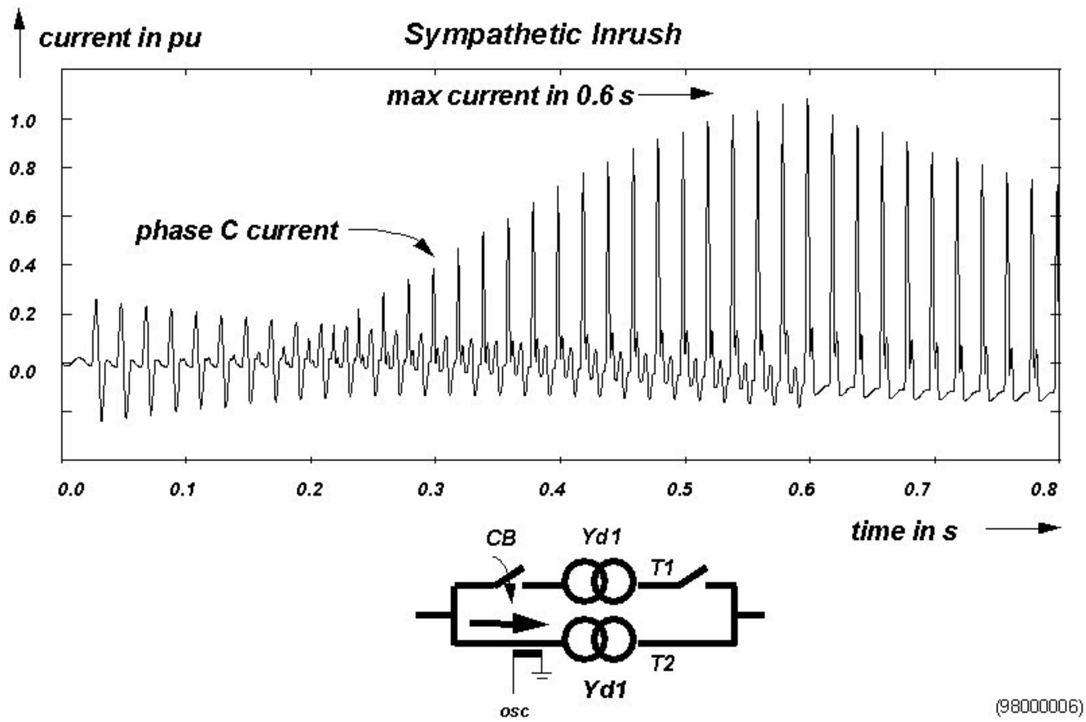

Figure 4: Sympathetic inrush

To make a relay stable against inrush currents, special measures must be taken in order to enable the relay to distinguish the inrush phenomena from an internal fault. It is necessary to provide some form of detection for all inrush conditions and restrain the differential relay from unwanted operation.

Typically transformer differential relays depends on one of the following methods:

- harmonic content of the magnetizing inrush current
- specific pattern of the magnetizing inrush current waveform

2.2.1.1. Inrush detection by harmonic analysis of instantaneous differential current

This method takes advantage of the fact that magnitudes of DC and harmonics in typical magnetizing inrush current are:

- dc component varies between 40% to 60% of the fundamental,
- the second harmonic is up to 70% of the fundamental,
- 3-rd harmonic is 10% to 30% of the fundamental.

On the other hand, the fault current is devoid of the higher harmonics (as long as CT is not saturated). It is thus appropriate to make use of harmonic analysis in order to detect inrush condition.
If the ratio of second harmonic (I2) over the fundamental (I1) is greater than the user-set limit, then inrush condition is detected and a block of the trip signal is issued. Practice has shown that although “I2/I1” approach may prevent false tripping during inrush conditions, it may sometimes increase fault clearance time for heavy internal faults followed by CT saturation. On the positive side, “I2/I1” approach will increase the security of the differential relay for a heavy external fault with CT saturation.

2.2.1.2. Inrush detection by waveform analysis of instantaneous differential current

It can be observed from Figure 4. that inrush current waveform is characterized by a period of time in each power system cycle during which very low magnetizing currents flow. The condition to declare an inrush condition would be that a low rate of change of the instantaneous differential current exists for at least a quarter of a fundamental power system cycle.
This criterion can be mathematically expressed for Phase A as:

$$\left|\frac{\partial I_{diff\_a}}{\partial t}\right| \le C_1 \qquad (8)$$

where I_{diff_a} is instantaneous differential current in Phase A, t is a time and C_1 is a constant fixed in the relay algorithm.

2.2.2 Inrush detection by adaptive techniques

The combination of the “I2/I1” and waveform analysis methods, allows the relay designer to take advantage of both individual methods, while at the same time avoiding their drawbacks. Two possible ways to combine these methods are:

2.2.2.1. Conditional (recommended)

In this mode of operation these two criteria are used as follows:

- employ both the "I2/I1" and the waveform criteria to detect initial inrush condition,
- disable the "I2/I1" criterion one minute after power transformer energizing in order to avoid long clearance times for heavy internal faults and let the waveform criterion alone take care of the sympathetic and recovery inrush,
- temporarily enable "I2/I1" for 6 seconds when heavy external fault has been detected to gain additional security for external faults

2.2.2.2. Always (traditional approach)

This option is like the usual "I2/I1" criterion. "I2/I1" is active all the times. In addition to the "I2/I1" criterion, the waveform criterion works in parallel. No speed benefits can be obtained for heavy internal faults.

2.3. Adaptive restrain current calculation for 1½ CB substations

In many countries the one-and-a half CB bus arrangement is extensively used in transmission networks. Typical example of a transformer bay in such a substation is shown in Figure 5.

Using standard substation design procedures will often lead to situations where main CTs located in the switchgear diameters will often have much bigger primary current ratings than the power transformer winding itself. In that case the protection engineer is left with one of the following two choices for transformer differential protection:

- use the transformer differential relay with five restrain inputs and base the overall scheme sensitivity on the main CT ratings
- galvanically interconnect the main primary and correspondingly secondary CTs and use the transformer differential relay with three restrain inputs; the overall scheme sensitivity is then based on the power transformer rating

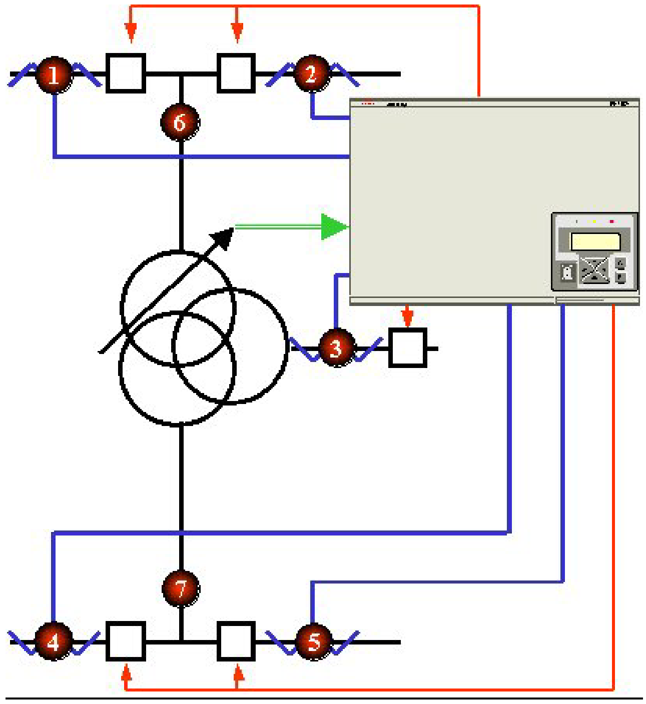

Figure 5: Transformer bay in one-and-half CB substation

However neither of these two solutions is the optimal one. The first solution has the drawback that it lacks the sensitivity for low level internal faults within the power transformer (i.e. inter-turn faults), but on the other hand it provides good stability for heavy external faults through the switchgear diameters (i.e. HV busbar fault).
The second solution will have directly opposite characteristics (i.e. good sensitivity for low level internal faults, but lack of security for external faults through the switchgear diameters).
Modern numerical transformer differential relay can combine the properties of these two solutions by adaptive calculation of the restrain current. It actually measures using all five sets of CT individually, but it takes seven “measuring points” (see Figure 5) in the calculation for potential restraint current. The restraint current is selected as the relatively highest p.u. current. However different base current values are used during this calculation depending on the position of the measuring points:

- for currents that flow through the main CTs, the CT primary rating is used as a base
- for currents that flow towards power transformer windings, the winding rating is used as a base

In this way the selected restrain currents have the following properties:
- it is never bigger than 1.0 pu during normal through load condition; therefore the differential relay is in the first and most sensitive part of its characteristic
- it is always high enough to prevent unwanted operation of the relay for heavy external faults through the switchgear diameters (i.e. HV busbar fault) in spite of possible main CT saturation

2.4 Adaptive external fault detection logic

The transformer differential relay must fulfill two directly contrary requirements:

- to be as sensitive as possible in order to detect low level internal faults in the power transformer (i.e. relay dependability)
- to be stable for heavy external faults followed by CT saturation (i.e. relay security)

In order to completely fulfill these requirements the modern numerical differential relay can include special external fault detection logic (or similar features), which can enable additional tripping criteria when heavy external fault is detected. By doing so, the security of the differential relay is drastically improved, while the speed of operation for real internal fault is not extended. Logic to detect heavy external faults is quite simple and can be based on fact that the sharp rise of the restrain current will not be simultaneously followed by rise of the differential current for external fault, while for heavy internal fault both of these quantities will increase simultaneously. By this approach the CT requirements for the transformer differential relay are reduced as well.

3. Testing of adaptive-differential relay performance

3.1 System set-up

Extensive tests were done to verify the adaptive protection techniques. ECEPA's (East China Electrical Power Administration) analog power system simulator was used to perform all tests. The simulator incorporates the analogue models of lines, cables, transformers, generators etc. For the transformer differential protection testing, the simulated test system was therefore set-up as shown in Figure 6.
A 1082/1082/541MVA, 500/250/115kV auto-transformer was simulated. Three single-phase transformers were connected in such a way to form a three-phase auto-transformer bank.

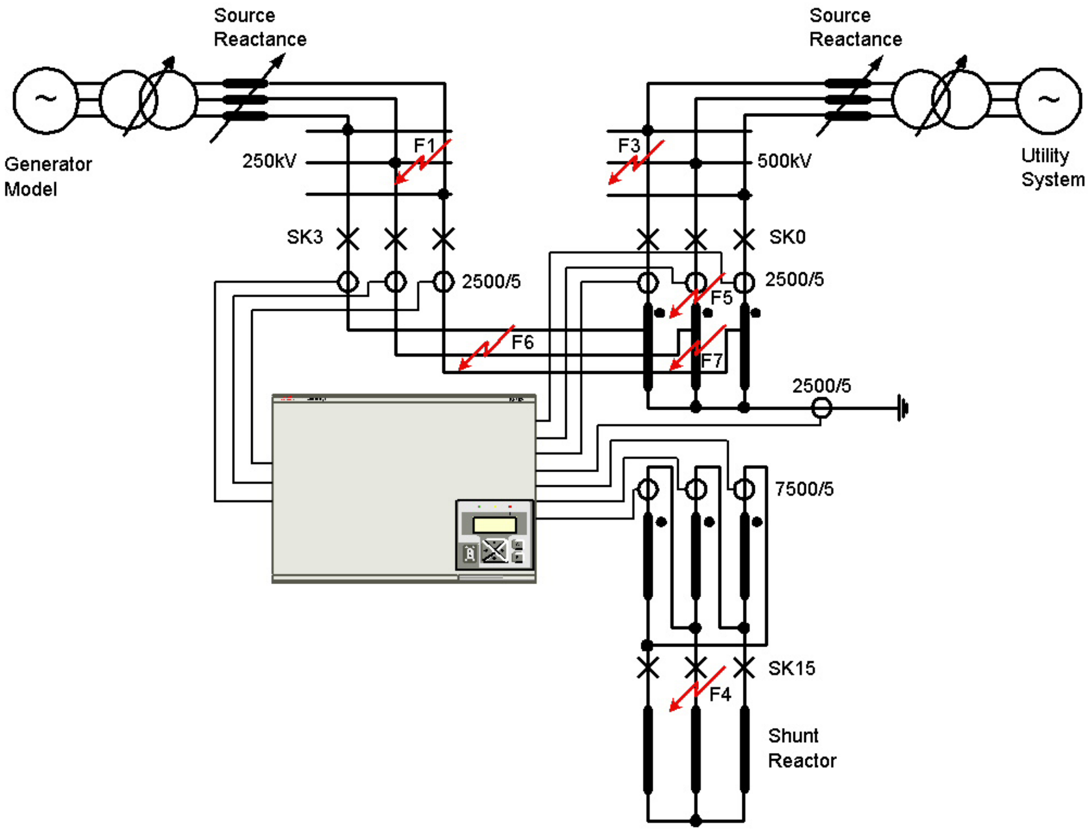

Figure 6. Test system set-up

The serial and common windings of the auto-transformer model consisted of more than twenty coils with independently connectable taps in order to facilitate auto-transformer connections with different turns ratio, faults close to the neutral, inter-turn faults etc.

3.2. Protection System connections and settings

Overall three winding biased differential protection (87T) with additional unrestrained operating level (87H) and the restricted ground-fault differential protection (87G) were enabled in the adaptive differential relay during all tests.

All ten currents were recorded during the tests.
The minimum pick-up current for the transformer differential protection was set to 30% on the protected auto-transformer base of 1082MVA. The differential protection function operating characteristic is given in Figure 7.

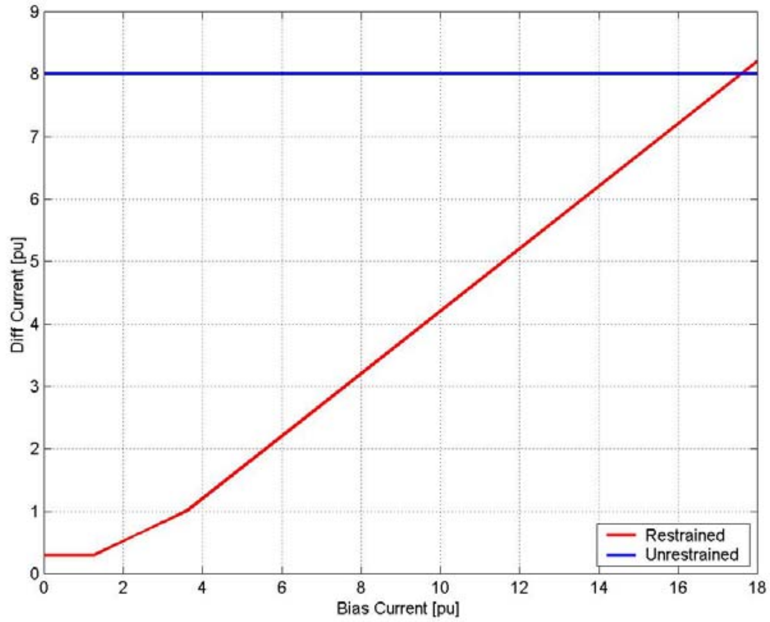

Figure 7. 87T and 87H operating characteristic

The restricted ground-fault 87G measured two sets of three phase currents from 500kV and 250kV sides and one single-phase current from the auto-transformer common neutral point. The minimum pick-up current for the 87G was set to 30% on the base of rated current of the 250kV winding. 87G operating characteristic is given in the Figure 8.

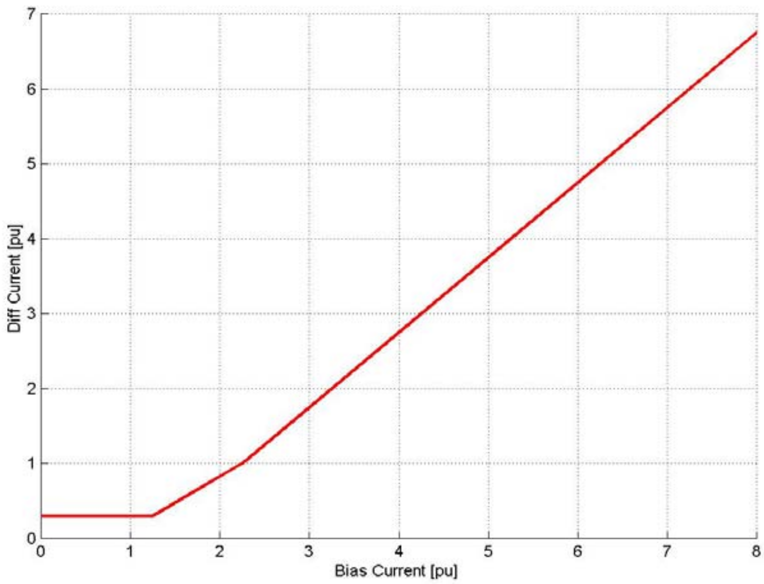

Figure 8. 87G operating characteristic

In the following figures all currents will be shown in per unit [pu] values based on the auto-transformer rated power of 1082MVA as a base.

3.3 Transformer Inrush

The power system model was adjusted in order to obtain big inrush currents. More than ten energizations of the auto-transformer were performed in succession. One of the test cases is shown in Figure 9.

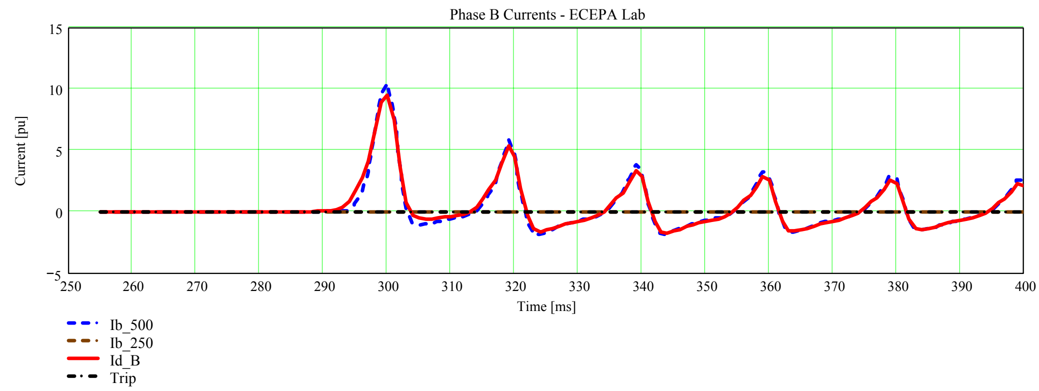

Figure 9. 500kV Inrush Current in Phase B

Adaptive differential relay remained stable for all inrush test cases during testing.

3.4. Internal faults followed by CT saturation

Traditionally the "I2/I1" approach is used to detect the inrush condition. However as stated before, "I2/I1" may delay or prevent the operation of the differential relay for heavy internal faults followed by CT saturation.
To test adaptive differential relay, the second harmonic ("I2/I1") was always active and the set value was 15%. The behaviour of the protection scheme for internal fault followed by CT saturation was recorded as shown in Figure 10.

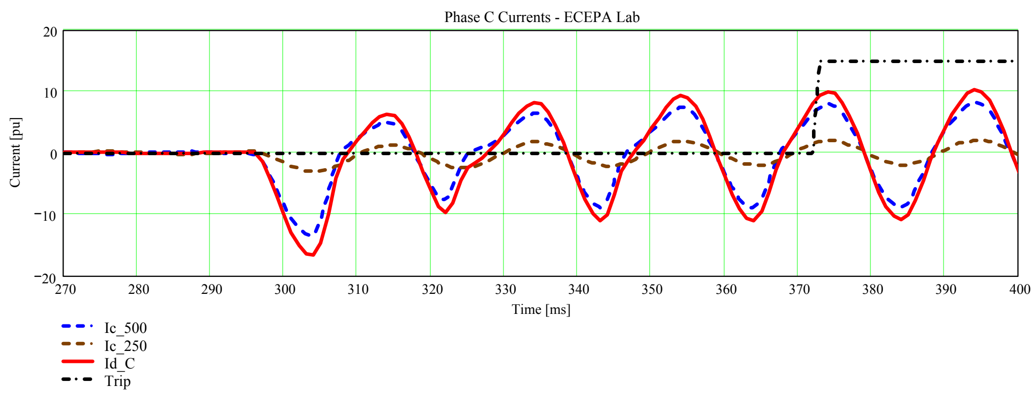

Figure 10. Late 87T trip due to traditional 2nd harmonic blocking criteria

As it can be seen the relay had late operation due to traditional "I2/I1" blocking criteria.
After that adaptive use of the second harmonic blocking as mentioned in 2.2.2.1 was enabled. No other settings were changed. The behaviour of the protection scheme was recorded again and it is shown in Figure 11.

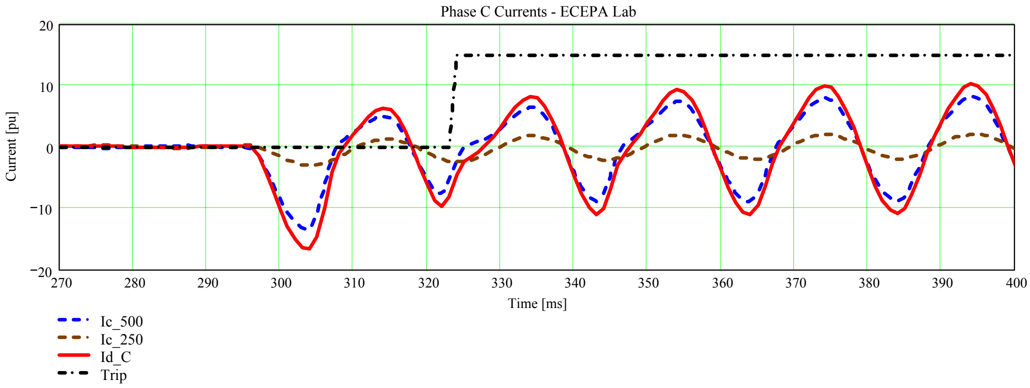

Figure 11. Fast 87T trip due to adaptive 2nd harmonic blocking criteria

These tests show how modern differential protection can adaptively use the second harmonic blocking criteria, resulting in quicker operation for the heavy internal faults with CT saturation.

3.4. Inter-turn faults

Inter-turn faults were simulated in serial, common and low voltage auto-transformer windings. The influence of the different fault locations within the windings was checked. Table 1. summarizes the test results.

Fault Position	Percentage of Short-Circuited turns	Differential current
Common Winding	1%	0.12 pu
Common Winding	2%	0.62 pu
Serial Winding	1%	0.11 pu
Serial Winding	2%	0.55 pu
LV Winding	6%	1.42 pu

Table 1. Summary of inter-turn faults

During these tests, the differential protection detected all inter-turn faults, which had two or more percent of short-circuited turns. One test case is shown here in Figure 12, with the operation of the differential function in 36ms.

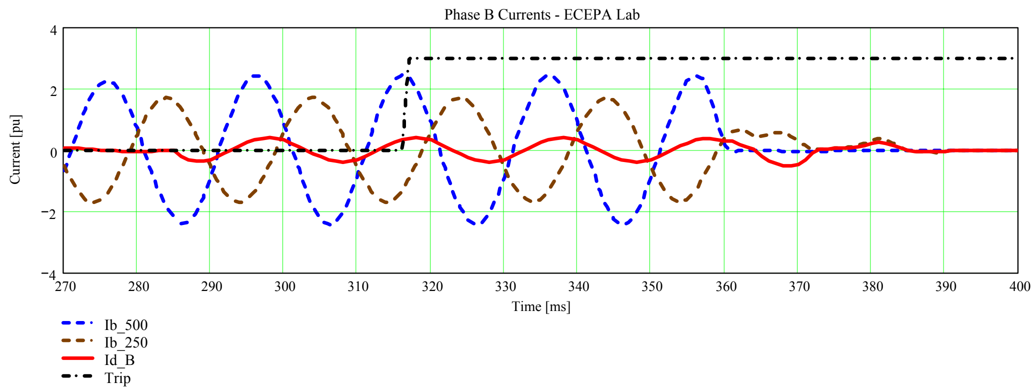

Figure 12. 2% inter-turn fault in the common auto-transformer winding

3.5. Internal winding-to-ground faults

For winding-to-ground faults, the fault voltage varies from full phase-ground voltage for faults close to the windings bushings to small values for the faults close to auto-transformer neutral point.
The most difficult faults to be detected are those close to the neutral point.
The 87G and 87T are the main differential protections for this type of faults. However due to the fact that ground current is always high for this type of faults, 87G has shown distinct advantages over the 87T during these tests. Table 2. summarizes the test results for several tests cases.

Fault Position	Percent of involved turns	Fault Resistance	Neutral Current
Common Winding	1% from neutral	0 Ohms	8.4 kA
Common Winding	2% from neutral	0 Ohms	10.0 kA
Common Winding	2% from neutral	6.5 Ohms	0.75 kA
Common Winding	4.3% from neutral	6.5 Ohms	1.6 kA
250kV Bushing	50% from neutral	0 Ohms	13.2 kA
500kV Bushing	100% from neutral	0 Ohms	9.9 kA
500kV Bushing	100% from neutral	60 Ohms	3.0 kA
500kV Bushing	100% from neutral	100 Ohms	1.9 kA

Table 2. Summary for winding-to-ground faults

3.6 Heavy external faults and evolving faults

In order to test external fault detection logic whole series of tests were conducted. First, relay operation during heavy external fault condition, followed by CT saturation was checked. Additional resistance was added in the secondary circuits of 500kV CTs in order to cause quick CT saturation on HV side. As an example one external C-Ground fault is presented here. Differential relay remained fully stable in spite of heavy CT saturation as shown in Figure 13.

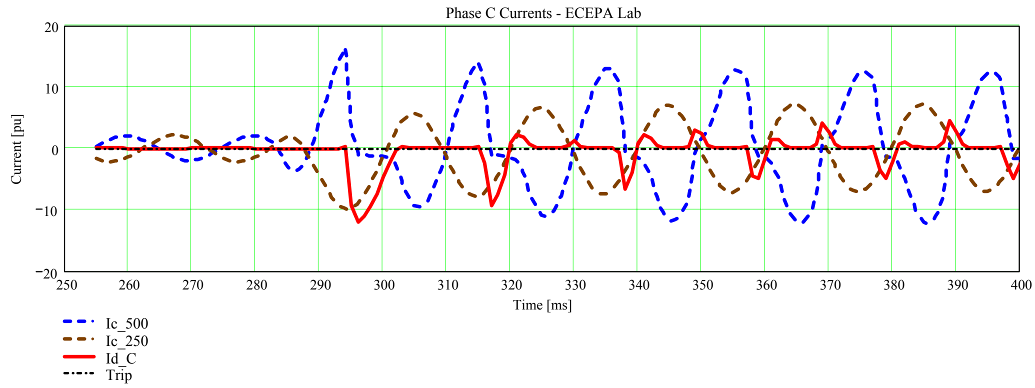

Figure 13. Heavy C-Ground external fault followed by CT saturation

After this, in order to check behavior of external fault detection logic for changing fault position, several evolving faults was simulated. One such test case will be presented here as an example.

During this test case, first C-Ground external fault with CT saturation was applied. Then 42ms after first fault, internal B-Ground fault was applied. Differential relay (87T) tripped in 32ms after inception moment of internal fault. For more details refer to Figures 14 & 15.

These tests proved that the external fault detection logic does not block the differential relay, but it only properly restrain relay operation for heavy external faults followed by CT saturation. If the fault position then changes to internal, the adaptive differential relay will properly operate and disconnect the faulty transformer.

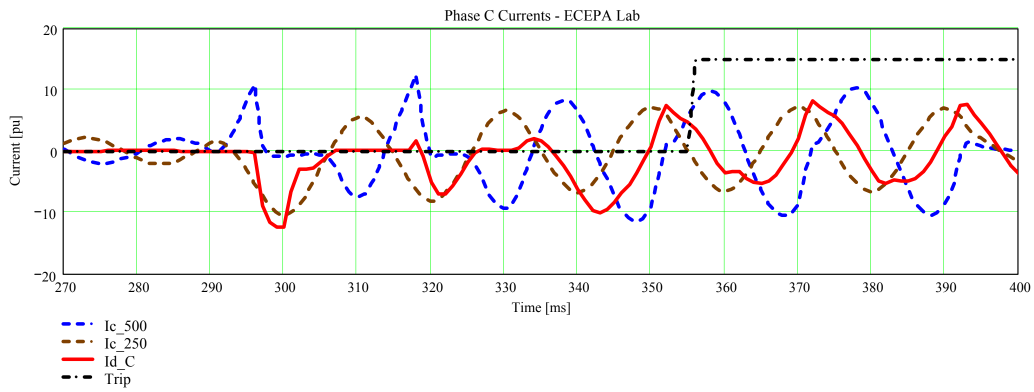

Figure 14. Relay Phase C Currents for Evolving C-Ground external to B-Ground internal fault

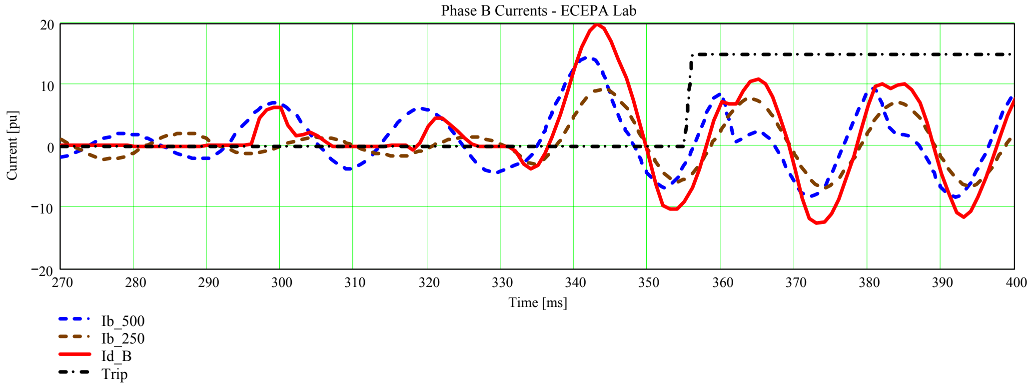

Figure 15. Relay Phase B Currents for Evolving C-Ground external to B-Ground internal fault

4. Field experience

4.1 Power Transformer Inrush Currents

Two inrush cases for 250/250/50MVA, 400/123±8*1,5%/31.5kV auto-transformer will be presented.
As it can be seen from Figures 18 & 19 the typical inrush currents for big auto-transformer have relatively small pick values (1-3pu), but their duration can be quite long, when auto-transformer is energized from strong 400kV network which has big X/R ratio. Inrush current picks up and inrush duration is much smaller when the same auto-transformer is energized from weaker 110kV network with comparatively smaller X/R ratio. It shall be noted that in both cases differential relay was properly restrained from operation during inrush conditions.

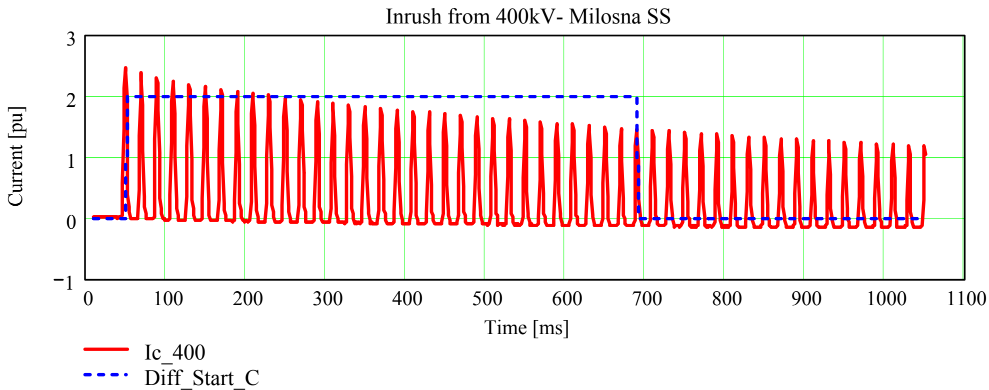

Figure 18. Phase C Current during inrush from 400kV side

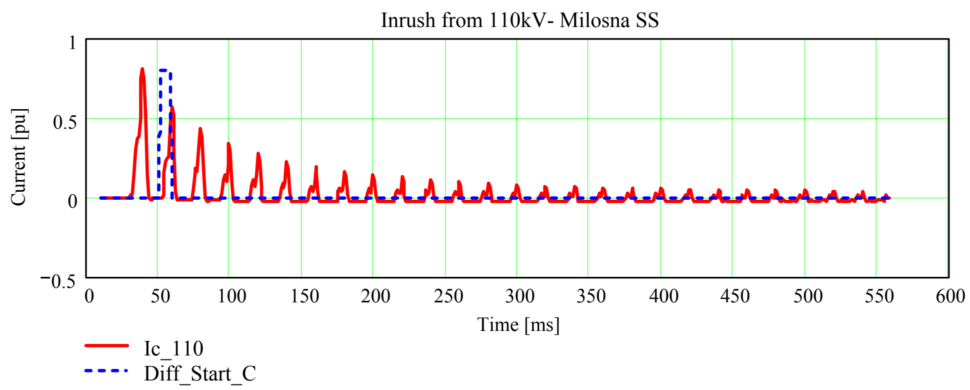

Figure 19. Phase C Current during inrush from 110kV side

4.2 Long Lasting External Fault

Phase to ground fault on phase C pole of HV circuit breaker of the three-winding auto-transformer with the rated data: 150/150/30MVA; 220±12*1,25%/115/10.5kV. For differential protection it was external fault just a couple of feet outside of the protected zone.

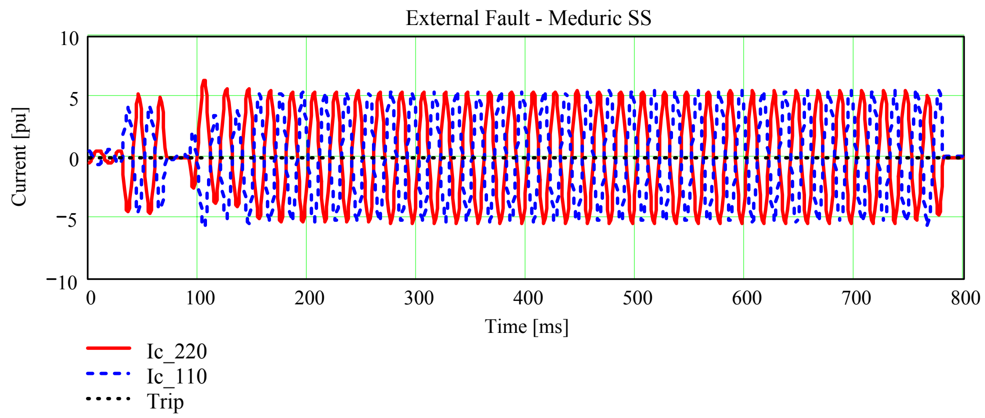

Figure 20. Fault Summary for Phase C from Meduric Substation

HV CB pole as well failed to open (see Figure 20) and external fault for transformer differential protection lasted for 700ms until cleared from 110kV side. Differential protection remained fully stable during this disturbance.

4.3 Low Level Internal Fault

Proper operation of the differential protection function for the internal fault located on the tertiary bushings of the three-winding auto-transformer with the following data: 300/300/100MVA; 400/115/31.5kV is presented in Figures 21 & 22.

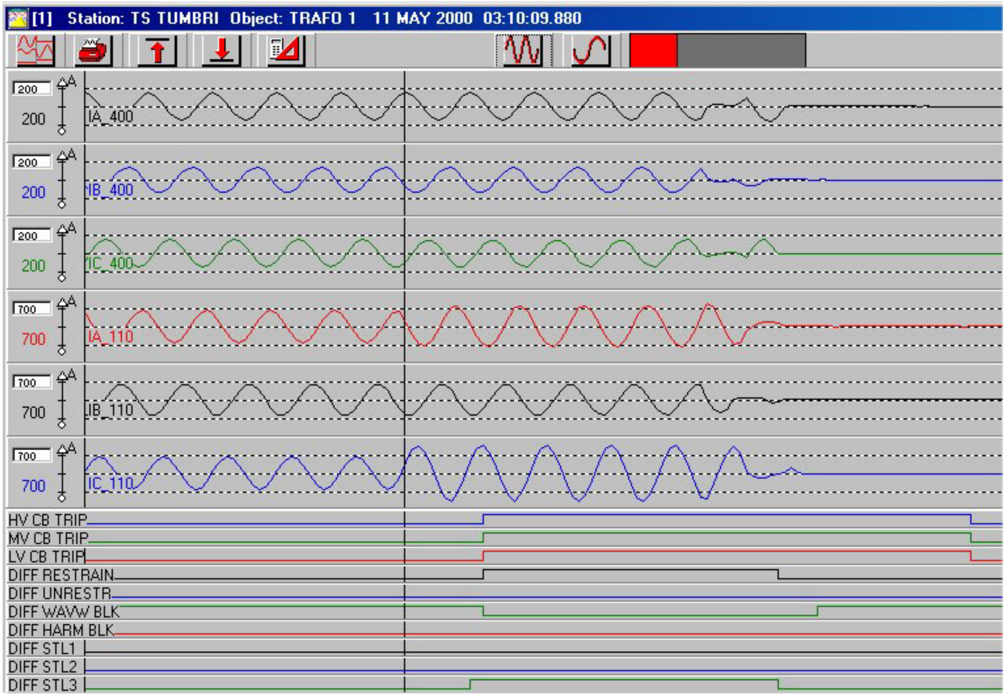

Figure 21. Disturbance Recording for internal fault in Tumbri Substation

For this low-level internal fault, where fault current is limited by the auto-transformer impedance, differential function operated in only 30ms from the moment of fault inception.

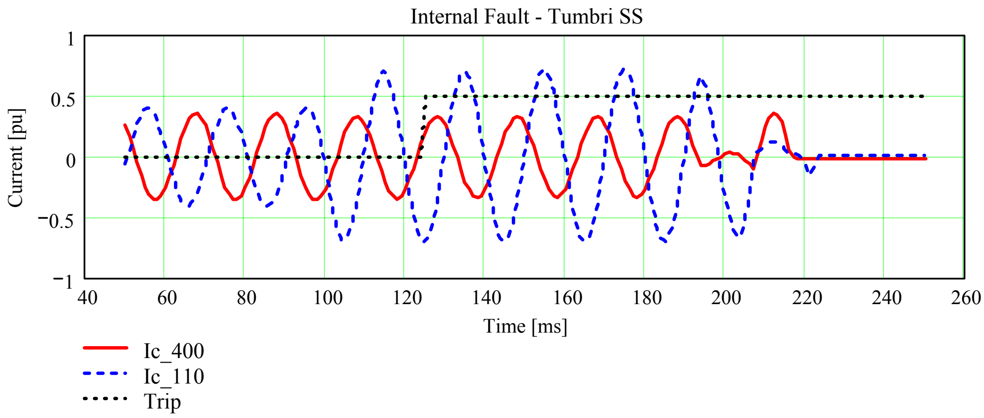

Figure 22. Fault summary for phase C from Tumbri substation

5. Conclusion

Modern numerical transformer differential protection with adaptive features exhibits the following capabilities:

- Detect and trip all winding-ground faults, even the one located one percent away from the neutral point (with help of 87G function)
- Detect and trip all transformer inter-turn faults with two or more percent of short-circuited turns
- Detect and trip with high speed all internal phase-to-ground & phase-to-phase faults
- Detect and trip all evolving internal faults
- Remain stable for all inrushes
- Remain stable for all external faults regardless the heavy CT saturation

This means that the adaptive numerical differential protection has better performance than the previous analog or electromechanical generation of transformer differential relays. It has high speed of operation, complete stability for external faults and very low requirements on the main current transformers. At the same time it offers all the other benefits of numerical technology such as communication, self-supervision, disturbance recording, no need for auxiliary CTs to match the different CT ratios etc.

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