Making sense of adaptive techniques to improve the stability of generator differential protection and its testing methods

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Abstract: Protective relays have evolved from a single phase, single function protection only devices to multifunction protection, control and communication devices. With the advancement in relay technologies, power system industry has gained a lot in terms of monitoring, diagnostics and adaptivity of protection and control. Standard schemes based on single contingency have evolved to adaptive systems based on specific conditions of the system at a given time.

Advanced microprocessor generator differential protection relays have incorporated techniques to enhance the stability of the differential protection, commonly referred to as high security mode. In the high security mode, the stability is enhanced by a DC restraint feature which decreases the sensitivity of the differential protection for a temporary period to avoid unnecessary disconnection of a machine during external fault that has a fault current with high DC current. The stability of differential protection is further enhanced by a CT saturation-based blocking which prevents unnecessary tripping in case of the detection of magnetizing inrush currents which can be present at the switching operation, over voltages or external faults. Additionally, CTs can saturate due to a high fault current magnitude. Such AC saturation does not happen immediately when the fault begins. The monitoring function of the differential protection sees the fault as external because of the high bias current and low differential current. However, if the AC saturation then occurs, the CT saturation-based blocking prevents an undesired tripping. The real challenge is however to test these adaptive techniques during the acceptance testing.

This paper discusses these adaptive techniques and present the analysis of a real fault in which the generator protection tripped for an out of zone event. It then compares how the false operation could have been avoided by employing the adaptive feature. Some methods to test the high security adaptive features is also addressed.

Key words- Generator differential protection, synchronous machine differential protection, 87G, 87M, CT saturation, AC saturation, DC saturation, adaptive techniques, adaptive protection, CT saturation-based blocking, DC restraint, CT selection, stability, security, fault current modeling, adaptive protection testing, playback testing, biased differential protection

I. INTRODUCTION

Protective relays have evolved from a single function device to multifunction device with advanced programming and communication capabilities. For a protection engineer, selectivity of fault detection is an important consideration apart from the stability and security of operation. The advanced microprocessor technology has enabled protective relay vendors to design traditional protection elements with adaptive capabilities to automatically adjust the parameters to varying system conditions thus enhancing the stability and security of its operation. The paper begins with the description of adaptive relaying. Next it focuses on Generator differential (87G) protection - the principle, the challenges to ensure secure operation and the adaptive techniques employed to overcome these challenges. There is a section on CT selection and its modelling tools as it is an important criteria of a stable different protection scheme. Further, the paper delve into the analysis of a real world misoperation event and discuss how proper implementation of the adaptive techniques will improve the stability of the protection. The paper ends with some suggested methods to test the adaptive features and the conclusion.

II. WHAT IS ADAPTIVE PROTECTION?

A. *Adaptive system*

An adaptive system is a system that changes its behavior in response to its environment. An example of adaptation is the growth of a plant around obstacles. Without obstacles a plant will grow according to a certain pattern. The growth of a plant will change if there are obstacles, and the specific change that occur depends on the arrangement of obstacles. We say that the plant adapted to its environment. [1]

B. *Adaptive relaying*

Conventional protection system has relays with fixed setting parameters. As soon as protection uses an outside variable to change an operating characteristic it becomes adaptive. [2]. Adaptive protection is defined by Horowitz, Phadke and Thorp as “a protection philosophy which permits and seeks to make adjustments to various protection functions in order to make them more attuned to prevailing power system conditions.” [4]

Adaptive relaying utilizes the continuously changing status of the power system as the basis for online adjustment of the power system relay settings. Consequently, it provides the required flexibility for obtaining very high levels of power system reliability. Digital relays with adequate software and communication capability make these devices ideal for implementing adaptive relaying concepts. [5] Adapting the behavior of the protection system to any change in their environment has become a necessity. [3]. Standard schemes based on single contingency have evolved to adaptive systems based on specific conditions of the system at a given time. Modern microprocessor relays provide the user with a flexibility in design to levels that were not even dreamed with electromechanical relays. [6]

The use of these adaptive algorithms can increase both the security and the dependability of the protective system. There are several methods to detect changes in the different factors that affect the operation of the relays. Some of the relay features that allowed the relays to adapt to changes in the relay condition are:

- Frequency tracking
- Multiple setting groups
- Programmable logic
- Adaptive restrained differential characteristic
- Voltage transformer supervision
- Circuit transformer supervision
- Changes in Substation configuration
- Adapting to loss of protection relays [3]

III. GENERATOR BIASED DIFFERENTIAL (87G) PROTECTION

A. *87G operation principle*

A short circuit between the phases of the generator stator windings normally causes large fault currents. The short circuit creates a risk of damages to the insulation, windings and stator core. The large short circuit currents cause large current forces which can damage other components in the machine. The short circuit can also initiate explosion and fire. When a short circuit occurs in a machine, there is a damage that must be repaired. The severity and the repair time depend on the degree of damage, which is highly dependent on the fault time. Therefore, the fast fault clearance of this fault type is of greatest importance to limit the damages and the economic loss. The fault current contributions from both the external power system (via the machine or the block circuit breaker) and from the machine itself must be disconnected as fast as possible. Although the short circuit fault current is normally very large, that is, significantly larger than the rated current of the machine, it is possible that a short circuit can occur between phases close to the neutral point of the machine, causing a relatively small fault current. The fault current fed from the synchronous machine can also be limited due to a low excitation of the synchronous generator. This is normally the case at the run-up of the synchronous machine, before synchronization to the network. Therefore, it is desired that the detection of the machine phase-to-phase short circuits shall be relatively sensitive, thus detecting the small fault currents. It is also important that the machine short circuit protection does not trip for external faults when a large fault current is fed from the machine. To combine fast fault clearance, sensitivity and selectivity, the machine current differential protection is normally the best alternative for the phase-to-phase short circuits.

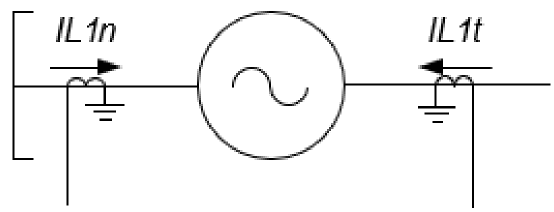

Figure 1 – Positive direction of the current

The differential protection works on the principle of calculating the differential current at the two ends of the generator winding, that is, the current entering the winding is compared to the current exiting the winding. In case of any internal fault, the currents entering and exiting the winding are different, which results in a differential current, which is then used as a base for generating the trip signal. Based on this principle, the differential protection is not expected to trip during external faults. 87G element has a differential calculation module (DCM) which calculates the differential current. The differential current is the difference in current between the phase and neutral side of the machine. The phase currents $I1$ and $I\,2$ denote the fundamental frequency components on the phase and neutral sides of the current. The amplitude of the differential current Id is obtained using the equation (assuming that the positive direction of the current is towards the machine):

$$I_d = \left|\bar{I}_1 + \bar{I}_2\right|$$

During normal conditions, there is no fault in the area protected by the function block, so the currents $I1$ and $I\,2$ are equal and the differential current Id = 0. However, in practice some differential current exists due to inaccuracies in the current transformer on the phase and neutral sides, but it is very small during normal conditions. The DCM calculates the differential current for all three phases. The low-stage differential protection is stabilized with a bias current. The bias current is also known as the stabilizing current. Stabilization means that the differential current required for tripping increases according to the bias current and the operation characteristics. When an internal fault occurs, the currents on both sides of the protected object are flowing into it. This causes the biasing current to be considerably smaller, which makes the operation more sensitive during internal faults.

The traditional way for calculating the stabilized current is:

$$I_b = \left| \frac{\bar{I}_1 - \bar{I}_2}{2} \right|$$

The current differential protection needs to be biased because of the possible appearance of a differential current which can be due to something else than an actual fault in the machine. In case of differential protection, a false differential current can be caused by (1) CT errors and (2) CT saturation at high currents passing through the machine. The differential current caused by CT errors increases at the same percent ratio as the load current. The high currents passing through the protected object can be caused by the through fault. Therefore, the operation of the differential protection is biased with respect to the load current. In the biased differential protection, the higher the differential current required for the protection of operation, the higher the load current.

B. 87G operation characteristic

A typical 87G operating characteristic is shown in Figure 2.

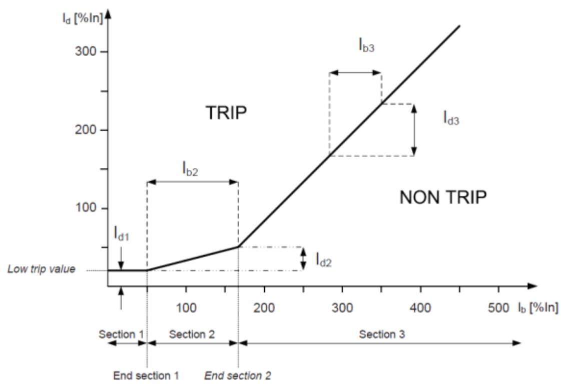

Figure 2 - Typical 87G operation characteristic

The *Low trip value* setting for the stabilized stage of the protection element is determined by the equation:

$$Low\,trip\,value = \frac{I_{d1}}{I_n} \cdot 100\%$$

The *Slope section 2 and section 3* settings are determined correspondingly by the equations:

$$Slope\,section\,2 = \frac{I_{d2}}{I_{b2}} \cdot 100\%$$

$$Slope\,section\,3 = \frac{I_{d3}}{I_{b3}} \cdot 100\%$$

The slope of the operating characteristic for the function block varies in different parts of the range. In section 1, where 0.0 < Ib/In < *End section 1*, the differential current required for tripping is constant. The value of the differential current is the same as the *Low trip value* setting selected for the function block. The *Low trip value* setting allows for small inaccuracies of the current transformers, but it can also be used to influence the overall level of the operating characteristic. Section 2, where *End section 1* < Ib/In < *End section 2*, is called the influence area of the setting *Slope section 2*. In this section, variations in *End section 2* affect the slope of the characteristic, that is, how big the change in the differential current required for tripping is in comparison to the change in the load current. The *End section 2* setting allows for CT errors. In section 3, where Ib/In > *End section 2*, the slope of the characteristic can be set by *Slope section 3* that defines the increase in the differential current to the corresponding increase in the biasing current. The required differential current for tripping at a certain stabilizing current level can be calculated using the formulae:

For a stabilizing current lower than *End section 1*

Idoperate[%*In*] = Set *Low trip values*

For a stabilizing current higher than *End section 1* but lower than *End section 2*

Idoperate[%*In*] = *Low trip value* + (*Ib*[%*In*]− *End section 1*) × *Slope section* 2

For higher stabilizing current values exceeding *End section 2*

Idoperate[%*In*] = *Low trip value* + (*End section* 2 − *End section* 1) × *Slope section* 2 + (*Ib*[%*In*]− *End section* 2)

IV. 87G OPERATION CHALLENGES

External short circuits result in the generator delivering large current to the fault. It is very important that the differential protection does not operate in case of such external short circuits. However, there is a risk of generator differential protection misoperation if a CT saturates. The risk of an unwanted differential protection operation caused by the current transformer saturation is a universal challenge for differential protection operation. If a large synchronous machine is tripped in connection to an external short circuit, it gives an increased risk of a power system collapse. Besides, there is a production loss for every unwanted trip of the machine. Therefore, preventing the unwanted disconnection of machines has a great economical value.

There are basically two types of saturation phenomena that must be detected: the AC saturation and the DC saturation. The AC saturation is caused by a high fault current where the CT magnetic flux exceeds its maximum value. As a result, the secondary current is distorted as shown in Figure 3.

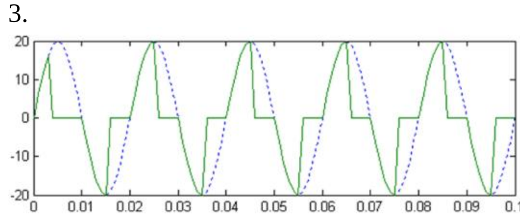

Figure 3 - AC saturation of the CT

A DC component in the current also causes the flux to increase until the CT saturates. This is known as DC

saturation. During a short circuit fault in the power line, the short circuit current contains a DC
component. The magnitude of the DC component depends on the phase angle when the short circuit occurs. Figure 4 shows the secondary current of the CT in the fault situation. Because of the DC component, the flux reaches its maximum value at 0.07 seconds, causing saturation. As the DC component decays, the CT recovers gradually from the saturation.

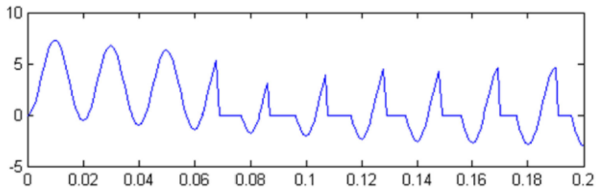

Figure 4 - DC saturation of CT

Close to power stations, the time constant of the DC-component of the short circuit current may be very long and in the order of 100 to 150ms. External short circuits with a fully developed DC-component puts severe demands on CT and differential protection.

V. ADAPTIVE TECHNIQUES TO ENHANCE STABILITY & SECURITY OF 87G OPERATION

The module diagram of a modern 87G protection element is shown in Figure 5. The Differential calculation module calculates the differential current as explained in Section III above. The through-fault (TF) detection module is for detecting whether the fault is external, that is, going through, or internal. This information is essential for ensuring the correct operation of the protection in case of the CT saturation. In a through-fault situation, CTs can saturate because of a high fault current magnitude. Such AC saturation does not happen immediately when the fault begins. The TF module sees the fault as external because the bias current is high, but the differential current remains low. However, if the AC saturation then occurs, a CT saturation-based blocking prevents the tripping of the element. Normally, the phase angle between the machine neutral and line side CTs is 180 degrees. If an internal fault occurs during a through fault, an angle less than 50 degrees clearly indicates an internal fault and the TF module overrules, that is, deblocks the presence of any blocking due to CT saturation.

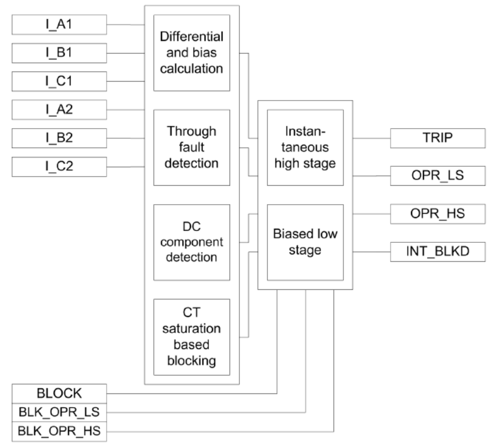

Figure 5 - Modern 87G element module diagram

A. *DC component detection and DC restrain*

On detection of a DC component, the function temporarily desensitizes the differential protection. The functioning of this module depends on the *DC restrain Enable* setting. The DC components are continuously extracted from the three instantaneous differential currents. The highest DC component of all three is taken as a kind of DC restraint in a sense that the highest effective, temporary sensitivity of the protection is temporarily decreased as a function of this highest DC offset. The calculated DC restraint current is not allowed to decay (from its highest ever measured value) faster than with a time constant of one second. The value of the temporarily effective sensitivity limit is limited upwards to the rated current of the machine or 3.3 times that of *Low trip value*, whichever is smaller. The temporary extra limit decays exponentially from its maximum value with a time constant of one second. This feature should be used in case of networks where very long-time constants are expected. The temporary sensitivity limit is higher to the set operating characteristics. In other words, the temporary limit has superposed the unchanged operating characteristics and temporarily determines the highest sensitivity of the protection. The temporary sensitivity is less than the sensitivity in section 1 of the operating characteristic and is expected to prevent an unwanted trip during the external faults with lower currents. This feature is effective at moderate through currents and ineffective at higher through-currents.

B. *CT saturation-based blocking*

Higher currents during the motor startup or abnormally high magnetizing currents at an overvoltage (transformer-fed motor) or an external fault may saturate the current transformers. The uneven saturation of the neutral and line side CTs (for example, due to burden differences) may lead to a differential current which can cause a differential protection to trip. This module blocks the operation of 87G biased low stage internally in case of the CT saturation.

Once the blocking is activated, it is held for a certain time after the blocking conditions have ceased to be fulfilled.

Based on the conditions checked from the through-fault module, the DC (component) detection module and the CT saturation-based blocking modules, the biased low-stage module decides whether the differential current is due to the internal faults or some false reason. In case of detection of the TF, DC or CT saturation, the internal differential blocking signal is generated, which in turn blocks the trip signal. In case of internal faults, the operation of the differential protection is affected by the bias current. As stated earlier, phase angle difference between the two currents I_A1 and I_A2 is theoretically 180 electrical degrees for the external fault and 0 electrical degrees for the internal fault conditions. If the phase angle difference is less than 50 electrical degrees or if the biasing current drops below 30 percent of the differential current, a fault has most likely occurred in the area protected by 87G. Then the internal blocking signals (CT saturation and DC blocking) of the biased stage are inhibited.

VI. CURRENT TRANSFORMER REQUIREMENTS FOR 87G PROTECTION

A. Greenfield projects

The performance requirement of CTs can be stated in several ways, for example as knee-point voltage. For the discussion of this paper we have expressed CT requirement in terms of *actual accuracy limit factor* (actual K_{ALF}). Actual K_{ALF} means that how many times of the nominal current of the CT the fault current can be, without exceeding the measurement error given by the class of the CT, assuming the fault current is sinusoidal and without DC component.

In IEC standards, a class CT is defined by its ratio, class, nominal accuracy limit factor and rated burden. In addition, the internal burden is relevant. If CTs defined by ANSI standards are used, the accuracy limit factor can be converted to knee-point voltage. Converting the rated accuracy limit factor of the CT, *Kalf*, into the rated equivalent limiting secondary voltage *Eal:*

$$E_{al} = K_{alf} \cdot (R_{ct} + R_b) \cdot I_{sn}$$

where
Kalf is the rated accuracy limit factor of the CT,
Rct is the secondary winding resistance (internal burden resistance) (unit: ohm),
Rb is the rated value of the secondary connected resistive burden (unit: ohm) and
Isn is the rated secondary current (1A or 5A)

Rated knee-point voltage *Ek*:

$$E_k = \frac{B_k}{B_{al}} \cdot E_{al} \approx 0.8 \cdot E_{al}$$

where
Bk is the flux density level at which the knee-point is defined at, typical value: 1.5 T and
Bal is the flux density level at which the accuracy limit factor is defined at, typical value: 1.9 T

For example:

- Ratio 2000/5A
- Class 5P10
- Rated burden S_n 35 VA, corresponding connected resistance Rb = 35 VA /5^2 A^2 = 1.4 Ω
- Internal resistance R_{ct} 0.6 Ω, corresponding internal burden S_{in} = 15 VA

$$E_{al} = 10 \cdot (0.6\Omega\ + 1.4\ \Omega\ ) \cdot 5A = 100\ V$$

Knee-point voltage

$$E_k \approx 0.8 \cdot 100\text{V} = 80\ \text{V}$$

In general, in new installations the CTs are chosen according to CT requirements, which are given as

$$F_a > K_r \times Ik_{max} \times K_{td}$$

In which,
Ik_{max} The maximum through-going fault current (in IR) at which the protection is not allowed to operate
This is the AC component of the fault current.
K_{td} Transient dimensioning factor. This factor is needed to account the decaying DC component of the fault current.
Kr The remanence factor 1/(1-r), where r is the maximum remanence flux in pu from the saturation flux.

The relay manufacturer documents the specific requirements for each function.

While the CT dimensiong involves many variables, for the relay algorithm the whole requirement is reduced to just one parameter, *Time-to-saturate*. For 87G (MPDIFF) function this is one half cycle of the power system, i.e 8.3 ms for 60 Hz (10 ms for 50 Hz) system. When a short circuit occurs, the first half-cycle of the fault should be measured correctly. After that, saturation of the CT does not cause a false trip for out-of-zone fault or prevent the trip for an in-zone fault.

B. Retrofit projects

In completely new installations the workflow for selecting CTs is straight forward. First the requirements for the CTs are calculated and then the CTs are chosen accordingly. In relay retrofit projects the situation is different. At the minimum, a relay retrofit project consists of replacing old relays with new ones, while the functionality remains the same as original.

Let us consider a typical case. Since the service life of protection relays is shorter than that of the primary equipment, at some point it becomes necessary to replace the original relays with new ones. The CTs, on the other hand, being passive components made of iron, copper wire and insulation materials and no moving parts, are among the components of longest expected service life in the generator installation. So, the situation in a relay retrofit project is reversed when compared to a new installation. The CTs are given as they are, and the new relay needs to be chosen so that it can perform the required protection applications reliably. Therefore, a relay with low requirements for CTs have an advantage; they can be used, while relays with higher requirements for CTs may not.

When the old relay to be replaced is an electro-mechanical one, a modern microprocessor relay has one favorable advantage: the lower burden of the current measurement input means that the existing CTs will perform better with the new relays. Another advantage is, that one new relay has several protection functions in the same physical device, while the old electro-mechanical protection could have had several physical relays connected to the same core of the CT.

Let us look at the 2000/5 A CT of the previous example. The external burden consists of an advanced microprocessor relay, which has a burden of 0.5 VA with 5A nominal current. Assuming burden of 4.8 VA from wiring, the external burden becomes 5.3 VA.

The actual accuracy limit factor becomes:

$$F_a = F_n \times \frac{S_{in} + S_n}{S_{in} + S_a} = 10 \times \frac{(15 + 35)\,VA}{(15 + 5.3)\,VA} = 24.6$$

Since the existing CTs perform better with new relays, this raises the question that - maybe - some protection functions which were not in the original scope, could now be taken into use. If the protected generator has small rated power, it is possible that in the original design the differential protection has been left out, for example because of price considerations. But now it perhaps could be used, since it is available in the new relay's functionality. When the protection functionality in expanded, we are not talking about just relay retrofit anymore. Instead, we are *upgrading* the protection system. This brings added value to the projects with only minor additional cost in form of commissioning testing of the new functionality.

C. *Tools for modeling of CT and the fault current*

For checking the CT requirements, the properties of the CTs, the wiring and the generator itself must be known. One complicating factor is, that the trough-fault current produced by the generator is not constant. There is the sub-transient, transient and steady-state fault current. Which one of them should be used as Ik_{Max} in the formula [3]?

The magnetic flux in the iron core of the CT is the integral of the current. If the value of the flux is to be modeled accurately, then the first step is to model the fault current accurately. In following, fault current and behavior of CT is studied using Matlab software. The purpose of the study is to find out if the set of CTs can be used for differential protection for a given generator.

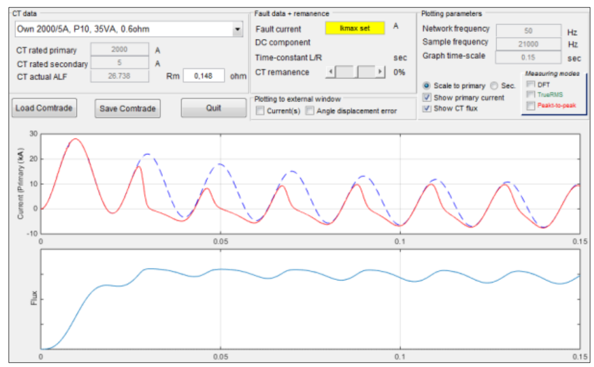

Figure 6 - Modeling of fault current and a CT (Upper graph shows current and lower the magnetic flux)

Fault current is simulated for the generator specified below. The CTs are the same as in previous examples.

Generator type	Synchronous generator
Rated output and voltage	35 MVA, 10.5 kV, 50 Hz
Full load current (FLC),	Ir 1925 A
Reactances	Xd 216 %
	Xd' (unsat/sat) 30/28 % Td' 1.14 s.
	Xd''(unsat/sat) 20/17 % Td'' 0.036 s.
CTs	2000/5A (of the previous example)

First the fault current magnitudes are calculated using the reactance of the machine. For generator differential protection the most demanding case is, when the fault is an external one (outside of the protected area defined by the CT locations), but located very close, so that the fault current is not limited by other impedances like the step-up transformer. Fault current calculated this way is the maximum trough-fault current.

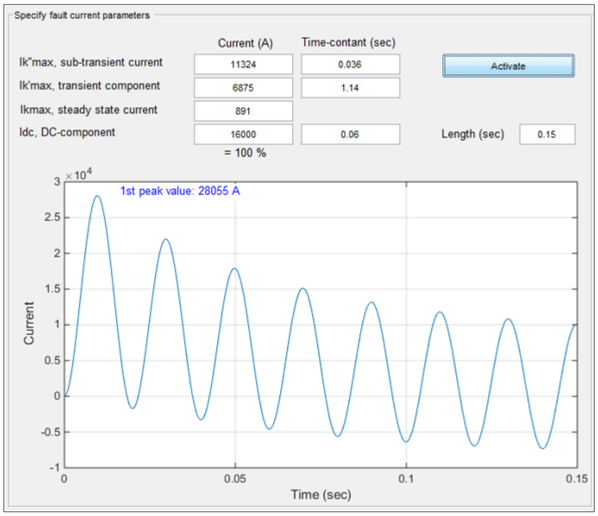

Figure 7 - Fault current specification

Then the CT behavior is analyzed. For checking if the CTs are capable to measure fault current for 10 ms without saturation (50Hz system), a simplified CT-model is enough. As input information, only the ratio and the actual accuracy limit factor of the CT is needed.

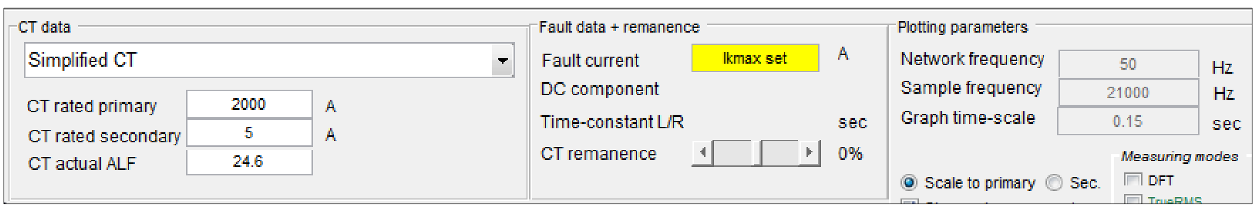

Figure 8 - Simplified CT model for simulation

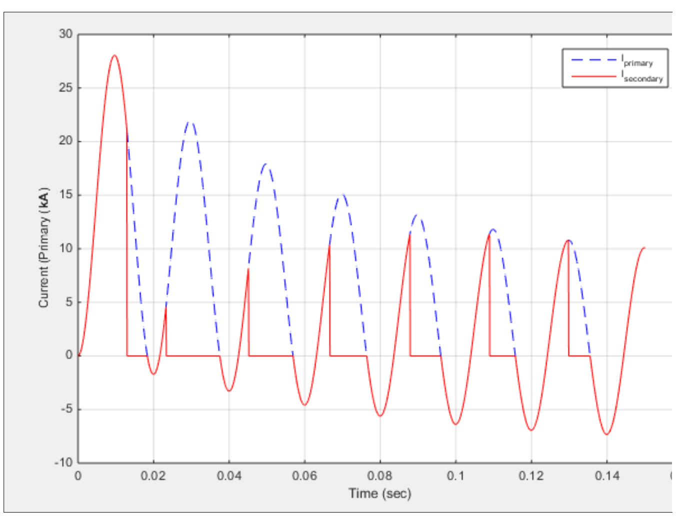

Figure 9 - Result of simulation

The real primary current is in blue, and the current measured by the relay in red (secondary current is scaled as a primary value for comparison).

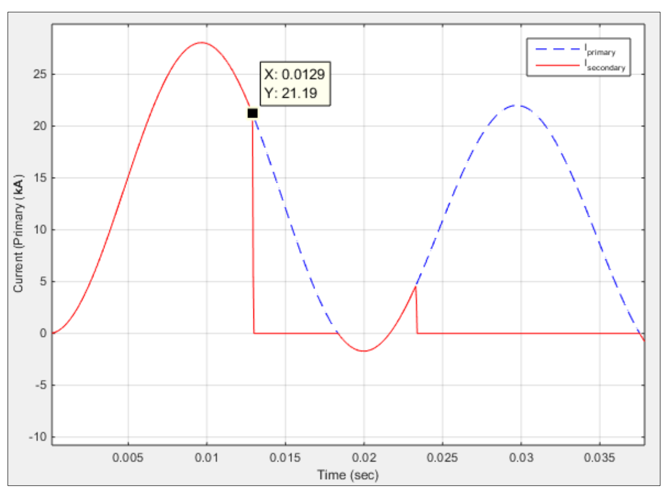

Figure 10 – Zoom-in view at the beginning of the fault

The CT saturates at time of about 13 ms => the CT is adequate for the application.

VII. ANALYSIS OF A REAL FAULT INCIDENT

A. Background

Many modern ships are equipped with electrical propulsion systems. Electrical propulsion offers many advantages over direct diesel engine drive, like better maneuverability and lower vibration and noise for the ship. It's also more economical, especially in lower speeds. For ice breakers, electrical drive has been used for longer time, for its ability to provide torque even in the condition when the propeller is jammed in ice.

Typically, the electrical system of such ships is powered by several small diesel generators rather than for example two large machines. A configuration of a cruise ship can be for example six diesel generators and two main propulsion drives. The rated power of the propulsion drive is then much higher than that of a diesel generator. The propulsion drive consists of a synchronous motor, which is fed by a frequency converter. The first component of the frequency converter is a transformer.

B. Fault description

The inrush current of such converter-feeding transformer is obviously considerable, due to the large rated power of the transformer compared with rated power of generator. The example case shows a false trip of generator differential protection in case of an external event, which is inrush current of a large transformer's energization.

Rating of protected machine

Sn =16 MVA

Un =11 kV

Differential protection settings

- Rated current (pu) = 840A
- Low operate value = 15%
- Slope section 2 = 20%
- End section 1 = 50%
- End section 2 = 150%

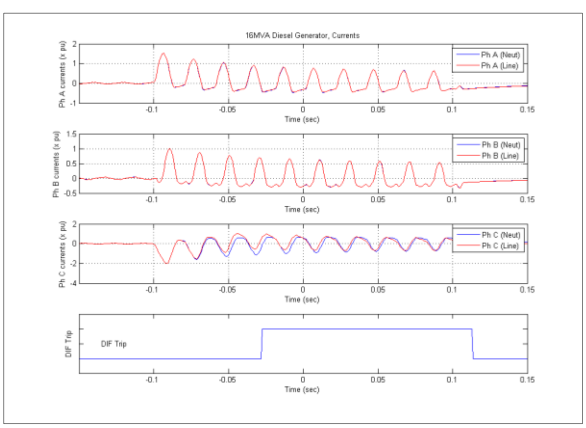

Figure 11 - Phase currents of the 16 MVA diesel generator

Neutral side currents are plotted in blue, while line side currents are in red. The currents match very well for phases A and B, but For Phase C there is a notable difference.

C. A closer look at phase C current

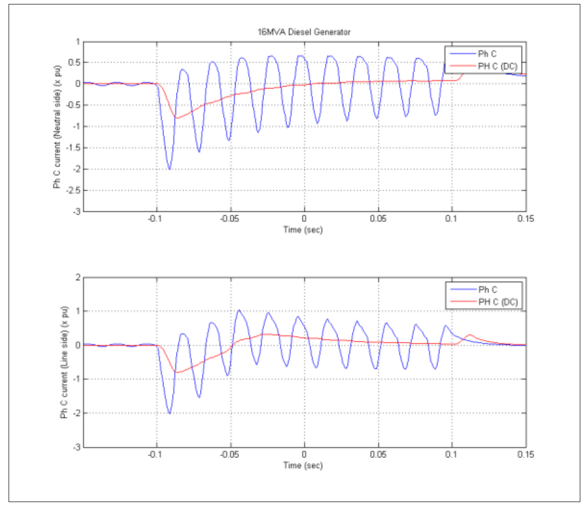

Figure 12 - Phase C currents, neutral side (top) and line side (bottom). The DC components of the currents are plotted in red.

The decaying DC components are clearly apparent in Phase C currents. But the DC component on the line side current reveals also the saturation of this CT. The DC component changes it's sign from minus to plus at t= 50 ms from the start of the event. This is not possible in real primary currents, neither in short circuits nor inrush currents.

When this false trip occurred, the DC restrain feature was not enabled in the settings.

The 87G (MPDIFF) function does not measure the DC component from phase currents, but from differential current. This way, the multiplication of the operate value can only occur in case differential current is present.

The effect of the DC-restrain feature is shown on the next figure.

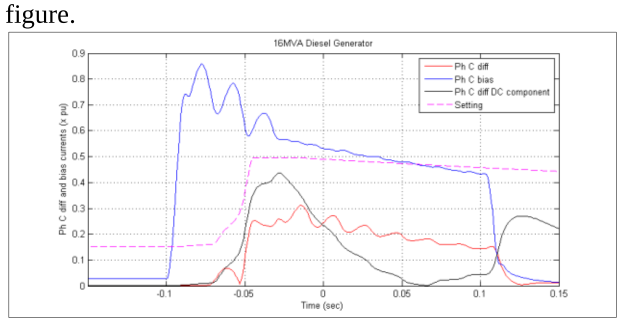

Figure 13 - Effect of the DC-restraint

The figure 13 shows the measured differential (red) and bias (blue) currents. The differential current appears much later than bias current, which is common in CT saturation cases. Since the differential current is caused by the CT saturation, the appearance of differential current indicates when the CT saturated.

The DC component (black), as measured from the differential current, starts to rise at the same time as the differential current. The relay setting (magenta) is increased with the highest DC component value of the three phases. In this case there is differential current in only

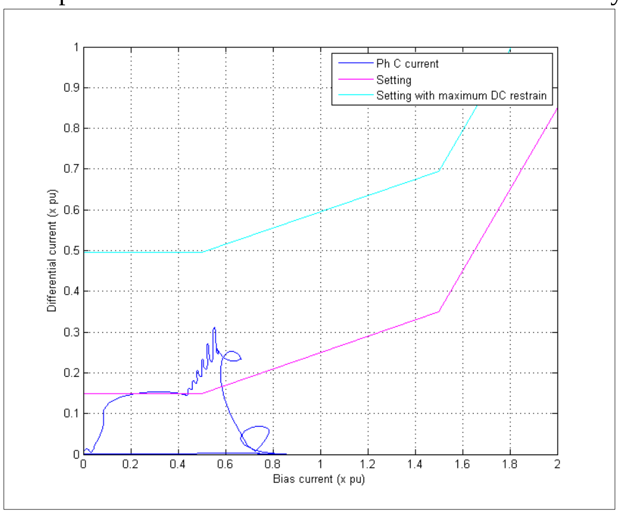

Figure 14 - The phase C current trajectory on the characteristic plane. The current clearly enters the operate area of normal settings, but not to the operate area of the DC-restrain multiplied characteristic.

VIII. METHODS TO TEST ADAPTIVE TECHNIQUES

Phase C, so the DC component of Phase C differential current is effective. However, the setting value is increased at maximum 3.3 times. This limit is reached at the time t=-0.05 s. After that, if the differential current does not get bigger anymore, the 3.3 times setting multiplication value decays with a time constant of 1 sec. This 1 second time constant is chosen so, that it is surely slower than time constant of any real DC component of primary current.

The same can be presented also in the characteristic plane of the differential protection. Here the bias current is on the horizontal axis and differential current on the vertical axis.

A. *Tools for testing*

Modern relay testing devices offer ready-made test modules and templates for almost all protection functions. However special manufacturer specific features, like the adaptive measures described in this document, have no pre-made testing possibilities. Injection test devices are mainly intended for routine commissioning testing. The adaptive techniques are considered as part of the function design and are not included in scope of commissioning testing.

When a new relay type is considered by a customer, more comprehensive acceptance testing may be required. The nature of such testing is more like demonstration of the effect of the feature, rather than measuring exact start or limit values. The adaptive techniques discussed here have no setting parameters, apart from the enable/disable setting of the DC-restraint feature.

The effect of an adaptive technique can be demonstrated by playback testing using disturbance record files in COMTRADE format. These tests can be made with any testing device, which is capable to play COMTRADE files.

Playback testing itself is simple. Basically, you just import the recording file and press play, and see how the relay reacts.

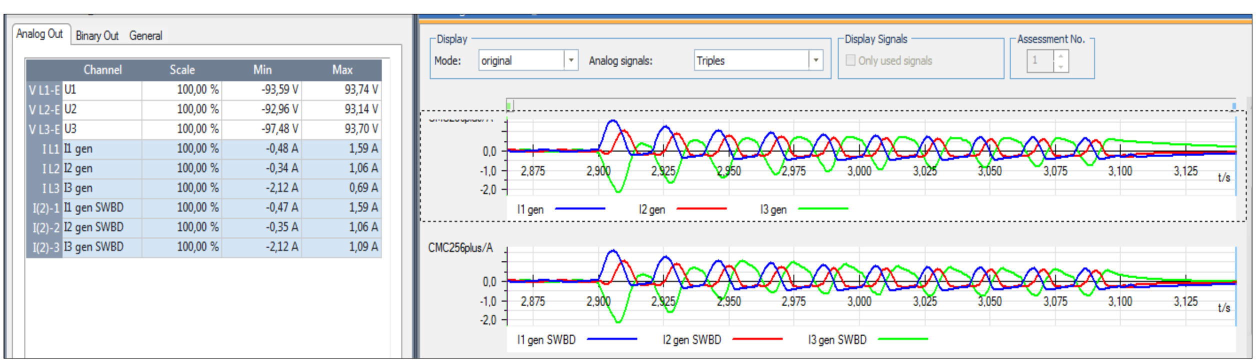

Figure 15 – Playback testing

But where can you get the suitable recordings for testing?

The first option is to use disturbance recordings of real events. The COMTRADE standard is a big help here, as it makes it possible to use disturbance records made with different relay types or relays from different manufacturers.

The second option is to create the test files with other tools. Here we discuss how to create test files with CT simulation tools and merging several record files to one file using the Wavewin software.

B. Test file for demonstration of CT saturation detection

First it is to be noted, that the adaptive techniques of 87G are affecting the low-set stage of differential protection. The high-set stage is not stabilized, and the setting used should be so high, that CT saturation will not cause a trip. When a generator is connected to a network, in which there are other sources too (like any utility grid), the fault current in a fault occurring inside the generator is higher than the fault current in external faults. Therefore, the setting of the high-set stage can be set above the maximum trough fault current generated by the machine itself.

It is also to be noted, that any blocking or de-sensitizing of protection can occur only when differential current is present. Therefore, for example the CT-saturation detection cannot be demonstrated by injecting the same saturated current on both sides of the generator, as then the differential current will be zero.

In this example CTs with ratio of 1000/1A are used [1]. The 1000A primary current is also used as rated current I_r of the protected machine

- 1A secondary current is chosen, so that the test currents don't get too big for the test device. [2]
- Fault current of 8 kA (primary) is used [3]. This value is high, but still below the high-set stage operate value, which is set to 1000% of I_r
- In the tool a model of a real current transformer with ratio 1000/1 is chosen [4]. For the CT saturation detection algorithm this is more difficult case than the simplified CT model. The actual accuracy limit factor can be adjusted by the value of the measurement circuit resistance [5]
- The DC component [6] and the remanence [7] are adjusted so, that the CT saturates after about 10 ms (8.3 ms for 60 Hz) after the start of the fault. Some DC component is necessary to make the CT saturate later than in the first half cycle. Remanence in the favorable direction (minus side, when the first half wave of fault current is positive) delays the saturation of the CT.

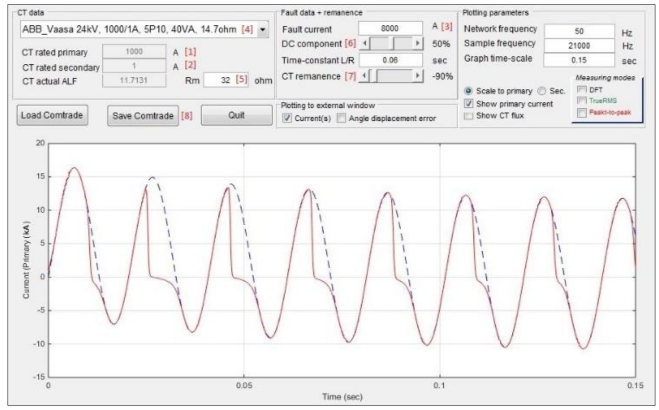

Figure 16 - Creating test files for CT saturation detection

- Then the waveform is saved as a COMTRADE file [8].
- Now we have a record for one side's current of one phase for testing. This could be for example the line side current. This measurement has severe saturation of the CT.
- Next step is to make the current record for the other (neutral) side of the generator. The fault current is kept the same, but the CT saturation is removed completely by reducing the external burden [5].
- The two files are opened and merged in the Wavewin software.

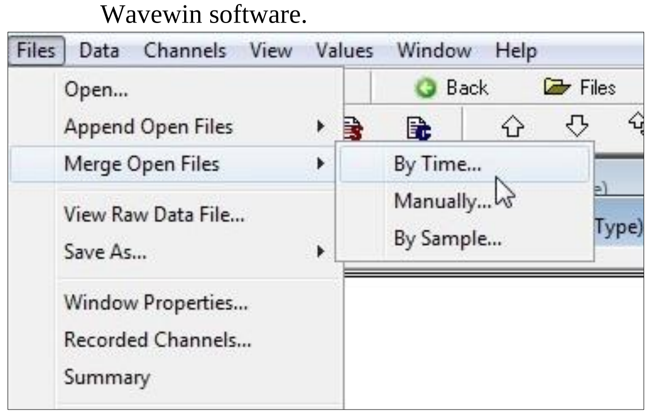

Figure 17 - Merging files with Wavewin

- The file is now ready for playback testing.

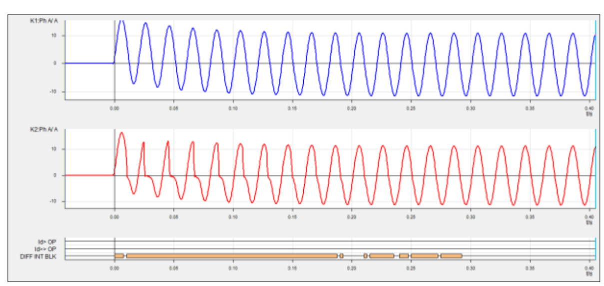

Figure 18 - Result of playback testing with created test files for CT saturation detection. The "DIFF INT BLK" signal

shows when the low-set stage of differential protection was blocked. Protection did not operate.

C. *Test file for demonstration of DC-restraint feature*

Test files can be created using similar steps as for the CT saturation detection. The difference now is that we want to demonstrate the effect of the DC -component. At the same time, the CT saturation detection should not occur.
One way to achieve this, is to make the differential current by some other means than CT saturation. One way is to use two different CT ratios, for example 1000/1A and 1200/1A. Then in the relay the ratio of 1000/1 A is used for both sides. This will make an apparent 17% differential current, when the load current is nominal 1000A.
Then two sets of files are created, one with full 100% DC component and another without any. The *low operate value* of differential protection is set to 10%Ir, and *EndSection* 1 to 100% Ir. The differential current will exceed the operate value this way. But in case when DC component is present, the operate value will rise to maximum 3.3 x 10% = 30 % and no trip should occur with 17 % differential current.

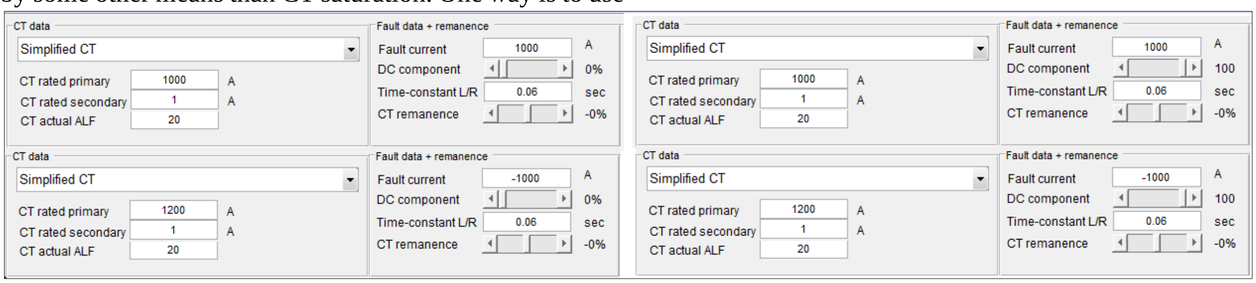

Figure 19 - Four sets of inputs for CT saturation demo, producing current waveforms with 20% differential current. On left, without DC component, and on right, with 100% DC component.

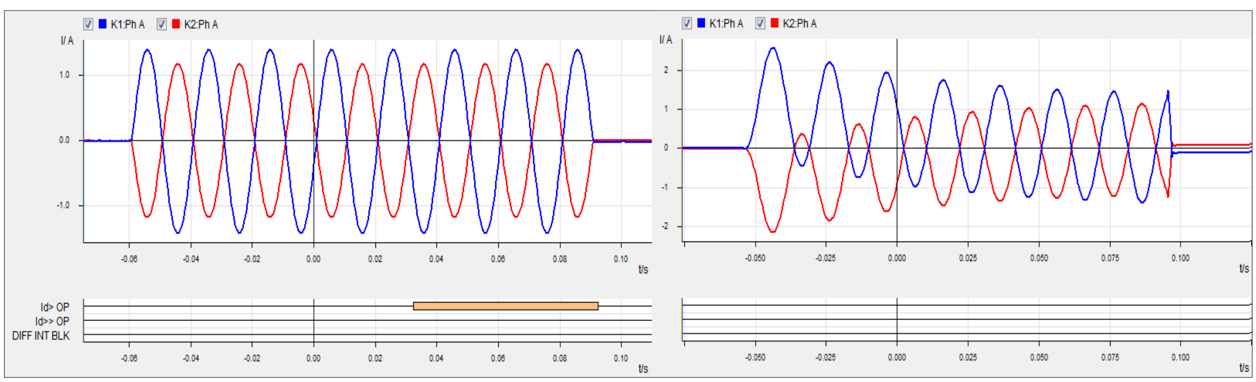

Figure 20 - Test results with 17% differential current. On left, without DC component, and on right, with 100% DC component. As excepted, the protection operates on test without DC component, and does not operate, when DC component is included.

D. *Testing with disturbance record file of a real event.*

The disturbance record of the event in Chapter VI can be used to demonstrate the effect of DC restrain. This kind of testing has some limitation, though. The settings of differential protection should not differ too much from the example case. It may be also necessary to scale the test currents up or down, to match the test object.

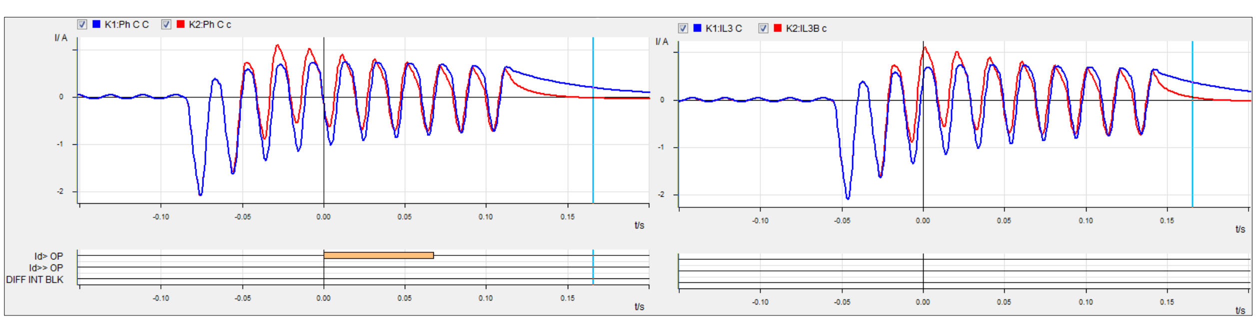

Figure 21 - Test results with disturbance record file of a real fault. On left, without DC-restraint and on right, with DC -restraint. Only Phase C currents shown.

IX. CONCLUSION

Generator is a very valuable part of the power system and it needs to be adequately protected. The generator differential protection will be able to detect fault currents much smaller than the generator current at normal operation giving good sensitivity. However, the differential protection scheme, which include the CTs, the protective relay, and the wiring, should be carefully chosen so that the relay operates only during faults within the protected zone and not for faults outside the protected zone. There are natural challenges to the stability and security of 87G operation, like AC saturation and DC saturation of the CTs. Modern microprocessor relays with advanced 87G algorithm provide adaptive capabilities to automatically adjust the operation based on the power system condition. By enabling CT saturation-based blocking and DC saturation restraint features, undesired operation of 87G element can be avoided, thus getting an uninterrupted service from the generator in the event of external faults. At the same time, these modern adaptive algorithms detect and operate for faults within the protected zone, without compromising the sensitivity of the protection. These adaptive techniques when carefully adopted will save lot of time and energy for the maintenance staff, increasing the productivity of the operations. The CT selection criteria for 87G protection and the testing methods of adaptive techniques discussed in the paper will be a valuable tool for the design and the testing engineers and technicians involved with synchronous machine protection.

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XI. BIOGRAPHY

Eduardo Colmenares is a Senior Relay Protection Application Engineer for ABB Digital Solutions Center with over 32 years of experience in the field of Protection and Control. He has been working for ABB US since 2010. Previously, he worked for 15 years in ABB Venezuela where he held several positions including Country Service Manager, BAU Manager for Protection & Substation Automation, BAU Manager for Power Generation and BAU Manager for Utility Communications. Also, he worked 5 years for an Electric Utility with a focus on protection and control. Eduardo has authored or co-authored several papers for Relay conferences. Eduardo has an Electrical Engineering degree from Universidad de Los Andes, Merida, Venezuela in 1987.

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