How to Determine the Effectiveness of Generator Differential Protection

Normann Fischer, Dale Finney, and Douglas Taylor
Schweitzer Engineering Laboratories, Inc.

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How to Determine the Effectiveness of Generator Differential Protection

Normann Fischer, Dale Finney, and Douglas Taylor, *Schweitzer Engineering Laboratories, Inc.*

***Abstract*—Differential protection is often touted as being *The* protection for generator stator windings. In this paper, we examine the degree of protection afforded by the various types of differential elements (phase, negative, and zero sequence) for stator winding faults.**

To understand why and how windings fail, we need to know how a stator is constructed, how the winding coils are made, and how they are mounted into the stator core. This paper examines various types of winding configurations and the makeup of the winding insulation. We analyze how different winding failures can be detected using the various differential elements mentioned. Because protection elements are not only required to be sensitive but also secure, we contrast the dependability and security of each element. Security of any differential element must include the performance of the primary current transformers (CTs); therefore, we extend the discussion to setting recommendations and CT selection rules.

Finally, the paper answers the question, How much protection does each type of differential element provide? Knowing the limits to performance will allow protection engineers to set the elements for realistic sensitivity without unnecessarily risking any security.

I. Introduction

Before protection for any piece of an electrical apparatus can be selected, a thorough understanding of the apparatus, as well as all of the possible failure modes of the apparatus, is required. Rotating synchronous machines are unique in that to provide comprehensive protection for the machines, separate measurements and protection are required for the stator and the rotor. This paper will concentrate on only the stator of a generator.

The rotating magnetic field produced by the rotation of the rotor induces voltage into the stator windings. These stator windings are connected in series, parallel, or both depending on the number of poles and the voltage and current rating of the machine. Typically, a winding is made of several turns to form a coil, and each coil occupies a slot or part of a slot in the stator. The turns that make up the winding are not only insulated from one another but also from the stator core. A winding fault occurs when insulation in one of the winding components fails. The type of insulation failure determines the fault type. For example, if the insulation between two turns fails, a turn-to-turn fault develops. This type of fault is difficult to detect using conventional protection techniques and may only be detected once the fault evolves into a turn-to-ground fault.

What is interesting about winding faults in general is that they can only be detected once the insulation has failed. However, unlike in an overhead transmission line, the winding insulation cannot be restored. Therefore, once the fault has been detected, the machine must either be taken out of service for a complete rewind or be temporarily repaired to keep the machine in service until a rewind can be scheduled. This implies that the protection is installed only to prevent cumulative damage after the fault has been detected and does not remove the need to repair the machine.

II. The Generator Stator Winding

Before trying to understand how a winding can fail and what fault current can be generated during a fault condition, it is useful to review how a stator is constructed. The stator consists of three main components: the stator core, stator windings, and insulation.

When assessing the impact of a winding-to-ground fault, another important aspect to consider is the grounding of the stator neutral terminal. This not only influences the magnitude of the fault current but also determines what protection will be required to detect such a fault.

A. Stator Core Construction

The rotational speed of the prime mover has a significant influence on the generator construction. In all large generators, the limiting factor is the centrifugal force on the rotor.

Generators driven by steam turbines rotate at high speeds; consequently, the rotor is made from forged steel. Because the nominal frequency is fixed at 50 or 60 Hz, the required rotor speed is attained by limiting the number of poles to two or four, which results in rotor speeds of 3,000 or 1,500 rpm at 50 Hz and 3,600 or 1,800 rpm at 60 Hz. We know that the stator phase voltage (V_{ph}) is proportional to the product of the effective air-gap flux (Φ_M) and the number of turns (N) per phase, as shown by (1).

$$V_{ph} = 4.44 N f \Phi_M \tag{1}$$

A large flux requires a large core area, and because centrifugal force limits the rotor diameter to approximately 1.2 meters, a long stator core is required to provide the required area. The core length of a large turbogenerator is typically several meters long. For example, a large 500 MVA, 50 Hz turbogenerator with a rotor diameter of 1.2 meters has an axial length of about 5 meters. Here, we make use of the rule of thumb that for every megawatt, an axial length of 10 millimeters is required [1]. The stator core of a turbogenerator is built of multiple sections of grain-oriented steel, as shown in Fig. 1.

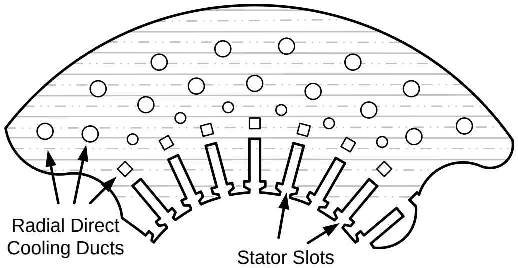

Fig. 1. Laminated stator core showing both the stator slots and the radial cooling ducts used for direct gas cooling.

As shown in Fig. 1, the radial cooling ducts occupy a large area of the stator core, enabling the heat generated by the windings to be effectively dissipated. As we will discuss in Section III, heat is one of the main factors that will lead to winding failure.

Generators driven by water power are built for a wide range of comparatively low turbine speeds. Therefore, these machines have a large diameter to accommodate the many salient poles. As a result of the large stator diameter, the hydrogenerators require only a short axial length to accommodate the flux. Because the diameter of these generators is large, it is not possible to manufacture the core in one piece. Instead, the core is made of several core segments, as shown in Fig. 2 [1].

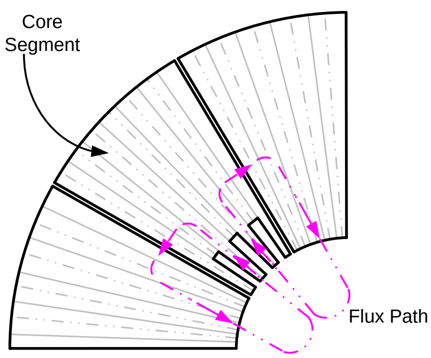

Fig. 2. Stator core segments used to make the stator core of a large diameter hydrogenerator.

B. *Types of Winding Structures*

Three basic types of stator winding structures ranging from 200 kW to more than 1,000 MW are used in machines today. These include the following:

- Random-wound stators. These are used in generators up to 200 to 300 kW.
- Form-wound stators using multiturn coils. These are used in generators up to about 100 MW.
- Form-wound stators using Roebel bars. These are used in generators with ratings larger than 100 MW.

In this paper we will mainly concentrate on the two types of form-wound windings [2].

1) *Coil-Type, Form-Wound Stator*

These stators are intended for machines that have a terminal voltage larger than 1 kV. The coils are made from one continuous piece of insulated copper wire with additional insulation applied over each coil. Typically, a coil can consist of two or more series turns. Several of these coils are connected in series and parallel to produce the rated current and voltage of the machine. Fig. 3 shows a picture of a typical form-wound stator coil.

Fig. 3. An example of a form-wound stator coil.

Careful design and machine manufacturing are employed to ensure that each turn of a coil is placed next to an adjacent turn during assembly so as to create the lowest potential difference between two adjacent turns. By doing this, thinner insulation can be used to separate the turns.

2) *Roebel Bar Form-Wound Stator*

As the machine rating increases above about 50 MVA, the form-wound coils become so stiff that it is nearly impossible to insert them into the narrow stator slots without damaging the coil. Therefore, most large generator coils today are not constructed using multiturn coils but rather with what is known as a half-turn coil, also referred to as a Roebel bar (see Fig. 4).

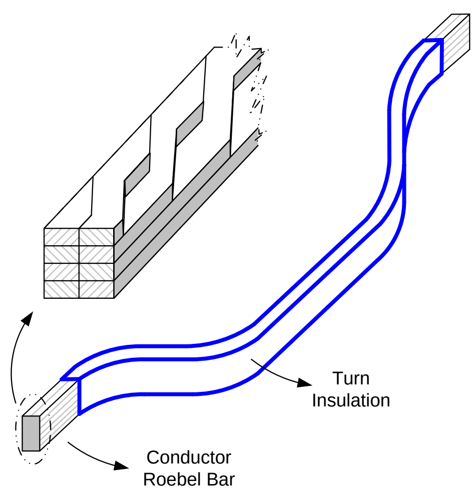

Fig. 4. Sketch of a half-turn coil, or Roebel bar, as would be commonly used in a large (> 50 MVA) generator.

Referring to Fig. 5, which demonstrates the insertion of a form-wound coil, it becomes clear that when winding large machines with sizable coils, it is easier to insert a half-turn coil (Fig. 4) into a stator slot than to insert two sides of a form-wound coil (Fig. 3) into two slots simultaneously.

Although both ends of a half-turn coil require an electrical connection, this is insignificant when compared with the effort required to simultaneously insert two sides of a coil into two slots without causing mechanical damage to the coil.

Fig. 5. Insertion of a form-wound coil winding into a small synchronous motor.

3) *Insertion of Coils Into Stator Slots*

Large machines are usually wound using single-turn coils that are made of double-layer bar windings. These windings are lap-connected, where each coil is lapped over the next to form the winding. A lap connection is preferred because it is easier to connect the coils. The turns that make up a coil must be insulated, not only from ground (the stator core is typically grounded) but also from one another. A turn of a coil used in a large machine is constructed with a number of individual strands. This is done to negate skin effect and eddy currents and to optimize the conductor area. Each strand and each turn is insulated. The turns are then formed into coils and insulated in what is known as the ground wall insulation. The ground wall insulation not only provides insulation for the coil but also ensures that there is no void between the coil and the stator wall. Before the coil is embedded into a stator slot, the stator slot is lined with semiconductive insulating paint. This semiconductive coating controls the voltage gradient and aids in heat dissipation. Fig. 6 shows a sketch of a form-wound stator coil in a stator slot. The sketch shows the different components, including the insulation material that makes up a stator coil.

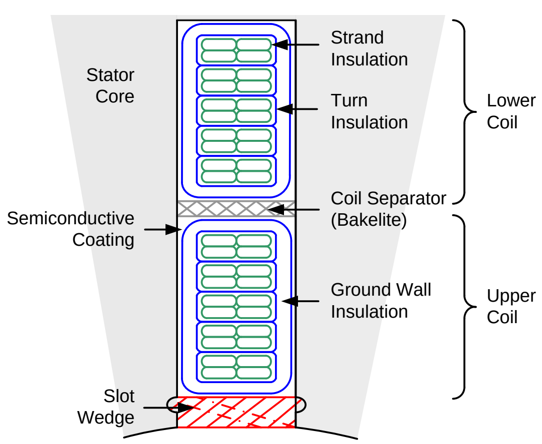

Fig. 6. Sketch of a form-wound stator coil in a double-layer stator winding with four strands and five turns per coil.

C. *Insulation Material*

The final component of the stator is the insulation. As shown in Fig. 6, the insulation can be divided into three parts: strand, turn, and ground wall insulation.

1) *Strand Insulation*

There are mechanical and electrical reasons for stranding the conductor in a form-wound winding or bar. As the MVA rating increases, the current being carried by the winding increases. This means that the cross-sectional area of the conductor must increase to support the increasing current. A conductor with a large cross-sectional area is difficult to bend and shape into the required form. It is easier to form a conductor made of multiple strands. From an electrical point of view, there are definite reasons to strand the conductor and insulate the strands from one another. One of the reasons has to do with skin effect. From electromagnetic theory, we know that when a conductor has a large enough cross-sectional area, ac current will not flow evenly throughout the cross section of the conductor but will tend to flow near the surface of the conductor. Skin effect gives rise to a phenomenon known as skin depth wherein most of the current flows. In such cases, the ac current does not make use of the cross-sectional area of the conductor, and as a result, the path resistance is higher than if a dc current of the same magnitude were flowing through the conductor. This means that the ac path resistance is higher than the equivalent dc path resistance and results in higher copper losses (I^2R) in the machine and higher thermal stresses.

As an example, for a machine operating at 60 Hz, the skin depth of a copper conductor would be 8.47 millimeters (for 50 Hz, this would be 9.22 millimeters). If the dimension of the conductor was such that the radius or width of the conductor was larger than 8.47 millimeters, no current would flow in this region and the conductor would serve no purpose in this region. Dividing the conductor into individual strands with dimensions such that the full cross-sectional area of the conductor is used negates the effect and associated losses of skin effect.

Another reason for stranding the conductor is for the reduction of eddy-current losses. The greater the conductor surface area, the greater the magnetic flux that can be encircled by a path on the conductor surface and the larger the induced current. This results in large I^2R losses because of the circulating surface currents. Reducing the area of the conductor reduces stray magnetic losses.

To maintain the electrical integrity of the strands, the strands need to be insulated from one another. Because the potential difference between the strands is very low, typically a few tenths of a volt, the insulation can be rather thin. However, the thermal and mechanical properties of the insulation must be good. If a few strands are shorted together, this will not cause immediate failure of the stator winding, but this will increase the stator winding losses (increased I^2R losses), resulting in higher localized heating.

2) *Turn Insulation*

Using turn insulation prevents current from flowing between the adjacent turns of a coil. If a turn-to-turn fault develops in a coil, the shorted turns can be thought of as the secondary winding of an autotransformer. These shorted turns will draw a current that is approximated by the ampere turns balance, as stated by (2).

$$N_{Healthy} I_{Healthy} = N_{Fault} I_{Fault} \tag{2}$$

To understand the magnitude of the current in the shorted turns, assume that a generator winding has 200 turns and a turn-to-turn fault develops across one of the turns. The current in the shorted turn is computed as follows:

$$I_{Fault} = \frac{N_{Healthy}}{N_{Fault}} \bullet I_{Healthy} \tag{3}$$

$$I_{Fault} = 199 \bullet I_{Healthy} \tag{4}$$

Using (3) and (4), we see that the current in the shorted turn is 199 times the current in the healthy turns. Turn-to-turn faults can be demonstrated using the transformer model shown in Fig. 7. Let the healthy turns and current represent one winding of the transformer, and let the faulted turns and the associated current represent the other winding of a transformer.

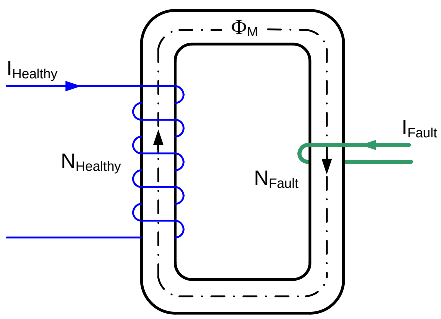

Fig. 7. Two-winding transformer model demonstrates the magnitude in the faulted turn(s) during a turn-to-turn fault.

The voltage difference between two turns in a random-wound stator can be very high—as high as the phase-to-phase voltage if the two adjacent turns are each connected to the voltage terminals of the machine. In a machine where form-wound coils are used, careful design ensures that the potential difference between adjacent coils is as small as possible. Typically, the voltage difference between two adjacent turns on a large machine is in the order of 250 V. However, turn insulation is exposed to very high transient voltage during switching events or lightning strikes. These transient voltages will age or even puncture the insulation. When a high-voltage transient is applied to machine terminals, the voltage distribution across the stator winding is nonlinear, with a significant voltage drop across the first few turns of the winding closest to the machine terminals. This is because the series inductive impedance of the winding is large when compared with the low shunt capacitive impedance to ground of the winding at high frequencies. The result of this is that very high voltages appear across the first few turns of a winding, severely stressing the turn insulation on the first few turns. As much as 40 percent of the surge voltage can appear across the first turn [3].

A high interturn voltage resulting from the surge can cause a partial discharge if there is an air pocket between the turns. If a sufficient number of surges occur, this can lead to an eventual turn-to-turn fault.

Turn insulation is also exposed to thermal and mechanical stress. The thermal stress of the turn insulation is similar to the thermal stress of the strand insulation previously discussed. Turns are exposed to mechanical stress as a result of the currents flowing within them (this is discussed in greater detail in the next subsection). The turn insulation must be selected such that it meets the electrical, thermal, and mechanical requirements of the coil.

3) Ground Wall Insulation

Ground wall insulation separates the turn from the grounded stator core, as shown in Fig. 6. Ground wall insulation failure usually results in a turn-to-ground fault. Large generators have operating voltages that range from approximately 13.8 to 20 kV. This means that ground wall insulation must be able to withstand a phase-to-ground voltage of between 8 to 11.6 kV and be of appreciable thickness.

Generator stator windings are designed to generate equal voltage per turn. For a generator that has 100 turns and generates a phase-to-ground voltage of 11.6 kV, the voltage per turn is 116 V. This means that the first turn from the machine neutral will have a potential difference to ground of 116 V, the second turn will have a potential to ground of 232 V, and so on. However, the turns closest to the machine terminals will have a phase-to-ground voltage greater than 11 kV. As a result, the turns closer to the machine neutral will require very thin ground wall insulation, whereas the turns of the winding close to the machine terminals will require thick ground wall insulation. Therefore, each coil could have its own ground wall insulation thickness, and if one looked at the stator winding as a whole, the winding would be made of graded insulation. Each coil would need to be custom made, and the stator slots would not have the same dimensions. Those close to the machine neutral would be narrower than those at the machine terminals. From a manufacturing point of view, it does not make sense to have coils of different thicknesses and core slots of different dimensions. Therefore, for manufacturing ease, all coils have the same insulation thicknesses and all stator slots have the same dimensions.

In indirectly cooled form-wound machines (large generators are typically cooled indirectly using hydrogen), the heat generated in the windings must travel through the ground wall insulation to reach the cooling medium in the stator cooling ducts, as shown in Fig. 1. Because of this, ground wall insulation thermal resistance should be as low as possible to prevent heat accumulation in the copper windings. To achieve a low thermal resistance, the material used for the ground wall insulation must have a high thermal conductivity and be free from voids. Voids inhibit the flow of heat through the insulation and also allow partial discharge (see Section III, Subsection B).

The mechanical stress (electromagnetic force) induced into the turns of a coil is a result of the current flow in the turns. It is typical in a large generator for stator windings to be doublelayered, as shown in Fig. 6. The two coils that occupy the same slot will have current flowing through them in the same or opposite direction. These currents create magnetic fields, which cause the coils in the stator slot to attract and repel one another at a frequency equal to twice the nominal frequency of the power system. Thus, for a machine operating at 60 Hz, the conductors vibrate approximately 104 million times a day. In 1931, J. F. Calvert published a paper describing these forces [4]. The force between conductors in a slot can be as high as 10 kN/m [1]. Therefore, it is important that the stator windings are braced and wedged properly. Fig. 8 illustrates how the stator winding coils are braced and wedged in a large machine.

Fig. 8. An illustration of how the stator coils are braced and wedged in a large synchronous machine.

One further reason why the ground wall insulation should be free from voids is that the ground wall insulation prevents the coils from vibrating in the stator slots. If the ground wall insulation were full of voids, the coils would be free to vibrate against one another, leading to insulation abrasion. For this reason, the insulation should be incompressible.

D. Grounding Method

ANSI C50.12 and C50.13 require that a generator be designed to withstand a three-phase short circuit at its terminals while operating at rated load and 1.05 pu rated voltage. Because the zero-sequence impedance of a generator is significantly less than its subtransient or negative-sequence impedance, a phase-to-ground fault will generate a fault current that is significantly higher than that generated by a three-phase fault. Because both the mechanical and thermal forces are proportional to the square of the current, reducing the magnitude of the fault current by external means will significantly reduce the mechanical and thermal stress imposed on a generator during a fault. This is the reason for grounding the machine through an impedance.

Generator grounding can be roughly categorized into two groups: high impedance and low impedance. As a general rule, machines that are connected to the power system through a delta-wye generator step-up transformer (GSU) are high-impedance grounded, and machines that are connected directly to a bus (along with other machines and loads) are low-impedance grounded.

Grounding is always a tradeoff between controlling the transient overvoltage and limiting the magnitude of the fault current. When connected through a GSU, only the machine and the low-voltage winding of the GSU are subjected to overvoltage conditions during the ground fault. In addition, the delta winding on the GSU side confines the zero-sequence current and the resulting zero-sequence voltage to the low-voltage side of the transformer. Grounding the generator neutral through a high-impedance limits the fault current to a few tens of amperes and allows voltage-based ground fault protection to be applied. Such protection systems only respond to ground faults on the generator and GSU low-voltage winding.

Protection methods are available to detect ground faults over 100 percent of the winding. Although fault contribution from the generator neutral is limited to a low value, an intermittent ground fault can still result in serious damage due to repetitive capacitive discharge currents and resulting high-transient overvoltages in the healthy phases [5].

On bus-connected generators, the overvoltage during a ground fault must be limited. Therefore, these machines are typically grounded through resistors that limit the fault current to between 200 and 400 A (low-impedance grounded). Current-based ground fault protection is applied for these machines. However, ground fault protection will respond to faults anywhere on the power system unless differential or directional schemes are employed (see Section V). The potential for damage is also much greater on bus-connected generators due to much larger available fault currents. Additionally, when an internal ground fault occurs, even after the protection has operated and the generator breaker has opened, the generator will still supply current to its own fault until the field has been de-energized. Consequently, hybrid grounding has become an increasingly popular method for grounding these machines. In a hybrid grounding scheme, the machine is normally low-impedance grounded. When a fault occurs and after the generator breaker has opened, a high impedance is inserted into the generator neutral, thereby limiting the fault current and greatly reducing damage to the winding [6].

III. Stator Winding Failure Mechanisms

Next we look into the mechanisms that lead to a winding failure.

Stator winding failures cause a significant percentage of generator outages. One study reports a value of 40 percent [7]. Fig. 9 shows a sketch of the possible types of stator winding faults. Each of these fault types should be detectable by the generator protection. Usually, dedicated ground fault protection is applied. Faults not involving ground must be detected by other means. Several commonly applied protection functions can detect phase-to-phase faults, including differential, generator unbalance, and backup distance. Of these, differential is arguably the most effective. Hydrogenerators, which have coil-type windings and parallel branches making up each phase, may employ split-phase protection for the detection of turn-to-turn faults. As will be discussed, other protection schemes can provide a degree of protection.

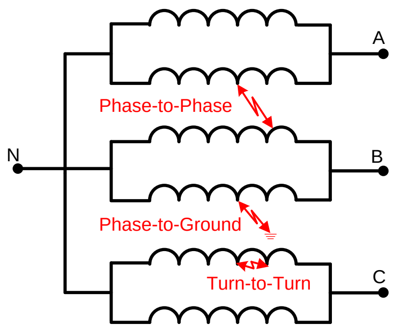

Fig. 9. A sketch showing the different types of faults that can be experienced by a stator winding.

A failure is usually the product of gradual deterioration, often due to multiple factors (thermal, electrical, mechanical, and environmental), followed by a transient event, such as a voltage surge, an external fault, a high-voltage (HiPot) test, or an operating error (e.g., out-of-phase synchronization or inadvertent energization) [2]. The following subsections discuss these deterioration mechanisms in more detail.

A. Thermal Deterioration

When insulation exceeds its design temperature, it begins to degrade; chemical bonds break down at an accelerated rate, making the insulation weaker and more brittle. The higher the temperature, the faster the insulation will break down. A number of problems can expose insulation to high temperatures, including overloading of the generator, a high ambient temperature, a cooling system failure, or an inadvertent shutdown of the cooling system due to operator error. A poor or failed electrical connection will also create localized overheating and consequent degradation of the insulation.

Generators that undergo rapid load changes or are frequently started and stopped (such as for pumped storage) and have relatively long stators can suffer from thermal cycling. Differing thermal expansion coefficients of the coils, insulation, and core produce shear forces. These forces can result in the separation of the ground wall insulation from the stator core. This, in turn, leads to slot discharge and a consequent breakdown of the insulation, which is described in the next subsection.

B. Electrical Deterioration

Electrical aging is usually a result of electrical stress created within small voids of the insulation. These voids are formed during the manufacturing process. To explain how voids in the insulation impact the electrical strength of the insulation, consider the following example.

Hydrogen has the best thermal conductivity of all gases (0.168 W/(m • K)), about seven to ten times better than air. For this reason, hydrogen is used as a cooling medium in large machines. Hydrogen and air have about the same electrical breakdown strength, approximately 3 kV/mm at 100 kPa. The operating pressure of hydrogen in a large turbogenerator is usually in the region of 3 atmospheres (300 kPa), thereby increasing the breakdown strength of hydrogen to 9 kV/mm.

Consider a machine with a rated voltage of 21 kV ($V_{LN} \approx 12$ kV) and a ground wall insulation of 5 millimeters. If a void 0.25 millimeters thick has formed within the ground wall insulation, what would be the potential difference across the void? To answer this question, we apply the voltage divider rule for two capacitors in series with one another (the capacitance of the ground wall insulation in series with the capacitance of the void). The potential difference across the void is calculated at 2 kV, creating an electric stress of 8 kV/mm. This is within the breakdown strength of hydrogen at 300 kPa. But, if for some reason the hydrogen pressure drops below 267 kPa, electrical breakdown will occur within the void and will cause an arc. The resulting spark is referred to as partial discharge because the discharge is only within the void. A complete discharge would, in essence, be a turn-to-ground fault. Partial discharge causes decomposition of insulation on the interior surface of these voids, gradually causing voids to grow and weaken the insulation over time [8].

Partial discharge can also occur in the end windings. This can happen when inadequate clearances create voltage gradients that exceed the breakdown strength of the insulation.

A slot discharge is similar to partial discharge but potentially more damaging. It occurs when a void develops between the ground wall and the core. The voltage at the surface of the insulation rises to the phase-to-ground value. This results in an arc, which breaks down the insulation at the surface, eventually resulting in an insulation failure.

C. Mechanical Deterioration

Inadequate bracing of the end windings due to poor design or construction can lead to excessive vibration in the end windings. The bracing may also loosen due to high transient torque produced by out-of-phase synchronization or close-in faults. The impact of repeated events is cumulative. Excessive vibration will lead to wearing or cracking of the insulation.

Large machines are often cooled by pumping water through the stator conductors. High levels of vibration can result in a small water leak. Stator insulation is applied in layers or laminations and water ingress causes delamination of the insulation, making it electrically less effective and more likely to fail during a voltage transient.

Loose coils can occur due to insulation shrinkage or poor design or construction. Magnetic forces at twice the line frequency cause the bars to vibrate, which can cause the insulation to wear and/or separate from the stator core. As with the case of thermal cycling, separation of the ground wall insulation from the core will result in slot discharges.

D. Environmental Deterioration

Generator contamination is the penetration of water, oil, or dust (e.g., coal and brush sediment) into the insulation. Contamination degrades the insulation in two ways.

First, it causes a reduction in the electrical or mechanical strength of the insulation. Some types of insulation are more susceptible than others. For example, insulation made from organic compounds will suffer more from water ingress than insulation made from an inorganic compound.

Secondly, contamination provides a medium for surface tracking, primarily in the end winding. Surface contamination creates a path for small capacitive currents driven by potential differences within a phase or between phases. These currents lead to surface discharge in the air adjacent to the surface and the formation of carbon tracking. The low-impedance paths formed by these tracks can lead to a phase-to-phase fault or a turn-to-turn fault.

IV. Evolving Faults

Ideally, any insulation failure should be quickly detected by protection functions. Failure to detect a fault early increases its duration and can result in its evolution into a more potentially damaging fault type. The following are examples of how generator faults can evolve without proper effective protection.

As outlined in Section II, turn-to-turn faults are possible in windings constructed from multiturn coils. One survey found that only about 25 percent of the total surface area of the insulation separates a conductor from ground or from another phase in this type of winding [9]. The remaining 75 percent of the insulation is between turns. Therefore, the potential for turn-to-turn faults is high. When a turn-to-turn fault occurs, the current flowing in the shorted turn can be significantly higher than the nominal current of the machine (as shown in Section II, Subsection C). Without effective turn-to-turn fault protection, this current will quickly burn insulation and melt conductors, resulting in a phase-to-phase or phase-to-ground fault.

Similarly, a ground fault can evolve into a much more damaging phase-to-phase fault. For instance, one of the deterioration mechanisms previously described could cause a weakening of the insulation in the vicinity of the stator neutral. Here, the voltage to ground will be low. Without effective ground-fault protection for 100 percent of the winding, this problem could go undetected. If a ground fault develops near the terminals, the neutral point voltage will rise to the phase-to-neutral voltage. The previously weakened insulation near the neutral will break down, resulting in a much more severe fault.

A third possibility is an intermittent ground fault. Due to inherent delays in ground fault protection schemes, the fault may go undetected. The successive transient overvoltages occurring at the inception of each arc could lead to a ground fault on a second phase.

V. Differential Protection Schemes

Differential protection is one of the main protection elements responsible for detecting the failures described in Section III. Generator differential protection schemes are designed to detect faults by comparing the current following into and out of the stator. A variety of schemes is possible.

A. Self-Balancing Differential

In this scheme, shown in Fig. 10, the overcurrent elements are connected to core-balance current transformers (CTs) on a per-phase basis. This allows for the detection of both phase and ground faults.

This scheme allows for low-ratio CTs to be applied, making it very sensitive and secure for external faults. However, saturation for internal faults is possible if the CT burden is too high. One drawback of this scheme is that both ends of the winding must pass through the windows of the core-balance CT, which makes it difficult to apply this scheme on large machines. In addition, these CTs are susceptible to stray flux from nearby current-carrying conductors. This susceptibility places some sensitivity limitations on this scheme. Defining $Ipkp_{SB}$ as the minimum pickup setting of the overcurrent element and CTR_{CB} as the CT ratio of the core-balance CT, we define sensitivity as the minimum current (Imin) detectable by a particular scheme. For this scheme, sensitivity is calculated by (5).

$$Imin_{SB} = CTR_{CB} \bullet Ipkp_{SB} \quad (5)$$

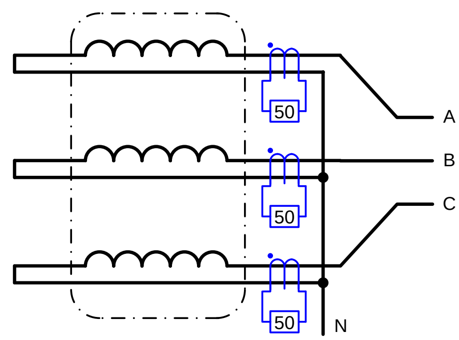

Fig. 10. Self-balancing differential protection scheme.

B. Biased Differential

This scheme, shown in Fig. 11, makes use of CTs on both sides of the winding on a per-phase basis. The CTs are sized to carry the total generator current. On low-impedance-grounded machines, this scheme can detect phase-to-phase, phase-to-ground, and three-phase faults, but on high-impedance-grounded machines, it is not effective for phase-to-ground faults. For security, a biasing method is used that requires the differential current (O_P) to be greater than a percentage of the restraint current ($K_B \bullet R_{ST}$). This method results in the well-known slope characteristic when the differential current is plotted against the restraint current. The restraint current is typically the scalar sum of the currents on each side of the zone (R_{ST}). This scheme employs a variety of characteristics, including variable slope, dual slope, and adaptive slope.

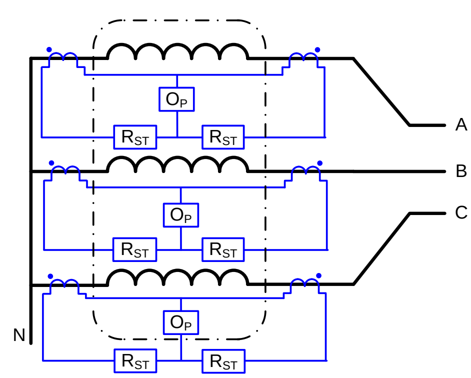

Fig. 11. Biased differential protection scheme.

Defining K_B as the biased slope setting of the differential element and CTR_{PH} as the phase CT ratio of the CT, and assuming that rated current (IG_{Rated}) flows out of the machine during the fault, the sensitivity of this scheme is calculated in (6).

$$Imin_B = 2 \bullet CTR_{PH} \bullet K_B \bullet IG_{Rated} \quad (6)$$

C. *High-Impedance Differential*

As can be seen from Fig. 12, this scheme is similar to the biased differential scheme in that it makes use of CTs on both sides of the winding on a per-phase basis. The CTs are connected in parallel via an overcurrent element in series with the large resistor. This connection creates a high-impedance path between the CT terminals, hence the name of the scheme.

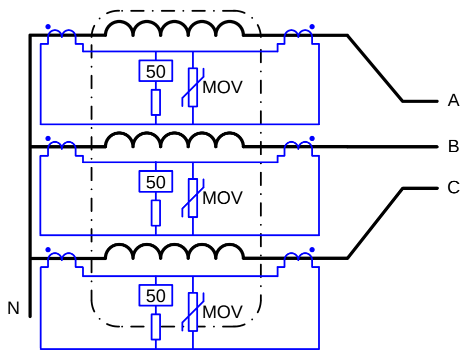

Fig. 12. High-impedance differential protection scheme.

This scheme is extremely secure for external faults in the presence of CT saturation. This scheme is generally more sensitive than the biased differential element because the high impedance in series with the operating coil allows the scheme to be set according to the voltage drop across the resistor. Some schemes have a pickup current as low as 20 mA. The main disadvantages of this scheme are that it requires dedicated CTs on both sides of the winding that these CTs must have matching characteristics. For these reasons, multifunction generator protection relays generally do not employ high-impedance differential protection elements.

Another disadvantage is the fact that a shorted CT disables the scheme. A variation of this scheme uses a single overcurrent element for restricted earth fault detection on low-impedance-grounded machines.

Defining $Ipkp_{HZ}$ as the operating current of the overcurrent element and neglecting CT excitation current and metal oxide varistor (MOV) current, the sensitivity of this scheme is approximated in (7).

$$Imin_{PH} \cong CTR_{PH} \bullet Ipkp_{HZ} \quad (7)$$

D. *Negative- and Zero-Sequence Differential*

These schemes are forms of biased differential protection, using the same definitions for differential and restraint signals but responding to the negative- or zero-sequence current component measured on either side of the winding. Fig. 13 shows the negative-sequence differential scheme. It can detect phase-to-phase and phase-to-ground faults but not a three-phase fault. The zero-sequence scheme can only detect faults involving ground. These schemes are more sensitive than the standard biased differential scheme because they do not respond to balanced load current. On the other hand, they can be susceptible to misoperation for balanced external faults during CT saturation unless properly secured. Defining $Ipkp_Q$ as the minimum pickup setting of the negative-sequence element (Q), the sensitivity of this scheme is calculated in (8).

$$Imin_Q = CTR_{PH} \bullet Ipkp_Q \quad (8)$$

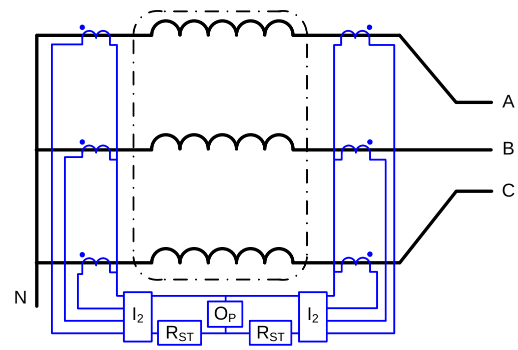

Fig. 13. Negative-sequence differential protection scheme.

E. *Restricted Earth Fault*

This scheme, shown in Fig. 14, uses a current-polarized ground overcurrent element. The operate signal is derived from a CT at the generator neutral. The polarizing signal is the zero-sequence component of the generator output terminal CTs. This scheme can provide effective protection for ground faults on low-impedance-grounded generators. Although the operate signal can be derived from a low-ratio CT, the limiting factor for sensitive operation is the magnitude of the polarizing signal and this signal is derived from the phase CTs. Defining $Ipol_{REF}$ as the minimum pickup setting of the element, the sensitivity of the scheme can be calculated using (9).

$$Imin_{REF} = CTR_{PH} \bullet Ipol_{REF} \quad (9)$$

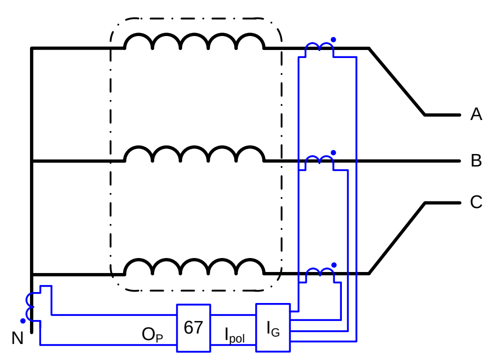

Fig. 14. Restricted earth fault protection scheme.

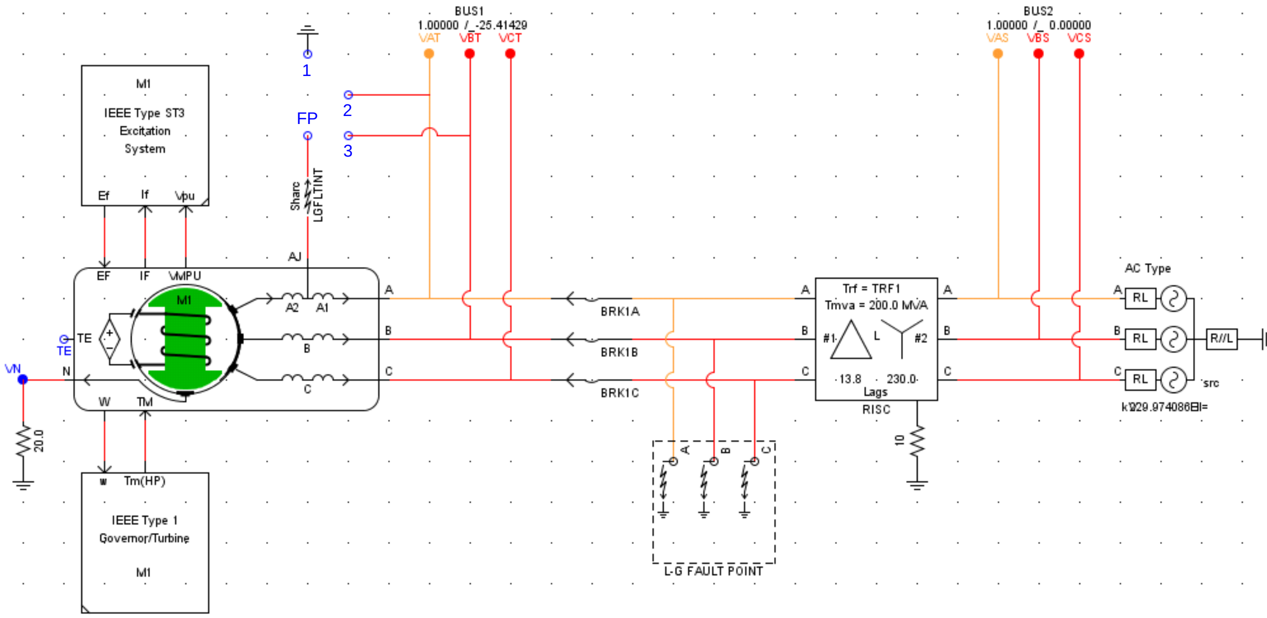

Fig. 15. RTDS model.

F. Comparison of Scheme Sensitivities

The various schemes can be compared with the aid of an example. We chose a small (1 MVA, 480 V) low-impedance-grounded machine such that any scheme is applicable. Table I lists the assumed values for each scheme. Applying (5) through (9) yields the sensitivities shown in Table II.

TABLE I
DIFFERENTIAL PROTECTION SCHEME ASSUMED VALUES

Scheme Variable	Value
CTR_{PH}	1200/5
CTR_{CB}	100/5
$Ipkp_{SB}$	0.25 A secondary
K_B	25%
$Ipkp_{HZ}$	0.1 A secondary
$Ipkp_Q$	0.25 A secondary
$Ipol_{REF}$	0.25 A secondary

TABLE II
DIFFERENTIAL PROTECTION SCHEME SENSITIVITIES

Protection Scheme	Imin (Amperes Primary)
Self-Balancing	5
Biased	600
High Impedance	24
Negative Sequence	60
Restricted Earth Fault	60

VI. Detecting Stator Winding Faults

We used the Real Time Digital Simulator (RTDS®) model shown in Fig. 15 to investigate protection sensitivity for internal faults. This model allows a fault to be placed on the Phase A winding at locations ranging from 5 to 95 percent measured from the neutral. Connecting the fault point (FP in Fig. 15) to Positions 1, 2, or 3 simulates a phase-to-ground, turn-to-turn, or phase-to-phase fault, respectively.

We modeled a 200 MVA machine for phase-to-phase and turn-to-turn faults and modeled a 5 MVA machine for ground faults. We set the terminal voltage for the machine to 13.8 kV and grounded the generator through a 400 A resistor. With the machine running at full load, we performed a series of tests simulating internal faults at various locations. We captured voltages and currents at the output and neutral terminals of the machine and processed the waveforms in MATLAB® to evaluate the protection performance.

A. Phase-to-Phase Fault Detection

We captured terminal and neutral currents and used them to calculate differential and restraint quantities for the 200 MVA generator. Fig. 16 shows the operate and restraint quantities plotted on the percentage differential characteristic.

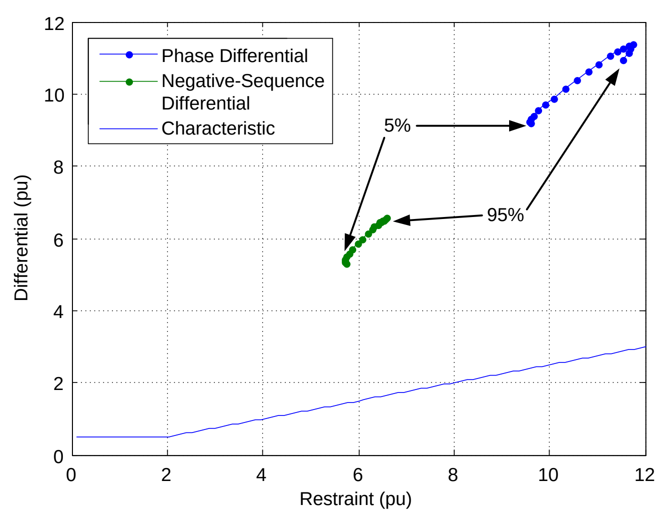

Fig. 16. Phase-to-phase faults plotted on the differential operating characteristic.

We chose a minimum pickup of 0.5 pu for the operate current and selected a slope of 25 percent (see Section VIII). Note that the locus of operating points lies well inside the operating region of the characteristic for both the phase and negative-sequence differential. The differential currents decrease as the fault point moves toward the neutral. Because the model allows for internal faults only on one phase, it was not possible to simulate phase-to-phase faults at any possible location on the winding (for instance 10 percent of Phase A to 10 percent of Phase B). However, one may assume a continuation of the locus toward the restraint region as the fault point moves toward neutral on the second phase. Quantities are plotted in per unit of the generator-rated current, which simulates CTs sized for generator-rated current. Increasing the CT ratio has the effect of moving the entire locus down and to the left, resulting in a decrease of the element sensitivity.

B. Phase-to-Ground Fault Detection

For the 5 MVA machine, we captured terminal and neutral currents and used them to calculate differential and restraint quantities. We then plotted these quantities on a percentage differential operating characteristic, as shown in Fig. 17. Quantities are in per unit of machine-rated current. For the minimum operate current, we chose a pickup of 0.5 pu and selected a slope of 25 percent.

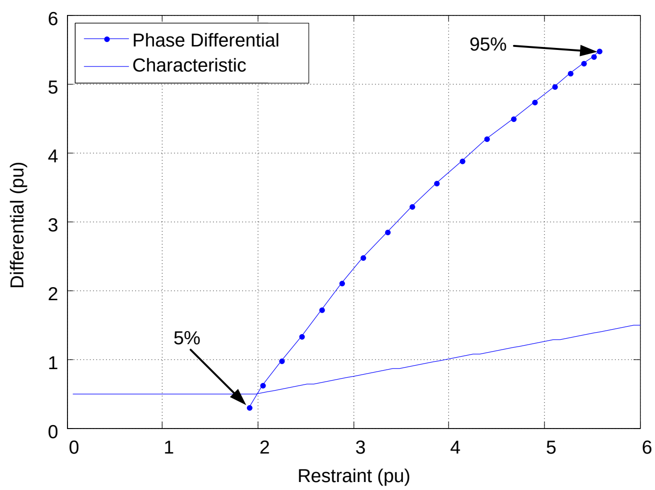

Fig. 17. Phase-to-ground faults plotted on the differential operating characteristic.

Note that for this machine, 90 percent of the winding is covered by the phase differential element. This very good coverage is a result of connecting a relatively small generator to a medium-voltage bus, allowing lower-ratio CTs to be applied. Changing the resistor to limit the fault current from 400 to 200 A or increasing the MVA rating of the machine will move the locus down and to the left. This will reduce the coverage of the differential element. A plot of the generator contribution and system contribution is shown in Fig. 18. This plot can be used to evaluate the effectiveness of a ground directional element. The generator contribution is shown for both a 5 MVA and 200 MVA machine. The same 400 A grounding resistor is used in both cases. The dotted lines in Fig. 18 represent a linear variation in fault contribution with fault location. Note that the actual variation in system and generator contribution is nonlinear. However, it could be estimated as linear, especially for faults in the vicinity of the neutral, which is where the element is expected to provide coverage. The two generator curves diverge for larger magnitude faults near the terminals of the machine. This is because the impedance of the smaller (5 MVA) machine is significant compared with the neutral resistance. As a result, the contribution of the 5 MVA machine does not reach the expected value of 400 A.

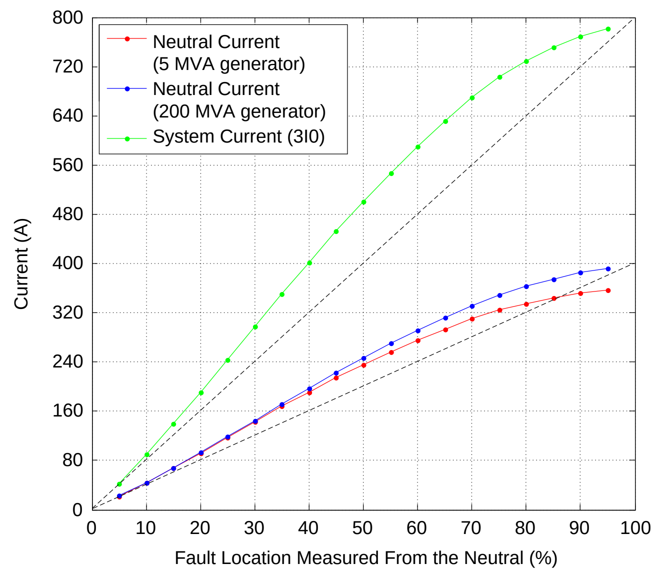

Fig. 18. Ground fault contribution versus location.

C. Turn-to-Turn Fault Detection

We captured currents and voltages at the terminal and neutral of the 200 MVA machine and then used them to calculate differential and restraint quantities. Because the phase currents entering and leaving the faulted winding are the same, the phase differential elements do not measure differential current and cannot detect these faults. One element that is commonly applied on the generator and that can see turn-to-turn faults is the backup distance element (21P). To illustrate this, the reach (M calculation) of the element is plotted against the portion of the winding that is shorted, as shown in Fig. 19. An arbitrary reach setting is applied. The element operates when the calculated reach is less than the setting.

Fig. 19 shows that the element is not sensitive for turn-to-turn faults involving a small portion of the winding. In addition, this element is time-delayed to coordinate with system protections. These two limitations impact the effectiveness of this element. Applying a second zone with a reduced reach to see only into the GSU would allow this element to trip instantaneously. However, the reach reduction would further reduce coverage.

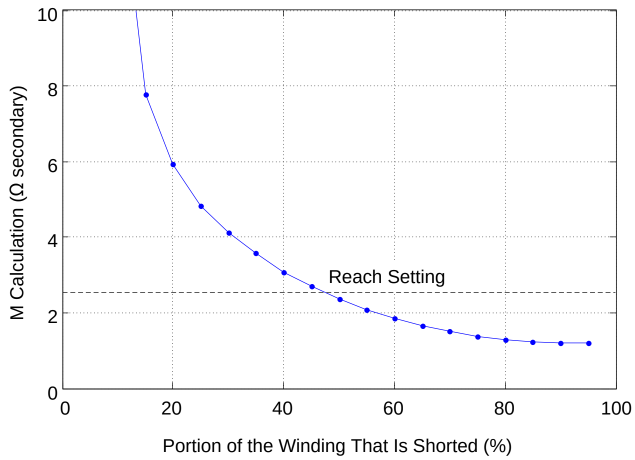

Fig. 19. Impedance versus percent of shorted winding for turn-to-turn faults.

An alternative scheme that provides more effective protection (although not commonly applied) is a negative-sequence directional element (67Q). This element is connected at the terminals (see Fig. 20) and therefore can more easily discriminate between internal and external faults.

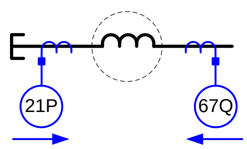

Fig. 20. Turn-to-turn fault protection using a 21P or 67Q element.

One type of directional element uses an impedance calculation to determine direction. Elements using the impedance method will see the system impedance during a turn-to-turn fault. The negative-sequence directional element is straightforward to set and does not need to coordinate with other protection. The sensitivity of the element is a function of the available operating current (I2) and polarizing voltage (V2). Fig. 21 plots these values.

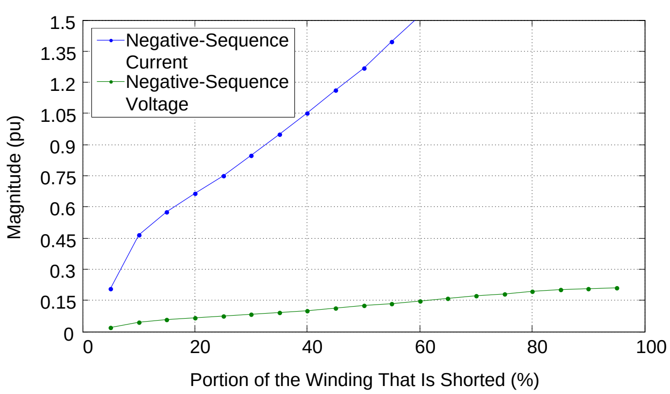

Fig. 21. Negative-sequence current and voltage magnitude versus percent of shorted winding for turn-to-turn faults.

Note that as the percentage of the shorted winding is reduced, the resulting magnitudes of V2 and I2 are reduced. For the modeled system, voltage will be the limiting factor. Element coverage will depend on the minimum voltage required by the element (often less than 1 V secondary) and the instrument transformer accuracy. It is likely that the scheme will be less effective for generators constructed of multiple parallel branches per phase.

VII. CT Selection for Differential Protection

Effective differential protection requires adequate CT performance. This section reviews the CT requirements for the schemes described in Section V.

A. *CT Ratio*

Biased, high impedance, and negative-sequence differential elements use the CTs on either side of the machine as inputs. The polarizing input of the restricted earth fault scheme uses the generator terminal CTs Because these CTs see the phase currents, the ratio selection is a function of the maximum expected current under normal operation of the machine. Because the minimum current that is measurable by the relay is a function of its nominal rating, choosing a higher ratio translates to a lower sensitivity for these functions. Many modern microprocessor-based relays can operate indefinitely for currents of up to three times nominal. Typically, the limiting factor will instead be governed by the rating factor of the CT. The rating factor is the maximum current that can be carried at a specified ambient temperature. Typical values are 1.0, 1.25, 1.33, 1.5, 2.0, 3.0, and 4.0. When the machine is at full load, choose a ratio that results in a secondary current at or near the CT nominal rating (1 or 5 A) and a rating factor that allows for temporary overloading of the machine (≥ 1.5 pu).

B. *CT Voltage Rating*

Selecting a CT with a voltage rating greater than 1 + X/R times the burden voltage for the maximum symmetrical fault current ensures that the potential for a misoperation due to saturation is not a concern. At the generator, the X/R ratio is often very high and saturation may be unavoidable. In general, a percent differential characteristic ensures that the phase differential remains secure during an external fault with CT saturation. Note that elements responding to sequence components may not develop a significant restraint signal for all fault types. These elements may make use of an external fault detector or other mechanism to provide additional security. Generally, CT performance is satisfactory if the CT secondary maximum symmetrical external fault current multiplied by the total secondary burden in ohms is less than half of the voltage rating of the CT.

A misoperation for an external fault can result if one CT enters saturation before the other. Therefore, CTs with identical excitation characteristics should be applied on both sides of the generator. It is usually not sufficient to match CTs by voltage rating alone; it is also important to match the CT secondary burden.

VIII. Differential Protection Application Recommendations

When applying differential protection, the most crucial factor to consider is the performance (characteristics) of the CTs at the terminals and neutral of the machine. For optimal sensitivity and security, all CTs in the differential zone should be identical. The sensitivity of a differential scheme arises from its operating principle—the summation of all of the currents within the zone. Historically, the setting considerations have been set to provide security during external faults, especially when the CTs become saturated. As was shown in Fig. 16 and Fig. 17, the differential element has essentially two settings: minimum pickup and slope.

Element sensitivity is established by the differential relay minimum pickup setting, which determines the smallest current that the element can detect. This pickup value must be set lower than the minimum fault current that can be generated during a fault condition. If we examine Fig. 16, we see that the minimum differential current for a phase-to-phase fault for both the phase- and negative-sequence element was well above the nominal current of the machine (1 pu). Therefore, a pickup setting of 0.5 pu (half the full load current of the machine) resulted in satisfactory performance of the element. Setting the element any lower would not enhance the sensitivity of the element but may reduce the security of the element.

The slope setting of the differential element is determined by calculating the maximum erroneous differential current (operating current) that the differential element will measure for a through-current event with no CT saturation. Defining ε as the CT error and I_{Neu} and I_{Term} as the currents on either side of the generator, the maximum erroneous differential current (IOP_{ERR}) is as follows:

$$IOP_{ERR} = (1+\varepsilon) I_{Neu} - (1-\varepsilon) I_{Term} \tag{10}$$

Because I_{Neu} and I_{Term} are equal, we can express the maximum error current in terms of the percentage of the terminal current as follows:

$$IOP_{ERR} = 2\varepsilon\% \tag{11}$$

For relaying CTs, the ANSI/IEEE C37.110 standard defines a limit of 10 percent for the ratio error, at 20 times rated secondary current at the standard burden [10]. This equates to a maximum erroneous current of 20 percent of the terminal current, so a slope setting of 25 percent would be in order. This calculation applies for the case when the CTs have identical characteristics and do not saturate. If this is not the case, then the performance of the CTs under different external fault conditions needs to be evaluated. For example, assume that for an external fault or during the energization of the GSU that the CT at the generator terminal saturates before the CT at the neutral of the machine. A large erroneous differential current will be computed by the differential element; the following two options are available to the protection engineer:

- Increase the slope setting to a value greater than the error created by the erroneous differential current.
- Employ a relay that has the ability to detect an external fault. Secure the relay element during this period, and return the relay to its normal operating mode once the external fault has cleared.

The first option sacrifices the sensitivity of the element; however, the second option maintains the sensitivity and increases the security of the differential element. Because generators not only have a large fault current but also a large X/R ratio, the possibility of the CTs becoming saturated for an external fault is very real. For this reason, selecting a relay with the ability to detect an external fault and to secure the relay during this time is advantageous.

Another issue that arises when the generator is used to energize the GSU is that the GSU and the generator have a very high X/R ratio. Even though the energization current may be low, the energization current will contain a high dc component. This will eventually drive the CTs into saturation and cause the differential element to operate. It is advisable to use a relay that has the ability to detect this condition and, similar to the external fault condition, switch the relay into high security mode.

IX. Conclusion

This paper describes the factors influencing the design of the stator winding of a synchronous generator. We discuss the construction of the individual components and describe in detail the factors that lead to winding deterioration and failure. This paper covers generator grounding practices and applicable protection methods. We also present and compare various differential protection methods.

Using an RTDS model, we simulate internal faults and determine the response of various protection elements. The results show that the phase, negative-, and zero-sequence differential protection elements have the sensitivity to detect all of the applied phase-to-phase faults. However, due to limitations of the model, it was not possible to simulate faults close to the generator neutral on both phases. Better models are needed to assess protection coverage for this fault type.

The simulation results also show that differential elements are effective in detecting ground faults. For this fault type, the model allows faults to be applied at any point on the winding. The results show that the relationship between fault position and fault contribution is approximately linear for faults near the generator neutral. This approximate linear relationship is very useful for assessing protection sensitivity for ground faults in general.

The RTDS simulation did not indicate that differential elements were effective in detecting turn-to-turn faults; however, other functions, such as impedance or directional protection, can provide a degree of protection. Model improvements, such as implementing parallel winding branches, would allow a more comprehensive investigation of this fault type.

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XI. Biographies

Normann Fischer received a Higher Diploma in Technology, with honors, from Technikon Witwatersrand, Johannesburg, South Africa, in 1988; a BSEE, with honors, from the University of Cape Town in 1993; and an MSEE from the University of Idaho in 2005. He joined Eskom as a protection technician in 1984 and was a senior design engineer in the Eskom protection design department for three years. He then joined IST Energy as a senior design engineer in 1996. In 1999, he joined Schweitzer Engineering Laboratories, Inc. as a power engineer in the research and development division. He was a registered professional engineer in South Africa and a member of the South African Institute of Electrical Engineers. He is currently a senior member of IEEE and a member of ASEE.

Dale Finney received his bachelor's degree from Lakehead University and master's degree from the University of Toronto, both in electrical engineering. He began his career with Ontario Hydro, where he worked as a protection and control engineer. Currently, Mr. Finney is employed as a senior power engineer with Schweitzer Engineering Laboratories, Inc. His areas of interest include generator protection, line protection, and substation automation. Mr. Finney holds several patents and has authored more than a dozen papers in the area of power system protection. He is a member of the main committee of the IEEE PSRC, a member of the rotating machinery subcommittee, and a registered professional engineer in the province of Ontario.

Douglas Taylor received his BSEE and MSEE degrees from the University of Idaho in 2007 and 2009, respectively. Since 2009, he has worked at Schweitzer Engineering Laboratories, Inc. and currently is a power engineer in research and development. Mr. Taylor is a registered professional engineer in Washington, is a member of the IEEE, and has authored several technical papers.

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