Working Group J12

Improved Generator Ground Fault Schemes

Power System Relaying and Control Committee
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of the
Rotating Machinery Protection Subcommittee

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1. Introduction

The purpose of this paper is to review new or improved methods related to generator ground fault protection. Established stator ground fault protection schemes as referenced in IEEE Guides C37.101-2006 [1] and C37.102-2006 [2] are proven to be effective under the most common failure modes but may fall short in detecting faults that develop due to arcing faults or via uncommon mechanisms such as broken conductors. This paper discusses the limitations of existing protection schemes and presents several new approaches that could be considered to complement traditional ground fault protection schemes in high impedance grounded generators.

Table 1 Definitions of Acronyms and Abbreviations

Acronym	Description
G	Generator
64G	Generator ground fault protection
59G	Fundamental NGR overvoltage element
27TH	Third-harmonic neutral undervoltage element
59THD	Third-harmonic voltage differential element
64S	Sub-harmonic injection element
46	Negative-sequence overcurrent element
47	Negative-sequence overvoltage element
59GS	Neutral overvoltage supervision element
GCB	Generator circuit breaker
GSU	Generator step-up transformer
IPB	Isolated phase bus
KAF	Kalman adaptive filtering
NGR	Neutral grounding resistor
NGT	Neutral grounding transformer
N_{NGT}	Neutral grounding transformer turns ratio
NT	GSU turns ratio
NVT	Generator voltage transformer turns ratio
RN	Neutral grounding resistance reflected to the NGT primary
SYS	Power system
UAT	Unit auxiliary transformer
VG_{PP}, VG_{PN}	Generator nominal phase-phase and phase-neutral voltage
VS_{PP}, VS_{PN}	Power system nominal phase-phase and phase-neutral voltage
VG_1, VG_2, VG_0	Generator positive, negative and zero sequence voltage
VS_1, VS_2, VS_0	Power system positive, negative and zero sequence voltage

V_{N3}, V_{P3}	Third harmonic voltage at the generator neutral and terminals
XC_0	Generator shunt zero sequence capacitive reactance
XC_{IW}	Transformer inter-winding capacitive reactance
Z_0	The parallel combination of $3 \cdot RN$ and XC_0
ZVT	Generator voltage transformer impedance
RF	Fault resistance
ZS_1, ZS_0	Power system positive and zero sequence impedance

2. Stator Winding Construction and Generator Grounding

The stator winding of a synchronous generator is made up of insulated copper conductors fitted into the stator core slots in a double-layer arrangement. Windings are categorized as lap-connected (where each coil is lapped over the next to form the winding) or wave-connected (where coil sides are located under alternating poles around the stator). In smaller machines the winding is built up from form-wound, multi-turn coils. They are made from an insulated continuous loop of copper wire that forms into coils before being inserted into the stator core. Additional insulation can be applied over each coil. In larger machines (greater than 50 MW) the winding will be the Roebel-bar type – also known as a "half-turn" coil. With this type, only one half of a coil is inserted into a slot at a time, which makes it easier than inserting two sides of a form-wound coils into two slots simultaneously. Electrical connection is made at both ends of the bar.

For both the coil and bar types, the groundwall insulation isolates the conductor from the stator core. It is rated for the full phase-phase voltage of the machine. It's important that the groundwall insulation be free of voids to prevent partial discharge. Windings rated above 6 kV also have a semiconducting layer to prevent large voltage gradients in areas where the insulation is not in direct contact with the core. The end-winding is the region at either end of the core where the bars or coils transition between the slots. The winding needs to be well braced in this region since it's outside the core [3].

A winding failure is usually the result of gradual deterioration of the insulation followed by a transient event. Deterioration can be due to thermal, electrical, mechanical, and environmental mechanisms. The effects are usually cumulative. Transient events include voltage surges, external faults, high-pot tests, poor synchronization or accidental energization [4].

Thermal degradation is the breakdown of chemical bonds in the insulation due to excessive heating. This weakens the insulation mechanically making it more brittle. Excessive heating results from overloading, cooling system failure, high resistance connections, and other factors.

Electrical degradation is the breakdown of insulation due to electrical stress; including partial discharge and slot discharge. Partial discharge is arcing across internal voids within the insulation. The arcing breaks down the insulation on the interior surface of the void, causing it to grow. Partial discharge can occur anywhere in the winding including the end winding. A slot discharge occurs when a void develops in the slot between the groundwall 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.

Mechanical degradation is the wearing or cracking of the insulation due to excessive movement. It can occur in the end winding due to poorly designed/constructed bracing. The high transient torque produced by an out-of-phase synchronization or a close-in fault can also loosen the bracing. The impact of repeated events is cumulative. Excessive vibration will lead to wearing or cracking of the insulation. The winding may also loosen within the slot due to insulation shrinkage or excessive thermal cycling. This allows the bars to vibrate due to magnetic forces, resulting in wearing of the insulation.

Environmental degradation is the breakdown of insulation due to the penetration of water, oil, or dust. Contaminants can weaken the insulation electrically and/or mechanically, depending on the type of insulation. Contamination also provides a medium for surface tracking, especially in the end winding.

It is important to note that the degradation effects described above often act in concert with one another. For instance, insulation that is weakened due to overheating then becomes more easily subject to cracking from vibration. Similarly, movement of a bar within a slot can cause wearing of the semiconducting layer. If the bar subsequently pulls away from the ground-wall, then a slot discharge will result.

This report is primarily concerned with synchronous generators connected via a GSU to a power system. High-resistance or resonant grounding is usually used to limit the fault current to a level below which core damage is not a concern. The trade-off is that significant overvoltages can occur on the healthy phases during a ground fault. These overvoltages are confined to the stator, IPB, GSU low voltage winding, and UAT high voltage winding.

Figure 1 shows a high-resistance grounded generator with a fault located at point m on the stator. Grounding is usually achieved using a distribution transformer and a resistor connected across the secondary winding of the transformer as shown in the figure.

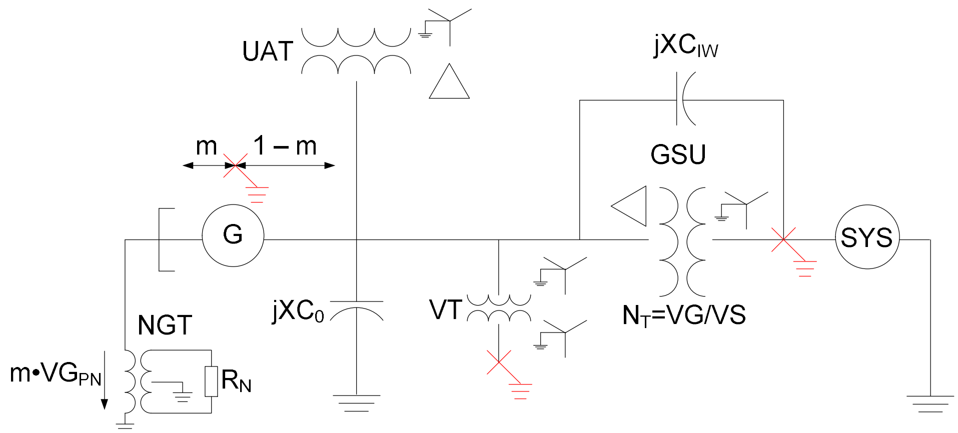

Figure 1: Example System

Note that in Figure 1, the GSU low voltage winding is delta-connected. The high-voltage winding of the unit auxiliary transformer (if present) is delta-connected at the output of the generator. There is a small coupling between other zero-sequence networks due to capacitance between transformer windings. However, generally, there is very little system contribution to ground faults on the stator.

The voltage rating of the primary winding of the distribution transformer is typically equal to the line-to-line voltage rating of the generator, with the secondary rating of the distribution transformer being in the range of 120–480 V. This arrangement allows for the resistor to be of a low ohmic value and of rugged construction. The kVA ratings of the transformer and resistor are related to the capacitive current to ground during a single-phase-to-ground fault. The resistance value is sized to limit transient overvoltages. This is done by setting the neutral resistance value (reflected to the primary) equal to one-third of the total phase-ground capacitance value [5].

3. Ground Fault Protection Methods

Figure 2 shows the various schemes that are in use for detection of grounds on high resistance grounded generators and the typical coverage provided by each scheme.

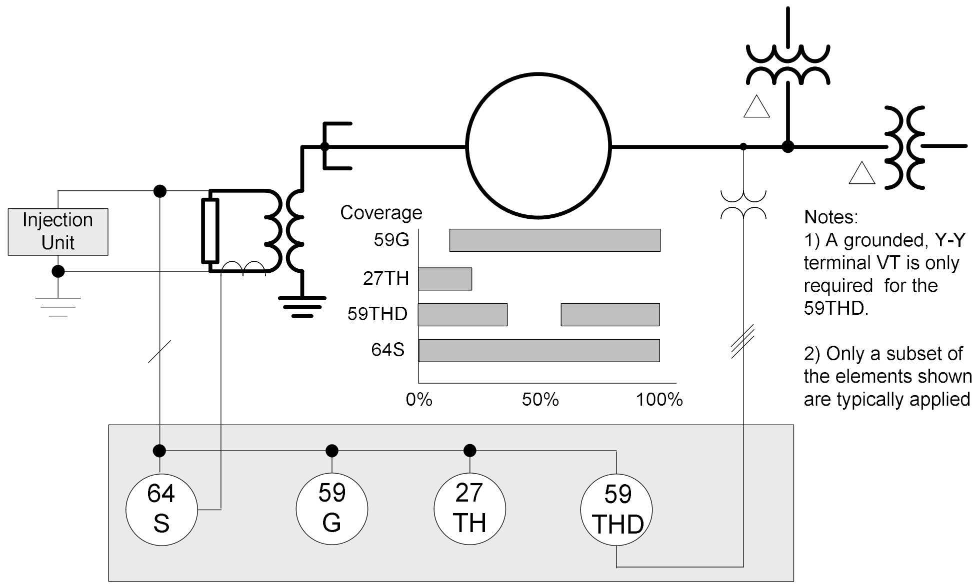

Figure 2: Generator Ground Fault Schemes

The system of Figure 1 is used to analyze generator internal ground faults at location m, external ground faults at the GSU HV terminals and external ground faults at the VT secondary terminals. The neutral resistor is assumed to be sized such that $R_N = X_{C0}/3$. Additional assumptions are $XG_0 \approx 0$, $XG_1 << XC_1$, and $XG_1 << XC_0 \| 3R_N$,

The parameters for the system are given in Table 2. Note that all impedances are in ohms referred at either the generator or system voltages.

TABLE 2. Example System Parameters

Symbol	Value
VG_{PP} / VG_{PN}	24 / 13.86 kV
MVAG	1450 MVA
INOM	34.9 kA
VS_{PP} / VS_{Pn}	345 / 199.2 kV
XG_1	$= X''_d = 0.057\ \Omega = 0.144$ pu ^{G}
XC_0	7.407 kΩ
RN	$= XC_0 / 3 = 2.469$ kΩ
ZT	$0.328+11.492j\ \Omega = 0.14j$ pu ^{S}
XC_{IW}	663 MΩ
ZS_1	$10 + 40j\ \Omega = 0.12 + 0.49j$ pu ^{S}
ZS_0	$6 + 30j\ \Omega = 0.07 + 0.37j$ pu ^{S}

Z_{VT}	12.8 + 19.7j kΩ [G]
N_T	VS_{PP} / VG_{PP} = 14.4
N_{VT}	VG_{PP} / 120 = 200
N_{NGT}	VG_{PP} / 240 = 100

[G] Referred to Generator

[S] Referred to System

3.1 Fundamental Neutral Overvoltage – 59G

One method to detect ground faults over a large portion of the generator windings is to connect an overvoltage relay so that it monitors the voltage impressed across the neutral grounding resistor. Significant harmonic components are produced by the generator due to the fact that a practical winding cannot have a sinusoidal distribution around the stator and additionally by the non-uniform air-gap in salient pole machines. Consequently, this element is typically designed to respond to only the fundamental component of the voltage and attenuate or reject any harmonic voltage components.

Because high-impedance-grounded machines are typically unit-connected, during normal generator operating conditions there should be only a very small neutral current and correspondingly, a very small voltage across the grounding resistor. In Fig. 1 a solid ground is placed on one phase of the machine at m. Since R_N, when reflected to the primary, is typically on the order of several thousand ohms and the generator zero-sequence impedance is very small, the voltage across the NGT primary is *m* times the generator rated line-to-neutral voltage.

Of note is that a ground fault at exactly the neutral of the generator winding will not impress any voltage on the 59G relay. So, this relaying scheme is blind to faults at or near the neutral of the generator windings.

Using the example from figure 1 we can calculate the pickup setting

For a desired coverage of 95% the pickup of the 59G will be:

$$59G_{PKP} = \frac{(1-m)VG_{PN}}{N_{NGT}} = \frac{(1-0.95)\cdot 13.86kV}{100} = 6.93\ V \qquad (1)$$

3.1.1 Coordination for GSU HV Faults

The 59G can respond to ground faults at the GSU HV terminals. This is due to capacitive coupling between the GSU windings. The circuit to determine this voltage is a simple series voltage drop circuit comprised of the interwinding capacitance in series with the parallel combination of the generator neutral resistance and the phase-ground capacitance of the generator bus system (usually dominated by the stator phase-ground capacitance). This circuit is shown in Figure 3.

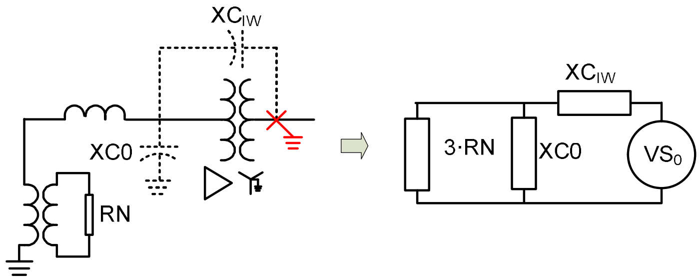

Figure 3 GSU HV Ground Fault and Equivalent Circuit

The interwinding capacitive reactance, XC_{IW}, is typically much larger than the parallel combination of 3·RN and XC_0. However, a small percentage of the VS_0 voltage will be impressed across 3·RN nonetheless. Due to the sensitive setting of the 59G it can operate during this HV phase-ground fault.

The example system can be used to calculate the voltage impressed across the neutral grounding transformer of a machine during an actual HV system ground fault as follows with Z0 being the parallel combination of 3RN with XC0. Using the example system of figure 1;

$$Z_0 = \frac{3RN\cdot(-jX\quad_0)}{3RN-j\quad_0} = \frac{7.4\cdot(-j7.4)}{7.4-j7.4}k\Omega = 3.7\ k\Omega\ -\ j3.7\ k\Omega\ =\ 5.24\ k\Omega\angle-45° \qquad (2)$$

A worst-case scenario assumes that the full phase-neutral system voltage appears across the zero-sequence network;

$$VG_0 = \frac{VS_0\cdot Z_0}{Z_0-jXC_{IW}} = \frac{199\ kV\cdot(3.7\ k\Omega\ -\ j3.7\ k\Omega)}{(3.7\ k\Omega\ -\ j3.7\ k\Omega)-j663\ k\Omega} = 1.95kV\ \angle 44.6° \qquad (3)$$

With a neutral VTN_{NGT} ratio of 100:1 this would impress 19.53 V across the 59G relay (which was set earlier to 6.93V to obtain 95% coverage). The traditional practice to maintain sensitivity of the function but prevent it from misoperating for the GSU HV fault was to time-delay its operation (delays of 1 to 5 seconds being common).

3.1.2 Coordination for VT Secondary Faults

The 59G will respond to ground faults at the VT secondary terminals as can be seen in Figure 4. Note that Z_0 is the parallel combination of $3R_N$ and jXC_0 which are approximately equal in magnitude. Therefore, I_0 is typically $\sqrt{2}$ larger than the current in the generator neutral.

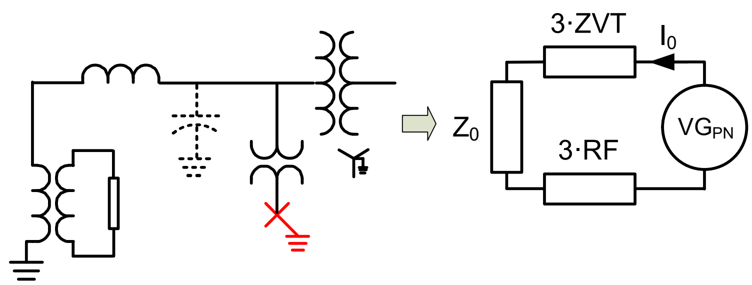

Figure 4 **VT Secondary Ground Fault and Equivalent Circuit**

The traditional way to avoid a misoperation is to time-delay the element to coordinate with the VT secondary fuses. Note that coordination with the primary fuses can lead to unacceptable delays. The 59G element voltage pickup must be converted to an equivalent minimum amperage pickup and time coordinated with the VT secondary fuses to ensure the 59G element does not operate prior to the VT secondary fuses.

The element must not operate at the minimum pickup of the 59G. The circuit of Figure 4 can be used to calculate the fault current. Setting RF to zero, the maximum VT secondary fault for which the 59G will respond is:

$$IFmax_{pri} = \left|\frac{3 \cdot VG_{PN}}{3 \cdot ZVT + Z_0 + 3 \cdot RF}\right| = \left|\frac{3 \cdot 13.86\ kV}{3 \cdot (23.5\ k\Omega\ \angle 57°) + 5.24\ k\Omega\ \angle -45°}\right| = 0.6\ A \tag{4}$$

A VT primary fault is not limited by Z_{VT}. This gives a fault current of:

$$IFPRI_{pri} = \left|\frac{3 \cdot VG_{PN}}{Z_0}\right| = \left|\frac{3 \cdot 13.86\ kV}{5.24\ k\Omega\ \angle -45°}\right| = 8\ A \tag{5}$$

However, even a small fault resistance will reduce the fault current. The minimum fault current for which the 59G will respond is:

$$IFmin_{pri} = \left|\frac{3 \cdot m \cdot VG_{PN}}{Z_0}\right| = \left|\frac{3 \cdot 0.05 \cdot 13.86\ kV}{5.24\ k\Omega\ \angle -45°}\right| = 0.4\ A \tag{6}$$

In Figure 5 the VT fault currents are plotted. In this example, a 0.2 second coordination margin is introduced between the VT secondary fuse and 59G at the minimum fault value. This results in a 59G delay of 0.3 seconds. The secondary fuse in this example is 30 amps. Selection of a smaller fuse can allow a somewhat shorter delay, but the improvement will be marginal.

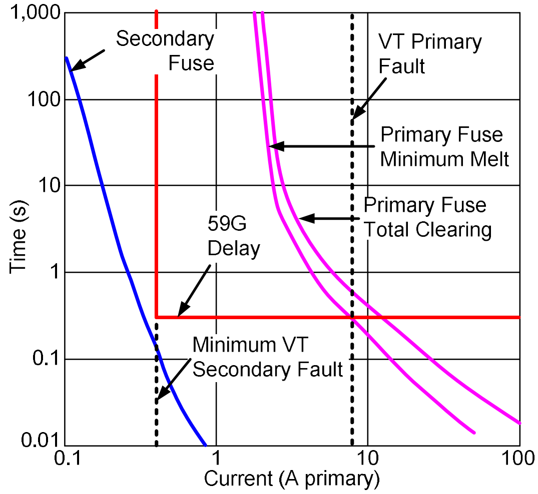

Figure 5 Coordination of the 59G with the VT Secondary Fuses

3.2 Third Harmonic Schemes – 27TH, 59THD

There are several protection schemes that utilize the third harmonic voltage at the neutral or at the generator terminals as a way of detecting faults near the generator stator neutral. These protection elements would be used in addition to the 59G element that is used to protect the upper 90-95% of the winding. These schemes assume there is adequate third harmonic voltage present at the neutral of the machine. According to [1], this typical value needed is approximately 1% of the rated voltage. There are three types of third harmonic element: 59TH, 27TH, and 59THD. Only the latter two are in common use.

The 27TH relay operates on the decrease in the third harmonic voltage across the grounding impedance in case of a single line to ground fault close to the neutral of the generator. Note that the undervoltage relay is required to be supervised (normally by an overvoltage relay at the generator terminal) to prevent the relay from operation while excitation is removed. The 59TH relay operates on the increase in the third harmonic voltage on the generator terminals in case of a single line to ground fault at or near the generator neutral. The last way is using the third harmonic voltage differential to detect stator ground faults in the lower and upper areas of the generator winding. A single line to ground fault either in the upper or lower portion of the winding would disrupt the pre-determined third harmonic voltage balance between the generator terminal and neutral causing the relay to operate. Note that this element has a blind spot near the middle of the stator winding. As a result, it is normally utilized in addition to the fundamental neutral overvoltage element to provide 100% stator ground fault coverage.

Setting the third harmonic voltage elements requires field tests to determine third harmonic voltage levels at all expected operating conditions of the generator. This is, however, especially critical when setting the 27TH.

3.3 Injection Scheme – 64S

An alternate method of 100% stator ground protection used on high-impedance grounded machines injects a signal to measure the stator insulation impedance. This scheme uses dedicated equipment to inject a zero-sequence off-nominal frequency signal into the stator of the generator. The resulting voltage and current of the injected signal are then measured via filtering and used to calculate insulation impedance to detect a ground fault. There are several variations of the 64S. This section focuses on the impedance-measurement approach.

The injection system is typically connected to the secondary circuit of the neutral grounding transformer; with a CT placed in the neutral grounding circuit, as shown in Figure 2, to measure the current reflected into the generator stator. By measuring the real and imaginary components of the injection current, and referencing the injection voltage, both the resistance and capacitance of the system can be calculated. Other implementations are possible.

As the system configuration changes, the calculated capacitance will fluctuate correspondingly, however, by monitoring magnitude changes in the resistive component, ground faults and insulation deterioration can be detected. Variations of this scheme exist including modifications of the injection point (e.g. a wye/broken delta set of transformers on the terminal side of the generator) and the injection frequency (including both subharmonic frequencies and slightly above nominal frequencies). The basic principle behind the scheme remains the same in each of these variations.

Commissioning of these systems is recommended to establish accurate baseline values such as transformer impedance. On new machines, the insulation resistance is typically well above 100 kΩ, but as the insulation ages, it degrades, and the value will begin to drop. Note that the relay measurement may not be very accurate above 100 kΩ, depending on the relay. An example table with impedances obtained during commissioning is shown in Table 2. Once a baseline measurement is established, a pickup is set based on this value using engineering judgment and manufacturer guidelines. Additionally, steps can be taken to provide coordination for a ground fault on the secondary of wye connected VTs. The injection system will be able to see this ground, but the VT winding resistance will be in series with the fault. Depending on the size of the VT and the turns ratio of the VT, it may be possible to set the pickup of the injection system such that it does not pickup for a fault on the secondary of the VT circuits, allowing faster tripping times as coordination with VT fuses is not required.

This scheme is not subject to the same security concerns of the third harmonic 100% stator protection schemes. It also does not need to coordinate with the clearing time of system faults as the 59G does. Additionally, the scheme can measure insulation degradation, and detect grounds while the unit is still at a standstill and remains secure during system configuration changes. However, there are a few considerations that must be taken into account. The injected voltage will now exist across the neutral grounding resistor, therefore, if the other generator relays have ground protection enabled, care must be taken to ensure they either will not respond to this frequency of voltage or that additional margin is added into the pickup. Also, this voltage will exist on the stator winding and generator bus, even while the unit is offline. Care must be taken to ensure this injection source is included in the safety clearance of the machine during maintenance activities.

Table 2 Subharmonic Field Measurements

	Stator Insulation (kΩ)	Capacitance (μF)	Measured by injection scheme (kΩ)
Unit Offline	59.2	3.036	24.387
VT Ground			
- Z Phase	8.05	2.902	6.234
- Y Phase	8.11	2.912	6.412
- X Phase	8.57	2.941	6.718

When this method was first developed, many implementations used the magnitude of the measured current; consisting of both real and reactive portions of the current. The reactive component is introduced by the capacitance-to-ground of surge capacitors, IPB, generator winding, GSU secondary winding and UAT primary winding. In some installations, if the generator to ground capacitance is large enough (i.e., due to a long IPB); the increased levels of total current, due to the increase in capacitive current, would require desensitizing the protection. However, the current can be resolved into real and reactive components. For faults not directly at the neutral, the use of the real component only for fault detection allows for more sensitive settings. The influence of current (fundamental or third harmonic) which could cause interference with the sensed injection current is minimal due to the choice of injection frequency and the higher capacitive reactance seen by these components. This resulting current is often orders of magnitude under the sensed real current trip setting.

3.4 Isolated phase bus (IPB) protection

Strictly speaking, this is not stator protection but IPB faults are part of the same protection zone. Furthermore, an intermittent ground fault in the IPB can produce voltage transients on the healthy phases which put the stator at risk as described in section 4.

Figure 6 is a typical protection scheme for a Combustion Turbine Generator. The equipment setup includes a generator circuit breaker.

During normal operation, when the GCB is closed, the isophase bus (IPB) is grounded through the neutral of the feeding generator. During startup and shut down operations, the plant auxiliary system is back fed from the switchyard through the GSU. During such operating conditions, the GCB is open and the IPB section from the GSU to the GCB becomes ungrounded.

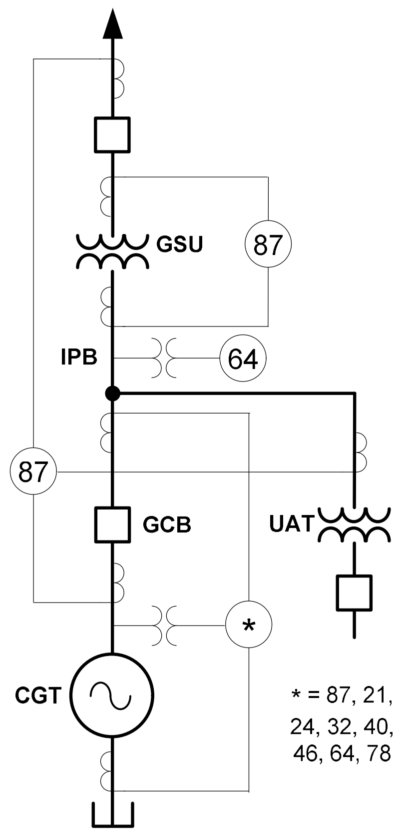

Figure 6: Typical CGT One-line

Per Section 5.4.1.1 of the IEEE Guide for the Application of Neutral Grounding [6], when an ungrounded system experiences a ground fault, the transient voltage on the unfaulted phases can exceed normal line-ground voltage:

> "The sustained voltages to ground on the unfaulted phases will reach line-to-line values … If the fault resistance is low, the predominant impedance is capacitance; current zero occurs at the fault at voltage crest. It becomes possible for the high voltage to re-ionize the arc path and for the arc to restrike. Such an intermittent fault may be established with the arc restriking every half-cycle, equivalent to switching a capacitor every half-cycle …"

Restriking arcs may lead to high transient overvoltages in ungrounded systems. These overvoltages are suspected of causing insulation failures in otherwise unrelated equipment during ground faults. To avoid these possibilities, it is becoming a frequent practice to use high-impedance grounding for the ungrounded section of the IPB. This is achieved by installing wye-broken delta grounding transformers with a stabilizing resistor across the broken corner.

3.4.1 Wye-Broken Delta Grounding Transformer Method

The IPB neutral is derived by using three small transformers (5 kVA to 10 kVA) connected in wye on the primary side and in broken delta on the secondary side. The primary winding neutral is solidly grounded. A current transformer and ammeter are sometime used so that ground-fault current can be measured. A resistor with taps is connected across the secondary broken delta winding so that the proper resistance can be used to control the current, which will flow into a ground fault. An over voltage relay is connected across the resistor for ground fault alarm and/or fault clearing purposes. This scheme is similar to Grounding Method VI of the IEEE Guide for Generator Ground Protection [1]. The component of ground-fault current determined by the high-resistance neutral ground must be slightly greater than the system charging current so that resonance is damped.

In this method, small conductor diameter cables are used to connect the grounding transformers to IPB system. In the event of faults in the grounding transformers, the connecting cables could ignite and cause fire. Such an event has been experienced at a power station. Also, the installation of the cable and its proper clamping is also an issue. Therefore, a risk of fire is associated with this grounding method. An alternate approach is to use the ferroresonance winding of the VTs in the GCB, if available, to prevent the transient over voltage from reaching an unacceptable level due to an arcing ground fault on the ungrounded section of the IPB.

3.4.2 Ferroresonance Suppression in the IPB VT Winding

Figure 7 is a typical drawing of a GCB with an integrated VT. It shows the ferroresonance suppression circuit. The generator capacitance and VT magnetizing reactance form a resonant circuit which will be excited during a voltage transient. This can cause undamped voltage oscillations which can drive the VT into saturation; causing VT damage. The suppression circuit is designed to dampen oscillations by adding burden to the circuit, The VT's primary winding is connected in wye and its neutral is solidly grounded. The VT's secondary winding for the ferroresonance circuit is connected in broken delta and a loading resistor is connected across the broken delta. This arrangement is similar to Wye-broken-delta grounding transformer method except that VTs are used instead of grounding transformers. This method eliminates the use of connecting cables and the risk of any fire hazard associated with using the grounding transformers scheme.

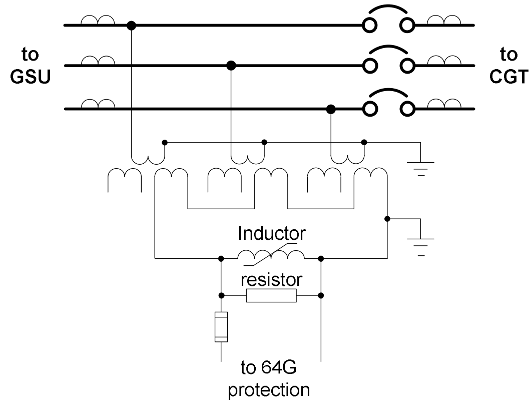

Figure 7: Generator Circuit Breaker with VT and Ferroresonance Suppression

The grounding of a system with voltage transformers requires a resistive loading that may be considerably above the accuracy volt-ampere rating of the transformers and may approach the thermal volt-ampere rating.

The VT can be used to ground the IPB during the back-feed scenario and will provide sufficient neutral grounding current and the necessary resistive damping to limit overvoltage on the IPB in the event of an arcing ground fault on the IPB section, if the thermal rating of the VT in the GCB with a ferroresonance suppression circuit is adequate.

Studies have shown that the continuous thermal rating of the VT windings can be exceeded. Therefore, tripping the breakers(s) from the ground fault detection relay will clear the source of the ground fault before the short time thermal rating of the VT winding is exceeded.

4. Intermittent Ground Faults

This section presents a simplified analysis of an intermittent ground in a high-impedance grounded network. The captured field events of section 6.5 show that actual grounds display a much more chaotic behavior. The circuit for a high-impedance grounded generator with a ground fault at the GSU HV terminals is shown for the example system of Figure 1. A simplified circuit for an intermittent ground fault with no fault resistance is shown in Figure 8.

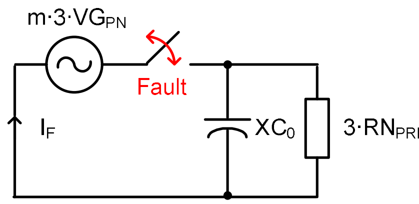

Figure 8: Intermittent Ground Fault Equivalent Circuit

The steady-state fault current is then,

$$I_F = \left|\frac{m \cdot 3 \cdot VG_{PN}}{Z_0}\right| \cong \sqrt{2} \cdot \frac{m \cdot VG_{PN}}{RN_{PRI}} \qquad (7)$$

Typically, the steady state fault current for a solid fault at the terminals (m=1) will be in the range of 10-25 amps and therefore below the level expected to cause damage to the machine.

At the instant of a fault there will also be two transient fault components [7]. The first component is a decaying exponential that results from the discharge of the faulted-phase capacitance. The second is a damped sinusoid that results from the current flow through the capacitance on the two healthy phases. The peak value of the decaying exponential is VPN/RF with a time constant of C0·RF. This component therefore takes the form of a large, narrow spike. The sinusoidal frequency and decay time constant of the second component are determined by 1.5·L″d and 2·C0. This component has a smaller magnitude but a slower decay.

Figure 9 is a plot of the fault current resulting from an intermittent AG fault that begins at the voltage peak of each half cycle. Note that this current is considerably larger than the steady-state fault current which is present but not discernable on this plot. The fault current is modeled for a fault at 100% and 10% of the stator winding (measured from the neutral). Figure 10 is a zoomed view of Figure 9.

Figure 11 is a plot of the voltage at the generator terminals for the same faults. Note that for the fault at 100% there is a significant transient superimposed onto the steady-state $\sqrt{3}$ voltage shift. Note also that the fault at 10% produces a much less significant transient.

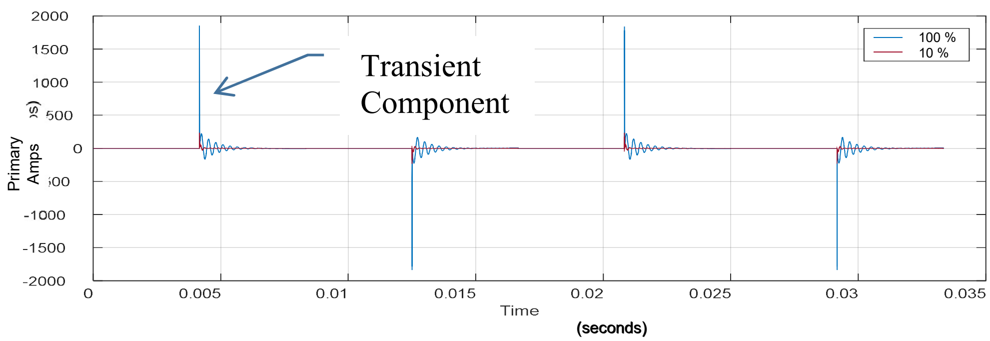

Figure 9 − Fault Current for an Intermittent Fault at 100% and 10%

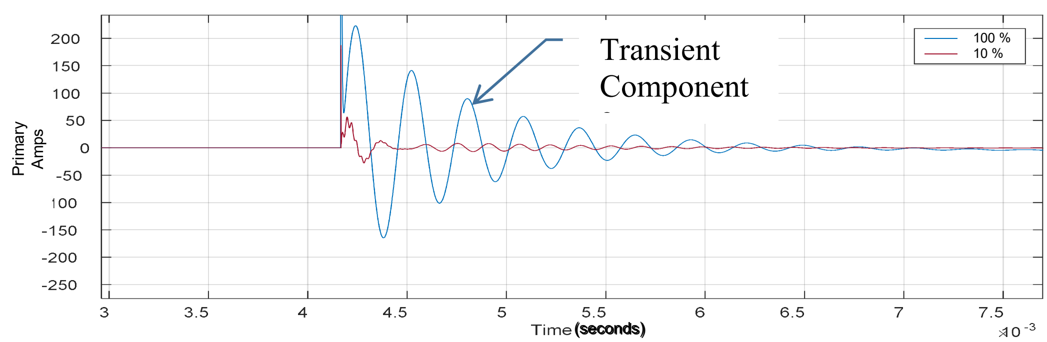

Figure 10 − Fault Current for an Intermittent Fault at 100% and 10% (Zoomed)

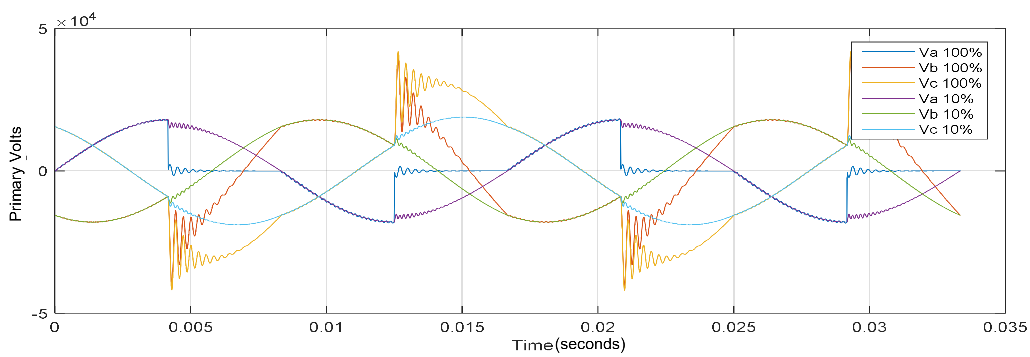

Figure 11 − Terminal Voltage for an Intermittent Fault at 100% and 10%

For a continuous fault, the transient components appear only at the beginning of the fault. When the fault is intermittent, transients appear at every restrike, which can potentially be every half-cycle. One study has shown that the peak value of the generator ground fault current can exceed the steady state value by a factor of 60-80 and that the fault energy for an intermittent fault occurring twice a cycle can exceed the steady state value by a factor of twenty [7]. Furthermore, the healthy phases are also exposed to voltage transients.

5. Ground Fault Evolution due to a Broken Stator Bar

Stator winding protection is chiefly provided by the stator differential (87G) and ground fault (64G) elements. These schemes are intended to detect shunt faults arising from insulation failures between phases or from phase to ground. Series faults are also possible within the stator winding. A series fault can result from a bar fracture (due to high vibration, for example) or the failure of a welded or bolted connection [8]. This fault will not be detected by a traditional differential since there is no difference in the current at each end of the winding. It will not be detected by the ground fault protection since no current flows to ground. The current unbalance (46) element could respond to a series fault but this protection is intended to provide thermal protection for the rotor and consequently it is not expected to operate quickly enough to provide effective protection. Split-phase protection (50SP) could detect a series fault but this element is usually only applied to hydro units.

When a series fault occurs, the stator current will continue to arc across the fault point. This arc will generate extreme heat; vaporizing the conductor in the region of the fault until it eventually burns through the insulation wall. At this point the arcing to ground can occur [8].

Once the series fault evolves into a ground fault, the ground fault protection can respond to the fault. It is important to note that stator ground fault protection has been applied primarily to detect shunt faults. On high-impedance-grounded generators the ground fault current from a shunt fault is limited to about 10-25 amps. This level of ground fault current is not high enough to cause iron burning. For this reason, it has not been considered critical to quickly remove the generator from service. For a ground fault that evolves from a series fault, the damage is due to the series fault and is much higher.

The fundamental neutral overvoltage element will operate to trip the unit for ground faults occurring over about 95% of the winding measured from the terminals. This protection is delayed to coordinate with system ground fault protection and with the generator VT secondary fuses (see section 3.1). It is warranted to apply 100% stator ground fault protection to cover the remainder of the winding. However, 100% stator ground protection presently is not universally applied to protect synchronous generators and, in some cases is configured to alarm only. It is important to note that series faults are often associated with the connections that make up the generator neutral [8]. Without effective coverage, a series fault occurring at the neutral could result in significant damage to the generator. Either of the two 100% stator ground methods discussed in sections 3.2 and 3.3 can detect this event. Clearly the element must be configured to trip to provide effective protection.

6. Methods for Improved Protection

A common belief has been that, since the phase-ground fault current in the generator is relatively small, there is little risk to the machine during the long trip delay that has been typically applied. Section 2 points out that ground faults are usually preceded by winding degradation. Once a ground fault occurs, a second ground is more likely due to existing degradation and the elevated voltage on the unfaulted phases. The resulting phase-phase-ground fault would most likely be catastrophic to the machine. Section 4 showed that ground faults usually start as intermittent faults and produce higher voltages and much more fault energy than the steady-state ground fault. In addition, as was seen in section 5, there are very damaging failure modes that can occur in the winding that may not be seen until they evolve into a ground fault. It is therefore apparent that the sooner a ground fault can securely be cleared, the better. This section describes several methods for improved protection.

6.1 Accelerated Tripping using Negative Sequence Current

During an external ground fault, significant negative sequence current will flow through the negative sequence network of the generator. This quantity can be used as a "torque control" to block fast operation of the 59G when the operating voltage it experiences is due to the zero-sequence voltage coupled across the winding-to-winding capacitance of the step-up transformer during an HV system ground fault. If the 59G experiences an operating quantity above its pickup in the absence of this negative sequence current it can be allowed to operate significantly faster than the typical 1 to 5 seconds. It can securely operate in as fast as 5-10 cycles [9].

The logic for the scheme is shown in Figure 12.

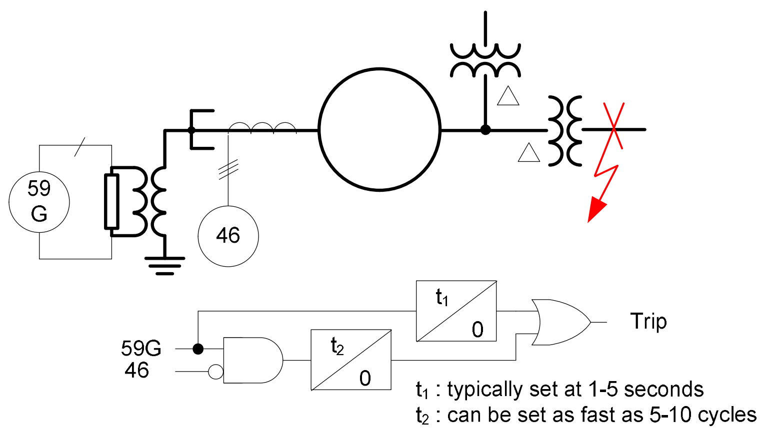

Figure 12 Negative Sequence Current Acceleration

It is critical that the negative sequence detector always picks up for an external fault. Otherwise false tripping may occur via the accelerated (t_2) path. The current can be calculated using the sequence network of Figure 13.

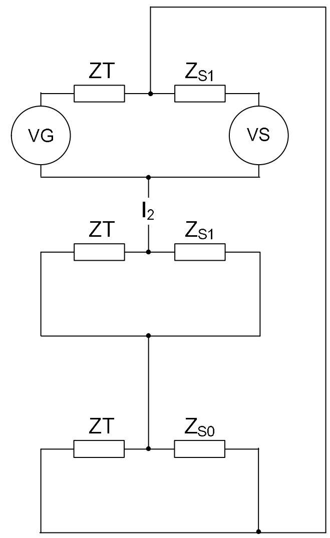

Figure 13 GSU HV Terminal Ground Fault

$$I_2 = \frac{1}{2(ZT \| Z_{S1}) + ZT \| Z_{S0}} = \frac{1}{2(0.14 \ \|(0.12+ \ .48j)) + (0.14j \| (0.07+0.36j))} \quad (8)$$

$$I_2 = 3.0 \angle -85.7° \ per \ unit$$

$$IG_2 = I_2 \cdot \frac{Z_{S1}}{Z_{S1}+ZT} = 3.0 \angle -85.7° \cdot \frac{0.12+ \ .48j}{0.12+0.48j+0.14j} = \ 2.38 \angle -88.4° \ per \ unit \quad (9)$$

The negative sequence current for an external fault is expected to be more than 200% of the generator rated current. The generator unbalance element is set to pick up at the negative sequence withstand of the generator; typically, 5-10% of generator rated current. Since unbalance protection is found on virtually all generators, the pickup operand provides a simple way to implement the scheme.

It's possible that a fault on the LV terminals of the UAT could cause the 59G to misoperate. This is much less likely due to the lower voltage at this terminal. However, analysis described above can be carried out to check for this possibility. If the 59G is at risk, the 50QS pickup can be reevaluated to determine a suitable pickup or the acceleration scheme can be not used [9].

The typical time delay of 5-10 cycles coordinates with VT secondary, NON fuses. It's generally acceptable to refrain from coordination with the primary VT fuses [9]. Otherwise much of the advantage of accelerated tripping are lost. Coordination is not required for certain VT secondary connections as described in Section 6.3

6.2 Accelerated tripping using Negative Sequence Voltage

This method uses the negative sequence voltage measured at the generator terminals to distinguish between a generator internal ground fault and an external ground fault at the HV terminals of the GSU [10]. The scheme is supervised by a negative-sequence overvoltage function (47) and a zero-sequence overvoltage function (59GS). The scheme is similar to the negative sequence current scheme described in section 6.1. As with that scheme it is critical that the supervising element, 47, always picks up for any external fault that could cause the 59G to operate. The scheme is shown in Figure 14.

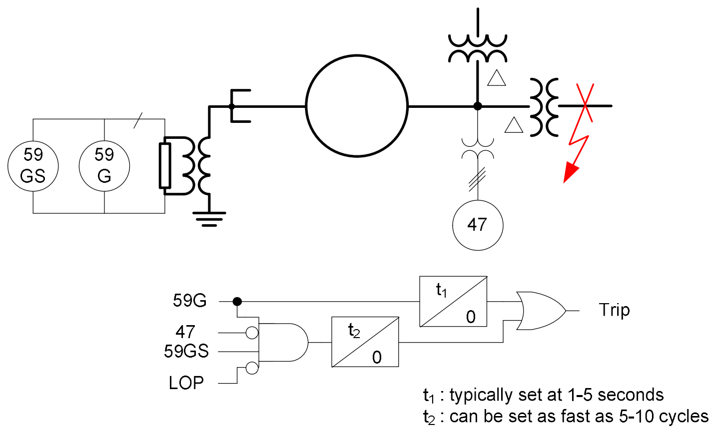

Figure 14: Accelerated tripping using sequence voltages.

It is also capable of distinguishing between internal faults and VT secondary ground faults. In Section 3.1.2 it was noted that fault resistance has a significant impact on the magnitude of a VT secondary fault. It is also noted that the impedance of the VT is required for analysis and can be similar in magnitude to the parallel zero sequence impedance Z_0. A procedure for calculating the VT impedance is included in the appendix.

The sequence network for this fault is shown in Figure 15. It is important to check the pickup settings for the supervising elements 59QS and 59GS. Since a GSU HV ground fault produces a transient response in the generator, the negative sequence voltage is the product of the negative sequence current and X''_d. Using the negative sequence current calculated in 6.1

$$VG_2 = IG_2 \cdot X''_d = 2.39 \cdot 0.14 = 0.33\, per\ unit \tag{10}$$

Note that under normal operation and for an internal stator fault the negative sequence voltage will be virtually zero. The circuit of Figure 15 can be used to analyze a VT secondary fault. The maximum fault resistance for which the 59G can pick up is 0.8 ohms. The plot of Figure 16 shows the negative and zero sequence voltages and their corresponding thresholds. Note that both supervising elements are picked up. The acceleration path is therefore shut down via the 59QS. In the case that VG2 is lower than shown, a higher 59GS setting can be selected. This would reduce the range for accelerated operation near the neutral.

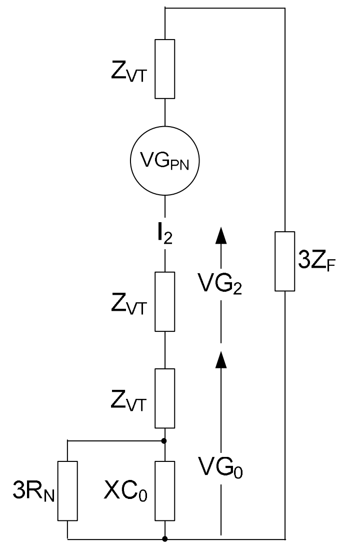

Figure 15 VT Secondary Ground Fault

$$I_2 = \frac{VG_{PN}}{3 \cdot Z_{VT} + Z_0 + 3 \cdot Z_F \cdot N_{VT}^2}\ amps \tag{11}$$

$$VG_2 = \frac{|I_2 \cdot Z_{VT}|}{VG_{PN}}\ per\ unit \tag{12}$$

$$VG_0 = \frac{|I_2 \cdot (Z_{VT} + Z_0)|}{VG_{PN}}\ per\ unit \tag{13}$$

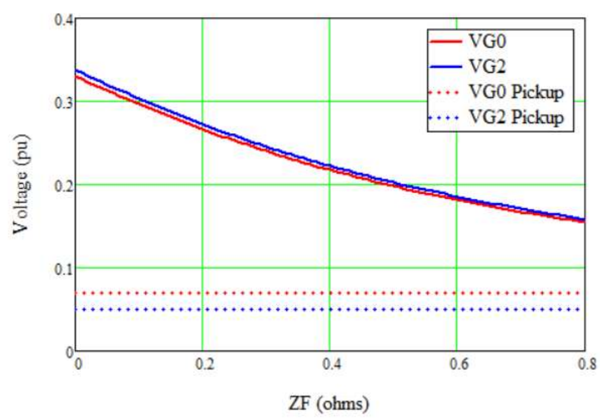

Figure 16 Sequence Voltages vs Fault Resistance for the circuit of Figure 15

6.3 Alternate VT Grounding Connections

There are a variety of generator VT configurations that may be used to provide a voltage signal for protection. Several of these are shown in Figure 17.

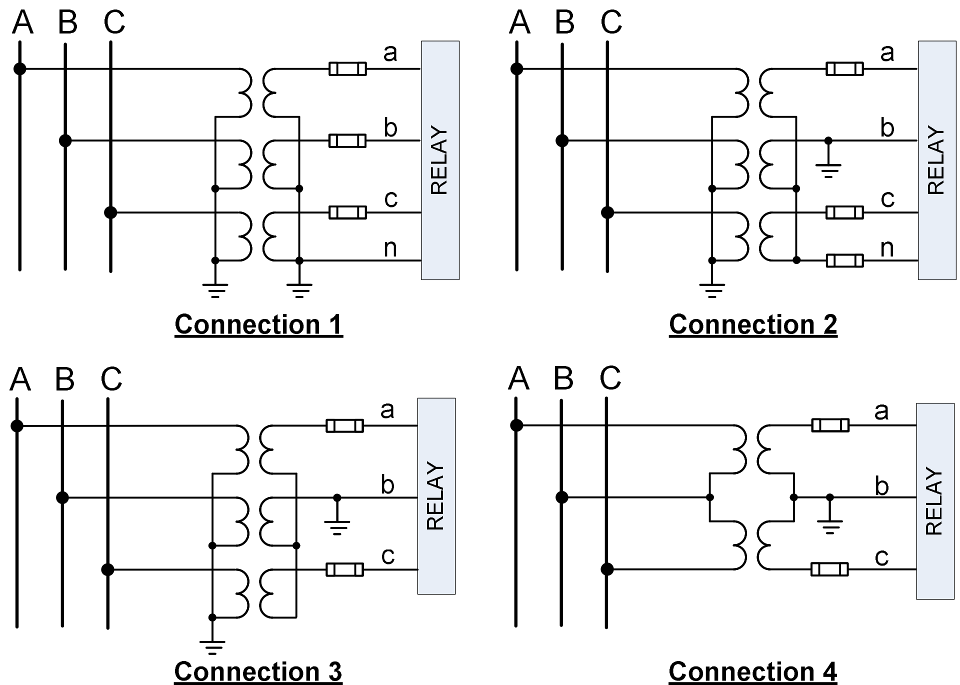

Figure 17 Generator VT Configurations

For Connection 1, a VT secondary ground fault at points a, b, or c would produce a voltage at the generator neutral which would put the 59G at risk of misoperation. In Connection 2, the ground reference is moved to b and only a ground fault at n would put the 59G at risk. Therefore, the exposure is reduced by two thirds. For Connections 3 and 4 a VT secondary ground presents no risk to the 59G.

The various VT connections have implications with respect to protection operating quantities. For connections 1 & 2, the phase-phase, phase-neutral, positive-, negative-, and zero-sequence, and third harmonic terminal voltages are all available for protection. For connections 3 & 4, only the phase-phase, positive-, and negative-sequence voltages are available. However, these are the voltages used in most generator protection functions. Protection functions not available using connections 3 & 4 include third harmonic comparison schemes and zero-sequence overvoltage.

If Connections 1 or 2 are used, then the 59G must be coordinated with the VT fuses. A coordination example is shown in Section 3.1.2.

6.3.1 VT Connections for IPB Ground Fault Protection

In Section 3.4, IPB ground fault protection was discussed. Figure 7 shows a wye/broken-corner-delta with a burden resistor which provides a neutral stabilization influence and ferroresonance suppression. It also provides a voltage for IPB ground fault protection. Using this connection does not pose a security risk for the 59G, since it's equivalent to placing a fault at the system neutral. An alternative implementation would use a separate VT winding with Connection 1 or Connection 2 from Figure 17, in combination with a zero-sequence overvoltage element in a digital relay. This implementation does put the 59G at risk of misoperation; as was seen in the previous section. Therefore, the broken-corner-delta connection is recommended.

6.4 Negative-Sequence Current Acceleration vs Voltage Acceleration

The negative-sequence current acceleration scheme, when used in combination with the VT connection recommendations of Section 6.3, provides fast tripping and is easy to apply. The only drawback is the need for time-coordination with VT secondary fuses in the case that Wye-grounded / Wye-grounded VTs are present. (typically required for a 3rd harmonic comparison scheme). On the other hand, it is well suited for use in conjunction with a sub-harmonic injection scheme.

The sequence voltage scheme can distinguish between internal faults and possible VT secondary faults. It is therefore better suited for use with 3rd harmonic comparison schemes. However, it requires a more detailed setting analysis and is disabled during loss of potential conditions due to blown fuse.

6.5 Considerations on Timers for Intermittent Ground Faults

Intermittent faults can occur due to dirty insulators or broken strands in the stator windings. It is highly desirable to detect such faults at an early or incipient stage so that remedial action can be taken before a complete failure occurs.

The references [10], [11] contain several examples of intermittent faults that are shown in Figures 18-21.

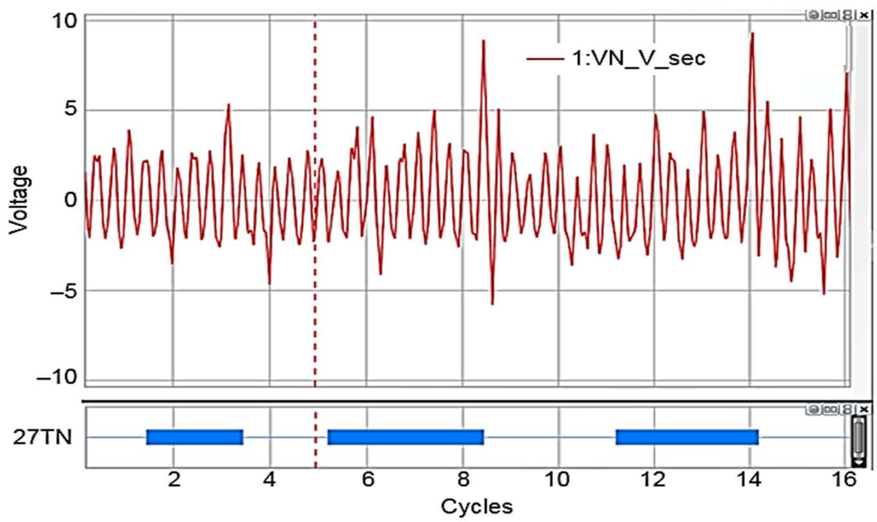

Figure 18 Intermittent fault #1

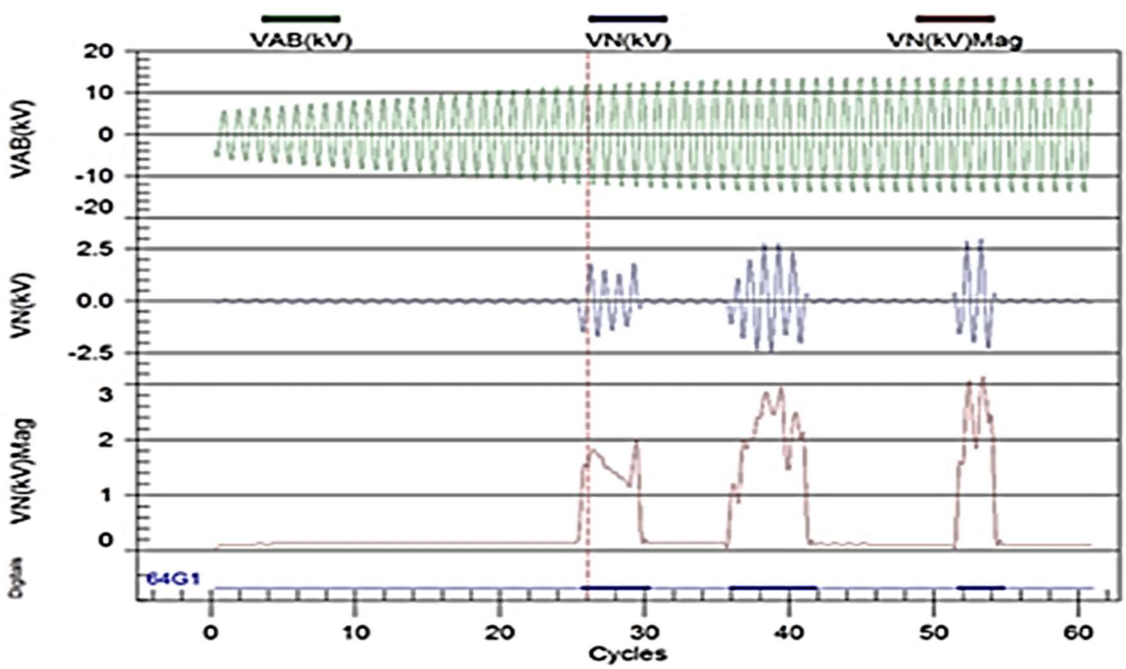

Figure 19 Intermittent Fault #2

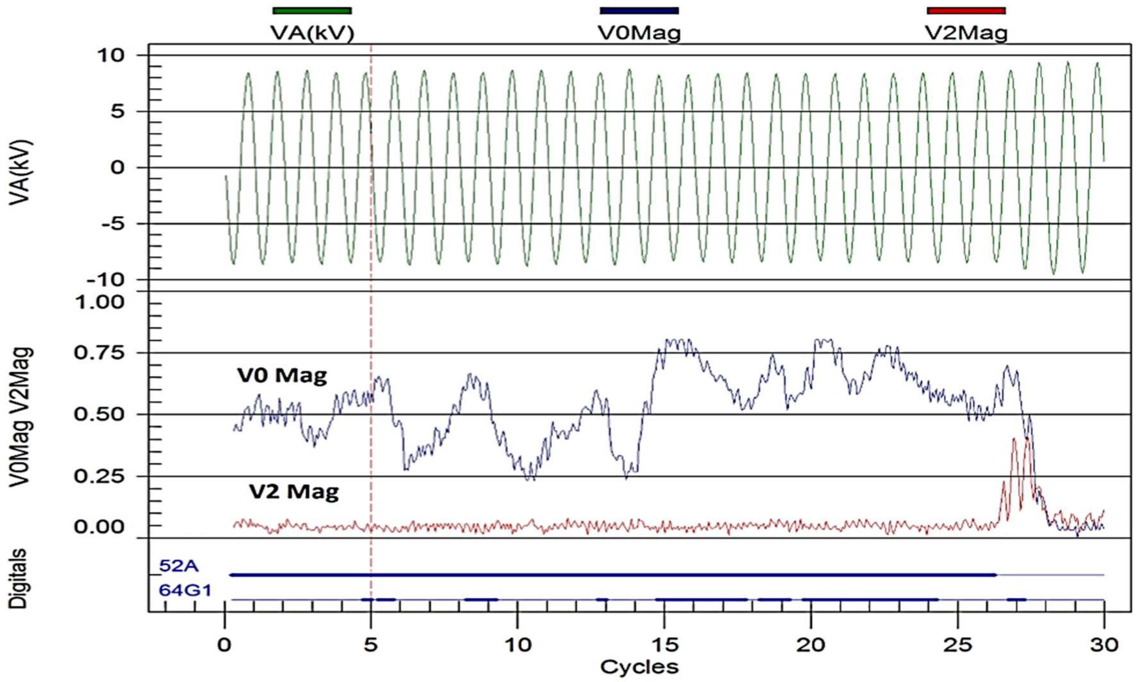

Figure 20 Intermittent Fault #3

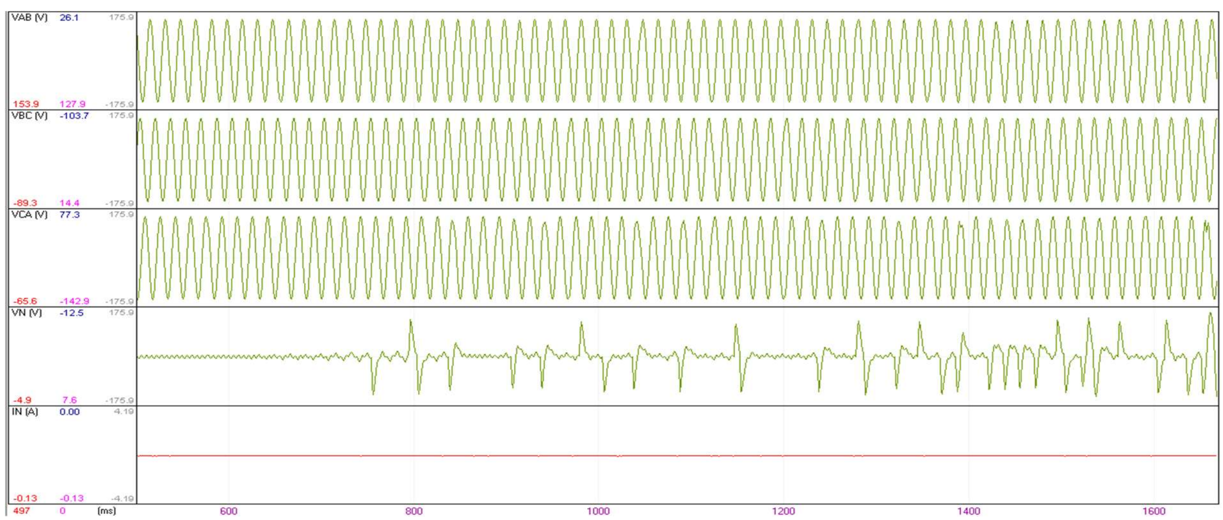

Figure 21 Intermittent Fault #4

Taken together the following generalizations can be made:

- Arcing can persist for periods of a fraction of a cycle to 5 cycles
- Arcing can be interrupted for periods of a fraction of a cycle to 10 cycles and perhaps longer
- There is a high degree of randomness in arcing behavior

6.5.1 Improved Timer Schemes

It's clear that conventional timer logic is not reliable due to the intermittent nature of an arcing fault. Any single arc may not last long enough to operate time delayed neutral overvoltage protection.

Improved timer logic needs to incorporate memory of previous arcing events. The logic of Figure 22 is a possible solution using a stall timer.

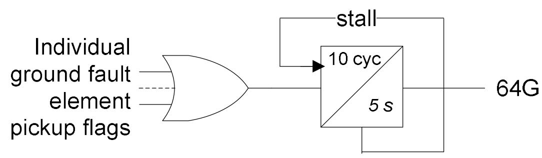

Figure 22 Integrated Stall Timer

Figure 23 shows the timing sequence for a trip during an intermittent ground fault using the timer of Figure 22. If any ground fault protection flag picks up, this starts the pickup timer. The reset timer stalls the pickup timer if the arc momentarily extinguishes and there is no output from the OR gate. Therefore, the timer continues to increment from the stall point when the arc reignites.

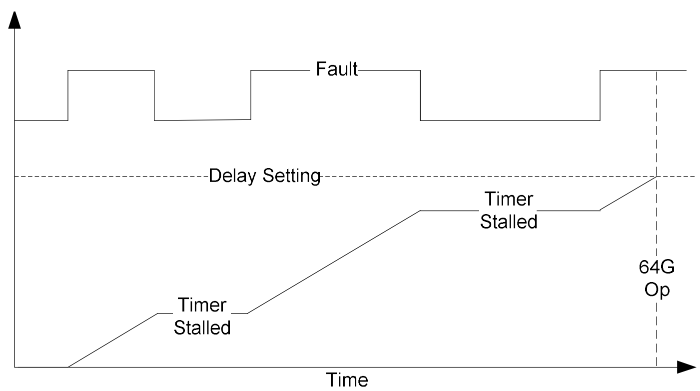

Figure 23 Timing Sequence to Trip on 59G during an Intermittent Fault

An integrating timer operates similarly to the stall timer; ramping up when its input is high and ramping down when its input is low and thereby providing a memory of previous arcing events.

For relays without a stall timer, several methods have been proposed that use multiple timers. The scheme of Figure 24 uses a dropout timer followed by a pickup timer. The dropout timer must be set longer than the longest expected period of interruption within an intermittent condition.

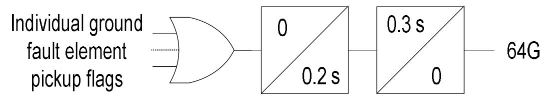

Figure 24 Intermittent Ground Fault Timer Scheme 1 Logic

The scheme of Figure 25 uses a counter to detect an intermittent fault. The timer resets when there is no arcing for a duration longer than the dropout time. This logic will not assert for a sustained fault. Therefore, a second trip path must be provided.

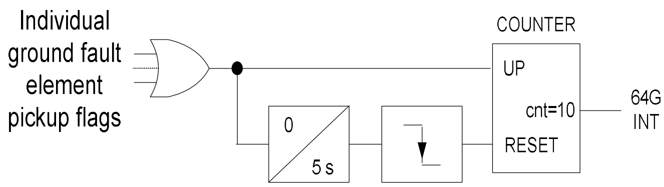

Figure 25 Intermittent Ground Fault Timer Scheme 2 Logic

The scheme of Figure 26 uses a combination of timers and logic gates. The first dropout timer and logic gate detect the first arcing event. A second event must occur within the second dropout time to satisfy the second timer and gate. The second event must also last longer than the pickup time of the third timer to generate an output. This logic will not assert for a non-intermittent fault. Therefore, a second trip path must be provided.

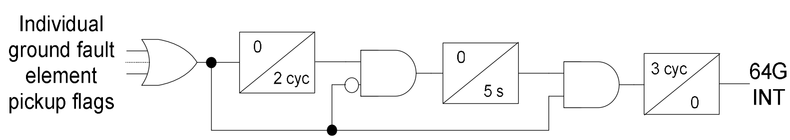

Figure 26 Intermittent Ground Fault Timer Scheme 3 Logic

In summary, several timer schemes have been presented. Any of these schemes can improve tripping response during an intermittent fault. It's likely that at least one of the schemes can be implemented in a digital relay. The scheme choice will depend on the functionality available in the specific relay.

6.5.2 Acceleration Schemes and Improved Timer Schemes

Acceleration schemes provide reduced tripping times for both sustained and intermittent faults. However, for some intermittent faults it's possible that an acceleration scheme may still fail to trip. Improved timer schemes are well-suited for intermittent faults but do not reduce tripping times for sustained faults. It is therefore recommended to apply both schemes for optimal protection.

6.6 Adaptive Third-Harmonic Differential Voltage Scheme

This section presents an adaptive 100% stator ground protection scheme for high-impedance grounded generators. In addition to being dependable, the new scheme has improved security over the conventional 59THD scheme. Moreover, the new scheme does not require any user specified setting, third-harmonic voltage testing, or additional hardware. Below is a synopsis of the new scheme. The interested reader is referred to [12] for additional details.

Figure 2 shows the conventional 59G and 59THD schemes which when used together achieve 100% stator ground protection.

It is well known that the 59G scheme can be set reliably without any generator fundamental voltage testing. Unfortunately, the same cannot be said of the conventional 59THD scheme. Specifically, the third-harmonic voltages at the neutral and terminal vary with load variations and disturbances. Therefore, comprehensive third-harmonic voltage testing is required to set the conventional 59THD scheme securely.

The main objective in third-harmonic voltage testing is to accurately estimate an important parameter known as the *third-harmonic voltage ratio* $\rho = \frac{V_{N3}}{V_{P3}}$. Here, ρ is real or complex depending whether the ratio of voltage magnitudes or phasors is used. The need for an accurate estimate of ρ is supported by empirical observations that this parameter varies depending on generator loading conditions sometimes by as much as 50% [1].

To appreciate the dynamic nature of the ratio ρ, Figure 27 shows the third-harmonic voltage characteristics of two unit-connected generators. Specifically, the upper plot shows the characteristics for a 235 MVA generator while the lower plot shows the characteristics for a 47 MVA generator. Here, V_{N3} and V_{P3} denote the neutral and terminal third-harmonic magnitude voltages. The data in both figures were taken at systematically defined operating conditions covering as much of the generator capability curve area as possible.

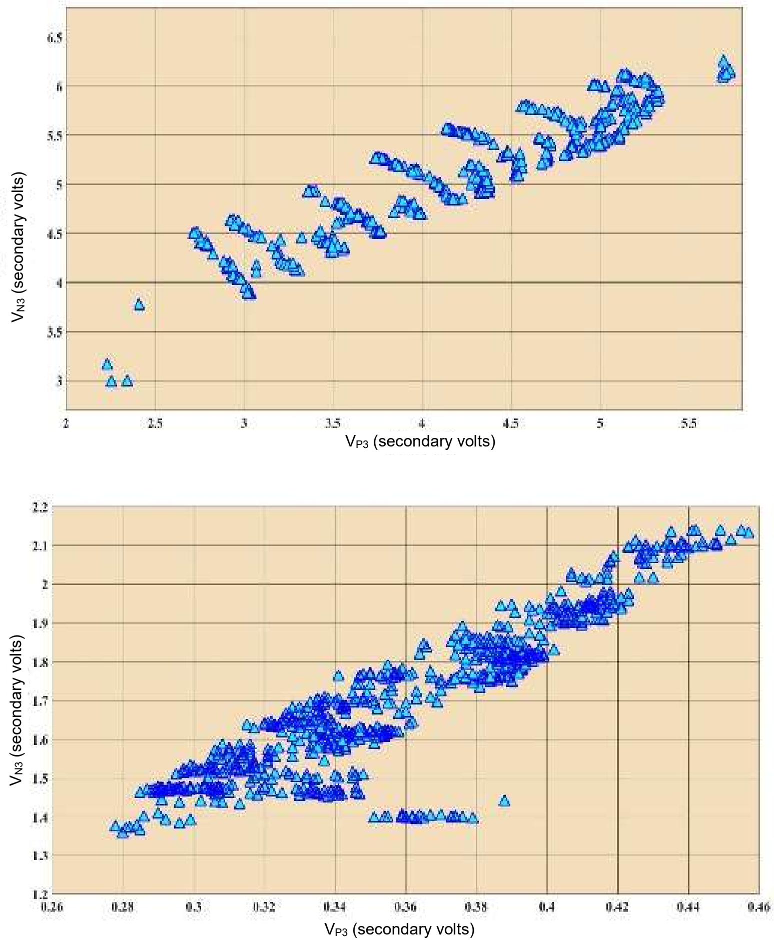

Figure 27 Third-harmonic voltage characteristics of two high-impedance grounded generators

The conventional 59THD scheme is set by calculating an estimate of the ratio ρ. Denoting this estimate as $\hat{\rho}$, the differential third-harmonic voltage trip equation used in the conventional 59THD is given by

$$\Delta V_3 = |V_{N3} - \hat{\rho}\ V_{P3}| > \beta_0 \tag{14}$$

Here, $\beta_0 > 0$ is a fixed pickup setting determined from third-harmonic voltage testing data. Due to the fixed nature of $\hat{\rho}$ and β_0, the conventional 59THD scheme is prone to misoperation due to load variations and disturbances. [12] gives a detail account of two such misoperations.

In contrast to the conventional 59THD, [12] presents an adaptive third-harmonic differential voltage scheme where the ratio ρ is learned (estimated) and then tracked in real-time using a Kalman adaptive filtering (KAF) algorithm. The learning period in the

KAF is denoted by L. This real-time estimated ratio is then used in an adaptive differential third-harmonic voltage trip equation given by

$$J_{AO}(t) > \beta_1 J_{AR}(t) \tag{15}$$

Here, $\beta_1 > 0$ is a fixed sensitivity factor and t is a sampling instance greater than L. Moreover, $J_{AO}(t)$ and $J_{AR}(t)$ denote the adaptive operate and restraint quantities, respectively. As shown in [11], $J_{AO}(t)$ is defined based on the *localized energy* of the residual third-harmonic voltage given by

$$v(t) = V_{N3}(t) - \hat{\rho}(t-1)\, V_{P3}(t) \tag{16}$$

while $J_{AR}(t)$ is defined based on the *localized energy* of the neutral third-harmonic voltage $V_{N3}(t)$. [11] suggests typical values for β_1 and L. The significant point to note is that these parameters are not generator specific. Hence, the new adaptive third-harmonic differential voltage scheme presented in [12] does not have any user specified settings. Furthermore, similar to the conventional 59THD, the scheme is applicable to any generator which produces more than 1% third-harmonic voltages at all operating conditions.

To demonstrate the response of the adaptive third-harmonic differential voltage scheme and compare it to the conventional 59THD, the test data shown in Figure 28 is used to simulate the fault-free response where plot A shows the neutral and terminal third-harmonic voltages recorded during testing, plot B shows the actual ratio $\rho(t)$ and its KAF estimate $\hat{\rho}(t)$, plot C shows the KAF estimation error variance P(t), plot D shows the response of the conventional 59THD, and plot E shows the response of the adaptive third-harmonic differential voltage scheme. Correspondingly, the plots in Figure 29 depict the same quantities during a simulated neutral ground fault occurring at t = 10.

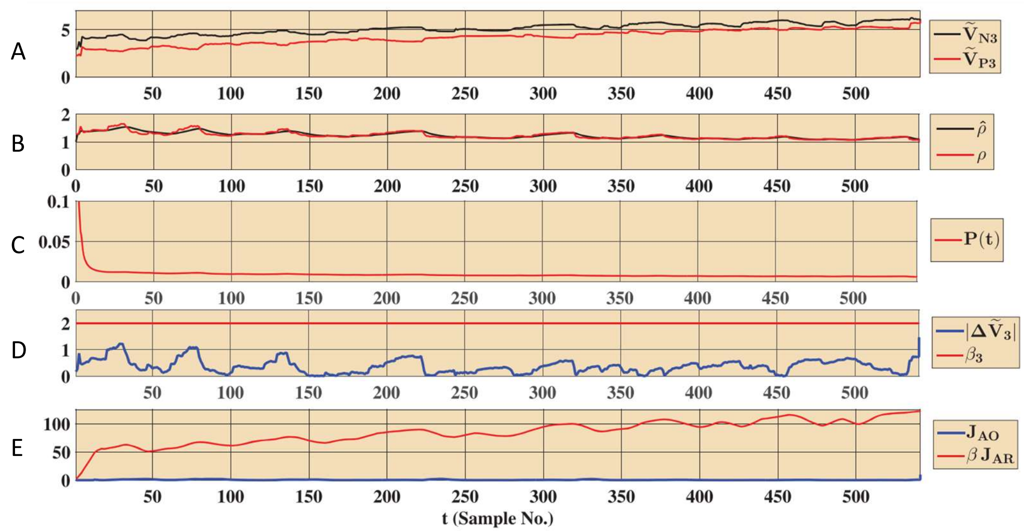

Figure 28 Fault-free response of the conventional 59THD versus the new adaptive scheme

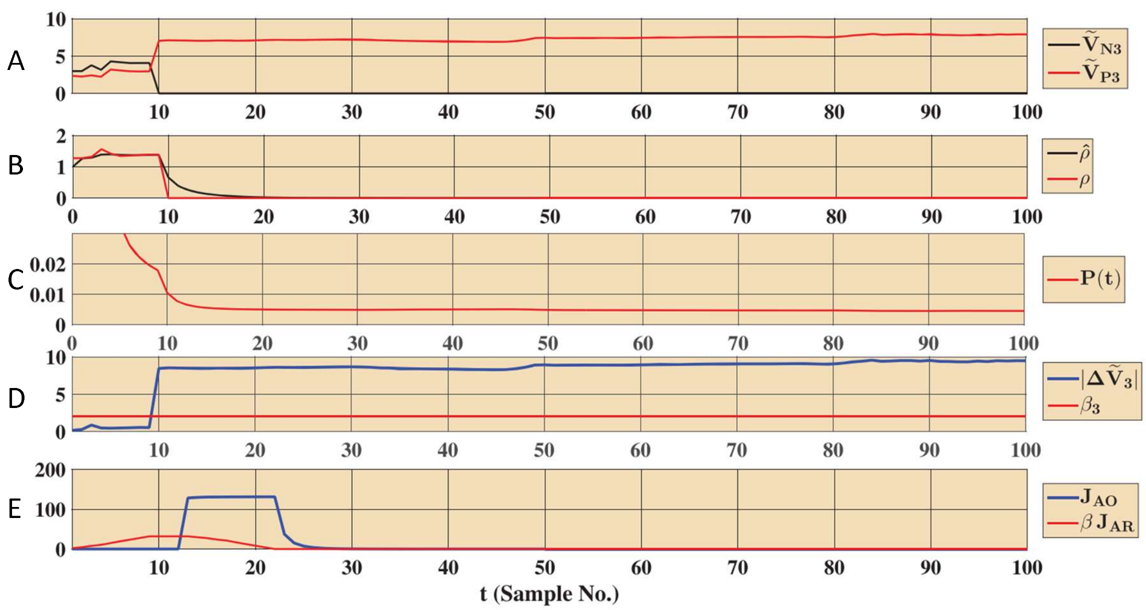

Figure 29 Neutral ground fault response of the conventional 59THD versus the new adaptive scheme

Figure 28 demonstrates the critical differences between the two schemes. First, the agitation in conventional 59THD response in the fault-free case is significant as compared to its well-restrained adaptive counterpart (plots D and E of Figure 28). This is because the real and reactive powers were being varied during testing. Hence, it is natural to expect that security of the non-adaptive conventional 59THD would be challenged. Second, when a ground fault occurs (Figure 29), the different fault detection algorithms produce dissimilar responses (plots D and E of Figure 29). In this case, despite different responses, both schemes prove dependable.

7. Conclusions

This report provides an overview of the mechanisms leading to a stator ground fault and the principles of stator ground fault protection. A focus of the report is a discussion on the limitations of protection schemes to effectively detect intermittent ground faults.

Several methods are presented to provide more effective protection:

> Sequence voltage and sequence current supervision schemes can differentiate between internal and external faults. This allows the tripping to be significantly accelerated while maintaining selectivity.
>
> Modified logic provides memory, thereby improving protection speed for an intermittent fault.
>
> Modified VT connections can eliminate the possibility of a protection operation for a VT secondary ground. This eliminates the need to coordinate the protection with VT secondary fuses.

A combination of these methods provides optimal protection.

The report points out that a series fault can cause considerable damage and this fault type may only be detected after it evolves to include ground. Consequently, to allow ground fault protection schemes to protect against a series fault, a turbine generator trip (rather than just an alarm) is the recommended action.

8. Appendix

Determination of VT Impedance

IEEE C57.13-2016 [13] defines VT accuracy in terms of an accuracy class (0.3, 0.6, and 1.2) and one or more burdens

For example, the following VT has an accuracy class of 0.3 for burdens of W, X, and Y.

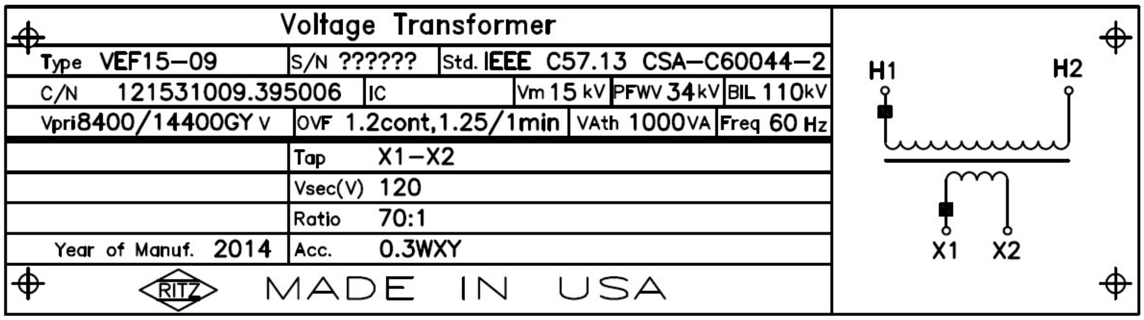

Figure 30 Typical VT Nameplate (Courtesy of Ritz Instrument Transformers)

The following table lists the standard burdens ranging from 12.5 VA to 400 VA and the corresponding burden impedance.

Table 3 Standard Burdens for Voltage Transformers (IEEE C57.13-2016 [13])

Designation	Burden (VA)	Power Factor
W	12.5	0.10
X	25.0	0.70
M	35.0	0.20
Y	75.0	0.85
Z	200.0	0.85
ZZ	400	0.85

Accuracy is defined by a parallelogram and a typical plot can be seen on Figure 31. The VT accuracy (described in terms of RCF and angle coordinate pairs) must lie inside the parallelogram for the specified accuracy class and burden [13]. The manufacturer will design the VT to stay just inside the parallelogram in order to minimize the use of copper and iron [14].

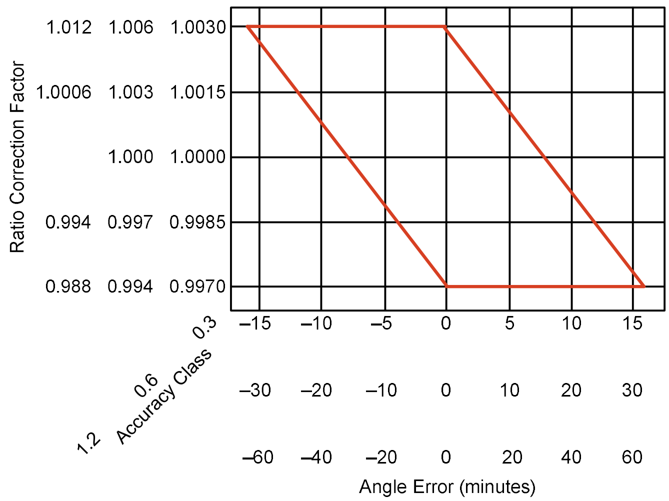

Figure 31 Limits of accuracy classes for voltage transformers for metering [13]

If the nameplate and accuracy tests are available for two different burdens, then the exact value of the VT impedance is given by the following equation [15].

$$Z_{VT} = Z_B \cdot \left(\frac{RCF_1 \cdot e^{-j(Ang_1 - Ang_2)} - RCF_2}{RCF_2}\right) \tag{17}$$

Where RCF_1, Ang_1, RCF_2, and Ang_2, are ratio correction factors and angle errors for the two tests. For the example of Figure 32, The VT has been factory-tested at zero burden and rated burden, which is typical. The accuracy class is 1.2 for a Y burden (200 VA at 0.85 PF).

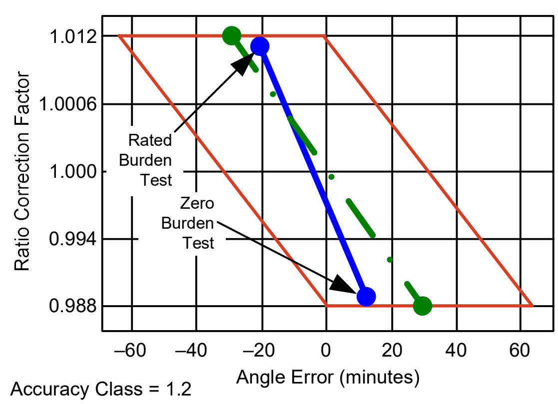

Figure 32 Example VT Test Results

The rated burden is calculated as

$$Z_B = \frac{69.3^2}{200} \cdot e^{j(acos(0.85))} = 20.4 + 12.65j\ \Omega \tag{18}$$

The end-points of the solid line are the test results. Using these in the previous equation yields

$$Z_{VT} = Z_B \cdot \left(\frac{1.011 \cdot e^{j(22min+13mi\ \ )} - 0.989}{0.989}\right) = 0.589\Omega\angle 56.9\ deg \tag{19}$$

If test results are not available but the nameplate data is known, then the best estimate would be to bisect the parallelogram as shown by the dashed line in Figure 32.

For this example, using the data points given by the dashed line, the estimated VT impedance is.

$$Z_{VT} = Z_B \cdot \left(\frac{1.012 \cdot e^{j(60min)} - 0.988}{0.988}\right) = 0.721\ \Omega\angle 68.3\ deg \tag{20}$$

The estimated value differs from the exact value by 31.49%

9. References

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