

Generator Third-Harmonic Protection Explained

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Generator Third-Harmonic Protection Explained

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Abstract—Because of the nature of stator winding construction, insulation failure typically results in a ground fault. Other failures—such as interturn, interbranch, and series faults—if undetected usually evolve into ground faults. Since these failure mechanisms can occur on any portion of the stator winding, 100 percent ground fault protection of the stator winding is recommended.

Various third-harmonic schemes have been used to provide neutral-side stator winding protection for high-impedance grounded generators. Applying such schemes in conjunction with a fundamental neutral overvoltage (59N) element, which protects the top 85–95 percent of the stator winding, provides ground fault protection coverage for 100 percent of the stator winding when sufficient third harmonic is available.

This paper compares the performance of different third-harmonic schemes and shows how these schemes can be applied to provide secure and sensitive stator winding coverage.

I. INTRODUCTION

In high-impedance grounded generators, faults in the top 85–95 percent of the stator winding can be detected by a fundamental neutral overvoltage (59N) element. However, ground faults near the machine neutral (~15 percent) require detection for the following reasons:

- If a ground fault near the neutral remains undetected, the machine becomes solidly grounded. A subsequent fault will bypass the grounding impedance, resulting in severe machine damage. Fig. 1 shows insulation damage near the neutral caused by a foreign object. Early detection of this condition can reduce insulation damage and the likelihood of a catastrophic subsequent ground fault.
- A series fault can result from the fracture of a conductor or the failure of an electrical joint. The current continues to flow via the arc across the fault point. The arc will vaporize the copper conductor between 8–12 inches before the arc breaks through the insulation wall of the stator core and evolves into a ground fault [1].

Some generator owners prefer to alarm for faults near the neutral terminal (~15 percent) and resolve the issue with a scheduled outage because it should not cause direct damage to the unit. However, the failure mode associated with a series fault evolving to a ground fault near the neutral does cause direct machine damage and requires protection.



Fig. 1. Damage caused by a neutral-side fault.

There are two general approaches for detecting ground faults near the neutral of a high-impedance grounded machine:

1. Third-harmonic schemes use the third harmonic produced by most machines. Exceptions include units with a two-thirds short-pitch ratio that notch the third harmonic.
 - a) If the terminal PT is wye-grounded, a third-harmonic measurement at the terminal (VT3) is available. In this case, both VT3 and the neutral third harmonic (VN3) measured across a neutral grounding transformer (NGT) are used.
 - b) If the terminal PT is open-delta or wye-ungrounded (VT3 unavailable), the third-harmonic neutral undervoltage element (27TN), which uses VN3, is applied.
2. Injection schemes require signal injection across the NGT. The operating principle is that of an insulation tester, where the impedance to ground is measured. If the impedance drops below a threshold, a ground fault is declared. This method requires injection equipment, but it does not rely on the third harmonic produced by the machine and can operate when the machine is at a standstill.

This paper, an expanded version of [2], compares the performance of the third-harmonic elements described in 1.a and provides protection guidance. A user may want to apply redundant relays that employ different operating principles using the third harmonic. Understanding the relative performance of the elements allows the proper protection to be applied. In this paper, we assume that both VT3 and VN3 are available.

II. PROTECTION ELEMENTS

We begin our analysis of third-harmonic protection by focusing on the third-harmonic circuit of the generator. The generator step-up (GSU) delta winding provides third-harmonic isolation from the power system, and the equivalent circuit is shown in Fig. 2.

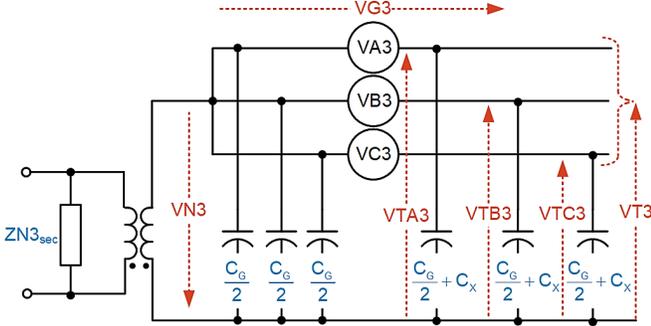


Fig. 2. Third-harmonic pi-equivalent circuit of a unit-connected high-impedance grounded generator.

The distributed stator ground insulation capacitance (C_G) is simplified to an equivalent pi-section split between the terminal and neutral sides. The terminal side has an additional external capacitance contribution (C_X) from the surge capacitor, isophase bus, and transformers. The neutral impedance ($Z_{N3_{sec}}$), when reflected to the primary side, is selected to equal the total capacitive reactance magnitude of C_G and C_X .

$VT3$ and $VG3$ are the average of the respective per-phase voltages. When a stator ground fault is applied at location m , the circuit is as shown in Fig. 3.

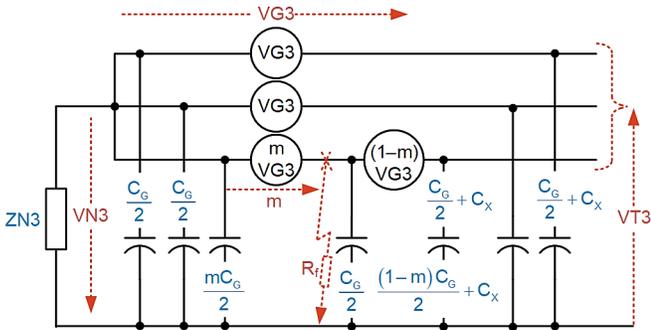


Fig. 3. Effect of an internal ground fault on the generator third-harmonic circuit.

Various approaches can detect a ground fault using the measured quantities $VN3$ and $VT3$ [3]–[8]. To develop an understanding of the various implementations, we consider the example system parameters shown in Table I for a single-branch machine with a resistive neutral grounding impedance. $VG3$ is the total third harmonic produced by the machine and is set as the reference (1 pu) to simplify analysis. Similar approaches can be applied to machines with multiple branches and/or resonance-grounded generators.

TABLE I
EXAMPLE THIRD-HARMONIC CIRCUIT PARAMETERS

Parameter	Data
Third-harmonic source ($VG3$)	1 pu $\angle 0^\circ$
Capacitances (per phase)	Stator ground (C_G): 0.342 μF External (C_X): 0.100 μF
Neutral-grounding impedance (Z_{N3})	2.0 k Ω equal to $1/(3\omega[C_G + C_X])$
Nominal frequency	60 Hz

For reference, Table II provides several calculated $VN3$ and $VT3$ values for various fault resistances (R_f) with a fault location of $m = 0.15$ pu. For a healthy, unfaulted machine $R_f = \infty$. Note that all values are in per unit to facilitate analysis.

TABLE II
 $VN3$ AND $VT3$ FOR DIFFERENT FAULT RESISTANCES

R_f	0 Ω	200 Ω	2 k Ω	10 k Ω	∞
$VN3$	0.15 pu $\angle 0^\circ$	0.21 pu $\angle 35.5^\circ$	0.51 pu $\angle 29.0^\circ$	0.57 pu $\angle 20.9^\circ$	0.58 pu $\angle 18.4^\circ$
$VT3$	0.85 pu $\angle 0^\circ$	0.84 pu $\angle -8.3^\circ$	0.61 pu $\angle -24.2^\circ$	0.51 pu $\angle -23.4^\circ$	0.48 pu $\angle -22.3^\circ$

A. Scheme A

The Scheme A operating equation is defined by (1):

$$\text{Scheme A} = \frac{|VN3|}{|VN3 + VT3|} < \text{PKPA} \quad (1)$$

The phasor sum of $VN3$ and $VT3$ always adds to $VG3$ and the operator, $||$, indicates magnitude. The behavior of the third-harmonic circuit in Fig. 3 for different fault resistances is shown in Fig. 4 along with the operating region for Scheme A with a pickup setting, PKPA, set to 0.15 pu.

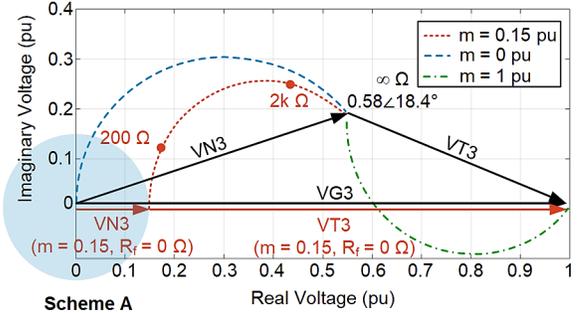


Fig. 4. Effect of fault resistance on $VN3$ and $VT3$ with respect to the operating equation of Scheme A.

When the generator is healthy, $VG3$ drops across the impedance divider circuit defined by the terminal-side capacitances ($VT3$) and the neutral impedance ($VN3$). For most installations, the ratio during healthy unit operation is 0.40–0.80. If the neutral impedance is sized too small, the ratio approaches 0.40. If there is a large capacitance external to the machine terminal, the ratio approaches 0.80. For the example, properly sized system, the ratio is 0.58.

During internal metallic faults ($R_f = 0 \Omega$), V_{N3} and V_{T3} are in phase with V_{G3} . For any metallic faults, the ratio in (1) equals the fault location. As R_f increases, V_{N3} diverges nearly perpendicularly to V_{G3} . This results in an increase in the magnitude of V_{N3} with an increase in R_f .

Based on the previous analysis, we conclude that Scheme A is a neutral undervoltage element that is normalized by the third harmonic produced by the machine (V_{G3}). The recommended guideline for the pickup setting is the percentage of the stator winding requiring protection. This method does not usually require a survey of the generator and relies on the fact that the neutral grounding impedance is matched with respect to the capacitance around the generator. The denominator of the ratio is a phasor sum, hence the NGT polarity needs to be consistent with Fig. 2.

In some implementations [3], Scheme A has the additional terminal-overvoltage supervision shown in (2):

$$\frac{|VT3|}{|VN3 + VT3|} > (1 - PKPA) \quad (2)$$

Mathematically, the Scheme A operating equation (1) is a subset of the overvoltage supervision in (2), hence there is no benefit to this supervision in a digital relay.

In some implementations [4], (1) is rearranged into (3), where β is a security-bias factor, mathematically the inverse of $PKPA$, which in turn corresponds to the physical per unit of the stator winding protection desired.

$$|VN3 + VT3| > \beta \cdot |VN3| \quad (3)$$

Generators typically produce V_{G3} in the range of 1–10 percent of the generator nominal line-to-neutral voltage (V_{LN}), depending on pole shape, winding functions, loading, and saturation. Scheme A includes a minimum supervision (e.g., $V_{G3} > 1\%$) to ensure that valid voltages are compared and that the element has adequate security for external third-harmonic events such as those described in Section III.

B. Scheme B

The Scheme B operating equation is shown by (4):

$$\text{Scheme B} = |RAT \cdot |VT3| - |VN3|| > PKPB \quad (4)$$

RAT is a setting obtained via a survey during commissioning. Typically, $VT3$ and V_{N3} are measured over a range of generator loading conditions and RAT is calculated as the average of $|VN3|$ divided by the average of $|VT3|$. For our example, $RAT = 1.20$, which indicates that the neutral impedance is 1.20 times the terminal capacitive reactance. The $PKPB$ setting provides security, but it is set with the intent of providing 100 percent stator-winding coverage when combined with a 59N element. One setting criterion is given by (5):

$$PKPB = 1.1 \cdot \left(0.1 + \text{MAX} \left\{ \left| |VN3| - RAT |VT3| \right| \right\} \right) \quad (5)$$

Note that a highly linear correlation between the survey values of $VT3$ and V_{N3} translates to an excessively sensitive pickup setting. Therefore, a thorough survey is recommended.

Scheme B compares a differential of the magnitudes, hence the element behavior for a fault can be represented as shown in Fig. 5. Because the element looks at magnitudes, the NGT polarity does not need to be consistent with Fig. 2.

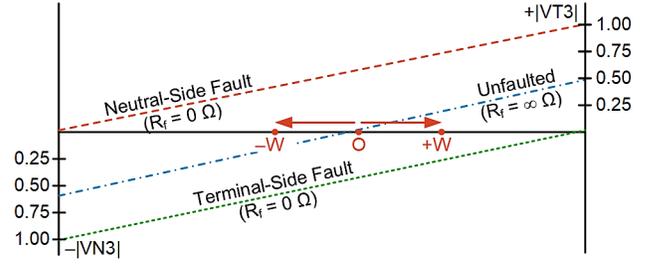


Fig. 5. Operating characteristic of Scheme B.

Based on the ratio of the impedances during healthy unit operation, at Point O in Fig. 5 the third-harmonic voltage with respect to ground is zero. This point is defined by (6). For our example, O resides at 0.55 pu and indicates that a metallic fault at 55 percent of the winding will not be detected by Scheme B.

$$O = \frac{|VN3|}{|VN3| + |VT3|} = \frac{RAT}{1 + RAT} \quad (6)$$

$PKPB$ is a security margin, and setting guidance is provided in Section III. $PKPB$ introduces a region around Point O ($\pm W$) where the element remains inoperative for metallic faults, as defined by (7), (8), and (9).

$$W = \frac{1}{V_{G3}} \left(\frac{PKPB}{1 + RAT} \right) \quad (7)$$

$$\text{Lower Winding} = O - W \quad (8)$$

$$\text{Upper Winding} = O + W \quad (9)$$

For instance, a $PKPB$ of 0.85 pu and $W = 0.39$ pu provides coverage to 16 percent of the lower winding. As the machine produces a larger V_{G3} , the protected region increases and the element gains sensitivity. Consequently, if V_{G3} is smaller than $PKPB/RAT$, the element provides no neutral-side coverage.

C. Scheme C

If we set $PKPB = 0$, (4) can be rearranged to form the Scheme C operating equation shown by (10):

$$\text{Scheme C} = \frac{|VT3|}{|VN3|} > \frac{PKPC}{RAT} \quad (10)$$

$PKPC$ provides a security margin to the RAT value obtained during healthy unit operation. With the security margin lumped into the ratio of V_{N3} and V_{T3} , the element can lose security when the third harmonic produced by the machine (V_{G3}) is small. For example, when $V_{G3} = 0$ pu (with $V_{T3} = V_{N3} = 0$ pu), the ratio of V_{T3} and V_{N3} is undefined, possibly resulting in unexpected behavior from Scheme C because of measurement errors. While Schemes B and C are similar in nature (i.e., both look for a deviation from the healthy machine characteristics), Scheme B does not suffer from this problem because of a separate setting ($PKPB$).

In some implementations [5], positive-sequence voltage (V1) supervision is required to address the Scheme C security problem based on the premise that sufficient V1 indicates sufficient VG3. However, this assumption may not always be valid, as in the case where the machine operates as a synchronous condenser. An alternate solution is to supervise the element with a VG3 check (e.g., $VG3 > 1\%$), as is done for Scheme A.

D. Scheme D

The Scheme D operating equation is defined by (11):

$$\text{Scheme D} = |\text{RAT} \cdot \text{VT3} - \text{VN3}| > \text{PKPD} \cdot |\text{VN3}| \quad (11)$$

The core operating principle is the same as that of Schemes B and C discussed previously. The element requires a survey and looks for deviations from a healthy distribution.

The left side of (11) is similar to the Scheme B operating equation. The distinction is that it includes phasor information and that RAT is a complex value. The right side of (11) scales with VN3. The resulting problem is the same as the Scheme C element, where at low values of VG3 the element security can be jeopardized.

III. SECURITY

Third-harmonic protection schemes rely on the circuit to behave as a voltage divider for two fixed impedances. This is not always the case, which negatively impacts element security. In this section, we review several real-world cases that challenge the security of third-harmonic schemes.

A. Factors Influencing Security

1) PT Secondary Faults

For a fault on the secondary side of the terminal PTs, an external impedance is introduced to the circuit. On a 24 kV, 800 MVA unit, the transformed impedance on the primary circuit is 8 k Ω . Schemes B and D can misoperate for this condition, which is shown in Fig. 6. Time coordination of the element with the PT fuses may be considered for these schemes. Some relay manufacturers provide a method to only detect faults in the lower winding region, thereby providing security for PT secondary faults.

Secondary faults can also occur across the NGT, as shown in Fig. 6, but this condition requires detection because it shorts the neutral side of the machine.

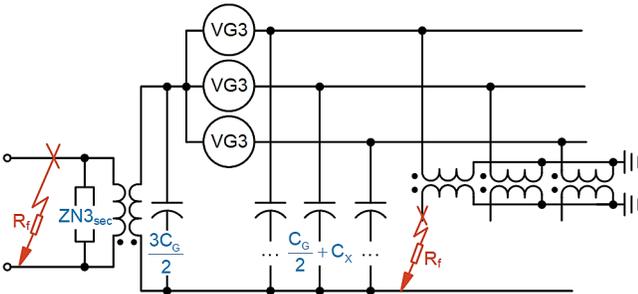


Fig. 6. Secondary-side fault locations.

2) System Events

Power system ground faults on the GSU high-voltage side can couple through the GSU interwinding capacitance (C_{IW}), inducing a zero-sequence voltage across the generator grounding transformer that must be considered to ensure the security of the 59N element [8]. The same phenomenon is observed when a system ground fault alters the third-harmonic circuit, as shown in Fig. 7.

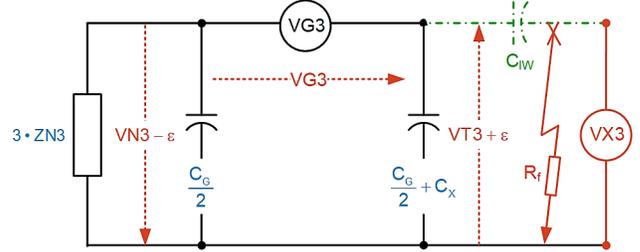


Fig. 7. Third-harmonic network for GSU high-voltage side ground faults.

This effect was illustrated very clearly in a real-world event at a plant that consists of two 23.5 MVA, 13.8 kV generators sharing a GSU. Each generator has a 13.8 kV:230 V grounding transformer. A ground fault on the 115 kV line leaving the plant caused the third-harmonic element to assert.

Prior to the fault, VN3 was 160 V (2%) and VT3 was 410 V (5.2%), for a ratio of 0.39. While the fault was on the system, the voltages on both generators changed significantly, with VN3 rising to 400 V (5%) and VT3 dropping to 166 V (2.1%), for a ratio of 2.41. Because the generator terminal impedance was reduced, VT3 decreased and VN3 increased, resembling a generator terminal-side fault. Schemes that only detect neutral-side faults remain secure for power system faults. Other schemes require a coordination time delay (e.g., 500 ms).

Faults and switching events on the GSU high side can also present an external third-harmonic source. This source (VX3) can couple via C_{IW} to generate an error (ϵ) that may add to VT3 or subtract from VN3, as shown in Fig. 7. The voltage transients from these events depend on the network impedances (e.g., long lines have lower natural frequencies). The frequency response of a third-harmonic filter (60 Hz nominal) is shown in Fig. 8. The filter attenuates (but does not notch out) the higher frequencies from system events.

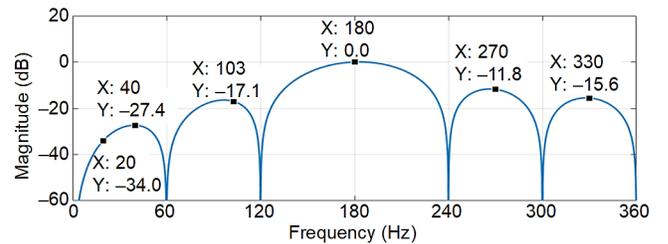


Fig. 8. Third-harmonic filter characteristic for some digital relays.

Fortunately, these transients do not last long (typically less than 50 ms), so a time delay larger than 100 ms (e.g., 500 ms) provides the required security unless trip-acceleration schemes are used [9].

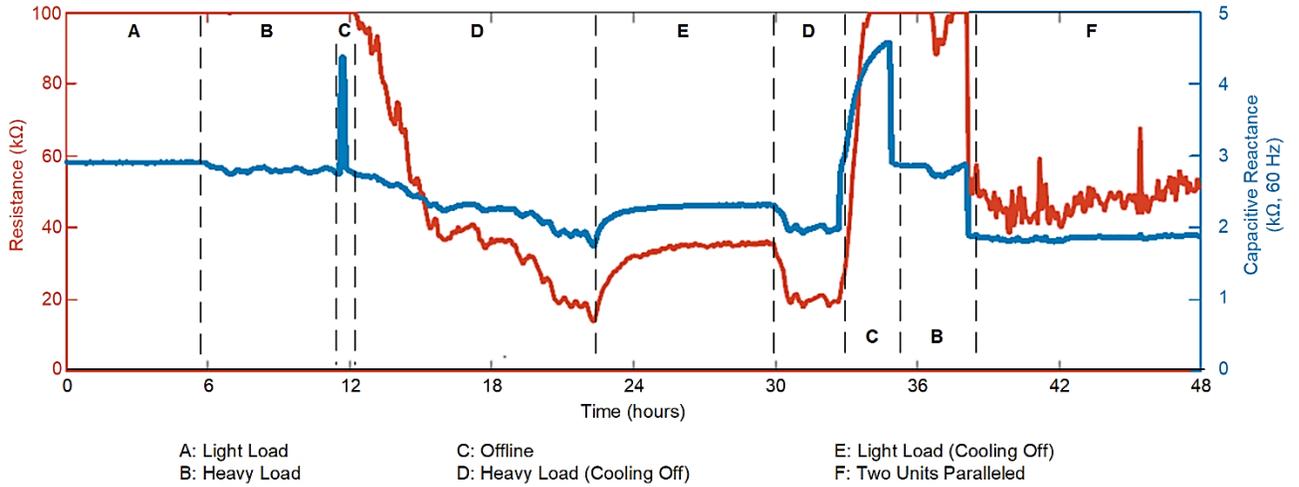


Fig. 9. Field event showing stator ground impedances for various machine states over a two-day period.

3) GSU Events

Nonlinear GSU events, such as inrush, can present an external third-harmonic source [10]. The coupling is not direct because the GSU low-voltage winding is connected in delta; indirect coupling occurs through C_{IW} , similar to Fig. 7. For one such event [11], $C_{IW} = 8$ nF and $VX3 = 6$ kV_{LN} (2 percent of a 525 kV_{LL} system), causing third-harmonic element misoperation. These events can last a few seconds. Adequate security must be built into the scheme pickup settings, as will be discussed in Section III, Subsection B.

4) Modification of Stator Ground Capacitance

The distributed stator ground capacitance of a generator originates from the insulation and varies with temperature (due to machine loading), moisture content, and age. While these factors provide minor capacitance deviations, large changes can occur as the result of the failure of the generator cooling system, for instance.

A field event captured by a 64S relay, which measures generator stator ground impedance, is shown in Fig. 9. The cooling system was accidentally left off in Region D, and the insulation resistance and capacitive reactance dropped to 13.9 kΩ and 1.74 kΩ, respectively, almost resulting in a fault. Adequate security must be built into the scheme pickup settings to prevent a trip during a thermal event, as will be discussed in Section III, Subsection B.

5) Impedance Profile Change at Generator Terminal

Some generators have a low-voltage breaker with a surge capacitor on the GSU side of the breaker. In such cases, the impedance of the third-harmonic circuit can change significantly, depending on the breaker state [4]. This behavior can be seen in Fig. 9. When the unit is online in Region A or B (relative to the offline state shown in Region C), the additional surge capacitance reduces the impedance significantly. Some relays provide alternate settings to tackle this problem [4].

Abnormal conditions, such as water ingress or other contamination of the isophase bus, can also modify the terminal-side impedance. Adequate security must be built into the scheme pickup settings, as will be discussed in Section III, Subsection B.

B. Security Analysis and Scheme Settings

Having reviewed scenarios that challenge third-harmonic protection, we now compare the security of individual schemes. We do this through the artificial introduction of an external source (ϵ) that adds to VT3 and subtracts from VN3, as shown in Table III. We solve the circuit of Fig. 7, apply the resulting voltages to each scheme, and determine the pickup threshold that causes each scheme to operate. In determining the pickup setting, we also consider the following manufacturer recommendations:

- Schemes C and D require a margin of approximately 50 percent, which corresponds to $\epsilon \sim 0.10$ pu.
- Schemes A, C, and D require a minimum VG3 supervision of 1 percent.
- Scheme B does not require supervision; this security is built into the PKP.

The results are given in Table III.

TABLE III
REQUIRED SECURE PICKUP SETTINGS FOR VARYING LEVELS OF ϵ

ϵ (pu of VG3)	Scheme A PKP	Scheme B PKP	Scheme C PKP	Scheme D PKP
0.00	0.58	0.00	1.00	0.00
0.10	0.48	0.20	1.41	0.43
0.20	0.38	0.40	2.04	1.08
0.28	0.30	0.56	2.87	1.92
0.43	0.15	0.88	6.79	5.85

Note that the pickup settings of Schemes A and B are fairly linear with ϵ , whereas Schemes C and D are quadratic and diverge very quickly. Based on field cases that demand high security, the above data should be considered at VG3 = 2% V_{LN}. This only affects the setting calculations of relays using Scheme B, which becomes 0.88 pu \cdot 2% V_{LN} \approx 1.75% V_{LN}.

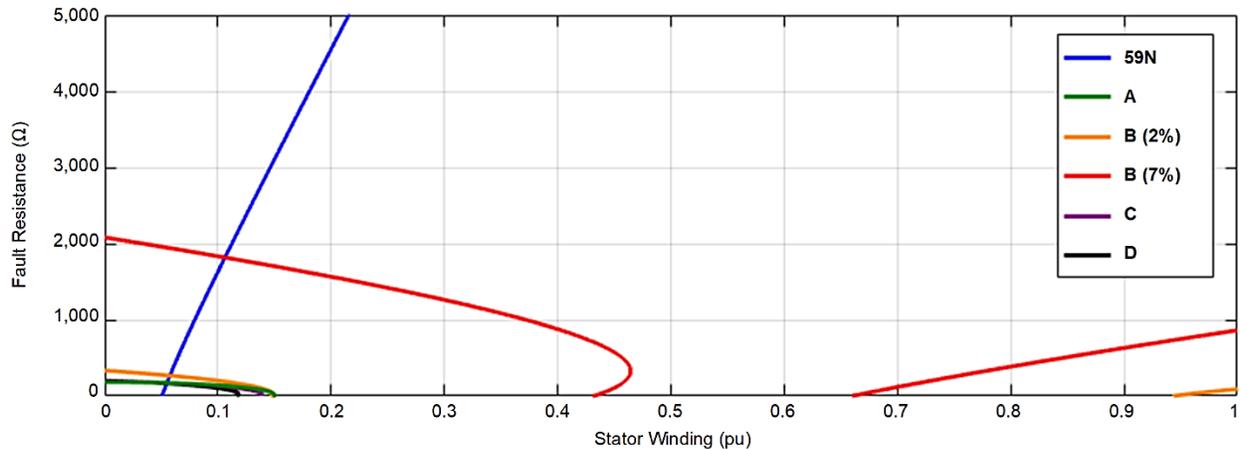


Fig. 10. Sensitivity provided by ground fault protection schemes with secure settings ($\epsilon = 0.43$ pu).

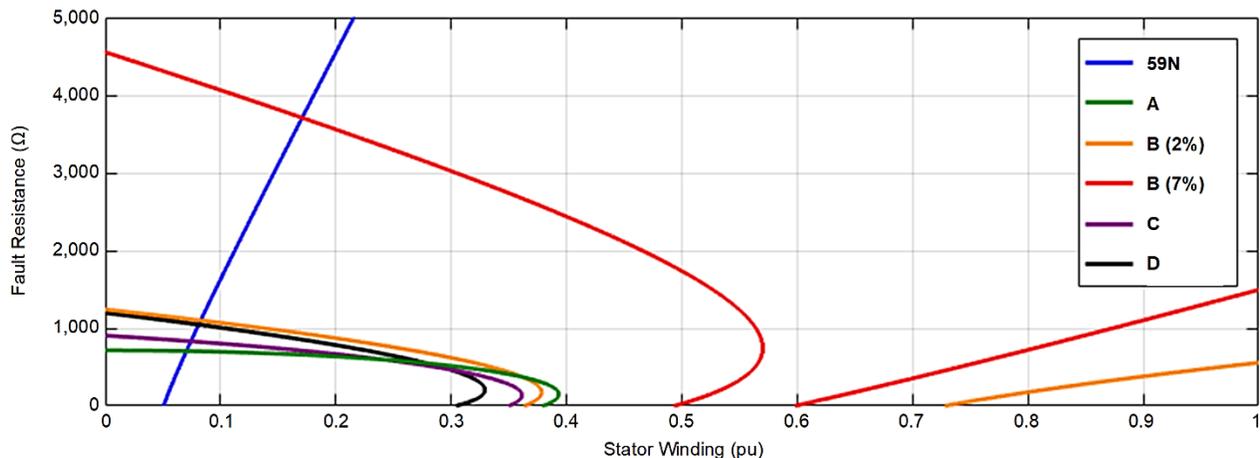


Fig. 11. Sensitivity provided by ground fault protection schemes with sensitive settings ($\epsilon = 0.20$ pu).

IV. SENSITIVITY

In Section III, we determined settings for each scheme that provided equal levels of security for an external event. We now compare the sensitivities of each scheme. To do this, we solve the circuit of Fig. 3 while varying the fault location and resistance. The resulting voltages are fed to each scheme, and we check the operation.

Using the secure ($\epsilon = 0.43$) settings, we show the resulting coverage and resistive sensitivity provided by the various elements in Fig. 10. The 59N sensitivity with a pickup of 0.05 pu is shown as a reference.

Note that Schemes A, C, and D have fixed characteristics. The characteristic of Scheme B varies with VG3, shown as a percentage in Fig. 11. Two typical values are shown for no-load (2%) and full-load (7%). At low levels, its resistive sensitivity is similar to that of the other schemes, but when VG3 is large, its sensitivity is much higher.

We repeated the exercise for a less conservative case ($\epsilon = 0.20$), and the results are shown in Fig. 11.

The primary sensitivity requirement for generator protection is to provide metallic fault ($R_f = 0 \Omega$) coverage for 100 percent of the stator winding. For our example system, all schemes provide this coverage for both sensitive and secure settings. For faults in the upper 90 percent of the winding, the 59N element

provides very high resistive coverage; the performance of third-harmonic schemes is not a concern in this region. Note that the schemes may operate for a resistive fault, but not for a metallic fault, at the same location.

All schemes can be set to provide similar levels of security and sensitivity at a given VG3, although this is not evident from an examination of the operating equations. Furthermore, manufacturers do not normally provide these comparisons.

We are not aware of any guidance with respect to minimum resistive coverage. However, for faults in the early stages of inception, a large fault impedance can be expected. Scheme B is most likely to detect the condition at full load with a lagging power factor (when VG3 is large). If sensitive detection for such conditions is desired, a sensitively set Scheme B with $PKPB = 0.40 \text{ pu} \cdot 2\% V_{LN} = 0.80\% V_{LN}$ ($\epsilon = 0.20$ pu, as shown in Fig. 11) can be used to alarm.

V. CONCLUSION

Various implementations of third-harmonic schemes are in use. All third-harmonic schemes can be set to provide similar and adequate security. When combined with a 59N element, all schemes provide sufficient neutral-side coverage to obtain 100 percent metallic fault coverage for stator ground faults when sufficient third harmonic is available.

Scheme A is the easiest scheme to set because the pickup setting correlates directly to the winding coverage for metallic faults. Scheme B provides the highest sensitivity, especially when the generator produces a large amount of third harmonic. A higher sensitivity may be desired for incipient faults.

While the methods described in this paper are explained in percentages and per-unit quantities, relays often use secondary voltages as settings. A sample application is provided in the Appendix.

VI. APPENDIX

The example system shown in Fig. 12 is used to demonstrate the application of stator-ground fault protection on a sample high-impedance grounded generator.

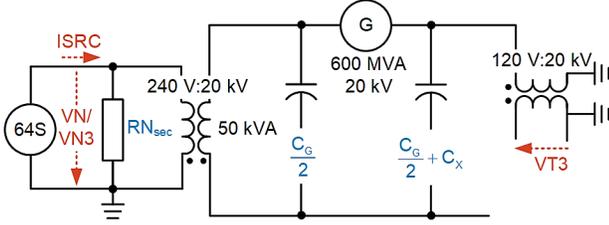


Fig. 12. Example third-harmonic system.

The system parameters are shown in Table IV.

TABLE IV
EXAMPLE THIRD-HARMONIC SYSTEM PARAMETERS

Parameter	Data
Nominal voltage	$V_{\text{RATED}} = 20 \text{ kV}$ $V_{\text{LG}} = 20 \text{ kV}/\sqrt{3} = 11.55 \text{ kV}$
Nominal frequency	60 Hz
Neutral PT ratio	$\text{PTRN} = 20 \text{ kV}:240 \text{ V} = 83.33$
Terminal PT ratio	$\text{PTR} = 20 \text{ kV}:120 \text{ V} = 166.67$
Capacitances (per phase)	Stator ground (C_G): $0.342 \mu\text{F}$ External (C_X): $0.100 \mu\text{F}$
Neutral-grounding resistance	$0.605 \Omega_{\text{sec}} = 2.0 \text{ k}\Omega_{\text{pri}}$ equal to $1/(3\omega[C_G + C_X])$

We assume the following protection philosophy:

- 59N is set to trip at 0.05 pu.
- Scheme A is set securely to trip the unit.
- Scheme B is set sensitively to alarm only when the fault is on the neutral side.
- A 64S relay injects a current and measures the associated voltage to calculate the resistance to ground to determine whether there is a ground fault. The secure setting used to trip is set to a similar level as Scheme A. The sensitive setting is set to a value higher than a PT secondary-side fault.

The time delays associated with tripping and alarming are not within the scope of this example. They can be set to coordinate with the terminal PT fuse and external system events [8] or they can be accelerated [9].

A. 59N Setting

The 59N setting is calculated as shown in (12).

$$59\text{N PKP} = 0.05 \text{ pu} \cdot \frac{V_{\text{LG}}}{\text{PTRN}} = 6.93 V_{\text{sec}} \quad (12)$$

B. Scheme A Setting

Since 100 percent stator ground protection is desired (barring additional security constraints), a 10 percent overlap with 59N is adequate.

$$\text{Scheme A PKP} = 0.05 \text{ pu} + 0.10 \text{ pu} = 0.15 \text{ pu} \quad (13)$$

$$\text{Scheme A } VG3_{\text{min}} = 0.01 \text{ pu} \quad (14)$$

The fault resistance coverage at the neutral by Scheme A can be analyzed by solving for R_f in the circuit represented in Fig. 13, as shown in (15).

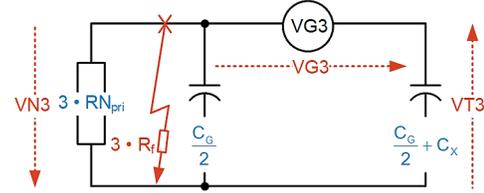


Fig. 13. Equivalent circuit for a fault at the neutral.

$$R_f = \frac{1}{3} \cdot \frac{X_t}{\left(\frac{1 \angle \alpha}{\text{PKP}}\right) - \left(1j + \frac{X_t}{Z_n}\right)} = 183.7 \Omega \quad (15)$$

where:

$$\text{PKP} = 0.15 \text{ pu} \quad (16)$$

$$\alpha = \sin^{-1} \left(\text{PKP} \cdot \text{Im} \left(1j + \frac{X_t}{Z_n} \right) \right) = 14.16^\circ \quad (17)$$

$$X_t = \frac{1}{\left(2\pi 180 \cdot \left(\frac{C_g}{2} + C_x \right) \right)} = 3,263 \Omega \quad (18)$$

$$Z_n = \frac{3 \cdot R_{N_{\text{pri}}} \cdot -jX_n}{\left(3 \cdot R_{N_{\text{pri}}} - jX_n \right)} = 3,917 \angle -49.25^\circ \quad (19)$$

$$X_n = \frac{1}{\left(2\pi 180 \cdot \left(\frac{C_g}{2} \right) \right)} = 5,171 \Omega \quad (20)$$

C. Scheme B Setting

Based on the recommended survey, the RAT setting for Scheme B is consistent with that of the system impedances.

$$\text{RAT}_{\text{sec}} = \text{RAT}_{\text{pri}} \cdot \frac{\text{PTR}}{\text{PTRN}} = \left| \frac{Z_n}{X_t} \right| \cdot \frac{166.67}{83.33} = 2.4 \quad (21)$$

In some relays, the RAT setting is scaled by 3, corresponding to the ratio between the neutral voltage and the sum of the per-phase terminal voltages. In such cases, RAT_{sec} for this system would be $2.4/3 = 0.8$.

The pickup setting is set sensitively to alarm with $\varepsilon = 0.20$ pu. The error in the primary signal is calculated as shown in (22):

$$\varepsilon_{\text{pri}} = \varepsilon \cdot 2\% \cdot V_{\text{LN}} = 46.19 V_{\text{pri}} \quad (22)$$

$$\text{Scheme B PKP} = \varepsilon_{\text{pri}} \cdot \left(\frac{1}{\text{PTRN}} + \frac{\text{RAT}_{\text{sec}}}{\text{PTR}} \right) = 1.22 \text{ V} \quad (23)$$

The following should be noted when choosing the settings using (22) and (23):

- If the relay uses a pickup setting in percent, then the pickup setting would be $0.40 \text{ pu} \cdot 2\% = 0.80\%$, where 0.40 pu is obtained from Table III.
- If the protection philosophy required Scheme B to trip, then $\varepsilon = 0.43$ would be used, with $\text{PKP} = 2.62 \text{ V}$.
- RAT_{sec} in (23) should always use the RAT_{sec} value shown in (21), irrespective of how the relay scales the RAT setting for Scheme B. For this example, we use 2.4 instead of 0.8.

The resistive coverage of this scheme varies with the level of the third harmonic produced, as shown in Fig. 10 and Fig. 11, and can be determined by using tools that solve the circuit based on available commissioning data.

Based on commissioning data, the example generator produces a VG3 in the range of 3 to 9 percent (or $346 V_{\text{pri}}$ to $1,040 V_{\text{pri}}$). Some relays provide a terminal third-harmonic value that is the sum of the per-phase third-harmonic voltages. In such cases, it is important to divide the sum by 3, as shown in (24).

$$\text{VG3} = |\text{VN3} + \text{VT3}| = \left| \text{VN3} + \left(\frac{\text{VA3} + \text{VB3} + \text{VC3}}{3} \right) \right| \quad (24)$$

D. 64S Setting

The 64S setting is set to trip at a similar resistive level as Scheme A; we can set this to 200Ω . Based on testing, a PT secondary fault resulted in a fault resistance of $6 \text{ k}\Omega$. The 64S is set to alarm at a more secure threshold, such as $5 \text{ k}\Omega$.

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IX. BIOGRAPHIES

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