

Advanced Generator Ground Fault Protections — A Revisit with New Information

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Abstract

Ground faults in generator stator and field/rotor circuits are serious events that can lead to damage, costly repair, extended outage and loss of revenue. This paper explores advances in field/rotor circuit ground fault and stator ground fault protection. These advanced protection strategies employ AC injection and other tactics to provide benefits in security, sensitivity and speed.

Introduction

Field/Rotor ground fault

Traditional field/rotor circuit ground fault protection schemes employ DC voltage detection. Schemes based on DC principles are subject to security issues during field forcing and other sudden shifts in field current.

To mitigate the security issues of traditional DC-based rotor ground fault protection schemes, AC injection-based protection may be used. AC injection-based protection ignores the effects of sudden DC current changes in the field/rotor circuits and attendant DC scheme security issues.

Stator ground fault

Traditional stator ground fault protection schemes include neutral overvoltage and various third harmonic voltage-dependent schemes. These exhibit sensitivity, security and clearing speed issues that may subject a generator to prolonged low-level ground faults that may evolve into damaging faults.

To mitigate the sensitivity, security and speed issues of traditional stator ground fault protection schemes, sequence-component-supervised protection, transient detection schemes and low frequency AC injection-based protection may be used.

- Sequence component-supervised protection is used to discriminate against out-of-zone ground faults and accelerate ground overvoltage schemes for in-zone faults.
- A transient fault detection scheme is used to identify fleeting arcing faults which may quickly evolve into permanent phase-to-ground or multiphase faults.
- Low frequency AC injection-based protection is used to identify ground faults regardless of operational mode or power level that cause difficulties with other schemes.

Field/Rotor Ground Fault Protection

1. Description and damage mechanism

The field/rotor circuit of a generator is an ungrounded DC system. The effect of one ground in the field/rotor circuit establishes a reference to ground on the normally ungrounded system. The voltage gradient to other parts of the field/rotor circuit increases as you move away from the ground reference point in the circuit. If weakened insulation exists, it is more likely to break down where the voltage gradient is now greater.

While an initial field/rotor circuit ground establishes a ground reference, the generator remains operational. In the event of a second ground fault, however, part of the field/rotor circuit is shorted out, and the resultant shorted portion of the rotor causes unequal flux in the air gap between the rotor and the stator with the rotor at rated speed. The unequal flux in the air gap causes torsional stress and vibration, and can lead to considerable damage in the rotor and the bearings. In extreme cases, rotor contact with the stator is possible. A second rotor ground fault also produces rotor iron heating from the unbalanced currents, which results in unbalanced temperatures causing rotor distortion and vibration. Field/rotor ground faults should be detected and affected generators alarmed with high resistance levels and tripped for low resistance levels.

This protection may be employed on *brushed* excitation systems and *brushless* excitation systems. The terms *brushed* and *brushless* refer to the use or nonuse of power commutation brushes to provide field current to the rotor.

- In the case of a brushed exciter, the ground fault protection system is coupled to the field/rotor circuit through power commutation brushes and the grounding brush as seen in Fig. 1.
- In the case of brushless exciter, the ground fault protection system is coupled to the field/rotor circuit through a measurement brush that is connected to the field/rotor circuit and the grounding brush as seen in Fig. 2.

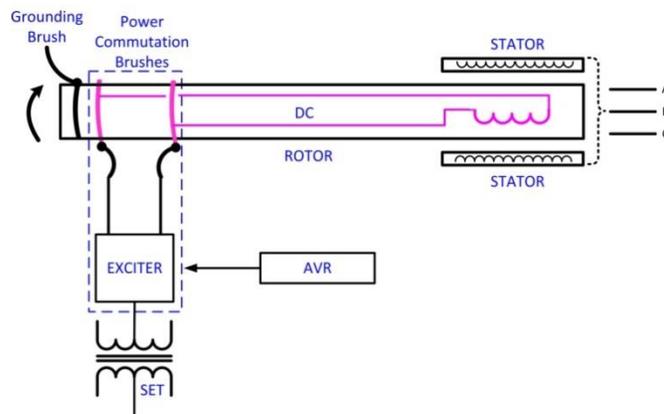


Fig. 1 “Brushed” Exciter

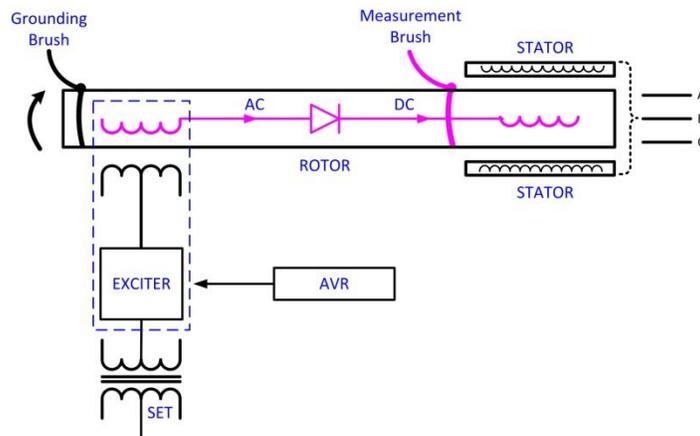


Fig. 2 “Brushless” Exciter

2. Traditional protection

Traditional field/rotor ground protection systems employ DC voltage injection and monitoring. The intent of the protection is to alarm or trip for ground faults in the field/rotor circuit.

The scheme shown in Fig. 3 employs a DC source in series with an overvoltage relay coil connected between the negative side of the generator field/rotor circuit and ground. A ground anywhere in the field causes current through the relay.

The scheme shown in Fig. 4 employs a voltage divider connected across the field and a sensitive voltage relay between the divider midpoint and ground. The voltage divider is composed of two standard resistors (R_1 and R_2) and one nonlinear resistor (R_{Varister}). Maximum voltage is impressed on the relay by a ground on either the positive or negative side of the field circuit. In order for a fault at the midpoint to be detected, the nonlinear resistor is applied. The nonlinear resistor's value changes with voltage, varying the nullpoint from the midpoint of the field/rotor circuit.

As both of these schemes use DC voltage, they are prone to insecure operation from DC transients in the excitation and field circuits.

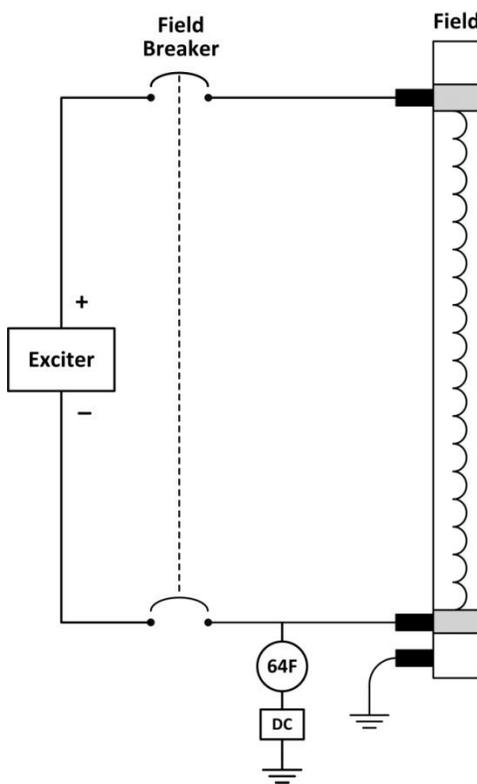


Fig. 3 DC Source 64F

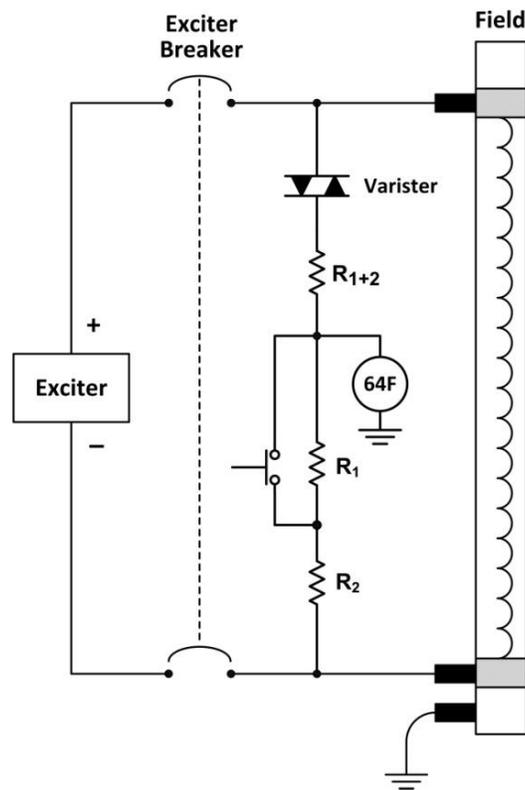


Fig. 4 Voltage Divider 64F

3. Advanced AC injection method

The scheme in Fig. 5 employs low frequency (0.1 to 1.0 Hz) ± 15 volt square wave injection. The square wave signal is injected into the field/rotor circuit through a coupling network. The return signal waveform is modified because of the field winding capacitance. The injection frequency setting is adjusted to compensate for field/rotor circuit capacitance and relay-to-coupler lead

length. Using the input and return voltage signals, the relay calculates the field insulation resistance. The element setpoints are in ohms, typically with a 20-kilohm alarm and 5-kilohm trip or critical alarm.

Using AC injection, the scheme is secure against the effects of DC transients in the field/rotor circuit. One issue with generator plant operators regarding field ground fault protection is the DC systems are prone to false alarms and false trips, so they sometimes are ignored or rendered inoperative, placing the generator at risk. The AC system offers much greater security so this important protection is not ignored or rendered inoperative.

Another benefit of the low frequency AC-injection system is that it can detect a rise in impedance which is characteristic of grounding brush lift-off. In brushless systems, the measurement brush may be periodically connected for short time intervals. If brush lift-off protection is applied, the brush lift-off function must be blocked during the time interval the measurement brush is disconnected.

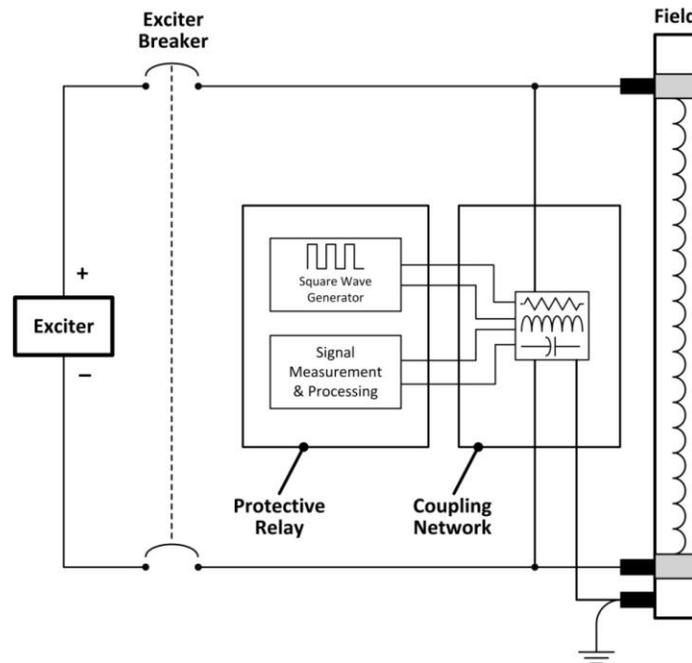


Fig. 5 AC Injection 64F

Stator Ground Fault Protection

1. Description and damage mechanism

Ground faults in a generator (stator winding) can cause considerable and severe damage as the level of fault current increases. Depending on the ground fault current available, the damage may be repairable or non-repairable. Generators that are subjected to prolonged exposure to stator ground fault become damaged due to the fact that even if the system connection and excitation are tripped, stored flux remains and contributes to the arc as the generator coasts down. Due to the exposure to this damage, several types of generator grounding are employed. The stator circuit of a generator may be ungrounded, impedance grounded, or solidly grounded. Some descriptions follow.

A. *Ungrounded*

Ungrounded generators are not typically applied in utility systems, and find special application in industrial systems (Fig. 6).

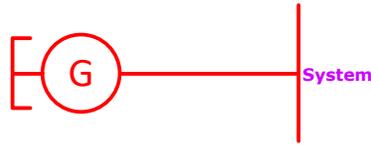


Fig. 6 Ungrounded Generators

Advantages:

1. The first ground fault on a system causes only a small ground current to flow, so the system may be operated with a ground fault present, improving system continuity.
2. Arcing with a ground fault on the system may be greatly reduced, which is seen as an advantage in certain industries (e.g., mining).
3. No expenditures are required for grounding equipment or grounded system conductors.
4. Generator damage is minimal if ground fault is in the generator (stator winding) unless resonance occurs with arcing.

Disadvantages:

1. Ground fault detection is more complicated than that in grounded generators.
2. There is decreased safety once an initial ground fault is established.
3. There is the possibility of excessive overvoltages that can occur due to restrikes in the generator breaker clearing the ground fault.
4. Detection and location of ground faults is more difficult when they do occur.

B. *Low impedance grounded*

Low impedance-grounded generators are typically applied in industrial systems, and find special application in utility systems (Fig. 7).



Fig. 7 Low Impedance Grounded Generator

Advantages:

1. Reduces burning and melting effects in faulted electric equipment, such as switchgear, transformers and cables.
2. Reduces mechanical stresses in circuits and apparatus carrying fault currents.
3. Reduces electric-shock hazards to personnel caused by stray ground-fault currents in the ground return path.
4. Reduces the arc blast or flash hazard to personnel who may have accidentally caused or who happen to be in close proximity to the ground fault.
5. Reduces the momentary line-voltage dip occasioned by the occurrence and clearing of a ground fault.
6. Controls transient overvoltages.

Disadvantages:

1. Generator damage occurs with a ground fault in the generator (stator winding).

C. High impedance grounded

High impedance-grounded generators are typically applied in utility systems and some industrial systems (Fig. 8). With a “unit connection,” the only ground source for the generator, the bus and the primary of the GSU is the high impedance ground formed by the grounding transformer and the reflected impedance of the grounding resistor.

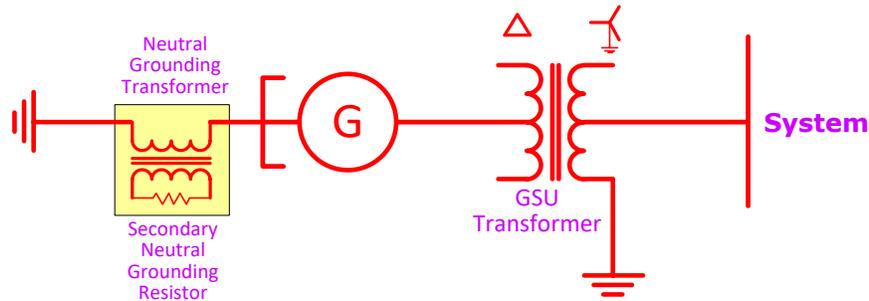


Fig. 8 High Impedance-Grounded Generator (Unit Connection)

Advantages:

1. Reduces burning and melting effects in faulted equipment, such as switchgear, transformers and cables.
2. Reduces mechanical stresses in circuits and apparatus carrying fault currents.
3. Reduces the arc blast or flash hazard to personnel who may have accidentally caused or who happen to be in close proximity to the ground fault.
4. Reduces the momentary line-voltage dip while clearing a ground fault.
5. Controls transient overvoltages.
6. Generator damage is minimal if ground fault is in the generator (stator winding).

Disadvantages:

1. Requires unit connection and specialized grounding equipment.
2. Full (100%) ground fault coverage may require advanced protection techniques.

D. Hybrid impedance grounded

Hybrid impedance-grounded generators are gaining acceptance in industrial systems. Hybrid impedance grounding, or hybrid grounding as it is commonly called, offers advantages of a low impedance-grounded system during unfaulted generator operation, and high impedance grounding when a fault is detected within the generator to minimize damage to the stator. The grounding impedance is switched depending on the presence of a ground fault within the generator (Fig. 9).

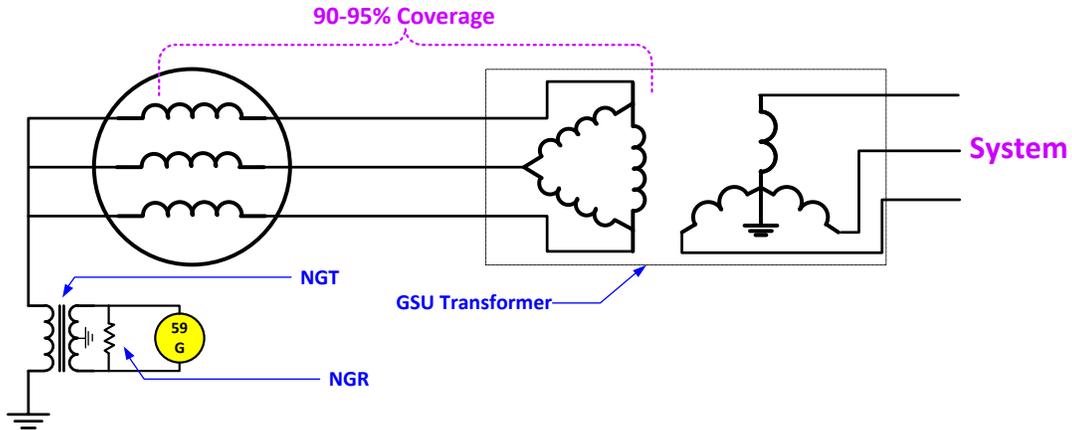


Fig. 10 59G Scheme

Selectivity and sensitivity issues with this protection develop for system ground faults outside the generator zone. These system ground faults, due to the capacitive coupling of the generator step-up transformer (GSU), can cause current to flow through the generator neutral, and therefore cause a voltage to be detected across the grounding resistor by the 59G element (Fig. 11).

To provide security for this possibility, two steps of ground overvoltage protection is typically employed (Fig. 11).

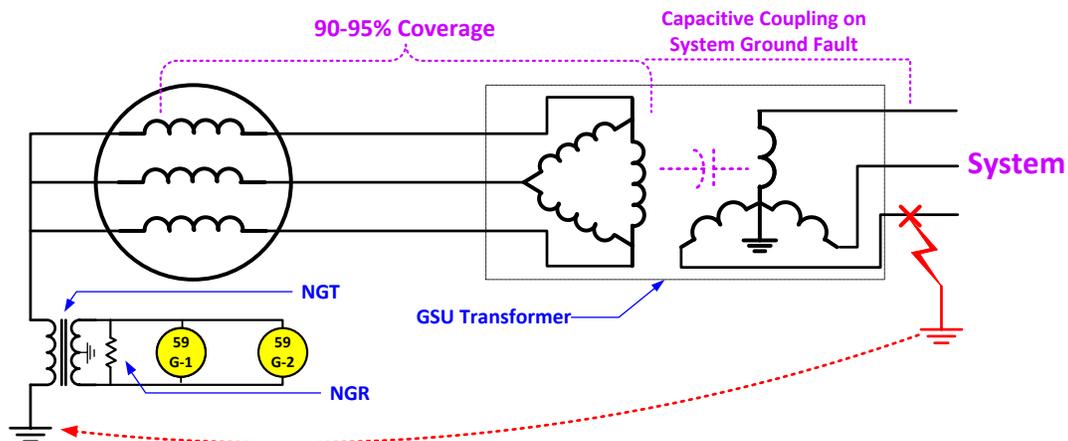


Fig. 11 GSU Capacitive Coupling for System Ground Faults

- 59G-1 is set for 95% stator coverage with a time delay set to coordinate with the longest possible uncleared ground fault on the power system. This is dependent upon the speed of the line relays off the generating station, with backup and breaker failure time considered in the setting (Fig. 12).
- 59G-2 is set for a level that is greater than the maximum calculated interference voltage from a ground fault in the system, with a short time delay (Fig. 12).

To cover the last 5% of the stator winding, use is made of the fact that generators typically produce small and sometimes measureable third harmonic voltage at the neutral and terminal ends

of the stator winding (Figs. 13 and 14). The presence or absence of these third harmonic voltages can be used to provide detection of ground faults near the ends of the stator winding.

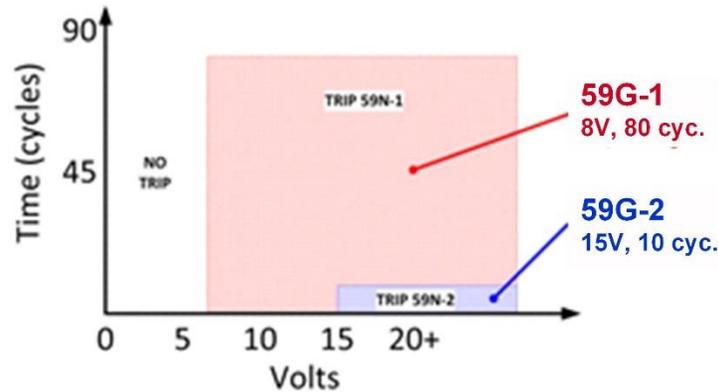


Fig. 12 Use of Dual 59-G Elements

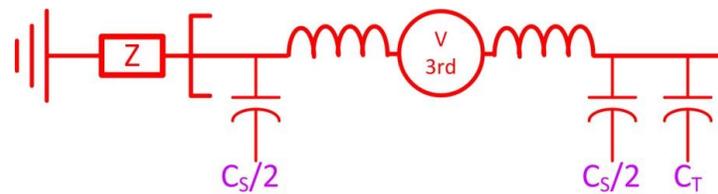


Fig. 13 Capacitive Model of Stator

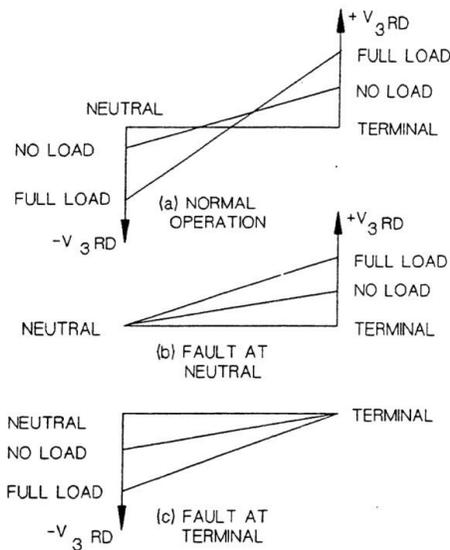


Fig. 14 Stator 3rd Harmonic Profiles and Terminal Connections

As the terminal end of the stator winding is easily covered by the 59G element, of interest is detecting and declaring ground faults at the neutral end of the stator winding. In high impedance-grounded generators, the ground fault current is typically limited to 5-20A with a ground fault at 100% of the stator winding. As the ground fault location moves to the neutral end of the stator winding, the current decreases proportionally. A great concern of operating a generator with a ground fault near the neutral is even though the resultant fault current is very small, the high

impedance used to limit ground fault currents is effectively shunted. If a second ground fault develops, the resultant ground fault current will be very large as there is not any ground impedance to limit such current (Fig. 15).

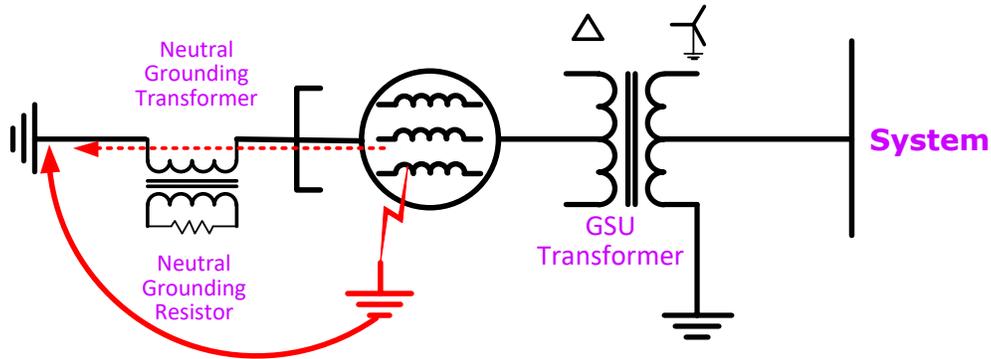


Fig. 15 Fault near Stator Neutral Shunting Grounding Impedance

Two schemes using 3rd harmonic voltage are commonly employed to detect faults near the generator neutral. The first technique applies an undervoltage element tuned to the 3rd harmonic voltage. This element, 27TN, operates on the fact that the 3rd harmonic voltage is shunted by a ground fault near the neutral (Fig. 16).

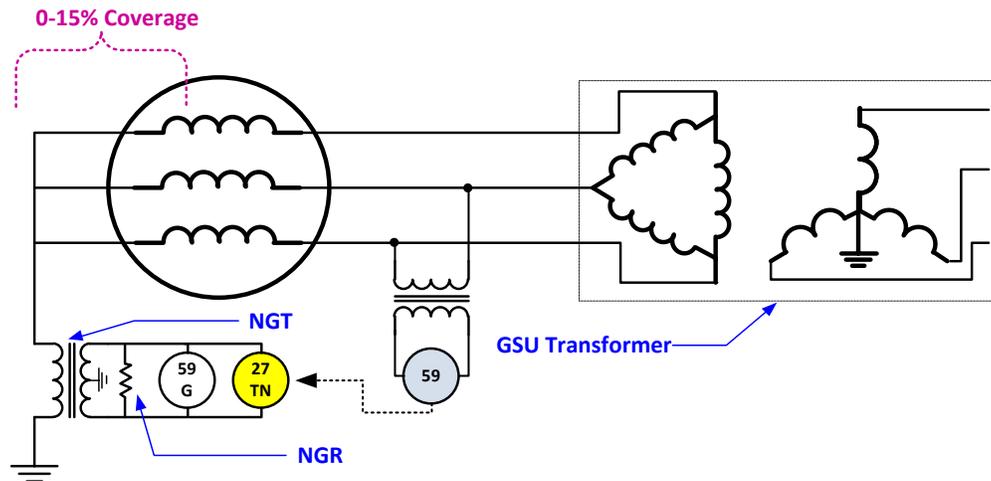


Fig. 16 27TN Scheme

The second technique applies 3rd harmonic voltage detection elements to the neutral and terminal ends of the generator. This element, 59R or 59D, operates on the fact that the 3rd harmonic voltage is shunted by a ground fault near the neutral or terminal end of the stator, thereby changing the ratio of neutral and terminal 3rd harmonic quantities (Fig. 17).

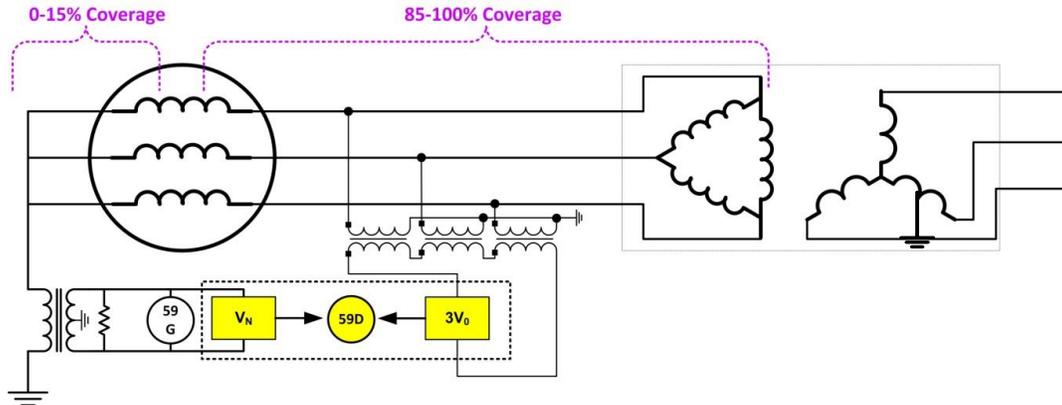


Fig. 17 59D or 59R Scheme

Both of these 3rd harmonic implementations can be rendered inoperable, or worse, insecure, by the fact that 3rd harmonic voltages produced by a given generator can vary widely over various modes of operation (generating or motoring, static starting), real power output and reactive power output (field forcing, absorbing VARs for voltage control). Depending on the generator and the system to which it is connected, use of 3rd harmonic-based protections may be severely limited or not applicable (Fig. 18).

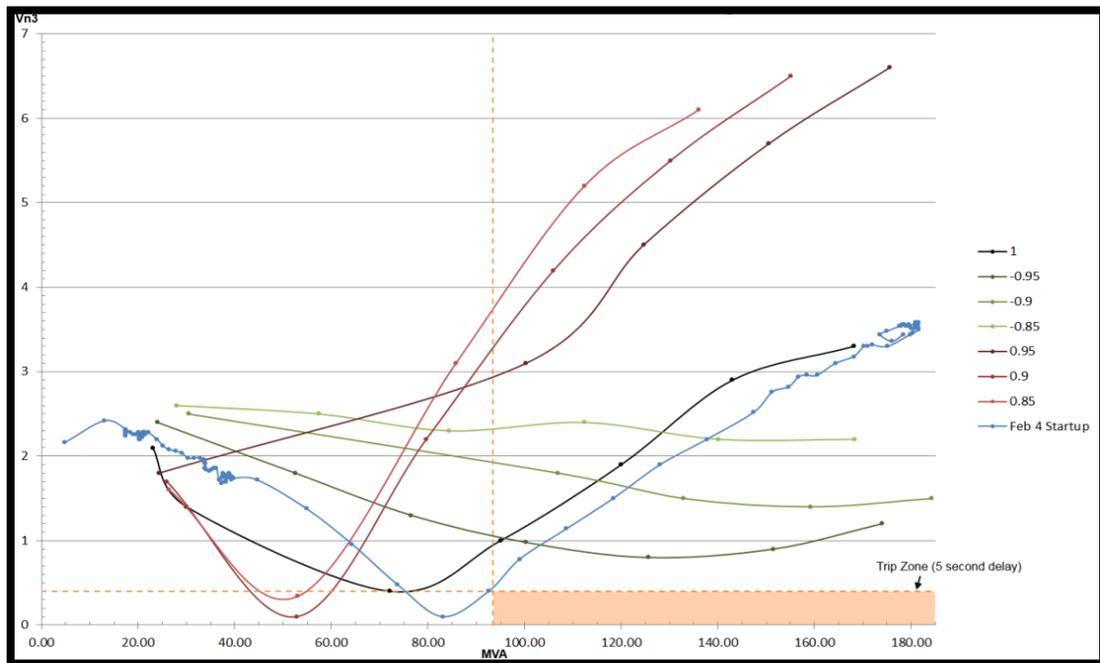


Fig. 18 Generator Power Output vs. 3rd Harmonics at the Neutral

3. Advanced methods

Sequence Component Supervision of 59G Element

To better cope with issues from capacitive coupling due to ground faults in the system side of the GSU, a 59G acceleration scheme can be employed using sequence component supervision. This method has been documented in two works [7] [8] and employs the fact that ground faults outside of the unit connection produce levels of negative sequence current and voltage. Either of

these quantities (I_2 or V_2) may be used to declare the ground fault is outside of the unit-connected generator, thereby employing a longer time delay on the 59G element than applied on the primary, backup and breaker failure protection for the ground fault outside the generator zone. If a negative sequence current or voltage is not detected, the ground fault is presumed to be in the generator zone and a short delay for the 59G element is employed (Fig. 19).

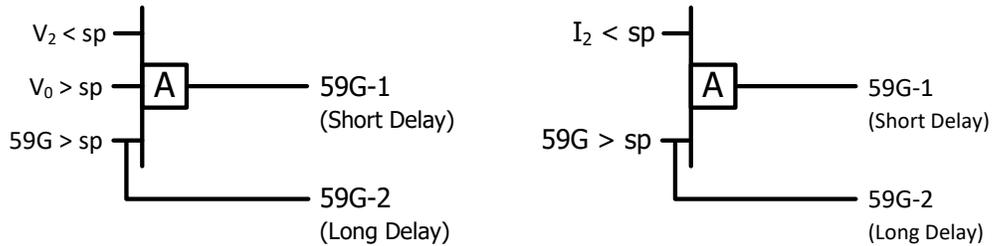


Fig. 19 Sequence Component Supervision of the 59G Element

Transient Ground Fault Retentive Timer for 59G and 27TN

Transient ground faults are characterized by existing for a short duration, then extinguishing. Over time, repeated transient ground faults can break down insulation and evolve into permanent ground faults, and perhaps evolve further into multiphase faults (Fig. 20).

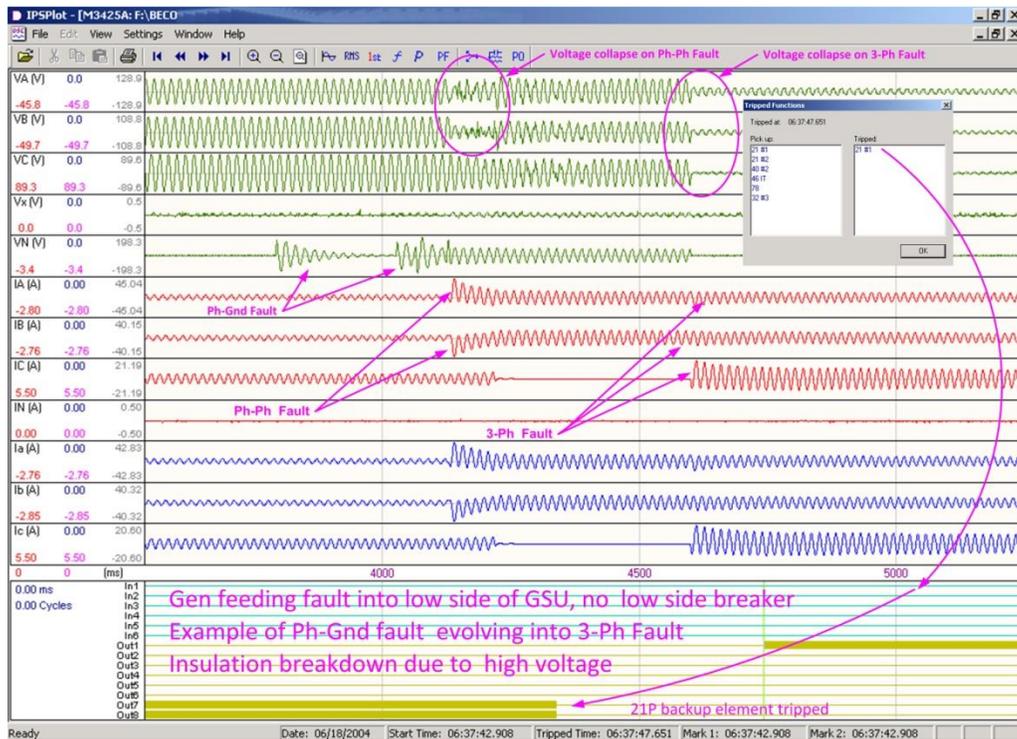


Fig. 20 Transient Ground Fault Evolving into Multiphase Faults

To detect transient ground faults, an interval timing scheme can be employed on the 59G or 27TN elements. If either the 59G or 27TN elements pick up and quickly drop out, a timer is started. If two or more (settable by delay manipulation) transient ground faults occur within the scheme timing window, a ground fault is declared and a trip for arcing fault is initiated (Fig. 21).

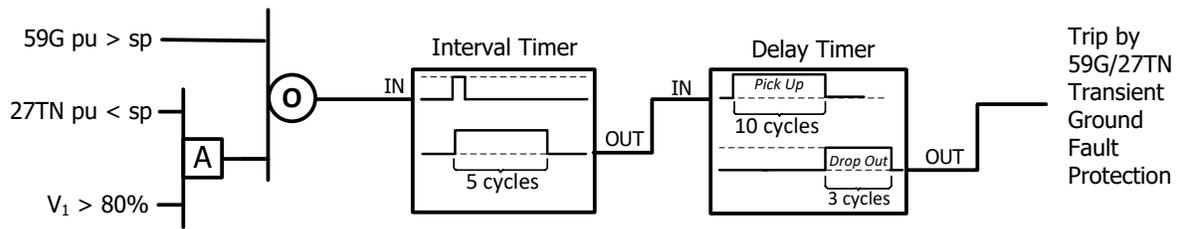


Fig. 21 Transient Ground Fault Timing Scheme Logic (59N/27TN)

100% Stator Ground Fault by Subharmonic Injection

To overcome limitations of the 100% stator ground fault protection offered by combining the 59G and 3rd harmonic elements (27TN, 59R, 59D), ground fault detection by subharmonic injection may be used. Subharmonic injection is used (versus superharmonic) because the capacitive coupling induced current effect is reduced by using a lower injection frequency (Fig. 22).

This example system uses a 20Hz injection signal. The signal is connected to the generator secondary ground circuit through a coupling network consisting of a low pass filter. This filter prevents high level fundamental voltage from the power system impacting the injector. When the injector is energized, the voltage is measured. That measured voltage ensures the injector is working. The 20Hz current flows through the grounding transformer, and in the normal state (a ground fault does not exist in the unit-connected generator zone), a small amount of current flows due to the naturally occurring capacitance to ground in the generator and isophase bus, plus capacitance of applied surge capacitors. A CT is used to measure current resulting from the injection. This current demonstrates the system is functioning, and ground circuit integrity is maintained. If a primary connection to ground opens, or the secondary ground circuit opens, the capacitive current drops and an alarm is issued (self-diagnostic). If a true resistive ground fault develops, the real component of the ground current increases. Detecting the real component, versus the total component, offers much greater sensitivity for fault detection.

The system is independent of generator operation, and will reliably function when the generator is offline, starting and during power system-connected operation. It does not rely on 3rd harmonic signatures, so generator loading (real, reactive) has no effect. By use of an injection signal, this method is independent of the generator and power system conditions. If the frequency of the connected power system approaches or is at the injection frequency, interference will not occur if the connected source is balanced three-phase. In the case of combustion turbine static starting, pumped hydroelectric plant starting and rotor warming, the source is balanced three-phase power; therefore, zero sequence current does not flow, and the neutral circuit is not affected. The current sensed by the injection system CT is not affected by positive sequence current of any frequency being impressed at the generator terminals (Fig. 23).

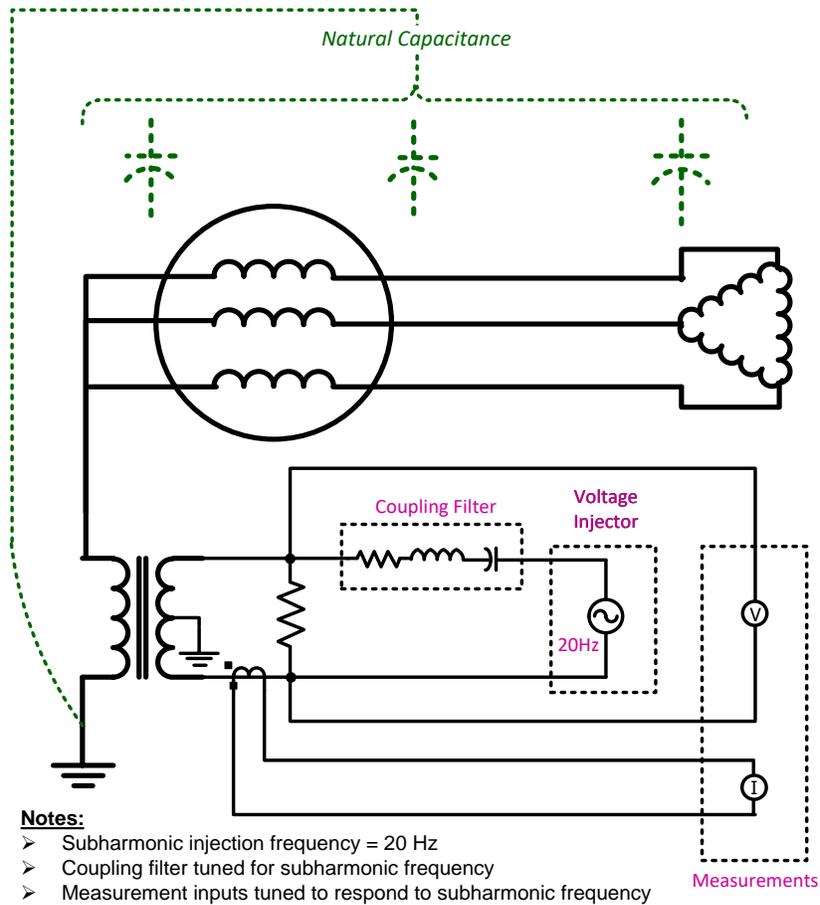


Fig. 22 100% Stator Ground Fault Protection Using Subharmonic Injection

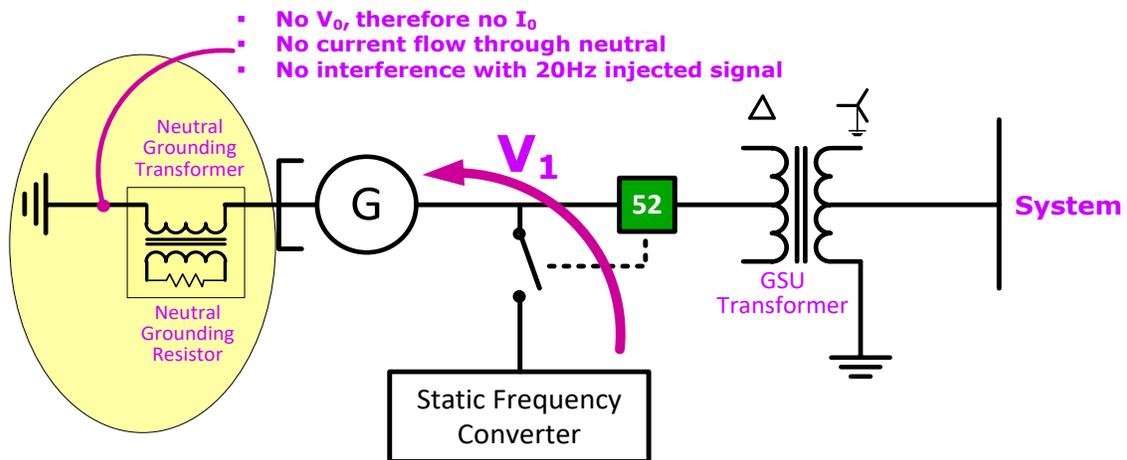


Fig. 23 Static Starting of a Combustion Gas Turbine

For intermittent ground faults, an approach similar to what is used for the combination of the 59N and 27TN element may be applied, the integrating timer. In this case, the 59N pickup and

64S pickup would be used as inputs to the timer. The 27TM is not applied as the 64S provides complete stator ground fault coverage anywhere in the generator or protected zone (Fig. 24).

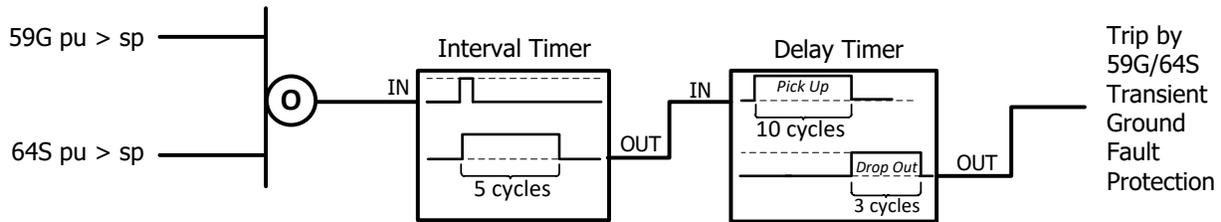


Fig. 24 Transient Ground Fault Timing Scheme Logic (59N/64S)

Summary and Conclusions

Field/Rotor Ground Fault

- Use of AC injection offers greater security than traditional DC systems, and also affords brush lift-off protection.

95% Stator Ground Fault Protection

- Use of the 59G element is a time-tested method of protecting 95% of the stator for generator ground faults.
- The traditional approach to cope with GSU capacitive coupling and interference with the 59G element is using two elements — one with a long time delay coordinated system ground protection, and the other with a short time delay for in-zone ground faults.
- An advanced method of using sequence component supervision allows determination of external ground faults, and allows the 59G element to quickly clear ground faults in the generator zone.

100% Stator Ground Fault Protection

- 3rd harmonic protection implementations are available to complement the 59N element to provide 100% stator ground fault protection. It should be noted that 3rd harmonic protections may not work with all generators, and may not work at all times on a given generator. The 3rd harmonic values available to the protection vary with operational mode and power (real and reactive) output. Both security and dependability issues may develop.
- Transient ground faults can be detected with the use of an interval timing scheme on the 59G and 27TN protections or 59N and 64S protections. This enhancement affords the ability to detect transient ground faults before a permanent ground fault develops.
- The use of subharmonic injection affords the ability to detect ground faults anywhere in the stator or in the unit-connected zone regardless of the generator operation and loading. If the element uses the real component for fault declaration, it is very sensitive. As long as external signals at or near the subharmonic-injected frequency are balanced, the element is highly secure. The element only responds to zero sequence current in the generator neutral, not positive sequence current from an external balanced system such as another generator during back-to-back starting or static converter employed in starting combustion gas turbine generators.

References

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Author Biography

Wayne Hartmann is Vice President of Protection and Smart Grid Solutions for Beckwith Electric. He provides customer and industry linkage to Beckwith Electric's solutions, as well as contributing expertise for application engineering, training and product development.

Before joining Beckwith Electric, Wayne performed in application, sales and marketing management capacities with PowerSecure, General Electric, Siemens Power T&D and Alstom T&D. During Wayne's participation in the industry, his focus has been on the application of protection and control systems for electrical generation, transmission, distribution and distributed energy resources.

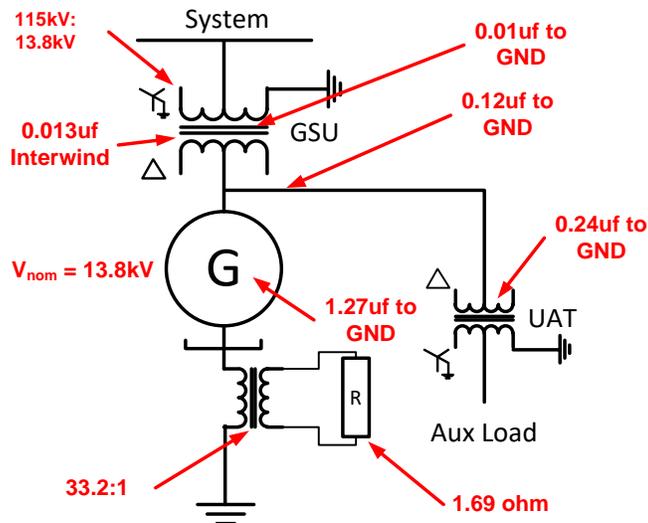
Wayne is very active in the IEEE as a Senior Member and has served as a Main Committee Member of the IEEE Power System Relaying Committee for 25 years. He is presently Chair of the Working Group "Investigation of the Criteria for the Transfer of Motor Buses." His IEEE tenure includes having chaired the Rotating Machinery Protection Subcommittee ('07-'10), contributing to numerous standards, guides, transactions, reports and tutorials, and teaching at the T&D Conference and various local PES and IAS chapters. He has authored and presented numerous technical papers and contributed to McGraw-Hill's *Standard Handbook of Power Plant Engineering, 2nd Ed.*

ANNEX 1: High Side of GSU Ground Fault and Influence on 59G Voltage

The following calculations are for the 59G elements.

- “59G V” is used for 95% stator winding coverage and would either be set to coordinate with high side GSU ground fault (long time delay), or use I_2 or V_2 inhibit and a short time delay.
- “59G V max coupled” is set to be blind to the influence of a high side GSU ground fault and employs a short time delay. Some margin would be added to the voltage setting in this calculation.

System 1-Line:



Calculate Generator Line-Neutral Voltage	
$V_{L-N \text{ rated}} = V_{L-L \text{ rated}} / 1.73$	
$V_{L-L \text{ rated}} =$	13,800 V
$V_{L-N \text{ rated}} =$	7,977 V

Calculate Total Capacitance	
$C_t = C_{gen} + C_{clead} + C_{gsu} + C_{uat} + C_{surge} \text{ (uf)}$	
$C_{gen} + C_{clead}$	1.27 uf
C_{surge}	0.12 uf
C_{gsu}	0.01 uf
C_{uat}	0.24 uf
$C_t =$	1.64 uf

Calculate Total Capacitive Reactance (ohms)	
$X_{ct} = 1/2 * (3.14) * f * C_t$	
$X_{ct} =$	1,864 Ω

Select NGT Ratio	
Desired $V_{sec} =$	240 V
$NGT \text{ Ratio} = V_{L-G} / V_{sec \text{ max}}$	
$NGT \text{ Ratio} =$	33.2

Calculate 95% 59G Setting	
Desired Coverage % (from terminal end)	95 %
$59G \text{ V} = V_{sec \text{ max}} * ((100\% - \% \text{ Desired Coverage}) / 100)$	
$59G \text{ V} =$	12 V

Select R ground pri to equal X_{ct} to limit transient overvoltage	
$R_{ground \text{ pri}} =$	1,864 Ω

Calculate NGR based on R ground pri	
$NGR = R_{ground \text{ pri}} / (NGT \text{ ratio})^2$	
$NGR =$	1.69 Ω

Calculate Max Primary Ground Fault Current Through Resistor	
$GFC-R \text{ pri max} = V_{L-N} / R_{ground \text{ pri}}$	
$GFC-R \text{ pri max} =$	4.28 A

Calculate Max. Total Ground Fault Current	
$I-R = I-C; I-f = I-r + jI-C; I-f = I-r (1.414)$	
$I-f =$	6.05 A

Calculate Max Secondary Ground Fault Current Through Resistor	
$GFC-R \text{ sec max} = V_{sec \text{ max}} / NGR$	
$GFC-R \text{ sec max} =$	142 A

Calculate NGT/NGR Power Dissipation	
$kW = (V_{sec \text{ max}} * GFC \text{ sc max}) / 1000$	
$kW =$	34.1 kW

Calculate Worse Case Coupling Voltage	
$GSU \text{ High side } V =$	115,000 V
$GSU \text{ interwinding capacitance} =$	0.013 uf
$GFC \text{ pri coupled} = V_{L-N \text{ highside}} / (1/6.28 * f * C)$	
$GFC \text{ pri coupled} =$	0.33 A

$59G \text{ V max coupled} = (GFC \text{ pri coupled} * R_{ground \text{ pri}}) / NGT \text{ ratio}$	
$59G \text{ V max coupled} =$	18.3 V

ANNEX 2: 64S Element Security Calculations

A 64S ground fault scheme using subharmonic injection can be made secure by using both the real and total components of the monitored 20Hz current resultant currents with proper settings and margins.

- *Real component*: Used to detect and declare stator ground faults through the entire stator winding (and the isophase and GSU/UAT windings), except at the neutral or faults with very low (near zero) resistance.
- *Total component*: A fault at the neutral or with very low resistance results in very little/no voltage (V_N) to measure; therefore, the current cannot be segregated into reactive and real components, so the total current is used as it does not require a voltage reference. In addition, presence of total current provides a diagnostic check that the system is functional and continuity exists in the ground primary and secondary circuits.

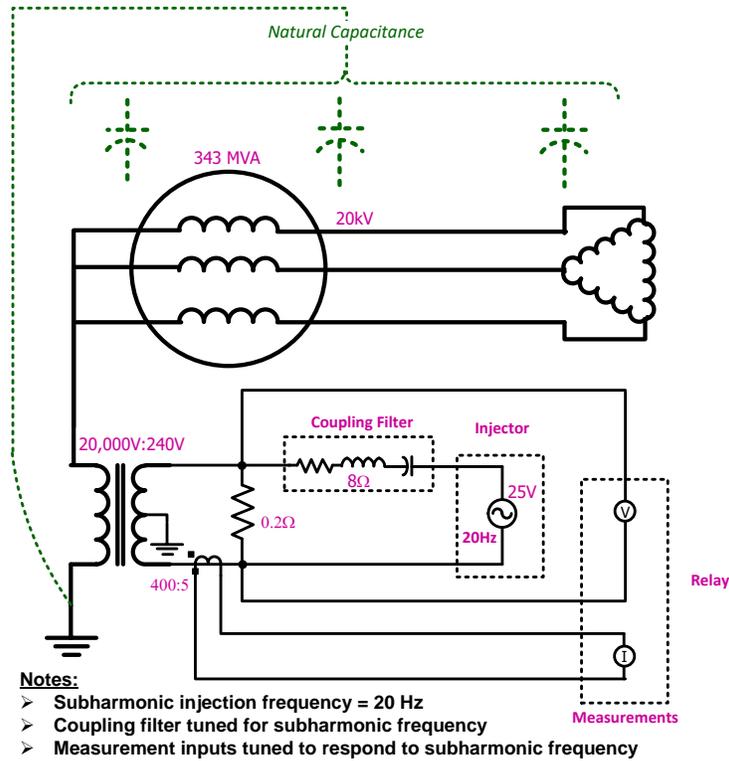
A typical stator resistance (not reactance) to ground is $>100k$ ohm, and a resistive fault in the stator is typically declared in the order of $\leq 5k$ ohm.

The two areas of security concern are when the generator is being operated at frequencies of 20 Hz and 6.67 Hz. All other operating frequencies are of no concern due to the 20 Hz filter and tuning of the element response for 20 Hz values.

For our analysis, we use data from a generator in the southeastern U.S.A. outfitted with a 64S, 20 Hz subharmonic injection system.

Case 1: Generator Operating at 20 Hz

- If the generator is operating as a generator at 20 Hz *without* an external source (e.g., drive, LCI, back-to-back hydro start), there is no concern as the 20 Hz at the terminals is at or very close to balanced; therefore, 20 Hz zero-sequence current will not flow through the neutral circuit.
- If the generator is being operated as a motor *with* an external source (e.g., drive, LCI, back to back hydro start), the phase voltages are balanced or very close to balanced.



1-Line Diagram

Generator Breaker Closed

- Generator plus isophase, surge caps and GSU delta winding

Metered values, including observed 20 Hz values, no fault conditions.

Currents (A)		Voltages (V)		Impedance (Ohm)	
Phase A	0.171	Phase A	68.7	AB R	275.73
Phase B	0.139	Phase B	68.0	AB X	229.46
Phase C	0.102	Phase C	68.5	BC R	238.65
Neutral	0.000	Neutral	0.2	BC X	327.67
Pos. Seq.	0.143	Pos. Seq.	68.5	CA R	327.67
Neg. Seq.	0.041	Neg. Seq.	0.2	CA X	327.67
Zero Seq.	0.002	Zero Seq.	0.4	Pos. Seq. R	327.67
49 #1	0.05	VX	0.0	Pos. Seq. X	327.67
Phase a	0.177				
Phase b	0.145				
Phase c	0.108				
I diff G	-0.02				
A-a diff	0.00				
B-b diff	0.02				
C-c diff	0.02				
49 #2	0.05				
Low Freq. Injection		3rd Harmonic		Power (p.u.)	
VN (V)	0.3	VN (V)	0.75	Real	0.023
IN (mA)	14.1	VX (V)	0.00	Reactive	0.026
Real (mA)	2.8	VX/VN	0.00	Apparent	0.032
				Frequency	
				Frequency (Hz)	59.97
				V/Hz (%)	99.1
				ROCOF (Hz/s)	0.00

- V_N 20 Hz = voltage across the neutral grounding resistor
- I_N 20 Hz (mA) = **total** current (combined real and reactive) measured by the relay
- **Real** 20 Hz (mA) = **real** component of current measured by the relay

Calculate the CT primary currents:

$$I_{N \text{ pri (total)}} = 14.1 \text{ A} * 10^{-3} * \text{CTR}$$

$$I_{N \text{ pri (total)}} = 14.1 \text{ A} * 10^{-3} * 80$$

$$I_{N \text{ pri (total)}} = 1.128 \text{ A}$$

$$I_{N \text{ pri (real)}} = 2.8 \text{ A} * 10^{-3} * \text{CTR}$$

$$I_{N \text{ pri (real)}} = 2.8 \text{ A} * 10^{-3} * 80$$

$$I_{N \text{ pri (real)}} = 0.224 \text{ A}$$

The currents and voltages at the grounding transformer primary:

$$I_{N \text{ pri (total)}} = 1.128 \text{ A} / \text{NGT ratio}$$

$$I_{N \text{ pri (total)}} = 1.128 \text{ A} / 83.33$$

$$I_{N \text{ pri (total)}} = 0.013536 \text{ A}$$

$$I_{N \text{ pri (real)}} = 0.0224 \text{ A} / \text{NGT ratio}$$

$$I_{N \text{ pri (real)}} = 0.0224 \text{ A} / 83.33$$

$$I_{N \text{ pri (real)}} = 0.002688 \text{ A}$$

$$V_{N \text{ pri}} = V_{\text{sec}} * \text{NGT ratio}$$

$$V_{N \text{ pri}} = V_{\text{sec}} * \text{NGT ratio}$$

$$V_{N \text{ pri}} = 25 \text{ V}$$

3rd harmonic voltage measured at relay = 0.75 V

$$V_{\text{pri}} = V_{\text{sec}} * \text{NGT ratio}$$

$$V_{\text{pri}} = 0.75 \text{ V} * 83.33$$

$$V_{\text{pri}} = 62.5 \text{ V}$$

Assuming a zero-sequence unbalance of 0.1% of the nominal at 60 Hz:

$$V_{\text{pri unbalance}} = \% \text{ unbalance} / 100 * V_{\text{L-L rated}} / \sqrt{3}$$

$$V_{\text{pri unbalance}} = (0.1\% / 100) * (20,000 \text{ V} / 1.73)$$

$$V_{\text{pri unbalance}} = 11.5 \text{ V}$$

$$V_{\text{sec unbalance}} = V_{\text{pri unbalance}} / \text{NGT ratio}$$

$$V_{\text{sec unbalance}} = 11.5 \text{ V} / 83.33$$

$$V_{\text{sec unbalance}} = 0.14 \text{ V}$$

Assuming V/Hz is kept constant in LCI or back-to-back generator start. The voltage at 20 Hz frequency is 20 Hz voltage during the start. Assuming 1pu V/Hz 120/60 = 2 = 1 pu

Frequency divisor: $60 \text{ Hz} / 20 \text{ Hz} = 3$. Voltage divisor is 3.

$$\begin{aligned} V_{\text{sec unbalance (20 Hz)}} &= V_{\text{sec unbalance (60 Hz)}} / 3 \\ V_{\text{sec unbalance (20 Hz)}} &= 0.14 \text{ V} / 3 = 0.0466 \text{ V} \end{aligned}$$

20 Hz current flowing through NGR:

$$\begin{aligned} \text{NGR } I_{20 \text{ Hz}} &= V_{\text{sec unbalance (20 Hz)}} * \text{NGR } \Omega \\ \text{NGR } I_{20 \text{ Hz}} &= 0.0466 / 0.2 = 0.223 \text{ A} \end{aligned}$$

Relay measured 20 Hz current:

$$\begin{aligned} I_{20\text{Hz Relay}} &= \text{NGR } I_{20 \text{ Hz}} * \text{CTR} \\ I_{20\text{Hz Relay}} &= 0.223 \text{ A} / 80 \\ I_{20\text{Hz Relay}} &= 0.0029 \text{ A} = 2.9 \text{ mA} \end{aligned}$$

Using pickup values are 20 mA total and 6 mA real, the element remains secure.



Note the margins:

- Total current calculated: 2.9 mA
- Total current setting: 20 mA
- Margin: 17.1 mA

- Total current calculated: 2.9 mA
- Real current setting: 6.0 mA
- Margin: 3.1 mA

Case 2: 6.67 Hz voltage at the generator terminals, assume 3rd harmonic (20 Hz) created in the neutral

In this case, we are assuming the generator under study is being started with a drive, LCI or back-to-back hydro start. The generator is acting like a motor and the unbalance is originating from the source.

Using typical values from a generator operating under full load, 3rd harmonic can be expected to be approximately 5X no load value.

$$\begin{aligned} 3^{\text{rd}} V_{60 \text{ Hz NGT pri}} &= 5 * (\text{no load } 3^{\text{rd}} \text{ harmonic}) * \text{NGT ratio} \\ 3^{\text{rd}} V_{60 \text{ Hz NGT pri}} &= 5 * 0.75 \text{ V} * 83.33 \\ 3^{\text{rd}} V_{60 \text{ Hz NGT pri}} &= 312.498 \text{ V} \end{aligned}$$

*The frequency during the start is reduced to 6.67 Hz ($3 * 6.67 \text{ Hz} = 20 \text{ Hz}$).*

Assuming the V/Hz is kept as constant, the 3rd harmonic voltage is reduced.

$$3^{\text{rd}} V_{20 \text{ Hz NGT pri}} = 6.67 \text{ Hz} / 60 \text{ Hz} * 312.498 \text{ V (without reduction in capacitance)}$$

$$3^{\text{rd}} V_{20 \text{ Hz NGT pri}} = 34.74 \text{ V (without reduction in capacitance)}$$

Since the frequency is 20 Hz and not 180 Hz, there is a further reduction in 3rd harmonic current due to the capacitance at 1/9th of the 60 Hz value. (180/20=9)

The model is complex and the relationship is not straightforward, so we assume a reduction of 1/5th instead of 1/9th

$$3^{\text{rd}} V_{20 \text{ Hz NGT pri}} = 34.74 \text{ V} / 5 = 6.9 \text{ V}$$

Voltage at NGT secondary:

$$\text{NGT } V_{\text{sec}} = 3^{\text{rd}} V_{20 \text{ Hz NGT pri}} / \text{NGT ratio}$$

$$\text{NGT } V_{\text{sec}} = 6.9 \text{ V} / 83.33 = 0.0828 \text{ V}$$

Current through NGR:

$$\text{NGR } I_{20 \text{ Hz}} = \text{NGT } V_{\text{sec}} / \text{NGR } \Omega$$

$$\text{NGR } I_{20 \text{ Hz}} = 0.0828 / 0.2 = 0.414 \text{ A}$$

Relay measured 20 Hz current:

$$I_{20 \text{ Hz Relay}} = \text{NGR } I_{20 \text{ Hz}} * \text{CTR}$$

$$I_{20 \text{ Hz Relay}} = 0.414 \text{ A} / 80$$

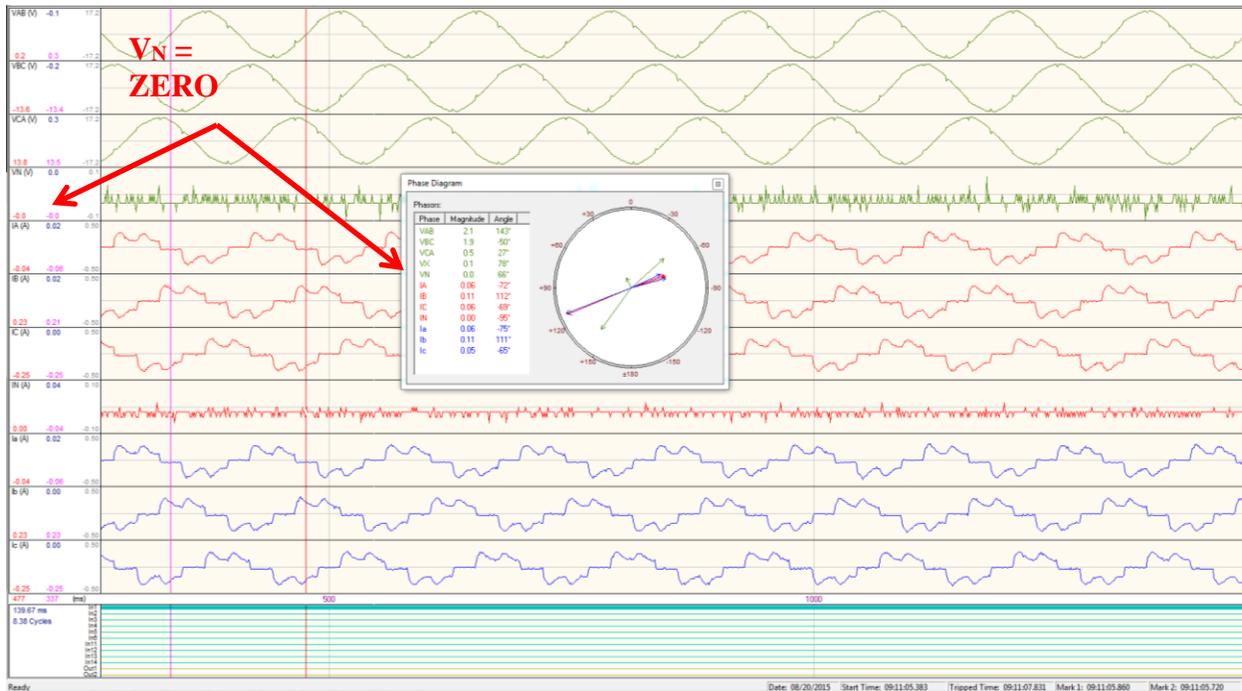
$$I_{20 \text{ Hz Relay}} = 0.005175 \text{ A} = 5.175 \text{ mA}$$

Note the margins:

- Total current calculated: 5.175 mA
- Total current setting: 20 mA
- Margin: 14.825 mA

- Total current calculated: 5.175 mA
- Real current setting: 6.0 mA
- Margin: 0.825 mA

Below is an oscillograph from a CGT during static start at 6.67 Hz. Note the VN is zero (the waveform seen under VN is noise).



By in-situ observation of the quiescent (non-faulted) real and total currents, and also observing the total current with a fault placed on the neutral during commissioning (on a deenergized and isolated generator), proper values can be selected with adequate margin to affect a coordinated protection scheme that is dependable, sensitive and secure.