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Power Plant Protection Event Analysis and Condition Monitoring

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Centennial 300A

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Generation – System Protection

INTRODUCTION

Contrary to popular belief, generators can fail, not only from short circuits, but more frequently due to abnormal electrical conditions such as overexcitation, overvoltage, loss-of-field, unbalanced currents, abnormal frequency, and grounds. Damage or complete failure of the generator can occur within seconds when subjected to these abnormal conditions. In many cases, these failures can be prevented by applying best generator protection practices. Condition monitoring can prevent faults from occurring by the early detection and trending of specific system conditions which indicate extended non optimal operation due to unwanted factors.

This paper explores several such events that occurred at large power plants in the southwest region of the US so that the lessons learned can help others to avoid similar cases. The summer of 2021 saw Arizona Public Service experience record breaking levels of rainfall throughout the entire season. Several generators tripped offline due to phase distance, rotor, and stator ground fault protection because of the water ingress. Some of the associated protection settings were optimized because of event analysis. Condition monitoring revealed the true source of the rotor ground fault and is shown how to calculate the stator capacitance-to-ground.

GENERATOR PROTECTION OPERATIONS

This section covers several interesting generator protection trips that occurred in the APS non-nuclear generation fleet. The first two events occurred during the summer of 2021 when there was heavy rainfall throughout the season.

1st EVENT – CLOSE-IN THREE-PHASE FAULT

A large gas combustion turbine generator experienced a close-in three-phase fault during a summer rainstorm. The generator terminal voltage is rated 13.8 kV line-to-line and the machine is high impedance grounded. The phase VTs are connected open delta. Figure 1 is the corresponding oscillography captured by the generator protection relay.

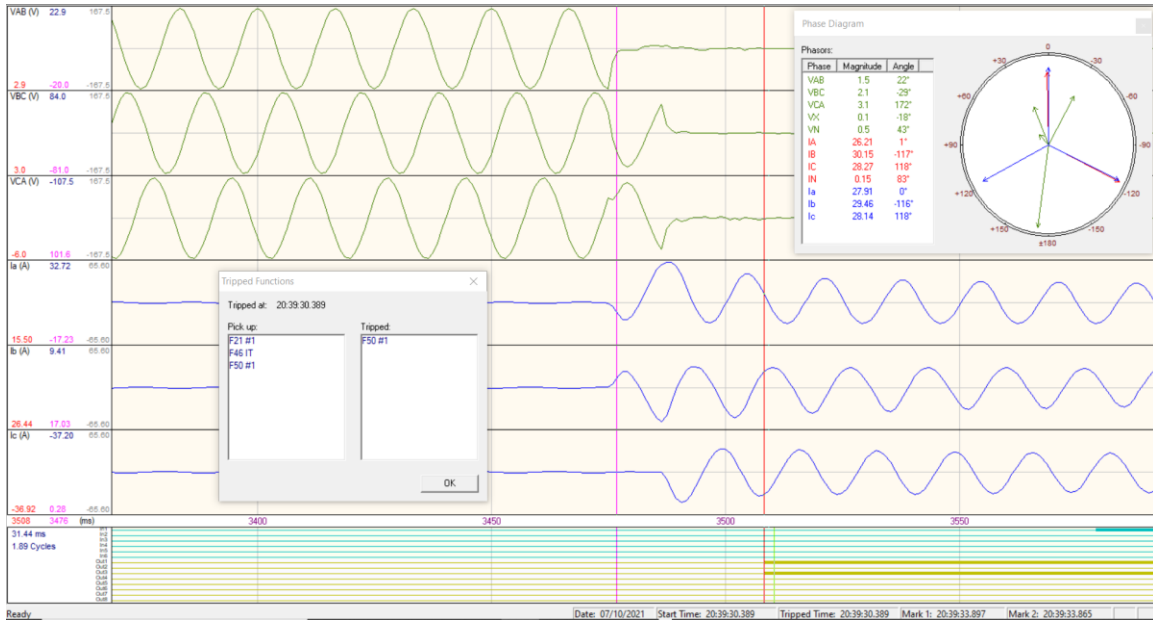


FIGURE 1. Oscillography for 1st Event

The fault was located close to the phase VTs and just external to the generator differential zone of protection. The fault was properly cleared by the 50 high set phase instantaneous protection which operated just under two cycles following fault inception. The generator breaker tripped open four cycles later. Pre-fault load current was 50 percent of rated full load.

Figure 2 shows the fault impedance Z_{AB} , Z_{BC} and Z_{CA} measured by the generator protection relay. The pre-fault load impedance drops close to zero ohms following fault inception.

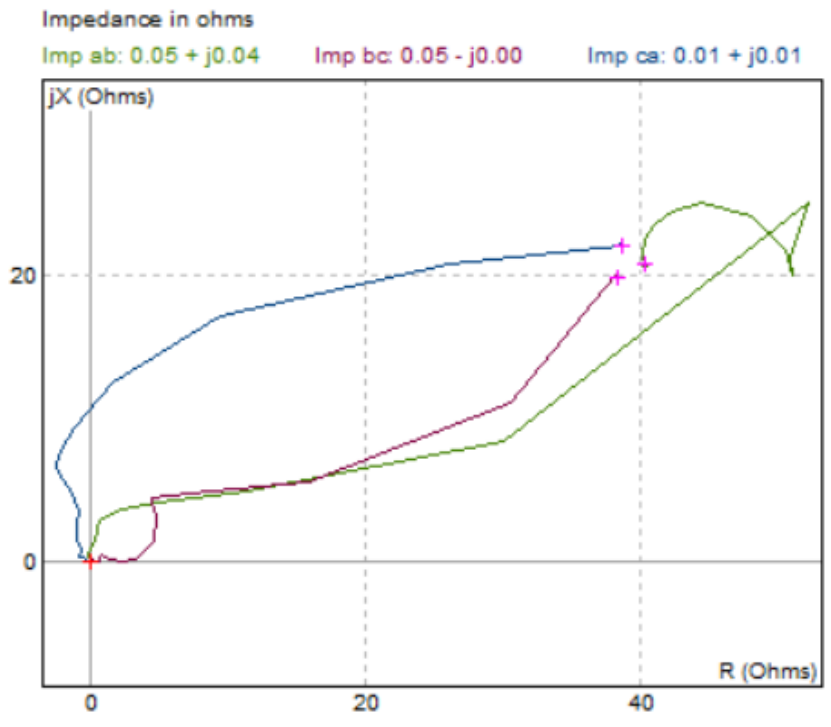


FIGURE 2. Fault Impedance Measured by Generator Protection Relay

Figure 3 shows the machine rotor which was pulled for inspection due to the fault.



FIGURE 3. Rotor

2nd EVENT – ROTOR GROUND FAULT

The second event is a rotor ground fault that occurred for another large combustion turbine generator that also occurred during another summer rainstorm. Figure 4 shows the rotor field resistance to ground measured by the generator protection relay over a period of one month leading up to the event.

The numerical generator protection relay can periodically data record analog quantities it measures such as voltage and current. The relay stores these values in non-volatile memory. Use this function to track the value of field insulation resistance over time. The relay for this example is programmed to record the phase current on both sides of the stator winding, phase-to-phase voltage magnitude at the generator bus, neutral voltage magnitude, rotor field ground resistance, volts per Hertz and frequency with respect to the generator bus every ten (10) minutes.

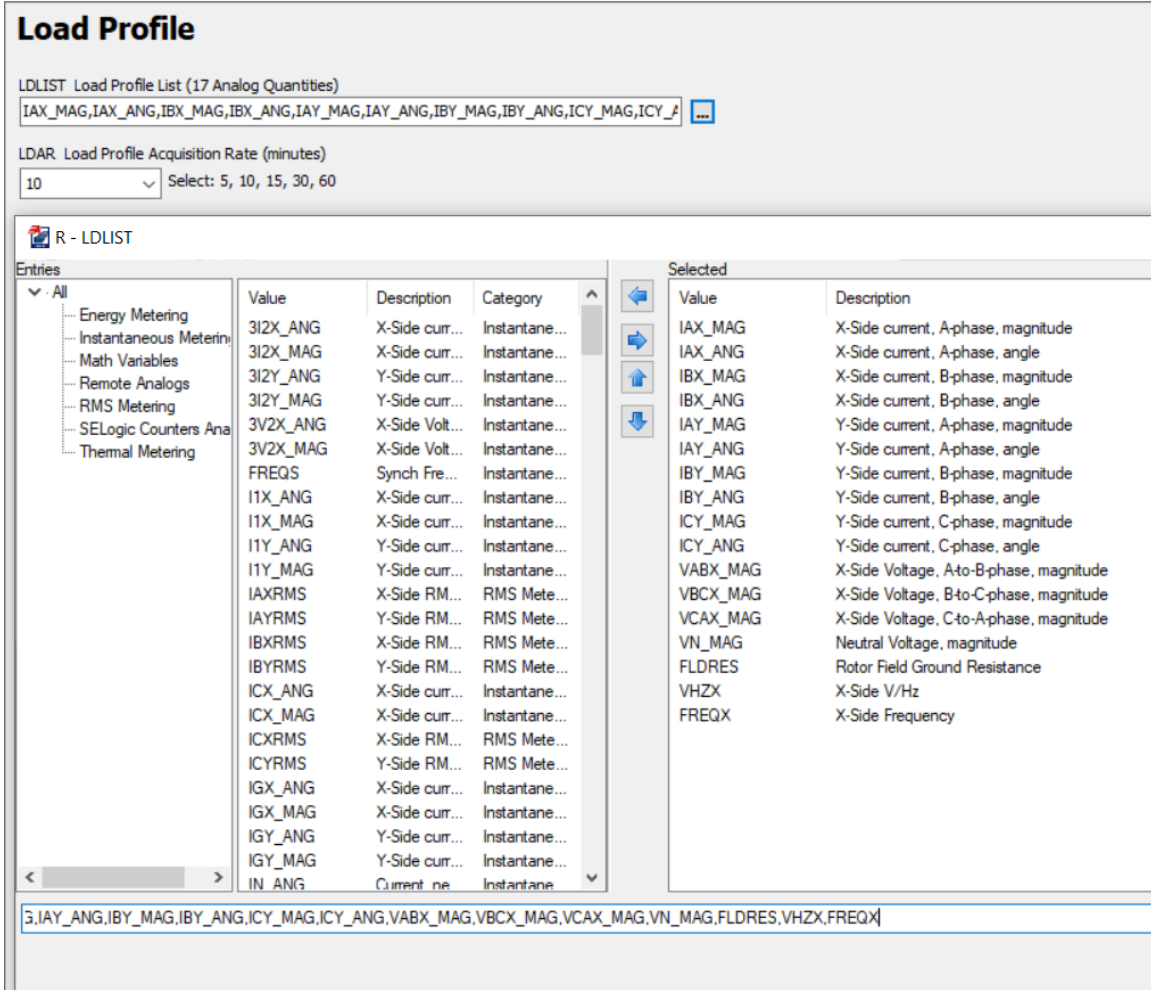


FIGURE 4. Data Recorder Configuration

The orange plot is of interest and represents the measured rotor field insulation resistance to ground. The ground fault occurred between 07-28-2021 and 08-02-2021. Review of the plot shows that the field resistance dropped to zero then slowly began to increase back to the pre-fault nominal value over the course of several days. The ground was due to water ingress which evaporated over time following the rainstorm. The spike was due to testing following the event; that is, the relay reports a large value when the measuring module is removed from service.

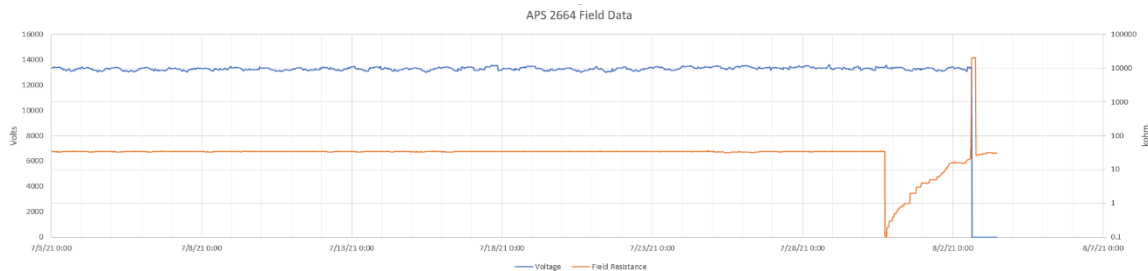


FIGURE 5. Rotor Field Resistance to Ground

3rd EVENT – STATOR GROUND FAULT

Analysis of the third event demonstrates how to enhance the performance of stator ground fault protection, including faster operating time. *Note that it is always assumed the generator is high impedance grounded through a neutral resistor across the secondary of a grounding transformer.*

GENERATOR DATA

The generator is rated 13.8 kV line-to-line. The phase VT ratio is 120 and the grounding transformer turns ratio is 100. Figure 6 below illustrates the connections for the grounding transformer. The generator is high impedance grounded through a neutral resistor across the secondary of the grounding transformer. The generator is high impedance grounded through a neutral resistor across the secondary of the grounding transformer to limit the magnitude of fault current flowing in the stator windings during a single phase-to-ground fault.

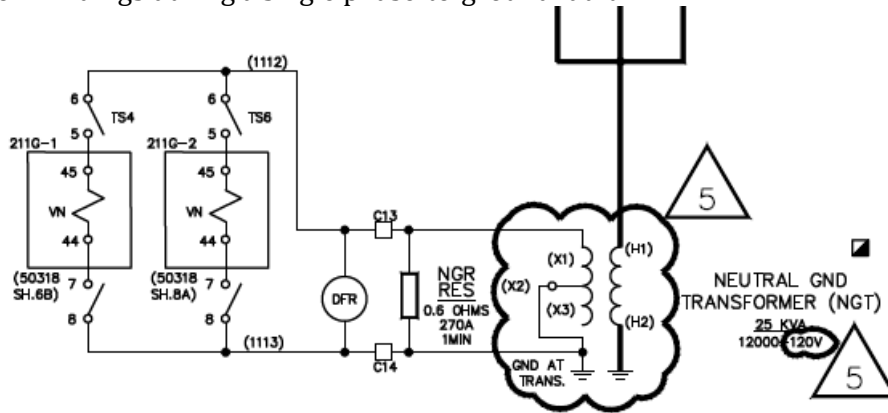


FIGURE 6. Grounding Transformer Connections

Figure 7A and 7B shows the oscillography and phasors corresponding to the fault signals recorded by the numerical generator protection relay during the event.

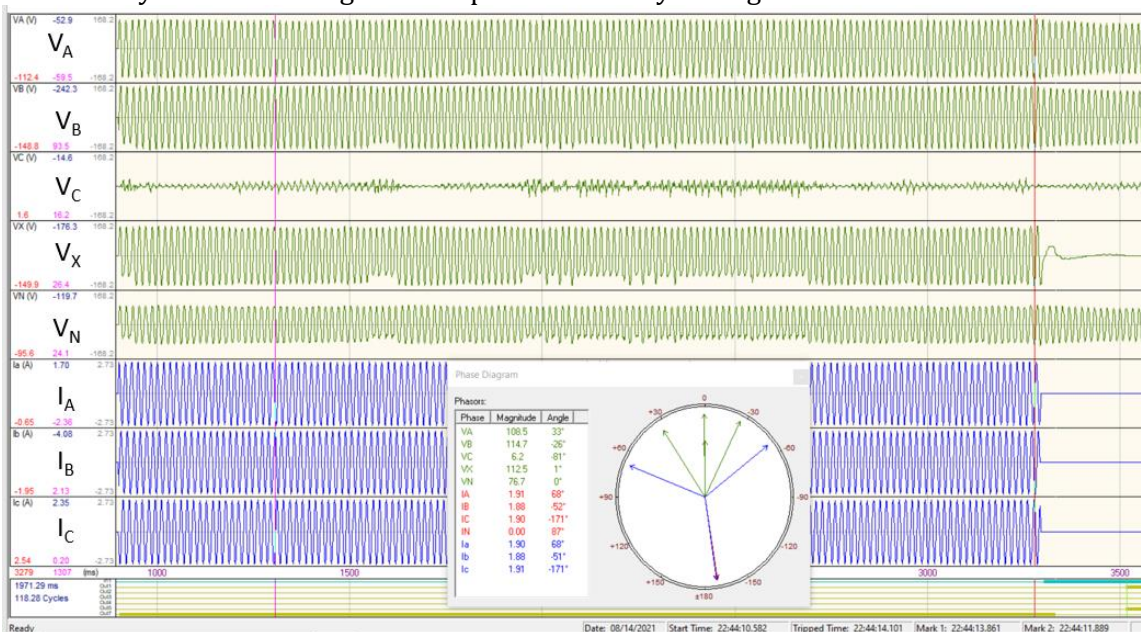


FIGURE 7A. Oscillography

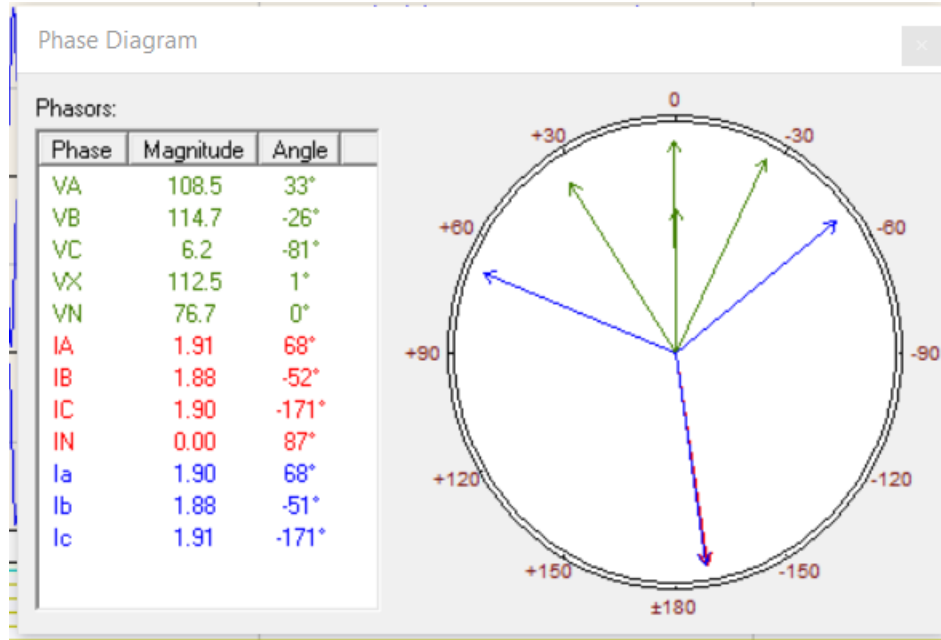


FIGURE 7B. Phasors

It can easily be seen by visual inspection of the oscillography that the stator ground fault was located on phase C.

FAULT LOCATION CALCULATION

Determine the location of the stator ground fault as follows:

- 1) Generator Terminal Voltage = $13.8 \text{ kV} / \sqrt{3} = 7.97 \text{ kV}$ line-to-ground (primary)
- 2) Voltage Across Grounding Transformer (V_G) = $(7.97 \text{ kV}) / 100 = 79.67 \text{ V}$ (secondary)
- 3) Neutral Voltage (V_N) = 77 V (secondary) taken from oscillography
(Voltage drop across neutral resistor)
- 4) Fault Location with respect to generator neutral:
 $(V_N * 100\%) / V_G = 96.64\%$



FIGURE 8. Fault Location with Respect to Generator Neutral

The actual fault location was close to the generator terminals and just external to the stator windings. There is some error in the calculated fault location due to relay accuracy and resistive losses in the grounding transformer. This calculation provided confidence that the stator ground was not internal to the stator winding and the generator could quickly be returned to service.

REACH OF 59N NEUTRAL OVERVOLTAGE PROTECTION

The neutral overvoltage function (59N) provides stator ground fault protection for high impedance grounded generators. The 59N function should provide ground fault protection for 90–95% of the stator winding (measured from the generator terminals). Note that the 59N function responds only to the fundamental frequency component.

Check the reach of the most sensitive element (59N1) which was originally set at 10.8 V secondary.

$$\text{Reach} = \left(1 - \frac{P_{59N1}}{V_G}\right) * 100\%$$

Where:

P_{59N1} = 59N1 Voltage Pickup (10.8 V secondary)

V_G = 79.67 V secondary (from fault location calculation)

Therefore, the original reach only covers up to 86% of the stator winding, which is less than recommended. Lowering the 59N1 voltage pickup to 5 V secondary (minimum setting) increases the reach to 94% of the stator winding, which is well within the recommended range. Now only the last six percent of the stator winding is unprotected.

INTERMITTENT ARCING ACCELERATED GROUND FAULT PROTECTION

Classic 59N stator ground fault protection may not operate for an arcing ground fault. 59N must be set with a long-time delay to properly coordinate with adjacent transmission system protection. If the arc extinguishes before 59N trips, then following any restrikes the protection must start timing over again since it is reset.

An integrated stall timer that incorporates memory of recent previous arcing events provides fast tripping during intermittent arcing. Timer memory is accomplished by stalling timing of the 59N pickup timer when the initiating function pickup intermittently drops out, as is the case for arcing faults.

The logic can be initiated by any ground fault protection function that is being used (for example, 59N, 27TN, 59D, and 64S). The integrated stall timer consists of both the pickup and reset timers shown in Figure 8. A pickup time of 10 cycles is used for this application, with a reset time of 300 cycles, that is, if there is an arcing fault with an accumulated 10 cycles worth of arcing with the time between arcs less than 5 seconds, then this scheme will trip:

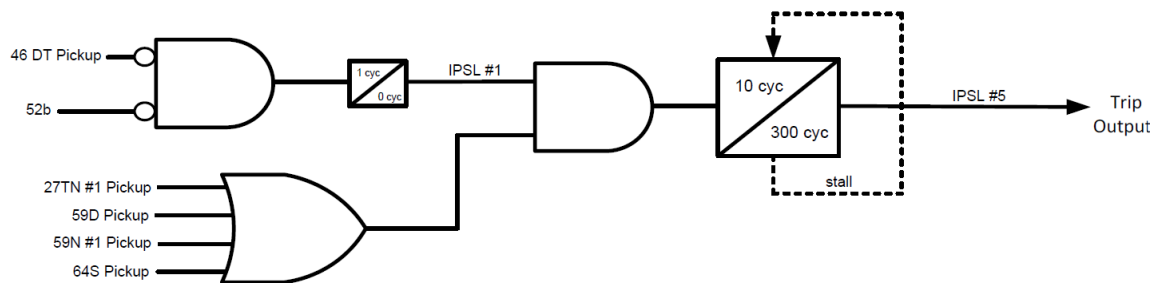


FIGURE 9. Intermittent Arcing Accelerated Tripping Logic

The logic NOT 46DT AND NOT 52b is ANDed with the ground pickups to improve the security of this intermittent arcing protection by ensuring it does not falsely assert due to a phase-to-ground fault on the high side of the GSU. 46DT is a definite time negative-sequence overcurrent element.

4th EVENT – BAD SYNC

Loss of a generator can have an adverse impact on the adjacent grid. It is vital to determine the root cause of the event when a generator is tripped offline due to a protective relay operation. The goal is to quickly restore service if there is no damage to the generator or any of the interconnected apparatus. Of course, safety is *always the number one priority*.

A large steam turbine generator tripped on 87 phase differential protection this year while attempting to synch the machine to the grid, however only the main generator protection relay operated and not the backup protection. The goal of the analysis is to determine why only one relay operated and what caused the trip to occur.

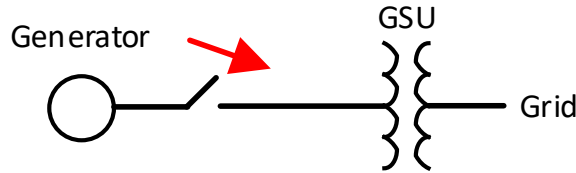


FIGURE 10. Power System Configuration

EVENT ANALYSIS

Figure 10 above shows the system configuration to sync the generator to the grid. The generator is brought online to full speed then ideally the generator breaker is closed when the generator is in sync with the grid. The main generator protection tripped on 87 phase differential when the generator breaker closed but not the backup protection.

Table 1 below shows the sequence of event report (i.e., SER) captured by the main relay for this event.

EVENT #22 05-21-2022 22:11:07.136		
IA = 1.24 A	Ia = 1.13 A	Ia DIFF = 0.26 A
IB = 0.98 A	Ib = 0.98 A	Ib DIFF = 0.00
IC = 1.96 A	Ic = 1.19 A	Ic DIFF = 0.96 A
EVENT #26 05-21-2022 22:11:07.161		
IA = 2.62 A	Ia = 3.24 A	Ia DIFF = 1.29 A
IB = 3.19 A	Ib = 3.17 A	Ib DIFF = 0.02 A
IC = 2.62 A	Ic = 3.25 A	Ic DIFF = 1.68 A
EVENT #27 05-21-2022 22:11:07.199		
IA = 3.74 A	Ia = 4.72 A	Ia DIFF = 2.00 A
IB = 0.99 A	Ib = 0.99 A	Ib DIFF = 0.00
IC = 3.32 A	Ic = 4.15 A	Ic DIFF = 1.71 A
EVENT #28 05-21-2022 22:11:07.207		
IA = 3.15 A	Ia = 4.75 A	Ia DIFF = 2.00 A
IB = 0.04 A	Ib = 0.04 A	Ib DIFF = 0.00
IC = 2.70 A	Ic = 4.41 A	Ic DIFF = 4.41 A

TABLE 1. Power System Configuration

Review of the SER reveals that the total time of the event following the generator breaker closing was approximately 4 cycles, which corresponds to one cycle for the main protection to assert the trip contact output and 3 cycles for the generator breaker to open. Review of the SER also reveals that the 87-phase differential protection repeatedly picked up and dropped out over the course of the event. Note that the trip output contact asserts the first time the protection operated since there is no intentional time delay.

Figure 11 below shows the oscillography captured by a digital fault recorder (i.e., DFR) for the event. The currents shown ($I_{a_{gen}}$, $I_{b_{gen}}$ and $I_{c_{gen}}$) are measured on the neutral side of the generator stator winding, which is the current flowing through the generator. Note that these signals are unfiltered and reveals the large dc offset present in these currents.

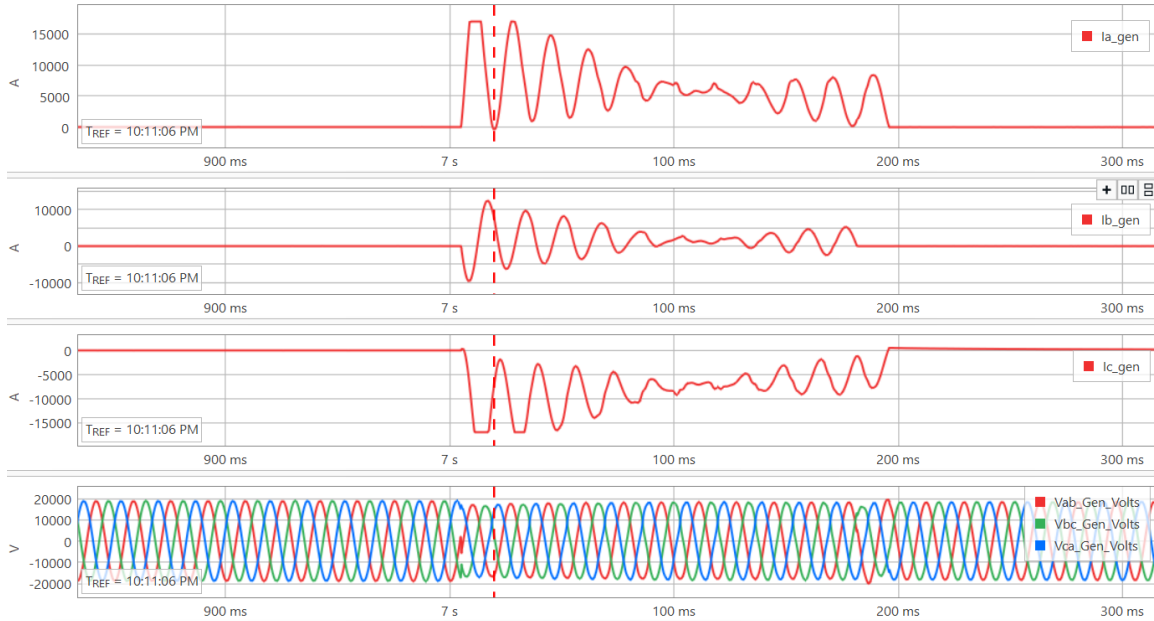


FIGURE 11. Generator Currents

At first glance the event appears to be an A-Phase-to-C-Phase fault, however the generator terminal voltages are balanced and nominal magnitude. Note that the generator currents are fully offset during the entire event. Figure 12 below shows the filtered currents flowing through the generator; that is, the 60 Hz fundamental component for each current waveform. Review of these waveforms reveal that the current magnitude is close to nominal and the currents are all balanced approximately 120 degrees apart. Thus, there was no phase fault present during the event.

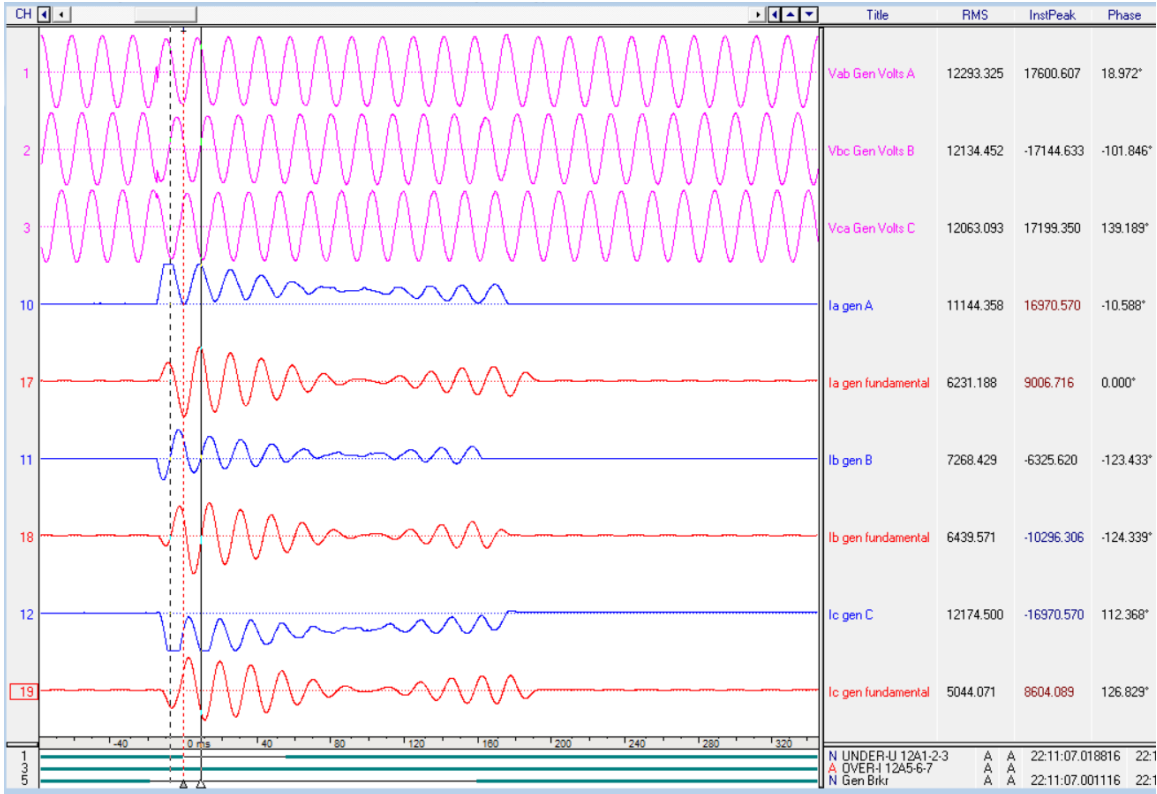


FIGURE 12. Filtered Generator Currents

Figure 13 below shows the corresponding 87 phase differential operating characteristics for both the main generator and backup protection. The operating point for the main protection is well within the zone of operation, while for the backup protection it is outside.

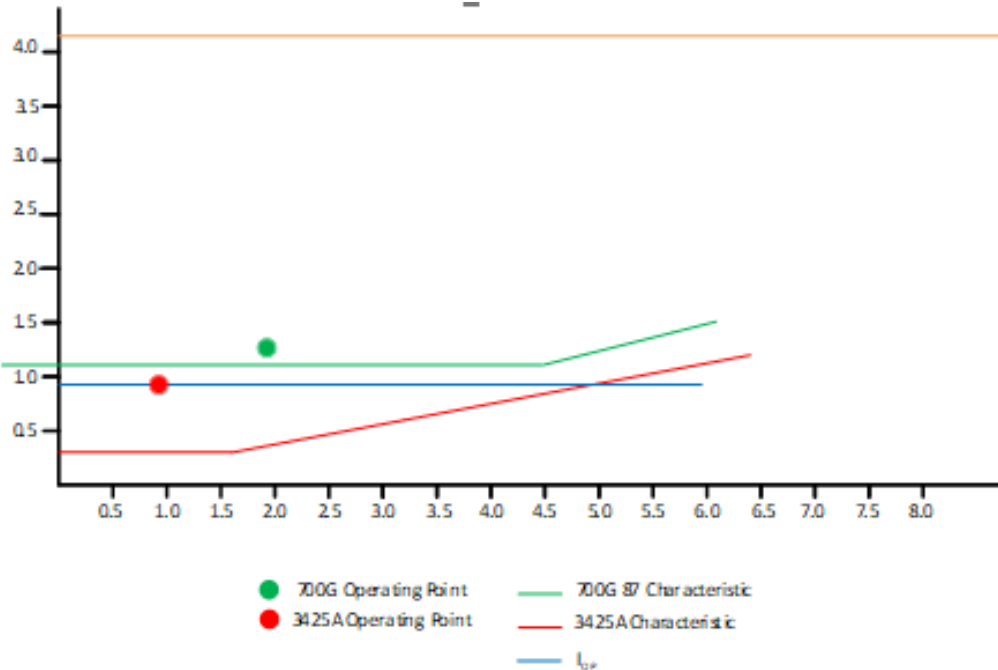


FIGURE 13. 87 Phase Differential Operating Characteristics, Main and Backup

ROOT CAUSE

The root cause of the unwanted trip was due to a bad sync; that is, the electrical angle across the generator breaker was close to 60 degrees at the time of the closing because of improper timing. 180 degrees is the worst case electrically, while 90 degrees is the worst case mechanically. Improper synchronization can affect the health of the power system and results in electrical and mechanical transients that can damage the prime mover, generator, transformers, and other power system components.

The bad sync was the source of large dc offset present in the generator currents. It is suspected that the internal relay CTs saturated as a result, which accounts for why the main 87 phase differential protection picked up and dropped out four times during the event.

Review of the 87 phase differential characteristics illustrate that the main protection is much more sensitive than the backup protection with respect to the operating point for this event. There is no need to change relay settings and the trip alerted the utility that there was a problem with the sync.

CONDITION MONITORING – GENERATOR STATOR GROUND CAPACITANCE

The second to last section of the paper demonstrates how to use a numerical generator protection relay profile capability to measure the stator ground capacitance of a large combustion turbine generator. The measurements are taken when the generator is online and running at full speed while the generator breaker is open (that is, no load), then during startup as the exported power increases. The stator capacitance-to-ground is indicative of conductive moisture and dirt in and around the stator insulation system. The apparent conductive surface area of winding insulation grows as contaminants build up. The value of the variable “plate” can be measured and trended over time as the change in stator capacitance-to-ground (C_g). *Compare the initial (baseline) measurement to future recorded values. A significant rise in magnitude may indicate one of the following conditions exist:*

- Internal contamination
- Moisture infiltration
- Problem with the circuit cables connected to the machine

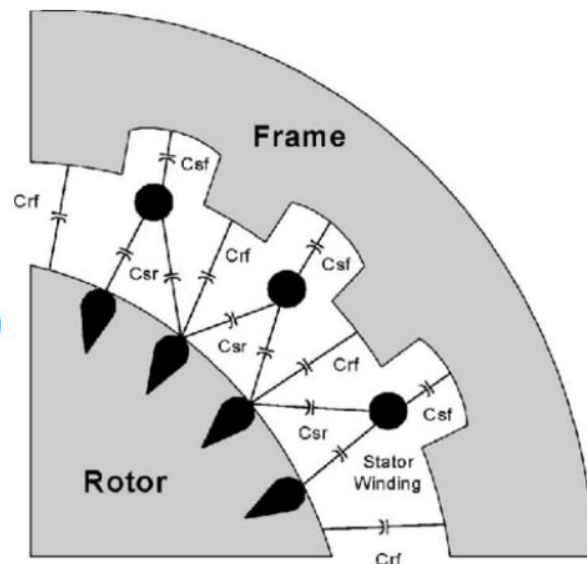


FIGURE 14 - Stator Winding Capacitance-to-Ground

Generators produce varying amounts of third harmonic voltage in addition to the fundamental. The stator winding pitch (that is, distance between the two sides of each loop relative to the distance between the rotor poles) influences the amount of third harmonic voltage produced. The amount of third-harmonic voltage generated by the machine also varies with loading. Changes in both real and reactive power alter the amount third-harmonic voltage produced.

Figure 15 below illustrates the third-harmonic circuit for a large unit connected generator that is high impedance grounded. The generator step-up (GSU) transformer low side delta winding provides third-harmonic isolation from the transmission system. Note that it is assumed the low side generator breaker is open and the machine is running at full speed (that is, no load) for the purpose of the calculations.

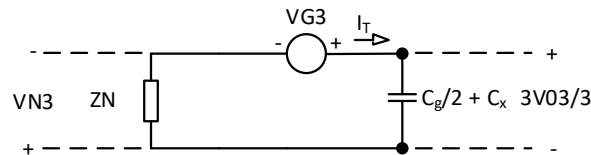


FIGURE 15 - Stator Winding Capacitance-to-Ground

The distributed C_G is represented as an equivalent pi-section divided between the system and neutral sides of the stator windings. The system side has additional external capacitance (C_X) from the surge capacitor, isophase bus, and auxiliary transformer. Note that only the capacitance of the surge capacitor is considered on the system side for the following calculations since it is assumed that the low side generator breaker is open. The neutral resistor (R_N) is reflected to the primary.

3V03 and VN3 are measured by the generator, while VG3 is calculated using those two values. Note that the terms 3V03 and 3V0Z3 are used interchangeably.

$VG3 \equiv$ Total 3rd Harmonic Voltage (Source)

$3V03 \equiv$ 3rd Harmonic Voltage Drop across Terminal Capacitance

$VN3 \equiv$ 3rd Harmonic Voltage Drop across Z_N

Figure 16 below shows the third harmonic voltage profile captured by the generator protection relay during startup:

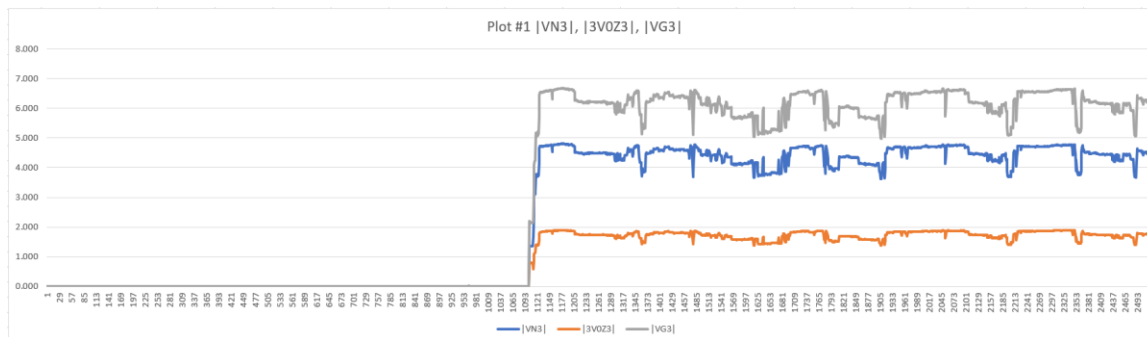


FIGURE 16 – Third Harmonic Voltage Profile Captured during Startup

Table 2 below shows the third harmonic voltage profile captured by the generator protection relay during a startup:

LOAD	PF	3V0Z3M	VN3M	VG3M		3V0Z3	arg(3V0Z3)	VN3	arg(VN3)	VG3M	P
MW	LEAD/LAG	V Pri	V Pri	V Pri		V sec	degrees	V sec	degrees	V Pri	MW
NO LOAD	NA	157.5	90.5	143		1.26	145.5	1.358	147.8	143	0
17	0.9449	116.5	109.9	148.8		0.932	-179	1.649	178.5	148.8	17
60.6	0.9962	217.5	201.1	273.6		1.793	-117.3	3.016	-123.9	275.4	60.6
63.3	0.9965	226.3	208	283.4		1.811	-114.5	3.12	-121.6	283.1	63.3
89.7	0.9973	280.9	252.6	346.2		2.247	-96.5	3.788	-104.4	345.5	89.7
90.2	0.9981	286.1	252.9	348.3		2.289	-96.6	3.794	-104.8	347.6	90.2
106.7	0.9985	313.1	276.3	380.7		2.505	-87.9	4.144	-96.2	379.9	106.7
145.5	0.9998	366.5	314.6	436.7		2.932	-73	4.718	-81.5	435.8	145.5
148.5	0.9989	374.9	317.7	442.6		2.999	-70.7	4.765	-79.2	441.7	148.5
149	0.9948	371.5	318.8	444.1		3.009	-69.2	4.781	-78	443.1	149

TABLE 2. 3rd Harmonic Voltage Profile

Figure 17 below represents the total third harmonic current flow through the neutral impedance Z_N , which is the parallel combination of the neutral resistor R_N and stator capacitance-to-ground ($C_g/2$). I_T is the total current while I_R is the resistive component and I_C is the capacitive component.

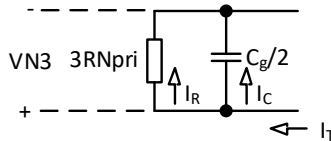


FIGURE 17 – Third Harmonic Neutral Circuit

First calculate the circuit impedance to solve for C_g :

$$\omega = 2\pi f$$

$$X_N = X_{C_g} = \frac{1}{\omega \cdot \frac{C_g}{2}} = \frac{2}{2\pi f \cdot C_g} = \frac{1}{\pi f \cdot C_g} \text{ (neutral side reactance)}$$

$$Z_{C_g} = -jX_N = -jX_{C_g}$$

$$X_T = \frac{1}{\omega \left(\frac{C_g}{2} + C_x \right)} = \frac{1}{2\pi f \left(\frac{C_g}{2} + C_x \right)} = \frac{1}{\pi f \cdot (C_g + 2 \cdot C_x)} \text{ (system side reactance)}$$

$$Z_T = -jX_T$$

$f = 180 \text{ Hz}$ (third harmonic frequency)

$C_x = 0.125 \text{ MF}$ (surge capacitance)

$$Z_N = \frac{3 \cdot RN_{pri} \cdot (-jX_N)}{3 \cdot RN_{pri} + (-jX_N)}$$

Next calculate the third harmonic neutral voltage VN3 dropped across the neutral grounding resistor (NGR) and stator capacitance-to-ground:

$$I_T = \frac{VN3}{3 \cdot RN_{pri}} + \frac{VN3}{Z_{C_g}} \quad \#1$$

$$I_T = \frac{3V0Z3}{3 \cdot Z_T} \quad \#2$$

$$RN_{pri} = N_G^2 \cdot RN$$

$N_G = \text{Grounding Transformer Turns Ratio (66.67)}$

$RN = \text{Neutral Grounding Resistor (0.25 } \Omega \text{)}$

$$RN_{pri} = (66.67)^2 \cdot (0.25 \Omega) = 1111.222 \Omega \text{ primary}$$

Set equations [1] and [2] equal and solve for Z_{Cg} .

$$\frac{3V0Z3}{3 \cdot Z_T} = \frac{VN3}{3 \cdot RN_{pri}} + \frac{VN3}{Z_{Cg}}$$

$$3V0Z3 = \frac{Z_T \cdot VN3}{RN_{pri}} + \frac{3 \cdot Z_T \cdot VN3}{Z_{Cg}}$$

$$3V0Z3 = VN3 \cdot Z_T \cdot \left(\frac{1}{RN_{pri}} + \frac{3}{Z_{Cg}} \right)$$

$$\frac{3V0Z3}{VN3} = Z_T \cdot \left(\frac{1}{RN_{pri}} + \frac{3}{Z_{Cg}} \right)$$

$$\frac{3V0Z3}{VN3} = \frac{-j}{\Pi f \cdot (C_g + 2 \cdot C_x)} \cdot \left(\frac{1}{RN_{pri}} + \frac{3}{\frac{-j}{\Pi f \cdot C_g}} \right)$$

$$\frac{3V0Z3 \cdot (C_g + 2 \cdot C_x) \cdot \Pi f}{VN3} = \frac{-j}{RN_{pri}} + 3 \cdot \Pi f \cdot C_g$$

$$\frac{3V0Z3 \cdot (C_g + 2 \cdot C_x) \cdot \Pi f}{VN3} = 3 \cdot \Pi f \cdot C_g - \frac{j}{RN_{pri}}$$

$$\frac{3V0Z3 \cdot C_g \cdot \Pi f}{VN3} + \frac{3V0Z3 \cdot 2 \cdot C_x \cdot \Pi f}{VN3} = 3 \cdot \Pi f \cdot C_g - \frac{j}{RN_{pri}}$$

$$\frac{-3V0Z3 \cdot C_g \cdot \Pi f}{VN3} + 3 \cdot \Pi f \cdot C_g = \frac{3V0Z3 \cdot 2 \cdot C_x \cdot \Pi f}{VN3} + \frac{j}{RN_{pri}}$$

$$3 \cdot \Pi f \cdot C_g - \frac{3V0Z3 \cdot C_g \cdot \Pi f}{VN3} = \frac{3V0Z3 \cdot 2 \cdot C_x \cdot \Pi f}{VN3} + \frac{j}{RN_{pri}}$$

$$C_g \cdot \left(3 \cdot \Pi f - \frac{3V0Z3 \cdot \Pi f}{VN3} \right) = \frac{3V0Z3 \cdot 2 \cdot C_x \cdot \Pi f}{VN3} + \frac{j}{RN_{pri}}$$

$$C_g = \left(\frac{3V0Z3 \cdot 2 \cdot C_x \cdot \Pi f}{VN3} + \frac{j}{RN_{pri}} \right) / \left(3 \cdot \Pi f - \frac{3V0Z3 \cdot \Pi f}{VN3} \right) \quad \#3$$

Equation [3] above solves for C_g , the stator capacitance-to-ground.

FINAL EVENT ANALYSIS – OVERALL DIFFERENTIAL TRIPPING

The overall differential protection for a GSU began to trip when the generator was synced to the plant switchyard. Figure 18 below is the one-line diagram for the overall differential protection. There is one set of CTs on the high side of the GSU, one set of CTs on the low side of the GSU not including the generator, and one set of CTs on the high side of the auxiliary transformer.

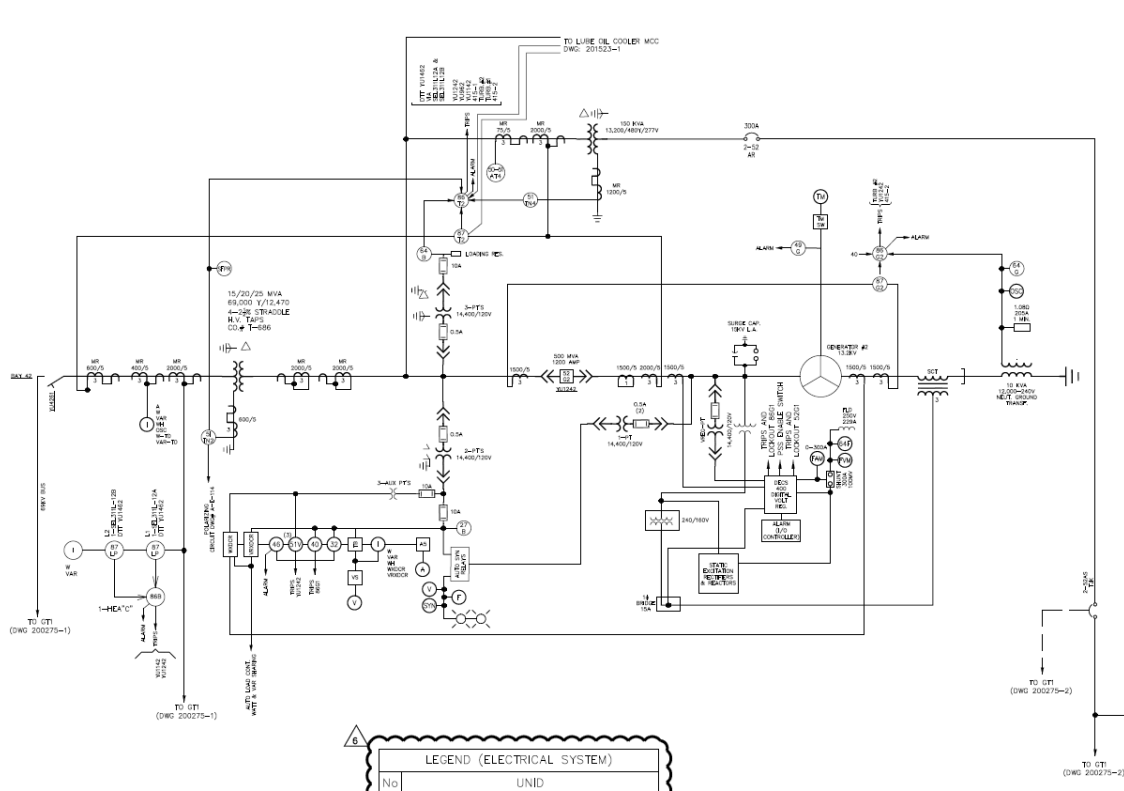


FIGURE 18 – Differential Single Line Diagram

Field inspection of the CT wiring revealed that both sets of CTs on the low side of the GSU had A-Phase and C-Phase rolled. Engineering initially requested that the wiring be changed to eliminate rolling the CTs, however inspection of the low side bus then revealed that A-Phase and C-Phase were also rolled. Further field inspection revealed that the B-Phase wire running from the set of CTs on the low side of the GSU had failed as a high impedance (refer to Figure 19).

The differential protection would have still tripped, had the wiring for the low side CTs been rolled, and it would have made discerning the actual root cause more difficult to determine. The adage “If it’s not broke don’t fix it.” comes to mind.

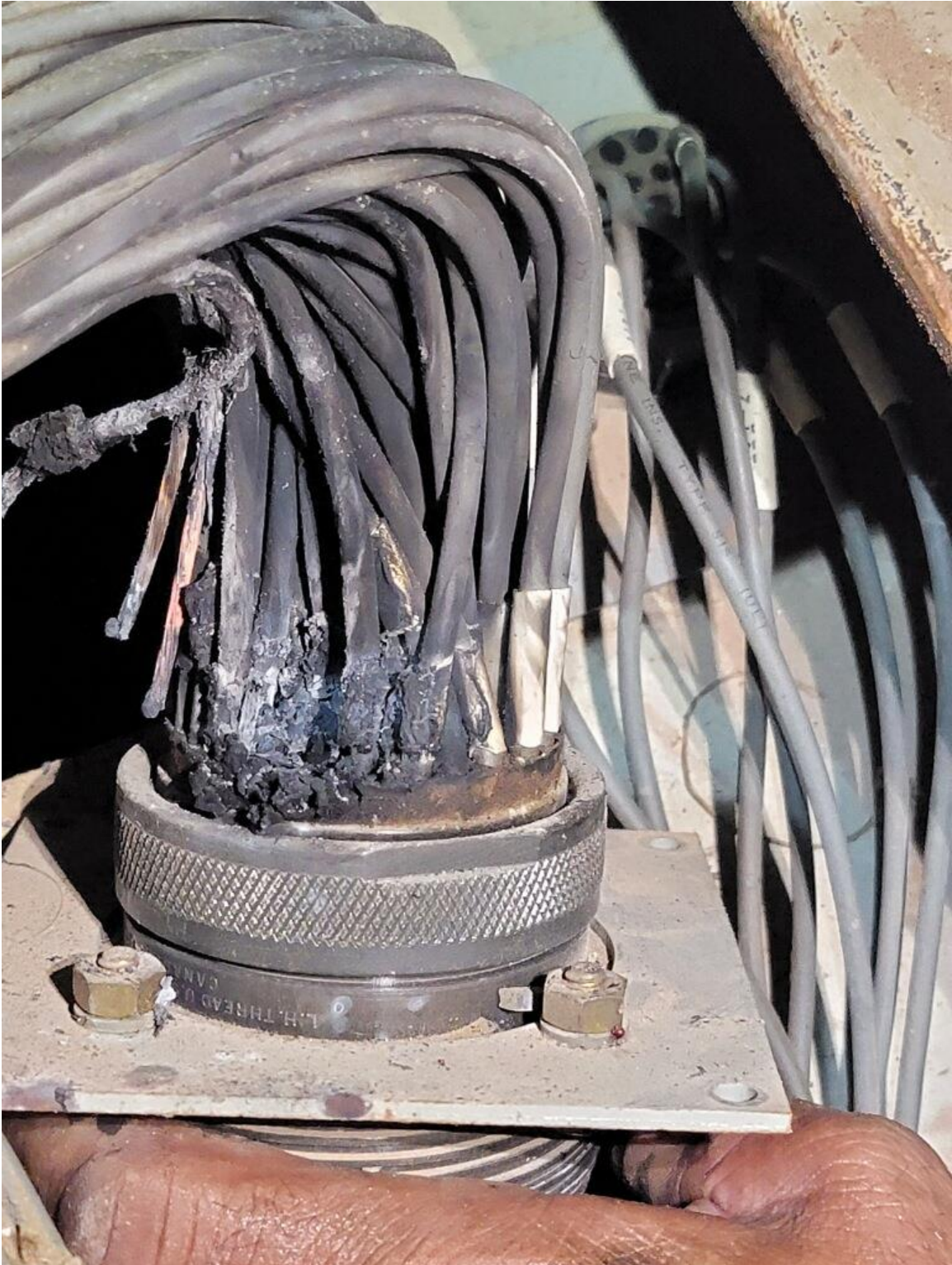


FIGURE 19 – Wiring Conduit

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CONCLUSION

This paper explores several generator protection events that occurred at large power plants in the southwest region of the US so that the lessons learned can help others to avoid similar cases. The summer of 2021 saw Arizona Public Service experience record breaking levels of rainfall throughout the entire season. Several generators tripped offline due to phase distance, rotor, and stator ground fault protection because of the water ingress. Some of the associated protection settings were optimized because of event analysis. Condition monitoring revealed the true source of the rotor ground fault, and it was demonstrated how to calculate the stator capacitance-to-ground for a large unit connected generator.

ACKNOWLEDGEMENTS

The author wishes to express his thanks to the following individuals for their help:

Caleb Thomas of APS developed the calculations shown in Figure 16. Jason Young of SEL, Inc. reviewed the equations to calculate C_g , the stator capacitance-to-ground. Dale Finney of SEL, Inc. provided detailed instruction on stator ground fault protection using third harmonic voltage.

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3. "M-3425A Generator Protection Instruction Book", Beckwith Electric

BIOGRAPHY

Steve Turner oversees system protection for the Generation Department at Arizona Public Service Company in Phoenix. Steve worked as a consultant for two years, and held positions at Beckwith Electric Company, GEC Alstom, SEL, and Duke Energy, where he developed the first patent for double-ended fault location on overhead high-voltage transmission lines and oversaw maintenance standards in the transmission department for protective relaying. Steve has BSEE and MSEE degrees from Virginia Tech University. Steve is an IEEE Senior Member and a member of the IEEE PSRC and has presented at numerous conferences.