

Power Plant “Horror Stories”

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Abstract: Contrary to popular belief, generators can fail—not only from short circuits—but more frequently from abnormal electrical conditions such as overexcitation, overvoltage, loss-of-field, unbalanced currents, and abnormal frequency. When subjected to these abnormal conditions, damage or complete failure of the generator can occur within seconds. In many cases, these failures can be prevented by proper generator protection. This paper relates a number of “horror stories” within the power plant in the hopes that the “lessons learned” will help others to avoid the cases described.

Introduction

Generators are the most expensive piece of equipment in a power system. The cost of a major generator failure to a utility or IPP (Independent Power Producer) owner is not only the cost of repair or replacement of the damaged machine, but also the substantial cost of purchasing replacement power when the unit is out of service. An alert and skillful operator, at manned locations, can sometimes avoid removing a generator from service by correcting an abnormal condition. In the vast majority of cases, however, the event will occur too rapidly for the operator to react and automatic detection and isolation is required. Operators have also been known to make errors and create abnormal conditions where tripping to avoid damage is required. Inadvertent energization and overexcitation are examples of such events.

Several power plant events within the last two to three years substantiate the premise that generators can, and do, sustain internal short circuits and abnormal operating conditions that require tripping. The following in-service events are described:

- Multi-phase generator faults
- Stator ground faults
- Accidental off-line generator energizings
- Overexcitation
- Loss-of-field
- Generator breaker failure (breaker flashover)

In many cases, human error caused or contributed to the event. These events were captured on oscillographs. This paper highlights the subtlety of analyzing non-fault events such as loss-of-field using COMTRADE format to convert current and voltage to R-X quantities to verify proper relay operation. The lessons learned in each event are also highlighted.

Multi-Phase Generator Faults

When a generator multi-phase fault is detected by generator differential relaying, it is separated from the power system by tripping the generator breaker, field breaker and prime mover. The system contribution to the fault will immediately be removed when the generator breaker trips as illustrated in Fig. 1. The generator current, however, will continue to flow after the trip. The generator short circuit current cannot be “turned off” instantaneously because of the stored energy in the rotating machine. This flow of damaging generator fault current will continue for several seconds after the generator has been tripped, making generator faults extremely damaging. Generator terminal leads are usually isolated through isophase bus construction to minimize multi-phase terminal faults.

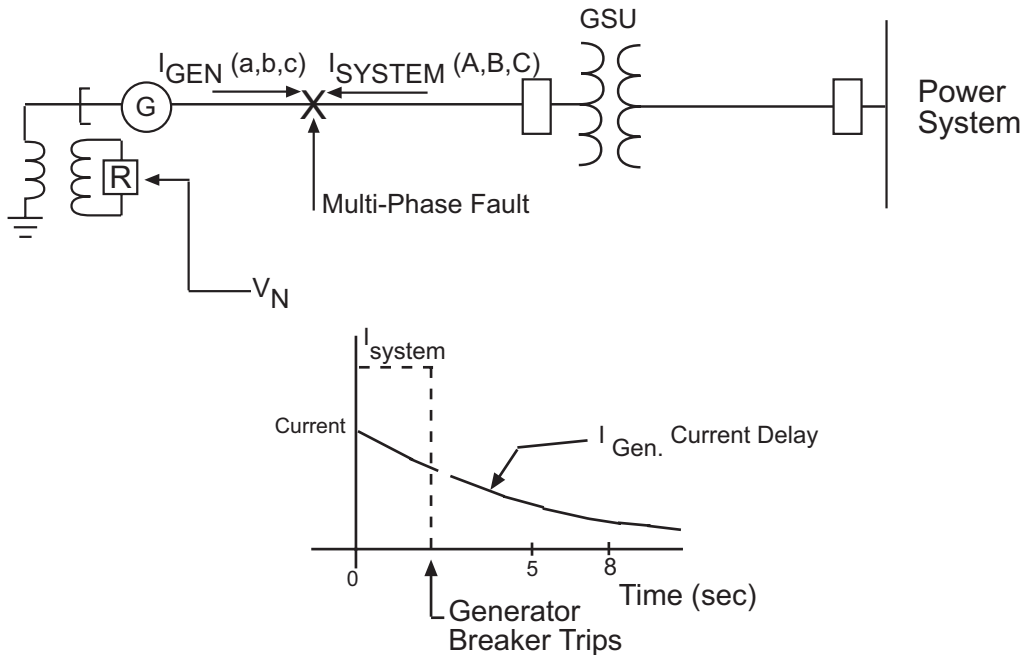


Fig. 1 Generator Terminal Fault Current

Fig. 2 is an oscillograph of a three-phase fault which occurred on a gas turbine when a connector failed at the generator lead connection to the generator breaker. The fault started as a line-to-ground fault, but after five cycles, it evolved into a three-phase fault. The system currents (I_A , I_B , I_C) were interrupted when the generator breaker was opened by differential (87G) relaying in about three cycles. The generator-side current (I_a , I_b , I_c) continued to flow after the unit was shut down. The oscillograph was programmed to cut off six cycles after tripping, thereby preventing the display of the total length of fault current flow which is estimated to have continued for eight seconds after tripping.

This extended flow of fault current is the reason that internal multi-phase generator faults typically damage the unit to the point where it cannot be economically repaired. There is no means of “turning off” the generator current. This long decay time results in the vast majority (about 85%) of the damage occurring after tripping. This is why every effort is made in generator and generator terminal design to make the only credible fault a ground fault. The generator is then grounded so as to substantially reduce ground current to minimize damage. If the fault is in the GSU transformer and the generator installation has no low-voltage breaker, the long fault current decay can substantially damage the transformer. A significant number of these transformers have failed catastrophically with tank ruptures and oil fires.

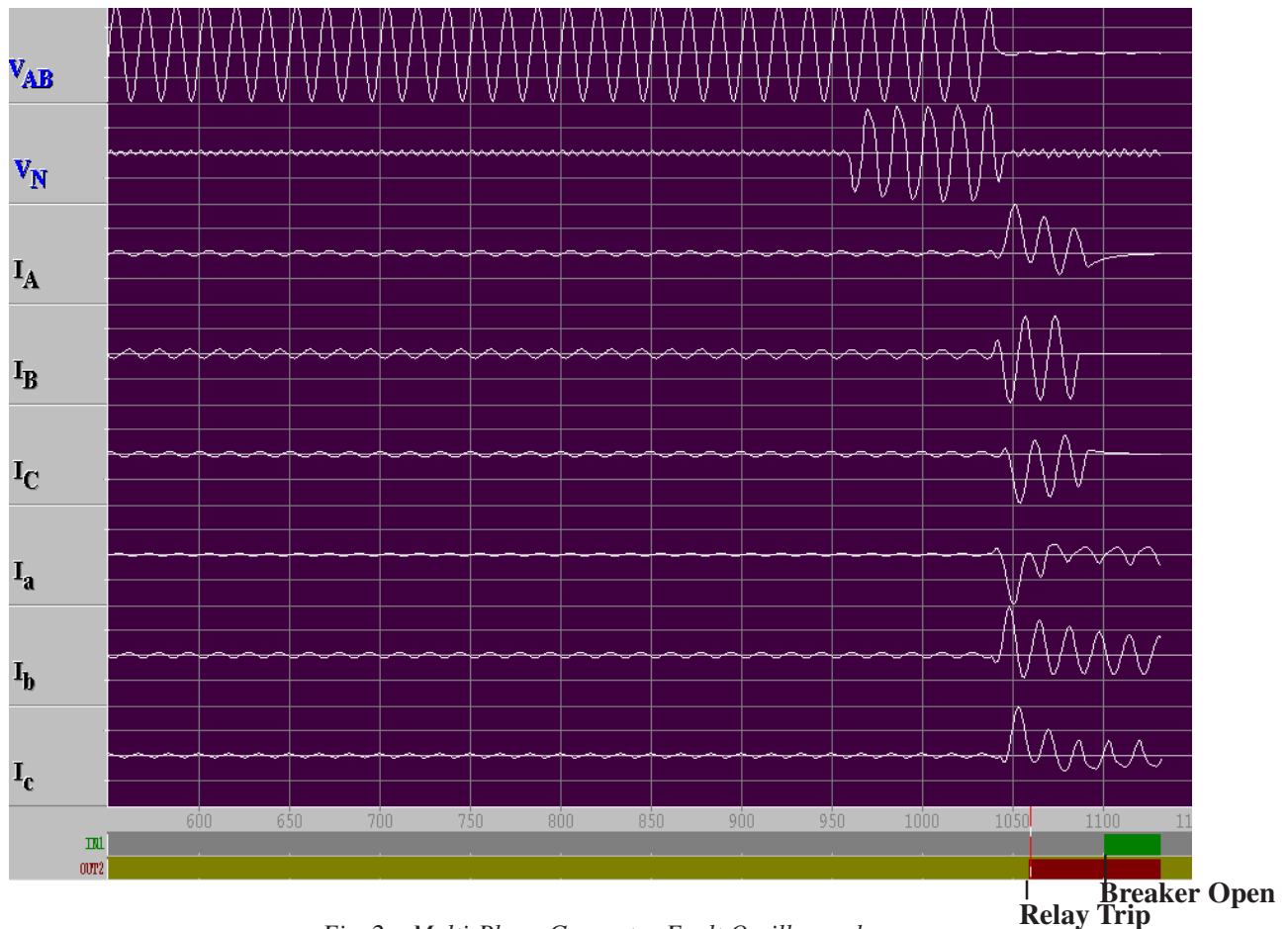


Fig. 2 Multi-Phase Generator Fault Oscillograph

Stator Ground Faults

The method of stator grounding used in a generator installation determines the generator's performance during ground fault conditions. If the generator is solidly grounded (not usually the case), it will deliver a very high current to a SLG (single-line-to-ground) fault at its terminals, accompanied by a 58% reduction in the phase-to-phase voltages involving the faulted phase and a modest neutral voltage shift. If the generator is ungrounded (also not usually the case), it will deliver a negligible amount of current to a bolted SLG fault at its terminals, accompanied by no reduction in the phase-to-phase terminal voltages and a full neutral voltage shift. These represent the extremes in generator grounding with normal practice falling predictably in between.

The high magnitude of fault current which results from solidly grounding a generator is unacceptable because of the fault damage it can cause. Shutting down the generator through tripping the generator breaker, field, and prime mover does not cause the fault current to immediately go to zero. The flux trapped in the field will result in the fault current slowly decaying over several seconds after the generator is tripped—substantially exacerbating damage. On the other hand, operating an ungrounded generator provides negligible fault current, but the line-to-ground voltages on the unfaulted phases can rise during arcing type faults to dangerously high levels which could cause the failure of generation insulation. As a result, stator windings on major generators are grounded in a manner that will reduce fault current and overvoltages yet provide a means of detecting the ground fault condition quickly enough to prevent iron burning.

Almost all large generators that are unit-connected are high-impedance grounded. High-impedance generator neutral grounding utilizes a distribution transformer with a primary voltage rating greater than or equal to the line-to-neutral voltage rating of the generator and a secondary rating of 120 V or 240 V. The distribution transformer should have sufficient overvoltage capability so that it does not saturate on SLG faults with the machine operating at 105% of rated voltage. The secondary resistor is usually selected so that for a SLG fault at the terminals of the generator, the power dissipated in the resistor is approximately equal to the reactive volt-amperes in the zero-sequence capacitive reactance of the generator windings, its leads, and the windings of any transformer(s) connected to the generator terminals. Using this grounding method, a SLG fault is generally limited to 3-5 primary amperes. As a result, this level of fault current is not sufficient to operate generator differential relays.

Fig. 3 illustrates a typical unit-connected high-impedance grounded generator. The most widely used protective scheme in high-impedance grounded systems is a time-delayed overvoltage relay (59N) connected across the grounding resistor to sense zero-sequence voltages as shown in Fig. 3. The relay used for this function is designed to be sensitive to fundamental frequency voltage and insensitive to third-harmonic and other zero-sequence harmonic voltages that are present at the generator neutral.

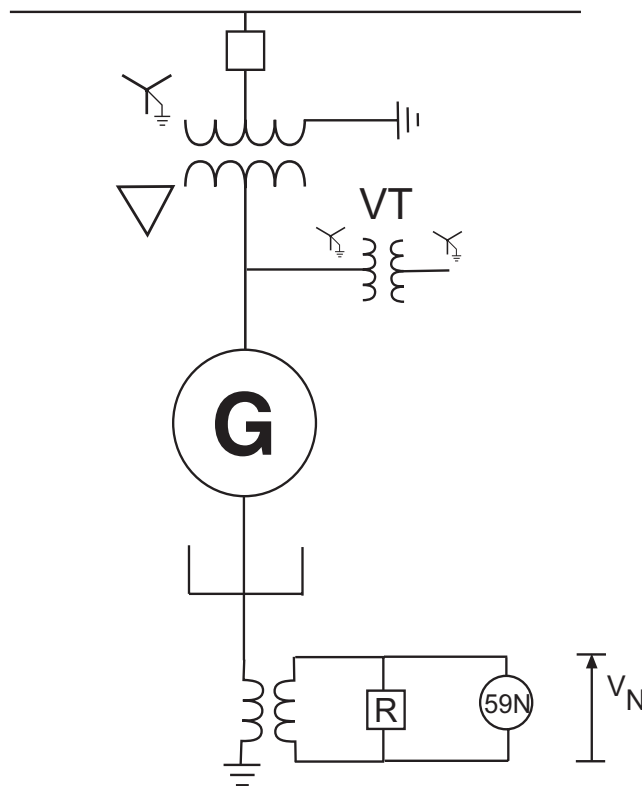


Fig. 3 Unit-Connected High Impedance-Grounded Generator

Since the grounding impedance is large compared to the generator impedance and other impedances in the circuit, the full phase-to-neutral voltage will be impressed across the grounding device for a phase-to-ground fault at the generator terminals. The voltage at the relay is a function of the distribution transformer ratio and the location of the fault. The voltage will be a maximum for a terminal fault and decreases in magnitude as the fault location moves from the generator terminals toward the neutral. Typically, the overvoltage relay has a minimum pickup setting of approximately 5 V. With this setting and typical distribution transformer ratios, this scheme is capable of detecting faults to within approximately 5% of the stator neutral. Third harmonic schemes (not described in this paper) are typically used to detect faults near the generator neutral.

The time setting for the overvoltage relay is selected to provide coordination with other system protective devices. The voltage relay should be coordinated with the transmission system relaying for system ground faults. System phase-to-ground faults will induce zero-sequence voltages at the generator neutral due to capacitive coupling between the windings of the GSU transformer. This induced voltage will appear on the secondary of the grounding transformer and can cause operation of the zero-sequence voltage relay. When grounded wye-grounded-wye VT's are connected at the machine terminals, the neutral ground overvoltage relay should be coordinated with VT transformer fuses to prevent tripping the generator for VT secondary ground faults.

Fig. 4 shows an oscillograph for a stator ground fault that occurred in a large unit-connected generator in the southeastern U.S.. Note that because of the very low level of ground fault current, it is not uncommon for the fault to self-extinguish and then re-establish itself. Also, the normal third harmonic voltage across the neutral resistor shifts to fundamental frequency when a ground fault occurs. By measuring the magnitude of the neutral voltage and comparing it to the calculated value for a terminal fault, you can determine the approximate fault location in relationship to the generator terminal.

The oscillograph shown in Fig. 4 played a key role in preventing a damaged generator from being returned to service by the power plant manager. When the tripping occurred, the new digital relay had only been in service for a few months. The generator stator windings were meggered, but the voltage produced was not adequate to break down the ground. The plant manager was ready to return the unit to

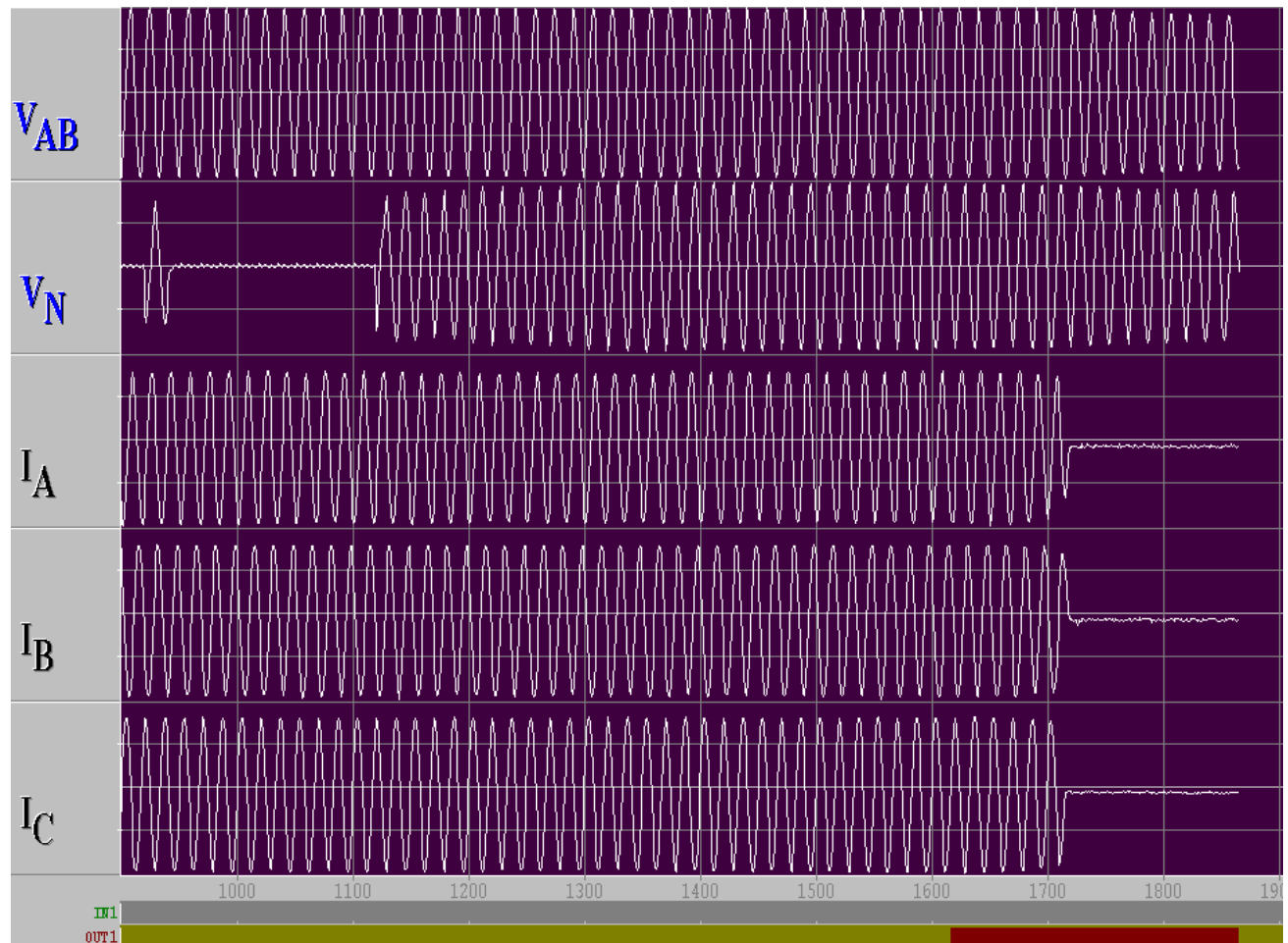


Fig. 4 Stator Ground Fault Oscillograph

Relay Trip

service. The oscillograph provided documented evidence that the ground fault did, in fact, occur. Based on the oscillographic data, the decision was made to bring a high voltage Hi-Pot Test set from another plant. The resulting test uncovered the ground fault which was caused by a cracked generator terminal bushing. The bushing was replaced and the unit was returned to service.

Accidental Off-Line Generator Energizing

Inadvertent or accidental energizing of synchronous generators has been a particular problem within the industry in recent years. A number of machines have been damaged or, in some cases, completely destroyed when they were accidentally energized while off-line. The frequency of these occurrences has prompted generator manufacturers to recommend that the problem be addressed through dedicated protective relay schemes. Operating errors, control circuit malfunctions, or a combination of these causes, have resulted in generators becoming accidentally energized while off-line. In modern gas turbine applications, the major cause of inadvertent energization of generators has been by closing the generator breaker through the mechanical close/trip control at the breaker itself, thereby defeating the electrical interlocks. Fig. 5 illustrates a typical gas turbine one-line diagram configuration.

During the commissioning of a new gas turbine in southeast Georgia, the commissioning crew was trying to simulate a generator breaker 52A contact closure by jumping the contact at a terminal block. The wrong terminals were inadvertently jumped, resulting in the generator breaker closing onto a “dead” machine. Fig. 6 shows the oscillograph of the event.

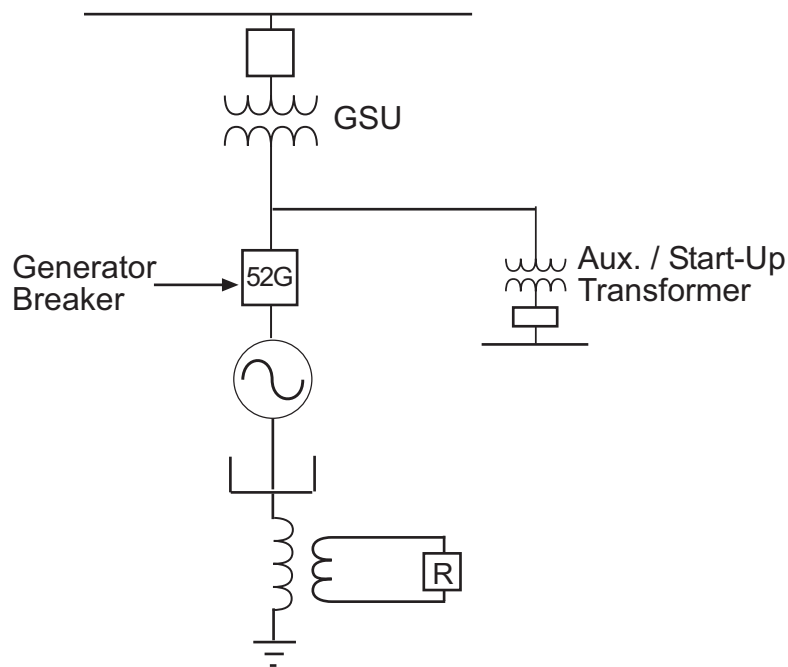


Fig. 5 Gas Turbine Inadvertent Energizing

Due to the severe limitation of conventional generator relaying to detect inadvertent energizing, dedicated protection schemes have been developed and installed. Unlike conventional protection schemes, which provide protection when equipment is in service, these schemes provide protection when equipment is out of service. One method widely used to detect inadvertent energizing is the voltage-supervised overcurrent scheme shown in Fig. 7. An undervoltage element with adjustable pickup and dropout time delays supervise an instantaneous overcurrent relay.



Fig. 6 Inadvertent Energizing Oscillograph

The undervoltage detector automatically arms the overcurrent tripping when the generator is taken off-line. The undervoltage detector will disable or disarm the overcurrent relay when the machine is returned to service. Great care should be taken when implementing this protection, so that the DC tripping power is not removed when the generator is off-line.

When an off-line generator is energized while on turning gear or coasting to a stop, it behaves as an induction motor and can be damaged within a few seconds. During three-phase energization at a standstill, a rotating flux at synchronous frequency is induced in the generator rotor. The resulting rotor current is forced into paths in the rotor body, similar to those rotor current paths for negative sequence stator currents during generator single-phasing. Rapid rotor heating, and damage to the rotor, will occur.

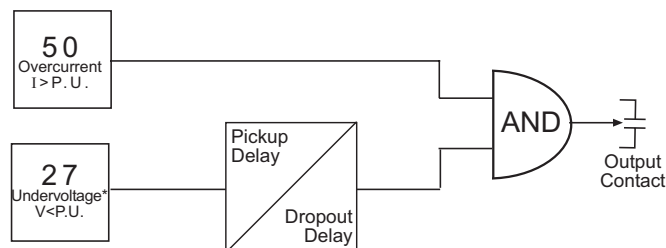
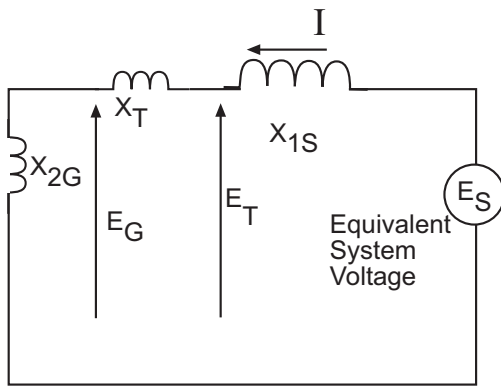


Fig. 7 Inadvertent Energizing Scheme

The machine impedance during this high-slip interval is equivalent to the generator negative-sequence reactance. Fig. 8 shows a simplified equivalent circuit that can be used to calculate the current and voltage associated with three-phase inadvertent energizing.



I = Inadvertent Energizing Current

X_{2G} = Generator Negative Sequence Reactance

X_T = GSU Transformer Reactance

X_S = System Reactance

E_G = Generator Terminal Voltage

E_T = GSU High Side Voltage

Fig. 8 Inadvertent Energizing Equivalent Circuit

Overexcitation

Overexcitation, or V/Hz, relaying is used to protect generators from excessive magnetic flux density levels. High flux density levels result in an overexcitation of the generator. At high-flux levels, the magnetic iron paths designed to carry the normal flux saturate, and flux begins to flow in leakage paths not designed to carry it. These resulting fields are proportional to voltage and inversely proportional to frequency. Hence, high flux density levels (and overexcitation) will result from overvoltage, underfrequency, or a combination of both. ANSI/IEEE Standards C50.13 and C57.12 for generators and transformers have established the following V/HZ limits for continuous operation:

Generators	1.05 p.u. (generator base)
Transformers	1.05 p.u.; (on transformer secondary base) at rated load, 0.8 pf or greater; 1.1 p.u. (transformer base) at no load

These limits apply, unless otherwise stated by the equipment manufacturer. When these V/Hz ratios are exceeded, saturation of the magnetic core of the generator or connected transformer(s) will occur. Damage can occur within seconds. It is the general practice to provide V/Hz relaying to protect generators and transformers from these excessive magnetic flux density levels. This protection is typically independent of V/Hz control on the excitation system.

Damage due to excessive V/Hz operation most frequently occurs when the unit is off-line, prior to synchronization. The potential for overexcitation of the generator dramatically increases if operators manually prepare the unit for synchronization. This is particularly true if the overexcitation alarms are inadequate, or if the VT has an open circuit due to an improper connection. This was the case for a large unit-connected system generator in the midwestern United States. The one-line diagram is shown in Fig. 9.

The unit was being returned from service after an outage where work had been done on the AVR (Automatic Voltage Regulator). To isolate the regulators, the VT fuses had been pulled, but they were not re-installed after the work was completed. When the unit was brought on-line prior to synchronizing,

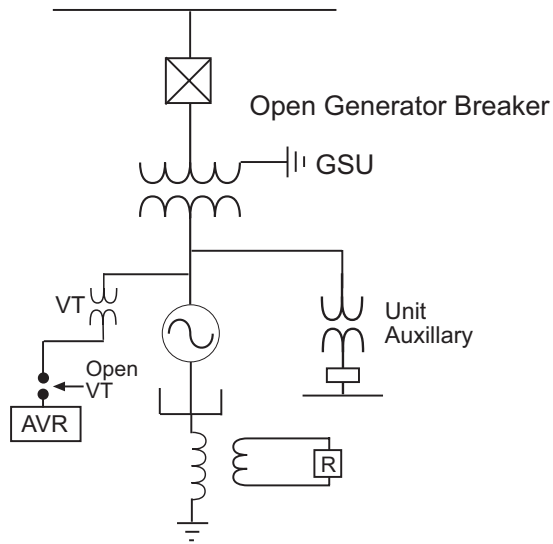


Fig. 9 Overexcitation One-Line Diagram

the operator transferred from manual to automatic AVR control. The AVR, sensing low voltage, went to full boost increasing field current to the maximum level in attempting to raise the generator terminal voltage. Fig. 10 is an oscillograph of the event. The voltage rose to 120% of normal and current to 30% of generator full load before the trip.

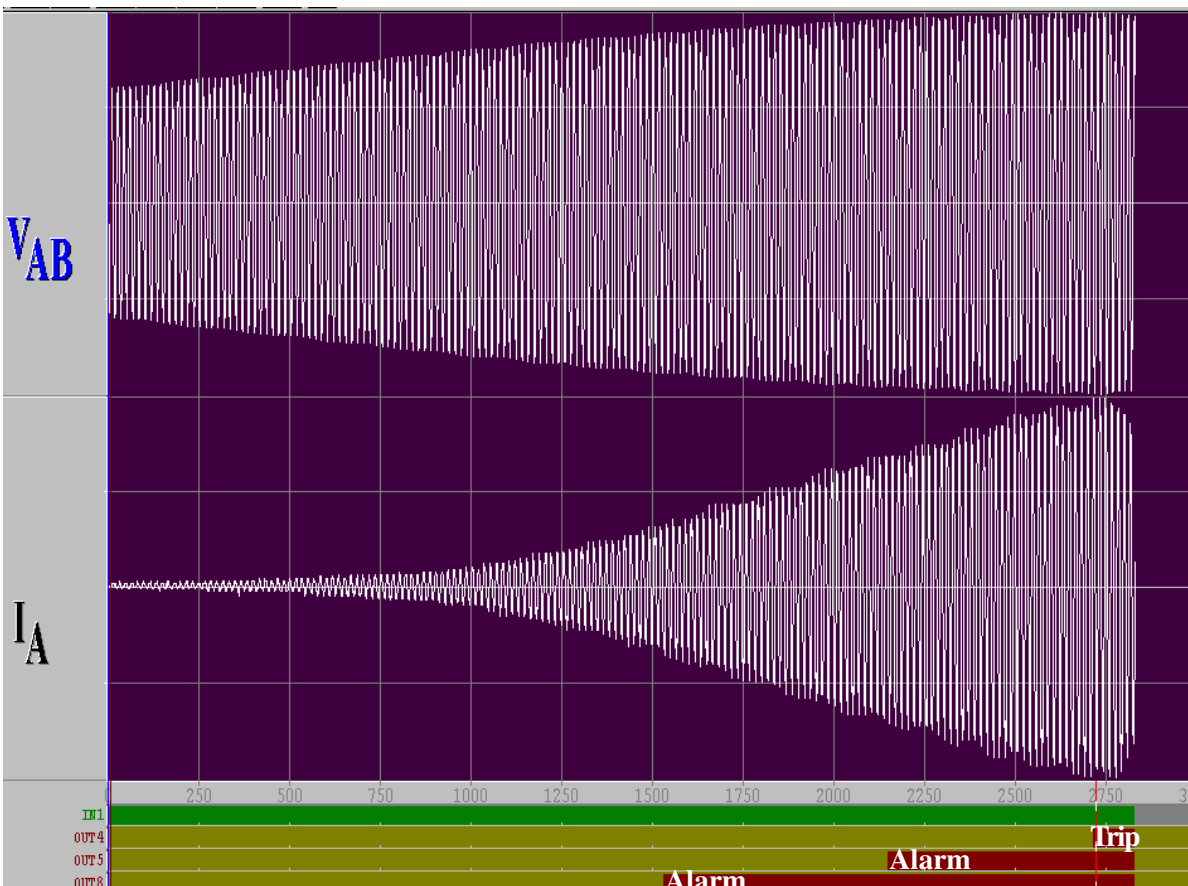


Fig. 10 Overexcitation Oscillograph

Fortunately, both generators and transformers can sustain V/Hz levels above their continuous capability for a substantial time (seconds) since it takes time to heat the iron core of both devices. Therefore, no damage was done to the generator. Operating procedures were revised to check VT continuity to the AVR prior to switching to automatic operation.

In another case, in a large industrial plant, a machine was completely destroyed when the VT open circuit disabled both the AVR and protection. Fig. 11 illustrates the one-line diagram. A “stuck” volt meter provided the operator with a false voltage reading. As he increased field current to raise terminal voltage, he overexcited the generator until it failed. The lesson here is that the protection should be in a separate VT circuit from the AVR control and voltmeter.

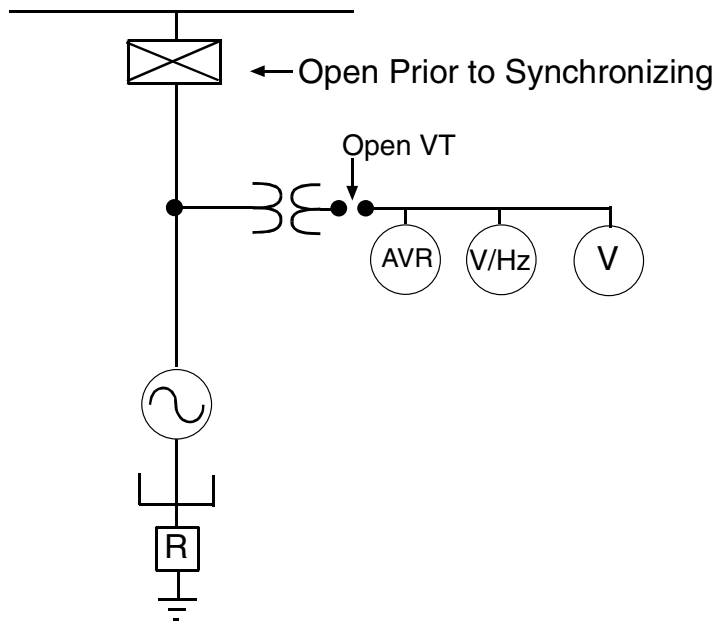


Fig. 11 Overexcitation - stuck voltmeter

Loss-of-Field

Partial or total loss-of-field on a synchronous generator is detrimental to both the generator and the power system to which it is connected. The condition must be quickly detected and the generator isolated from the system to avoid generator damage. When the generator loses its field, it operates as an induction generator, causing rotor heating. A loss-of-field condition which is not detected can have a devastating impact on the power system by causing a loss of reactive power support as well as creating a substantial power drain. If not detected quickly on large generators, this condition can trigger a system voltage collapse.

If the excitation current is reduced or lost, the generator absorbs reactive power from the power system, rather than supplying it, and it operates in the underexcited region of the capability curve. If a total loss of field occurs and the system can supply sufficient reactive power without a large terminal voltage drop, the generator will run as an induction generator, otherwise synchronism will be lost. The change from normal overexcited operation to underexcited operation upon loss-of-field is not instantaneous, but occurs over a time period (generally cycles) depending on the generator's output level and connected system capability. The generator's capability curve (Fig. 12) outlines the generator's operating limits.

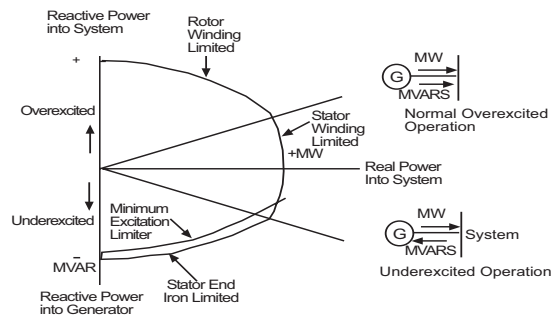


Fig. 12 Generator Capability Curve

The most widely applied method for detecting a generator loss-of-field is the use of distance relays to sense the variation of impedance as viewed from the generator terminals. It has been shown that when a generator loses its excitation while operating at various levels of loading, the variation of impedance as viewed from the machine terminals will have the characteristics shown on the R-X diagram in Fig. 13.

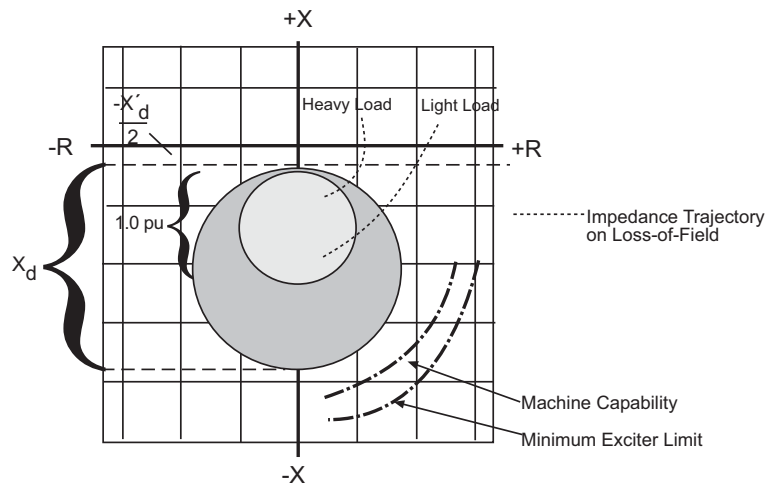


Fig. 13 Modern Loss of Field Using Two-Zone Off-Set mho Method

The loss-of-field relay measures the impedance as viewed from the machine terminals, and it operates when the impedance falls inside the circular characteristic. The relay is offset from the original by one-half of the direct axis transient reactance ($X'_d/2$) to prevent misoperation during system disturbances and other fault conditions. The diameter of the circle is adjusted to be equal to the direct axis synchronous generator reactance. A time delay is used to provide security against false tripping for stable power swings. This time delay increases the operating time of the relay, which means that the MVARs drawn by the generator persist for a longer time, making the system more susceptible to severe voltage dips. Many users have upgraded to modern two-zone mho relays to enhance protection. This scheme is shown in Fig. 13. The inner small mho circle is set to trip with only a few cycles of delay and is within

the impedance locus trajectory for most loss-of-field events. The fast operation of the inner mho unit quickly detects a loss-of-field condition.

The locus of the impedance trajectory for a loss-of-field condition depends on the value of system impedance. For machines connected with system impedances approximately less than 20% of the generator X'_d , the impedance locus will take a direct path to the final point. With higher system impedances, the trajectory will spiral to the final point. If the machine is fully loaded prior to the loss-of-excitation condition, the machine at the final impedance point will be operating as an induction generator, with a slip of 2 to 5% above normal. The machine will also start receiving reactive power from the system while supplying reduced real power.

Complete loss-of-excitation occurs when the DC source of the generator field is interrupted. The loss of excitation can be caused by such incidents as an open circuit in the field, a short circuit in the field, accidental tripping of the field breaker, regulator control system failure, loss-of-field to the main exciter, or loss of ac supply to the excitation system. The accidental trip of the field breaker can occur in the “heat of battle” when the unit operator is trying to react to a number of events occurring in rapid succession. Oscillography and sequence-event recorders are often used to “sort out” the event and uncover what happened. This was the case during a cascading event at a large paper mill. The one-line diagram is shown in Fig. 14.

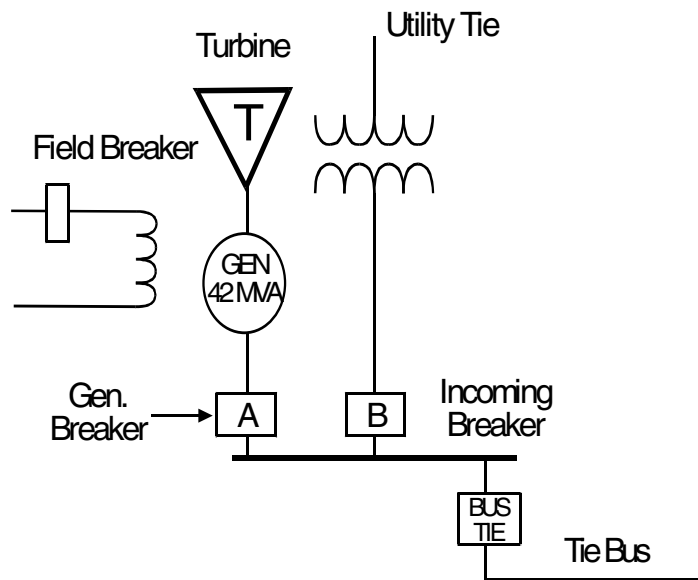


Fig. 14 Paper Mill One-Line Diagram

The event occurred shortly after start-up with a significant load on the unit when the turbine oil trip device failed— dumping the oil header and closing the main stop valve. The oil trip solenoid linkage had worn badly, causing failure. Reverse power relaying picked up, but was unable to trip. Upon realizing the main generator breaker had not tripped, the operator mistakenly tripped the utility tie (breaker B in Fig. 14) instead. He followed by tripping the field breaker about seven seconds later. Detecting the loss-of-field condition, the loss of field protection tripped the generator just in time to avert a mill shutdown from undervoltage from the reactive power upset. Sequence of events and oscillography captured by the digital relays verify the following:

1. The relaying verified the repeated reverse power (32) pick-ups but the 32 relay could not trip the main and field breakers through lockout relays due to a wiring error. For about two minutes after the oil trip linkage failure, the generator motored with the field, supplying up to 25 MVARs to support bus voltage after the accidental loss of the incoming utility tie. The current can be seen to be 90 degrees lagging the voltage in the oscillograph in Fig. 15.
2. When the field breaker opened, reactive power flow reversed in 18 cycles and the generator drew in leading current rising to 800 amps from the system to re-establish field as shown in Fig. 15. The unit was now operating without field as an induction machine and placing a large reactive load on the mill system, with the bus voltage sagging to about 11 kV on a 13.8 Kv system.

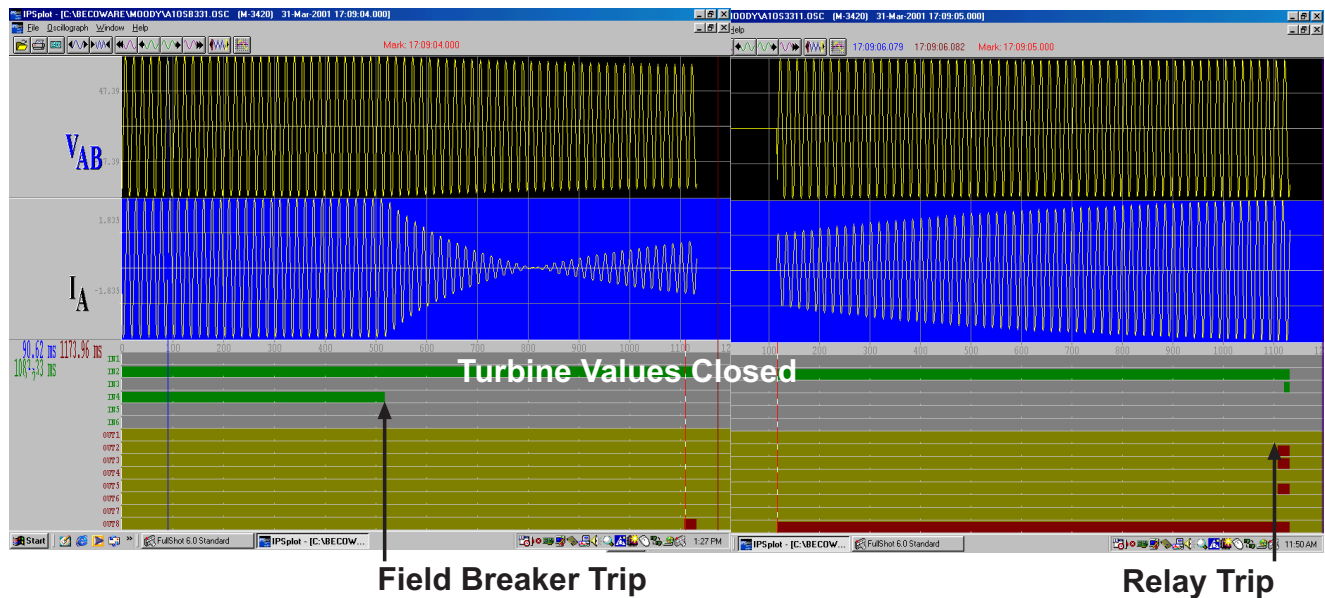


Fig. 15 Loss of Field with Turbine Tripped

3. Sensing the loss-of-field condition, the loss-of-field relaying tripped the unit about two seconds after the field breaker had been opened. Separate bus tie relay data verified the tie was in an overload condition and the overcurrent relay was timing to trip the bus for a total bus shutdown.
4. Initially, the operator believed he had followed normal operating procedure and that the utility tie had opened on overload from the loss of the generator. The relay data provided unbiased evidence to show that he had misoperated and tripped the utility tie breaker.

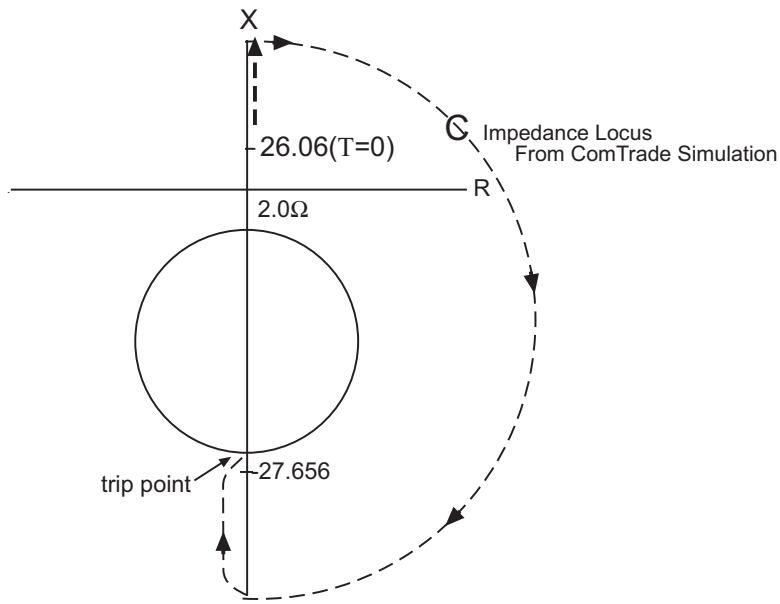


Fig. 16 R-X Diagram of Loss of Field Event with Turbine Tripped

To further analyze this event, the oscillographic data was converted to COMTRADE format to allow it to be conveniently plotted on the loss-of-field R-X diagram. The R-X diagram plot is shown in Fig. 16.

When a loss-of-field event occurs on a machine prior to the turbine tripping, the oscillograph looks much different. The event depicted on the oscillograph in Fig. 17 occurred on a large steam generator. Again, an operating error resulted in the field breaker being tripped with the generator breaker still closed. The machine tripped by loss-of-field relaying. A key in analyzing loss-of-field events is that the current will lead the voltage resulting in VARS being taken into the generator. The use of COMTRADE to “play” the event back to the relay provides an excellent tool in analyzing loss-of-field events.

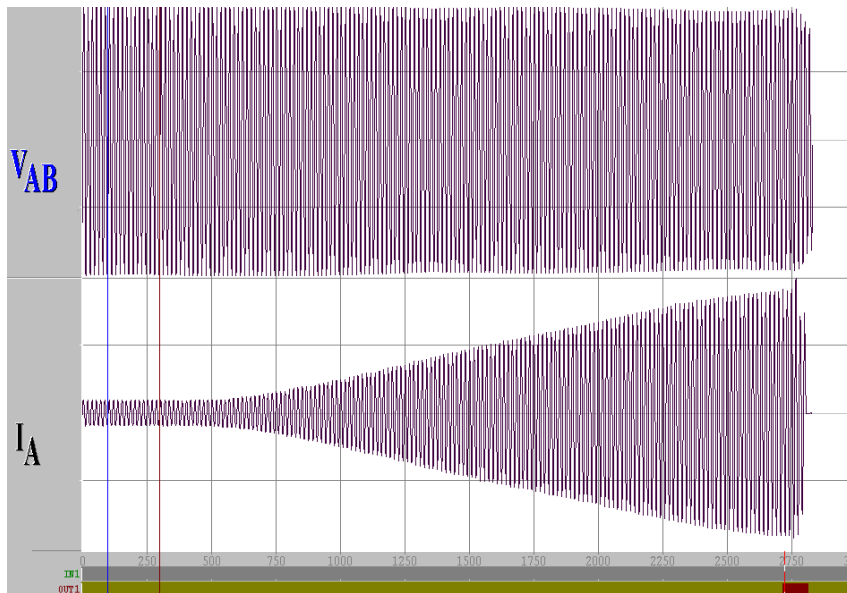


Fig. 17 Loss of Field Prior to Turbine Trip

Generator Breaker Failures

A unique form of generator high-voltage breaker failure is the case where the breaker contact flashover energizes the generator. Fig. 18 illustrates such a flashover case. This type of flashover has occurred on a number of EHV air-blast breakers where SF6 pressure was lost prior to the unit being synchronized to the system. With the loss of dielectric in the interruptor, the contact flashed across when a 2.0 per unit voltage is placed across the interruptor in each slip cycle. Because the 2.0 per unit voltage only occurs on generator breakers, this type of flashover is more likely on these breakers. Fig. 19 shows the equivalent circuit that can be used to calculate the resulting currents.

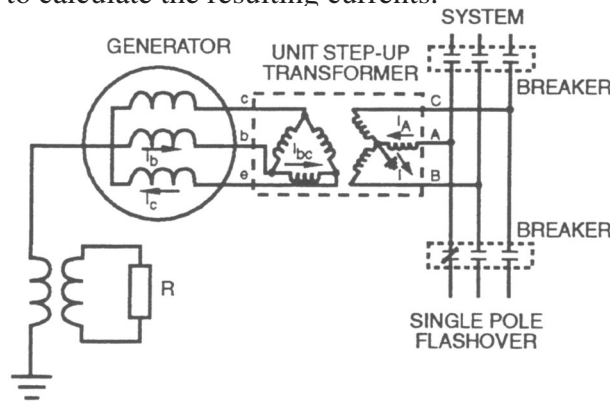
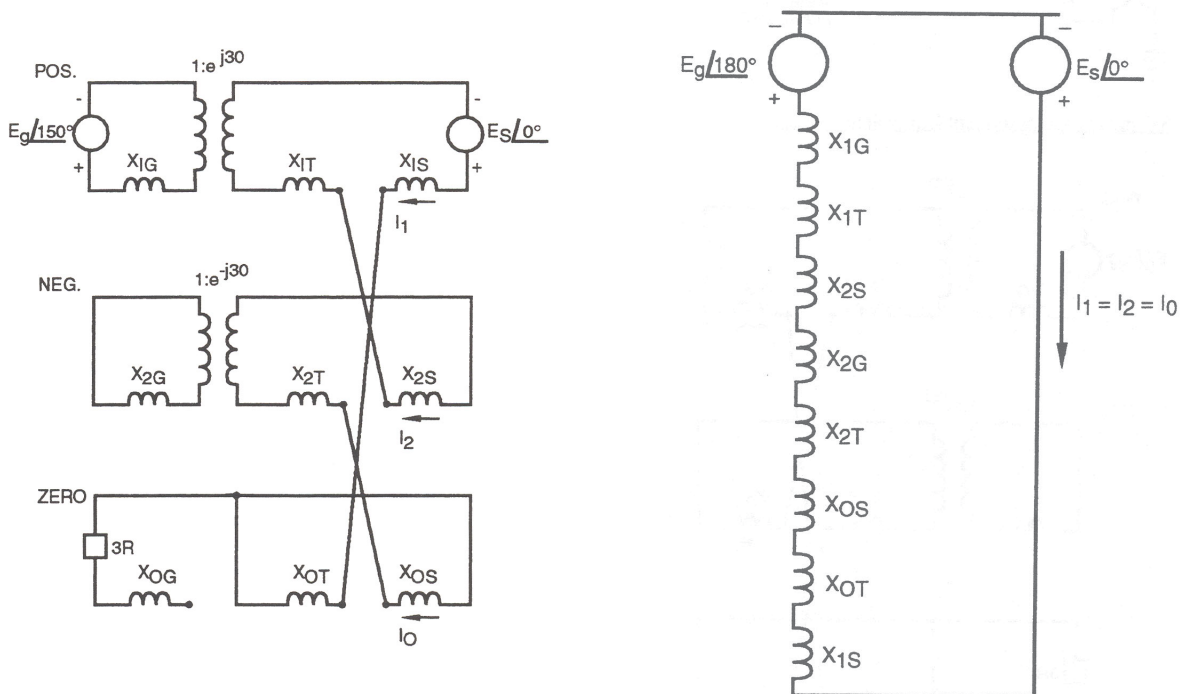


Fig. 18 Open Breaker Flashover



- X_{1G}, X_{2G}, X_{0G} = Generator Positive, Negative and Zero Sequence Reactances
- X_{1T}, X_{2T}, X_{0T} = Unit Step-Up Transformer Positive, Negative and Zero Sequence Reactances
- X_{1S}, X_{2S}, X_{0S} = System Equivalent Positive, Negative, and Zero Sequence Reactances
- E_g = Generator Voltage
- E_s = System Voltage
- I_1, I_2, I_0 = Positive, Negative and Zero Sequence Currents

Fig. 19 Headflashover Equivalent Circuits

A breaker generator flashover event recently occurred on a large steam generator in Mexico. The one-line configuration is shown in Fig. 20a. For the flashover of a generator high voltage breaker pole, re-tripping of the breaker will not de-energize the machine because the breaker is already open. The initiation of breaker failure is required to trip additional local, and possibly remote, breakers to de-energize the generator.

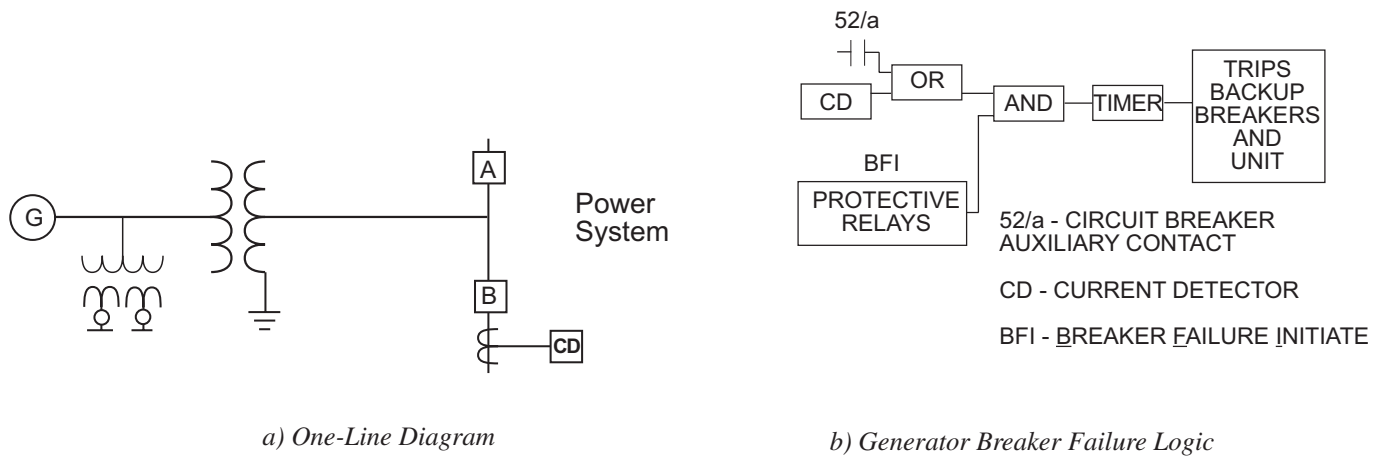
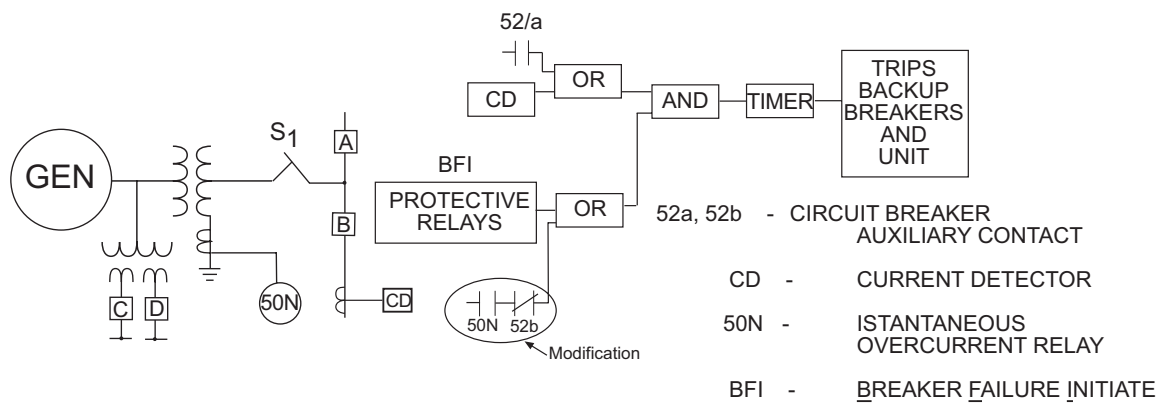


Fig. 20 Breaker Flashover and Breaker Failure Logic

Unbalanced currents associated with breaker head flashover will generally cause the generator negative-sequence relay to operate. This will initiate tripping of the generator breaker(s) (which are already open), shutting down the generator and providing the BFI signal (Breaker Failure Initiate) to the breaker failure. The Breaker Failure Logic (Fig. 20b) breaker failure will be initiated only if the breaker failure current detectors are set with sufficient sensitivity to detect the flashover current. The equivalent circuit in Fig. 19 provided the circuitry to calculate the flashover current. In the case of the unit in Mexico, the current detectors were set higher than the flashover current and breaker failure was not initiated. The result was the catastrophic failure of the generator. The key consideration for setting the breaker failure current detector is to set it below the level of the current expected for breaker-pole flashovers. This was an expensive lesson learned by this Mexican utility.

One approach used to speed the detection of a breaker flashover is to modify the breaker failure scheme as shown in Fig. 21. An instantaneous overcurrent relay (50N) is connected in the neutral of the generator step-up transformer and is set to respond to an EHV breaker pole flashover current. The relay output is supervised by the generator breaker “52B” contact providing an additional start to the breaker failure scheme. When the generator breaker is open and one or two poles of the breaker flash over, the resulting transformer neutral current is detected by the 50N relay without the delay that would be associated with a negative sequence relay. The current detectors (CD) associated with the generator breaker scheme must be set with sufficient sensitivity to detect this flashover condition. This scheme is used by a number of utilities and is also described in ANSI/IEEE C37.102 (Guide for the Protection of Synchronous Generators). The Mexican utility that sustained the generator failure retrofitted their breaker failure with this scheme.



a) One-Line Diagram

b) Generator Breaker Failure Logic

Fig. 21 Modified Breaker Flashover and Breaker Failure Logic

Conclusion

Major generator tripping events are not as rare as many people believe. Should they occur, such events can be very disruptive and costly to utility power production. Delays in determining the cause of the disruption and in assessing equipment damage can add hours to reenergizing and returning to normal operations. It is critical to assess the integrity of the generator and perform any testing necessary before reconnecting to the system. It is critical to have good sequence-of-events and oscillographic data to review protective relay performance, assess fault levels and clear the machine of any damage. To proceed otherwise, risks restarting the unit with possible increased damage and extensive downtime.

The loss of a generator immediately costs the utility money for lost production and there is great pressure placed on those involved to determine if the generator is damaged, determine what generator testing needs to be done and return the machine to service as quickly as possible. Oscillographs and sequence-of-events data from a digital relay have greatly aided in this effort.

References

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Biography

Charles J. Mozina is Applications Manager, Protection Products and Systems, for Beckwith Electric Co. He is responsible for the application of Beckwith products and systems used in generator protection and intertie protection, synchronizing and bus transfer schemes.

Chuck is an active member of the IEEE Power System Relay Committee and is the past chairman of the Rotating Machinery Subcommittee. He is active in the IEEE IAS I&CPS committee, which addresses industrial system protection. He is a former U.S. representative to the CIGRE Study Committee 34 on System Protection and chairs a CIGRE working group on generator protection. He also chaired the IEEE task force, which produced the tutorial "The Protection of Synchronous Generators," which won the PSRC's 1995 Outstanding Working Group Award. Chuck is the 1993 recipient of the PSRC's Career Service Award.

Chuck has a Bachelor of Science in Electrical Engineering from Purdue University and has authored a number of papers and magazine articles on protective relaying. He has over 25 years of experience as a protective engineer at Centerior Energy, a major investor-owned utility in Cleveland, Ohio where he was the Manager of the System Protection Section. He is also a former instructor in the Graduate School of Electrical Engineering at Cleveland State University as well as a registered Professional Engineer in the state of Ohio.