Switching Transient Analysis and Specifications for Practical Hybrid High-Resistance Grounded Generator Applications—An IEEE/IAS Working Group Report #2

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***Abstract*—This paper reports on the continuing efforts of an IAS Working Group to investigate industry concerns with excessive stator fault-point burning damage in conjunction with various industrial generator grounding and ground fault protection practices. Previous working group efforts were reported in a series of papers discussing typical voltage bus connected industrial generator applications. These papers proposed a new method of grounding, called hybrid grounding, that offered the ability to limit damage while still providing the required level of ground fault current under all operating conditions. This new Working Group paper reports on the detailed design requirements for hybrid grounding. The paper reports the results of switching transient studies that formed the bases for recommended overvoltage protection. It also provides guidance in selection of equipment and fault protection required for hybrid grounding. The experience gained with several hybrid grounding applications is also reported.**

***Index Terms*—Ground fault protection, grounding, hybrid high-resistance ground, medium-voltage industrial generator.**

I. Introduction

The fault type to which generator stator windings are most often subjected is a short circuit to ground. In recent years, severe damage to bus-connected medium-voltage generators from stator ground faults has been observed at a number of industrial plants. Most of these generators are at plants with multiple generators operating on plant distribution buses at the medium-voltage level (see Fig. 1). Traditionally, the neutrals of these industrial generators have been grounded through resistors designed to limit ground fault current to somewhere in the range of 200–800 amperes. Reference [1] describes these failures in detail. Such generator failures required extensive stator lamination repairs at the manufacturer's premises with the associated down time. Investigation revealed that most of the burning damage was caused by fault current produced by the faulted generator itself (see Figs. 2 and 3).

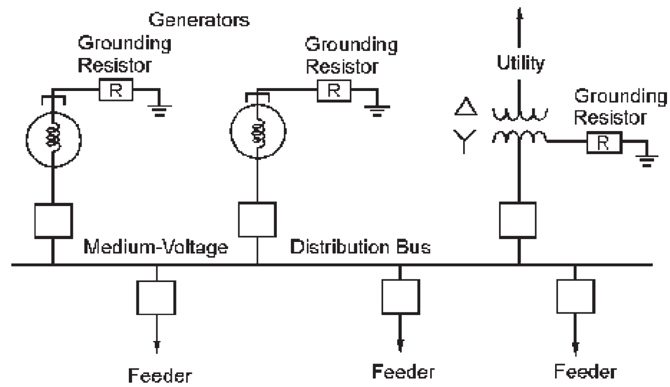

Fig. 1. Medium-voltage industrial distribution system with multiple sources.

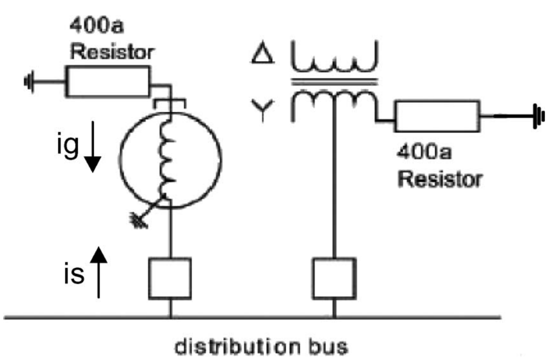

Fig. 2. Grounding example.

For the grounding example shown in Fig. 2, the fault will have a total magnitude equal to 800 A, with 400 A flowing into the generator from external sources (supply transformers and other generators) and 400 A generated within the generator itself. The watt-second damage associated with each of these currents can be determined by integrating their values over the time the fault current flows and summing the two component

Manuscript received May 6, 2008; accepted September 28, 2009. Date of publication November 22, 2011; date of current version January 20, 2012. Paper ICPSD-08-5, presented at the 2008 IEEE/IAS Industrial and Commercial Power Systems Technical Conference, Clearwater Beach, FL, May 4–l8, and approved for publication in the IEEE Transactions on Industry Applications by the Power System Protection Committee of the IEEE Industry Applications Society.

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Digital Object Identifier 10.1109/TIA.2011.2176989

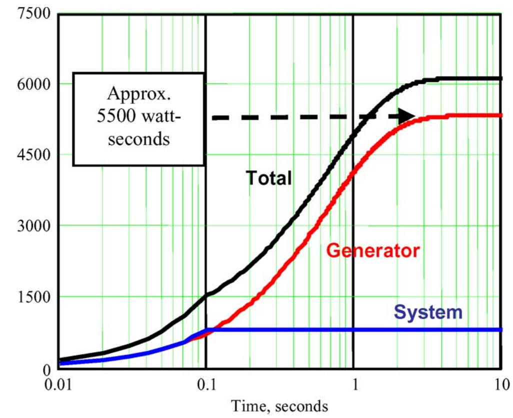

Fig. 3. Watt-second fault energy versus time.

currents to determine the total energy. Reference [2] provides a detailed discussion of the above described failure mechanism.

$$\text{energy} \propto \underbrace{\int_0^{\text{duration}} (i_g \times \varepsilon^{1/\tau})^k dt}_{\substack{\text{Generator}\\ \text{contribution}}} + \underbrace{\int_0^{6\text{ cycles}} i_s^k dt}_{\substack{\text{System}\\ \text{contribution}}} \quad (1)$$

where $\tau =$ generator short circuit time constant $= 1.0$ sec $\mathrm{K} = 1.5$. Energy is in watt-seconds assuming that right-hand side of equation is multiplied by a hypothetical arc resistance of one ohm - for comparative analysis purposes only.

The energy associated with the fault is calculated in the above equation and is a function of two variables, the magnitude of current, I, and the duration of the fault, t. The value of K (exponent in the above equation) is also a factor. A value of 2 would apply in the case of purely resistive heating. Various researchers have predicted values for K for an arc in the range of 1 to 2 [2], [3]. For the purpose of this analysis, a value of 1.5 was chosen. The system fault current contribution is quickly interrupted when the generator breaker is tripped after a six-cycle delay, which assumes a five-cycle breaker with one cycle of relay time. Fig. 3 plots the watt-second energy from both sources of ground fault current. It can be seen from this plot that the vast majority of damage occurs from the generator current source after tripping has occurred. Even with one cycle fault recognition, the resulting fault decay time of the generator current result in the vast majority of damage.

The more system sources of ground current, the higher the energy will be from the system contribution, but clearly if fault damage is to be reduced, the contribution from the generator must be reduced.

II. Hybrid Generator Grounding

Previous efforts of the Working Group explored a number of methods to reduce the generator source of ground current [1] for a stator ground fault. The hybrid grounding scheme combines both high-resistance (HRG) and low-resistance (LRG) grounding as shown in Fig. 4 (Hybrid High Resistance grounding = HHRG). The scheme adaptively switches the grounding in the generator neutral to HRG when a generator ground fault is detected by opening a high-speed switch to remove the LRG source.

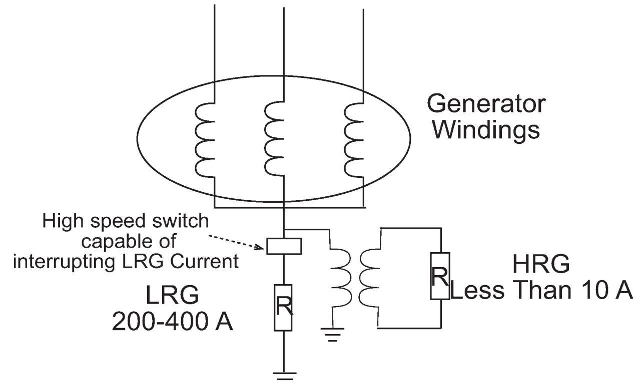

Fig. 4. Generator hybrid ground.

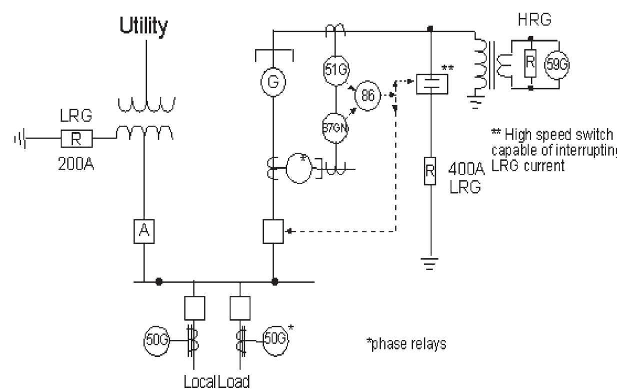

Fig. 5. Hybrid grounded and associated ground fault protection.

Simply HRG the generator was not a viable option because during emergency situations when the utility source is unavailable (Breaker A open in Fig. 5), the generator can be the sole source of power to the industrial facility. A sufficient level of ground current must be maintained to: 1) stabilize neutral shift on the unfaulted phases; 2) provide enough ground current to allow proper operation of ground fault protection on the industrial system. Those objectives require a ground current in the range of 200–1000 A. Only for internal generator ground faults is the high-speed switch tripped to HRG the generator.

Fig. 5 shows the ground fault protection required for a hybrid grounded generator connected to an industrial medium-voltage system. The use of a ground differential (87GD) relay is extremely important in providing the necessary sensitivity in detecting stator ground faults. Relying solely on the generator phase differential protection typically leaves a substantial portion to the stator winding without high-speed ground fault detection.

The introduction of a switching device in the generator neutral resulted in a number of questions. Specifically:

- Are there significant over voltages being introduced when the neutral switched is open or closed?
- Is there a need for additional surge protection as a result of this switching?

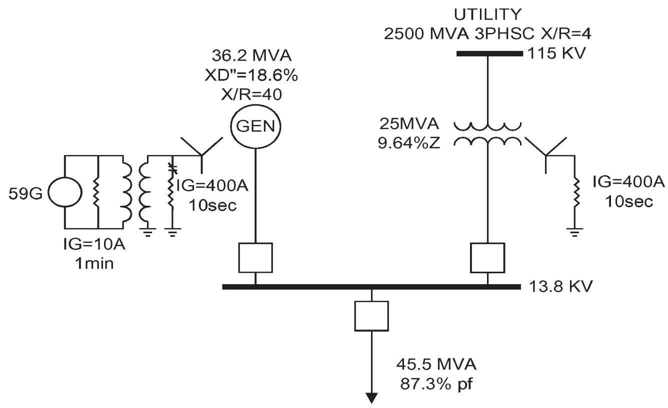

Fig. 6. Study system.

- What are the ratings of the new equipment required to accommodate hybrid grounding?
- What system protection changes are required?
- Are there any operating changes that are recommended?

III. Simulations

IEEE IAS Generator Grounding Working Group has undertaken Electromagnetic Transients Program (EMTP) simulations of switching within the generator hybrid high-resistance ground system (HHRG). The intent of these simulations was to model the possible switching transients caused by opening of the neutral breaker or switch. This section documents and summarizes the EMTP simulations. The specific objectives of the EMTP simulations were:

- Study the possible switching transients caused by opening the neutral breaker or switch.
- Study these switching transients with and without the HRG element in the circuit (determine damping benefits of the HRG, if any)
- Determine if surge protection is desirable
- Evaluate the distributed winding capacitance impact throughout the winding (pi based, distributed, or lumped).

A. Description of the System

Fig. 6 gives the system selected by the working group for the EMTP simulations as was described by Wu, Tang, and Finner in [3]. The facility is served by the utility at 115 kV with available short circuit of 2500 MVA and is stepped down to 13.8 kV by a 115/13.8 kV utility tie transformer rated 25 MVA. The total 13.8-kV bus load is 39.7 MW and 22.2 MVAR. The 13.8-kV generator is rated 32.6 MVA with Xd" of 18.6%. The generator grounding consists of a LRG resistor of 400 A, 10 s, as well as a HRG resistor of 10 A, 1 min. The generator terminal lumped capacitance 0.63 micro-Farads per phase.

Fig. 7 gives the initial EMTP model that consists of the generator with LRG, generator breaker, and load as represented in [3]. This model was selected so initial results could be compared to those given in [3]. Two refinements were made to the model as defined in [3]: 1) Ungrounded sources were used to model the generator rather than solidly grounded sources used in [3]; and 2) the generator was loaded to 32.6 MVA rather than 45.5 MVA as in [3]. This initial model served as the starting point for the simulations and allowed for complex modeling and analysis.

B. Case Descriptions

The following is a brief description of the EMTP cases:

- Case 1^{*,a,b} - Open the neutral switch in series with the LRG component to interrupt generator ground fault current and clear before the main generator breaker. (i.e., the neutral switch opens in three cycles and the main breaker opens in five cycles). The switch interrupts 400 amperes.
- Case 2^{*,a,b} - Same as case 1 but the neutral breaker opens in 1.5 cycles and main breaker opens in five cycles.
- Case 3^{*,a,b} - Same as case 1 but the neutral breaker clears after the main breaker clears (five cycle neutral switching and three cycle main breaker).
- Case 4 - Repeat case 1 but without a ground fault—the neutral switch interrupts 3 to 5 amps of third harmonic current—using a vacuum interrupter.
- Case 5 - Repeat case 2 - using case 4 conditions.
- Case 6 - Simulate an arcing ground fault - then open the neutral switch without the HRG component—to simulate escalation of the arcing ground fault voltage. Also, evaluate with and without voltage decay as a function of time and excitation removal.
- Case 7 - Depending on the results of case 6, simulate adding the HRG component to case 6.

**Note*: Solid ground faults, all others fault cases are arcing ground faults.

1) Model Validation Cases 1, 2, and 3: The results of EMTP Cases 1, 2, and 3 demonstrated the EMTP model was working. The initial results compared favorably to those presented in [3]. The EMTP model established for Cases 1, 2, and 3 served as the starting point for more complex analysis as outlined by the working group in the case descriptions.

2) Model Enhancements Cases 1a–3a and Cases 1b–3b: The EMTP model was enhanced to include a pi-equivalent for the cable from the generator neutral to the HHRG unit. A single insulated 350 MCM cable of approximately 50 feet in length was represented by five pi-sections. Each pi-section consisted of appropriate series R and X as well as shunt C elements.

Case 1a as shown in Fig. 8 shows a solid ground fault with 400 amps flowing and the appropriate breaker clearing times indicated. There is a little high-frequency ringing when the generator is ungrounded. Everything else appears as expected.

Fig. 9 gives the results of EMTP Cases 1b showing the effects of the pi-equivalent for the cable between the generator neutral and the HHRG unit and current chopping of the neutral breaker. Note the increased high-frequency ringing (compared to Fig. 8).

3) Third Harmonic Voltage Cases 4 and 5: Synchronous generator may produce some third harmonic voltage in addition to 60-Hz fundamental. Reference [6] The magnitude of third harmonic voltage will vary depending on the pitch factor. The EMTP model was enhanced to represent about 800 V of third harmonic voltage which results in about 30 A of third harmonic current flowing in the generator neutral. The third

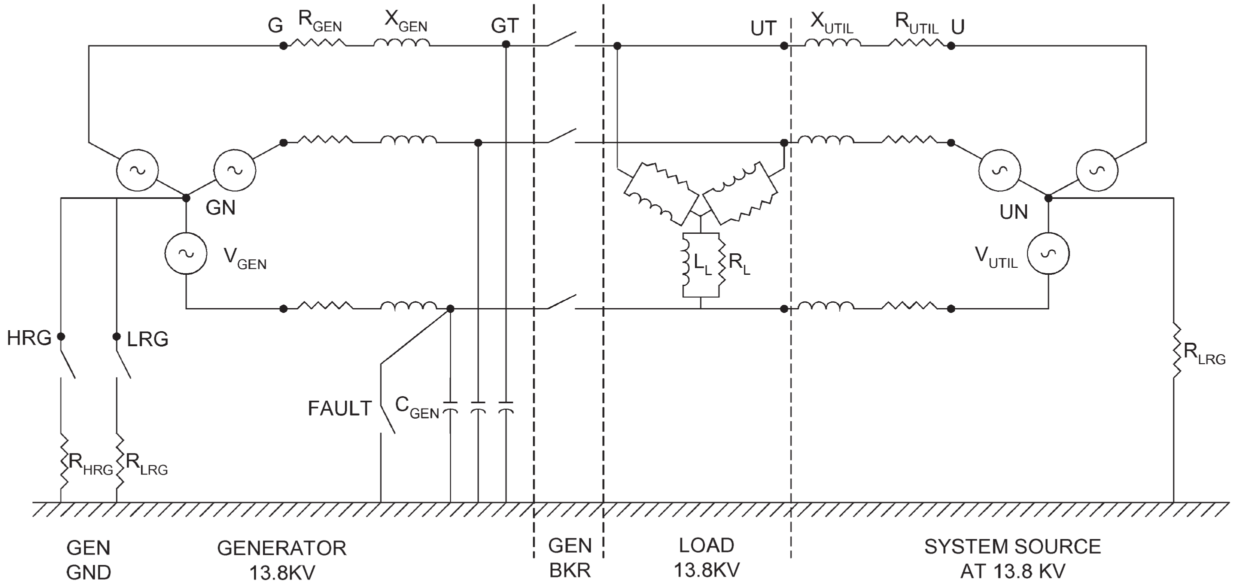

Fig. 7. Initial system model for EMTP simulations.

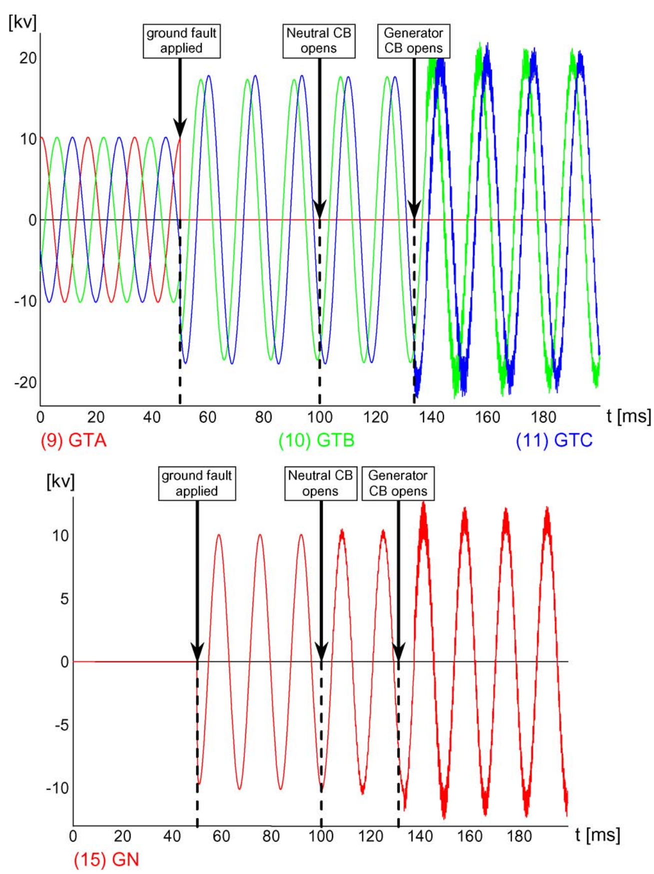

Fig. 8. Generator terminal voltage (top) and neutral voltage (bottom) for Case 1a-Neutral breaker opens in three cycles, and the main breaker opens in five cycles (cable pi-equivalent).

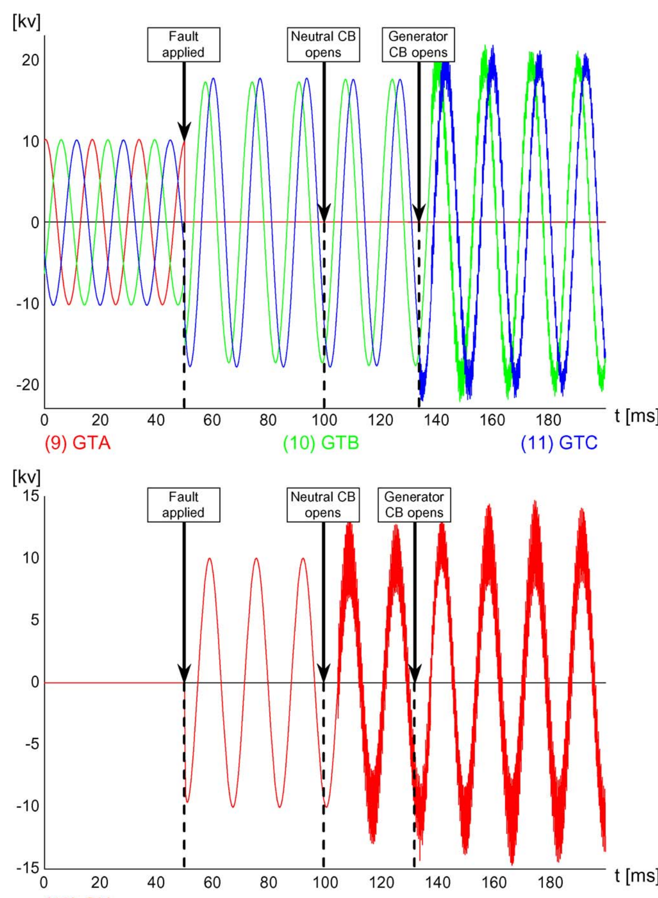

Fig. 9. Generator terminal voltage (top) and neutral voltage (bottom) for Case 1b-Neutral breaker opens in three cycles, and the main breaker opens in five cycles (cable pi-equivalent plus current chop).

harmonic current is important because vacuum contacts are known to chop current typically in the 3 to 10 amp range (some manufacturer's have higher chop currents) with the potential associated voltage transient. The model simulated interrupting 30 amps of third harmonic current—the breaker arcs until the current magnitude decreases to 10 amps—at which time it is instantaneously chopped to zero magnitude.

EMTP Cases 4 and 5 simulate chopping of 10 A of third harmonic current. Fig. 10 gives the results of EMTP Cases 4

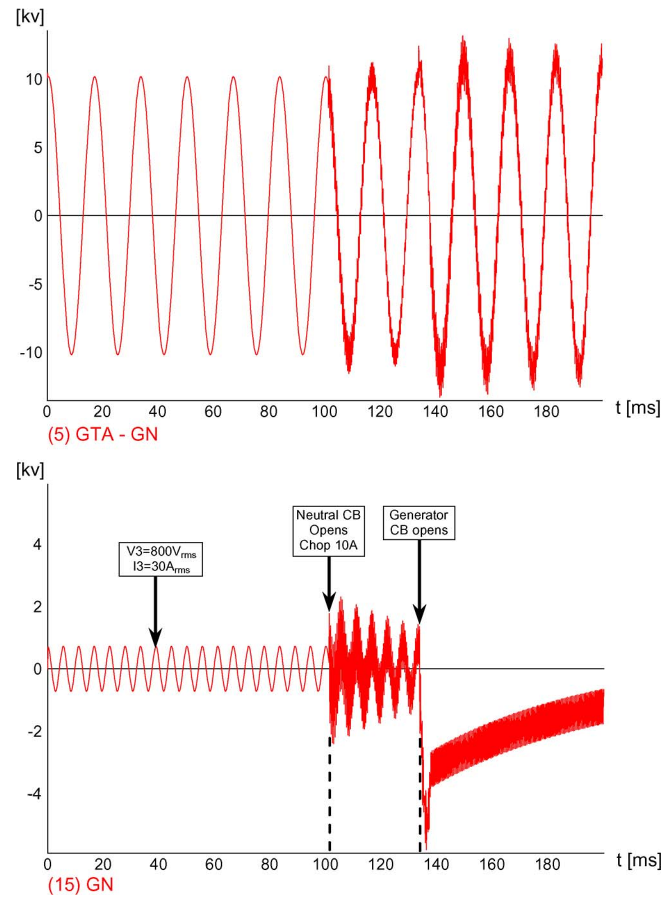

Fig. 10. Generator terminal voltage (top) and neutral voltage (bottom) for Case 4 - Neutral breaker opens in three cycles, and the main breaker opens in five cycles (chop at 10 A of third harmonic current).

showing the effects of chopping 10 A of 3rd harmonic current by a vacuum contact without a ground fault.

4) Arcing Ground Fault Case 6: An arcing ground fault is a complex phenomenon and results in voltage escalation on ungrounded systems [4], [5]. The initial model of the arcing ground fault consisted of a fault to ground at the peak of the phase-A voltage. One electrical degree, or 46.296 μs later, the arc extinguishes. At the next voltage peak 180° later, the same sequence takes place. The arcing ground fault is initiated at 50 ms and continues for the remainder of the simulation.

Fig. 11 gives the results of EMTP Case 6 showing the effects of an arcing ground fault on one phase of the generator. Once its main breaker opens, the arcing ground fault continues with the generator ungrounded. Notice the doubling of the terminal voltage and neutral voltage on each successive arcing ground fault. Also, note where the system goes into a high-frequency resonance exacerbating the condition. This simulation shows voltage escalation and resonance that are reasons to avoid operation with the neutral ungrounded.

5) Internal Voltage Decay Cases 6b and 6c: After the generator circuit breaker opens, the ground fault current continues to flow from the generator neutral because of the residual generator internal voltage. The residual generator internal voltage decays according to the generator open circuit time constant

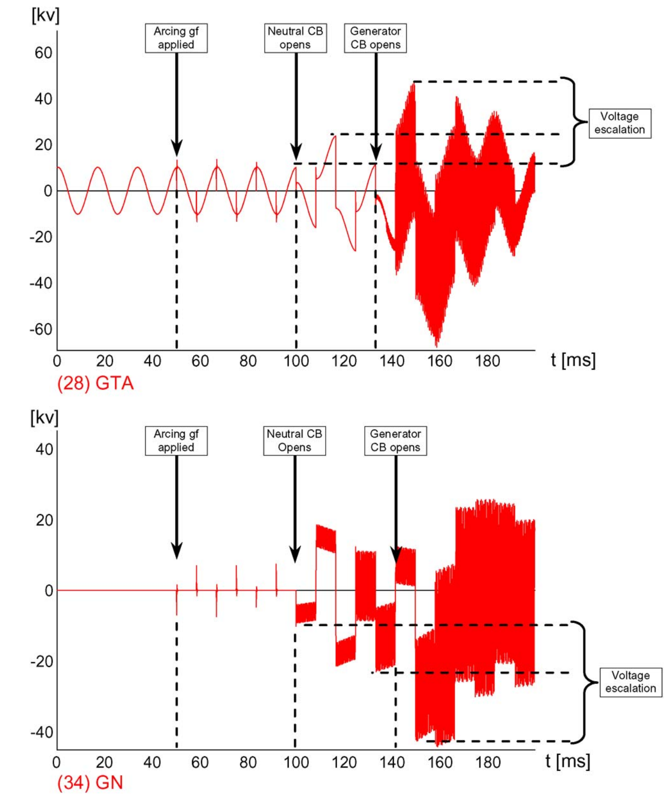

Fig. 11. Generator terminal voltage (top) and neutral voltage (bottom) for Case 6-generator ungrounded - Neutral breaker opens in three cycles, and the main breaker opens in five cycles (arcig ground fault on phase-A).

$\mathrm{T'_{do}}$. One approximation for the internal voltage decay is given below

$$\text{internal voltage} \propto \mathrm{e}^{(-\mathrm{t}/\mathrm{T_{lg}})}$$

$$\text{where } \mathrm{T_{lg}} = \mathrm{X'_d}/\mathrm{X_c}\mathrm{T'_{do}}$$

Powell [2] estimated $\mathrm{T_{lg}}$ to be in a range of 0.8 to 1.1 s. Wu estimated [1] $\mathrm{T_{lg}}$ to be in a range of 0.4 to 1.5 s. Mozina provided an oscillograph of a stator ground fault, and curve fitting gave a $\mathrm{T_{lg}}$ of approximately 1.6 s. (but for a much larger generator than most cogeneration systems). The above relationship was used to represent the internal voltage decay in the study system model. Case 6b considered a $\mathrm{T_{lg}}$ of 1.0, and Case 6c considered a $\mathrm{T_{lg}}$ of 1.6. A $\mathrm{T_{lg}}$ of 1.0 results in an internal voltage of 84.7% in ten cycles, while a $\mathrm{T_{lg}}$ of 1.6 results in an internal voltage of 90.2% in ten cycles.

Fig. 12 gives the results of EMTP Case 6b taking into account generator internal voltage decay considering $\mathrm{T_{lg}}$ of 1.0. This case shows the effects of the generator internal voltage decay which can be compared to Case 6a with a fixed internal voltage. Case 6b shows the rate of voltage escalation due to each successive arc is much more rapid than the internal voltage decay. In Case 6b, the voltage doubles in three cycles, while the internal voltage decays to 90.2% in ten cycles. High-frequency resonance also occurs after the generator breaker opens. Similar results were obtained for EMTP Case 6c using $\mathrm{T_{lg}}$ of 1.0.

6) Arcing Ground Fault With HRG Case 7: In EMTP Case 7, the HRG component is added with appropriate neutral surge protection, and the arcing ground fault and internal

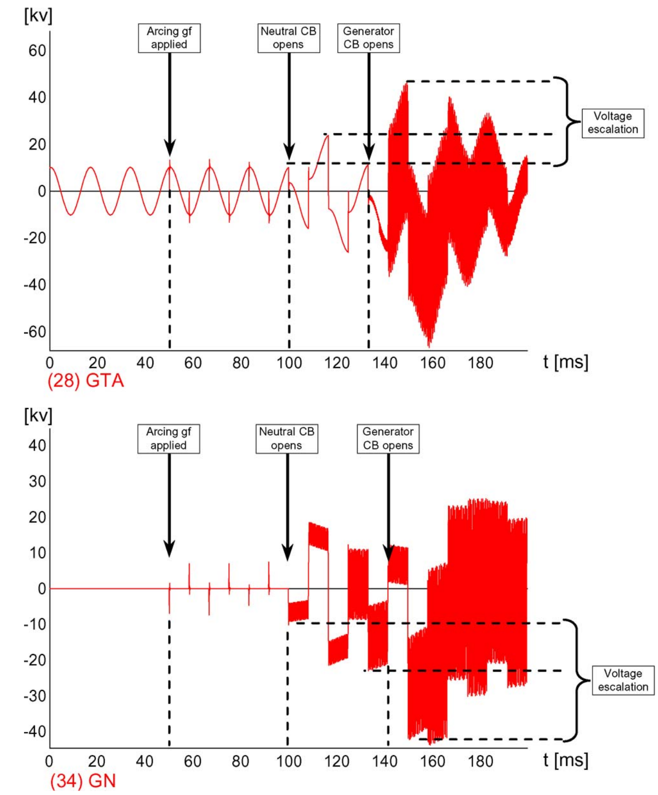

Fig. 12. Generator terminal voltage (top) and neutral voltage (bottom) for Case 6b (generator ungrounded) arcing ground fault at 50 ms and internal voltage decay (T_{1g} of 1.0).

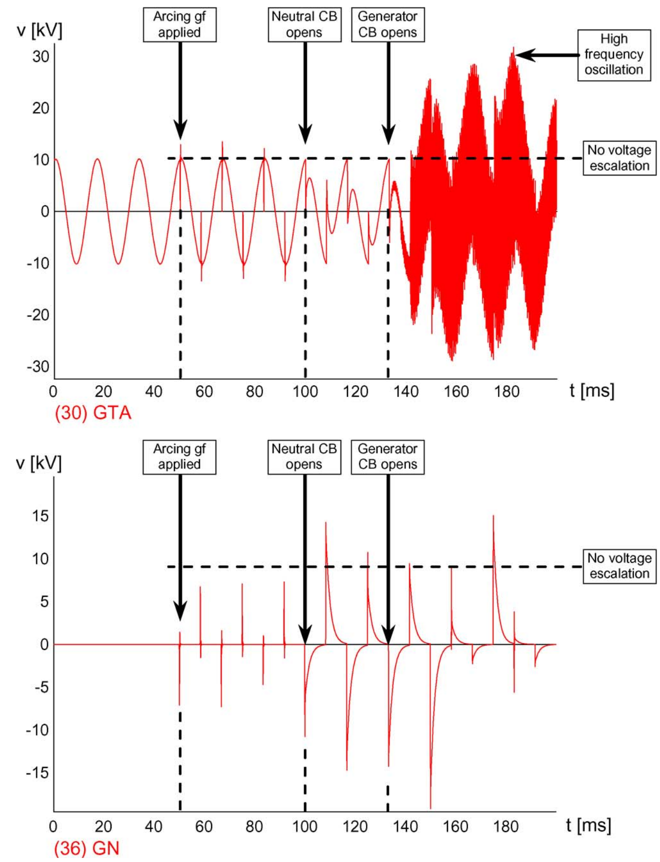

Fig. 13. Generator terminal voltage (top) and neutral voltage (bottom) for Case 7b with HRG component and arcing ground fault at 50 ms and internal voltage decay (T_{1g} of 1.0).

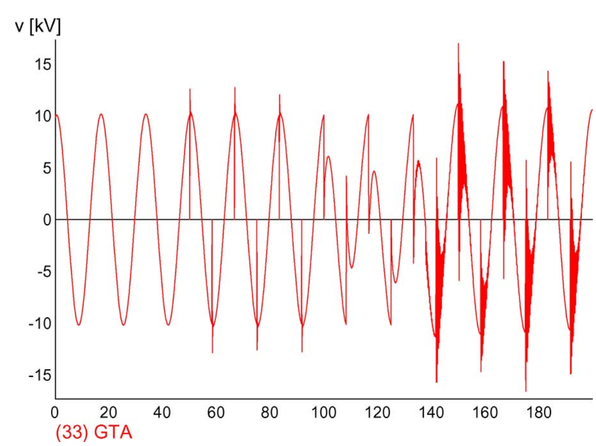

Fig. 14. Generator terminal voltage for case 7g—added line terminal snubbers to case 7b.

voltage decay of Case 6b are simulated. The results of Case 7b are given in Fig. 13. After the neutral breaker opens, the arcing continues, but the voltage escalation in terminal and neutral voltage is eliminated by the HRG. The HRG limits neutral voltage to 20 kV_{peak}. Until the generator breaker opens, the HRG limits terminal voltage to 12 kV_{peak}.

After the generator breaker opens, the terminal voltage increases to 30 kV_{peak} with a high-frequency oscillation of approximately 4800 Hz. Preliminary analysis shows this high-frequency oscillation exists when opening the neutral breaker to the LRG both with and without the HHRG. This high-frequency oscillation is not related to the HRG but is consistent with damage previously seen on generators and warranted further investigation. However, the HRG system greatly dampens this oscillation compared to leaving it out of the circuit (compare Figs. 12 and 13). Realizing that this high-frequency oscillation could overstress generator insulation (dv/dt) limits, a conventional RC snubber was applied on the generator's terminals (case7g) and re-evaluated. As can be seen in Fig. 14, the generator terminal high-frequency oscillation is all but damped out.

IV. Ratings of Hybrid Grounding Components

A. Low-Resistance Grounding Resistor

The LRG resistor is intended for use with a relaying scheme that will detect ground faults and initiate automatic tripping with time delays generally limited to no more than a few seconds. For that reason, the LRG resistor is usually rated on the basis of intermittent rather than continuous duty. There are three ratings required to specify the LRG resistor.

1) Voltage: The voltage rating for the LRG resistor should be at least equal to the rated line-to-neutral voltage of the system.

2) Current Rating: The current rating is the magnitude of current that will flow immediately after a ground fault is applied to the system as limited by the resistance of the LRG resistor. Several system-related factors must be considered in selecting this initial current rating.

The initial magnitude of ground fault current must be sufficient to trigger operation of the least sensitive ground fault protective device(s) on the system supported by the generator while operating in the LRG mode. Residually connected feeder overcurrent relays and their associated current transformers are an obvious factor, but differential relays may often impose more strenuous limits.

- A separate concern exists for motor feeders where ground fault protection is provided by current-responsive relays associated with zero-sequence (or flux balance) current transformers. In these applications, the sensitivity of the relay and instrument transformer combination is generally fixed. A rule-of-thumb that has been applied for many years is the relay system should be able to detect faults in at least 90% of the stator winding of the protected motor. This translates into a minimum initial ground fault current magnitude of at least ten times the rated ground fault current sensitivity of the relay and current transformer.
- The initial magnitude of ground fault current generally should be limited to a reasonable value in order to minimize fault damage and potentially harmful voltage gradients in the industrial workplace. Resistor short time current ratings of 400 A. are very typical, and lower ratings would be preferable if the other two constraints could also be met. A total available ground fault current not exceeding 1000 amperes as a design criterion as set forth in [1] is usually achievable.

3) Short-Time Rating: Because the flow of current through the resistor causes an increase in its temperature above the initial (ambient) value, the resistance will also change resulting in a reduction in the actual current magnitude over time. Ultimately, if the current flows long enough, the temperature of the resistor will reach a maximum allowable value under the standards governing LRG resistors. The short-time rating of a LRG resistor is the maximum allowable time that rated resistor voltage can drive current through the resistor based on not exceeding that maximum allowable temperature rise. Because the LRG resistor application is designed in concert with protective functions that are expected to detect and automatically remove ground faults in a short period, most LRG resistors are specified with a 10-s short-time rating.

It should be noted that the standards governing LRG resistors do not provide for an inherent continuous current capacity in grounding resistors. That is, the standards assume that the initial resistor temperature is equal to the ambient temperature. Under some circumstances, a generator can drive a small third-harmonic circulating current that will flow through the generator neutral and its associated LRG resistor. If this harmonic current flow is sufficient to cause an appreciable steady-state temperature rise above ambient, special consideration should be given to the application as described in [6].

B. Grounding Transformer and Resistor (HRG)

The hybrid grounding system also includes a HRG resistor, or "distribution transformer" grounding package. The HRG portion should be sized to control transient overvoltages under arcing grounds fault conditions with the generator breaker open. To meet this criterion, the HRG resistive current must be greater than the capacitive charging current [7].

It is possible to measure the zero-sequence capacitive charging current in an existing system. This is the preferred method for existing (retrofit) generators, but new arc flash safety rules generally result in calculations being made instead based on capacitance measurements. For new installations, the usual preference is to design for a value that is believed to be above the maximum that the real system is expected to have and fine tune during commissioning.

The value most often chosen as the upper design current for the HRG portion of a hybrid scheme is 10 amperes. Through both analytical work and many years of experience [7], industry has gained confidence that generator stator ground faults limited to less than this threshold will not produce significant burning damage, and that there is essentially no risk of escalation to a multiphase fault at this level of grounding.

In most installations, the components that most influence the actual magnitude of distributed zero sequence charging current are the surge capacitors at the terminals of the generator, and in most instances, the current associated with these capacitors will be less than 2.5 amperes. Selecting a design criterion of 10 amperes for the HRG equipment therefore provides ample margins for voltage escalation control.

Once a decision has been made about the desired ground fault current magnitude, specifying the grounding transformer and resistor involves selecting seven component parameters. A dry type transformer is normally selected to avoid special fir retardant liquids and their requirements within enclosures.

1) Transformer Secondary Voltage: This rating is generally selected to equal the rating of the voltage-sensing relay used for protection in the high-resistance scheme. Traditionally, a 240-V rating has been chosen.

2) Transformer Primary Voltage: The primary voltage rating of the transformer, kV_g, must be equal to or greater than the maximum sustained line-to-neutral operating voltage of the generator. It may be simpler (and possibly more conservative) to select a primary voltage rating of the transformer that is equal to or greater than 110% of the rated generator line-to-neutral voltage.

It might be noted that some older references suggested selecting a transformer primary voltage rating equal to or slightly greater than the rated line-to-line generator voltage rating. The rationale behind that recommendation was that by selecting a higher transformer voltage rating, the possibility of ferroresonance would be completely avoided. More recent work [7] has shown that practice to be excessively conservative.

3) Transformer Thermal Rating: The transformer primary must be capable of withstanding the thermal stress associated with a ground fault at the design magnitude of 10 amperes.

If the hybrid grounding scheme will be used to initiate automatic tripping, it may be possible to apply an intermittent duty rating to the transformer. Traditionally, these applications have been designed for a 60-s duty (one minute) duty cycle (very conservative for a HHRG application). The actual derating factor, K, (from IEEE 32) required to account for this duty, depends on the technology selected for the transformer.

Therefore, the maximum continuous kVA rating of the transformer must be

$$\mathrm{kVA} = \mathrm{K} \times 10\ \mathrm{A} \times \mathrm{kV_g}.$$

4) Resistor Ohmic Rating: The secondary loading resistor used in the high-resistance package can be a more traditional power resistor rather than the stainless-steel or cast-iron plate form used as LRG resistors. As such, it is necessary to specify both an ohmic rating and a thermal dissipation, or power rating.

The ohmic rating of the resistor can be most easily visualized by recognizing that the principle involved in the high-resistance design is that the secondary loading resistor has an effective value in the primary equal to the actual second resistance multiplied by the square of the turns ratio of the transformer. Therefore, the required ohmic rating can be found by first determining the effective resistance required to achieve a 10-ampere ground fault current, and then dividing that value by the square of the transformer turns ratio (TTR)

$$\begin{aligned} \mathrm{R_{primary}} &= \mathrm{V_g/I_{pri}} = \mathrm{V_g}/10\ \mathrm{A} \\ \mathrm{R_{secondary}} &= \mathrm{R_{primary}}/(\mathrm{TTR})^2. \end{aligned}$$

A tapped resistor is frequently applied to fine tune to a specific generator.

5) Power Rating: Finally, a power rating must be specified for the secondary loading resistor. Since the power dissipated in the resistor is the power delivered by the transformer, the resistor must have a thermal rating equivalent to the thermal rating of the transformer, derated for short-time duty.

Advancements in resistor technology now make it possible to apply HRG without a transformer. For cost and space reasons, it may be beneficial to use a HRG resistor directly connected to the generator neutral without the transformer.

6) LRG Switching Device: This switching device can be either a breaker or a switch provided it has the following characteristics: 1) Must interrupt in the same time, or faster than the main generator breaker; 2) Must be able to interrupt the LRG maximum current; 3) Must have mechanical memory (same as main breaker; not electrical memory as a contactor would have); 4) Must have reliable control power consistent with the requirements of the generator switchgear.

7) Surge Protection: Wye point (generator neutral) surge protection is almost always recommended. The neutral switching device will generate a switching transient upon opening (due to current chopping) and compromise the insulation integrity at the wye point. This is particularly a concern for aging generators. Both magnitude (arrester) and dv/dt (surge capacitor or resistive-capacitive snubber) should be addressed. For older installations, with existing air-magnetic or oil circuit breakers, neutral breakers (with minimal chop characteristics), a simple arrester may be sufficient. Conversion of the existing terminal surge capacitors to RC snubbers is also recommended. A noninductive M.V. series resistor sized to match cable surge impedance serves this purpose.

V. Installation Experience to Date

There is growing awareness of the risks involved with leaving medium-voltage generators LRG only—the major industrial practice used for over 70 years in North America. The most notable industry to embrace re-evaluating their design criterion is the pulp and paper industry. The members of the Working Group are aware of about 50 generators that have been evaluated to date (in the pulp and paper, petro chem, and metals industries)—with the vast majority of them applying HHRGs. The HHRG concept lends itself readily to retrofitting exisiting systems that have extensive LRG systems - with minimal external system changes required.

Most of these HHRGs have been applied to generators rated between 7.5 MVA and 60 MVA at the 15-kV class level (11 kV; 12.47 kV. 13.8 kV). At least two generators were at or near “end-of-life” and were exhibiting poor insulation properties. The desire was to extend generator life a few years until they would be replaced—and minimize risk in the interim. Their ground fault protection systems were altered such that the preferred mode of operation for the generator itself was HRG only (with tripping). There was enough available ground fault current from other sources to meet the system needs. If a ground fault were to occur in the generator zone, the damage would be greatly limited such that a less costly field repair only would be required and not a complete rewind at an off-site repair facility. In the few instances where the generator and its local system operates as an island, the HHRG could easily and quickly insert the generator LRG to meet system needs.

A number of these installations were found to have a rather high total available ground fault current (with 2000 A to 3000 A total rather common). Even though the HHRG quickly reduced the internal generator ground fault current, the current from external sources through the generator breaker is enough to cause unacceptable damage (1384 A’s for 0.1 s will release as much energy at the fault point as 400 A’s will for several seconds inside the generator zone). In these cases, a ground system redesign was performed to significantly lower the available ground fault current and redesign the ground fault protection to accommodate the lower available levels. For these systems, the available energy to burn iron has been lowered to between 5% and 10% of what it was prior to the HHRG and ground system redesign.

A. HHRG—Functional Design

As HHRGs were repeatedly designed into real systems, it became apparent that the HHRG unit is much more than just an HRG design for a generator. It must work in conjunction with the entire generator main breaker and its protection and control circuits.

Its primary purpose is to minimize damage caused by internal ground faults in the generator. The HHRG system allows the system to be LRG for external ground faults but quickly reverts to HRG for internal generator ground faults. Here is how the design evolved to provide maximum flexibility and generator protection.

1) A generator is spun up mechanically by its prime mover. Once near full speed, the field is energized, and voltage is produced. If a ground fault occurs or is present before synchronization takes place with the generator being LRG, there will still be significant damage to the

generator–even though the main breaker is still open. For this reason, it is best to energize the generator in HRG mode only. To prevent the generator from being synchronized during this condition, a 59G relay function needs to be applied. It should trip and block synchronization for this condition. The 59G relay will also provide backup protection to the 51G relay when LRG.

2) If there is no ground fault present, then the system will allow the generator to be synchronized. Once synchronized, the HRG switching device should close very quickly after synchronization, converting the generator to LRG—as required by the external system.
3) When the generator is to be taken out of service for other than protective relay trips, the control switch on the main breaker should cause the main breaker to clear first then the HHRG switch to open very quickly afterward to avoid interrupting third harmonic current with the neutral switching device.
4) Generator neutral surge protection should always be applied.
5) A third harmonic filter needs to be applied within the controls circuits or the relay itself (59G and 51G) to prevent nuisance alarms/tripping.
6) If the generator sustains an internal fault–or any of its protective relays trip the generator offline, the 86 relay should cause the HHRG switching device to open simultaneously with the main breaker or slightly ahead of the main breaker.
7) If the generator develops weakened insulation in its life, risk due to extensive damage can be further reduced by choosing to operate the generator HRG only–provided there is enough available LRG current from other sources to properly ground the external system with reliable relay tripping for that condition. The controls in the HHRG should allow this condition to be manually selected.

VI. SUMMARY

The Working Group paper has shown that hybrid grounding offers the best solution to limiting damage from arcing ground faults while still providing the required level of ground fault current under all operating conditions. The paper also reported on the detailed design requirements for hybrid grounding to enable successful installation. The paper reported the results of EMTP studies that formed the bases for the recommended overvoltage protection. The paper also provided guidance in selection of equipment and fault protection required for hybrid grounding. Further investigation to evaluate the line-to-ground high-frequency resonance discovered is planned.

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