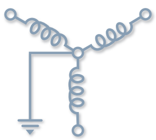
GARD

ASK THE EXPERTS



Resistance Grounding

Q&A

with industry experts

System Grounding – Definition and Different Types

What Is Grounding? The term "grounding" is commonly used in the electrical industry to mean both "equipment grounding" and "system grounding." "Equipment grounding" means the connection of earth ground to non-current-carrying conductive materials such as conduit, cable trays, junction boxes, enclosures, and motor frames. "System grounding" means the connection of earth ground to the neutral points of current-carrying conductors such as the neutral point of a circuit, a transformer, rotating machinery, or a system, either solidly or with a current-limiting device. Figure 1 illustrates the two types of grounding.

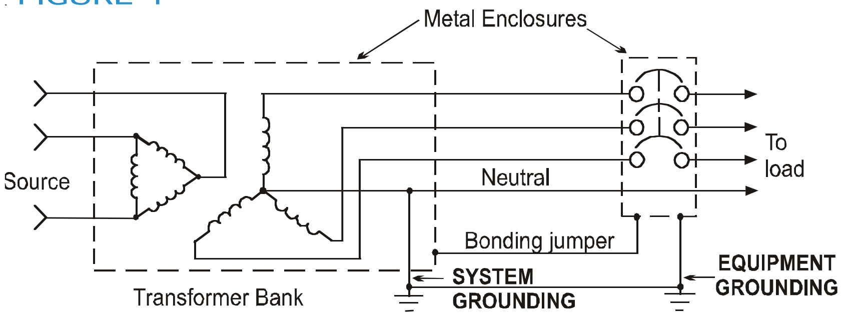
What Is a Grounded System? It is a system in which at least one conductor or point (usually the middle wire or neutral point of transformer or generator windings) is intentionally grounded, either solidly or through an impedance (IEEE Standard 142-1991 1.2).

The types of system grounding normally used in industrial and commercial power systems are solid grounding, low-resistance grounding, high-resistance grounding, and ungrounded.

What Is the Purpose of System Grounding? System grounding, or the intentional connection of a phase or neutral conductor to earth, is for the purpose of controlling the voltage to earth, or ground, within predictable limits. It also provides for a flow of current that will allow detection of an unwanted connection between system conductors and ground [a ground fault].

What Is a Ground Fault? A ground fault is an unwanted connection between the system conductors and ground. Ground faults often go unnoticed and cause havoc on plant production processes. Shutting down power and damaging equipment, ground faults disrupt the flow of products, leading to hours or even days of lost productivity. Undetected ground faults pose potential health and safety risks to

FIGURE 1



personnel. Ground faults can lead to safety hazards such as equipment malfunctions, fire, and electric shock.

Ground faults cause serious damage to equipment and to your processes. During a fault condition, equipment can be damaged and processes shut down, seriously affecting your bottom line.

I Have Over-Current Protection; Do I Need Additional Ground Fault Protection? The over-current protection will act to interrupt a circuit for currents for which it was designed and set to operate. However, some ground faults, particularly low-level arcing faults, will produce significant damage and create a fire-ignition source without ever reaching the level necessary to activate the over-current protective device.

Ungrounded 480-Volt System

Is there any danger in running a 480-volt ungrounded system in an old manufacturing plant? Should we ground the system?

The main danger in running a 480V ungrounded system is that, when a ground fault occurs, the only indication you will have is the three lights. The voltage on the ungrounded phases will increase to 480V with respect to ground, the voltage on the grounded conductor will be 0V with respect to ground. With this system, the only way to indicate the presence of a ground fault will be when two lights are of greater brilliance than the faulted phase light. In order to locate the ground fault, you must cycle every feeder breaker until all three lights appear at equal brilliance again. Once this is done, you continue down that feeder until you find the fault. This sounds very easy to do but proves to be very difficult in the real world.

The plant is normally ungrounded because it is a continuous operational plant, and isolation due to a ground fault should be avoided. This unfortunately translates to locating the ground fault. The only way to locate the ground fault is through cycling of the feeder breakers. This is what you are trying to avoid. So at the end of the day, the ground fault remains on the system, because there is no easy way to locate it. This is dangerous because any maintenance being performed on the system in a grounded state is subject to full line-to-line potential with respect to ground. The good news is that there is a solution. Ungrounded facilities can be easily converted to high-resistance grounded facilities, and the detection and location of a ground fault can accomplished without power interruption.

Floating Ground

What is the impact, if any, on moving equipment designed for a plant with a floating ground or ungrounded secondary to a plant that has a true grounded system? My thoughts are, it shouldn't really matter, but I could be mistaken.

In your case (from an ungrounded system to a solidly grounded system), no, it does not matter.

However, if you were going the other way (from an SG to a UNG system), then, yes, it would matter. During normal operation, it more than likely will not matter; however, during a ground fault it will. In an ungrounded system, the faulted phase voltage collapses to ground potential (or ~0V), and the unfaulted phases rise to phase-to-phase voltage with respect to ground. For example, a 480V system will have ~277V phase-to-ground voltage during normal operation, so it should work adequately. However, a ground fault on one phase makes its voltage go to 0V, and the other two phases will rise from 277V to 480V, phase-to-ground.

Since this doesn't happen on a solidly grounded system, anything rated only 300V phase-to-ground will explode, such as TVSSs, VFDs, meters, etc.

Ungrounded System

How can we measure earth fault and unbalanced current in an ungrounded system? And how do open delta PT and CB-CT function against faults? What is the effect on open delta PT?

In an ungrounded system, the phase-to-ground voltages of the three phases change when there is an earth fault. Under normal conditions, phase-to-ground voltage equals phase-to-phase voltage/1.73, and it is the same for the three phases. On the occurrence of an earth fault, the phase-to-ground voltage on the faulted phase is 0, and for the other two phases, it becomes equal to phase-to-phase voltage. The unbalance in phase-to-ground voltages is measured by YY-connected PTs and is used to indicate an earth fault. Open delta connected PTs are connected line-to-line, and do not see this change; they are unaffected, hence cannot be used for earth-fault detection.

Any energized conductor will have capacitance-to-ground, so in a three-phase system, there are three balanced distributed capacitances to ground due to natural conductor insulation. In an ungrounded system, these three capacitive-charging currents, Ico, are normally balanced, and there is no net ground current flow. In an earth fault, as the voltage-to-ground on the faulted phase goes to 0, the charging current in that phase also goes to 0; however, the charging current increases in the other two phases, which are driven at line-to-line voltage magnitude. And they add up to become 3 Ico. This charging current can be detected by a zero-sequence sensor (also called CB-CT) to indicate an earth fault. These currents are normally 0.1A to 2A in LV systems and up to 20A in MV systems.

Grounding System

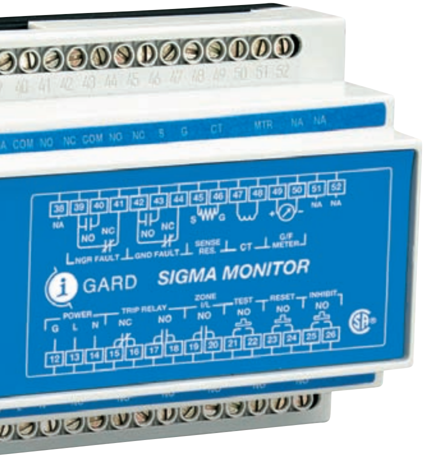
Why are HV and LV systems always solidly earthed, and an MV system resistance-earthed?

Solid earthing lowers the power conductor insulation requirements. The insulation level only needs to be suitable for the phase-to-ground voltage, not the line-to-line voltage. This has major cost benefit for insulators on transmission lines, cables, and lightning arrestor ratings. Solid earthing reduces the impedance in the return path in the event of a phase-to-ground fault. A fault current can then operate protective relays. With solid earthing, no transient over-voltages due to earth faults occur. So solid earthing is preferred for the HV systems.

The consequence of high ground-fault current with solid grounding is the very high energy dissipation at the fault point, which can be devas-

tating. For MV systems, insulation systems suitable for phase-to-phase voltage usually can be applied. The penalty for a higher insulation level at MV is not significant, and the benefit of low fault damage far outweighs the cost. For systems up to 5KV, in many jurisdictions, continuous operation of the faulted circuit is permitted if the current in the ground path can be 10A or less. This provides a major benefit to the power systems where trip-out due to a phase-to-ground fault cannot be tolerated and causes consequential loss due to power interruption.

LV systems have been solidly earthed to maximize the phase-to-ground-fault current so that circuit protective devices such as fuses and breakers will open. With modern electronic relays, detecting and locating ground faults can be done even when ground currents are small. Hence, in the industrial LV distribution systems, where a neutral conductor is often not required, the practice of limiting the earth-fault current to less than 10A allows power continuity. The fault can be detected, alarmed, and located using electronic relays. This allows the faulted feeder to be serviced when convenient. So LV three-phase, three-wire systems can be high resistance grounded; such



systems are permitted by the installation codes.

In most three-phase, four-wire LV systems, where neutral conductor is distributed, solid earthing of neutral is mandated. With a phase-to-ground fault, the neutral will elevate in potential when the LV system is resistance-grounded. So resistance grounding of LV three-phase, four-wire circuits is not used and often not permitted by codes.

Three-Phase Grounding

What voltage would you read if you placed your leads from L1, L2, or L3 to ground of a 460-volt AC, three-phase power system, Y-connected?

If the Y-connected system is solidly grounded, you will read 266V from line to ground. If the Y-connected system is ungrounded or high-resistance grounded and the system does not have a ground fault, you also read 266V. In the event that there is a fault on one phase, then the faulted phase will show low voltage near 0, and the other two phases will read near 460V.

Earth Fault

How can we detect earth fault on floating earthing system through core balance CT?

Any energized conductor will have capacitance to ground, so in a three-phase system, there are three balanced distributed capacitances to ground due to natural conductor insulation. In an ungrounded system, these three capacitive charging currents, Ico, are normally balanced, and there is no net ground current flow. In an earth fault, as the voltage to ground on the faulted phase goes to 0, the charging current in that phase also goes to 0, whereas the charging current increases in the other two phases, which are driven at line-to-line voltage magnitude. They add up to 3 Ico. This charging current can be detected by a zero-sequence sensor (also called CB-CT) to indicate earth fault. These currents normally are 0.1A to 2A in LV systems and up to 20A in MV systems.

Solid Grounding

Where is solid grounding more favored?

The only reason to solid ground is for line-to-neutral loads.

Delta System Grounding

1. How do you select a zigzag transformer grounding or Y/broken delta for delta system grounding?
2. How do you calculate kVA rating and voltage ratio of the zigzag transformer and Y/broken delta (with voltage system rating of 6.6kV and NGR rating of 125A)?
3. Which type of the zigzag transformer and Y/broken delta do you recommend?

1. A zigzag creates a neutral point. The advantage is that it is physically and electrically smaller than the Y/broken delta, so should be less expensive. The disadvantage is that there are only a couple of manufacturers, and UL/CSA is not always available. Also, zigzags only create neutral, so for a 4160V system, the neutral point would be 2400V. You could not add a 59 relay to this resistor or pulse to locate ground faults. With a Y/broken delta, the secondary can be any voltage you choose, so the resistor will be < 240V, you can use a relay and/or low-voltage CT, and you can pulse the low-voltage resistor to locate ground faults.

2. In your 6.6kV system and 125A, pulsing is not recommended. I suggest a zigzag transformer with a rating of 125A. The line-to-neutral voltage

(6.6kV/ 1.73=3815V) equals 476.9kVA. Since it is 125A, I am assuming that it is rated for only 10 seconds; you can de-rate the transformer by a factor of 10. The new rating is 476.9kVA / 10 = 50kVA.

3. It depends on your environment, but the oil type typically has much longer lifespan than the dry type and is better for harsh environments. However, it is more expensive and requires some maintenance.

Unbalanced Loads

As you know, in unbalanced three-phase systems, there would be a residual current, which would pass through the neutral of the system. In such systems, how can the grounding resistor affect the normal operation of the system? Is there any power delivery decrement to the load due to the limitation of the neutral current? Does the replacement of the system voltage neutral point affect the performance of the system?

In power systems with a resistor connected between neutral and ground, or resistance-grounded, there cannot be any line-to-neutral loads. The neutral is not allowed to be distributed, so there is no return path. Only three-phase and/or two-phase loads are permitted.

Earth Fault Protections on IT System

We are doing a project in Mexico in which the LV system is 440V three-phase, three-wire that is an IT earthed system. We have to supply some LV switchboards, MCCs, and PDBs. What kind of earth-fault protection system has to be provided? As far as I understand, in an IT system for the first ground fault only alarm and in the second (healthy phase) ground fault trip has to be provided. Can you please tell me the product for this?

IT systems (or ungrounded systems) have advantages and disadvantages that have been very well documented for several decades. The advantages are continuous operation (no downtime due to ground faults) and no arc flash hazards during ground faults. However, it impossible to effectively locate a ground fault, and large transient overvoltages may occur during intermittent (or arcing) ground faults or resonance conditions.

Many industries have retrofitted existing plants/facilities from ungrounded to high-resistance grounded systems, which provide a method to effectively locate ground faults and prevent transient over-voltages. In fact, one major manufacturing company with over 50 plants worldwide using HRG has a policy that each fault must be located in one hour.

To answer your question, I would recommend an HRG system. HRG systems have all of the advantages of an IT system and none of the disadvantages. An HRG system does exactly what you are looking for only better. It will alarm on the first ground fault and trip only one feeder if a second ground fault occurs by shunt-tripping the lesser priority feeder. (In an IT system, both feeders will trip since it is essentially a phase-phase fault.)

HRG and Single-Phase Loads

Why is there a requirement in NEC 250.36 about not having HRG on single-phase loads?

On most single-phase loads, normally lighting ballasts, the neutral terminal is designed to have very low voltage insulation with respect to ground. So if a ground fault occurs, the voltage of the neutral can elevate to 277V on a 480V system. The neutral on the single-phase loads are not rated for this elevated voltage. If the neutral breaks down to ground, then you have bypassed the resistor, and you are left with a solidly grounded system.

The other issue is that for single-phase loads, we only switch the phase conductor and not the neutral. So if maintenance is performed on a 277V ballast, and the switch is in the off position, the risk of a ground fault elevating the neutral to 277V exists. As there is no isolation for the neutral, the maintenance personnel are placed in a dangerous position.

Neutral Grounding Resistors – Design and Application

Neutral grounding resistors are similar to fuses in that they do nothing until something in the system goes wrong. Then, like fuses, they protect personnel and equipment from damage.

Damage comes from two factors: how long the fault lasts and the fault magnitude. Ground fault relays trip breakers and limit how long a fault lasts based on current. Neutral grounding resistors limit the fault magnitude.

To improve coordination between resistors and relays, and to avoid loss of protection, many neutral grounding resistors are now being designed with integral combination ground fault and monitoring relays. In distribution systems employing resistance grounding, the relay protects against ground faults and abnormal conditions in the path between system and ground possibly caused by loose or improper connections, corrosion, foreign objects, or missing or compromised ground wires.

Neutral grounding resistors limit the maximum fault current to a value which will not damage generating, distribution, or other associated equipment in the power system, yet allow sufficient flow of fault current to operate protective relays to clear the fault.

To ensure sufficient fault current is available to positively actuate the over-current relay and that the fault current does not decrease by more than 20% between ambient and the full operating temperature, it is recommended that the NGR element material to be specified have a temperature coefficient not greater than 0.0002 ohms/C.

The element material is critical in ensuring high operating performance of the neutral grounding resistor. The element material must be a special grade of electrical alloy with a low temperature coefficient of resistance. This prevents the resistance value from increasing significantly as the resistor operates through a wide temperature range. It also ensures a stable value of the fault current for proper metering and relaying.

There are two broad categories of resistance grounding: low-resistance grounding and high-resistance grounding.

In both types of grounding, the resistor is connected between the neutral of the transformer secondary, and the earth ground and is sized to ensure that the ground fault current limit is greater than the system's total capacitance-to-ground charging current.

Low-resistance grounding of the neutral limits the fault current to a high level (typically 50 amps or more) in order to operate protective fault clearing relays. These devices are then able to quickly clear the fault, usually within a few seconds.

The key reasons for limiting the fault current through resistance grounding are:

- To reduce burning/melting effects in faulted electrical equipment, such as switchgear, transformers, cables, and rotating machines.
- To reduce mechanical stresses in circuits and apparatus carrying fault currents.
- To reduce electric-shock hazards to personnel caused by stray ground-fault currents in the ground return path.
- To reduce arc blast or flash hazard to personnel who may have accidentally caused or who happen to be in close proximity to the fault current.
- To secure control of transient over-voltages.

Advantage of Neutral Earthed Resistor to Solidly Earthed Neutral

What is the advantage of neutral earthed resistors to solidly earthed neutrals when plants have high-voltage motors (3300V)? Which is best earthing method and why?

Solidly grounding systems have safety hazards that must be considered due to the very high ground-fault currents.

IEEE Std. 141-1993 (Red Book – Recommended Practice for Electric Power Distribution for Industrial Plants) Section 7.2.4 states, "A safety hazard exists for solidly grounded systems from the severe flash, arc burning, and blast hazard from any phase-to-ground fault." By placing a resistor between the neutral and ground, the ground-fault current is typically reduced to 5A for 3300V systems.

IEEE Std. 141-1993 (Red Book – Recommended Practice for Electric Power Distribution for Industrial Plants) Section 7.2.2 states, "There is no arc flash hazard, as there is with solidly grounded systems, since the fault current is limited to approximately 5A." So by limiting the ground fault to 5A, you have avoided the hazards with solidly grounded systems.

IEEE Std. 142-1991 (Green Book – Recommended Practice for Grounding of Industrial and Commercial Power Systems) Section 1.4.3 states, "The reasons for limiting the current by resistance grounding may be one or more of the following:

1. To reduce burning and melting effects in faulted electric equipment, such as switchgear, transformers, cables, and rotating machines.

2. To reduce mechanical stresses in circuits and apparatus carrying fault currents.

3. To reduce electric-shock hazards to personnel caused by stray ground-fault currents in the ground return path.

4. To reduce the arc blast or flash hazard to personnel who may have accidentally caused or who happen to be in close proximity to the ground fault.

5. To reduce the momentary line-voltage dip occasioned by the clearing of a ground fault.

6. To secure control of transient over-voltages while at the same time avoiding the shutdown of a

faulty circuit on the occurrence of the first ground fault (high-resistance grounding).

Resistance-Neutral-Grounding

A 2MVA, 480V, Y-Y generator set is connected to a 2.5MVA, 0.48/25V, Y-Y step-up transformer. The step-up transformer is connected to metal-clad switchgear. There are two sets of 2MVA generators and step-up transformers (same size). Three feeders are running out from the switchgear and feeding three step-down transformers (each capacity is 2MVA, 25/0.48V, Y-Y connected). Length of the feeder is about 2KM. These transformers are resistance-neutral, grounded, and feeding MCC's busbar (2000A, 65 KA I.C., 480V). This distribution system is a process unit. So I want to make a resistance-neutral ground at either the step-up transformer or the generator set for rising up the fault level of the whole system. What is the optimum choice of neutral grounding (at transformer or generator set) and why?

You can apply the neutral grounding resistor at the generator or at the LV winding of the step-up transformer; functionally, it is the same. Most people prefer to apply them at the generator. A continuously rated 55 ohm, 277V resistor would be sufficient, and it would allow you to just raise an alarm and continue operation.

NGR in Alternator

What is the advantage of using NGR to connect an alternator?

You are referring to an ungrounded system, which does not have a direct connection from neutral to ground. Because of this, there is no direct return path for a ground fault. The ground fault is then made up of only the system capacitive charging current, which is typically 2-3A for a 600V or less system. Due to this low ground fault current, no over-current protection device operates, and the ground fault is left on the system (continuous operation). The problem is an intermittent (or arcing) ground fault causes transient over-voltages due to the charging of the system capacitance.

IEEE Std. 242-2001 (Buff Book – Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems) Section 8.2.5 states, "If this ground fault is intermittent or allowed to continue, the system could be subjected to possible severe over-voltages to ground, which can be as high as six to eight times phase voltage. Such over-voltages can puncture insulation and result in additional ground faults. These over-voltages are caused by repetitive charging of the system capacitance or by resonance between the system capacitance and the inductance of equipment in the system."

IEEE Std. 141-1993 (Red Book – Recommended Practice for Electric Power Distribution for Industrial Plants) Section 7.2.1 states, "Accumulated operating experience indicates that, in general-purpose industrial power distribution systems, the over-voltage incidents associated with ungrounded operation reduce the useful life of insulation so that electric current and machine failures occur more frequently than they do on grounded power systems."

Another hazard is the inability to locate ground faults. So, in the 1950s a couple of end-users and manufacturers collaborated with a common goal of designing a system that has the only advantage of an ungrounded system (continuous operation) and without the disadvantages (severe transient over-voltages and inability to locate ground faults). The resolution was high-resistance grounding (HRG).

HRG systems allow for continuous operation by inserting a resistor between the neutral and ground, which allows for a direct return path for ground faults so that they can be easily found. The resistor also provides for discharging of the system capacitance to avoid severe transient over-voltages, ONLY IF the resistor current is higher than the system capacitive charging current, which is extremely easy to design and install.

Recently, HRG systems have been used to eliminate another hazard – arc flash hazards associated with ground faults on solidly grounded systems. There are other hazards that must be considered due to the very high ground-fault currents.

IEEE Std. 141-1993 (Red Book – Recommended Practice for Electric Power Distribution for Industrial Plants) Section 7.2.4 states, "A safety

hazard exists for solidly grounded systems from the severe flash, arc burning, and blast hazard from any phase-to-ground fault." By placing a resistor between the neutral and ground, the ground fault current is typically reduced to 5A for 600V or less systems.

IEEE Std. 141-1993 (Red Book – Recommended Practice for Electric Power Distribution for Industrial Plants) Section 7.2.2 states, "There is no arc flash hazard, as there is with solidly grounded systems, since the fault current is limited to approximately 5A." So, by limiting the ground fault to 5A, you have avoided the hazards with solidly grounded systems.

In addition, several generator manufacturers require resistance grounding since the generators are not rated for ground faults as they are oftentimes higher than three-phase faults. IEEE Std. 142-1991 (Green Book – Recommended Practice for Grounding of Industrial and Commercial Power Systems) Section 1.8.1 states, "Unlike a transformer ... a generator will usually have higher initial ground-fault current than three-phase fault current if the generator has a solidly grounded neutral. According to NEMA, the generator is required to withstand only the three-phase current level unless it is otherwise specified ..." This is due to very low zero-sequence impedance within the generator causing very high earth-fault currents. For generators 600V or below, this may not be an issue. However, it is usually always an issue as the voltage class increases.

The resistor also significantly reduces any circulating currents, which are typically triplen harmonics leading to overheating in the generator windings.

System Capacitive Charging Current

What do you mean by capacitive charging current? Is it the max generator current to create the magnetic field for your generator?

No. Capacitive charging current is current created by the system, almost solely from feeders and surge arrestors/capacitors. Think of a feeder, which is in this case is a cable in a conduit. If you physically look at the installation, the two (cable and conduit) are parallel to each other AND at different potentials: cable = phase voltage and conduit = ground potential. Both are separated by an insulating material. The result is a very big capacitor, at least in terms of physical size.

When you energize the system, current flows from the phase conductor to conduit (This isn't technically true; it actually causes a displacement of charge within the dielectric according to the academics. In the real world, it is called current.) through the dielectric; you just can't see it or measure it because it is happening all along the cable. It doesn't just flow in one spot; it is equally distributed along the cable.

So when you have an ungrounded system and a ground fault occurs, the phase voltages with respect to ground changes on the two unfaulted phases, e.g., from 277V to 480V. What happens to the charge within the feeder capacitance? It rises from 277V to 480V; we are now charging the capacitance.

In this case, we now can measure it because there is a single spot (the ground fault wire). So the easiest way to measure a system capacitive charging current is to unground the system, place a ground fault on the system through a fast-acting fuse (~10A or less), and measure the current in the wire. This is your system capacitive charging current since it returns to the other two phases through the insulating material, or dielectric. Just remember, this is 3*Ico; if you want just Ico, you must divide by 3.

Neutral Grounding Resistor

We are going to erect a new 22.1MW AC generator of 11kV with 1450A .What is the earth-fault current to limit? What rating of NGR should be used?

The key to resistance grounding is to know the system capacitive charging current. Once known, then you can decide high- or low-resistance grounding (good engineering practice sets 10A as the threshold – over 10A, then LRG; 10A or below, then HRG).

With that being said, you must determine your system and goal of grounding, i.e., system protection or generator protection. Are the generators unit-connected or bus-connected? If unit-connected (directly connected to either step-up or step-down transformer), then I would recommend 5A as the physical size of the 11kV system is small; so the system capacitive charging current is <5A.

If the generator is connected to a bus with distribution, then you must calculate the system capacitive charging current (see Tables 4.1 and 4.2 in our Application Guide "Ground Fault Protection on Ungrounded and High Resistance Grounded Systems" at www.i-gard.com/appguides.htm).

If the calculations are 10A or less, then I would recommend using 1.5X system capacitive charging current. If it is >10A, then I would recommend using a hybrid high-/low-resistance grounded system. In this case, the generator has two parallel grounding paths, one at 5A and one at 100A. For ground faults external to generator, then the ground-fault current is 100+5=105A. For generator internal ground faults, the 100A resistor path is tripped off-line with the generator main circuit breaker. Now the ground-fault current within the generator's stator winding is only 5A, significantly reducing the damage that occurs while the machine is coasting to a stop.

Grounding Resistor Sizing Considering the System Capacitive Charging Current

I realize that to have a proper NGR size for a 7.2kV mining project the let-through rated current of NGR should be equal to or greater than the system capacitive charging current. Based on the number of the feeders on the 7.2kV bus, am I supposed to add all connected feeder capacitive charging currents (3Ico) up and the sum of them will be the system capacitive charging current? If so, then there should be a kind of limitation in terms of the number of feeders with the associated long trailing cable that are going to be connected to the 7.2kV bus. My issue is an existing 7.2kV system with available 25A NGR that is going to be extended to have more feeders. We have come up with total system capacitive charging current around 50A (after summation of all prospective connected feeders capacitive charging currents). I guess the NGR has to be changed. Is that correct?

Ico is the net phase-to-ground capacitive charging current at line to neutral voltage. The 3Ico is caused by the net distributed capacitance at 7.2kV. So all the cable lengths have to be accounted for. If the 3Ico exceeds 25A, then the resistor let-through current should be increased as you have indicated.

NGR Sizing

I am a design engineer currently involved in designing of NGR for 33kV/6.6kV transformer (delta/star) configuration. The capacity is 40/50MVA .We had already installed two similar transformers of 35MVA capacity. Its NGR details are 76 ohms with 50A for 10 seconds.

We have a 25 HT motor and five distribution transformers, so what value do I need to select to limit any ground fault to a safe value?

I do not know the feeder distances or if there are any surge capacitors/arrestors. General rule of thumb is 1.5A/MVA. So with a 40/50MVA, the capacitive charging current is approx. 1.5A x 50 = 75A. This means that the 50A NGR will not dissipate the capacitive charging current, resulting in transient over-voltages. Unless the length of the feeders is short and there are no surge capacitors/arrestors, I would consider using a larger NGR, say 100A or 150A.

Earth Fault

A 20MVA, 30/6kV transformer is earthed with NGR to limit the earth-fault current to 220A for 5 seconds. After routine maintenance, the 6kV circuit breaker of the switchgear from the 6kV transformer secondary side was inserted, and immediately one of the phases made contact with the earth. This resulted in the melting of the internal metal body of the switchgear, and the NGR was burnt out. There is a current transformer on the neutral of 6kV connected to a restricted earth-fault relay with setting of 150A and an earth-fault relay with setting of 100A and tripping time of 100 milliseconds on the 30kV switchgear feeding the transformer. Neither of the relays protected the NGR from damage. Could you enlighten me on what went wrong with the relays and what is the correct protection required to avoid such occurrences in the future?

Review the CT location and connections of the restricted earth-fault relay. It is probably set up and connected only to respond to earth faults in the zone located between the CTs. The CTs are usually connected in differential mode. Typically, restricted earth-fault relays trip for earth faults in the transformer secondary windings. If this is the case, then it will explain why the restricted earth-fault relay did not trip.

The zero-sequence current caused by the earth fault in the 6kV side will appear as phase current on the 30kV primary side. The earth-fault relay on the 30kV side will not sense the earth fault in the 6kV side.

To provide protection for the NGR, the CT on the NGR should be connected to a current-sensing relay which will trip the 30kV breaker. This relay can be set for 150A and have a time delay of less than 5 seconds to protect the NGR. This relay will sense current going through the NGR and will thus respond to any ground fault on the 6kV. It will need to be time- and current-coordinated with other ground-fault relays on the 6kV distribution, such as the one on the 6kV breaker. Residually connected CTs or zero-sequence sensors can be applied for the 6kV breaker. The zone of protection will extend from the load side of the CTs. So if the fault was on the load side of these CTs associated with the 6kV breaker and set for 100A, 100 milliseconds, then it would have operated and protected. To allow the breaker to be included in this zone of protection, the residually connected CTs are mounted on the line side bushings of the breaker.

You can also examine if the 220A NGR let-through current is appropriate. A reduction in the let-through current will reduce potential damage on ground fault. For example, if it can be reduced to 100A and earth-fault relays adjusted to suit, then your exposure to damage will be reduced.

IDMT Protection in Low-Resistance Grounded System

What could be the normal earth-fault current in case of 6.6kV system having NGR restricting the maximum earth-fault current to 250A? Would it be as low as 30%, i.e., 75A? In such a case, it would not be possible to detect the earth fault by IDMT earth-fault relays connected in residual connection with the phase CTs (for transformer rating 20MVA) as the minimum relay setting would be 10% (approx. 200A). What is the alternative in such a case? Is it preferable to increase the earth-fault current value by reducing the resistance, or should I go for a separate neutral CT of lesser ratio instead of the residual connection?

Yes, it is possible to be that low. The biggest problem with residual-connected CTs or standard-issue CTs on circuit breakers is the minimum detection. In some cases, it can be as high as 20%; at least in your situation, it is only 10%. However, this is still a problem as 10% = 200A on a 250A NGR is an 80% pickup. Most times, the earth fault will quickly rise to full NGR value on 6.6kV systems, but not always. I would recommend using a zero-sequence CT for faulted feeder detection, a neutral CT for ground fault alarm, or both.

You may also consider a system ground monitor, such as our SIGMA relay. This relay is in parallel with the neutral conductor, NGR, and ground conductor. If an open or short circuit exists due to corrosion or loose connections, it will alarm indicating a grounding problem.

Grounding Resistor

Could you please tell me what's the general resistance range of grounding resistor for a 35kV zigzag grounded system? Which criterion should be considered?

Due to the voltage level, I would recommend low-resistance grounding. A typical resistor range at 34.5kV would be 400A to 1000A, depending on the total size of the system.

How do I calculate the mass of resistance required? I had calculated the resistance of NGR 100 ohms for 10 seconds for 400A current for 6.6kV system. Now I need to calculate the mass of resistance required considering using stainless steel ANSI 304 Grade. How do I calculate that?

Each company calculates this differently, and it is usually proprietary information. One thing to consider using 304 stainless steel, the resistivity increases due to heat rise. This means that the ground-fault current will start out at 400A and then drop to ~250A after 10 seconds. Hopefully, the decrease in current doesn't leave the pickup range of the relay!

Could you comment briefly on low-resistance grounded systems?

Low-resistance grounded systems are complicated. The principle is the same as HRG. A resistor is place between the neutral and ground to limit the fault current to a desired value for a length of time. This is mainly done to limit the damage at the point of fault and to allow coordination of the electrical system in order to isolate only the faulted circuit. There are a couple of items that you need to consider when using low-resistance grounding systems.

The first and by far the most frequent question I am asked is what to limit the fault current to? There is no formula to apple, no rule of thumb, and no parameters you can measure to determine this. You must consider your system protection and determine the minimum value of fault current you can detect. If, for example, the smallest breaker you have on your system is a 600A from with 600:5A current transformers. The minimum pickup on the protection relay for the ground fault is 20%. Then the minimum ground fault you can detect is 120A. However, if the main breaker is 2000A with 2000:5A current transformers, then 400A is needed to trip the main.

The second thing to consider is the type of steel you request for the grounding resistor. Many people today request stainless steel for the resistor element, and that it should comply with IEEE 32. The stainless steels used today are similar but not identical. The thing you have to be aware of is that most stainless steels have a temperature coefficient of resistivity. This is an indication of how the resistance changes with respect to temperature. IEEE 32 allows the temperature of the resistive element to change 760°C for a short-delay resistor. Following is a table of some common stainless steel materials, their temperature coefficients of resistivity, and the per-unit change in resistance after 10 seconds.

Stainless Steel	Temperature Coefficient of Resistivity(Ω/°C)	Per unit change in Resistance
AISI 430	0.00135	102.6%
AISI 304	0.001	76%
18SR	0.000397	30.2%
1JR	0.00012	9%

Voltage Limit Application of HRG

Up to how high a voltage can we use high-resistance grounding? Up to how low a voltage can we use high-resistance grounding? Can we use high-resistance grounding up to 240Y/139 system voltage? Neutral will not be used.

It mostly depends on application. Rule of thumb is that HRG can be and is used on most systems 5kV and less, and used on some 15kV systems. The reason is system capacitive charging current. As system voltage rises, so does capacitive current. The resistor current must be higher than the capacitive current. Good engineering practice limits the HRG current to 10A, and standards limit it to 25A. Anything above that is known as low-resistance grounding.

Although the NEC is unclear about the issue of using HRG on 240V, 3-W systems, there are no technical reasons to suggest it could not be used. In fact, I know several installations of HRGs on 240V systems.

Resistance and Resonance Grounding

When do I use and not use resistance and resonance grounding?

Just a quick note about resonance grounding: Resistance grounding is preferred in the U.S. mostly due to economics and complexity. Resistance grounding is a passive device that performs independent of system topology and frequency, whereas resonance grounding must adapt to system capacitance.

Resonance grounding uses an inductor to create an impedance to match the system capacitance impedance. In doing so, both components cancel, and the result is a small resistive ground-fault current.

Disadvantages of resonance grounding: 1) Typically the inductance is slightly larger to avoid a true resonancy condition (if not, an over-voltage condition will occur). 2) System capacitance continually changes as feeders are brought on- and offline (so monitoring system must be installed and inductor must be variable). 3) Costs for monitoring and inductor variability are high. 4) Physical size of inductor is significantly larger than resistor.

Resistance grounding offers a fixed ground-fault current independent of system topology. However, the fixed current must be larger than the system capacitive charging current. So a value of 100-400A is usually selected.

Charging Current Calculation

I am a design engineer. As per your view, for selecting the value of resistance, the system capacitive charging current is less than restricted current during single line-to-ground fault for resistance ground systems; otherwise, the system may experience transient over-voltages. Is there an easier way of estimating the value of system capacitive charging current? If yes, please suggest the process. Otherwise, how can I estimate the same current?

There are three ways to estimate the charging current (all of which are shown in our Application Guide "Ground Fault Protection on Ungrounded and High Resistance Grounded Systems" on our website at www.i-gard.com/appguides.htm):

1. You can quite easily measure it. When a protected phase-to-ground fault is applied on an ungrounded three-wire system which has balanced voltages to ground on the three phases, then the current in the fault is the net charging current. If the system is resistance-grounded, then the current through the resistor will need to be subtracted vectorially, as it is 90 degrees out of phase with the capacitive current.

2. You can estimate the distributed cable capacitance by the cable characteristics and add to it all other known capacitances to ground from other equipment. Then calculate the charging current in each phase, Ico; then 3*Ico will be the net charging current flow.

3. Apply rule of thumb. In general, on low-voltage systems up to 600V, the charging current is predictable to be less than 1A per 1000kVA of installed source capacity. For example, if the supply transformer is 3000kVA, then the expected charging current will be less than 3A. Add to this any exceptional capacitances to earth which may be present in devices such as surge suppression, etc.

Neutral Grounding Resistor Installed on Three Transformers Working in Parallel

A local utility system consists of three step-down transformers from 13.2kV to 4.16kV in parallel (delta/Y system) is solidly grounded. All transformers are feeding a common 5kV switchgear bus with two tie breakers and outgoing feeders vacuum circuit breakers. It was required to limit ground fault of the system considering limitations on cable shielding. Present L-G fault values are within 16kA to 20kA (depending on location). One solution would be to install NGR on existing transformers to L-G limit fault current below 1000A.

1. What are the pros and cons of that solution?

2. What type of difficulties could be faced when it comes to relay settings?

3. What would be more advisable: to install resistor on all three transformers or one common ground resistor?

1. The pros would be that you limit the fault current to 1000A. By limiting the fault current, you are allowed the time to isolate only the faulted feeder and allow all nonfaulted feeders to stay online.

The con to this type of system is the additive line-to-ground-fault current when a tie is closed. Instead of having 1000A, there are 2000A when two transformers are connected via a tie if you are paralleling.

If you are limiting the fault current to 1000A, the resistor will have to be rated for a short-duty cycle; 10 seconds would probably be the most common. It would be beneficial to specify the coefficient of resistivity when specifying the resistor material. Please look at our NGR Guide at www.i-gard.com for more information.

The other con is that you have to isolate the faulted circuit. Had you chosen to limit the fault current to 5A or 10A per transformer, then it may be possible to not trip at all during a ground fault.

2. Relay settings. The difficulty with relay settings would be that you would have to consider all possibilities. Are you paralleling? Ties open? Closed? Other than that, it should be fine.

3. The only way you can safely use one resistor is to connect all neutrals together and place one resistor on the common neutral to ground. I would never recommend this, since you can never treat the transformer as completely isolated and dead or safe because the neutral can elevate to 2400V during the presence of a ground fault without notice. You would have to use isolation switches in order to service the transformers, and that can be costly.

Grounding of Standby and Emergency Power Systems

Power Continuity Is Essential in many industrial and commercial installations where a trip-out due to ground fault can have serious economic or operational consequences. An arcing phase-to-ground fault can pose a flash hazard to the maintenance worker close to the fault and can totally destroy the equipment. Consequential down time adds to the economic loss. Four typical grounding methods for standby generators and emergency power systems are examined for these factors. High-resistance grounding provides the best power continuity, the best protection against arcing ground fault damage in low-voltage distribution systems (up to 1000V), and improves reliability and availability of standby and emergency power systems.

Standby and emergency systems are often configured to provide 600V or 480V, three-phase, four-wire service and are thus solidly grounded. In solidly grounded systems, the ground-fault currents are very high and damaging, and circuit protective devices have to operate to isolate the faulty circuit and interrupt the supply. This even applies to the emergency or standby system, such as a fire pump where the faulted circuit is tripped and the system de-energized with potentially disastrous consequences if there were no power during an emergency.

In most large commercial buildings and industrial installations, generators are used for standby power or for emergency. So when the distribution includes a distributed neutral, then by the electrical code, it must be solidly grounded. There are three ways in which this can be integrated:

1. Each generator neutral is independently grounded, and the neutrals are connected to-

gether with the normal source neutral that is also grounded and then distributed.

2. Generator neutrals are connected and grounded at one location. Normal supply neutral is also grounded, and the common neutral is distributed.

3. The generator common neutral is connected to the normal supply neutral and is grounded only at one location.

In all of the above, the ground-fault current has multiple paths through the ground and the neutral conductor to return to the source. Sensing ground-fault current becomes very difficult and may cause nuisance tripping, or ground faults may not be sensed at all.

Automatic transfer switches are used to supply the emergency load. A four-wire system necessitates the use of four pole devices with or without an overlapping neutral. The ground-fault protection and coordination becomes difficult and complex. Changing the distribution to three wires overcomes this. Connecting standby or emergency supply in a three-phase, three-wire system only requires three pole transfer switches, whereas four-wire distribution systems with the sources independently grounded require four pole transfer switches. In multiple-source distribution schemes where single grounding location of the neutral is used, the application of ground-fault protection becomes very complex and very expensive. False tripping can occur if circulating load neutral currents and the returning ground fault current are not properly sensed.

In most large commercial and industrial distribution systems at 600V, the single-phase 347V load is very limited (mostly for high-voltage lighting). The load is essentially three-phase motors and transformers; therefore, conversion of three-phase, four-wire to three-phase, three-wire is entirely practical and feasible. If the neutral is not distributed, it can be impedance-grounded. Only three-pole transfer switches are used. Small lighting transformers are used for the 347/600V or 120/208V distribution to service single phase loads. The generator bus is grounded through an artificial neutral, and the normal supply transformer neutral is grounded through high resistance. A three-pole automatic transfer switch feeds the essential load. Only alarm and indication of ground fault are required, and no tripping occurs in the main and standby switchboards. Fire pumps are usually three-wire loads, and conversion to three-wire distribution becomes an easy retrofit for existing installations.

HT Neutral Grounding Via Resistor

We have a 3.3kV system with only one generator grounded via a neutral earthed resistor and the other generators running in parallel. All three generators are provided with a neutral isolator, and at any time only one of them is connected. If the generator is offline, then we select the other to be connected to the neutral earth. Why is only one generator grounded and not more? Are the other generators floating, and if not, why not?

There are at least two main reasons why I would not recommend connecting all three neutrals to a common bus:

1. Circulating currents will flow within neutrals and generators. This will cause overheating of generators (resulting in a de-rating factor) and other problems common to harmonic issues.

2. If the neutral isolator is left closed while the generator main circuit breaker is open, then a shock hazard exists due to neutral voltage rise during ground faults.

The main reason why this grounding scheme is selected is to reduce costs. However, after factoring in the de-rating for each generator and the safety factor of losing a ground and going to an ungrounded system, your current system significantly costs more than an NGR, which is typically 3%-5% the price of a new generator.

4160V Generator Grounding

What is the grounding practice (solid or low-resistance) for three 4160V, 1000kW generators operating in parallel? This is a Level I (Life Safety) generator installation and requires high availability. The load is a 4160-

480V, 3000 kVA step-down transformer located 600 feet from the generators. I assume charging currents must be considered.

Regarding solidly grounding the generator, there are hazards that must be considered due to the very high ground-fault currents.

IEEE Std. 141-1993 (Red Book – Recommended Practice for Electric Power Distribution for Industrial Plants) Section 7.2.4 states, "A safety hazard exists for solidly grounded systems from the severe flash, arc burning, and blast hazard from any phase-to-ground fault." By placing a resistor between the neutral and ground, the ground-fault current is typically reduced to 5A only if the capacitive charging currents are <5A. Since the transformers are ~600ft from generators, the capacitive charging currents are probably <5A (please check for surge capacitors on generator terminals; if so, then charging current may be >5A). Also, since your application is high availability, I would recommend HRG (5A) on the generators to allow for operation during ground faults.

IEEE Std. 141-1993 (Red Book – Recommended Practice for Electric Power Distribution for Industrial Plants) Section 7.2.2 states, "There is no arc flash hazard, as there is with solidly grounded systems, since the fault current is limited to approximately 5A." So by limiting the ground fault to 5A, you have avoided the hazards with solidly grounded systems.

In addition, several generator manufacturers require resistance grounding as the generators are not rated for ground faults since they are oftentimes higher than three-phase faults. IEEE Std. 142-1991 (Green Book – Recommended Practice for Grounding of Industrial and Commercial Power Systems) Section 1.8.1 states, "Unlike a transformer ... a generator will usually have higher initial ground-fault current than three-phase fault current if the generator has a solidly grounded neutral. According to NEMA, the generator is required to withstand only the three-phase current level unless it is otherwise specified ..." This is due to very low zero-sequence impedance within the generator causing very high earth-fault currents.

The resistor also significantly reduces any circulating currents, which are typically triplen harmonics leading to overheating in the generator windings.

I typically recommend either resistance grounding each source OR derive a neutral on the paralleling bus via a zigzag transformer and resistance-grounding the derived neutral (which is not to be used for any loads or connected to anything except the resistor).

In addition, I would use HRG (5A) on the 480V systems as well. Our Application Guides on our website, www.i-gard.com, discuss this in detail.

Circuit Breaker Tripping During Paralleling of Generators

We have three 1000kW generators in parallel operation. When each generator runs in single operation, it operates normally. When we start to parallel the units, the generator circuit breaker trips off and indicates a ground fault. But when we disable the ground-fault protection of the circuit breakers, the generators run in parallel, taking load .Is it not advisable to use these circuit breakers with ground-fault protection for generator paralleling?

All generators create a third harmonic (and triplens) due to fractional pitch windings. Generator windings are fractionally pitched to reduce the number of end turns and to control harmonics. Each fractional pitch cancels that harmonic (i.e., a 2/3 pitch generator has very little third harmonic, a 4/5 pitch has very little fifth harmonic, and so on). Unfortunately, coil pitch cannot eliminate all harmonics simultaneously. As one is eliminated, others increase. These harmonics circulate between the system's neutrals and the associated grounding system.

Relays are detecting this circulating current and providing a trip signal. However, it is not a fundamental current. Hence, one resolution is to use a relay that only monitors fundamental current, i.e., ground faults. Although you have fixed the nuisance tripping problem, you still have circulating harmonic currents that cause overheating, so a de-rating factor must be applied. Generator manufacturers suggest matching all third harmonic voltages produced by each machine by installed same-pitch machines. Even with matched pitches, you will still have a circulating current.

So if your system is solidly grounded, the impedance is very low, and these harmonics cause significant damage within the generator windings in the form of heat. If high-resistance grounding is used, then the extra resistance in the circulating path reduces the harmonics to negligible levels. Also, most generators are not rated for ground faults (as they often exceed three-phase fault levels due to internal low zero-sequence impedance). So they require impedance grounding to reduce the ground fault below three-phase fault levels.

When synchronizing generators, there are several ways to ground the neutral. For example, each generator can have its own grounding system or one can be established on the synchronizing bus. If each generator has its own grounding system, then it can operate as a separately derived system. However, if all are synchronized, then each generator's available fault current is accumulative at the point of fault. For example, if each generator had a 5A NGR and there were two synchronized generators, then the total ground fault at the point of fault would be 5A x 2 = 10A. The total ground fault current is dependent upon the number of synchronized generators at the time of fault. This may lead to coordination issues.

Another method of grounding is at the synchronizing bus via neutral deriving transformer (i.e., zigzag transformer); DO NOT connect anything to the neutral of the generators. The advantage is that the total ground fault current is independent upon the number of synchronized generators and will be fixed.

In addition, since the generators' neutrals are disconnected, there cannot be any circulating currents. (Remember, although the generator neutrals are disconnected, the system is grounded via zigzag transformer.) However, if the synchronized bus is out of service, the generators cannot supply a load as they will be ungrounded.

Synchronization of Generators

For synchronizing generators of different ratings, what are the criteria for neutral grounding? What is floating neutral?

When synchronizing generators, there are several ways to ground the neutral. For example, each generator can have its own grounding system or one can be established on the synchronizing bus.

If each generator has its own grounding system, then it can operate as a separately derived system. However, if all are synchronized, then each generator's available fault current is accumulative at the point of fault. For example, if each generator had a 400A NGR and there were five synchronized generators, then the total ground fault at the point of fault would be 400A x 5 = 2000A. The total ground fault current is dependent upon the number of synchronized generators at the time of fault. This may lead to coordination issues.

Another method of grounding is at the synchronizing bus; DO NOT connect anything to the neutral of the generators. The advantage is that the total ground-fault current is independent of the number of synchronized generators and will be fixed. However, if the synchronized bus is out of service, the generators cannot supply a load as they will be ungrounded.

After determining the location of the grounding point(s), you must decide on type of grounding. The most common is either solidly grounded (SG) or resistance-grounded, either HRG or LRG. If 600V or below (HRG), the ground fault is typically left on the system until it is located, and then a decision is made to immediately shut down the faulted circuit to prevent a future hazard or allow it to remain on the system until a convenient time to repair the fault. If 5kV and below, it is either HRG or LRG, dependent upon the system capacitive charging current. Systems above 15kV are typically LRG and trip within 10 seconds.

The advantage of resistance-grounding versus solidly grounding is at least twofold (please refer to our Application Guides on our website for further discussion on RG vs. SG at www.i-gard.com). Regarding synchronization, all generators create a third harmonic and triplens due to fractional pitch windings. These harmonics circulate between the system's neutral and the associated grounding system. If SG is used, the impedance is very low, and the harmonics cause significant damage within the generator windings. If RG is used, the extra resistance reduces the harmonics to negligible levels.

Also, most generators are not rated for ground faults (as they often exceed three-phase fault levels due to internal low zero-sequence impedance). So they require impedance grounding to at least reduce the ground fault below three-phase fault levels.

Disconnect Switch for NGR

In our project, we have three generators (11kV). The neutrals of these generators are grounded separately through NGR. These generators can run in parallel. Our client requires a means of disconnecting be fitted in the neutral earthing connection at each generator, so that generators may be disconnected for maintenance. My question is do we really require these disconnect switches? If we do not install these switches, what problems can we face?

If the neutrals are connected together and then run through a common NGR, then yes. A disconnect switch is required as the common neutral bus voltage rise with respect to ground during a ground fault. This voltage could and will backfeed into the generator windings.

If each generator has its own NGR, I would suggest that a disconnect switch is not needed. With the generator's MCB open, an open circuit is created. There is no potential rise. If your client still wants a disconnect switch, then I would install one on the ground side (save money by using a 600V disc SW) of the NGR and ONLY open when generator MCB is open.

Earth Fault Protection of Alternator

We are operating a 625kVA DG set with a 500kW alternator; the star point of the alternator is solidly earthed, and we have placed a CT for earth-fault protection on the neutral wire in the downstream of the alternator in the ACB panel. Is this acceptable? How is the fault before the ST going to be protected?

The current transformer for earth-fault protection needs to be placed on the generator neutral-to-earth link so that any earth-fault current returning to the generator from the earth carried by this neutral-to-earth link will be seen. This should be the only path available from earth. So a second neutral earthing at any other location is not allowed; it will disable the earth-fault protection.

Earth faults anywhere in the system on the load or line side (including the generator winding) will be sensed, and the load neutral current will not be sensed as it will directly go to the generator.

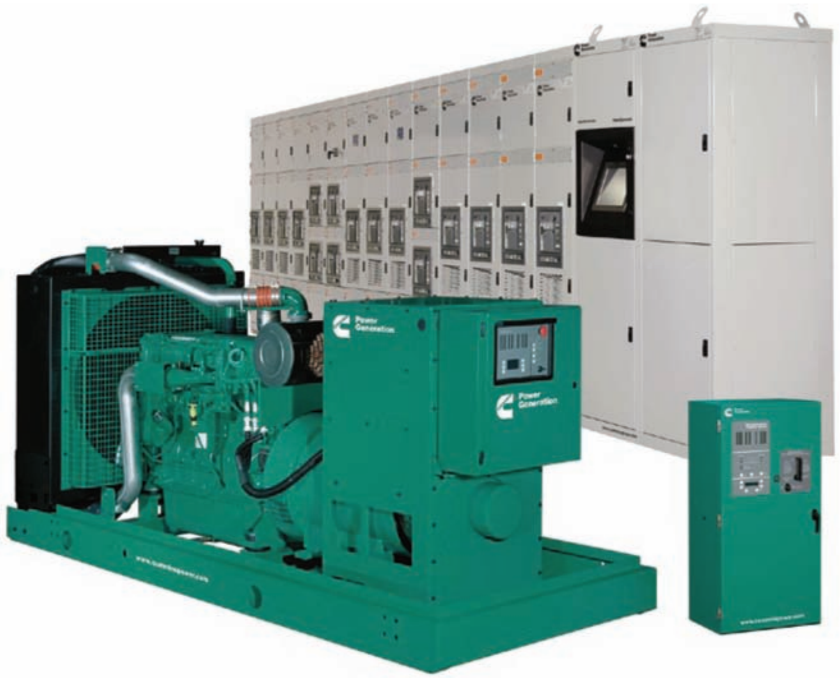
Switching Transients Causing Suppressor Failure

We have a 4160V/2.8 MW generator installation into a 5kV paralleling transfer switch. The utility feeder is from a 2500kVA grounded-Y transformer with no neutral. The new transfer switch feeds existing customer 5kV switchgear. The new generator is connected as the utility transformer with three-phase wires with a ground.

The neutral and the ground at the generator are not bonded. Twice now, when transferring from utility to generator in a closed transition mode, we have blown the "A" Phase suppressor on the first load breaker within the customer's switchgear. The PowerCon two-breaker transfer switch looks at voltage and frequency, and brings them into specs; then it looks at the phase angle difference between the two sources and will close in the generator breaker when the phase angle gets to 5 degrees or less.

They use a Woodward LS4 relay for this function. Since there is no customer neutral, should the generator neutral be bonded to the ground at the generator? Could the current connection setup during the closed transition operation be causing the suppressor to fail?

It appears that the 4160V utility supply is solidly grounded and, from your description, that the generator is ungrounded. It is possible that the Phase A surge-suppression device, which must have been selected for a solidly grounded system, will see phase-to-ground voltage swings after the utility breaker opens. This could cause the Phase A suppressor to blow. With the generator alone supplying the load, the current through the suppressor when it fails should be quite small perhaps 5A-10A. So I am surprised that it has blown twice. Please verify the current and the voltage rating of the device.



When the generator is supplying the load, you would probably want to retain the solidly grounded characteristics of the system. So you have two choices:

1. Connect the generator neutral to ground. This will maintain the phase voltage to ground before and after the transition and keep the system stable. The negative aspect is that, while utility and generators are running in parallel, there could be a small circulating current flow through the ground driven by the unbalance in phase voltage and triplen harmonics. Another problem is that the zero-sequence impedance of the generator is smaller than the positive sequence, so the phase-to-ground current will be high and could cause high fault damage at the point of ground fault.

2. You could have small resistance (NGR) between the generator neutral and ground, which will overcome both difficulties with solid grounding. I suggest that a resistor with let-through current of 400A or more will keep the generator phase-to-ground voltages in balance. A 10-second-rated resistor could be applied with suitable ground fault relay.

480V generator grounding

There are three 1100kW/480V/60Hz generators used in a MOPU (mobile operating production unit). We are adopting the IT system of earthing. Is it required to go for high-resistance grounding of the generators at the neutral point and leave the neutral floating?

The requirement depends upon your application. If it is used in mining, then yes; HRG systems are not only required but a resistance monitor (that continually monitors the resistor integrity) is also required by all mining codes and standards. If it is used in petroleum and/or chemical facilities, then yes; it is a requirement per good engineering practices, as HRG systems have been adopted as standard practice within petroleum and/or chemical facilities. If for any other application, then I would say yes based on the following:

In your question, "Is it required to go for high-resistance grounding of generators at the neutral point and leave the neutral floating?" I assume that you meant "…OR leave the neutral floating" (as in an ungrounded system) and that the generators will be paralleled.

In high-resistance grounding (HRG) systems, the neutral is not floating. During ground faults, it is held to line-to-neutral voltage with respect to ground, hence, eliminating the damaging transient over-voltages associated with ungrounded systems.

Other advantages with HRG are:

1. NO arc flash hazard – Resistor limits ground faults to 5A, thus, no arc flash hazards associated with solidly grounded systems. ~95% of all electrical faults are ground faults, so a simple resistor lowers your risk of personal injury or death (and equipment damage) by 95%!

2. NO damaging transient over-voltages – Ungrounded systems are subjected to severe transient over-voltages caused by intermittent ground faults and system capacitance.

3. Reduced third harmonics – When paralleling generators, a third harmonic current circulates between generators and ground. So adding a neutral resistor for each will significantly reduce this current to negligible levels.

4. Continuous operation – No shut-down required during ground faults, allowing production to continue.

5. Fault-locating feature – Pulsing system allows electrician to quickly locate ground fault.

6. Reduce ground-fault currents – Most generators have ground-fault currents above three-phase fault currents and are not rated for this higher fault current. So most manufacturers require impedance grounding to reduce the ground-fault current below three-phase fault current level.

HRG systems are the safest and least expensive system available today. IEEE supports this by saying, "A safety hazard exists for solidly grounded systems from the severe flash, arc burning, and blast hazard from any phase-to-ground fault." (IEEE Std. 141-1993, Red Book – Recommended Practice for Electric Power Distribution for Industrial Plants).

Ungrounded systems may experience damaging transient over-voltages and lack the ability to locate ground faults, presenting another danger to personnel.

Please remember that in HRG systems, the neutral cannot be distributed. So if you have loads requiring 277V, a small isolation transformer can be added to serve the 277V panel. The cost savings in not distributing the neutral, smaller ground wires, and no GF feature in the MCB will more than pay for the isolation transformer.

In summary, HRG saves money by using less copper (very expensive nowadays) and makes systems safer by eliminating hazards mentioned above.

Generator System Ground Connection

I have a 750kW generator set in an industrial plant. My question is, should I ground the neutral conductor at the generator terminals? If so, how should I size the GEC? I've heard sometimes this case is not considered a separately derived system, and the neutral should not be grounded.

Low-voltage generators should only be solidly grounded if the loads they feed are four-wire loads and must have a neutral. Generators that feed three-wire loads do not need to be solidly grounded. Instead they should be high-resistance grounded to limit ground-fault current. Generators are not braced for the ground-fault current that can occur when solidly grounded. Generators have higher ground-fault current than three-phase fault current. Transformers do not experience this phenomenon.

At any rate, assuming you must solidly ground the generator neutral for your application, here are your rules:

1. If the automatic transfer switch (ATS) is a three-pole type with sold neutral terminal, then you must not ground the generator neutral at the generator; instead, you must connect the generator neutral to the neutral terminal of the ATS,

which is in turn connected to the neutral of the normal power source transformer. The neutral of the transformer will be solidly grounded at the transformer, and this will be also the grounding point for the neutral of your generator. When you have a three-pole ATS with solid neutral, your four-wire generator is not a separately derived source.

2. If your ATS is either a three-pole with an overlapping neutral type or a four-pole type, then your generator will be a separately derived source. In this case, the neutrals of the transformer and generator will not be connected together, and you must ground the generator neutral at the generator.

3. If your ATS is three-pole only with no neutral terminal and your load is three-wire, then your generator is a separately derived source and you can ground the neutral at the generator. However, as above, standards such as NEMA MG 1-2003 (Motors and Generators, Section 32.34) and the IEEE Std. 142-1991 (Green Book – Recommended Practice for Grounding of Industrial and Commercial Power Systems, Section 1.8) recommend that generators not be solidly grounded unless they are rated for such duty (which they rarely are).

How to Determine Neutral Ground Resistor Value for a Power Station

We are in the process of installing a 3x5.5MW, 11kV, 50hz gas turbine generator. The star point of the alternator is to be grounded via a neutral ground resistor (NGR). Can you determine the value of the resistor and the ratio of the neutral current transformer?

I recommend using low-resistance grounding (LRG) due to the voltage and capacity. At 11kV and 3x5.5MW, the capacity (MVA) indicates the system is large (in terms of total length of all of the feeder cables, which are typically the greatest contributor to system capacitive charging current), and the voltage induces higher amounts of system capacitive charging current. The next largest contributor to system capacitive charging current is surge arrestors.

If this is a unit-connected generator, then I would recommend high-resistance grounded (10A-15A) to minimize fault damage ONLY IF there are very limited number of small feeders (resulting in a very low system capacitive charging current).

This can be estimated and measured. See our Application Guides, particularly "Ground Fault Protection on Ungrounded and High-Resistance Grounded Systems" for additional information at our website, www.i-gard.com. I would recommend 200A, as this is becoming the industry standard. The NGR is determined by taking the line-to-neutral voltage (11kV/1.73 = 6.36kV) divided by desired current (200A) to get ohms (31.8 ohms). Most people only allow the fault to be on the system for 10 seconds or less. So, the NGR would be rated for 200A/10 seconds. Just make sure that the protective relaying scheme clears the fault within 10 seconds. You can either use a 200:5 or a 100:5 ratio CT.

In general, the lower the fault current, the lower the damage at the fault. Therefore, it is desirable to keep the fault current as low as possible. If MV motors are being protected, then keeping the fault current low also helps in lowering the damage to the laminations at the fault point in the event of a fault in the stator winding. In Y-connected motor windings, the driving voltage for the ground fault reduces as the fault location moves closer to the star point; hence, the ground-fault relay must be set sensitive enough to detect the fault and sufficient amount of current must flow. This will also dictate how low you can go with the resistor let-through current.

Generator Grounding Point

I want to ask about generator grounding point and why we use it.

IEEE Std. 142-1991 (Green Book – Recommended Practice for Grounding of Industrial and Commercial Power Systems) Section 1.4.2 states, "Numerous advantages are attributed to grounded systems, including greater safety, freedom from excessive system over-voltages that can occur on ungrounded systems during arcing, resonant, or near-resonant ground faults, and easier detection and location of ground faults when they do occur."

OK, now that we have established why you need to ground the neutral, let's discuss how to ground the neutral. If you effectively ground the neutral, you have just replaced the hazards of ungrounded systems with new hazards in the form of arc flash/blast hazards associated with solidly grounded systems.

IEEE Std 141-1993 (Red Book – Recommended Practice for Electric Power Distribution for Industrial Plants) Section 7.2.4 states, "A safety hazard exists for solidly grounded systems from the severe flash, arc burning, and blast hazard from any phase-to-ground fault." For this reason, IEEE recommends resistance grounding.

IEEE Std. 142-1991 (Green Book – Recommended Practice for Grounding of Industrial and Commercial Power Systems) Section 1.4.3 states, "The reasons for limiting the current by resistance grounding may be one or more of the following:

1. To reduce burning and melting effects in faulted electric equipment, such as switchgear, transformers, cables, and rotating machines.
2. To reduce mechanical stresses in circuits and apparatus carrying fault currents.
3. To reduce electric-shock hazards to personnel caused by stray ground-fault currents in the ground return path.
4. To reduce the arc blast or flash hazard to personnel who may have accidentally caused or who happen to be in close proximity to the ground fault.
5. To reduce the momentary line-voltage dip occasioned by the clearing of a ground fault.
6. To secure control of transient over-voltages while at the same time avoiding the shutdown of a faulty circuit on the occurrence of the first ground fault (high-resistance grounding).

IEEE Std. 141-1993 (Red Book – Recommended Practice for Electric Power Distribution for Industrial Plants) Section 7.2.2 states, "There is no arc flash hazard, as there is with solidly grounded systems, since the fault current is limited to approximately 5A."

As you can see, it is best to not only ground the neutral, but ground through high-resistance (typically 5A) for all systems <600V and most systems >600V to 5kV. For systems >5kV, low-resistance grounding (typically 200A or 400A) is used.

Just a quick note about resonance grounding: Resistance grounding is preferred in the U.S. mostly due to economics and complexity. Resistance grounding is a passive device that performs independent of system topology and frequency, whereas resonance grounding must adapt to system capacitance.

Resonance grounding uses an inductor to create an impedance to match the system capacitance impedance. In doing so, both components cancel, and the result is a small resistive ground-fault current.

Disadvantages of resonance grounding: 1) Typically the inductance is slightly larger to avoid a true resonancy condition (if not, an over-voltage condition will occur). 2) System capacitance continually changes as feeders are brought on- and offline (so monitoring system must be installed and inductor must be variable). 3) Costs for monitoring and inductor variability are high. 4) Physical size of inductor is significantly larger than resistor.

Resistance grounding offers a fixed ground-fault current independent of system topology. However, the fixed current must be larger than the system capacitive charging current. So a value of 200A-400A is usually selected.

Zero Sequence Through YY

A 480V, Y-connected generator, resistively grounded, feeds a 480V Y - 4160V Y transformer, both neutrals solidly grounded. I understand that the YY transformer is not a ground source, yet zero-sequence currents will pass through the windings. In the event of a ground fault on the 4160V system, the ground current will try to get back to the generator neutral through the grounding resistor. The zero-sequence currents in the 480V windings must therefore be equal to the zero-sequence currents in the 4160V winding. What is not clear to me is the maximum voltage the grounding resistor will be subjected to; is it 277V or 2402V?

By solidly grounding both sides of the step-up transformer, you allow zero-sequence currents to flow. The voltage across the resistor will be 277V.

Arc Flash Hazard and High-Resistance Grounding

During a 20-Year electrical fault study, one of the world's largest consumer products company found that 98% of their electrical faults were ground faults. So why is this important? IEEE Std. 141-1993, 1993 (Red Book – Recommended Practice for Electric Power Distribution for Industrial Plants) Section 7.2.4 states, "A safety hazard exists for solidly grounded systems from the severe flash, arc burning, and blast hazard from any phase-to-ground fault."

The good news is that the same standard recommends a solution to resolve this issue. Section 7.2.2 of the IEEE Red Book states that when using high-resistance grounding, also known as HRG, "There is no arc flash hazard as there is with solidly grounded systems, since the fault current is limited to approximately 5A."

When it comes to minimizing arc flash/blast hazards, there is no silver bullet. There are many different tools that can be used. However, none of them offer the protection that HRG does for the price. While it is true that HRG does not protect against phase-to-phase faults, there is test data suggesting that it does significantly lower the hazard. Without question, HRG provides the most safety in terms of protection for the price when compared to any other mitigation tool. HRG lowers your risk by 98% by eliminating arc flash hazards during ground faults and reducing the hazards during phase-to-phase arcing faults when enclosed.

Even though the IEEE Red Book dates back to 1993, many people think that the only advantage to HRG is continuous operation during the first ground fault. Although this is true, there are many safety advantages as well. In addition to elimination of arc flash hazards associated with ground faults, it also prevents dangerous transient over-voltages associated with ungrounded systems.

High-resistance grounding was first developed over 50 years ago to solve the problems with ungrounded systems. During a ground fault, the arcing nature "charges" the system capacitance. When the arc extinguishes (possibly due to AC waveform – zero crossover), the charged system cannot dissipate the charge, so it holds it. When arc re-strikes, more charge is added to the system. This continues until the insulation breaks down at the weakest point in the system. So in the 1950s and 1960s, a group of people developed HRG to dissipate this charge between strikes and add the ability to locate a ground fault.

Nowadays, it is being used to replace solidly grounded systems as mentioned previously. Although it is the safest grounding method available today, there are design considerations that must be addressed. Fortunately, modern technology helps incorporate these considerations, making the design process straightforward.

There is a concern that the first ground will be left on the system and ignored. Since the zero-sequence current transformers identify the faulted feeder, the relay has the ability to begin a (user-programmable, usually in hours) timer when the ground fault first occurs. Unless the ground fault is removed or the timer is reset, the faulted feeder is shunt-tripped offline. The purpose is to continually remind maintenance personnel to either remove the ground fault or to reset the timer every so many hours.

In the event that a second ground fault occurs prior to removing the first ground fault, a phase-to-ground-to-phase or phase-to-phase fault can occur. When this occurred on the original HRG, it would cause both feeder circuit breakers and possibly the main circuit breaker to trip. However, the modern relay can be programmed to prevent this and only shunt-trip the lesser priority feeder, leaving the more important feeder online.

A major safety concern is the loss of neutral path, e.g., broken wire from source neutral to resistor or between resistor and ground, or even a bad or loose connection. The result is changing from a high-resistive grounded system to either an ungrounded or solidly grounded system without anyone knowing it! This would cause severe safety hazards. With modern technology, the neutral path from neutral to ground (including resistor) can be continuously monitored for integrity. If an open or short circuit occurs, the relay will alarm.

We have a 2000kVA, 6.6kV/433V transformer, dyn11 vector group, 6.21 % impedance HV CT 200/1; LV CT 3000/1. I wish to provide an earth-fault relay on HV as well as LV to protect against the earth fault. The LV of the transformer is solidly earthed. At what value should I set the relays, and what will be the value of earth-fault current in the case of earth fault on HV and LV sides. Some people suggest 10%. So what is the logic behind setting the relay at 10% of the CT primary rating?

If you set the relay to 0%, there will be nuisance tripping. So the question is how high do you set the relay to avoid tripping? Over the years, 10% was selected due to older mechanical relays protecting 90% of the windings. The trade-off is that there must be enough ground-fault current to trigger a relay without causing nuisance tripping. More information is available in protective relaying texts.

Presumably you have a shunt-trip device (52) on the HV side and the transformer feeds a switchboard with main LV breaker and some feeder breakers. Assuming an infinite source supplying the 6.6kV, then the maximum earth-fault current on the LV side will be ~43kA. Earth fault downstream from the main breaker will most likely involve arcing, thus the potential for very high arc flash and blast damage exists on solidly grounded systems.

This can be avoided one of three ways:

– Install high-resistance grounding (i-Gard Sleuth or DSP MKIII System) on the LV side. This will eliminate arc flash hazards for ground faults per IEEE and allow for continued operation. More information can be found on our website at www.i-gard.com/appguides.htm.

– The earth-fault protection can be maximized by lowering the tripping time of the earth-fault element on the feeder breakers. To reduce arc flash damage, zone-selective interlocking protection should be used. Example: The main breaker earth-fault element should coordinate with the downstream feeder earth-fault settings. For example, the feeder breaker earth-fault is set at 100A with 0.1 second delay; the main breaker earth-fault element is set at 200A at 0.2 second; and the earth-fault relay connected to the residually connected 3000/1 LV CTs monitoring the transformer output can be set at 300A or 500A at 0.3 seconds. Alternatively a CT can be mounted on the neutral-to-ground bus and connected to the earth-fault relay set at 300A at 0.3 seconds.

– The HV side will have phase over-current condition due to LV ground fault. The earth-fault function on the 6.6kV breaker feeding the transformer will need to be set to suit the HV side earthing. If the 6.6kV source is also solidly grounded then, residually connected 200/1 HV CTs can be set at 20A at 0.2 seconds to provide transformer primary winding earth-fault protection.

Zone-Selective Interlocking

How can zone-selective interlocking reduce the arc flash hazard from ground faults?

Arc flash hazard is quantified by the incident energy released in an arc flash at a particular location, expressed in calories per centimeter squared, as determined by an arc flash hazard analysis.

The incident energy is proportional to the length of time the arcing fault persists; hence, arc flash hazard can be reduced by lowering time delay settings of the phase and ground-fault over-current protective devices.

Continuity of service is important in many plants and is maximized by time-current coordination of the phase over-current devices and ground-fault devices. Where coordination does not exist, a breaker further upstream will trip first, knocking out more of the plant than was necessary. In extreme cases, the plant main breaker will trip. The drawback of time-current coordination is that extra time delay is required on upstream protection devices. More damage is tolerated from upstream arcing faults in the interests of service continuity.

Today, there is increased awareness of arc flash safety; engineers and electricians are taking a second look at these tripping time delays upstream in the distribution system. Arc flash safety now overrides service continuity on switchboards that require inspection while energized.

Zone-selective interlocking (ZSI), also known as zone-selective instantaneous protection (ZSIP), offers an excellent solution to this problem. It improves arc flash safety upstream in the plant distribution system without affecting service continuity.

ZSI is applied both to phase over-current devices (on the short-time protection function) and to ground-fault protective devices. It is available on electronic trip units and relays of circuit breakers.

With ZSI, a breaker which senses a fault will trip with no intentional time delay unless it receives a restraint signal from the breaker immediately downstream; if so restrained, the breaker will wait to time out before tripping. The downstream breaker only sends a restraint signal upstream if it also senses the fault, i.e., only for faults located downstream of both breakers. For the fault at point Y, the sub-feeder breaker will restrain the feeder breaker, and the feeder breaker will restrain the main breaker. Hence, the main and feeder will wait to time out. In the meantime, the sub-feeder breaker will clear the fault.

Zone-selective interlocking has been available for decades but has not been widely used because time-current coordination was deemed safe enough; damage upstream in the distribution system was a tolerable trade-off.

However, the push today for increased arc flash safety means that shorter trip times will be used. The cost of the ZSI twisted-pair control wiring between switchboards, panelboards, and motor control centers will now be considered a worthwhile investment because it improves arc flash safety without compromising service continuity.

Arc Flash and HRG

What about existing installations? Is it just by installing HRG that we solve possible risks? What else should we consider in an industrial installation?

HRG will limit ground-fault currents to a low value. You should have an arc flash hazard assessment performed so you know what the hazards are. You should acquire the appropriate PPE and insure you have good training programs and safety policies. This is just a start.

Are you kidding? How can you ensure your electrician ONLY drops his screwdriver between one phase and ground? The other two phases are only inches away! This is why IEEE 1584 and NFPA 70e base everything on three-phase bolted faults!

Correct; the other two phases are inches away. I go to many conferences, and I hear stories of people who are racking in breakers with a misaligned stub, causing a ground fault and an arc flash. Another case had someone testing voltage with a meter; the probe slipped and caused a ground fault and an arc flash. These arc flash incidents could have been avoided by a high-resistance grounded system. The operator, wearing the appropriate PPE, would have been alarmed that a ground fault occurred, rectified the situation, and most importantly hugged his wife and kids when he went home instead of the grim reality that did occur.

Now I cannot guarantee that electrical accidents will only affect a single phase and ground. There will be incidents that will involve other phases and ground or all three phases, but you should be wearing the appropriate PPE for that. We are not stating that you need to wear less PPE just because you have a high-resistance grounded system. I can guarantee that if you are working on an electrical system with no faults on it and accidentally contact a single phase to ground, you will walk away and the equipment can be put back into service. No one can guarantee the same thing with a solidly grounded system.

If I had the choice, I would prefer the added insurance with a high-resistance grounded system. But the choice in the end is yours, and you are gambling with a lot more than an opinion.

High-Resistance Grounding DC Power

Are there disadvantages to utilizing a high-resistance grounding scheme on 4000A 1000V DC switchgear? Does this class of DC gear have arc flash hazards the same as AC switchgear?

No, I do not see any disadvantages in high-resistance grounding 1000V DC switchgear.

Where would you apply the high-resistance grounding? Is center tap available to allow +/-500V? This would be the most convenient place to apply HRG, and you can monitor the system for ground faults.

Yes, arc flash hazard exists in the 1000V DC systems as well and can be quite severe because of low source impedance.

LV Feeder Protection

We have an arrangement of a 11kV/0.415kV transformer feeding an LV (415V) switchboard. Total load is around 280kVA, with most of the three-phase motors, started DOL with few on VSD. I am proposing to use a MCCB as incomer with shut trip. It will provide thermal/magnetic protection. Do you think earth-fault and under-voltage protections are necessary for this configuration? What is the best way of achieving earth-fault protection economically as well, e.g., CB-CT, residual CTs? What should be the settings for both earth-fault and under-voltage relays in that case?

Before you select earth-fault protection, you need to decide the system earthing for the 415V supply. Conventionally, it would be solidly grounded; but then you will have to trip when an earth fault happens and subject yourself to severe arc flash hazards. If instead you apply high-resistance earthing, then power flow to the motors can be maintained even when there is an earth fault and there are no arc flash hazards associated with ground faults. For the size of the transformer and the load, a 2A let-through, 230V, neutral-earthing resistor would be sufficient. Occurrence of an earth fault can now be detected by simply monitoring the voltage to ground from each phase or by monitoring the current through the resistor by a sensor and an earth-fault relay. This relay can be set for 1A pickup. This would be quite economical. To get more information on high-resistance grounding, you can get technical literature from www.i-gard.com.

If you decide not to use high-resistance grounding and instead opt for solid grounding, then you could choose an earth-fault relay setting of 100A. This can be obtained through an earth-fault element on the incomer MCCB, which has built-in CTs and a loose neutral sensor. Time delay setting should be as low as possible to reduce the fault damage, about 0.1 to 0.5 seconds. There are time/current coordination issues with load-side protective devices that you will need to consider to avoid nuisance tripping the MCCB, another problem with SG systems.

The under-voltage function needs to be set for 80% of the nominal. With a large percentage of the loads being motors under single-phasing conditions, the open phase will regenerate and would be difficult to detect if under-voltage setting is below 80%.

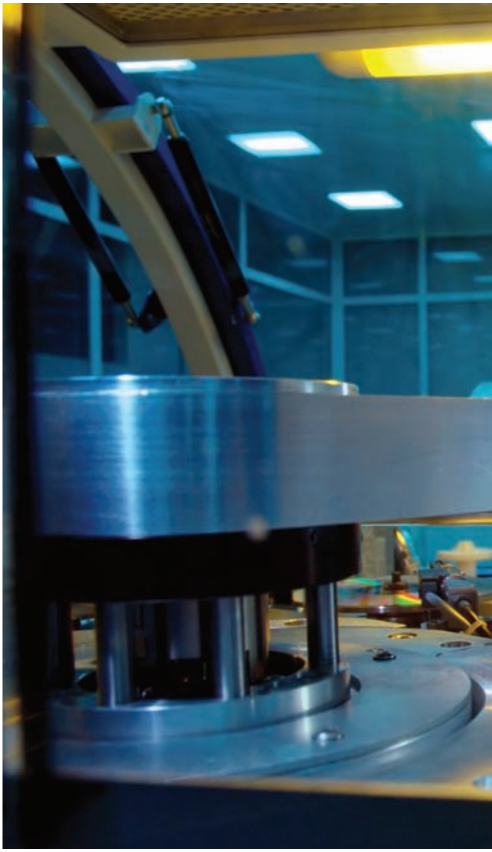
Arc Flash and HRG

I would say that use of HRG will greatly reduce the risk of arcing faults on a 480V system, since the large majority of faults begin life as a line-to-ground fault. But what the others are saying is that it does NOT reduce the hazard that can exist for a three-phase arcing fault, so the required PPE is still based on the worst-case three-phase fault. This is pretty clearly addressed in IEEE 1584. There is still an arc flash hazard since the HRG has no effect on phase-phase or three-phase faults.

You are correct. Arc flash calculations are based on the arc flash current, time, distance, and bolted fault data. There is no way that the grounding system can reduce the arc flash hazard analysis.

The only thing a high-resistance grounding system can do is limit the fault current of a single phase-to-ground fault. Now that the fault current is limited to 5A, the probability of that fault escalating to a phase-to-phase fault or a three-phase fault is greatly reduced. In contrast, a single phase-to-ground fault in a solidly grounded system has the highest probability of escalating to a three-phase fault.

The Red Book states that most faults in the electrical industry start as ground faults. The probability of that fault escalating to a three-phase fault in a solidly grounded system is high; the probability of that fault escalating to a three-phase fault in a high-resistance grounded system is low. If Section 7.2.2 is interpreted this way, then the statement is true.



Low- and Medium-Voltage Distribution Systems

Electrical Distribution Systems can generally be classified as low-voltage (208 volts to 4,160 volts), medium-voltage (4,160 volts to 13,800 volts), and high-voltage (above 13,800 volts). You can broadly classify medium-voltage (MV) grounding (earthing) systems into four categories: solidly grounded, low-resistance grounded (LRG), high-resistance

grounded (HRG), and insulated neutral (ungrounded) systems.

With the solidly grounded system, there is no intentional impedance in the neutral-to-earth path. Instead, the neutral is solidly connected to earth. The phase-to-ground voltage remains constant during a ground fault, and there are very high fault-current flows, resulting in extensive damage. The protective device closest to the fault must trip and isolate the circuit as fast as possible. The cost of repair is high due to extensive emergency repairs. If the fault is in a rotating machine, then there is a high possibility of core damage and replacement costs. Also, the cost associated with the downtime can be enormous.

With LRG, the ground-fault current is controlled and normally limited to between 25A and 1000A. The voltage to ground on the unfaulted phases increases to the phase-to-phase voltage level, so you must use adequately rated insulation systems and surge-suppression devices. Also, the ground fault must be detected and isolated. Since the ground fault current is smaller and controlled, ground-fault relaying still has the requirement of fast tripping. But better time/current coordination can be achieved with this type of grounding system. Damage at the fault point is also reduced, and thus the maintenance and repair costs are also reduced. The neutral-grounding resistor needs to be short-time-rated (typically 10-30 seconds), as the fault will be cleared by the protective relay closest to the fault.

With HRG, the ground-fault current is in the 10A range. The intention here is to allow the system to operate without tripping even with a phase-to-ground fault on one phase. When a ground fault does occur, only an alarm is raised. This permits time to locate the fault while power continuity is maintained. This also allows repairs to be done at a scheduled shut-down of the faulty equipment. Damage at the fault location is small.

With the insulated-neutral (ungrounded) system, there is no intentional connection of the system to ground. In effect, the three phases of the system float. When a ground fault occurs, the fault current is contributed by the system capacitance to earth on the unfaulted phases. This is usually small, and the system can be operated without tripping. Since the system is floating, if the ground fault is an arcing or intermittent type, there is possibility of substantial transient over-voltages, which can be six to eight times the phase voltage. These transients often cause a subsequent failure elsewhere and thus raise the possibility of a phase-to-earth-to-phase fault, leading to high fault current and extensive damage.

For station service at distribution voltages of less than 15kV, power continuity is very important. Here, you would size the neutral grounding resistor so that the let-through ground-fault current is higher than the net current from the distributed capacitance. If the let-through ground fault current is less than 10A, then this would be high-resistance grounding. If this current were more than 10A, then it would be low-resistance grounding.

It is rare to have station service voltage that is higher than 15kV. If the voltage is higher than this, then the same rule as noted above would apply, except the fault should be detected and isolated by tripping the faulted feeder at the closest protective device.

More recently, hybrid grounding has been proposed. Here, a current-limiting device is in parallel with a resistor, such as a resistor of low resistance and the other of high resistance (5A). In the event of an internal earth fault in the stator winding of the generator, a fast-acting generator ground-differential relay opens the current-limiting device (in this case, the low-resistance grounding path), allowing the high-resistance (5A let-through) resistor to control and lower the fault current, thus reducing the stator damage caused by the internal ground fault after the generator has been isolated and while it is slowing down. Without this reduction of current, the generator would continue to feed energy in to the fault while it is coming to a stop. The result would be extensive stator iron damage at the ground fault location.

Neutral Earthing Resistor

1. What is your guidance in choosing resistance-neutral earthing when we have to use low or high resistance?

2. How do you define current protection of resistance earthing?

High-resistance earthing is used on three-phase, three-wire distribution systems up to 5kV (line-to-line), where:

(a) you want to maintain service continuity upon earth fault (i.e., do not trip faulted feeder on earth fault);

(b) the system charging current is less than 6A;

(c) the neutral-earthing resistor is sized for an amperage between 1A-10A. Typically 2A-5A is used for system voltages up to 690V; 5A-10A is used for system voltages above 690V, up to 5kV; and

(d) the neutral-earthing resistor let-through current is equal to or higher than the system charging current.

Low-resistance earthing is used on medium-voltage systems above 1kV, where the system charging current is higher than 6A. Distribution systems above 5kV must not be high-resistance-earthed, even if the charging current is less than 6A; the sole exception to this rule is a utility generator-transformer unit, where a 15kV generator generates utility power and feeds directly a step-up transformer for transmission – in this case, the 15kV system charging current is so low that high resistance grounding with a 5A-10A resistor may be used. Industrial distribution systems above 5kV must trip on earth fault, in order to avoid escalation of the earth fault into a phase-to-phase fault at the point of fault. The system charging current and the voltage to ground are large enough that the risk of escalation is too high. So low-resistance earthing is used to limit the earth-fault current, typically within the range of 50A-400A to allow for the earth fault to be sensed and selectively tripped offline by an earth-fault relay. High current (400A) must be used if residually connected CTs are used to sense the earth fault for the earth-fault relay. Lower currents can be used (50-200 A) if a core-balance CT is used for input to a relay with sensitive earth-fault feature. Low-resistance earthing is better than solid earthing (TN) because it limits the earth-fault current to a safe value, thereby reducing arc flash incidents and equipment damage on earth fault.

To protect star-connected motors, a feeder earth-fault relay should be set to trip at 10%-20% of resistor let-through current. 10% is the minimum but may lead to nuisance tripping; this can be increased to 20% in case nuisance tripping occurs – this can be easily adjusted at commissioning time. This setting allows capture of earth fault that occur in the stator winding close to the neutral point (within 10%-20%), where the voltage to drive the earth fault will only be 10%-20% of rated, hence the current will be 10%-20% of resistor let-through rating. The trip setting should be equal to or higher than the system charging current to avoid nuisance tripping of unfaulted feeders whose earth-fault sensors will sense each of their own feeder's contribution to system charging current during earth faults elsewhere in the system. So if the system charging current on a 15kV system is 15A, then the minimum earth fault pickup setting could be 20A, using a core-balance CT and sensitive earth-fault relay. Then the resistor should be 10 times this, or 200A.

To protect delta-connected transformers, the minimum fault current for a delta winding is 50%, because no matter where the earth fault is located in the winding, it will always be between 50%-100% of the line-neutral voltage; hence, the earth-fault current will be at least 50% of resistor let-through current. An earth-fault pickup setting of 20%-50% is acceptable.

For selectivity, earth-fault pickup settings over the range 20%-60% of resistor let-through current on feeders are acceptable.

For backup protection, earth-fault pickup settings over the range 50%-80% of resistor let-through current on the earthing resistor are acceptable.

For high-resistance grounding, neutral earthing resistors must be continuous-duty-rated. ¶

For low-resistance grounding, neutral earthing resistors are rated for 10-second duty. Earth faults are tripped offline between 100 milliseconds to 1 second.

On parallel generators, use a single neutral earthing resistor connected to the paralleling bus through a zigzag earthing transformer.

Grounding for Co-Generation in 13,8kV

I would like to know about the concept of grounding for generators in 13,2 kV or 13,8kV; in this case, should the practice be neutral-resistance grounding system or may it be solidly grounded?

IEEE Std. 142-1991 (Green Book – Recommended Practice for Grounding of Industrial and Commercial Power Systems) gives some information about this case; is this the formal and the final position?

Medium-voltage industrial generators should be low-resistance grounded, not solidly grounded. See Section 1.8 in IEEE Std. 142-1991 (Green Book – Recommended Practice for Grounding of Industrial and Commercial Power Systems) for a good discussion of generator grounding. Another good source for medium-voltage generator grounding and protection is Section 12.4 of the IEEE Std. 242-2001 (Buff Book – Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems). Solidly grounded generators typically experience 20%-50% higher fault current under ground faults than under three-phase faults. The same is not true for transformers. Yet generators are normally braced only to withstand three-phase bolted faults, not ground faults. Generators should not be solidly grounded unless they are rated for solid grounding duty, regardless of voltage level. Medium-voltage generators are quite expensive and have a long delivery time; their loads are always three-wire, lending themselves to resistance grounding. To limit ground-fault current, they are usually low-resistance-grounded with a neutral grounding resistor rated 200A-400A, 10 seconds. To avoid stator iron burning damage during a stator ground fault in a generator, a new technique of MV generator protection, called hybrid grounding, has been developed recently. In addition to the 200-400A NGR, a 10A continuous-duty NGR is connected to the generator neutral. Upon generator ground fault, the affected generator is immediately tripped off-line from the large NGR; the stored magnetic energy within the generator is safely discharged through the 10A NGR without damaging the stator. This ground-fault scheme requires a 51N ground-fault relay on each feeder, and an 87GD directional-ground differential relay on the generator. The 87GD relay distinguishes between internal and external ground faults. For external ground faults, the 51N feeder relay selectively trips the faulted feeder. For internal ground faults, the 87GD relay trips the faulted generator offline. Backup ground-fault protection is provided with a 51G relay on the large NGR, coordinated to allow the primary 87GD and 51N relays to trip first. A failure of the primary relay causes the NGR 51G relay to trip the generator(s) offline, de-energizing the distribution system. For more details of the hybrid grounding scheme, refer to the following four-part article: *IEEE Transactions on Industry Applications*, Jan/Feb 2004, Vol. 40, No. 1, "Ground and Ground Fault Protection of Multiple Generator Installations on Medium-Voltage Industrial and Commercial Power Systems," by Prafulla Pillai, et al.

Harmonics

How are harmonics produced in the HT system inside a plant? We use convertors and rectifiers on LT side only. How do these harmonics interact with the HT motors?

HT and LT stand for high tension and low tension, also known as medium voltage (MV) and low voltage (LV), respectively. Typically delta-Y transformers provide power to the LV system from the MV system. Triplen harmonic currents on the LV side get trapped in the delta winding (at least the balanced portion of the triplen harmonics do) and do not flow in the MV side. Non-triplen harmonic currents (5th, 7th, 11th, 13th, etc.) pass right through the transformers and flow in the MV side. These can interact with the MV motors in two ways: If there are power factor correction capacitors on the motors, then the harmonic currents can be attracted to the capacitors instead of the utility source. Harmonic resonance can occur, and the power factor correction capacitors can overheat, degrade, and lose their capacitance over time. Or excessive harmonic currents can cause excessive harmonic voltage distortion through the impedance of the MV distribution system, causing the motors to overheat. This does not always occur, but when it does, solutions include adding harmonic filters at the main LV switchboards to keep the non-triplen harmonics from getting onto the MV system or using "anti-resonant" power factor correction capacitors, which have de-tuning reactors to prevent harmonic resonance between the capacitors and the power source impedance.

High-Resistance Grounding

Transient over-voltages on ungrounded electrical systems due to intermittent ground fault exist. The high-resistance grounding reduces the potential over-voltage significantly. But what about surge suppressors? Do they protect a medium-voltage system from the over-voltage? Do they protect the system with a high-resistance grounding when the grounding resistance is not selected correctly and a capacitive charging current is several times higher than the resistor current?

The transient over-voltage caused by intermittent ground fault on an ungrounded system is due to the distributed capacitances to ground on the three phases. The magnitude can be 5 to 6 times phase-to-phase voltage. The neutral grounding resistor allows this charge to be dissipated and holds the neutral above ground at phase-to-neutral voltage, allowing the voltage to ground on the unfaulted phases to increase from phase-to-neutral value to phase-to-phase value; this will exist continuously as long as the fault is present so there is no over-voltage beyond the phase-to-phase voltage magnitude. However, very short duration transients can still occur and exist on the three phases such as those caused by the lightning strikes and switching.

Surge suppressors are normally intended to clip and absorb very short duration (millisecond to microsecond) transient over-voltages such as those caused by lightning strikes and switching. They cannot handle continuous excessive voltage. Their clipping voltage is also quite high. It could be more than 1.5 times the normal steady state peak voltage. So when TVSSs are applied on HRG systems, they need to be rated for line-to-line voltage. They will then clip transients above their continuous rating.

Sizing of NER on Medium-Voltage System

This is related to sizing of a neutral earthing resistor for 33kV system. The main power transformer rating is 132/33kV, 25/31.5MVA YNd1. To introduce system earthing in 33kV side, an earthing transformer is introduced. Rating of the earthing transformer is 33/0.433kV, 315kVA, ZNy11. To have resistance-grounded earthing, NER is introduced in the neutral path of earthing transformer. We would like to restrict the earth-fault current to 550A.

The question is, while determining the resistance value of NER, should we consider total impedance in the circuit from source right up to the fault point in 33kV system? What will be the impact if we neglect the zero-sequence impedance of the power transformer and earthing transformer?

Yes, the total ground-fault current is dependent upon line-to-neutral voltage and impedance of entire return path, which includes everything you mentioned.

Experience shows that at medium voltage (and within in industrial setting), the voltage across the earthing resistor quickly rises to line-to-neutral voltage, indicating that the impedance of the return path and transformers is relatively small compared to impedance of earthing resistor. So yes, it should be considered, but typically, it has a small impact.

Selection Criteria for Medium-Voltage NGR

I am sizing an NGR for a 132kV/11kV, Dyn11 40 MVA transformer. The biggest motor connected in the 11kV system is a 5.3MW slip-ring motor and the smallest one is 300kW. I am looking for a low-resistance earthing system. What should be the current limiting value for the NGR? How it is arrived at? What are the criteria?

As you suggested, I recommend using low-resistance grounding (LRG) due to the voltage and capacity. At 11kV and 40MVA, the capacity (MVA) indicates the system is large (in terms of total length of all of the feeder cables, which are typically the greatest contributor to system capacitive charging current), and the voltage induces higher amounts of system capacitive charging current. The next largest contributor to system capacitive charging current is surge arrestors/capacitors on generators.

This can be estimated and measured; for additional information, see our Application Guides, particularly "Ground Fault Protection on Ungrounded and High-Resistance Grounded Systems," on our website, www.i-gard.com. I would recommend 200A, as this is becoming the industry standard. The NGR is determined by taking the line-to-neutral voltage (11kV/1.73 = 6.36kV) divided by desired current (200A) to get ohms (31.8 ohms). Most people only allow the fault to be on the system for 10 seconds or less. So the NGR would be rated for 200A/10 seconds. Just make sure that the protective relaying scheme clears the fault within 10 seconds.

In general, the lower the fault current, the lower the damage at the fault. Therefore, it is desirable to keep the fault current as low as possible. If MV motors are being protected, then keeping the fault current low also helps in lowering the damage to the laminations at the fault point in the event of a fault in the stator winding. In Y-connected motor windings, the driving voltage for the ground fault reduces as the fault location moves closer to the star point; hence, the ground fault relay must be set sensitive enough to detect the fault and sufficient amount of current must flow. This will also dictate how low you can go with the resistor let-through current.

Multiple Transformers 415-7.5V

I am currently faced with a delta-wired three-phase motor

and need to connect a digital circuit to display the temperature of the windings. I have a display unit that runs off 240V mains fine, but I only have access to the three actives (415V in Australia) and want to use a transformer to bring the voltage from 415V-240V. Would this be safe considering there is no neutral in this setup? I have connected the "neutral" of the secondary winding of the 240-7.5V transformer to ground to ensure it is grounded properly. Is this safe, or will I get earthing problems and trip circuit breakers, etc?

It is perfectly safe to connect a single-phase, double-wound isolation transformer rated 415V primary, 240V secondary, across two of the phases of the 415V delta power source. The secondary may be earthed as you have done (that is the preferred practice). You will not affect the earthing system on the primary. Just ensure the transformer is not an auto-transformer. The magnetic isolation between the primary and secondary windings on double-wound transformers de-couples the earthing (grounding) systems between the primary and secondary. For example, a ground fault on the secondary will not cause a ground fault on the primary, but rather a phase over-current, which won't trip any ground-fault protective devices.

400kV/220kV Interconnecting Transformers

What is the necessity of 33kV reactors in the transformers and what are zigzag type transformers?

Reactors on MV systems can be used in two ways. 1) When the available short-circuit current from the network is too high and beyond the capability of circuit-protective devices, the reactors in the three phases can provide the limiting impedance that reduces the available short-circuit current. The additional voltage drop introduced needs to be considered. 2) Reactors can also be applied between neutral and ground to provide reactance grounding of the system. This provides a lagging ground current which adds to the leading capacitive current contributed by the net distributed line-to-ground capacitance from the two unfaulted phases in the event of a line-to-ground fault. If this reactance is made large enough to exactly match this capacitive current, then there would be zero current in the fault – consequently no arcing and very low fault damage. However, the reactance can also cause transients and resonance with the line capacitance. So mostly resistance is used for earthing.

A zigzag transformer is a three-phase autotransformer in which each leg has two identical coils; they are cross-connected to form a star. First, the terminals of the three coils get connected to three phases – A, B, C. Then the Phase A second terminal gets connected to the second coil on Phase B leg; similarly, the second terminal of Phase B gets connected to second coil on Phase C, and the second terminal of Phase C gets connected to the second coil on Phase A. The ends to these three second windings are connected in a star. This is now the neutral point of the system that can be connected to a ground through impedance, normally a resistor. With normal excitation, magnetizing currents are taken from the phases which balance out and no zero-sequence current or residual current will flow to ground. In the event of phase-to-ground fault, unbalanced current will flow through the resistor. The resistor essentially controls the current simply dictated by phase-to-neutral voltage divided by the resistor value.

Zigzag Grounding Transformer

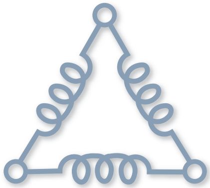
I have an application where I have a 75kVA dry-type lighting isolation transformer 480V three-phase delta to 480V three-phase delta.

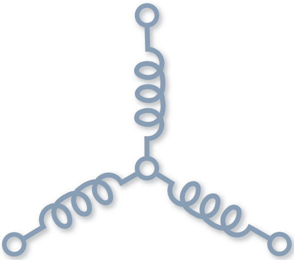
The owner does not like the ungrounded delta since there is no reference to ground for lighting ground faults and wants a ground reference established in order to ensure a blown lighting fuse when a ground fault occurs. All the lighting is 480V single-phase with fuses in the fixtures. Rather than replace the transformer, I though it would be cheaper to install a 3kVA zigzag grounding transformer, three-phase grounded Y without a secondary and attach it to the delta secondary of the 75kVA transformer. This would in essence establish a ground and give lighting ground faults a direct path back to the source. I have found literature on these types of zigzag grounding transformers but I cannot find anyone who can sell me one in the 3kVA size range. Can you help? And to your knowledge, is this a reasonable application?

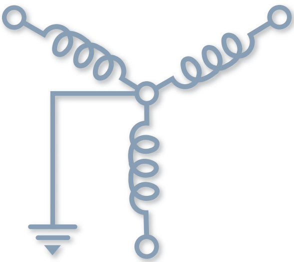
I have seen 277V lighting applied on 277/480V three-phase, four-wire systems and 347V lighting applied on 347V/600V three-phase, four-wire systems. Assuming that lighting is actually 480V, to blow a fuse on ground fault, you will need substantial ground current, above 6-10 times the fuse rating.

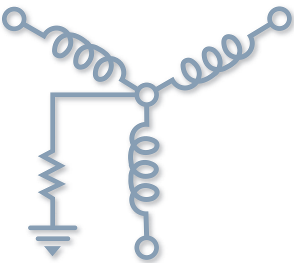
3kVA zigzag is a possible option if it can provide sufficient ground current to open the fuse. Two possible suppliers are Hammond and Rex Transformers.

Delta-connected windings are often used so that nothing needs to be tripped on the first phase-to-ground fault. A small continuously rated zigzag with up to 5A grounding resistor will provide stability and allow ground current to flow which can be detected by ground fault relays. An alarm is raised indicating a ground fault, though nothing is tripped. The fixtures are connected to ground through the ground wire which carries the ground current continuously and keeps them safe to touch.









Notes:

For a complimentary application guide, visit:

www.i-gard.com

C-101 **StopLight**

High Resistance Grounding System Manual

C-102 **Gemini**

High Resistance Grounding System Manual

C-105 **Fusion**

Ground Fault Protection System Manual

C-107 **Sentinel**

High Resistance Grounding System Manual

C-408 **Sleuth**

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Ground Fault Protection on Ungrounded and High Resistance Grounded Systems

Application Guide

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