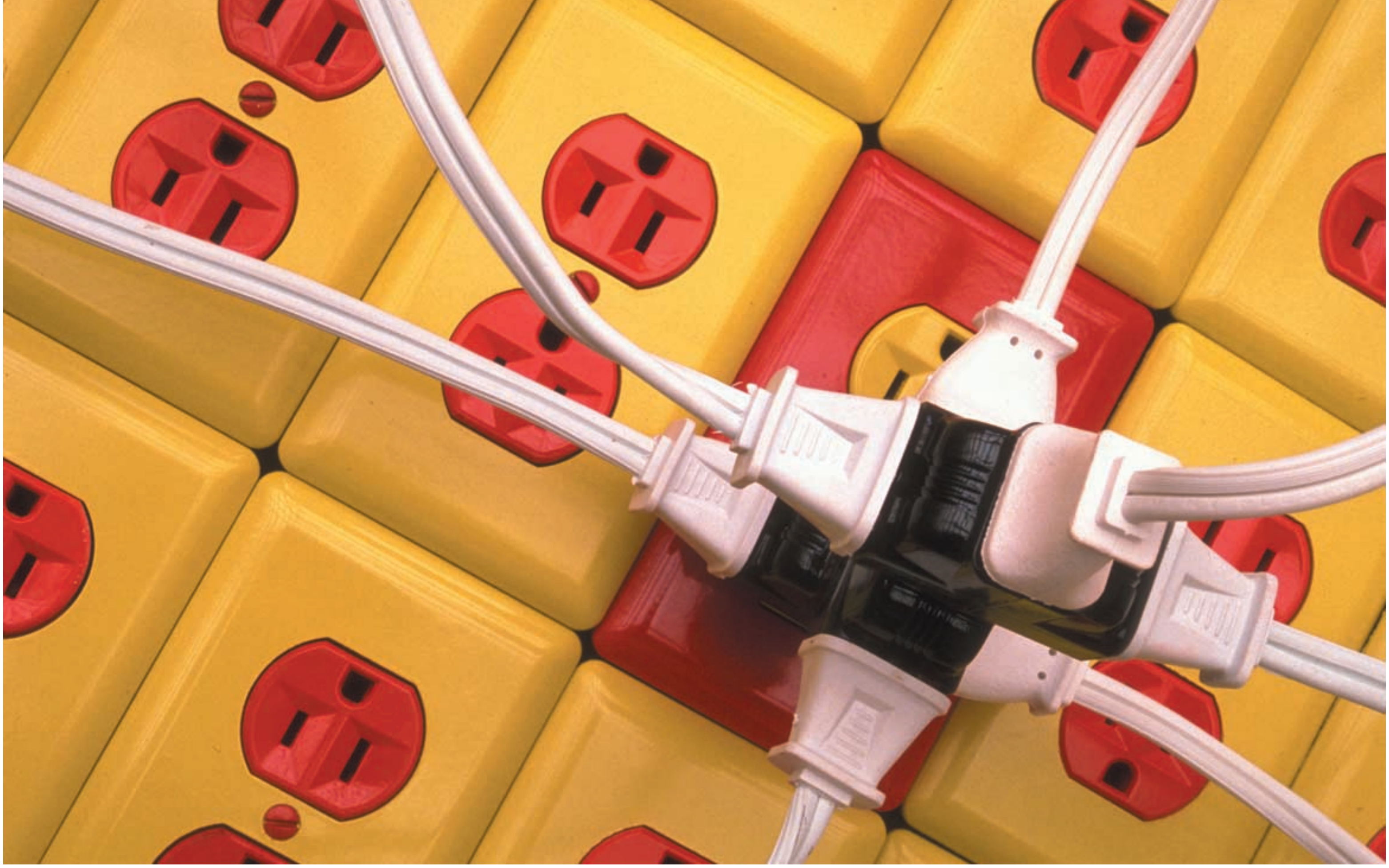


© 1993 PHOTODISC, INC.

DISTRIBUTED GENERATION

Operating conflicts for DISTRIBUTED GENERATION interconnected with UTILITY DISTRIBUTION SYSTEMS

BY ROGER C. DUGAN & THOMAS E. MCDERMOTT

THE DEREGULATION OF UTILITIES and the emerging power markets are creating renewed interest in operating generators in parallel with the utility system. Some of the more common reasons are

- utility perspective
  - transmission capacity relief
  - distribution capacity relief
  - hedge against high market prices

1077-2618/02/$17.00©2002 IEEE

- end-user perspective
  - efficient use of energy from combined heat and power
  - improved reliability by having backup generation
  - incentives from utility to provide capacity reserve or power market hedge
- commercial power producer perspective
  - power market (to sell power)
  - to sell ancillary services (reactive power, standby capacity, etc.).

The emphasis of this article will be on those generators that would be connected to the utility distribution system. These will generally be units smaller than 10 MW. Larger units are generally connected directly to transmission facilities and will most likely be commercial power producers. The units installed on distribution systems will typically be no larger than 1 or 2 MW. These would be installed mostly by the utility itself or by end users. This method of generation is commonly referred to as "distributed generation" (DG).

The utility may install such generation to provide additional feeder or substation capacity. One planning methodology that utilities might use to determine if DG is an attractive option for adding capacity was described in [1]. To achieve additional feeder capacity, the generation must often be installed some distance away from the substation, and the best location may be at a customer's site. One issue that arises is the question of ownership of the generation. Some utilities that are chartered as regulated "wires" companies may be prohibited from owning any generation, but might benefit from some distributed generation being on the feeder. Service agreements can be structured to provide incentives for customers or independent power producers to install DG so that it can be operated to the benefit of the power delivery system.

THERE WILL BE A SUBSTANTIAL INCREASE IN DISTRIBUTED GENERATION CONNECTED TO UTILITY DISTRIBUTION SYSTEMS OVER THE NEXT DECADE.

Much of the value of DG today is on the end-user side of the interconnection. For example, a factory may have a process that requires steam heat, purchases gas to make the steam in a boiler, and purchases electricity to power the machines. A more efficient use of energy resources might be to first burn gas to make electricity and then use the waste heat for process steam. Another example would be an industrial or commercial customer with a very high-value product that easily justifies the purchase of standby generation. In areas of frequent interruptions or power shortfalls, this greatly enhances the apparent reliability of the system to that customer.

An astute wires company with a power delivery or power market constraint problem might be wise to seek out customers with a sufficient value of service to warrant the investment in generation and work with them to facilitate its use to the mutual benefit of all.

Whatever the reason, we will increasingly find DG being installed to operate in parallel with the distribution system. This brings about several potential operating conflicts that have been addressed since the early 1980s [2]-[5]. A few of the conflicts will be discussed here. Specifically,

- overcurrent protection
- instantaneous reclose
- ferroresonance
- reduced insulation
- transformer connections and ground faults.

Overcurrent Protection

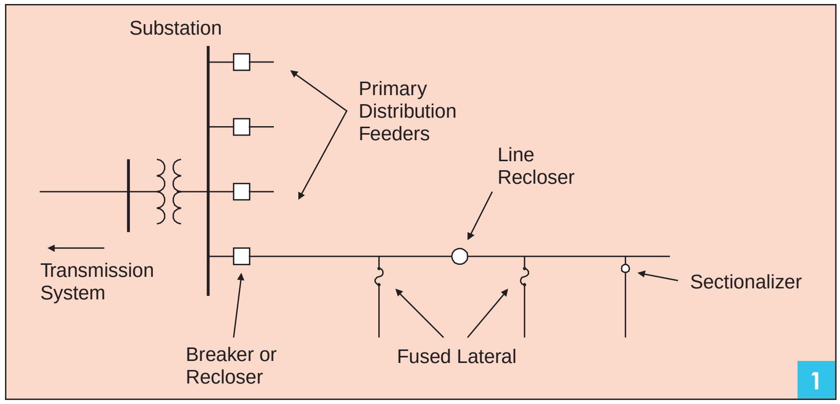
Most distribution systems—especially rural systems—are operated in a radial configuration. That is, there is one source and the feeders extend radially from the source. The main reason for this structure is the simplicity of operation and the economy of the overcurrent protection system (Fig. 1). Most conflicts over operation with DG arise from this structure. (Distribution networks have some serious issues, too, but we will not cover them here.)

The most basic element is a fuse, which dictates the characteristics and behaviors of all overcurrent protective devices. The setting of the utility breakers and reclosers that enables them to work in concert with the fuses is referred to as the "coordination" of the overcurrent devices. The guiding principle is to position these devices to minimize disruption to customers in the inevitable case of a fault. An excellent resource on the art and science of the coordination of series overcurrent devices on radial utility distribution systems is [6].

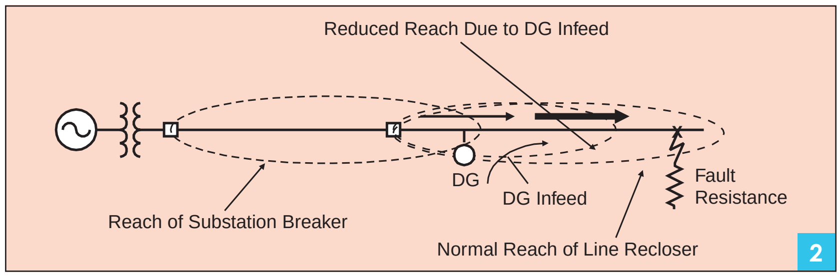
There are two classes of utility system faults: temporary and permanent. Most systems have a large number of overhead lines, and most faults on overhead lines are temporary. That is, if the fault arc is interrupted, the fault will heal itself without outside intervention, and power can be restored immediately by reclosing the interrupting device (a breaker or recloser).

On a radial system, fault clearing requires the opening of only one device, because there is only one source contributing current to the fault. In contrast, meshed transmission systems require breakers at both ends of a faulted line to open.

When DG is present, there are multiple sources, and opening only the utility breaker does not guarantee that the fault will clear promptly. It would be far too costly to revamp the distribution system protection scheme to operate it in the same manner as a meshed transmission system. Therefore, DG will be required to disconnect from the system when a fault is detected so that the system reverts to a true radial system and the normal fault-clearing process may proceed. There is the possibility that the DG will disconnect either too quickly or too slowly to avoid detrimental impacts on the distribution system. Either case creates potential operating conflicts with respect to overcurrent protection and voltage restrictions.



The typical overcurrent protection of a utility distribution feeder.



The generator infeed reduces the reach of utility relaying.

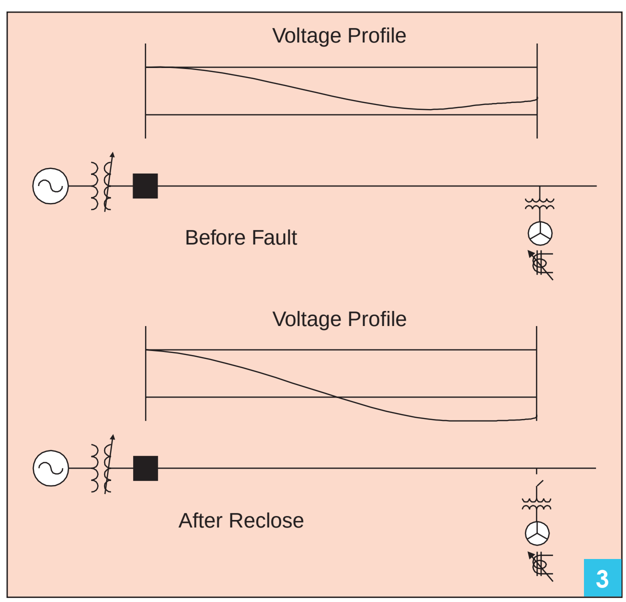
Fig. 2 illustrates one impact DG can have on utility protective relaying. Utility breakers and reclosers are set to "see" a certain distance down the radial feeder. This is sometimes referred to as the "reach" of the device. The reach is determined by the minimum fault current that the device will detect.

At peak loading, when the DG is likely to be interconnected, the relaying is actually fairly sensitive—the reach is large. It doesn't take much additional current to trip the breaker. The DG infeed, as shown, can cut sharply into that reach. That is, there is a significantly increased risk that faults with high resistance will go undetected until they burn into larger faults. The obvious result is that there will be more damage to the utility physical plant than without the DG. There is also more risk of sustained interruption to customers. Thus, while there is the perception that DG will bring more reliability to the system, that is generally true only for the entity that owns the generator, assuming it can be operated as backup generation as well as cogeneration. For the example shown, the net effect on the utility distribution system reliability is probably slightly negative.

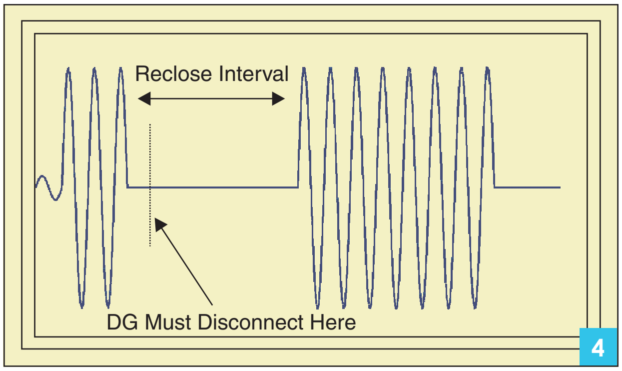
Fig. 3 illustrates the concern with voltage regulation that often yields the most restrictive limits on how much DG can be served from a particular distribution feeder. This is particularly true of rural feeders where the DG is more likely to be sited a long distance from the substation.

Before a fault occurs, the DG will help support the voltage and may be large enough to actually raise the voltage as suggested in the top diagram in Fig. 3. In one sense, the DG improves the reliability of the distribution system by allowing it to serve more load at a good voltage than without the DG. However, if the load has increased to the point where the feeder is actually *dependent* on the DG to support the load, there can be significant operational difficulties when the inevitable fault occurs. In order for the utility system fault protection scheme to operate, the DG must disconnect. It will remain disconnected until it can be determined that the utility voltage has stabilized (usually a few minutes). However, if the load is too great, the voltage will sag too low, the utility will not be able to successfully serve the load upon reclosure, changes in operating procedure will be required to restore power, and it will take longer to restore power to some customers. In that sense, the reliability of the power delivery system might appear to have worsened slightly, although the DG may actually be mitigating a voltage regulation problem under normal conditions.

If one limits the maximum voltage change permissible for this condition to a certain value, such as 5% (or 10%, if there are fast line regulators), this is frequently the most limiting factor in determining how much DG can be supported on a given feeder without significant modifications to operating practices. For example, on a typical rural, 15-kV class feeder, the maximum amount of generation with respect to this rule is in the range of 500-1000 kW, depending on the actual location(s) of the DG on the feeder. When generation is located close to the substation, as it might be in an urban area, this range could increase to 3000-4000 kW with respect to this criterion.



The voltage sags too low after generators are disconnected to clear a fault.



The first two shots of a typical utility distribution system reclosing sequence during a short-circuit fault.

Instantaneous Reclosing

Because many faults are temporary, reclosing is prevalent throughout North America. Fig. 4 illustrates this principle by showing the fault currents and the reclose interval (dead time) between "shots."

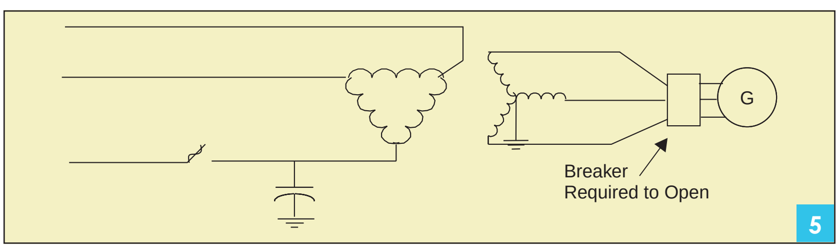
Reclosing and some types of DG are fundamentally incompatible. For the reclose to be successful (the one shown in Fig. 4 is not), there must be sufficient time between shots for the fault arc to dissipate and clear. That means any DG on the system must detect the presence of the fault and disconnect early in the reclose interval. Otherwise, the fault continues as indicated.

This is a problem with significant consequences. A clearing failure means that there will be prolonged arcing and the utility transformers will experience another "through fault." Either can mean shortened life and expensive repairs to utility equipment. Likewise, if the DG is still connected upon reclosing, the DG equipment itself is subject to damage. For a rotating machine, which is the most common type of generator, owners can expect damage to the shaft, coupler, and prime mover due to out-of-phase switching. In one instance from our experience, a piece of insulation detached from the rotor winding, presumably from either the electrical forces or the mechanical shock. Solid-state inverters have much less inertia and would normally be less susceptible to the out-of-phase reclose, assuming proper protection against current surges.

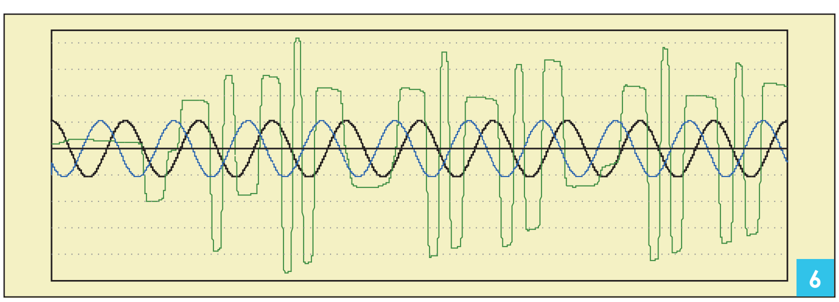
The failure to clear also means that some of the utility's customers will now see a sustained interruption when they should have been subjected to only a momentary one. Again, the reliability of the power delivery system is slightly degraded.

Complicating this issue is the fact that many utilities use "instantaneous" reclose for power quality purposes. This reclose interval is nominally 0.5 s but can be as short as 0.2 s. The utilities that use this short interval have done so because they wanted to improve the power quality for their customers. For example, many of the nuisance blinking clock problems can be avoided. However, this increases the probability that the DG will not disconnect in time.

While there may be few problems with today's low level of penetration on distribution systems, as DG installations increase in number and size there is almost certainly going to be a conflict between the needs of DG and the use of instantaneous reclose. We recommend against using instantaneous reclose on feeder sections that contain DG. A reclose interval of 1 s or more would be preferable. This will dramatically reduce the chances that the DG will fail to separate in time, but will also result in reduced power quality to a certain segment of customers. Thus, we have a clear conflict on this issue.



A riser-pole fuse blowing on a cable-fed transformer leads to ferroresonance.



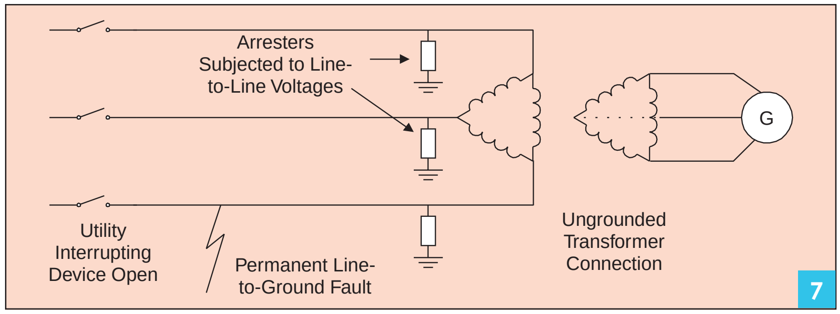
An example of ferroresonant overvoltages for delta primary with one phase open. Scale is 1 p.u. per vertical division.

Ferroresonance

As we have seen, it is necessary to disconnect the DG when a fault occurs so that the utility can proceed with the fault-clearing process that was originally intended. This is sound practice, but sometimes there are unintended consequences. In one example, related to us by Feero [7], ferroresonance can occur and damage customer load or the service transformer.

Many modern loads are served with underground cable. The cable is commonly run from an overhead line, where it is nearly universal to apply fuses at the riser pole to protect the overhead line from faults on the cable. The fuses are sized to blow quickly because it is assumed that all cable faults are permanent and there is no reason to attempt fuse saving. Requiring the DG to disconnect at the first sign of trouble will leave the service transformer isolated without load and served with an open phase. Fig. 5 shows the situation with a delta-wye grounded service transformer.

This is a classical ferroresonance condition [8]. The capacitance of the cable appears in series with the magnetizing inductance of the transformer, often resulting in very irregular and high voltages and currents (Fig. 6). If a small amount of load-side equipment remains connected, it can be damaged. A common casualty in this situation are surge protectors on the secondary system. Under the right conditions, the transformer and its primary arresters are also at risk if the condition is allowed to persist. Unfortunately, this condition does tend to persist for some time unless line crews happen to be standing nearby. Conventional overcurrent protection will frequently not detect ferroresonance until something fails.



Some fault conditions can expose arresters to excessive steady-state overvoltages.

It should be noted that this situation is not unique to a DG installation; it also occurs in many commercial loads where the loads are automatically disconnected from the mains and transferred to backup sources. This, likewise, leaves the service transformer isolated on a section of cable with little or no load. That is the customer's choice. In the case of DG, however, the typical utility interconnection standards require the separation to occur, exposing the customer to the risk of ferroresonance. On the other side of the conflict, it is inadvisable to leave the DG connected with an open phase, because the negative sequence heating could damage the machine.

One solution is to arrange the circuit, if possible, so that there is always some significant load on the transformer when the isolation occurs. Another, more certain solution is to employ a three-phase switch (such as a recloser) on the primary side of the service. This adds a relatively large expense for smaller DG sites that may eliminate much of the economic advantage of the DG.

DISTRIBUTED GENERATION MUST ADAPT TO THE DISTRIBUTION SYSTEM NEEDS.

The root cause of the ferroresonance problem is that there are fuses employed for line protection between the substation and the DG. Ideally, the only fuses in series with the DG would be transformer fuses, which should blow only for internal transformer faults. If line fuses can be avoided, the probability of this situation occurring is greatly diminished. It can still happen if a jumper were to come loose or a line were to become open, but the odds of this should be much lower than a line fuse blowing.

Of course, one could avoid cable-fed transformers for DG installations. Note that using a wye-wye transformer does not completely eliminate the ferroresonance problem [9]. A grounded wye-delta connection might help, but there are other operational problems with this that we will discuss later.

Reduced Insulation

The prevalence of the four-wire multigrounded primary distribution system yields numerous economies due to reduced insulation requirements. Line equipment ranging from transformers to switches to line insulators can be made smaller at a lower cost. This has been exploited for decades over the entire system, and a change in the accepted practice at this point in time would be inconceivable.

To protect the insulation, appropriately sized arresters are required. Like other equipment, the arresters are manufactured with a voltage rating that is less than the nominal line-to-line voltage of the system. For example, on a 12.47-kV feeder, one may typically apply arresters rated for either 7.65- or 8.4-kV maximum continuous operating voltage (MCOV). (These correspond to a 9- or 10-kV arrester duty-cycle rating.) This works as long as the system is effectively grounded.

The assumption of effective grounding is violated in the condition shown in Fig. 7. A permanent single line-to-ground fault has occurred, and the utility interrupting device has opened. This leaves an isolated system energized by the DG that is connected through a delta-connected transformer. There is no longer a grounded source on the utility side of the transformer.

Besides at least one resonant condition that can occur in this situation, the two arresters on the unfaulted phases are now subjected to line-to-line voltage. These will likely fail unless the DG relaying picks up on the abnormal islanding condition promptly. Frequently this delta transformer connection will be found at industrial loads when the DG is also supplying the load. If the net flow across the transformer at the time of the fault is small, it may take some time before the DG protection is able to detect something is wrong using only the signals available on the load side.

Transformer Connection and Ground Faults

The previous two sections highlight some of the drawbacks of using an ungrounded primary connection for transformers used for DG interconnection. This can make it difficult to detect the most common type of utility fault—the single line-to-ground (SLG) fault—and can subject utility equipment to excessive duty if the fault goes undetected. However, that does not mean all problems can be solved by using a grounded wye connection, which we will examine in greater detail.

Many utility engineers believe the best transformer connection for DG is grounded wye-delta, with the grounded wye side connected to the utility side, just like central station generation connected to the transmission grid. The protective relaying for this connection is well understood from decades of experience with central station generation. SLG faults are relatively easy to detect from the phase-to-phase voltages on the DG side. Other fault conditions are also relatively easy to detect. If the DG accidentally becomes isolated in an island, the utility side still appears to be effectively grounded, although somewhat less so than before the island formed. There are fewer strange resonant conditions that can occur and ferroresonance is considerably less likely. Triplen harmonics produced by the machines are blocked by the delta winding (very important for some machines) and there are probably other benefits we have not mentioned.

Despite these apparent benefits for DG, it is rather ironic that most utilities forbid this connection on radial distribution systems.

Fig. 8 illustrates the reason for this restriction. A grounded wye-delta transformer creates additional ground current paths. Thus, it is sometimes referred to as a "ground source." The current into a SLG fault is increased, and breakers or fuses attempting to interrupt this current may see excessive duty. The fault currents are no longer flowing in just one path from the substation to the fault, but are flowing in other paths—even those downline from the fault. Thus, relays can be fooled and line or transformer fuses can blow needlessly. Faulted circuit indicator (FCI) devices will register fault current in many locations in the feeder not normally involved in the fault, delaying the fault repair. One common side effect is that the feeder breaker will trip for any SLG fault on all feeders served off the same substation bus.

The transformer itself is subject to failure. Utility transformers are nominally designed to withstand 25 times the normal rated current briefly during a through fault. They seldom are subjected to such currents in actual service to prove this capability. However, a grounded wye-delta transformer would see the majority of faults that occur on the distribution system, including all feeders fed from the substation bus. Thus, it would be subjected to many high current impulses that can shorten its life. To compound this, many distribution transformers have less than 4% impedance, which will allow more than 25 times rated current to flow. Thus, they would be overstressed repeatedly, which is a certain recipe for early failure.

WE WILL INCREASINGLY FIND DG BEING INSTALLED TO OPERATE IN PARALLEL WITH THE DISTRIBUTION SYSTEM.

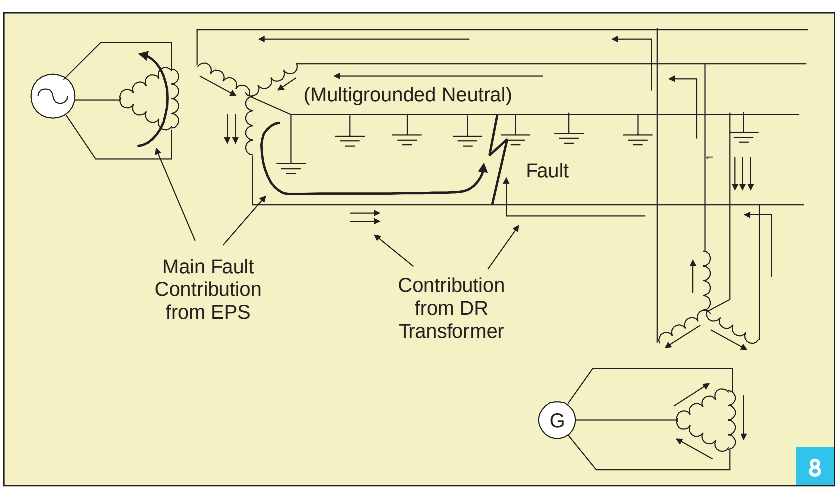
There are two common solutions to this problem:

- Purchase transformers with a higher impedance.
- Add a reactor to the neutral on the wye side.

These can be technically effective solutions, but are disliked by utility operating personnel. While utilities may often specially engineer equipment for transmission systems, the preference for distribution systems is consistency. "Specials" are discouraged, because that information often gets lost over the years. The results can be disastrous. For example, assume the wye-delta transformer is made up of a bank of special 6% transformers. Now, assume one of the transformers fails some years later. In a rush to get the customer back in service, the transformer is replaced with a conventional 2.5% transformer. That transformer will likely fail upon the occurrence of next SLG fault, perhaps catastrophically.

A neutral reactor value has to be carefully selected so that the fault current flowing through the transformer is limited yet still appears effectively grounded from the perspective of the generator. This is not a great difficulty, but does require additional expense. Another objection of operating personnel is that it requires special care and training. Utility line personnel are not accustomed to seeing large reactors in the neutral and must be aware of the voltage hazards. This is a particular problem when out-of-town crews are brought in during emergencies. Therefore, there is a tendency to discourage such installations and stick with something more familiar—even if it doesn't work as well.

To prevent the sympathetic tripping of the feeder breaker for SLG faults on other feeders, one of the more popular solutions is to replace standard overcurrent relays with directional overcurrent relays.



A grounded-wye/delta transformer creates mulitiple ground current paths and disrupts utility ground fault coordination.

Perhaps the most common three-phase connection in the United States is the grounded wye-wye. This is generally well behaved in DG installations, except that it does not block third harmonic currents produced by the machine. The harmonics produced by the machine are dependent largely on the "pitch" of the winding. A 2/3-pitch machine produces very little third harmonic voltage and can be easily connected to a grounded wye-wye transformer. However, other designs can produce significant amounts of third harmonics, and generator owners/operators are often unpleasantly surprised when they first connect their old standby generator to the utility system. Where they had previously experienced no problems, there are now high currents flowing in the neutral. The load presents a high impedance to these harmonics so there are few symptoms when operating in standby backup. However, the utility is essentially a short circuit sink for the harmonic currents that can be produced by the normal voltage distortion of the machine.

This problem can also occur for DG interconnected through the common delta-wye grounded (e.g., 480/277 V secondary) transformers. This will result in high neutral currents on the customer side of the transformers.

Conclusions

At present, it seems almost certain that there will be a substantial increase in the amount of DG connected to utility distribution systems over the next decade or so. The systems were designed for unidirectional flow and, as the penetration of DG increases, it should not be surprising that operating conflicts arise. Several have been identified here and the following conclusions may be drawn.

- Too much existing utility infrastructure has been built on the assumption of simple protection schemes for faults and effective grounding for insulation structures to consider changing to better accommodate DG. DG must adapt to the distribution system needs.
- While DG may greatly improve reliability for some DG owners, it can degrade the reliability and power quality for other customers on the feeder.
- Established practices on overcurrent protection must be revisited. For example, instantaneous reclosing is probably incompatible with widespread DG usage. Line fusing must be weighed against the adverse effects of single-phasing three-phase generators.
- There are several tradeoffs to be considered concerning transformer connections. Some of the more common connections yield some difficulties. One connection that might be very good for DG will, unfortunately, conflict with the existing overcurrent protection scheme.
- Because of the conflicts and tradeoffs, there are no easy answers, and special engineering is required for many DG installations.

Despite these conflicts, DG installations on utility distribution systems can nearly always be successfully engineered. There may be some cost involved in additional equipment or some compromises made with respect to long-established utility operating practices.

References

[1] R.C. Dugan, T.E. McDermott, and G.J. Ball, "Distribution planning for distributed generation," in *IEEE IAS Rural Electric Power Conf. Rec.*, Louisville, KY, 2000, pp. C4/1-C4/7.

[2] *Distributed Resources Interconnected with Electric Power Systems*, IEEE Standard P1547 P1547.

[3] "Integration of distributed resources in electric utility systems: Current interconnection practice and unified approach," EPRI, TR-111489, 1998.

[4] "Engineering handbook for dispersed energy systems on utility distribution systems," EPRI, TR-105589, 1995.

[5] "Protection of electric distribution systems with dispersed storage and generation (DSG) devices," Oak Ridge National Laboratory, Rep. ORNL/CON-123, 1983.

[6] *Electrical Distribution-System Protection*, 3rd ed. Cooper Power Systems, 1990.

[7] W. Feero, "Interconnecting distributed generation to utility distribution systems," presented at the Univ. Wisconsin-Madison Eng. Professional Development Short Course, 2000.

[8] R.H.Hopkinson, "Ferroresonance overvoltage control based on TNA tests of three-phase delta-wye transformer banks," *IEEE Trans. Power App. Syst.,* vol. 86, pp. 1258-1265, Oct. 1967.

[9] D.R. Smith, S.R. Swanson, and J.D. Borst, "Overvoltages with remotely-switched cable-fed grounded wye-wye transformers," *IEEE Trans. Power App. Syst.,* vol. 94, pp. 1843-1853, Sept./Oct 1975.

Roger C. Dugan (rdugan@electrotek.com) and Thomas E. McDermott are with Electrotek Concepts in Knoxville, Tennessee and Jefferson Hills, Pennsylvania, respectively. Dugan is an IEEE Fellow, and McDermott is an IEEE Senior Member. This article first appeared in its original form at the 2001 IEEE/IAS Rural Electric Power Conference.