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Operating DGs in parallel with utility distribution systems is not without hazards.

This article discusses the current technology in the interconnection of DGs to utility distribution circuits. Generators of 10MW or less are typically connected to the utility grid at the distribution level. Protection requirements to connect DGs to the utility grid had typically been established by each utility. Distribution utility circuits are designed to supply radial loads. The introduction of generation provides a source for redistribution of the fault current on the feeder circuit, which can cause the loss of relay coordination. Overvoltages can also occur. Within the past few years, there have been efforts by the IEEE (Standard 1547), as well as individual states, to develop standards and guidelines for the interconnection of DG. The stated goal of these standards/guidelines is to have a single document of standard technical requirements for DG interconnection rather than having to conform to local utility practices and guidelines. This article examines how well this objective has been met.

Until the passage of the Public Utility Regulatory Policies Act (PURPA) in 1978, U.S. utilities were not required to interconnect with small generators. At the transmission level, there were always non-utility co-generating industrial facilities such as petrochemical plants and pulp and paper mills which operated in parallel with the utility. But at the distribution level, utilities could simply say “no” to small generator owners that wanted to operate in parallel with their system. PURPA was the first step in utility de-regulation and required utilities to interconnect with small generation as

long as the owners of such generation followed “reasonable requirements” set forth by the utility. PURPA also provided a substantial tax incentive to DG owners. By the mid-1980’s however, the tax incentive had expired and DG died.

DG remained relatively dormant until the mid-1990’s when utility rates started to increase. The driving force for that resurgence was the belief that power could be generated cheaper at the point of consumption rather than purchasing power from a utility. During this period, most of the DG installations in the U.S. were in areas of the country where power costs were high. In these areas, small industrial and commercial customers supplied from distribution circuits started to install DG in peak-shaving or load-following applications where a significant portion of their load was generated on-site. Most of these generators were fired with natural gas. When natural gas prices increased by a factor of four in the late 1990’s, DG died again. It remained relatively dormant until the mid-2000’s when the issue of global warming came to the forefront of concerns by states and the federal government. The idea of “green power” was born.

To promote green power, utility regulators either set high buy-back prices for power generated from green sources or required utilities to generate a portion of their future power needs from green sources. Green sources included: wind, solar, hydro, fuel cells, biomass, diesels powered from synthetic fuels and methane from landfills which power gas turbines or diesels.

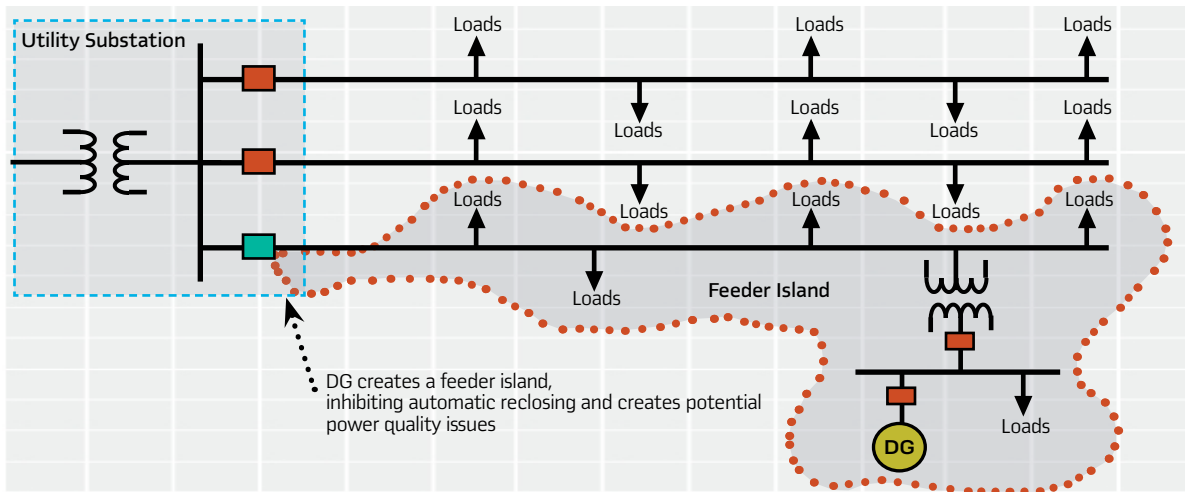
Basic types of DG generators

IEEE 1547 discusses three basic types of DG generators. Induction and synchronous generators are traditional types of distributed generation, which operate interconnected with the utility system

Induction generators

DG induction machines were typically small—less than 500 KVA. These machines were restricted in size because their excitation is provided by an external source of VARS. In

1 Islanding operation of DG with the utility system that is generally not allowed



The connection of significant amounts of distributed generation to distribution circuits will require a major shift away from the traditional interconnection method cited in this article.

Interconnection protection

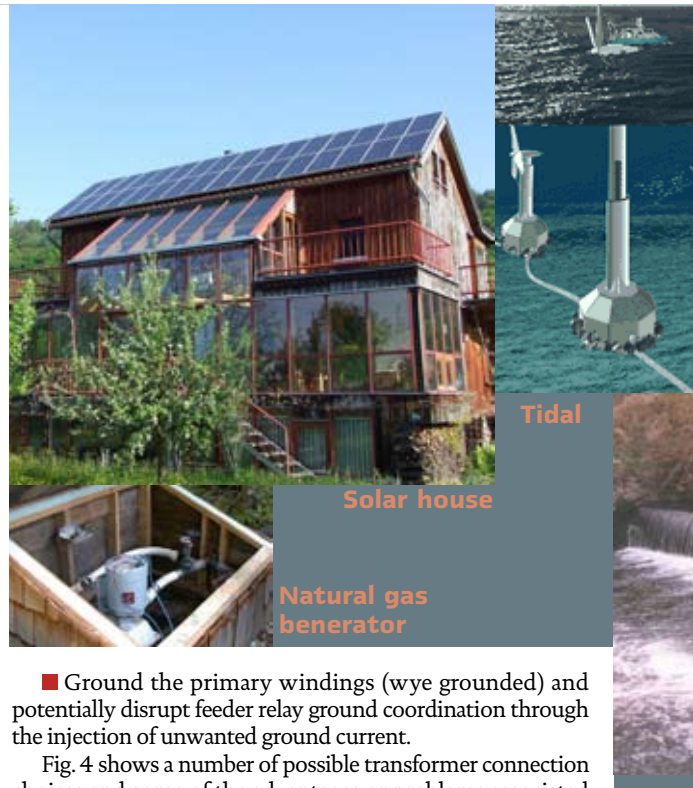
Interconnection protection provides the protection that allows the dispersed generators to operate in parallel with the utility grid. Typically, protection requirements to connect a dispersed generator to the utility grid are established by individual utilities or state guidelines. These guidelines generally cover smaller generators. Typically, interconnection protection for these generators is installed at the Point of Common Coupling (PCC) between the utility and the DG. This can be at the secondary of the interconnection transformer as illustrated in Fig. 3a, or at the primary of the transformer as illustrated in Fig.3b, depending on ownership and utility interconnect requirements.

Interconnection transformer grounding

The selection of the grounding of the interconnection transformer is one of the most important decisions in the development of the DG interconnection project. In the U.S., distribution systems range from 4 to 34.5 KV and are multi-grounded 4-wire systems as shown in Fig. 5. The use of this type of system allows single-phase, pole-top transformers, which typically make up the bulk of the feeder load, to be rated at line-to-neutral voltage. Thus, on a 13.8 KV distribution system, single-phase transformers would be rated at 13.8 KV/1.73-8 KV. Fig. 4 shows a typical feeder circuit. For synchronous generator DGs interconnections, line-to-neutral rated transformers and lightning arrestors can be subjected to damaging overvoltages depending on the choice of DG interconnection transformer.

Five transformer connections are widely used to interconnect dispersed generators to the utility system. Each of these transformer connections has advantages and disadvantages. There is no standard transformer connection to connect a DG to the utilities distribution system. The utility and DG owner have only two basic choices in selecting the primary winding configuration of the interconnection transformer.

■ Unground the the primary windings (delta or wye ungrounded) and risk possible overvoltages.



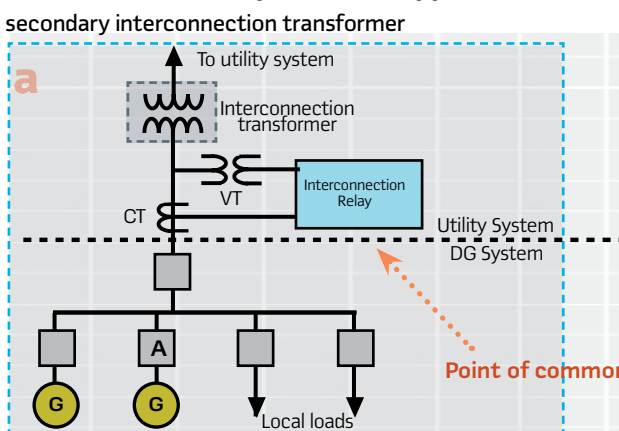
■ Ground the primary windings (wye grounded) and potentially disrupt feeder relay ground coordination through the injection of unwanted ground current.

Fig. 4 shows a number of possible transformer connection choices and some of the advantages or problems associated with each connection.

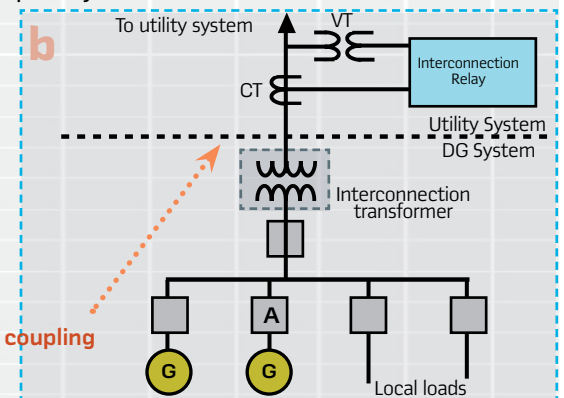
Ungrounded primary transformer windings

The major concern with an interconnection transformer with an ungrounded primary winding is that after substation breaker A (Fig. 4) is tripped for a permanent ground fault at location F1, the multi-grounded system is ungrounded. This subjects the L-N (line-to-neutral) rated pole-top transformers and lightning arrestors on the unfaulted phases to an overvoltage that can approach line-to-line (L-L) voltage. This occurs if the DG is near the capacity of the load on the

3 Interconnection protection applied at the: secondary interconnection transformer



3 Interconnection protection applied at the: primary interconnection transformer



Major innovations such as microgrids or other technical break-throughs will be necessary.

The ferroresonance is not confined to induction generators but can also occur on synchronous machines. Overvoltages of over 3.0 per unit can occur. The discharging and charging of the system capacitance through non-linear magnetizing reactance of the DG interconnection transformer produce these overvoltages. The ferroresonance associated with DG differs from the traditional ferroresonance caused by single-phase switching in that no unbalanced condition is necessary. A detailed description of the phenomenon is contained in an IEEE paper entitled, "Relay Performance in DGS Islands," IEEE Transactions on Power Delivery, January 1989. It identifies the following conditions needed for ferroresonance:

- The DG must be separated from the utility source (islanded condition).
- The KW load in the island must be less than three times the rating of the DG.

- The system capacitance must be greater than 25 percent and less than 500 percent of the rating of the DG.
- There must be a transformer in the circuit to provide nonlinearity.

If all these conditions exist, ferroresonance can occur. What are the techniques for mitigating the resulting overvoltages? Studies have shown that both induction and synchronous generators are susceptible. Also, all types of interconnection transformer connections (wye-delta, delta-wye, wye-wye, delta-delta) are susceptible. Surge arresters will clip the peaks of the overvoltage, but will not suppress the ferroresonance condition and may be damaged in the process. Metal-oxide arresters have an increased ability to survive longer but can also be damaged. The most practical solution is to trip the DG to remove the driving source. This is not as simple as it sounds since the voltage waveshape for this resonance condition is non-sinusoidal.

A major concern in trying to detect this condition with a digital relay is that with frequency and voltage waveshapes not being sinusoidal at normal system frequency, overvoltage and frequency measurements will be effected to where the digital relay may not operate. The measurement of peak overvoltage rather than RMS provides the best solution to detection of this type of event. IEEE 1547 does not mention the possibility of ferroresonance another shortcoming of the standard.

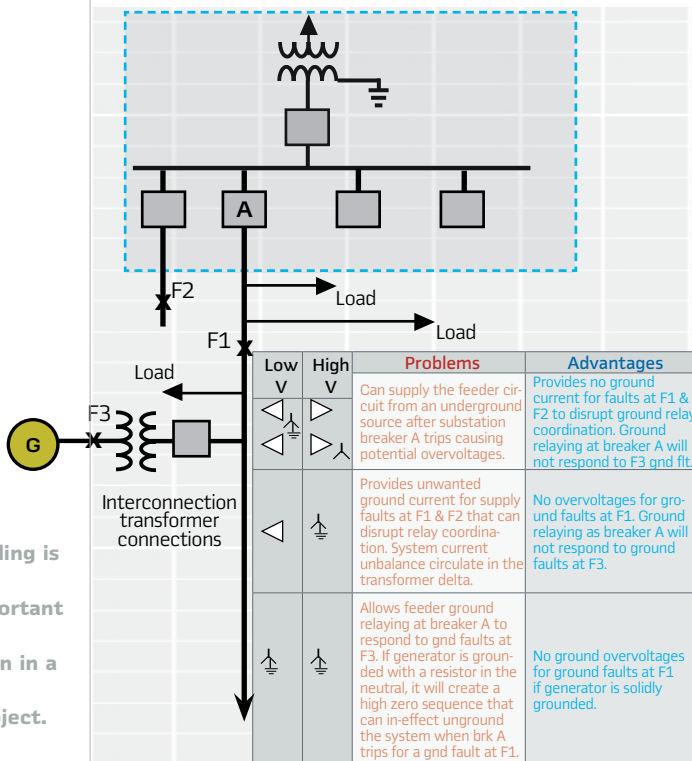
DG Interconnection Protection Methods and Practices

The functional levels of interconnection protection vary widely depending on factors such as: generator size, point of interconnection to the utility distribution system, type of generator (induction, synchronous, asynchronous) and interconnection transformer configuration. As shown in Table 1, specific objectives of an interconnection protection system can be listed, as well as the relay functional requirements to accomplish each objective. Other than a very simplistic discussion of the detection of loss of parallel with the utility, IEEE 1547 does not address protection areas such as: use of fault current at the DG facility to detect supply tripping, abnormal power flow, and damaging system conditions.

Detection of loss of parallel operation with the utility system

The most basic and universal means of detecting loss of parallel operation with the utility is to establish an over/underfrequency (81O/U) and over/undervoltage (27/59) "window" within which the DG is allowed to operate. The sensitive setting of both the underfrequency and voltage windows prevent the DG from supporting the power

4 Interconnection Transformer Connections



Grounding is an important decision in a DG project.

table 1 Interconnection Protection Areas

Interconnection Protection Objective	Protection Function Used
Detection of loss of parallel operation with utility	81O/U, 81R*, 27/59, 59I, TT**, 32***
Supply Fault detection	Phase Faults: 51V, 67, 21 Ground Faults: 51N, 67N, 59N, 27N
Detection of damaging system conditions	47, 46, 78
Abnormal power flow detection	32
Restoration	25
* Rate of change	** Transfer trip
	*** Rule 21 California

system during emergency conditions. When the DG is islanded from the utility system, either due to a fault or other abnormal condition, the frequency and voltage will quickly move outside the operating window if there is a significant difference between load and dispersed generation levels. If the load and generator are near a balance at the time of separation, voltage and frequency may stay within the normal operating window and under/overfrequency and over/undervoltage tripping may not take place. If this is a possibility, then a transfer trip (TT) using a reliable means of communication may be necessary. As discussed in the previous section of this article, when induction or synchronous DGs are islanded with pole-top capacitors and the generator capacity is near that of the islanded load, a resonant condition that produces a non-sinusoidal overvoltage can occur. For these cases, an instantaneous overvoltage relay (59I) that responds to peak overvoltage needs to be used to detect this situation.

Interconnection protection requirements in the state of California are defined in a filing to the state utility commission called Rule 21. A key provision of this rule is the unique application of a directional power relaying (32) to detect loss of utility parallel operation. This provision is only applicable to DG units that are installed for peak shaving or load following and do not sell power back to the utility.

Supply fault detection

On many small DGs, no specific supply fault detection is generally provided. Induction generators provide only two or three cycles of fault current to external faults similar to induction motors. Small synchronous machines are typically so overloaded after the utility substation breaker trips that their fault current contribution is very small. For these small generators, as well as asynchronous generators, the detection of loss of parallel operation via 81O/U and 27/59 relays are all the interconnection protection necessary.

The larger the synchronous DG, the greater is the chance that it will contribute significant current to a utility system fault. For this situation, supply fault backfeed detection in addition to loss of parallel operation protection is generally provided. Typically, relay functions such as the 67, 21 or 51V are used to provide phase-fault detection. When

developing settings for the 67 and 21 relays, the relay pickup setting must be set above the level of generator current being supplied by the DG to the utility system. Ground fault backfeed removal depends on the primary winding connection of the interconnection transformer. For grounded primary transformer windings, a 51N neutral overcurrent relay or, in some cases, a 67N ground directional relay is used. For ungrounded interconnection transformers, neutral overvoltage relays (59N, 27N) provide the detection for supply ground faults.

Detection of damaging system conditions

The major damaging condition that can be imposed on the synchronous and induction generators by the utility system is single-phasing. Negative sequence current (46) and voltage protection (47) is provided to detect this condition. Negative sequence voltage detection prevents re-synchronizing of the generator after a tripping if an open conductor condition exists. Out-of-step (78) protection is used to detect loss of synchronism for diesel generators, which have very low inertia and can lose synchronism if subjected to sustained low voltage caused by a slow-clearing fault.

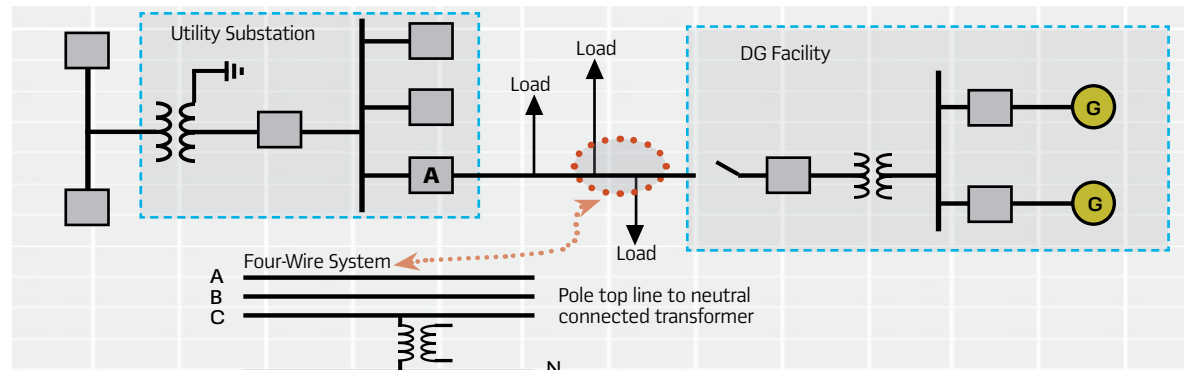
Abnormal Power Flow

A directional power relay function (32) is used in peak-shaving and load-flowing DG applications where the DG is operated to supply only a portion of the local load at the installation and there is no intent to sell power back to the utility. The directional power relay is used to enforce the contract that states that no power will flow to the utility.

Typical Protection for Moderately-sized Synchronous DGs

For the ungrounded interconnection transformers, neutral overvoltage relays (59N, 27N) provide the detection for supply ground faults. As previously stated, the functional levels of interconnection protection vary widely depending on factors such as: generator size, point of interconnection to the utility distribution system, type of generator (induction, synchronous, asynchronous) and interconnection transformer configuration. The relay engineer typically selects the protection functions that are appropriate for a specific application.

5 Typical 4-wire distribution feeder circuit



Additional
IEEE Standards
Committees
working groups
(particularly
P1547.2)
were formed
to address
practical issues
not covered by
the IEEE 1547
standard.