Impact of Green Power Generation on Distribution Systems

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I. INTRODUCTION

A significant amount of green power is being installed at the distribution level through the installation of green power generation facilities in many parts of the United States and Canada. Green sources such as wind, solar, methane (from landfills), hydro and diesels powered from synthetic fuel are some of the green generation being interconnected with the utility at the distribution level. These generators operate in parallel with utility distribution feeders.

It is forecasted by many experts that the installation of green power generation will be increased due to the need to provide more clean energy. Utility regulators are encouraging green power resulting in utilities seeing more and more green power installation on their distribution systems.

This paper discusses green power generating sources (of 10 MW or less) which are connected to the utility system at the distribution level, and their impact on distribution system reliability. Distribution circuits are designed to supply radial loads. Therefore, the introduction of green generation could mean: redistribution of fault and load currents on the feeder circuit, overvoltage and ferroresonance, plus a possible loss of protection system coordination—all of which can result in customer outages. These factors are not well understood by many distribution engineers and can adversely affect distribution system reliability. This paper discusses the specific reliability issues in interconnecting green power generators to utility systems to mitigate the above cited reliability issues. These issues are not adequately discussed in IEEE standard 1547, which addresses interconnection of DG to utility systems.

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.

.II AN UPDATE ON DG INTERCONNECTION STANDARDS AND GUIDELINES

In attempting to facilitate the installation of DG Generation, a number of efforts have been made to try to" standardize" interconnection protection requirements. This has proven to be extremely difficult due to variables such as:

1. **Design variations of utility distribution circuits:** Some utilities use "fuse saving," while other choose not to try to over trip line fuses. Some utilities use line reclosers and sectionalizers while others do not. Automatic reclosing practices vary from utility to utility.
2. **Various types of DG generators:** The section of this paper on types of DG generators addresses the electrical characteristics of the generators listed below.

   Synchronous Generators:
   - Reciprocating engines
   - Combustion turbines
   - Small hydro

   Induction Generators:
   - Wind generators

   Asynchronous Generators:
   - Micro turbines
   - Fuel cells
   - Photovoltaic

3. **Mixed views on specifications and performance requirements of interconnection equipment.**

4. **Interconnection functional requirements vary from utility to utility for the same type and size ofgenerator.**

IEEE 1547 – An Attempt at a National Standard for DG Interconnection

In this author's view, IEEE 1547 provides very limited guidance to the industry on interconnect protection requirements other than calling for over/underfrequency and over/undervoltage interconnection protection. It also clearly defines interconnection protection be installed at the Point of Common Coupling (PCC) between the DG and the utility system. The standard cites obvious requirements for DG interconnection operation but offers few methods, solutions or options to meet these requirements. Key issues such as: potential overvoltages, interconnection transformer choices, loss-of-utility-relay coordination, application of DG on secondary grid networks, damage to DG generators due to unbalanced current caused by utility single-phasing, and out-of-step protection are not addressed to any significant level. While the goal of 1547 was to provide standard technical requirements for DG interconnection, it does this on such a basic level that the solutions to problems are not addressed to the degree required to help those struggling with the problems cited in this paper. 1547 is not a document that engineers in utilities or those consultants designing DG interconnection protection can use to design their DG facilities. In recognition that much more work was needed, three additional IEEE Standards Committees were formed. These new Standards Committees are to address issues only briefly touched upon in 1547. These new standard Committees are:

IEEE 1547.1; *Draft Standard for the Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power System.*

IEEE 1547.2; *Draft Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources With Electric Power Systems.*

IEEE 1547.3; *Draft Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected With Electric Power Systems.*

State Guidelines for DG Interconnection

A number of states have established guidelines for DG interconnection. These state guidelines are primarily filings with the state utility commissions that outline the general requirements for interconnections of DG to utilities' power systems within that state. The most unique and perhaps famous state guideline is California's Rule 21.

California Rule 21- California requires a unique application of directional power relay (32) protection for anti-islanding detection. Because of the high price of power in the state, most DG applications are either peak-shaving or load-following where the DG generator is supplying a portion of the local load at the facility. Thus the DG is not selling power back to the utility. In SectionVII of this paper, application of directional power relaying specified in Rule 21 is described in more detail.

New York State Requirements - Provides specific functional interconnection requirements and provides state qualification procedures for interconnection devices. This eliminates the need to get approval for protective relays from each utility. Once interconnection protection is qualified at the state level, all utilities in New York accept it as qualified for use on their system.

Texas State Requirements - Provides specific interconnection relay functional requirements similar to those described in this paper. It specifically addresses interconnection requirements for DGs connected to the utility distribution system through ungrounded sources.

III. INTERCONNECTION VERSUS GENERATOR 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. Larger generators, generally greater than 10 MVA, are reviewed on a case-by-case basis and are usually connected to the utility's transmission system. These larger generators do not typically employ specific interconnection protection because they are integrated into the utility's transmission system protection. DGs (10 MVA or smaller) are usually connected to the utility's sub-transmission or distribution systems. These utility circuits are designed to supply radial load. Thus, the introduction of generation provides a source for redistributing the feeder circuit load and fault current as well as a potential source of overvoltage. Typically, interconnection protection for these generators is established 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. 1a, or at the primary of the transformer as illustrated in Fig.1b, depending on ownership and utility interconnect requirements.

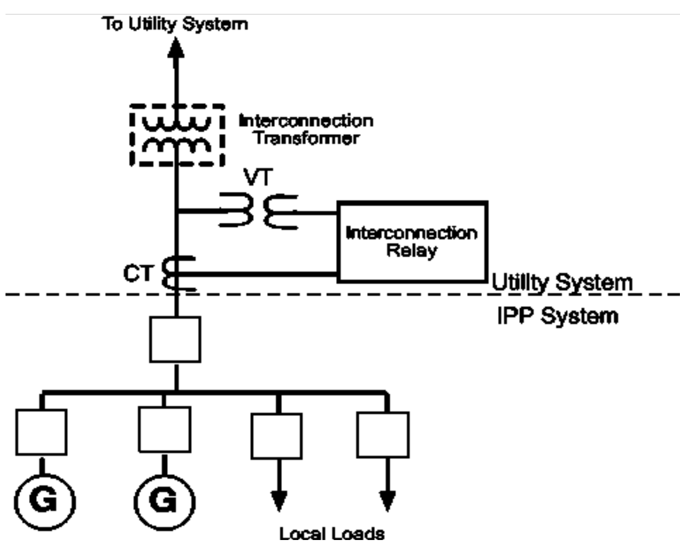


Fig. 1a Typical Interconnection Protection Applied at Secondary of the Interconnection Transformer

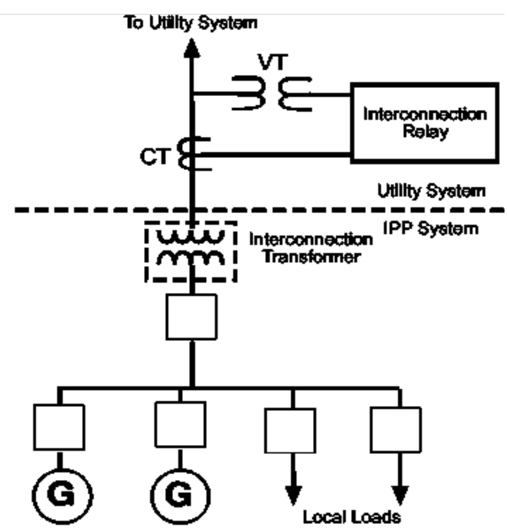


Fig. 1b Typical Interconnection Protection Applied at Primary of the Interconnection Transformer

Interconnection protection satisfies the utility's requirements to allow the DG to be connected to the grid. Its function is three-fold:

1. Disconnects the DG when it is no longer operating in parallel with the utility system.
2. Protects the utility system from damage caused by connection of the DG, including the fault current supplied by the DG for utility system faults and transient overvoltage.
3. Protects the generator from damage from the utility system, especially through automatic reclosing.

Generator protection is typically connected at the terminals of the generator as shown in Fig. 2.

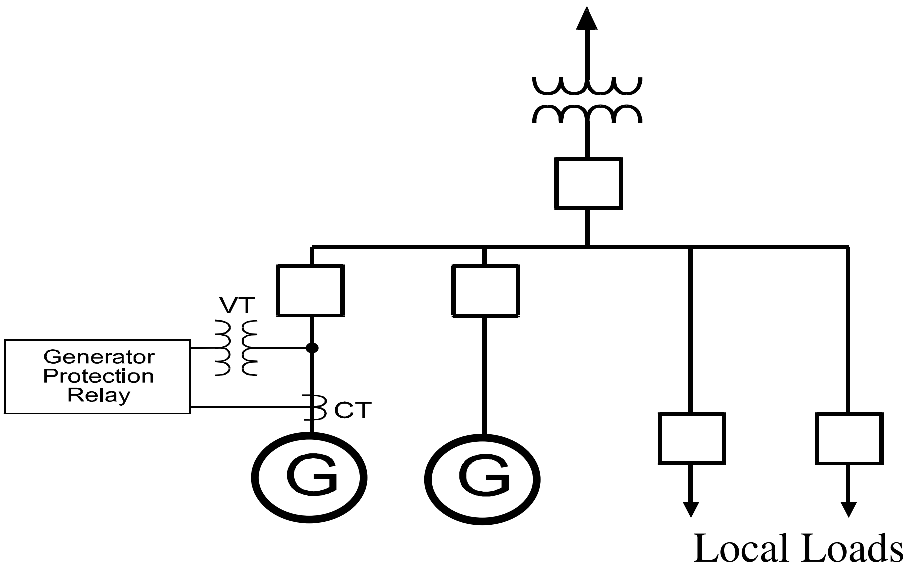


Fig. 2 Typical Generator Protection

Generator protection provides detection of:

1. Generator internal short circuits
2. Abnormal operating conditions (loss-of-field, reverse power, overexcitation and unbalanced currents)

For smaller DGs, most U.S. utilities leave the responsibility to the DG owners and their consultants to select the level of generator protection they believe is appropriate. Utilities, however, become very involved in specifying interconnect protection. Typically, the following interconnection areas are specified by many utilities:

1. Winding configuration of the interconnection transformer
2. General requirements of " utility-grade" interconnection relays
3. CT and VT requirements
4. Functional protection requirements—8 1O/U, 27, 59, etc.
5. Settings of some interconnection functions
6. Speed of operation required to disconnect the DG prior to utility system automatic reclosing

IV. BASIC TYPES OF DG GENERATORS

IEEE P-1547 discusses three basic types of DG generators. Two are traditional types of dispersed generators which operate interconnected with the utility system. They are induction and synchronous generators. The third type is inverter-based DGs that do not operate in synchronism with the utility system.

Induction Generators

Induction machines are typically small—less than 500 KVA. These machines are restricted in size because their excitation is provided by an external source of VARS as shown in Fig. 3a. Induction generators are similar to induction motors and are started like a motor (no synchronizing equipment needed). Induction generators are less costly than synchronous generators because they have no field windings. Induction machines can supply real power (WATTS) to the utility but require a source of reactive power (VARS), which in some cases is provided by the utility system. These generators can provide fault current for only a few cycles for faults on the utility system. Interconnection protection associated with induction generators typically requires only over/under voltage and frequency relaying. Self-commutation is also possible with utility pole-top capacitors and can result in non-sinusoidal waveforms and overvoltage. Section VI of this paper on overvoltage discusses this condition in more detail.

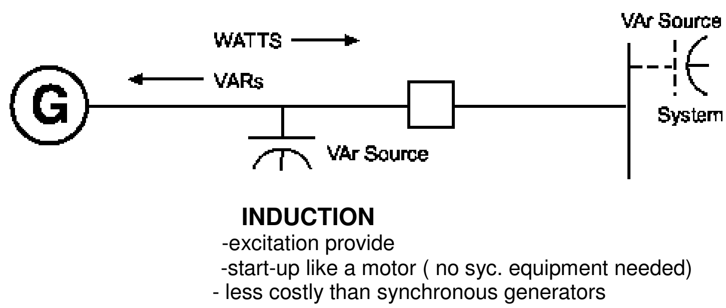


Fig. 3a Induction Generator.

Synchronous Generators

Synchronous generators have a dc field winding to provide a source of machine excitation. They can be a source of both Watts and Vars to the utility system as shown in Fig. 3b and requires synchronizing equipment to be paralleled with the utility. These generators can provide sustained fault current for faults on the utility system.

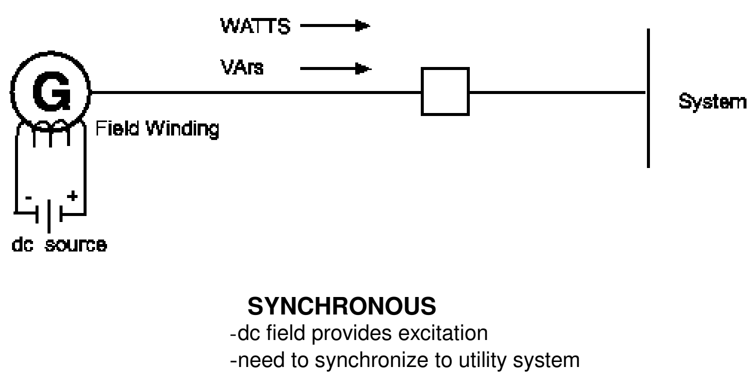
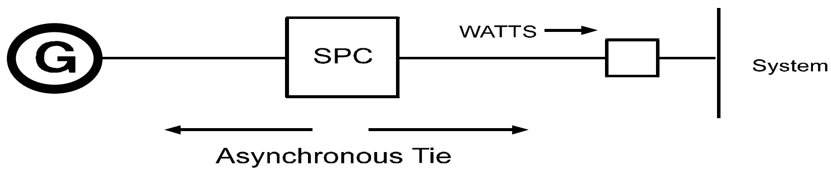


Fig. 3b Synchronous Generators

Asynchronous Generators

Non-traditional, small dispersed generators, especially the new micro-turbines, fuel cells and photovoltaic technologies, are being talked about more frequently as an energy source for the next decade. Most of these devices are asynchronously connected to the power system through Static Power Converters (SPCs). These SPCs are solid-state microprocessor controlled thyristor devices that convert DC or AC voltage at one frequency to 60 Hz system voltages. Digital electronic control of the SPC regulates the device's power output and shuts down the machine when the utility system is unavailable. Some of the newest micro-turbine controls have built in anti-islanding protection (Ref. 11) to detect when the generator is not operating in parallel with the utility. Every cycle or so, the microprocessor SPC control attempts to increase the frequency of the micro-turbine. This is not possible if the micro-turbine is operating in parallel with the utility system. If the generator is islanded from the utility system, the frequency will change and the control is programmed to trip the micro-turbine for this condition. The ability to verify the performance of this scheme through traditional testing is difficult. Thus the utility must rely on factory tests of the system. The need for traditional independent protection to avoid system islanding is thus required by some utilities while others rely on anti-islanding protection embedded in the microprocessor control. Fig. 3c shows a typical one-line diagram for these types of generators.



ASYNCHRONOUS

-static power converter (SPC) converts generator frequency to system frequency

-generator asynchronously connected to power system

Fig. 3c Asynchronous Generator

V. MAJOR IMPACT OF INTERCONNECTION TRANSFORMER CONNECTIONS ON INTERCONNECTION PROTECTION

As mentioned in the previous section, the major function of interconnection protection is to disconnect the generator when it is no longer operating in parallel with the utility system. DGs are generally connected to the utility system at the distribution level. In the U.S., distribution systems range from 4 to 34.5 KV and are multi-grounded 4-wire systems. 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. 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. Fig. 5 shows a number of possible choices and some of the advantages or problems associated with each connection.

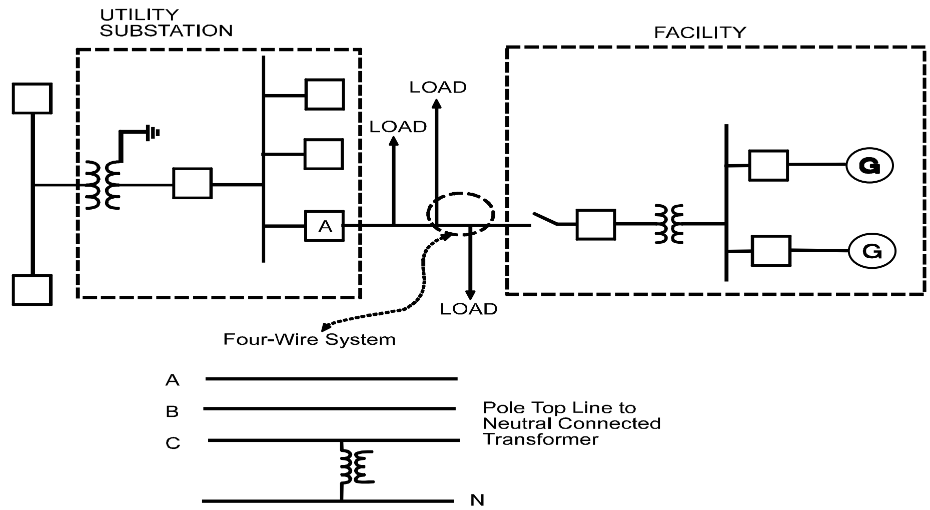


Fig. 4 Typical 4-Wire Distribution Feeder Circuit

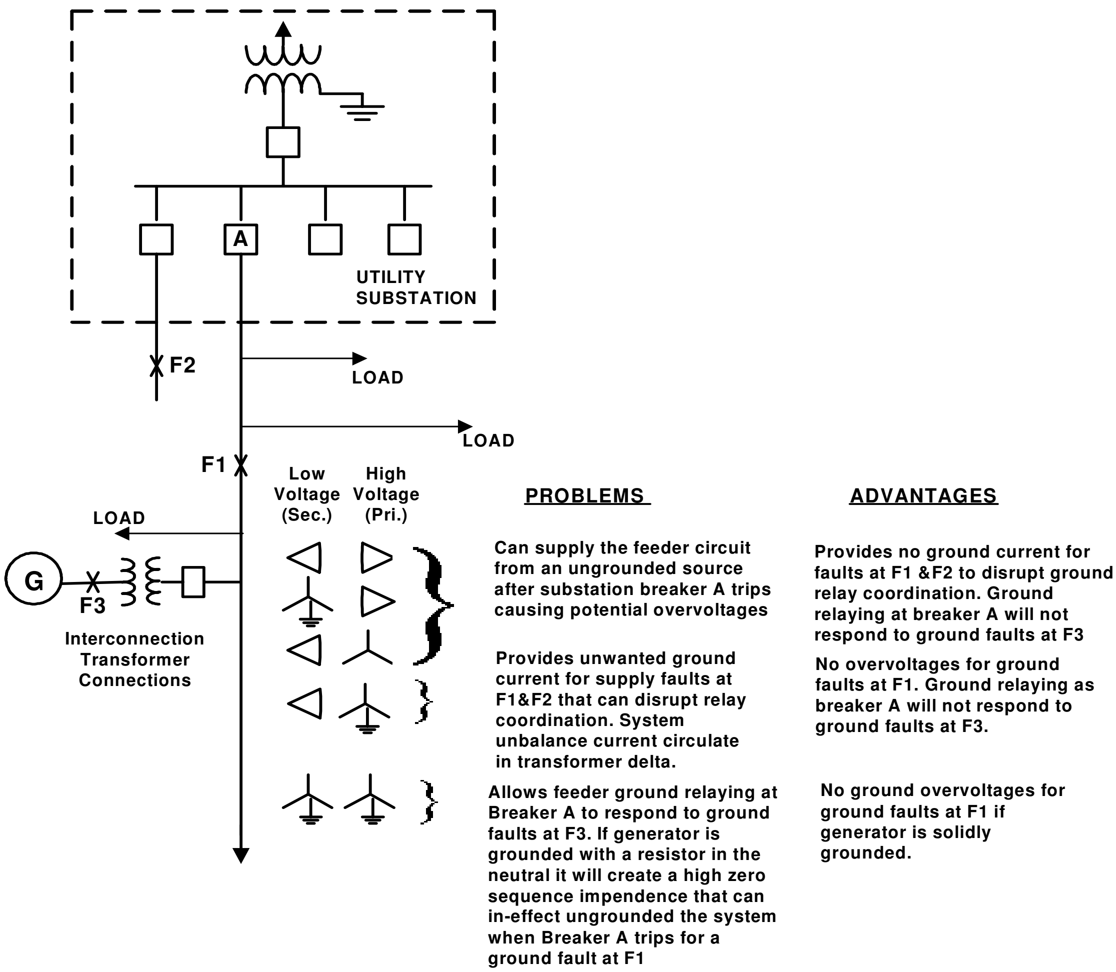


Fig. 5 Interconnection Transformer Connections

IEEE 1547 addresses the question of overvoltages that can be caused by a DG operating in parallel with the utility distribution system with a single sentence that states: *"The grounding scheme of the DG interconnection shall not cause overvoltages that exceed the rating of the equipment connected to the area electric power system and shall not disrupt the coordination of the ground fault protection on the area electric system."* The consideration to do this is not spelled out in the standard and is a major shortcoming of the document. Hopefully, grounding concerns will be covered in greater depth in the future IEEE 1547.2 guide. The utility and DG owner have only two choices in selecting the primary winding configuration of the interconnection transformer.

1. Unground the primary windings (delta or wye ungrounded) and risk possible overvoltage.
2. Ground the primary windings (wye grounded) and potentially disrupt feeder relay ground coordination through the injection of unwanted ground current.

Ungrounded Primary Transformer Windings

The major concern with an interconnection transformer with an ungrounded primary winding is that after substation breaker A (Fig. 5) is tripped for a permanent ground fault at location F_1, the multi-grounded system is ungrounded. This subjects the L-N (line-to-neutral) rated pole-top transformer and lightning arrestors on the unfaulted phases to an overvoltage that will approach L-L voltage. This occurs if the DG is near the capacity of the load on the feeder when breaker A trips. The resulting overvoltages will saturate the pole-top transformer which normally operates at the knee of the saturation curve. Many utilities use ungrounded interconnection transformers only if a 200% or more overload on the DG occurs when breaker A trips. During ground faults, this overload level will not allow the voltage on the unfaulted phases to rise higher than the normal L-N voltage, avoiding pole-top transformer saturation. For this reason, ungrounded primary windings should generally be reserved for smaller DGs where overloads of at least 200% are expected on islanding.

Grounded Primary Transformer Windings

The major disadvantage with this connection is that it provides an unwanted ground fault current for supply circuit faults and reduces the current from breaker A at the utility substation. This can result in a loss of relay coordination. Consider the following cases:

1. If the fault is near the end of the feeder, the reduction in substation ground fault current may result in substation ground fault relaying not responding to the fault. If this is the case, the utility will have to add pole-top line reclosure to detect ground faults near the end of the feeder circuit.

2. If the utility uses a "fuse saving scheme," the reduction of source current and increase in current seen by the fuse can result in failure to over trip fuses and the resulting loss of coordination with substation relaying. Fig. 6 illustrates this point for a typical distribution circuit.

3. If the fault is on an adjacent feeder (F_2 in Fig. 5) the resulting ground current flow through the substation bus could result in loss of coordination and the undesirable tripping of breaker A. To avoid this situation, the overcurrent feeder relays at breaker A may have to be directionalized to respond to faults only on feeder A.

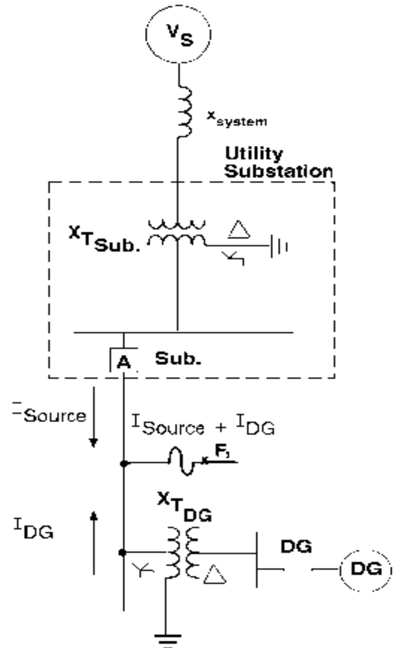


Fig. 6 Single-line diagram for Wye-Grounded(Pri)/Delta(Sec.) Interconnection Transformer

Wye-Grounded(Pri)/Delta(Sec.) Interconnection Transformer Connection

Analysis of the circuit in Fig. 6 also shows that even when the DG is off-line (the generator breaker is open), the ground fault current will still be provided to the utility system if the dispersed generator interconnect transformer remains connected. This would be the usual case since interconnect protection typically trips the generator breaker. The transformer at the dispersed generator site acts as a grounding transformer with zero sequence current circulating in the delta secondary windings. In addition to these problems, the unbalanced load current on the system, which prior to the addition of the dispersed generator transformer had returned to ground through the main substation transformer neutral, now splits between the substation and the DG transformer neutrals. This can reduce the load-carrying capabilities of the DG transformer and create problems when the feeder current is unbalanced due to operation of single-phase protection devices such as fuses and line-reclosers. Even though the wye-grounded/delta transformer connection is universally used for large generators connected to the utility transmission system, it presents some major problems when used on 4-wire distribution systems. The utility should evaluate the above points when considering its use.

Wye- Grounded (Pri)/Wye-Grounded (Sec) Interconnect Transformer Connections

The major concern with an interconnection transformer with grounded primary and secondary windings is that it also provides a source of unwanted ground current for utility feeder faults similar to that described in the previous section. It also allows sensitively set ground feeder relays at the substation to respond to ground faults on the secondary of the dispersed generator transformer (F_3 in Fig. 5). This can require the utility to increase feeder ground relay pickup and/ or delay tripping to provide coordination. This reduces the sensitivity and speed of operation for feeder faults and can increase feeder circuit wire damage.

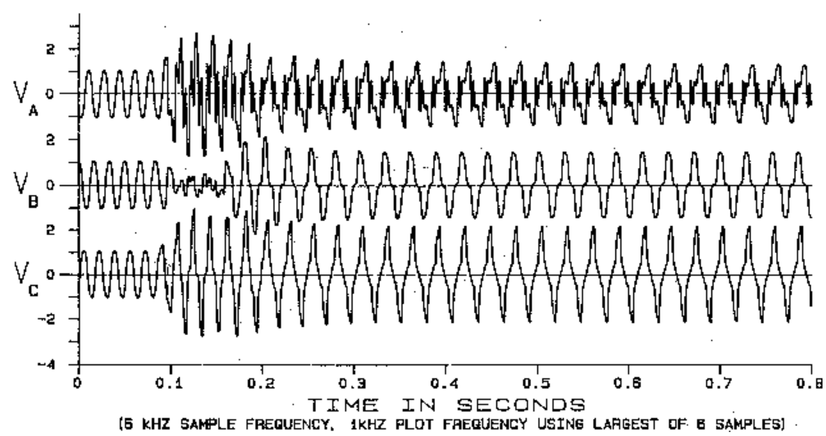
IEEE P-1547 does not provide enough background to lead the reader of the standard to consider the above-cited conclusions

VI. OTHER SOURCES OF DG INDUCED OVERVOLTAGE AND PQ PROBLEMS

The phenomenon of self-excitation of induction generators has been known for many years. It occurs when an isolated generator is connected to a system having capacitance equal to, or greater than, the magnetizing reactance requirements. Depending on the value of the capacitance, and the KW loading on the machine, voltages in the island of 1.5-2.0 per unit can be produced. To compound the problem of islanding of DGs with distribution system capacitor banks, a unique form of ferroresonance can occur that 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. While the exact description of the phenomenon is contained in Ref. 4, the following conditions must exist for it to occur:

1. The DG must be separated from the utility source (islanding condition).
2. The KW load in the island must be less than 3 times the rating of the DG.
3. The system capacitance must be greater than 25 and less than 500 percent of the rating of the DG.
4. 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 (Ref. 4) 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 wave shape for this resonance condition is non-sinusoidal. An example of the voltage waveform is shown in Fig. 7 and was taken from field tests conducted in New York State in the 1980's.



50 KW synchronous DSG, 9 kw load, 100 kvar capacitance, and wye-delta step-up transformer. Maximum voltage: A=2.74 p.u., B=2.34 p.u., C=2.92 p.u.

Fig. 7 Overvoltage Caused by Ferroresonance (taken from Ref. 4)

Frequency and voltage measurements in digital, electronic and electromechanical relays may not operate as expected since the waveshape is not sinusoidal. The measurement of peak overvoltage rather than RMS provides the best detection solution to detection of this type of event.

VII. 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 system (distribution or subtransmission), type of generator (induction, synchronous, asynchronous) and interconnection transformer configuration (see previous section of this paper). 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 P-1547 does not address protection areas such as: fault backfeed removal, abnormal power flow, damaging system conditions or restoration practices addressed in this section of the paper.

Table 1 Interconnection Protection Areas

Interconnection Protection Objective	Protection Function Used
Detection of loss of parallel operation with utility system	81O/U, 81R*, 27/59, 59I, TT**, 32***
Fault backfeed 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	

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. 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 transfer trip (TT) using a reliable means of communication may be necessary. When induction or synchronous DGs are islanded with pole-top capacitors and the generator capacity is near that of the islanded load (as described in Section VI of this paper, 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.

When the loss of parallel operation is detected, the dispersed generator must be separated from the utility system quickly enough to allow the utility breaker at the substation to automatically reclose. High-speed reclosing on the utility system can occur as quickly as 15 to 20 cycles after utility substation breaker tripping. The utility needs to provide guidance to the DG owner on the speed of separation required. The use of underfrequency relays coupled with the need to separate the dispersed generator prior to utility breaker reclosing precludes the ability of most DGs to provide power system support to the utility during major system disturbances. When frequency decreases due to a major system disturbance, these generators will trip off-line. It may be possible to reduce underfrequency settings to comply with regional Reliability Council requirements, but the required trip time cannot generally be extended to exceed automatic reclosing times.

An approach to mitigate this problem is to use rate-of-change frequency (8 1R) protection, which is widely used outside the U.S. in place of, or in conjunctions with, underfrequency (81) relaying to detect islanding of the DG. It offers the advantage of more rapid tripping for severe DG overloads while allowing the DG to remain connected to the system when frequency is being slowly dragged down due to the loss of utility generation. The problem of DGs providing some system support will become more critical if the percentage of total system generation provided by these generators increases over the next ten years as forecasted by some industry experts. The modification of substation reclosing using source voltage supervision along with synchrocheck reclosing may be needed if underfrequency trip times are extended. This type of scheme is illustrated in Fig. 8 and provides security against reclosing prior to disconnection of the dispersed generator.

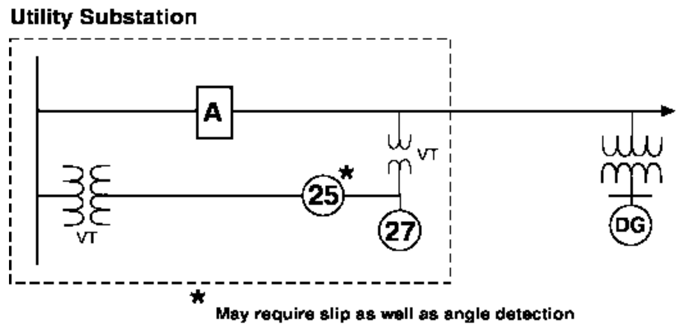


Fig. 8 Utility Substation Scheme

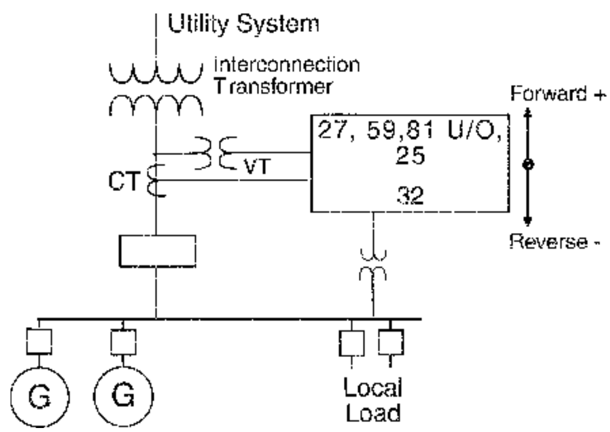


Fig 9 California Rule 21 - Directional Power Options

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. The scheme is applied where minimum verifiable local load is 50% or less of the total installed DG KVA. Fig. 9 illustrates this scheme.The DG owner can select one of two 32 directional power options.

The DG owner can select one of two 32 directional power options.

Option 1: This option uses a very sensitive forward direction power relay that is set to trip on the charging Watts of the interconnection transformer. This requires an extremely sensitive 32 element that can detect secondary CT current levels in the 5-10 Ma range. Tripping time is specified at 2 seconds. This option is not practical for two reasons:

1. Almost all commercially available directional power relays do not have the sensitivity to detect the low power levels required.

2. The reason users would choose this option is to operate the interconnection such that under normal conditions almost no power is purchased from the utility. Therefore there is very little or no power flow at the intertie point. Operating experience has shown that sudden decreases in local load (motors cycling off or local feeder circuits tripping) resulted in frequent nuisance tripping of the 32 relay. This forced the DG owner to operate their generator(s) to allow sufficient power to flow into the bus so sudden local load decreases will not cause nuisance tripping of the 32 relay. In effect, they must operate with power flow into the bus at least to the level described in Option 2 to avoid nuisance tripping.

Option 2: This option uses a directional under power relay that operates when power flow into the generator bus is below 5% of the total DG KVA at the facility. When power flow falls below this level for 2 seconds, a trip condition is initiated. This option requires an under power relay (a relay that operates to close an output contact when power falls below its setting). The relay must also be set above the power flow into the bus that would occur for a sudden *decrease* in local load to avoid nuisance tripping. The 32 sensitivity requirements for this application are much less than Option 1. Option 2 has become the method chosen by almost all DG owners.

Fault Backfeed Detection

On many small DGs, no specific fault backfeed 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, the detection of loss of parallel operation via 81O/U and 27/59 relays is 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, fault backfeed detection in addition to loss of parallel operation protection is generally provided. It should be recognized that the longer the generator is subjected to a fault, the lower the current that the synchronous generator provides to the fault. In developing backfeed removal protection, the decay of current for external faults needs to be addressed. Typically, relay functions such as the 67, 21 or 51V are used to provide phase fault backfeed 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 winding, a 51N neutral overcurrent relay or, in some cases, a 67N ground direction relay is used. Fig. 10 shows typical interconnection protection for grounded primary winding interconnection transformer installations. For ungrounded interconnection transformers, neutral overvoltage relays (59N, 27N) provide the detection for supply ground faults. The VTs which supply these relays have their primary windings connected line-to-ground. These primary VT windings are generally rated for full line-to-line voltage. VT connections using a single VT with 59N and 27N relays or three VTs connected in a broken-delta configuration are used by many utilities. Fig. 11 shows typical typical interconnection protection for a dispersed generator with an ungrounded interconnection transformer configuration.

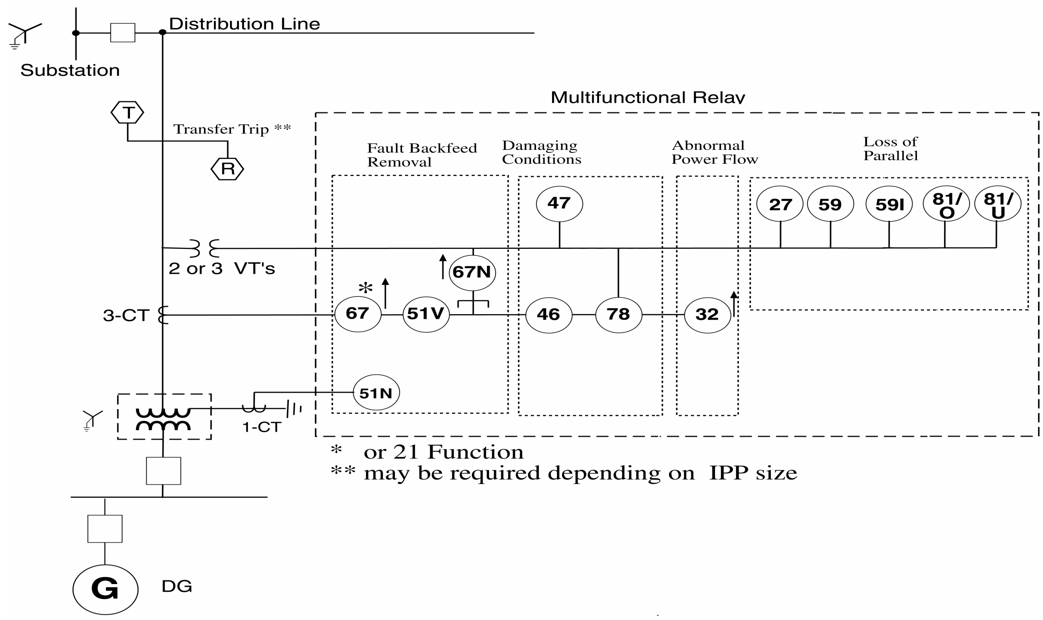


Fig. 10 Typical Protection for Moderately-Sized Dispersed Generator with Wye-Grounded (Pri) Interconnection Transformer

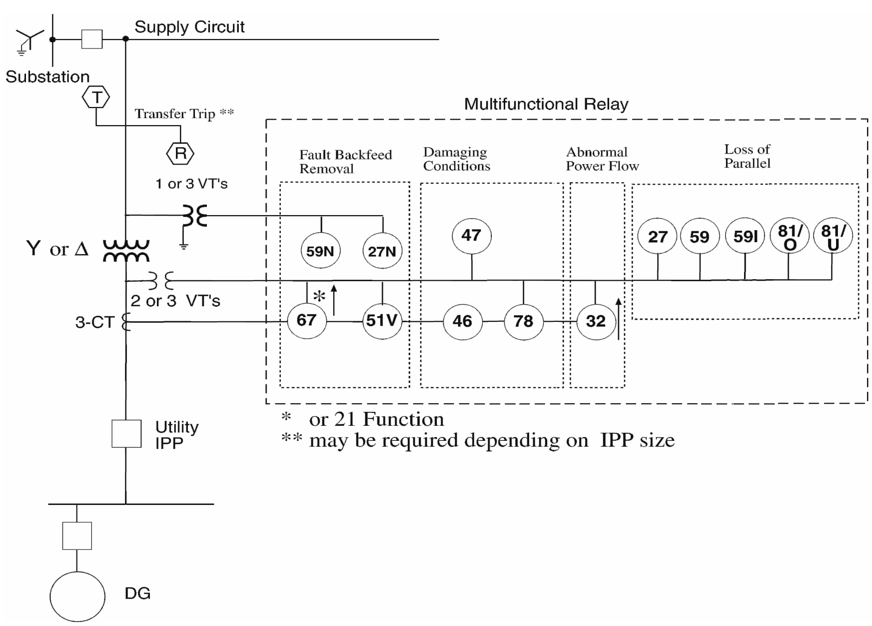


Fig. 11 Typical Protection for Moderately-Sized Dispersed Generator with Ungrounded (Pri) Interconnection Transformer Detection of Damaging System Conditions

Dispersed Generator Tripping/Restoration Practices

Once the DG has been separated from the utility system, after interconnection protection operation, the intertie must be restored. Two DG tripping/restoration practices are widely used within the industry. The first restoration method (case 1) is used in applications where the generation at the dispersed generation facility does not match the local load. In these cases, interconnection protection typically trips the DG breakers, as illustrated in Fig. 12. When the utility system is restored, the dispersed generators are typically automatically resynchronized. Many utilities require a synchrocheck relay (25) at the main incoming breaker to supervise reclosing as a security measure to avoid unsynchronized closure. The synchrocheck relay is generally equipped with dead bus undervoltage logic to allow reclosure from the utility system for a dead bus condition at the dispersed generation facility.

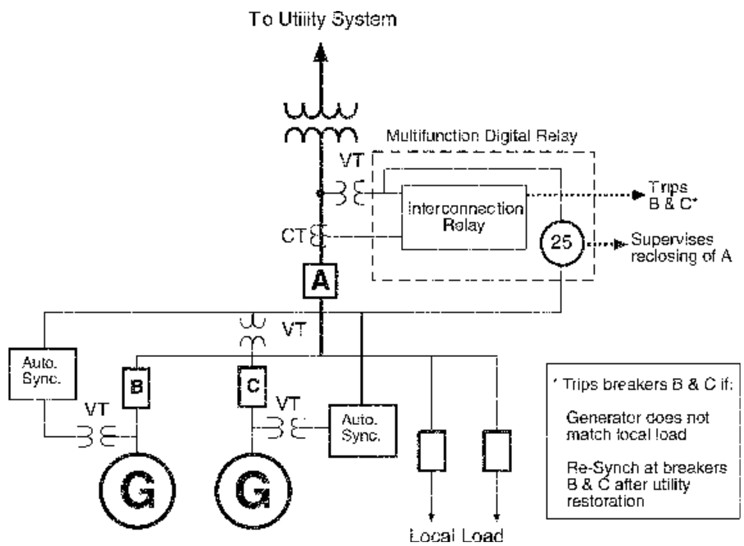


Fig. 12 Restoration after Interconnection Tripping—Case 1

The second restoration method (case 2) is used where the DG roughly matches the local load. In these cases, the interconnection protection trips the main incoming breaker (breaker A) as illustrated in Fig. 13. In many cases, the dispersed generation facility may have internal underfrequency load shedding as is the practice at petro-chemical and pulp and paper facilities to match the local load to available dispersed generation after the utility separation. To re-synchronize the dispersed generation facility to the utility system, a more sophisticated synchrocheck relay is required which not only measures phase angle but also slip frequency and voltage difference between the utility and dispersed generation systems. Typically, such relays supervise automatic, manual and supervisory reclosing.

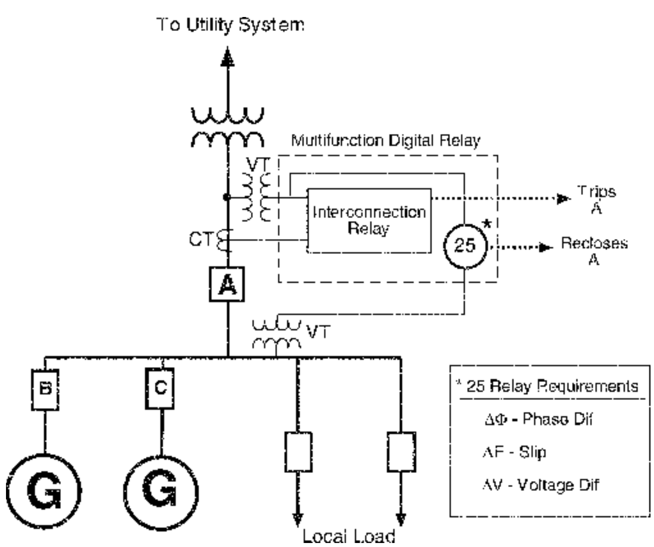


Fig. 13 Restoration after Interconnection Tripping—Case 2

VIII. USE OF DIGITAL TECHNOLOGY FOR INTERCONNECTION PROTECTION

Modern multifunction digital relays have a number of features, which make them an ideal choice for interconnection protection of dispersed generators. The most important of these features are user-selectable functionality, self-diagnostics, communications capabilities and oscillographic monitoring.

User-Selectable Functionality

As pointed out in this paper, interconnection protection functionality varies widely with generator size, point of interconnection to the utility system, type of DG (induction, synchronous or asynchronous) and grounding of the interconnection transformer. These variables make user-selectable ("pick and choose") functionality an important feature. Many manufacturers provide two DG interconnect relay hardware platforms–one with the basic functions needed in most applications that address interconnection protection for smaller DGs at a low cost, and a second, more sophisticated relay for larger DGs with a complete library of functions. Both hardware platforms are user configurable for the specific applications. Fig. 14 shows a typical interconnection application for the high-end package used for larger DGs.

Self-Diagnostics

Self-diagnostics of a multifunction digital relay provides immediate detection of relay failure. Without interconnection protection, the DG, as well as the utility's system, may be subjected to damaging conditions such as undetected fault currents, overvoltages and high DG shaft torque damage due to utility system automatic reclosing. For these reasons, self-diagnostics takes on renewed importance. Some utilities trip the DG on failure of the interconnection protection package to avoid such damage. Self-diagnostics provide the utility with some assurance that the interconnection protection is functional. This type of assurance was not available in older electronic or electromechanical technologies.

Communications Capability

All multifunction digital relays have communication ports. These are typically RS-232, RS-485 or in some cases, fiber-optic connections. Most moderate-to-large sized DGs are required to provide continuous telemetry data on generator operation to the utility. Information such as on-line status (open or closed) monitoring of key interconnection and generation breakers, as well as instantaneous MW and MVAR generator output is typically required. Much of this information can be obtained from the digital interconnect relay package, eliminating the need for separate transducers and metering. Also, the ability to interrogate the interconnection protective relay from a remote location to determine the relay targets and sequence-of-event records can provide information that is vital in restoring the DG to service.

Oscillographic Monitoring

Oscillographic monitoring of relay inputs (currents and voltages) provide information on the cause of the interconnect relay's operation and if the relay has operated as planned. Since interconnection protection is applied at the point of common coupling between the utility and the DG facility, it provides valuable information as to which system may have precipitated the tripping. Oscillographic information has resulted in settling a number of arguments between utilities and DG owners as to the cause of a particular tripping event.

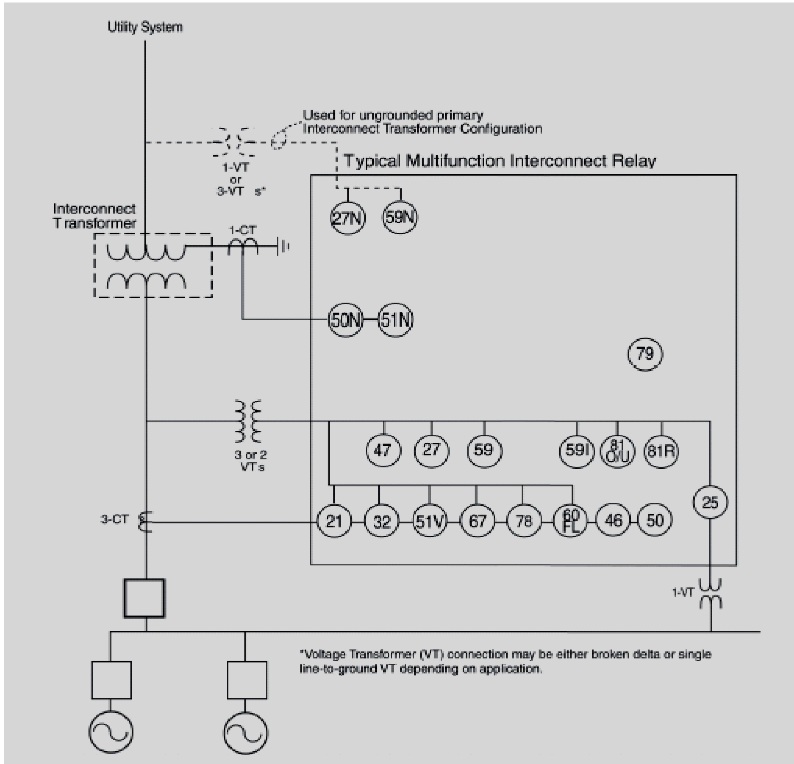


Fig. 14 One-Line Diagram for Digital Multifunction Interconnect

IX. CONCLUSIONS

In the view of this author, IEEE 1547 provides very limited real guidance to the industry on DG green power interconnect protection requirements other than calling for over/underfrequency and over/undervoltage interconnection protection. The standard cited obvious requirements for DG interconnected operation but offered few methods, solutions or options to meet these requirements. Key technical issues such as: mitigating potential overvoltages, interconnection transformer choices, loss of utility relay coordination, application of DG on secondary grid networks, damage to DG generators due to unbalanced current caused by utility single phasing, and out-of-step protection are not addressed at all or not at a significant level. This paper has attempted to highlight these and other problems and concerns and offers solutions or options for the consideration of both utilities and DG owners. The stated goal of 1547 was a single document of standard technical requirements for DG interconnection. The standard does this on such a basic level that solutions to real problems are not addressed to the degree required to help those struggling with the problems cited in this paper. 1547 is not a document that engineers in utilities or those consultants designing green power DG interconnection protection had hoped for from this standards group. In recognition of the fact that much more work needs to be done, three additional IEEE Standards Committees were formed.

The connection of significant amounts of green power distributed generation at a point on the power system (distribution and subtransmission circuits) never designed for the interconnection of generation presents significant technical problems for both the utility and DG consultant engineers. This paper highlights these technical problems, many of which have no standard solutions but only choices with undesirable drawbacks. Hopefully, the issues raised in this paper will be addressed in the future efforts of the IEEE Standards Committees.

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