Impact of Green Power Inverter-Based Distributed Generation on Distribution Systems

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Abstract: ***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 solar and wind are some of the green generation being interconnected at the distribution level. These non-conventional generators use inverter-based technologies and operate in parallel with utility distribution feeders. The fault behavior of an inverter-interfaced solar or wind distributed generator (DG) is determined by its control, which is significantly different from conventional synchronous and induction generators.***

In addition, utilities have expressed a concern that distributed generators interfaced to the grid via inverters could cause a transient overvoltage during a single phase to ground fault, after the substation breaker opens. The concern is that this overvoltage will damage utility equipment such as lightning arresters or saturate line-to-neutral rated utility feeder transformers resulting in transformer failure. This paper examines both the fault current and overvoltage issue and compares inverter based distributed generations (DGs) with conventional synchronous and induction DGs.

I. Introduction

There are three basic types of DGs which are in-service today on distribution systems: synchronous generators, induction generators and inverter-interfaced generators. Many DGs, such as most wind turbines and microturbines, and all photovoltaics, interface with power systems through inverters. Utility regulators as well as government policy makers extol the environmental advantages of inverter-based green power in reducing greenhouse gases and reliance on fossil fuels. Today, DGs are not considered a source of firm power since they cannot be counted on to supply power when the power system is under stress. Inverter-based DGs will also bring some challenges to distribution system protection and operation. Utility engineers have two major concerns. First is the impact of fault current and its duration on distribution protection system coordination. Second is the possibility of transient overvoltage that can occur when the inverter-based DG becomes isolated from the system due to a supply ground fault.

Fault behavior of conventional generators, such as synchronous generators and induction generators, is well known. A voltage source behind a reactance is typically used to represent a conventional generator during the fault condition. As for inverter-based DGs, the fault behavior is highly determined by the converter control and protection, which is designed and implemented by the inverter manufacturers to both protect their equipment and follow the industry standards. Interestingly, this fault behavior dependence on control is not widely discussed, although the inverter-based DG fault current contribution is substantially different from that of the conventional generators. Utility engineers have also expressed a concern that distributed generators interfaced to the grid via inverters could support a transient or temporary overvoltage during a single-phase-to-ground fault, after the substation breaker opens, and especially when the inverter-based DG feeds the distribution feeder through a delta-Y transformer with the delta on the high voltage side of the interconnect transformer.

This paper will discuss these two issues as well as compare the effect that inverter DGs have on the distribution system to those of conventional synchronous and induction generators.

II. Fault Current Behavior of Inverter-Based DGs

In a power electronics-based inverter, the fault behavior is largely determined by its control. Essentially, the inverter designer controls how the inverter-based DG will perform under fault conditions. Therefore, it is neither practical nor possible to come up with one or several generalized model(s) and use them to accurately predict the fault behavior. There are two basic types of control schemes (one is a voltage control scheme and the other is a current control scheme). A basic logic block diagram is shown in Fig. 1. Typically, both schemes regulate real and reactive power.

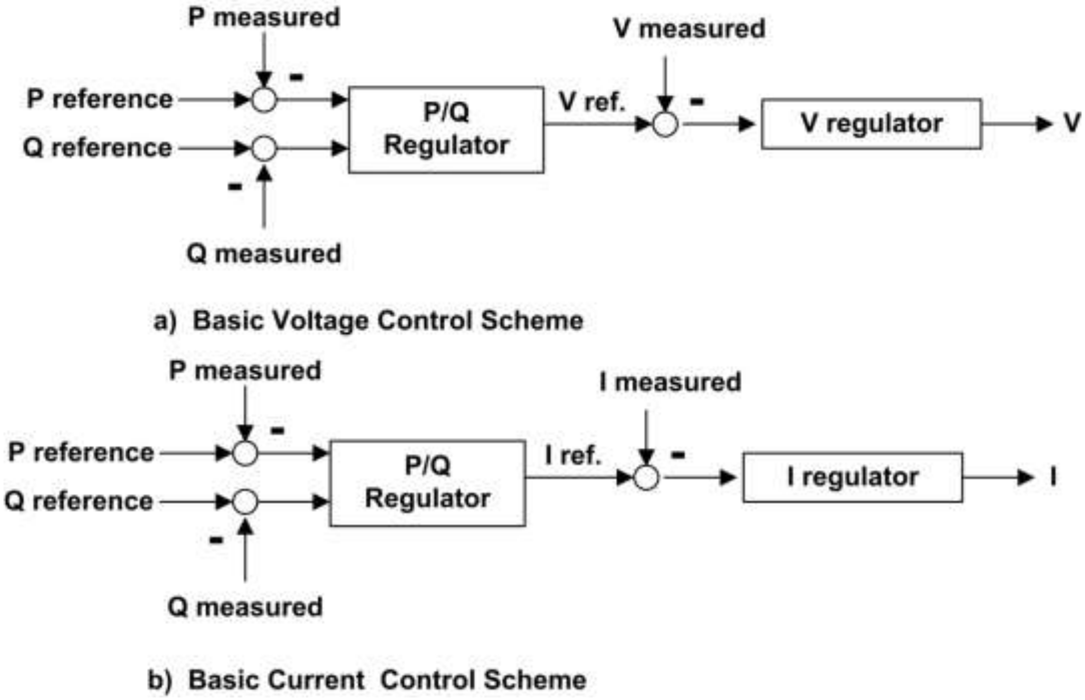
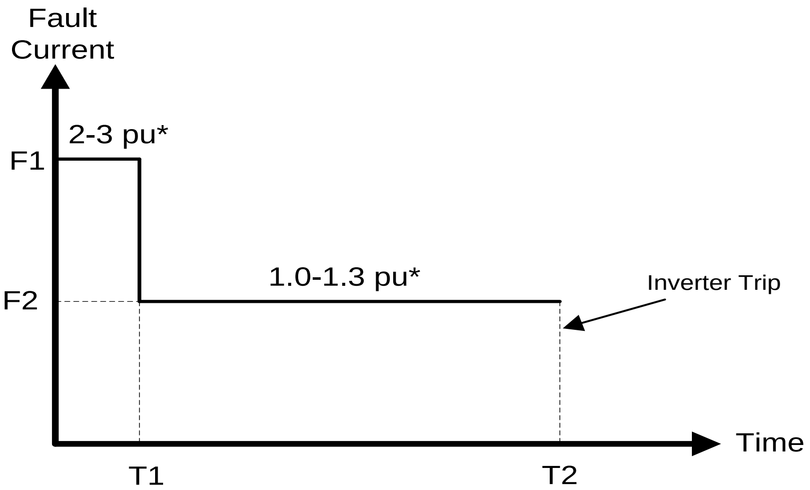


Fig. 1 Inverter Based Control [1]

The voltage control scheme directly regulates voltage magnitude through either open or closed loop control. The current control scheme has a fast current control loop to regulate the current directly. Knowing the type of control scheme is important to understand the fault behavior of an inverter-based DG.

Design features, such as hardware current limiting functions on gate-drives that control certain functions hitting their limits, play a major role in the transient behavior. Unless these nonlinearities are adequately modeled, fault analysis will be inaccurate and often misleading. However, it is still possible to obtain a rough idea of the fault behavior of an inverter-based DG and estimate its impact on system protection given the specific application requirements. This is because there are always constraints to all inverter-based DG designs, including the overload limitations of the electronics and standards pertaining to grid integration requirements.

Fault Current Profile -- Unlike rotating electric machines, power electronics-based DGs often have limited overload capability. Some commercial inverter DGs allow 10% to 30% overloading for a short time (one to several seconds), but seldom more than that. To protect those semiconductor switching devices from thermal breakdown, an inverter DG often has at least two layers of overcurrent protection. During a fault, if the inverter DG's output current becomes very high (e.g., peak value exceeds a threshold that is typically 2~3 pu), the hardware overcurrent protection on the gate drive will stop firing temporarily and clamp the instantaneous current to that threshold. This period is short, and within several cycles the control-based protection is able to effectively reduce the RMS current to a lower level (1.0~1.3 pu). If the fault lasts for more than several seconds, a trip could be issued to disconnect the inverter DG unless other protection functions trip first. Transient and steady-state can be used to describe the two fault durations. Fig. 2 illustrates the magnitude of the fault current through the two time periods.



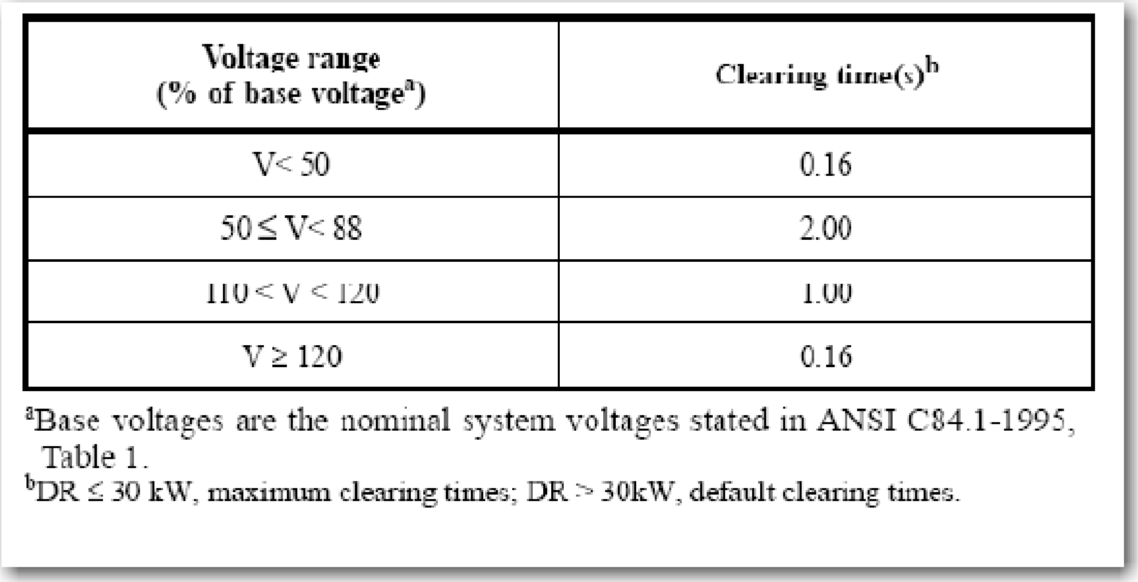
T1 = Current Control -- Less than ½ cycle
= Voltage Control -- Several Cycles
T2 = Ends when Inverter Trips -- Can be Several
Seconds Based on Inverter Component Capability

* per unit (pu) of Inverter Rating

Fig. 2 Inverter Fault Current Signature [1]

In Fig. 2, the transient current magnitude, F1, is determined by the impedance between the inverter DG and the fault location. The closer the fault is to the DG, the higher the transient current (T1). However, even under the worst condition, F1 will not exceed the threshold determined by the inverter hardware overcurrent protection.

The transient time duration, T1, depends on the bandwidth of the inverter control-based protection function (for current control schemes, it is the current control loop). In most cases, inverters with current control schemes react much faster (sometimes less than half a cycle) than those with voltage control scheme (several cycles) due to the high bandwidth of current control loops. The steady-state fault current, F2, is determined by the application requirement that a specific inverter design may be subject to during the fault event. The steady-state fault duration, T2, ends when the inverter trips or the fault is cleared. IEEE Std.1547 [2] gives the maximum tripping time for various fault voltage levels (see Table 1). This could be a determining factor if the inverter design follows this standard. In the future, as the penetration level keeps increasing and islanding operation becomes an option, fault-ride-through capability may be required. In such a circumstance, T2 may continue until the fault is cleared or isolated, or the maximum fault duration is reached—whichever happens first. T2 is critical to determine the how the inverter-based DG will impact the operation of distribution protection. For this reason, dedicated interconnection protection should be considered where tripping time can be precisely established to allow coordination with utility distribution protection and automatic reclosing.



Voltage range (% of base voltage[a])	Clearing time(s)[b]
V< 50	0.16
50 ≤ V< 88	2.00
110 < V < 120	1.00
V ≥ 120	0.16

[a]Base voltages are the nominal system voltages stated in ANSI C84.1-1995, Table 1.
[b]DR ≤ 30 kW, maximum clearing times; DR > 30kW, default clearing times.

Table 1 IEEE Standard 1547 Maximum Tripping Time for DGs [2]

Fault Current Composition Watts vs. Vars - For system protection studies, the fault current composition (i.e., real and reactive current components) is another important aspect to be considered. Today IEEE Std. 1547 requires that a DG shall not actively regulate the voltage. The steady-state fault current may contain very little reactive current if unity power factor is a design requirement. In the transient duration (T1 in Fig. 2), a higher reactive current may be observed—either because the sudden grid voltage drop is not picked up by the measurement or the control takes some time to capture the phase jump caused by the fault. In contrast, if an inverter design is required to provide voltage regulation, such as transmission interconnected wind turbines, then a significant level of reactive current will be expected depending on the voltage level.

In Reference 1, the authors present a case study for a commercially available solar inverter and control externally connected to a power system simulator to control the operation of the inverter. The inverter control studied was a current-based control scheme. The case study was conducted for a three-phase fault. Fig. 3 shows the one-line diagram used for the case study and an oscillograph taken from the simulator of the inverter fault current up to when the inverter control shut down the inverter. Table 2 is a summary of the DG behavior for three-phase fault cases where the fault location was moved from near the Inverter DG location to the far end of the feeder. Since the inverter is a constant-current device, the fault current remains almost constant and is not affected by the impedance to the fault.

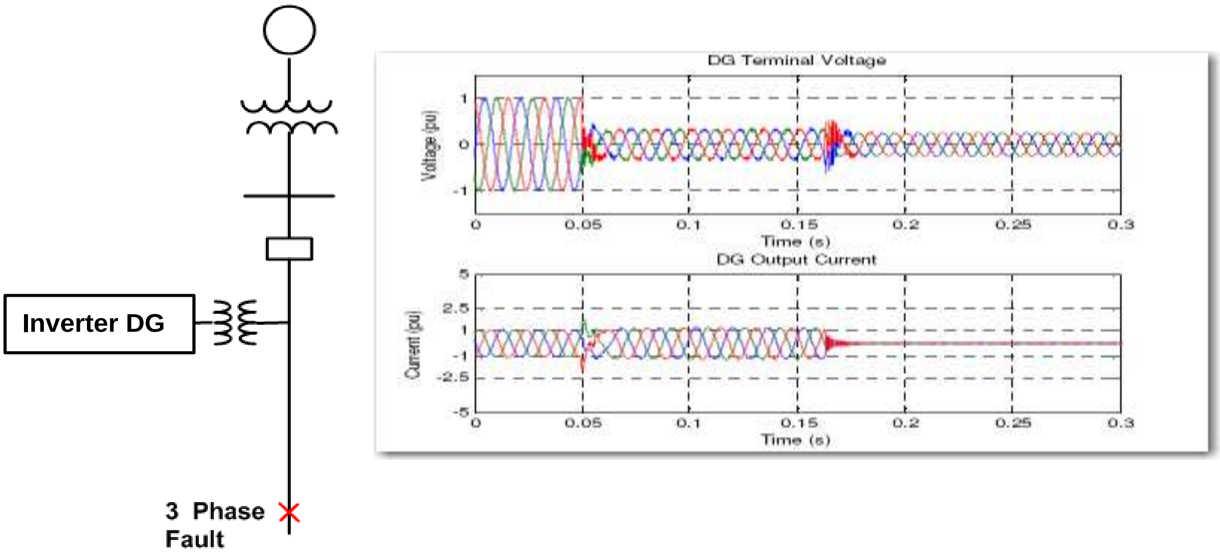
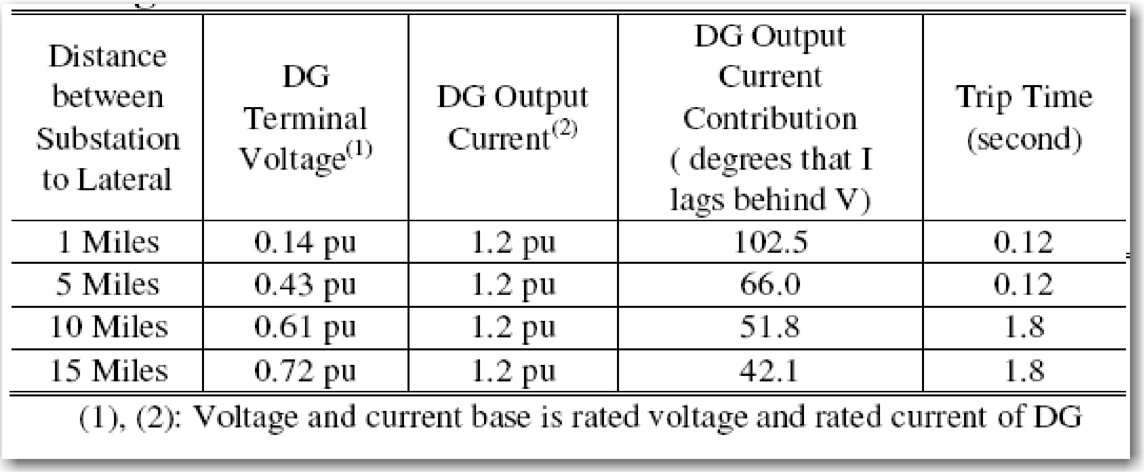


Fig. 3 Case Study –One-Line Diagram and Oscillograph [1]



Distance between Substation to Lateral	DG Terminal Voltage$^{(1)}$	DG Output Current$^{(2)}$	DG Output Current Contribution (degrees that I lags behind V)	Trip Time (second)
1 Miles	0.14 pu	1.2 pu	102.5	0.12
5 Miles	0.43 pu	1.2 pu	66.0	0.12
10 Miles	0.61 pu	1.2 pu	51.8	1.8
15 Miles	0.72 pu	1.2 pu	42.1	1.8

(1), (2): Voltage and current base is rated voltage and rated current of DG

Table 2 Case Study – Inverter Behavior with Different Distances to Fault Location [1]

III. Impact of Interconnection Transformer – Synchronous & Induction DGs

The impact of interconnection transformer grounding for induction and synchronous DGs is well understood and has a major impact on unbalanced fault current contribution to feeder supply faults as well as potential overvoltage. In induction generators, the fault current will decay within a few cycles; in synchronous generators, the current reduces much more slowly as the generator goes through its various impendence modes (X″, X′, Xsyn). The impact of various interconnection transformer grounding alternatives and its effects on the distribution system are outlined in this section of the paper.

In the U.S., as well as many other countries, distribution systems range from 4 to 34.5 KV and are multi-grounded four-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 few possible choices and some of the advantages or problems associated with each connection.

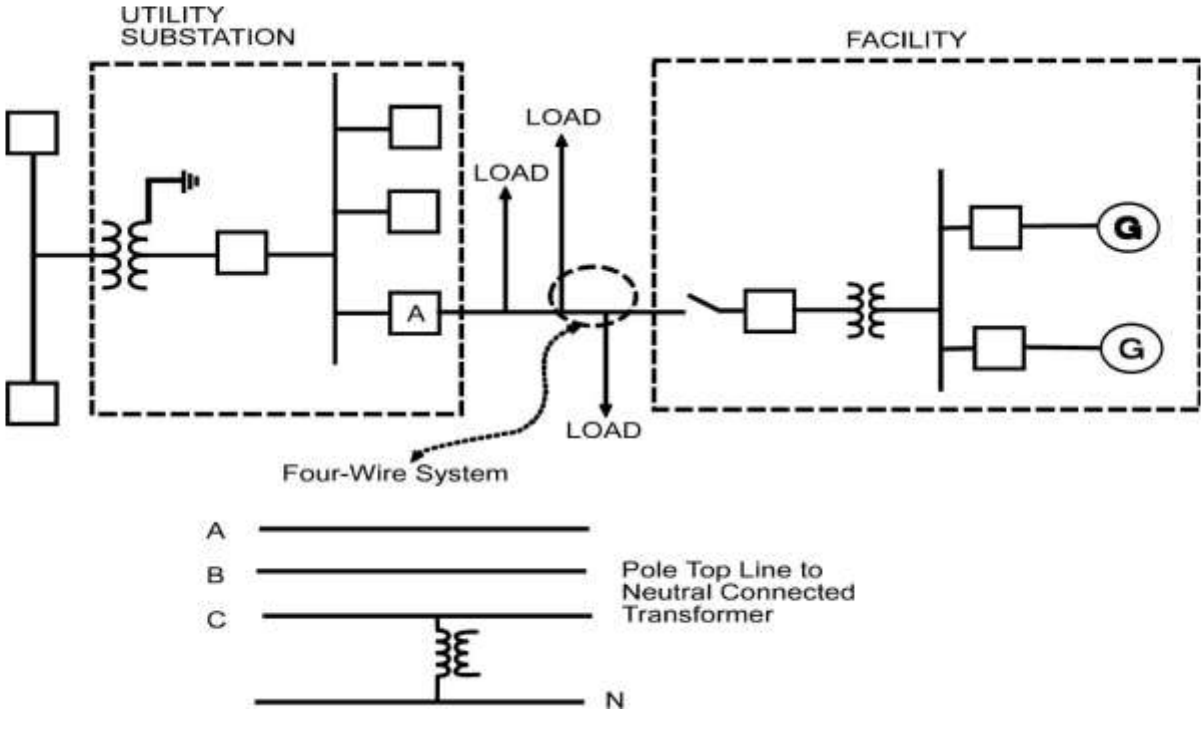
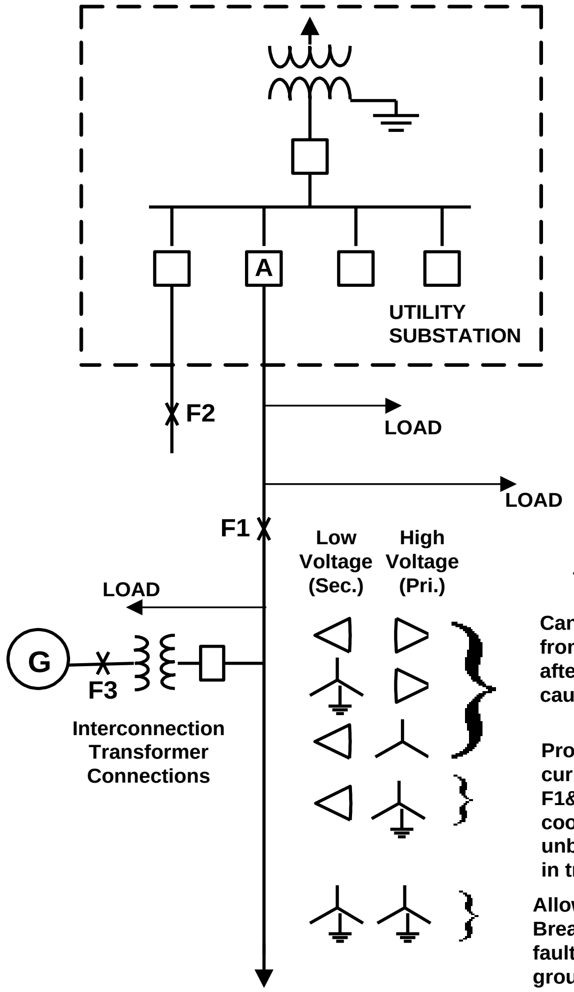


Fig. 4 Typical 4-Wire Distribution Feeder Circuit

With a single sentence, IEEE Std. 1547 addresses the question of overvoltages that can be caused by a DG operating in parallel with the utility distribution system: *"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. Grounding concerns are covered in greater depth in the IEEE 1547.2,7,8 guides. 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.



PROBLEMS	ADVANTAGES
Can supply the feeder circuit from an ungrounded source after substation breaker A trips causing potential overvoltages	Provides no ground current for faults at F1 &F2 to disrupt ground relay coordination. Ground relaying at breaker A will not respond to ground faults at F3
Provides unwanted ground current for supply faults at F1&F2 that can disrupt relay coordination. System unbalance current circulate in transformer delta.	No overvoltages for ground faults at F1. Ground relaying as breaker A will not respond to ground faults at F3.
Allows feeder ground relaying at Breaker A to respond to ground faults at F3. If generator is grounded with a resistor in the neutral it will create a high zero sequence impendence that can in-effect ungrounded the system when Breaker A trips for a ground fault at F1	No ground overvoltages for ground faults at F1 if generator is solidly grounded.

Fig.5 Interconnection Transformer Connections – Conventional Generation

<u>Ungrounded Primary Transformer Winding</u> - 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 F1, 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 can approach L-L voltage. Fig. 6 illustrates this overvoltage. 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 300% 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 300% are expected on islanding.

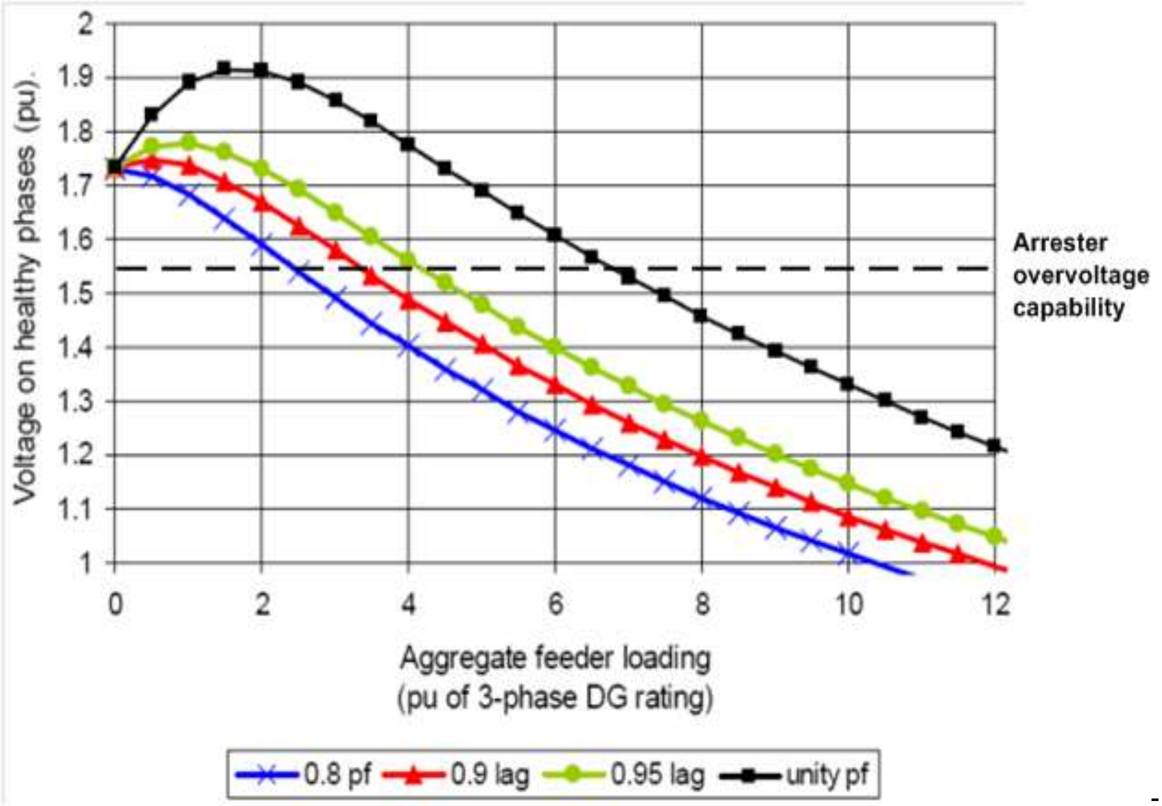


Fig. 6 Overvoltages on the Unfaulted Phases [2]

Grounded Primary Transformer Winding - 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 reclosers 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. 7 illustrates this point for a typical distribution circuit.
3. If the fault is on an adjacent feeder (F2 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.

<u>*Wye-Grounded (Pri) / Delta (Sec.) Interconnection Transformer Connection*</u> - 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 DG 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 four-wire distribution systems. The utility should evaluate the above points when considering its use.

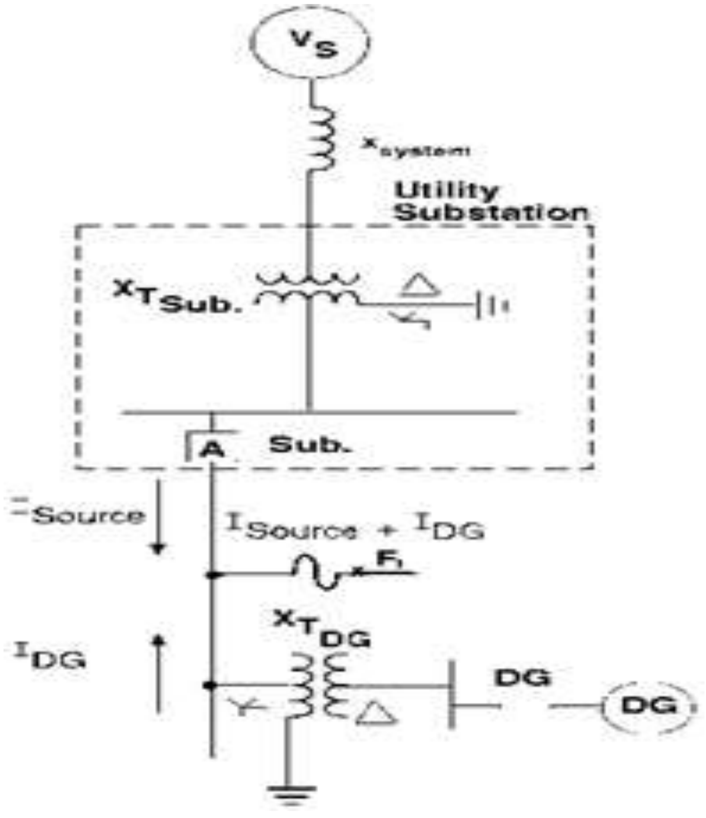


Fig. 7 Fuse Saving for Wye-Grounded (Pri)/Delta(Sec.) Interconnection Transformer

<u>*Wye-Grounded (Pri)/Wye-Grounded (Sec) Interconnect Transformer Connections*</u> - 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

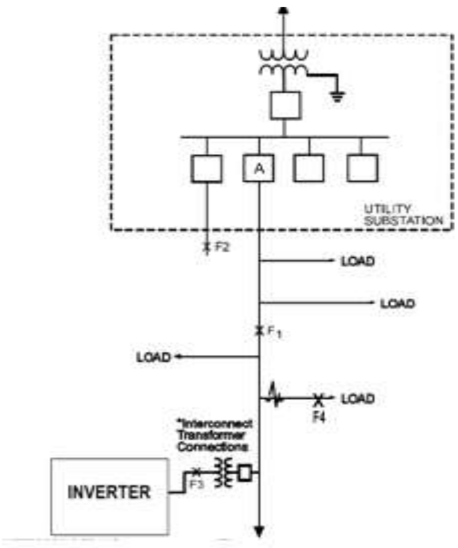
(F3 in Fig. 5). This can require the utility to increase feeder ground relay pickup or delay tripping to provide coordination. This reduces the sensitivity and speed of operation for feeder faults and can increase feeder circuit wire damage. In addition, if the generator is grounded through a neutral resistor (a typical practice on large diesel generators), the resistance to the zero sequence circuit will be large enough so that the system will no longer be effectively grounded. Neutral overvoltage can occur similar to these for delta primary interconnection transformer applications with voltage rises as shown in Fig. 6.

IV. Impact of Interconnection Transformer – Inverter-Based DGs

Most faults on distribution systems are ground faults. Therefore, the fault generated by an inverter-based DG is also an important aspect of its fault behavior. There are two factors that will affect the sequence current during an unbalanced fault. One is the negative sequence behavior of the inverter DG. Some designs use certain control logic to generate large equivalent negative sequence impedance in the inverter DG to lower the negative sequence current. If this is the case, the positive sequence and negative sequence circuits of the inverter DG in the fault analysis have to be treated separately. Another factor is the grounding of the inverter and the interfacing transformer. Most inverters operate ungrounded, but a check should be made to ensure that this is the case for each installation. Also, most inverters meet UL1741 [4] Standards which means they will shut down for loss of supply. However, the time to shut down may be long enough to effect coordination on the distribution system. Also, the inverter may not shut down for single-phasing conditions. Both these factors make the case that, for larger inverters, interconnection protection external to the invert may be prudent.

The introduction of an inverter-based DG results in some of the same problems that occur with synchronous and induction DGs which are challenges to feeder protection coordination. First, fault current will be bidirectional since multiple sources including the grid and inverter DG could feed a fault. Second, fault current contribution from an inverter DG will either increase or decrease the fault current that a protection device will experience—depending on its relative location to the DG and the fault. Previously-coordinated protection might not coordinate anymore. Third, since the connection status of an inverter DG is highly unpredictable and variable, the feeder protection is now facing constantly-changing fault levels.

Compared to conventional DG generators (synchronous and induction), inverter-based generators supply much less fault current to the system which helps with coordination issues. Fig. 8 outlines the various coordination issues for various fault locations on a typical feeder. One of the major concerns is that distributed generators interfaced to the grid via inverters could support a transient or temporary overvoltage during a single phase to ground fault, after the substation breaker opens, and especially when the distributed generation feeds the grid through a delta-Y transformer with the delta on the primary side of the interconnection transformer. These concerns were discussed in Section III of this paper for conventional DGs. Many utilities require that, at the point of common coupling, the DG installation should be effectively grounded ($Xo/X_1 < 3$ and $Ro/X_1 < 1$) when the source ground source is tripped.



Advantages

- Less fault current than a synchronous generator
- Makes fuse save easier (F4)
- Are there overvoltages due to neutral shift ???
- Inverters are generally ungrounded

Problems

- Provides an unwanted fault current for supply circuit faults at F_1 and F_2
- Allows source feeder relaying at A to respond to a secondary ground fault at F_3 (Y_{gnd}-Y_{gnd} only)
- Ground current duration from DG difficult to determine.

Fig. 8 Coordination Issues with Inverter DGs

Recent work reported in Reference 4 indicates that the overvoltage problem about which many relay engineers were concerned is mitigated because the inverters are almost always operated ungrounded. The phase currents produced by three-phase inverters are balanced or averaged, but close examination of the waveforms on an instantaneous basis indicates the waveforms are not perfectly balanced at all times. These small, short-lived imbalances occur because of slight variations in phase-switching times that are a natural by-product of most inverter-switching control schemes. If the neutral is allowed to float, some of these imbalances can be absorbed by movements or "wiggles" in the neutral potential, which are not seen by the larger system if the neutral is not solidly connected. Thus, the inverter's harmonic performance is improved. Most inverters operate ungrounded as shown in the simplified one-line diagram in Fig. 9.

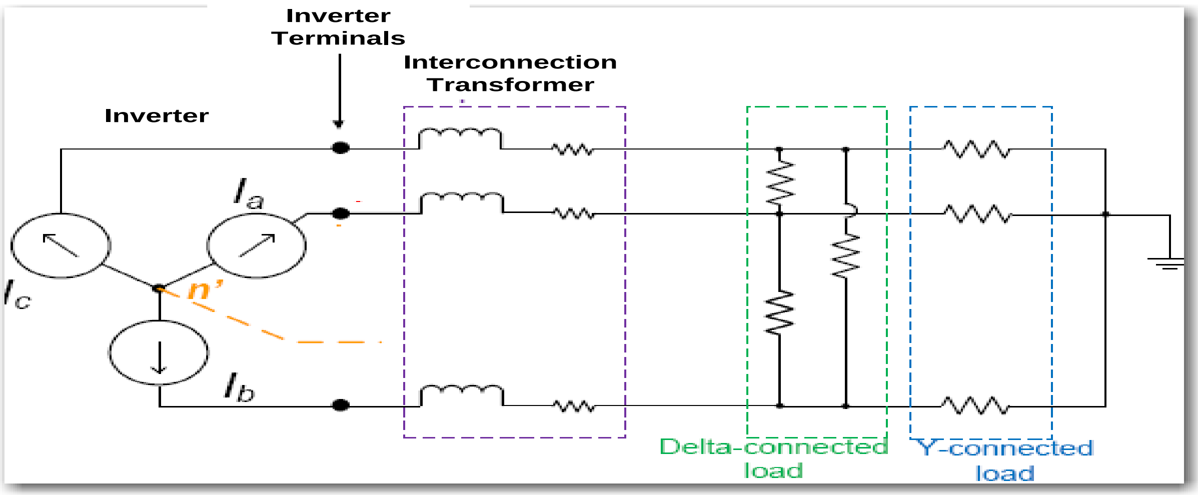


Fig. 9 Simplified Schematic of an Inverter-Based DG [3]

The investigators in Reference 3 used a MATLAB simulation model to investigate the overvoltage issue. The one-line of the feeder studied is shown in Fig. 10. The ground fault location was at the inverter DG location. Many inverter installations use an interposing transformer to isolate the inverter or, in some cases, to balance the inverter to standard system voltages such as 480 or 240 volts.

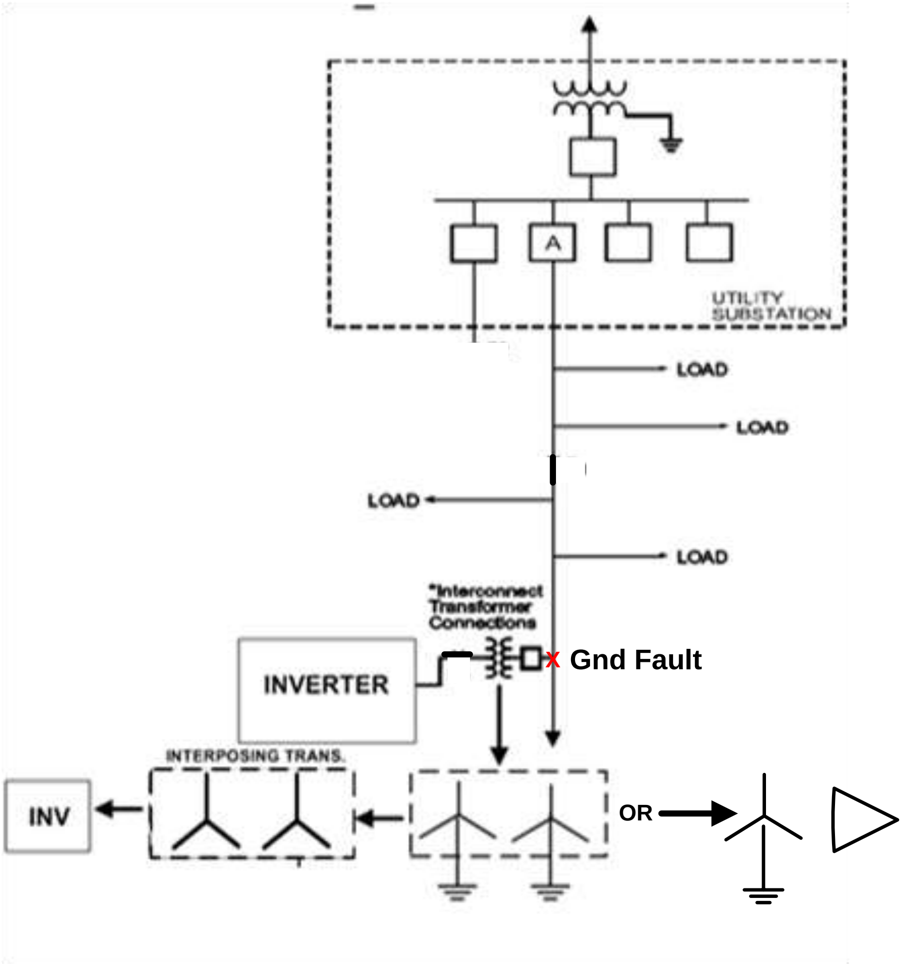


Fig. 10 One-Line Diagram of Feeder in Overvoltage Study

Fig. 11 is a summary of the findings from the study. For the D-Yg interconnection transformer, the delta was on the primary. The solid columns in Fig. 11 correspond to grounded interposing isolating transformer cases and the cross-hatched columns correspond to ungrounded isolating interposing transformer cases. It was found that grounding the isolating transformer primary winding made little difference in system overvoltage during a ground fault, but was undesirable because of increased harmonics. As expected with a low load-to-inverter DG generator ratio and delta primary interconnection windings, a 1.73 increase in line-to-ground voltage occurs—similar to what happens with conventional synchronous DGs. As the overload on the inverter DG increased, the overvoltage decreased on the unfaulted phases. The best interconnection transformer grounding to reduce overvoltage appears to be a wye grounded – wye grounded interconnection transformer. Grounding of the interposing isolating transformer primary winding has little effect on overvoltage.

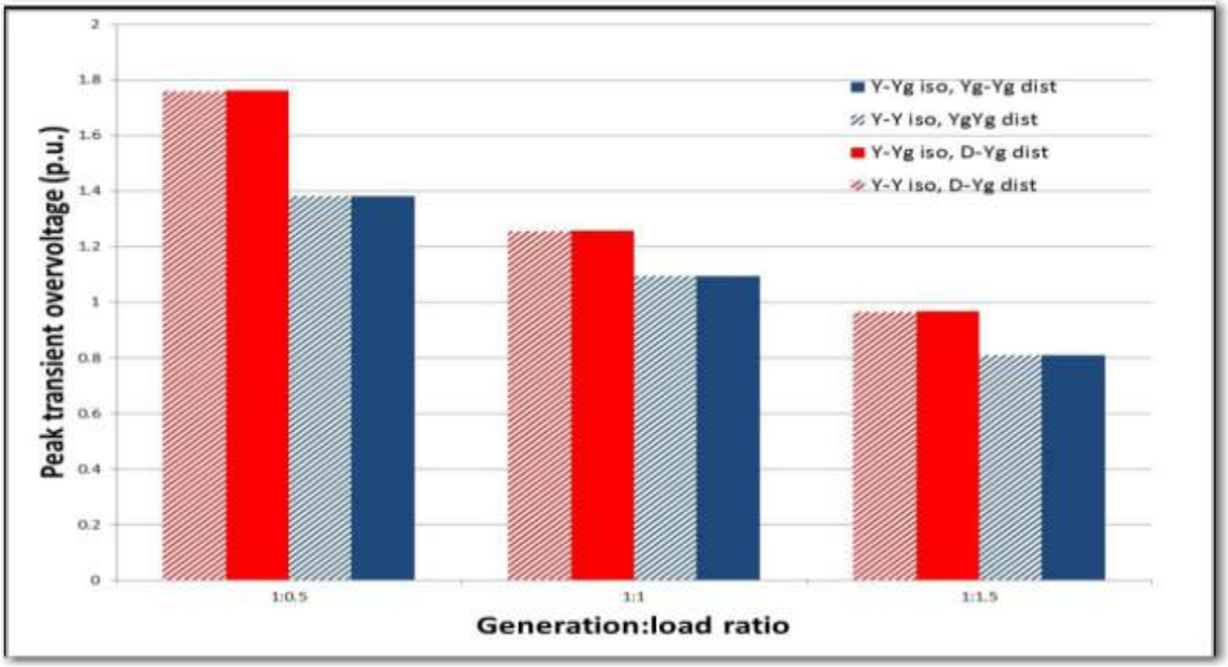


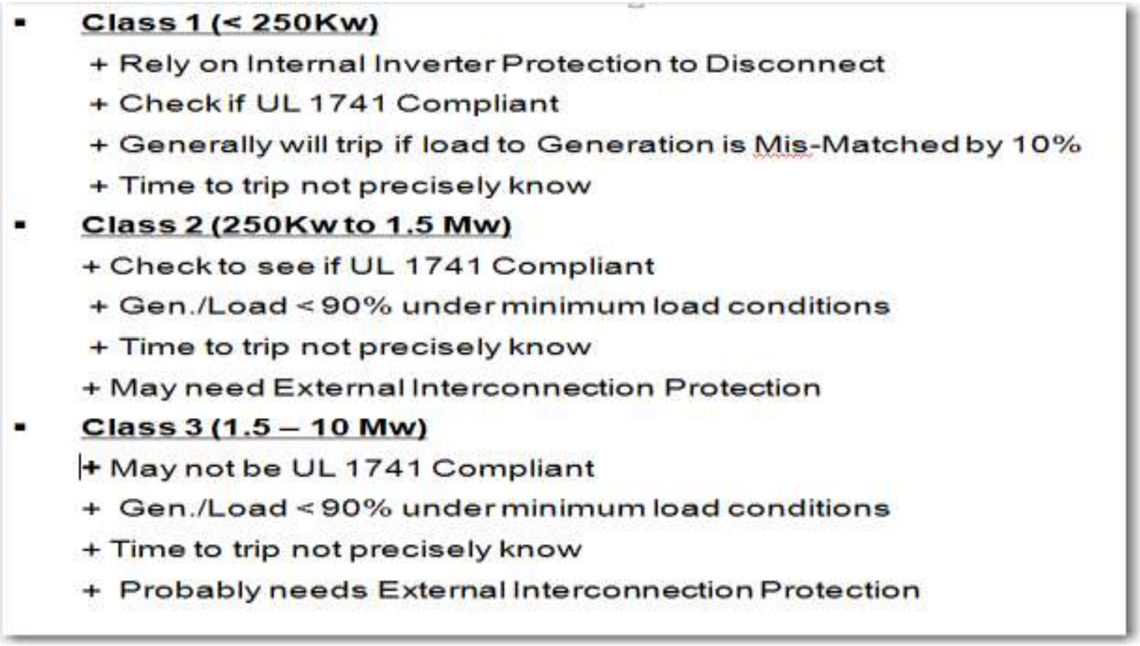
Fig. 11 Summary of Overvoltages for a Feeder Ground Fault [3]

V. Interconnection Protection Considerations for Inverter Based DGs

One of the key decisions that relay engineers have to make when it comes to developing criteria for the interconnection protection of inverter-based DGs is whether to install independent interconnection protection. The size of the inverter DG plays a key role in this decision. For smaller inverters (if they meet UL 1741[4]), the internal control within the inverter is typically relied upon to trip the inverter. However, how fast it will restore is typically an unknown time depending on the control design. The advantages of providing an independent interconnection relay to trip the inverter are:

- A precise tripping time of the inverter fault current contribution can be established—making coordination easier.
- The precise time is established without detailed and in most cases unavailable information on inverter performance under fault conditions.
- A precise reconnect time after restoration can be established.
- Tripping is independent of the inverter control.
- Change on the utility distribution system requiring changes in interconnection protection can be more easily accommodated.

IEEE 1514.7 (a draft document) provides a little guidance as summarized in Table 3. As the inverter size increases, the case for independent protection becomes more important because the level of fault current from the inverter increases and it has more of an effect on the distribution feeder protection coordination. Typical protection functions would be 81O/U, 59 and 27 relays.



- **Class 1 (< 250Kw)**
  - + Rely on Internal Inverter Protection to Disconnect
  - + Check if UL 1741 Compliant
  - + Generally will trip if load to Generation is Mis-Matched by 10%
  - + Time to trip not precisely know
- **Class 2 (250Kw to 1.5 Mw)**
  - + Check to see if UL 1741 Compliant
  - + Gen./Load < 90% under minimum load conditions
  - + Time to trip not precisely know
  - + May need External Interconnection Protection
- **Class 3 (1.5 – 10 Mw)**
  - + May not be UL 1741 Compliant
  - + Gen./Load < 90% under minimum load conditions
  - + Time to trip not precisely know
  - + Probably needs External Interconnection Protection

Table 3 Application of External Interconnection Protection [2]

VI. Conclusions

There are substantial differences between inverter-based and synchronous DGs that effect both fault current and overvoltage. Fault current behavior is largely determined by inverter control design. Inverter-based DGs fault current magnitude is typically limited to around 1.3 pu of the inverter rating while time-to-trip depends on DG terminal voltage. The need to have effective grounding at the point of interconnection with inverter-based DGs is not necessary to reduce overvoltages if wye-grounded/wye grounded transformers are used as the interconnection transformers. Independent interconnection protection which brackets voltage and frequency is prudent for larger inverter-based DGs.

VII. References

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VIII. About the Author

Charles (Chuck) Mozina, IEEE Life Fellow, is a Consultant for Beckwith Electric Co. Inc., specializing in power plant and generator protection. He is an active 25-year member of the IEEE Power System Relaying Committee (PSRC) and is the past chairman of the Rotating Machinery Subcommittee. He is active in the IEEE IAS committees that address industrial protection. He is a former U.S. representative to the CIGRE Study Committee 34 (now B-5) on System Protection.

Chuck has a Bachelor of Science in Electrical Engineering from Purdue University and is a graduate of the eight-month GE Power System Engineering Course. He has more than 25 years of experience as a protection engineer at Centerior Energy (now part of FirstEnergy), a major investor-owned utility in Cleveland, Ohio where he was the Manager of the System Protection Section. For 10 years, Chuck was employed by Beckwith Electric as the Manager of Application Engineering for Protection and Protection Systems. He is a registered Professional Engineer in Ohio. He has authored a number of papers and magazine articles on protective relaying.