Effective grounding of distributed generation inverters may not mitigate transient and temporary overvoltage

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***Abstract*—Utilities have 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 distributed generation feeds the grid through a delta-Y transformer with the delta on the MV side. It has been suggested that requiring effective grounding (as defined by IEEE 142) of inverters will solve this issue. However, recent work suggests that this is in fact not the case; effective grounding of inverters does not mitigate overvoltages because the specific type of overvoltage that is mitigated by effective grounding does not occur with inverters. In addition, effective grounding does *not* mitigate overvoltage mechanisms that *do* occur with inverters, and grounding of inverters can have detrimental impacts on inverter performance. This paper presents and discusses simulation and experimental results to support these conclusions.**

***Index Terms*—Distributed Power Generation, Power Distribution Faults, Inverters, Power System Protection, Temporary Overvoltage, Transient Overvoltage**

I. Nomenclature

DG	Distributed Generator
LG	Line to Ground (single-phase fault)
PV	Photovoltaic
TOV	Temporary Overvoltage
TrOV	Transient Overvoltage

II. Introduction

DISTRIBUTED generators (DGs) are being deployed at an increasing rate on distribution systems around the world, with the increase being driven by a number of real or perceived benefits [1]. A growing proportion of DGs are interfaced to the grid through an inverter. The distribution systems to which they are connected tend to be radial and were, in general, designed from a perspective of unidirectional power flow, from the utility source to the customer loads. Embedding DGs in distribution circuits thus gives rise to certain planning, operational and protection challenges. In particular, a distribution system operator must take special care to ensure that the voltages on distribution circuits with DGs remain within operational limits, because there are several circumstances under which transient or steady-state voltages could be made abnormal by the DG.

One such concern centers around the phenomena of temporary overvoltage (TOV) or transient overvoltage (TrOV). TOV is usually taken to mean the RMS steady-state voltage during a temporary condition—in other words, the TOV itself is a steady-state voltage, but it occurs during a network event that is temporary. By contrast, TrOV occurs during the transient phase of the event, and may be expressed in instantaneous or RMS terms. Any overvoltage can be a concern, and thus TOV and TrOV are important.

There are six basic physical mechanisms that lead to TOV or TrOV. Those mechanisms are as follows.

- Mechanism 1: Ground potential rise.
- Mechanism 2: Derived neutral shift.
- Mechanism 3: Inductive coupling to fault currrents.
- Mechanism 4: Isolation of heavy generation with light loads.
- Mechanism 5: Interruption of current through an inductor (TrOV only).
- Mechanism 6: Saturation of inverter controls.

Mechanism #1 is caused by the finite conductivity of the physical earth. During a fault or lightning strike, the potential at the strike or fault location will rise relative to the potential farther away, and a neutral grounded to that point will see the raised potential of its ground reference, resulting in both TOV and TrOV [2]. Mechanism #2 arises when a rotating generator presents an ungrounded source to a four-wire system that is subjected to a line-to-ground (LG) fault [3]. In this case, one of the three phases becomes grounded and its voltage collapses. By its internal physics, a rotating generator will enforce the voltage relationship between the faulted and unfaulted phases, and the result is that it (theoretically) raises the line-to-ground voltage of each of the unfaulted phases to the line-to-line voltage. The result is that any single-phase load connected line-to-neutral on an unfaulted phase then sees a 1.73 ($\sqrt{3}$) per-unit TOV, in addition to a potential TrOV. Mechanism #3 arises because of inductive coupling between the unfaulted phases and the large fault current flowing in the faulted phase [4]. Mechanism #4 arises when a generator

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controlled as a current source, like an inverter-based DG, is islanded with a load whose power consumption is much smaller than the output of the generator. Because the inverter's output current changes slowly relative to the time period under consideration, the voltage in the island will momentarily jump to the product of the current times the load impedance (Ohm's Law), and the result is a peak TrOV, V_{TrOV}, equal to the ratio of the generator's power output S_{gen} to the load's consumption S_{load} at nominal voltage V_{nom}:

$$V_{TrOV} = IZ = \left(\frac{S_{gen}}{V_{nom}}\right)^* \frac{V_{nom}^2}{S_{load}}$$

$$\frac{V_{TrOV}}{V_{nom}} = \frac{S_{gen}^*}{S_{load}}$$

where the asterisk denotes complex conjugation. Mechanism #5 is also a TrOV mechanism that occurs when the current through an inductor is interrupted, forcing a collapse of the inductor's magnetic fields. Mechanism #5 is the primary reason for the existence of snubbers. Finally, Mechanism #6 is a TOV/TrOV mechanism unique to inverter-based DG that will be described more fully below.

Three of these, Mechanisms #2, 4 and 6, are important in conjunction with inverter-based DG, but the one that dominates the conversation at present is #2, derived neutral shift. Thus, Mechanism #2 will be the focus of this paper.

III. Theory

A. Why inverters are ungrounded

The phase currents produced by a three-phase inverters are balanced in a larger-scale, averaged sense, but if one examines the waveforms on a more instantaneous basis one finds that 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 minute 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. If the neutral is hard-grounded, the neutral cannot absorb those minute fluctuations and the result is an increase in output distortion. In addition, previously existing voltage imbalances and harmonics in the host electrical system can lead to potentially large flows of neutral current in the inverter transformer that are not related to inverter operation. Thus, there is an advantage to leaving the inverter ungrounded.

B. Physical explanation of TOV/TrOV expectations

A highly simplified schematic of a DG is shown in Figure 1. The DG is assumed here to be a photovoltaic (PV) plant, but the concept illustrated should apply to any DG using a similarly-controlled inverter. In Figure 1, the DG is operating in a current-controlled mode, and has been isolated from the grid source, so no utility voltage is shown. The PV plant is represented by three ideal current sources at the left, connected in wye with a floating star point. The PV current sources are balanced. This is obviously a steady-state representation, and it is reasonable for nearly all inverter-interfaced DG because of the way in which the inverters' outputs are controlled, as long as the current controls are not in a saturated state (that is, the inverter switch duty ratio does not go to 1 at any point in the AC waveform cycle). Because the DG is islanded, the PV plant currents flow through the feeder series impedances and into the loads, part of which is connected in delta and part in wye, and the voltage seen at the PV plant is determined by the PV current and the load impedance. The loads are visually represented as resistances in Figure 1 for simplicity. Consider the phase a current source, and for the moment neglect the delta-connected load. If one follows a loop from the PV plant's star point through i_a, through the phase impedance, and through the Y-connected load on phase a, one sees that the voltage $\hat{V}_{an}$ is:

$$\hat{V}_{an} = \hat{I}_a \hat{Z}_a \tag{1}$$

where $\hat{Z}_a$ is the total impedance seen looking into phase a from the DG's phase a terminal, and the "hats" on all quantities indicate that they are complex. The voltage $\hat{V}_{an}$ is referenced to ground. Similarly,

$$\hat{V}_{bn} = \hat{I}_b \hat{Z}_b \tag{2}$$

$$\hat{V}_{cn} = \hat{I}_c \hat{Z}_c \tag{3}$$

If one draws the phasor diagram for the voltages at the terminals of the DG plant (Figure 2), one sees that those voltages are fixed to the values given by (1-3), which determine the corners of the phasor triangle, and that all three voltages are ground-referenced. This holds true regardless of whether the load is balanced, and if the delta connected load is introduced, the currents in (1-3) will change but the basic concept will still hold true. In summary:

- As long as the inverter's current controls are working (nonsaturated), when the inverter-based DG is isolated from the utility voltage source, there is no derived neutral shift.
- The reason why this is true is because the inverter operates as a current source, so the voltage is determined by the Ohm's Law response of the load, which is grounded.

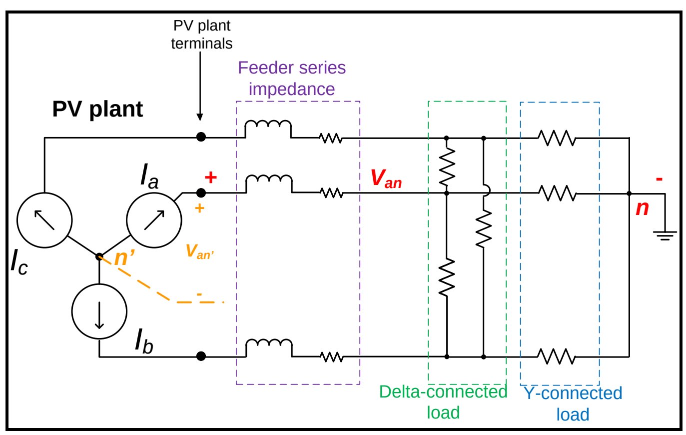

Figure 1. Highly simplified schematic of an inverter-based DG isolated from the grid and serving delta- and Y-connected load.

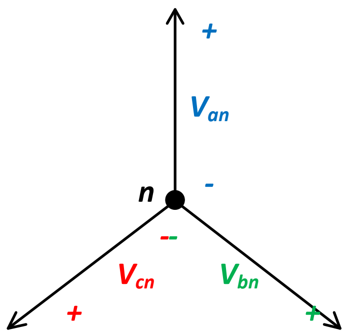

Figure 2. Phasor diagram showing PV plant terminal voltages.

Now consider the system in Figure 1 but with an LG fault between the feeder impedance and the load. Arbitrarily, place the fault on phase c. This has the effect of shorting out the phase c part of the wye-connected load, which will drive $\hat{V}_{cn}$ to a low value because $\hat{Z}_c$ in (1) becomes much smaller. The phase c voltage collapses as shown in Figure 3, but again because the inverter is acting as a set of current sources, (1-3) still hold. The corners of the triangle are still fixed by (1-3), and the voltages are still referenced to ground. In summary:

- One should not expect a Mechanism 2 TOV/TrOV during an LG fault when an inverter-based DG is isolated from the utility voltage source, again as long as the current controls are nonsaturated.
- The reason why this is true is that because unlike a rotating generator [3], a current source inverter does not inherently maintain specific phase-phase voltage relationships, and thus it tolerates the voltage collapse on the faulted phase, provided that the inverter controls are not saturated.

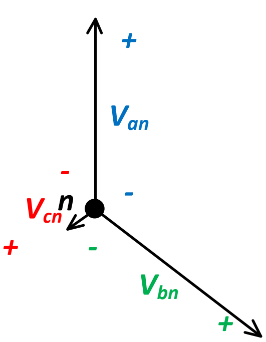

Figure 3. Voltage phasors at the DG terminals during an LG fault on phase c.

One important point: the foregoing discussion should ***NOT*** be taken to mean that inverter-based DG does not support TOV or TrOV at all. For example, if the impedances $\hat{Z}_a$, $\hat{Z}_b$ and $\hat{Z}_c$ are relatively high and the DG is isolated with these high impedances, the voltages given by (1-3) may be considerably higher than the nominal values expected, and a Mechanism #4 TOV may result, although that voltage will be constrained by the available power from the PV plant which must satisfy

$$P_{out} = P_{max} = \frac{V_{an}^2}{R_A} + \frac{V_{bn}^2}{R_B} + \frac{V_{cn}^2}{R_C} \qquad (4)$$

where P_{max} is approximately fixed for a PV plant. When there is an LG fault, one would expect the voltages to rise on the unfaulted phases because there is suddenly essentially zero power being sent on the faulted phase. Because power must be conserved, voltage (and possibly current) on the unfaulted phases must jump upward. . However, that voltage rise is from Mechanism #4, not Mechanism #2.

This analysis suggests that a Mechanism #2 TOV/TrOV should not be expected when an inverter-based DG is isolated from the grid during an LG fault. Furthermore, because effective grounding of the inverter-based DG would mitigate Mechanism #2 but not the others, it is also expected that requiring effective grounding of the DG plant will have a negligible effect on TOV/TrOV in this case.

C. *Importance of Mechanism #6*

In both of the foregoing summaries of the conceptual discussion, it was emphasized that the conclusions were only accurate if the inverter controls were not saturated. If the inverter controls *do* saturate, the inverter will enter a mode known as square-wave pulse switching [5] in which during significant portions of the switching period the switches do not change state; they are either on or off for that entire period. In terms of pulse width modulation, this condition corresponds to a modulation index or a duty ratio larger than unity.

In this mode of operation, for much of the line cycle, the DC voltage source behind the inverter is connected directly to the line without any switching control. If that happens, then the inverter *would* enforce a specific phase-phase voltage relationship, and Mechanism #2 would occur. That Mechanism #2 TOV could potentially be very large, because the DC voltage must always be larger than the peak of the nominal AC voltage (accounting for the winding ratio of the isolation transformer).

IV. Procedure

This work included modeling, experimental model validation, and then application of the model to a variety of cases.

A. *Model development*

A detailed model of a feeder, loads, and inverters was constructed in the MATLAB/Simulink environment and is shown in Figure 4. The feeder model used here is based on the one presented in [4]. This feeder model was explicitly designed for TOV work. It includes representations of the mutual inductance between the phases and neutral, and also the multigrounded neutral itself, with each feeder segment being modeled in detail and with all parameters supplied. The feeder loads are represented by a constant-impedance model. The feeder model was validated by running the scenarios in [4] and verifying that the two models agree. Then, a PV plant was added. For this work, a 1.25 MW, five-inverter PV plant was represented using detailed switching models for the inverters. A detailed switching model and not an averaged inverter model was used, because it was found during this work that the averaged representation led to significant overprediction of the TOV. The PV plant, AC and DC filters,

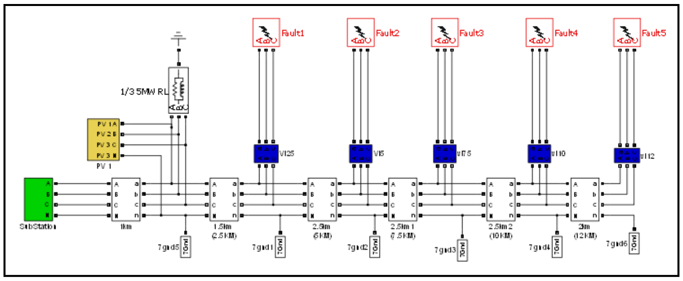

Figure 4. Diagram of the system model used in the simulation portion of the TOV/TrOV work.

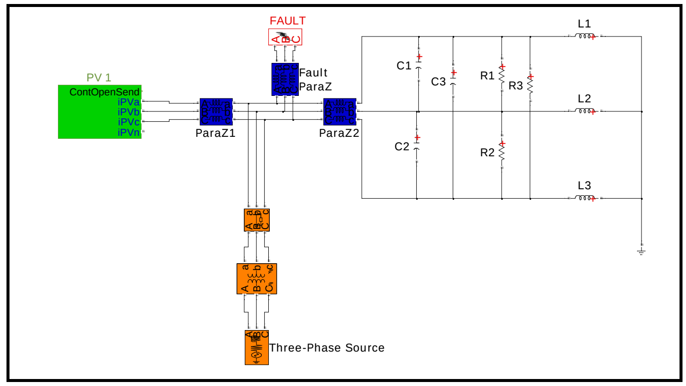

Figure 5. Schematic of the circuit used for experimental validation of the inverter model.

and the inverter controller are all represented in detail. The inverter is assumed to include a low voltage isolation transformer and a medium voltage step up transformer. When the inverter was grounded this was done by grounding the star point on the utility side of that isolation transformer. Simulations were conducted using two different detailed switching models: a generic model that has been validated against multiple manufacturers' models and has shown good results across a broad range of products; and a manufacturer-specific model developed in close cooperation with Advanced Energy Industries. The inverter model includes the DC and AC filter components, with estimates of the parasitic components therein; highly detailed models of the current controllers; maximum power point trackers (included for generality, because the MPPTs have little to no influence on TOV/TrOV due to their long action times); and protection schemes, including IEEE-1547 trips and additional voltage/frequency trips. The PV plant's distribution transformer and each inverter's isolation transformer are also represented, although transformer saturation was not included.

B. Model validation

In any study as reliant on simulation as this one is, model validation is crucial. The MATLAB/Simulink representations of power system elements such as mutual inductances and faults are considered trustworthy and reasonable, and the generic feeder model was validated against the results in the original paper [4]. This section focuses on the all-important validation of the model of the inverter and its controller.

The generic inverter model used here has been extensively tested against data from a number of manufacturers, including data on transient response, THD, and MPPT operation, and provides reliable representations of these inverters in all respects with accuracy in the ±10% range or better, and has also correctly predicted the experimentally-measured behavior of islanded PV inverters in multiple test cases. This model is considered to be tried and tested.

The manufacturer-specific model developed with Advanced Energy was derived from the generic model. To validate this model, Advanced Energy investigators constructed the test shown schematically in Figure 5. In this test, a single 260 kVA inverter (green block at the left) is connected through a finite-impedance bus (blue blocks) to a load consisting of delta-connected capacitors, delta-connected resistors, and grounded Y-connected inductors. All active anti-islanding within the inverter was turned "off", and the RLC load was tuned to resonate at 60 Hz at a quality factor sufficiently high that the inverter would island. The grid source (orange blocks) was then removed. Then, an LG fault was applied to phase b between the PV and load (the red "FAULT" block in Figure 5), and the transient voltage was recorded. The same configuration and sequence of events was reproduced in Simulink using the manufacturer specific inverter model.

A comparison between the voltages measured in the lab and those predicted by the simulation is shown in Figure 6. The simulated results are the solid lines, and the lab results are the dots. The fault strikes at 6.999 sec in both sets of data. The phase b voltage collapses, and a TrOV is initiated, primarily on phase c. The simulated inverter tripped at 7.005 sec, actually just before the highest positive-going peak of the phase c waveform. Figure 6 shows that the simulation matches the actual inverter voltages extremely well, and predicted the peak value of the TrOV to within 1%. After the inverter trips, there is some deviation between the two sets of waveforms during the ring-down of the load, which is likely due to the presence of the series resistances in the experimental inductors and capacitors that are not represented in the simulation. Also, the waveform for phase a suggests that there may be a small discrepancy between the trip times of the simulated and actual inverters (the exact trip time of the experimental inverter was not captured). Figure 6 can be considered a good validation of the model, and suggests that the model's predictions should be trustworthy.

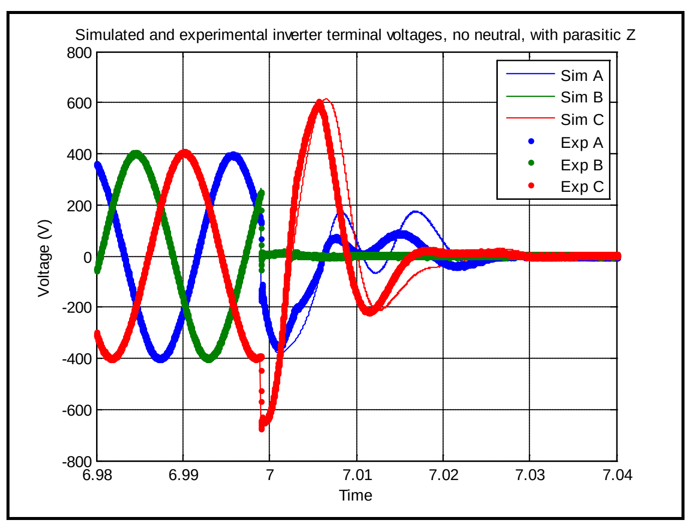

Figure 6. Comparison of experimental (dots) and simulated (thin solid lines) voltage waveforms during the validation test.

C. *TOV/TrOV simulations*

For purposes of this work, the TOV/TrOV experienced during an LG fault is separated into two periods. The first period, termed "first TOV", is the period between the occurrence of the fault and the opening of the breaker that islands the DG and the fault. During the first TOV, the utility source is still in control of the voltage. The second period, "second TOV", occurs after the utility breaker opens, and thus the DG and load are in control of the voltage. These definitions are illustrated in Figure 7.

The feeder and inverter models described above were used to run a large battery of simulations. The first set of 36 simulations was aimed at determining the locations of the fault and PV on the feeder that led to the worst-case TOV. In these simulations, six locations on the feeder were selected, as indicated in Figure 4. The six locations included the five Fault Block locations (indicated by the red blocks in Figure 4), and a point just outside the substation (the location of the yellow PV plant block in Figure 4). Every combination of DG and fault location was simulated and checked for TOV/TrOV.

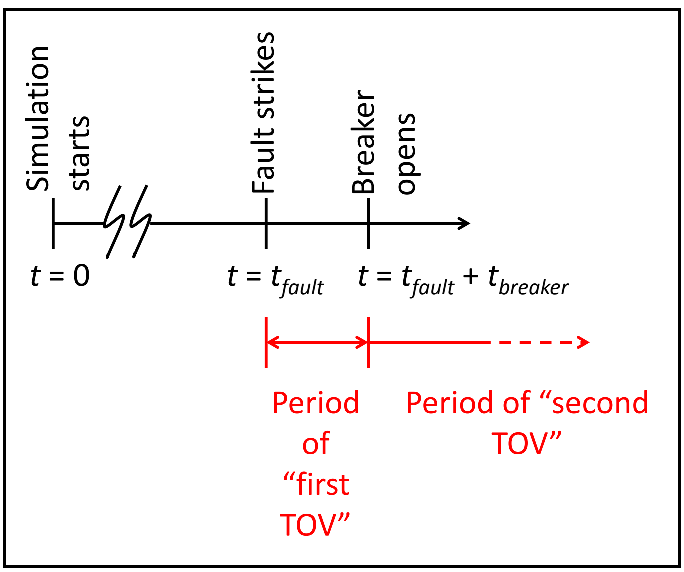

Figure 7. Definitions of "first TOV" and "second TOV".

Then, once that configuration was determined, 72 additional simulations were run in which the DG was connected to the feeder through Yg-Yg, Yg-delta, and delta-Yg distribution transformers. For every distribution transformer, both grounded and ungrounded inverters were simulated using Y-Y, Y-Yg, delta-Y, or delta-Yg isolation transformers. The generation:load ratio in the island was also varied; values of 0.5:1, 1:1, and 2:1 were simulated for every combination of transformers noted earlier. For every simulation, the voltage waveforms were recorded, and the peak voltages attained during the island were marked (this would be the peak TrOV).

Later, one additional fault location was checked: the TOV/TrOV was investigated for faults on the customer side (480 V) of the distribution transformer. The fault was added inside the yellow "PV 1" block at the left of Figure 4. That block's contents are shown in Figure 8. The PV inverters are shown in green blocks at the left, and the distribution transformer is indicated just to the right of center. A local impedance load is also included as shown. The red and magenta blocks are measurement blocks. The fault is applied at the location of the red and yellow star, and the fault causes the indicated facility breaker to open.

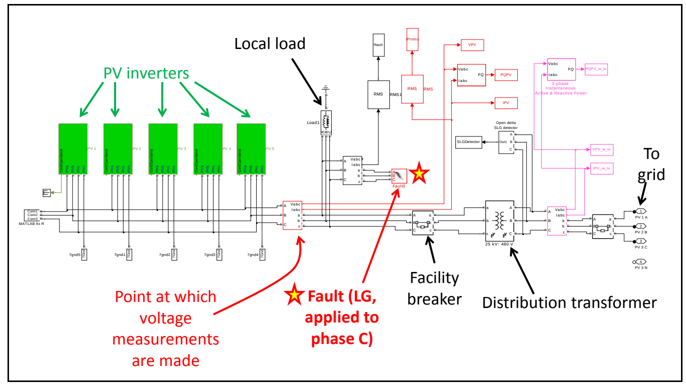

Figure 8. Illustration of the system configuration used to simulate faults on the customer's 480 V bus.

For all combinations of distribution transformer and generation:load ratio, cases were compared in which the only difference was whether the inverter was grounded or ungrounded, to ascertain the impact of that factor.

V. Results and Discussion

Due to space constraints, only representative results are presented here. First, the study in which the PV and fault locations were varied showed that the worst-case overvoltages occurred when the PV was close to the substation, and the fault was as far downstream as possible. The reasons were that a) if the fault were upstream from the PV, the fault-induced undervoltage was usually low enough that the inverter would trip during the first TOV period on undervoltage; and b) with the PV upstream from the fault, it became possible for the PV to remain online during the first TOV if there was sufficient impedance between the PV and the fault that the faulted phase voltage did not lead to a fast undervoltage trip, and thus the worst case was the one in which the impedance between the PV and fault was maximized.

Once that determination was made, the PV location was fixed at the location shown in Figure 4, and all feeder faults were applied at the far end of the feeder (Fault5 in Figure 4), except for the faults applied on the customer's 480 V bus as shown in Figure 8. All faults were applied to Phase C. Representative results from these simulations are shown in Figures 9-12. Figures 9 and 10 show the 480 V bus voltage waveforms during an LG fault on the customer side of a Yg-Yg distribution transformer, with a 1:1 generation-to-load ratio. The inverter is ungrounded in Figure 9, and grounded in Figure 10. In both figures, the fault strikes at 5 sec and the breaker opens three cycles later. Thus, the first TOV lasts from 5 to 5.05 sec, and the second TOV lasts from 5.05 sec until the inverter trips. In these cases, the breaker that opens is the customer's facility breaker, which isolates the DG only with the local load (the distribution transformer is outside the island) and leaves a configuration essentially the same as that shown in Figure 1. In Figures 9 and 10, the inverter is represented by the manufacturer-specific model. The figures show that there is a small first TOV, the mechanisms of which are discussed in [4]. Then, at 5.05 sec, the breaker opens and second TOV begins. The inverter quickly detects the overvoltage and shuts down, and thus the second TOV is actually a TrOV in this case. Note that the *only* difference between Figures 9 and 10 is the grounding of the inverter. Key points on the voltage waveforms are marked. From left to right, the first cursor marks the peak of the voltage waveform before the fault; the second cursor marks the peak value of the first TOV; and the third cursor marks the peak value seen during the second TOV (actually the peak TrOV). Comparing Figures 9 and 10, it is clear that there is essentially no difference between the TOV (TrOV) seen between the grounded-inverter and ungrounded-inverter cases, as expected: grounding the inverter has not made a difference, because the TOV mechanism at work here is Mechanism #4, not Mechanism #2.

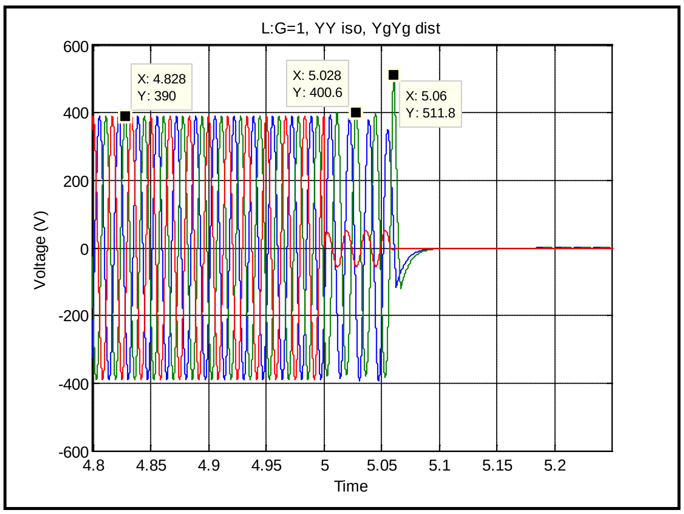

Figure 9. Voltages on the 480 V load bus during an LG fault on the customer side of a YgYg distribution transformer. Generation:load ratio = 1:1; inverter isolation transformer is YY (ungrounded).

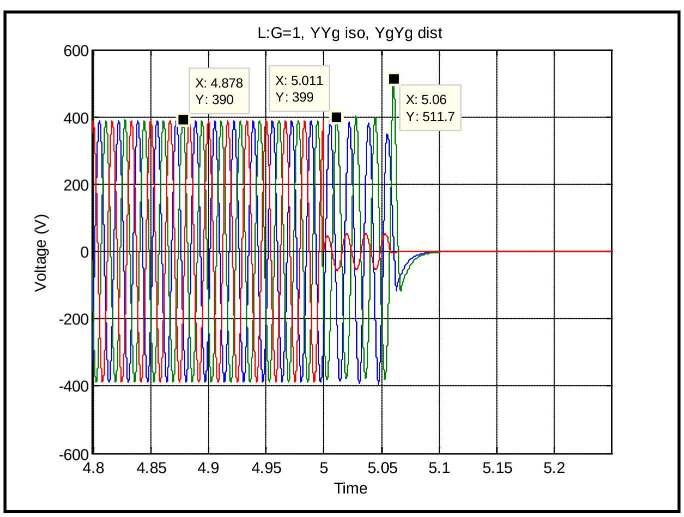

Figure 10. Voltages on the 480 V load bus during an LG fault on the customer side of a YgYg distribution transformer. Generation:load ratio = 1:1; inverter isolation transformer is YYg (grounded).

Figures 11 and 12 are the same as Figures 9 and 10, except that the generation:load ratio has changed to 2:1 (twice as much generation as load). The substation LTC has been adjusted so that the pre-fault voltage is approximately the same as in the earlier generation:load case. Looking at the peak TrOV, marked by the rightmost cursor in Figures 11 and 12, it can be seen that the value has increased from what it was in Figures 9 and 10 due to Mechanism #4. This underscores the earlier statement that it is not the objective of this paper to claim that TOV/TrOV do not exist at all with inverter-based systems. However, as was the case in Figures 9 and 10, there is essentially no difference in the peak value of TrOV between the ungrounded (Figure 11) and grounded (Figure 12) cases. Grounding the inverter has provided no real benefit.

The results of all of the simulations are summarized in Figures 13 and 14. Figure 13 compares the peak TrOV for grounded and ungrounded inverters, for the case of an LG

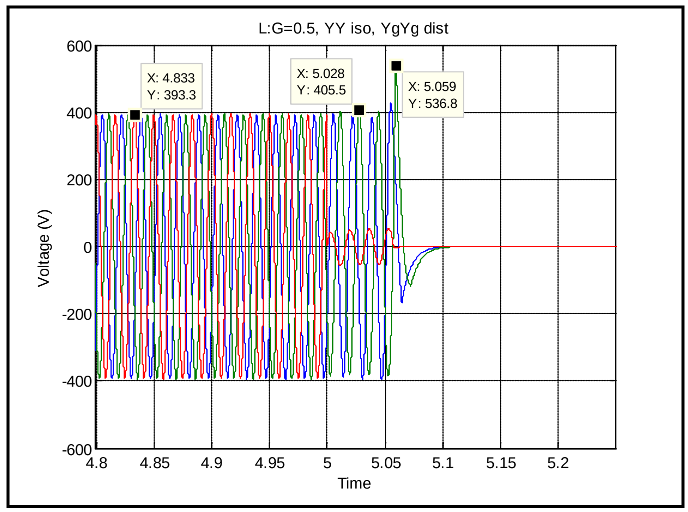

Figure 11. Voltages on the 480 V load bus during an LG fault on the customer side of a YgYg distribution transformer. Generation:load ratio = 2:1; inverter isolation transformer is YY (ungrounded).

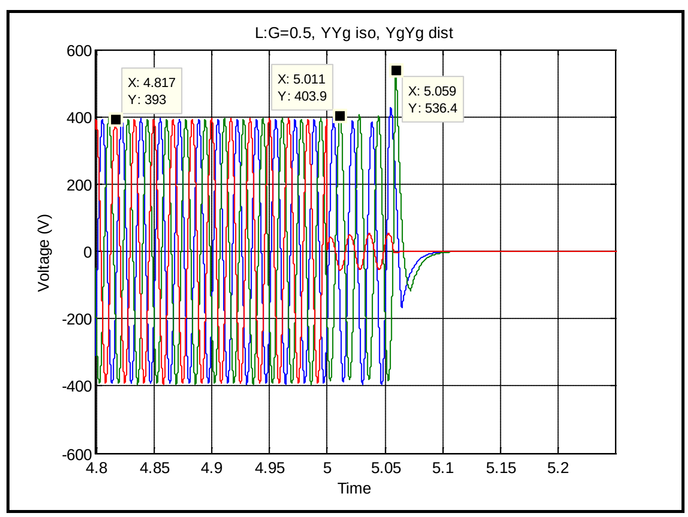

Figure 12. Voltages on the 480 V load bus during an LG fault on the customer side of a YgYg distribution transformer. Generation:load ratio = 2:1; inverter isolation transformer is YY (grounded).

fault on the feeder (location Fault5 in Figure 4), for different generation:load ratios, with the transformer configurations taken as a parameter. The blue columns are for Yg-Yg distribution transformers, and the red ones are for delta-Yg distribution transformers. The solid columns correspond to grounded inverters (grounded isolation transformers), and the cross-hatched columns correspond to ungrounded inverters. As the generation:load ratio increases, the value of TrOV increases, as expected under the action of Mechanism #4. It is also clear that the configuration of the distribution transformer makes a difference; the TrOV is larger for distribution transformers with a delta winding, which is consistent with expectations. However, when one compares any of the solid bars with its corresponding cross-hatched bar, it is clear that they are virtually identical, meaning that grounding the inverter did not make a difference and supporting the notion that Mechanism #2 is not active here.

Figure 14 is similar to Figure 13, except that in Figure 14 the fault is located on the 480 V bus as illustrated in Figure 8. The blue bars again correspond to Yg-Yg distribution transformers and the red to delta-Yg distribution transformers.

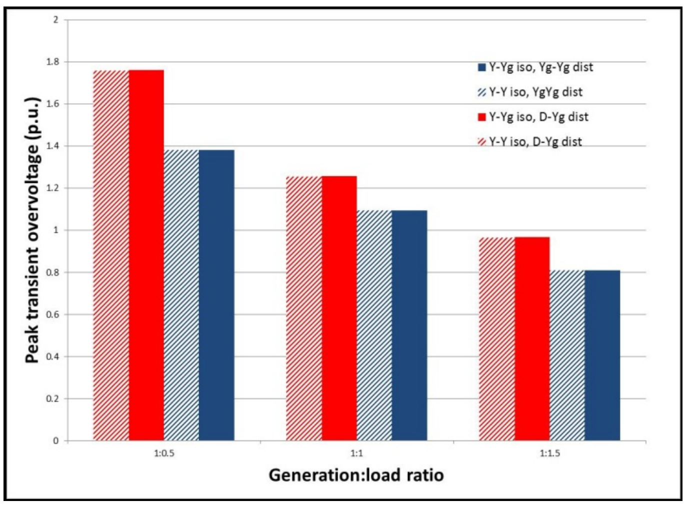

Figure 13. Grounded/ungrounded comparisons on feeder, fault on feeder.

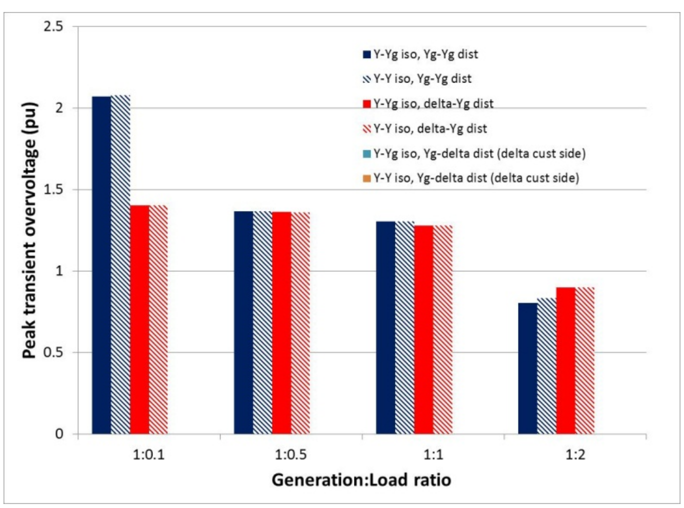

Figure 14. Grounded/ungrounded comparisons, fault on cust side, V on cust side.

As in Figure 13, the impact of Mechanism #4 is apparent, but if one compares any solid bar (grounded inverter) in Figure 14 with its corresponding cross-hatched bar (ungrounded inverter) at the same generation:load ratio, one sees that grounding the inverter has not impacted the peak TrOV. In other words, there is no evidence of Mechanism #2.

It is important to note that in none of the simulations or experimental results did Mechanism #6 appear. In nearly all cases, the inverters' controllers began to react soon after the fault occurred, but the inverter tripped well before square-wave pulse switching set in. This does not mean that Mechanism #6 can be dismissed entirely; some controller designs will reach saturation more quickly than others, and inverters' protection schemes will respond differently once saturation is reached. However, for both the generic and manufacturer-specific models in this work, Mechanism #6 was not a factor.

In the legend of Figure 14 one can also see two entries for Yg-delta transformers, with the delta on the customer side. This is a configuration that has recently been used by some utilities for dedicated transformers (i.e. not customer serving but dedicated only to the DG plant). Although such a configuration is not likely in a load-serving transformer, it was included here for completeness. There are no bars in Figure 14 corresponding to the Yg-delta distribution transformers because in these cases there was no second TOV; the inverter tripped virtually immediately because the TOV during the "first TOV" period was large enough to trigger a fast overvoltage trip. An example of this is shown in Figure 15, which is a plot of the 480-V bus voltages during an LG fault on the 480 V bus (phase C) with a 1:1 generation:load ratio and a Yg-delta distribution transformer with the delta on the customer side. The inverter is grounded in this case (Y-Yg isolation transformer). The voltage during the "first TOV" can be seen to be approximately 1.7 p.u., which causes the inverter to trip before the facility breaker does. The reason for the TrOV in this case actually is Mechanism #2—because of the delta windings on the customer side, and the fact that the utility source *does* enforce phase-phase voltage relationships, during the "first TOV" period Mechanism #2 does come into play.

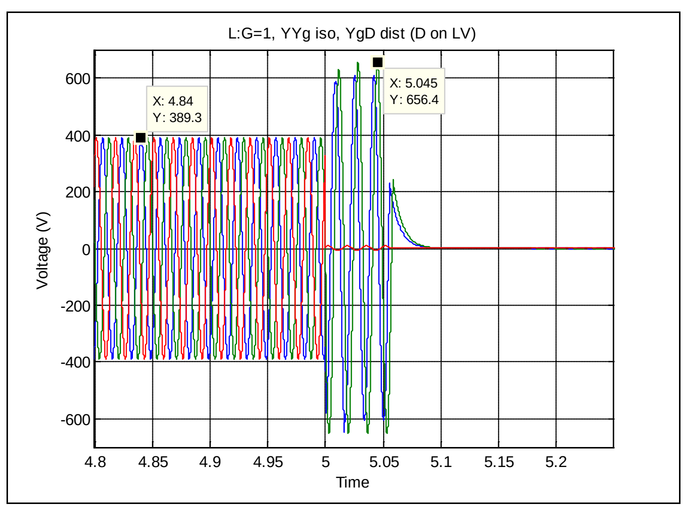

Figure 15. Voltage on the 480 V bus during an LG fault on the 480 V bus, with a Yg-delta distribution transformer (delta on the 480 V side). In this case the inverter is grounded.

The reader may look at Figure 14 and wonder why there is such a difference between the Yg-Yg distribution transformer case and the delta-Yg distribution transformer case at a 10:1 generation:load ratio. Because the facility transformer isolates the fault from the distribution transformer (see Figure 9), at first it seems counterintuitive that the transformer configuration would make any difference. The reason for the difference appears to be caused by the point on the waveform at which the fault strikes and the breaker opens. The fault time and the breaker opening time were not adjusted to account for the phase shift of the delta-Yg transformer, so the voltage was at a different point on the waveform when the breaker opened. Thus, the TrOV had a different voltage level as a starting point in the two cases; the Yg-Yg transformer case started from a higher voltage than did the delta-Yg case. Because the inverter's time to trip after detection of a trip condition is fixed, the Yg-Yg case reached a higher voltage before tripping.

VI. Conclusions

This paper has presented a theoretical, simulation-based, and experimental argument that suggests that grounding of inverter-based DG will not mitigate temporary or transient overvoltage, because Mechanism #2, the TOV/TrOV mechanism mitigated by grounding, is not present in inverters. This notion appears to be strongly supported by the fundamental physics, an extensive simulation study using thoroughly validated models, and the available experimental evidence. This study does NOT suggest that TOV/TrOV are not present at all with inverters; Mechanism #4 appeared numerous times during the simulations. However, Mechanism #4 is not mitigated by grounding, and thus it appears that grounding of inverters does not solve any TOV/TrOV problem in inverter-based DG.

VII. Acknowledgment

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IX. Biographies

Michael Ropp (M'1999) received the BS in Music from the University of Nebraska-Lincoln in 1992, and the MS and PhD in electrical engineering from the Georgia Institute of Technology in 1996 and 1998 respectively. He is currently the President and Principal Engineer of Northern Plains Power Technologies in Brookings, SD, and is a licensed Professional Engineer in SD and HI. In addition to experience with PV devices, Dr. Ropp has worked on power system computer modeling and design, grid integration of PV (including islanding detection), control algorithm development, and PV power electronics for over fifteen years. His current work focuses on microgrids, synchrophasors, systems integration, and controls development. He is currently serving on the IEEE 1547.8 standard committee.

Marc Johnson (M'2012) received the BS and MS in electrical engineering from New Mexico State University in 1990 and 1992 respectively. Mr. Johnson is a licensed Professional Engineer in CA, and has wide ranging experience in solar power system design, computer hardware and software design, and manufacturing test equipment engineering.,. He is currently Senior Applications Engineer at Advanced Energy Industries, where his work focuses on solar power grid integration.

Dustin Schutz (M'2010) received the BS in Electrical Engineering in 2006 and MS in Electrical Engineering in 2011, both from South Dakota State University. Mr. Schutz has wide-ranging experience in power electronics, embedded control systems, and power electronics and power system simulation. His current work focuses on multi-inverter islanding scenarios and microgrid controls.

Steve Cozine (M'2010) received the AAS in Industrial Electrical from North Dakota State College of Science in 2000, and the BS in Electrical Engineering from South Dakota State University in 2010. He worked as an electrician from 1998-2010, and during his contribution to this work he was an EIT at Northern Plains Power Technologies from 2010-2011. Mr. Cozine is currently at Idaho Power, specializing in diagnosis and solution of power quality issues.