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LDRD PROJECT TITLE: Foundations for Protecting Renewable-Rich Distribution Systems

PROJECT TEAM MEMBERS: Abraham Ellis, Sukumar Brahma and Satish Ranade (NMSU)

ABSTRACT: High proliferation of Inverter Interfaced Distributed Energy Resources (IIDERs) into the electric distribution grid introduces new challenges to protection of such systems. This is because the existing protection systems are designed with two assumptions: 1) system is single-sourced, resulting in unidirectional fault current, and (2) fault currents are easily detectable due to much higher magnitudes compared to load currents. Due to the fact that most renewables interface with the grid though inverters, and inverters restrict their current output to levels close to the full load currents, both these assumptions are no longer valid - the system becomes multi-sourced, and overcurrent-based protection does not work. The primary scope of this study is to analyze the response of a grid-tied inverter to different faults in the grid, leading to new guidelines on protecting renewable-rich distribution systems.

INTRODUCTION: Electric power delivery systems have been undergoing a crucial topological transformation. The old model of bulk energy being generated transmitted and distributed to remote load centers is being transformed into a model where distribution systems are becoming "active", *i.e.*, distributed energy resources (DER) are being connected right at the load, and enhanced sensing, computing, and communication are seen as enablers for more informed and efficient operation of power distribution systems. However, like any change, this also comes with "teething troubles". A large part of DER is in the form of renewable generation like solar, wind, plug in hybrid electric vehicle (PHEV) that connect to the power system through power inverters. In addition, electronic loads are increasingly becoming common in distribution systems. The characteristics of these nonlinear loads and inverters will significantly impact the behavior of distribution systems. Though the impact of inverter-interfaced distributed energy resources (IIDERs) is multifaceted, this project focuses on developing foundations of protecting such systems.

From protection standpoint, a major operational issue resulting from the way the inverters are controlled is their response to disturbances. All commercial inverters used to interconnect IIDERs are designed to limit their output current to a value very close to the rated current in order to protect the component devices. Traditional protection schemes that depend heavily on current magnitude for fault detection become ineffective in this scenario, crashing the whole paradigm of protecting distribution systems. To add to the problem, sudden switching of a capacitor bank in distribution systems can also create similar rise and resulting limitation of currents from IIDERs, making discrimination of faults difficult.

The primary scope of this study is to analyze the response of a grid-tied inverter to different types of faults in the grid, and investigate methods for detection of faults at output of the inverter. A 100 kW three phase Voltage Source Inverter (VSI) is simulated in PSCAD® environment. The controls implemented on the inverters are similar to those found on commercial inverters, including the current limiting feature that limits the maximum inverter current to 110% of the rated full load current. The inverter is then interfaced through a Delta/Wye step-up transformer to the benchmarked IEEE 13 node 4.16 kV distribution grid modeled in the same PSCAD® environment. Different types of faults and capacitor switching events are simulated at various locations in the grid, and variations in inverter output currents and voltages in response to these disturbances are observed. Based on the observations of these waveforms, three strategies are examined to reliably detect fault:

1) Quantifying and using the transient content in the inverter output: Due to the disturbance, and the accompanying change in voltage, inverter's filter capacitor typically discharges its energy in form of transients that manifest on the voltage and current waveforms generated by the inverter. A sophisticated time-frequency resolution technique is used for fast quantification of the transient content.
2) Using zero sequence current magnitude at the high side of the interfacing transformer: Due to the fact that the grid side winding of the transformer is Wye-Grounded, it acts as a zero sequence source for all ground faults taking place in the grid. Though inverter produces only positive sequence currents even for unbalanced faults, the transformer secondary helps detect ground faults due to its contribution to zero sequence currents to ground faults.
3) Using voltage drop at the transformer terminals. Although inverter currents are limited, the grid faults still result in lowering of system voltage. This is also considered as an indicator of fault.

A summary of the strategies and their performance for reliable detection of faults is presented. After analyzing the results, protection strategies are recommended.

Inverter Parameter	**Value**	**Unit**	**Description**
V_{dc}	900	V	dc source voltage
F_S	8000	Hz	Switching Frequency
V_{LL}	480	V	Line-to-line Voltage
P	100	kW	Rated power
pf	1		Power factor

Table 1. Inverter Specifications.

DETAILED DESCRIPTION OF EXPERIMENT/METHOD:

1. Inverter Design:

Inverter specifications are shown in Table 1. These specifications are adopted from [1], and are based on a commercial GE grid-connected inverter platform. As the output from the PV modules can be modeled as a dc source, the input to the inverter is modeled as an ideal dc voltage source. PV characteristics are not modeled, since they are not essential to the scope of this study. The dc source is connected to a controlled bridge circuit consisting of three pairs of power electronic switches (normally Insulated Gate Bipolar Transistors (IGBTs)). Each IGBT is accompanied by a free-wheeling diode to allow flow of current in reverse direction. The switching pattern of the power electronic switches are controlled through pulse width modulation (PWM) to generate the required ac power. The current and voltage waveform at the output of the bridge are further conditioned by a Inductor/Capacitor (LC) filter circuit to reduce harmonic distortions. The control objectives of the inverter are:

- The voltage and current waveforms out of the inverter should be clean (less distortions).
- The real and reactive power output should follow the instructed command values.
- The output current of the inverter should not exceed 110% of the rated current, even during faults or grid disturbances.

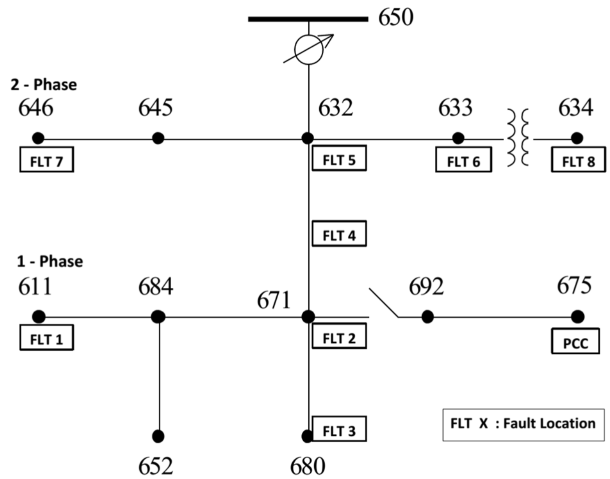

Figure 1. Layout of the IEEE 13-node distribution system.

2. Simulation:

The inverter is implemented in PSCAD® on the lines described in the NREL report [2]. It is connected to the IEEE 13-node distribution system [3] through a 480V/4.16kV, Δ/YG transformer. The feeder layout is shown in Figure 1. Note that inverter itself does not provide a ground reference, but the transformer secondary is a zero sequence source. Node 650 is the substation source which is modeled as a grounded 4.16 kV Thevenin source. Various types of faults were simulated at different buses of the system. The fault locations on the test feeder are marked in Figure 1. Cases of capacitor switching were also simulated at nodes 675 and 611 in this test system.

3. Characterizing the fault waveforms:

Voltages and currents shown in Figure 2 indicate that faults introduce transients in the voltages and currents on the inverter side. It can also be seen that there is a significant voltage dip during faults. It is also expected (and was observed) that the zero sequence current on the YG side will significantly increase for all faults involving ground. Therefore, a fault detection criterion based on each of these observations is conceived and tested, as described in the following subsections.

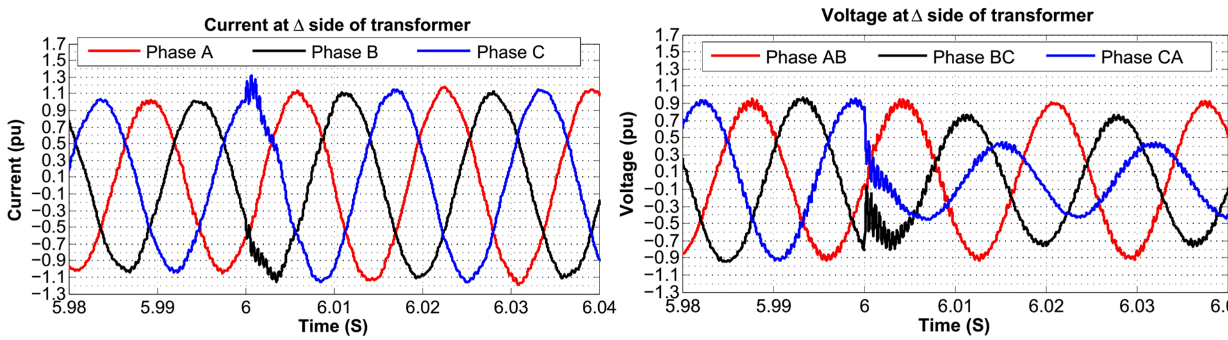

Figure 2 Current and voltage waveforms at the delta side of the interconnecting transformer for a BC fault at node 646.

Transient Based Detection: Looking at Figure 2, short duration of significant transients can be observed in the Delta side currents and voltages at the instant when the fault occurs (at 6 s). In order to detect the occurrence of fault, we attempt to quantify these transient signatures. There are various time-frequency analysis techniques; we chose Fast Variant of Discrete S-Transform (FDST) due to its superior performance [4]. The time-frequency representation of the current and voltage signals at the inverter terminals were calculated through the FDST algorithm explained in [4]. The intensity profile of dominant frequency components above 500 Hz was extracted, which was shown to capture the transient profile or envelope of the transient. The average intensity throughout the duration of transient is used as an indicator for occurrence of fault.

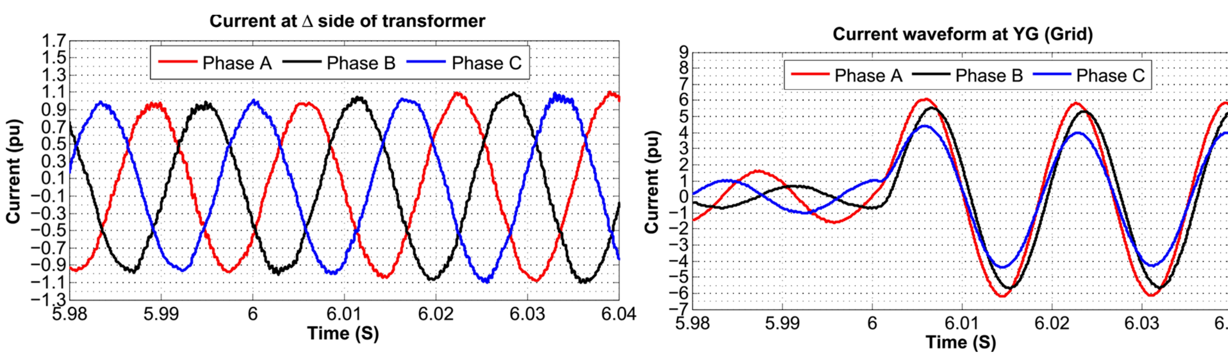

Figure 3. Current waveform at delta side and YG (grid) side of the interconnecting transformer for AG fault at node 633.

Zero Sequence Based Detection: Inverters do not generate negative or zero sequence currents. However, the YG side of the interfacing transformer will act as a zero sequence source for all ground faults in the grid. For example, Figure 3 shows the inverter output currents on the delta side, and at YG side, for a phase-A-to-ground fault with fault resistance of 0.5 Ω, at node 633. Though no current magnitude-based detection is possible on the Delta side, the zero sequence currents make it possible for such detection method on the YG side. This was chosen as a detection method for ground faults.

Undervoltage based Detection: As seen in the voltage waveform in Figure 2, faults result in undervoltage at the point of interconnection, and also across the system. This was also chosen as one of the detectors for faults in the system.

RESULTS:

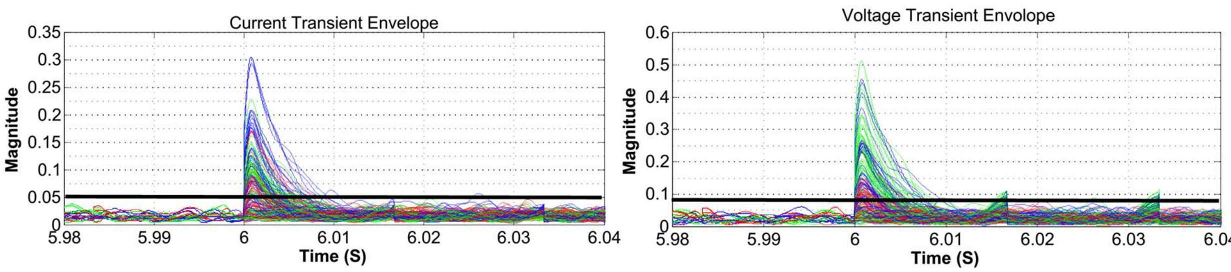

Figure 4. Transient Envelope of the current and voltage waveforms at delta side of the interconnecting transformer for all the simulated faults. The thick black line represents the detection threshold.

Total of 67 different fault cases were simulated at various locations and fault resistances (locations shown in Figure 1). Figure 4 shows plots of the transient envelopes calculated from the current and voltage waveforms at the Δ side of the inverter for all the simulated faults. Based on this figure, a threshold value of ρ = 0.05 units for current and ρ = 0.08 units for voltage are taken as thresholds for detection of faults. Out of the 67 cases, 56 faults could be detected by current-transient based detection, and 57 faults could be detected by voltage-transient based detection. All the line-to-line and three phase faults were detected, but some Line to Ground faults could not generate enough transients. This is because transients depend on the fault-inception angle of the voltage waveform, and Line to Ground faults with inception angles near zero could not generate enough transients to be detected.

To detect ground faults, sequence component based method was implemented. For all ground faults simulated in the system, the minimum and maximum values of the rise in ground current were observed to be 4.5 times and 12.9 times the steady state value respectively. Therefore, ground overcurrent relay with a conventional threshold (twice the maximum unbalance in system) could detect all the line-to-ground and line-line-ground faults. Transient and zero sequence based detection could detect all faults between themselves.

It was also considered worthwhile to use voltage dip in the grid side as an indicator for fault. All faults resulted in significant voltage drop at the YG side of the transformer. Voltage dip attains a minimum value of 0.1812 pu, and a maximum value of 0.7596 pu in one of the three phases, considering all the 67 faults. Thus, an undervoltage threshold of 0.8 pu can detect all the faults. Table 2 shows the results at a glance.

Type of Fault	Total Simulated Cases	Detected with Current Transients	Detected with Voltage Transients	Zero Sequence Relays	Voltage Threshold
LG	22	11	12	**22**	**22**
LLG	17	**17**	**17**	**17**	**17**
LLLG	6	**6**	**6**	0	**6**
LL	17	**17**	**17**	0	**17**
LLL	5	**5**	**5**	0	**5**
All	67	56	57	39	**67**

Table 2. Summary of performance of methods for fault detection.

DISCUSSION:

The results provide good insight into the behavior of inverters when connected to a distribution system. Though inverters do not inject high fault current into the system, the fault can be detected with a combination of transients, zero sequence currents, and undervoltage. There is however, a chance that a capacitor switching can be confused as fault, because capacitors draw an inrush current that can ride on the fundamental currents to the point of interconnection of the inverter. In order to verify this, 10 capacitor switching cases were created by switching ON and OFF the capacitor banks at nodes 675 and 611. None of the cases at 611 (both ON and OFF) got detected with transients. In addition, capacitor switching OFF cases at node 675 didn't get detected. However, three capacitor switching ON cases were picked up by both current and voltage transients, obviously due to the proximity of node 675 to the interfacing point of the inverter. The current and voltage transient envelopes for all the case are shown in Figure 5, where the black horizontal lines are the thresholds determined to detect faults. It can be observed that the signature of transients in case of capacitor switching is similar to that of fault, making them difficult to segregate from faults. This is a limitation of transient based protection.

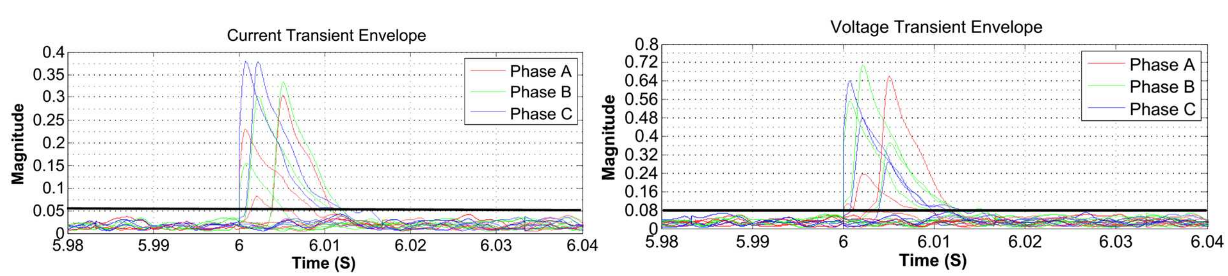

Figure 5. Transient envelopes of the current waveforms and the voltage waveforms at delta side of the interconnecting transformer for capacitor switching events.

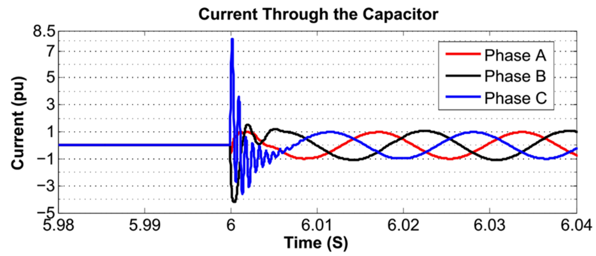

Figure 6. Current drawn by the capacitor bank at bus 675 while being switched ON.

However, this can be easily remedied by monitoring the currents drawn by capacitors. The capacitor inrush current that rides the system fundamental current to cause confusion at the Δ side of the transformer is in itself devoid of the fundamental component. This is a well-known feature that is used by overcurrent relays protecting capacitor banks to distinguish between capacitor inrush and faults. Therefore, a simple DFT of the capacitor current can resolve this problem. Of course if we solely depend on the local information at the interconnecting transformer, the confusion between some capacitor inrush cases and faults cannot be overcome. To illustrate this rationale, current drawn by the capacitor bank at bus 675 for a capacitor switching ON event is shown in Figure 6. Observe that, at 6 s, when the capacitor is switched on, the inrush current shoots up multiple folds before settling down to steady state. Notice the absence of fundamental component during the inrush period, which is the key to distinguish the inrush from fault currents.

ANTICIPATED IMPACT:

This study shows results that clearly show the fault detection strategies that can be employed for renewable-rich distribution systems. The problem will be the worst for islanded systems, when the strong substation source is not available. The next stages in this research are as follow (anticipated time-period is two years):

1) Analyze the behavior of the distribution grid during faults when multiple inverters are connected. This is nontrivial because the individual controls of these inverters may interact with one-another and create instability. In that case, reduced short circuit models may need to be developed, validated, and implemented based on the insight gained into the inverter performance. The team has good expertise in this area - the Principal Investigator (Sukumar Brahma) is chairing Working Group C24 of the IEEE Power System Relaying and Control (PSRC) committee that is looking at such models to be recommended to software vendors for fault analysis of renewable-rich systems.
2) Analyze and test islanded microgrids, where large fault current from the substation source is absent.
3) Design protection schemes for microgrids that work during grid-connected and islanded modes. This will entail determining zones of protection, sensing devices, and the required communication.
4) Locating the fault. All fault location methods for distribution systems use linear model. Now that the inverter sources exhibit nonlinear behavior during fault, these methods are prone to error. A state estimator based fault locator will be explored.

5) Testing the developed scheme with extensive simulation and limited hardware in the loop simulation.

The follow up projects will yield mature and validated protection methods for renewable-rich distribution systems, and pave the way for safe large scale integration of renewables in the distribution grid.

CONCLUSION:

In this phase of the project, a three-phase inverter modeled as per the publication from NREL [2] was designed and implemented in time domain. This inverter was connected to a 13-node, 4.16 kV IEEE test distribution feeder for fault analysis in order to derive insight into protection. The effectiveness of transient based fault detection technique relies on the transient signature left by the faults at the inverter terminals. Some faults, particularly single phase to ground faults, do not give rise to a significant transient signature, masking their detection by the transient based technique. Another limitation of the transient based technique is its sensitiveness to capacitor switching, which could be circumvented by monitoring the current drawn by the capacitor. All the unbalanced ground faults can be detected by a zero sequence relay at the interconnection due to the YG connection of the transformer secondary. The detection based on undervoltage at one of the phases was found to work for all the faults. This shows that a combination of these three approaches should provide reliable fault detection at the inverter terminals. For detecting faults at any bus of the system, the same criteria should work.

[1] Z. Ye, R. Walling, L. Garces, R. Zhou, L. Li, and T. Wang, “Study and development of anti-islanding control for grid-connected inverters,” National Renewable Energy Laboratory, 2004.
[2] E. Muljadi, M. Singh, and V. Gevorgian, User Guide for PV Dynamic Model Simulation Written on PSCAD Platform. National Renewable Energy Laboratory, 2014.
[3] Distribution Test Feeders. IEEE PES Distribution System Analysis Subcommittee. [Online]. Available: http://ewh.ieee.org/soc/pes/ dsacom/testfeeders/index.html.
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