An Active Protection Scheme for Islanded Microgrids

Md Asif Uddin Khan*, Qiteng Hong, Adam Dyśko and Campbell Booth

Department of Electronic and Electrical Engineering, University of Strathclyde
Glasgow, United Kingdom
**Email: asif.u.khan@strath.ac.uk*

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Abstract

The paper proposes a relatively simple active protection strategy incorporating controllers of the inverter for islanded microgrids dominated by inverter based distributed generators (IBDGs) that can overcome well-understood shortcomings in traditional overcurrent protection schemes applied to weak islanded systems. During a fault, the scheme identifies that a fault has occurred and instructs each IBDG in the islanded microgrid to inject specific harmonic components in conjunction with fault current; relays in the network can subsequently detect the presence and location of the fault based on the injected combination of harmonic components. The coordination of relays is achieved through definite time settings, hence communication between the protective relays is not required to operate the scheme. Furthermore, the scheme categorises the protective relays into two groups to isolate the faulty section effectively to cater for bidirectional fault current flow – this is described fully in the paper. The paper presents the structure of the proposed protection scheme along with injection strategy through the control of IBDGs. Different fault scenarios are presented using a realistic microgrid model so that effectiveness of the proposed scheme can be demonstrated in terms of detecting, identifying the faulted section and isolating the fault to ensure dependability, security and selectivity of the microgrid protection scheme.

1 Introduction

There is a global push to reduce (and even eliminate) carbon emissions from power systems. This will undoubtedly require large integration of inverter based distributed generators (IBDGs) with renewable energy resources (wind, solar, etc.) into the future network [1]. Microgrids (which can operate grid-connected or in islanded modes – for example to enhance resilience and availability of supplies) is an attractive option to manage those IBDGs effectively and efficiently. With proper control and design, microgrids can provide uninterrupted power supply, improve power quality and reduce operational costs [2-5].

However, there are several technical challenges associated with the proper operation of the microgrid and out of those challenges protection issues are the most severe one [6]. Fault current magnitudes in microgrids may vary a lot depending on the mode of operation (grid-connected or islanded). Also, microgrids are active, in the sense of net export or import during grid connected mode and power balancing/sharing during islanded mode. Hence, it is extremely difficult to maintain the protective relay coordination at all times due to variations in fault current magnitude and the bidirectional nature of load and fault current. Even detection of faults can be very challenging since power electronics devices of the inverters have limited thermal overcurrent capacity [7]. Moreover, the fault current behaviour of the islanded microgrid, as evaluated by [8], shows that during faults, each IBDG behaves as a constant current source with limited fault current magnitude. Hence, traditional overcurrent protection may not be suitable for islanded microgrids [9].

Numerous methods or schemes are available in the literature to solve microgrid protection issues. Differential relay based protection schemes are suggested [10-12] for microgrid protection and [13] suggests a protection scheme using communication. However, those schemes are relatively expensive and require communications infrastructure which may not be a cost-effective or reliable option for microgrid protection. The most widely researched protection scheme is adaptive protection [14-16], which modifies protection settings based on the configuration and fault level of the network. The main drawback with the scheme is it requires extensive power flow and short-circuit current calculation, central controller with communication and pre-defined knowledge of all possible network configuration – it may not be "future proof" or generically applicable. Several other protection solutions, such as voltage based and total harmonic distortion based schemes are suggested by [17] and [18] respectively but those schemes might not solve the coordination issues. Various other issues and alternative protection solutions are discussed in [19, 20].

The most important fact regarding the aforementioned protection schemes is that they use passive methods to tackle microgrid protection challenges, but the emerging impacts of IBDGs might not be solved by any of the proposed schemes. Hence, [12, 21-23] propose schemes that intentionally modify the controllers of the IBDGs to control the IBDGs' fault behaviour. This paper builds upon such schemes and proposes a protection scheme which is active i.e. after detecting a fault, the IBDG controllers will inject specific harmonic components so that relays can make decisions based on analysis of the injected components, thereby tripping the appropriate circuit breakers to isolate the faulted network section(s). The advantages of the proposed protection scheme are: (1) the algorithm of the scheme is relatively simple; (2) fault identification in the network does not depend on fault current magnitude; (3) it can effectively protect the network with bidirectional current flows; and (4) the scheme does not require any communication between the relays to maintain coordination or effect protection/tripping; hence, the scheme is relatively more reliable and cheaper than communications-based schemes.

2 Microgrid model

To illustrate the proposed protection scheme and to demonstrate its efficiency, a simple and realistic model of microgrid is implemented in the Simulink, MATLAB. Figure 1 shows the radial model of the microgrid with three IBDGs and three resistive loads. Different control strategies are used for the IBDGs and the strategies are discussed in detail in the next section.

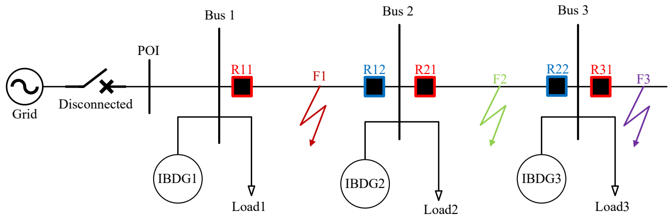

Figure 1: Schematics of the implemented microgrid model.

This microgrid can be connected and can get disconnected from the 11 kV distribution grid through a controllable switch at the point of common coupling (PCC) to enable it to operate in both grid connected and island modes. Three buses are considered in this network and each of the buses connects one IBDG and one load. The length of section 1 (between bus 1 and 2) and section 2 (between bus 2 and 3) are assumed 1.8 km and 2 km respectively. Details of the line parameters [24] and IBDGs are presented in the Table 1.

System Parameters	Value and Description of the Parameters
Line impedance	$Z_{Line} = (0.868 + j0.086)\ \Omega/km$
IBDG rating	600 kVA (for each generator)
Reference value of IBDGs	$IBDG_1 = 300\ kVA$, $IBDG_2 = 100\ kVA$ and $IBDG_3 = 50\ kVA$
LC Filter	$L = 2\ mH$ and $C = 72\ \mu F$
Load rating	$Load_1 = 300\ kW$, $Load_2 = 200\ kW$, $Load_3 = 100\ kW$ and $rest\ of\ the\ network = 50\ kW$; $Total\ Load = 650\ kW$

Table 1: System parameters for the microgrid model.

3 Control schemes for IBDGs

Figure 2 shows the generic diagram of the each IBDG unit and it is represented by a DC voltage source, power electronics based inverter with three IGBT bridges and a LC filter. DC voltage source represents the renewable based generators or energy storage devices. Although the dynamics of the intermittent renewable voltage sources are different, for simplicity and to explain the fault behaviour with proposed protection method, the control of the power sources is disregarded and focused on the control of the inverter since fault characteristics largely depend upon the control and fault current supplying capabilities of the IBDGs [25].

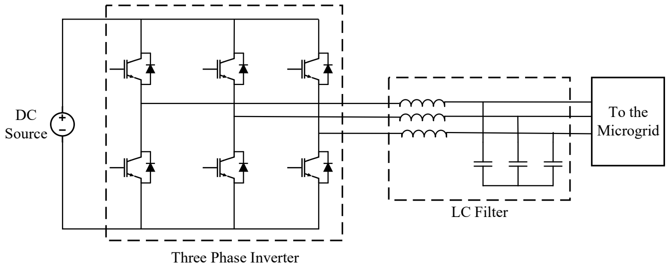

Figure 2: Generic diagram of an IBDG unit.

Several IBDG control schemes are available for microgrids and they use different power sharing techniques to ensure suitable power supply to the loads. However, this paper used only two control schemes (which are widely used in microgrids): PQ (active and reactive power) control and V/F (voltage and frequency) control. The design diagram of the both PQ and V/F controlled are shown in Figure 3 and Figure 4 respectively.

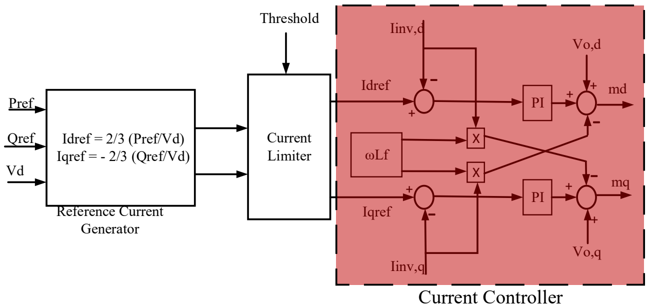

Figure 3: Design diagram of PQ controller.

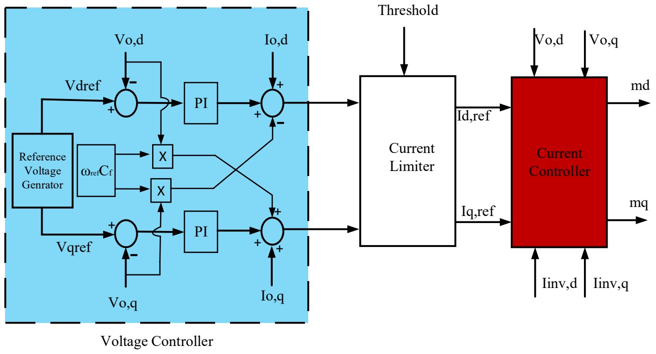

Figure 4: Design diagram of V/F controller.

PQ controlled IBDG operates as a current source regulated by reference active and reactive power values. While V/F controlled IBDG works as a voltage source (i.e. mimic synchronous generators, but not during faults) and can control voltage and frequency (i.e. attempt to maintain reference values) of the islanded microgrid. During grid connected mode all IBDGs are controlled as constant current sources and hence use PQ controllers. However, during islanded mode IBDG1 uses a V/F controller and controls the voltage and frequency of the microgrid.

Since a current limiter is used before the current controller in the model (as can be seen from Figure 3 and Figure 4), fault current will be limited to the value imposed by the current limiter and during a fault, all IBDGs will behave like as constant current sources. In this paper, the fault current threshold is set to 1.2 of the nominal current value which recognises IEEE Std. 1547.4 relating to fault current levels injected by IBDGs [26].

4 Proposed protection scheme

4.1 Overview of the proposed scheme

After detecting a fault condition (based on the IBDG's terminal voltage and current – detection methods are discussed more in section 4.4), each IBDGs in the islanded microgrid will intentionally inject a specific harmonic component with the limited fault current. The relays detect the fault presence and location based on the injected combination of harmonic components. To illustrate this further, it is assumed that during a fault all of the IBDGs in Figure 1 are injecting harmonic components in the following way: $IBDG_1$ is injecting I_{C1}, $IBDG_2$ is injecting I_{C2} and $IBDG_3$ is injecting I_{C3}. The details of the fault detection algorithm by the relays are discussed in the next subsection.

4.2 Fault detection algorithm

Since microgrids are active, it is not preferable to use only one isolator or circuit breaker beginning of the line (as is sometimes the case in passive radial system, with only downstream non-fault interrupting isolators or fuses used) as, even if a fault is detected and isolated properly, the downstream generators may still generate fault current into an upstream fault (although the generators may have breakers installed at their interface connection too – but these should not all be opened if supply continuity to healthy network sections and coordination of protection is desired). Hence, in this paper, the proposed protection scheme has two relays for each section, and they are split into two groups: forward group relay (FGR) and backward group relay (BGR). In Figure 1, relays R_{11}, R_{21} and R_{31} are considered as FGRs and R_{12} and R_{22} are considered BGRs.

The FGR makes tripping decisions based on analysis of the upstream IBDGs' injected harmonic components and the BGR makes decisions based on the harmonic components injected by downstream IBDGs. In Figure 1, R_{11} will analyse the harmonic components injected by the upstream generator, $IBDG_1$ (I_{C1}); and similarly, R_{21} will check the harmonic components of I_{C1} and I_{C2}; and R_{31} will check the harmonic component of I_{C1}, I_{C2} and I_{C3}. For BGRs, R_{12} will check harmonic components injected by the generators downstream from its position, I_{C2} and I_{C3} (components from $IBDG_2$ and $IBDG_3$). Similarly, R_{22} will analyse the harmonic component I_{C3}. This process can be represented by the fault detection algorithm shown in Figure 5. Table 2 illustrates the specific harmonic components injected by each IBDG.

A case study scenario using a fault, F_2 (a fault in section 2), can be used to simplify the explanation of operation of the proposed protection scheme. After detection of the anomaly due to the fault F_2, all IBDGs will include specific harmonic components within their injected fault currents. FGRs R_{11} and R_{21} will detect the fault, but R_{31} will remain inoperative since the fault current (along with harmonic component) is directional towards the fault (i.e. I_{C1}, I_{C2} and I_{C3} are in the direction towards F_2 and hence, R_{31} is not sensing any harmonics). For the BGRs, R_{22} will only detect the fault and R_{12} will remain inoperative because I_{C2} and I_{C3} (components needed to be analysed by R_{12}) both are in the direction towards F_2. One of the main decisions is deciding which of the relays R_{11} and R_{21} should operate first and how to coordinate their operation. The next section of the paper explains the coordination relays, both FGRs and BGRs.

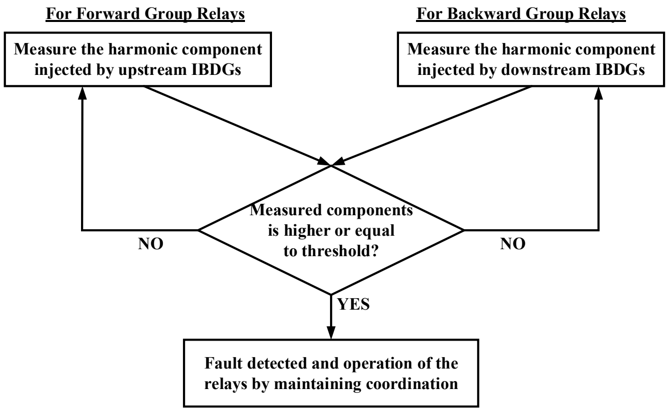

Figure 5: Fault detection algorithm for FGRs and BGRs.

Injected Generators	Injected Harmonic Components
$IBDG_1$	2^{nd} Harmonic (I_{C1})
$IBDG_2$	3^{rd} Harmonic (I_{C2})
$IBDG_3$	4^{th} Harmonic (I_{C3})
Relays	**Harmonic Components Measurement**
R_{11}	2^{nd} Harmonic (I_{C1})
R_{21}	2^{nd} Harmonic (I_{C1}) & 3^{rd} Harmonic (I_{C2})
R_{31}	2^{nd} Harmonic (I_{C1}), 3^{rd} Harmonic (I_{C2}) & 4^{th} Harmonic (I_{C3})
R_{12}	3^{rd} Harmonic (I_{C2}) & 4^{th} Harmonic (I_{C3})
R_{22}	4^{th} Harmonic (I_{C3})

Table 2: Specific injected harmonic components by IBDGs and relays' measured components.

4.3 Relay coordination

Due to limitations of the IDMT characteristics (e.g. in catering for variable fault levels) and concerns over costs and reliability of communication channels, the proposed method uses definite time characteristics for relay operation and coordination. Figure 6 presents the definite time characteristics used for relay operation and coordination for the proposed scheme.

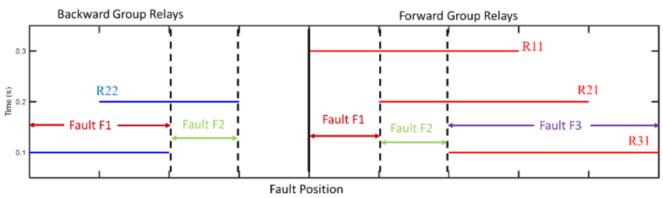

Figure 6: Relay coordination during different position of faults.

From Figure 6, it can be seen that during fault F_3 (in section 3), R_{31} will operate first, with R_{21} and R_{11} acting as backup protection if required with a grading margin of 0.1 s. For fault F_2 (in section 2), R_{21} will operate first at around 0.2 s and R_{11}

would operate as backup at around 0.3 s. For the BGR, only R_{22} will operate at around 0.2 s. Similarly, for fault F_1 (in section 1), only R_{11} will operate at around 0.3 s (FGR), R_{12} will operate around 0.1 s (BGR), with backup provided by R_{22} if required (will operate around 0.2 s).

One major drawback of definite time coordination is that longer operation times are inherent in such schemes for faults at the most upstream locations, which, in grid-connected mode, have the relatively highest fault levels. However, during islanded modes of operation, fault current will generally be very low may not vary according to location "linearly" (from the source to the remote end of the feeders) as with passive grid-connected networks. Accordingly, using definite time schemes may not be disadvantageous. Furthermore, for a fault at the furthest upstream locations, e.g. for fault F_1, the BGR, R_{12} will operate faster according to the settings and will isolate most of the fault contributing generators relatively quickly. Thus, definite time coordination can be a suitable option for coordination of relays in islanded microgrids.

4.4 Harmonic injection by IBDGs

Figure 7 shows the harmonic injection process used by the IBDGs. To detect the fault, in this scheme both current and voltage will be measured at the IBDG terminal (which would typically be required for control purposes anyway) and if the measured voltage is less than threshold or measured current is greater than threshold, the controller will inject specific harmonics – unbalance (presence of negative or zero sequence current) could also be used for initial fault detection – the fault detection process requires further investigation and definition. In this initial work, a fault will be deemed to exist and harmonics will be injected if IBDG terminal voltage is less than 0.8 pu and current is greater than 1.2 pu.

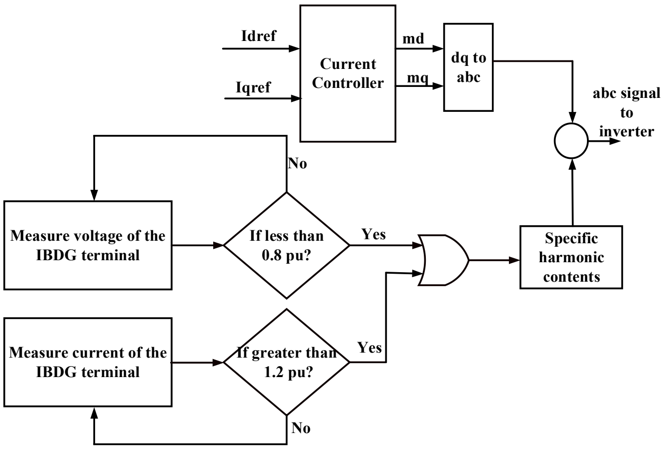

Figure 7: Harmonic injection process through the controller.

5 Simulation results and verification

To examine and verify the performance of the proposed scheme, several case scenarios have been simulated using Simulink with the microgrid model shown in Figure 1. Due to space limitations, a small number of scenarios with solid three phase balanced faults are presented in the next section.

5.1 Scenario #1: Fault after Bus 3

A three phase fault is simulated on section 3 (end of the line). Hence, all IBDGs should inject harmonic components and fault currents will pass through all the relays. Figure 8 shows the rms magnitude measured by FGRs with harmonic components. Finally, Figure 9 shows successful operation of the relay, R_{31} based on the reading from Figure 8. For this fault, all the BGRs remain inoperative.

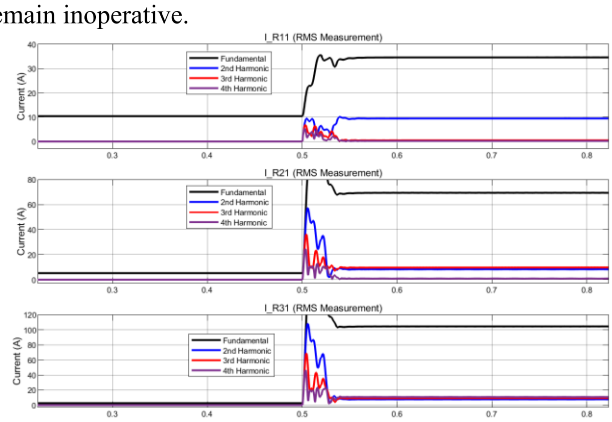

Figure 8: RMS value of fault current during F_3 with injected harmonics measured by FGRs.

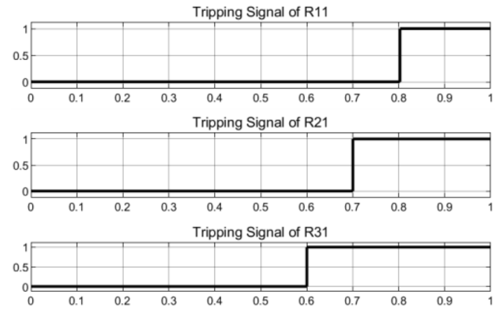

Figure 9: FGRs tripping operation during F_3.

5.2 Scenario #2: Fault between Bus 2 and Bus 3

For fault in the middle section of the line (F2), Figure 10 illustrates the measured rms current value by the FGRs and Figure 11 shows the rms value measured by the BGRs. Finally, Figure 12 and Figure 13 prove the correct operation of the both FGRs and BGRs due to fault F_2.

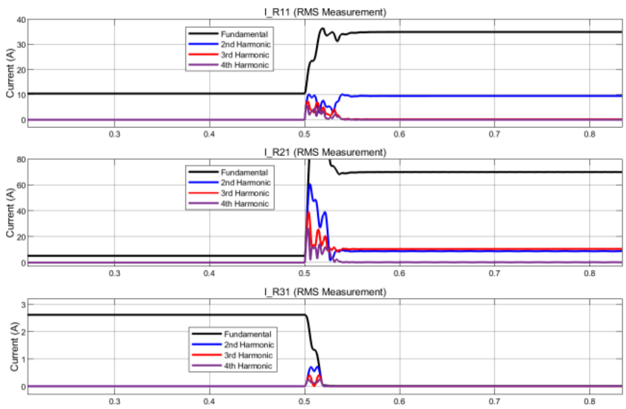

Figure 10: RMS value of fault current during F_2 with injected harmonics measured by FGRs.

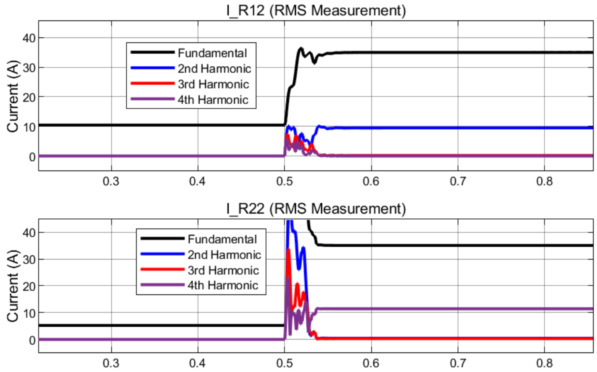

Figure 11: RMS value of fault current during F_2 with injected harmonics measured by BGRs.

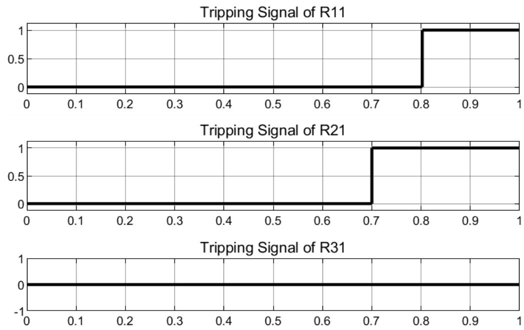

Figure 12: FGRs' tripping operation during F_2.

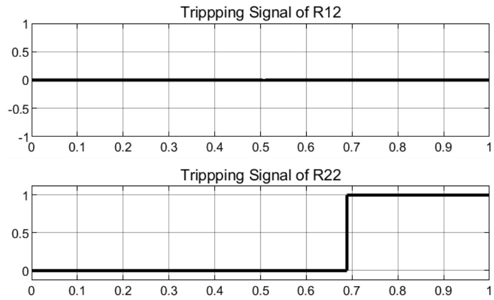

Figure 13: BGRs' tripping operation during F_2.

5.3 Scenario #3: Fault between Bus 1 and Bus 2

In this scenario, a fault is injected on the first line section (fault F_1) and simulation results are shown for the FGRs and BGRS in Figure 14 and Figure 15 respectively, while Figure 16 and Figure 17 show the operation of the relays.

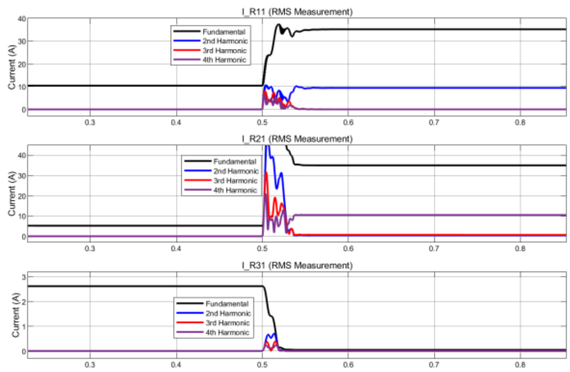

Figure 14: RMS value of fault current during F_1 with injected harmonics measured by FGRs.

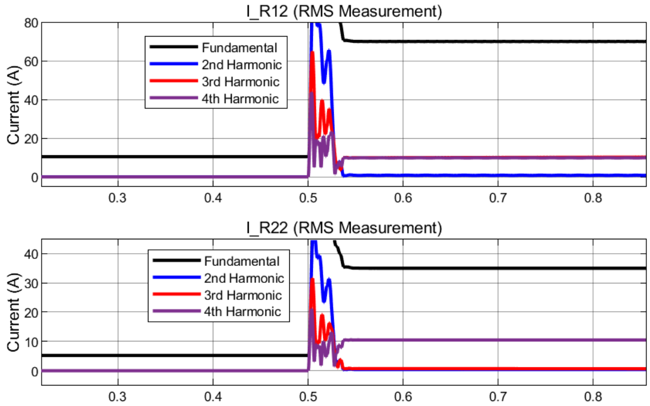

Figure 15: RMS value of fault current during F_1 with injected harmonics measured by BGRs.

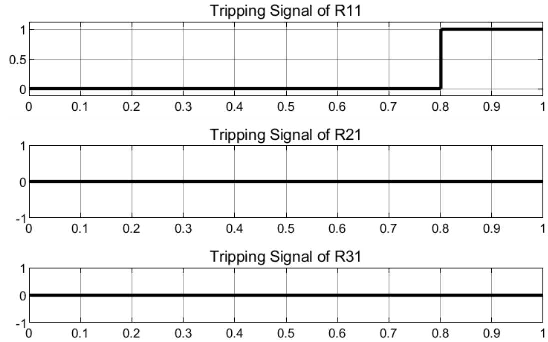

Figure 16: FGRs' tripping operation during F_1.

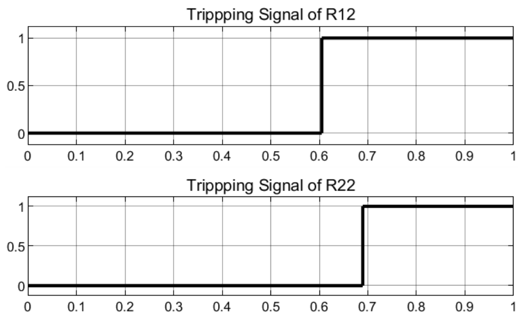

Figure 17: BGRs' tripping operation during F_1.

6 Conclusions and future work

It is clear that protection of islanded microgrids can be challenging; accordingly, this paper has proposed an active and novel protection scheme. The scheme is relatively simple and should be relatively inexpensive to implement since it does not require communications to operate. Simulation results for a range of scenarios have verified the effectiveness of the proposed scheme.

The results are preliminary in nature and in future, the scheme must be tested across a wider range of scenarios to establish its full applicability and any limitations in its ability to detect and clear faults. Different types of faults, including asymmetrical and high impedance faults, will be simulated and tested in the laboratory to verify the operation of the proposed protection scheme, with hardware-in-the-loop facilities being used to prototype a practical solution as a key element of future work.

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