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A review of protection systems for distribution networks embedded with renewable generation

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Keywords

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A Review of Protection Systems for Distribution Networks Embedded with Renewable Generation

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achieve microgrid protection adequacy in future networks.

Keywords: microgrid protection, distributed generation, smart protection, smart grid

1. Introduction

The increasing pressure for renewable or 'green' energy coupled with government funded economic incentives has caused a paradigm shift in the way residential, commercial and governmental bodies approach energy investment. The shift has predominantly manifested through the dramatic increase in the presence of grid-connected embedded generation (EG) in distribution networks (DNs).

DNs were designed under the premise of radial power flow [1, 2, 3, 4, 5]. The introduction of small-scale EG introduces the possibility of bi-directional power flow, rendering the network non-radial. The integrity of DN design philosophy is compromised and a detailed analysis is required to ascertain the implications of various levels of EG penetration.

For the purposes of this paper, the DN encompasses the electrical infrastructure between a zone substation and a customer's point of connection[1] (POC).

Reviews of proposed protection schemes in microgrids have been conducted by Mirsaeidi et al. in [6] and Gopalan et al. in [7]. Both offer excellent synopses of microgrid protection schemes. The purpose of this paper is to expand upon the range of investigated microgrid protection schemes and proffer a more in-depth explanation and analysis of each proposed protection scheme. Furthermore, this paper provides supplementary recommendations

[1]IEC definition: the reference point on the electric power system where the users' electrical facility is connected

for a more holistic approach towards microgrid protection design philosophy.

The remainder of this paper is organised as follows: Section II discusses the possible issues concerning the continued proliferation of EG in DNs. The discussion extends to recloser, fuse, sectionaliser and EG coordination in contemporary DNs. Section III reviews proposed protection strategies by various authors for DNs employing grid-connected only operation. Section IV provides a critical analysis of microgrid protection strategies encompassing both grid-connected and autonomous modes of operation. Finally, Section V outlines the preferred protection schemes to be adopted should a modular microgrid become a reality. A summary of the analysed protection schemes is given in the appendix.

2. Contemporary DN Protection Systems

2.1. Over Current and Earth Fault protection

Traditional protective devices in DNs consist of reclosers, sectionalisers and fuses. All reclosers interrupt fault current using a circuit breaker (CB). To coordinate protective devices, traditional DN protection schemes implement graded over current (OC) protection and earth fault (EF) protection. OC and EF protection gradings are achieved using inverse definite minimum time (IDMT) curves. Each curve incorporates an error margin in order to account for delays in signal processing, signal transmission and the time for the circuit breaker to open and extinguish the fault.

A radial network has only one source of fault current. Therefore, any protective devices located between the fault source and the fault will observe (almost) the same fault current. IDMT curves must be arranged carefully to ensure that the minimum number of customers are disconnected when a fault is isolated. The design process of choosing appropriate IDMT curves does not incorporate the effects of EG. In fact, the IEEE Standard 1547-2003 states that:

> "Any distributed resource installation connected to a spot network shall not cause operation or prevent reclosing of any network protectors installed on the spot network. This coordination shall be accomplished without requiring any changes to prevailing network protector clearing time practices of the area electric power system [8]."

Experimentally, OC and EF protection have been shown to be susceptible to poor discrimination in networks with a high EG penetration [9, 10]. Hence, a threshold of EG penetration must exist that defines the boundary where a network does not comply with the protective requirements stipulated within the IEEE Standard IEEE1547-2003. The determination of such a boundary has not been ascertained as there are other limiting factors of EG connection such as over voltage; empirically, over-voltage instances precede protection failure. However, there are control mechanisms such as reactive power absorption and real power curtailment capable of eliminating over-voltage occurrences [11]. The EG threshold before DN protection failure is poorly defined and is an area of research that requires further investigation.

Failure of OC and EF protection discrimination can be achieved in two ways. Firstly, a protection devices can trip unnecessarily for a fault outside of that protection device's zone of protection. Secondly, a protection device can fail to trip when a fault occurs within that protection device's zone of protection. These protection failures are referred to as a nuisance trip and fail-to-trip respectively. Consider the circuit shown in Fig. 1. The star designates a fault which is located in CB2's zone of protection. Fault current will flow through all circuit breakers; however, CB1 and CB3 will experience a fault current in the opposite direction to normal power flow. OC and EF devices are not equipped with directional elements in DNs; hence, the trip time of CB1 and and CB3 can be expressed through each circuit breaker's respective IDMT curve.

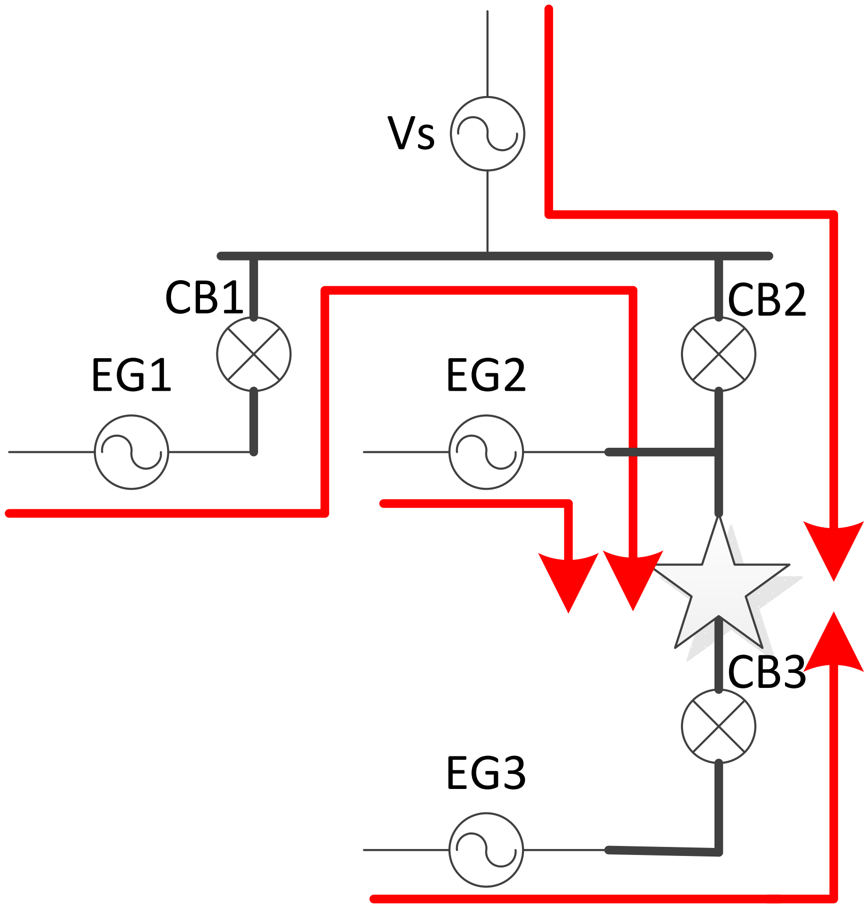

Figure 1: Protection Discrimination Example

The IDMT curves of CB1 and CB2 are not graded in the protection planning process due to the assumption of radial power flow – no fault current will flow through CB1 during a fault in CB2's zone of protection if the DN is radial. While it is unlikely that CB1 would trip before CB2 isolates the fault, a CB1 nuisance trip may occur if the pick-up current of CB1 is significantly lower than CB2. The result would be the unnecessary loss of all customers on the CB1's corresponding feeder. Customers will likely be reconnected after an auto-reclosure once CB2 isolates the fault. However, the reliability of the overall network is compromised.

Similarly, CB3 would observe fault current in the opposite direction of radial power flow during the fault in CB's zone of protection. In the unlikely event that the reverse fault current is sufficient to trip CB3, no extra customers are lost. A trip at CB2 isolates all customers downstream of CB2 which includes all customers downstream of CB3. All islanded EG units will isolate themselves via anti-islanding protection and reclosure attempts of CB2 and CB3 will ensure that the final operational state of each circuit breaker is identical to an equivalent situation with no EG connection. However, the operation of CB3 violates the IEEE Standard 1547-2003 [8].

The fault current provided by EG2 will increase the voltage drop between EG2 and the fault, reducing the fault current passing through CB2. During a high impedance end of zone fault, the presence of EG may cause the fault current flowing through a protection device to be below the pick-up current. In such a case, a fail-to-trip would occur, increasing the likelihood of bushfires as well as electrocution risk to customers and utility personnel. Fault discrimination problems caused by high penetrations of EG can pose a significant threat to DN reliability and safety.

Contrary to discrimination, protection selectivity between reclosers can be improved through EG connection. Consider the circuit shown in Fig. 2.

CB2 and CB3 are graded to ensure that CB3 will operate before CB2 for a fault in CB3's zone of protection. Due to the presence of an EG unit between

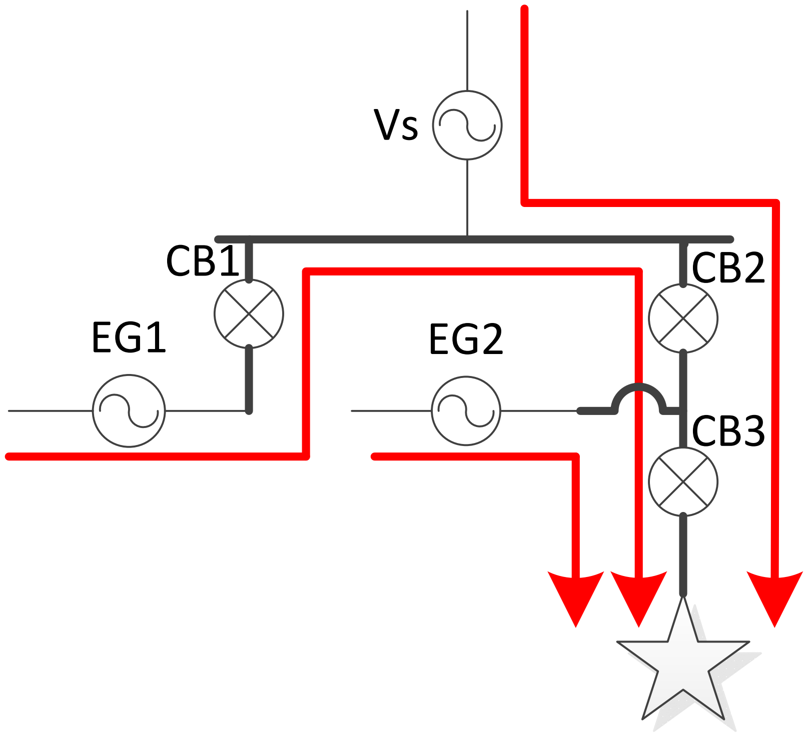

Figure 2: Protection Selectivity Example

CB2 and CB3, the current observed by CB3 is greater than CB2. Hence, the time difference between a CB3 trip and a CB2 trip will be greater than the graded IDMT curves would suggest. Hence, the selectivity of an OC/EF protection scheme can be improved through EG connection. However, there are further complications that must be considered concerning auto-reclosure.

2.2. Recloser-EG Coordination

Reclosers will typically trip before an EG unit's anti-islanding protection will detect loss of mains (LOM). The maximum allowable time it should take for passive anti-islanding protection to operate is two seconds according to Australian Standard 4777.3 and IEEE Standard 1547 [12, 8]. Reclosers will often remain open in the range of hundreds of milliseconds up to seconds, before a reclosure attempt [13]. The time that a recloser remains open before a reclosure attempt is referred to as the recloser dead time. After the formation of an island, it is likely that a phase difference of the voltage waveforms across the open recloser will occur. Thus, an out-of-phase reclosure would create a large disturbance in the network, possibly damaging network infrastructure and EG technology. IEEE 1547-2003 states that an EG must cease to energise a network prior to a reclosure by the DN protection system [8]. Hence, it is important to consider the impact of EG anti-islanding operation when selecting reclosure times.

Further, it is possible for an EG unit to sustain an arc even after a recloser has isolated the fault from the main supply [13]. The purpose of the recloser dead time is to allow the arc path to de-ionise, thus removing the fault, assuming the fault is temporary. If the arc is sustained by EG, a temporary fault may become permanent, reducing the reliability of the network.

A trade-off is necessary when coordinating reclosers with EG units. The recloser must be open for long enough to ensure that anti-islanding protection can operate, but short enough such so that the interruption experienced by customers is minimised. The coordination is further complicated when fuses and sectionalisers are installed within the DN.

2.3. Recloser-Fuse-EG Coordination

Reclosers are essential to maintain high reliability levels as most faults on DNs are temporary [5]. Spurs, off the backbone of a feeder, are normally protected by a fuse. Whenever a fuse isolates a fault by burning out, that fuse has to be replaced by utility personnel before supply is regained to customers downstream of the blown fuse. In order to further increase the reliability of DNs, reclosers are coordinated with fuses such that the recloser will isolate before the fuse will blow on the first detection of a fault. If the fault is temporary, the fault will usually be cleared before the first reclose and no more protection operations will be necessary. If the fault is still present, the fault is considered permanent; the fuse will blow faster than the recloser trip time. Hence, two separate IDMT curves are used for reclosers which are coordinated with fuses: a fast IDMT curve that will trip the recloser before the fuse blows and a slow IDMT curve that will allow the fuse to burn out if the fault is still present (and downstream of that fuse). The inclusion of EG in DNs increases the likelihood of a fuse blowing out on a temporary fault before the recloser with a fast IDMT curve trips [2, 14].

In contemporary DNs, EG penetration levels are low and do not provide sufficient fault current to interfere with protection grading nor selectivity. However, as EG penetration rises, the aggregate fault current supplied by EG units may cause fuses to blow unnecessarily. Fig. 3 shows an example DN where a fuse has been coordinated with an upstream recloser programmed with both a fast and slow IMDT curve. The additional fault current supplied by the local EG implies that the fault current measured by the recloser is smaller than the fault current flowing through the fuse. If the difference in fault current is significant enough, the fuse may blow before the fast IDMT curve programmed within the recloser will send a trip signal. The overall reliability of the network will be significantly reduced as most faults within DNs are temporary in nature [5].

2.4. Recloser-Sectionaliser-EG Coordination

Sectionalisers are incapable of extinguishing the fault current levels associated with that sectionaliser's zone of protection. Hence, sectionalisers are only useful when coordinated with reclosers. Sectionalisers will open after a set number of identified reclosures and when the fault current has been extinguished by an upstream circuit breaker. The sectionaliser in Fig. 4

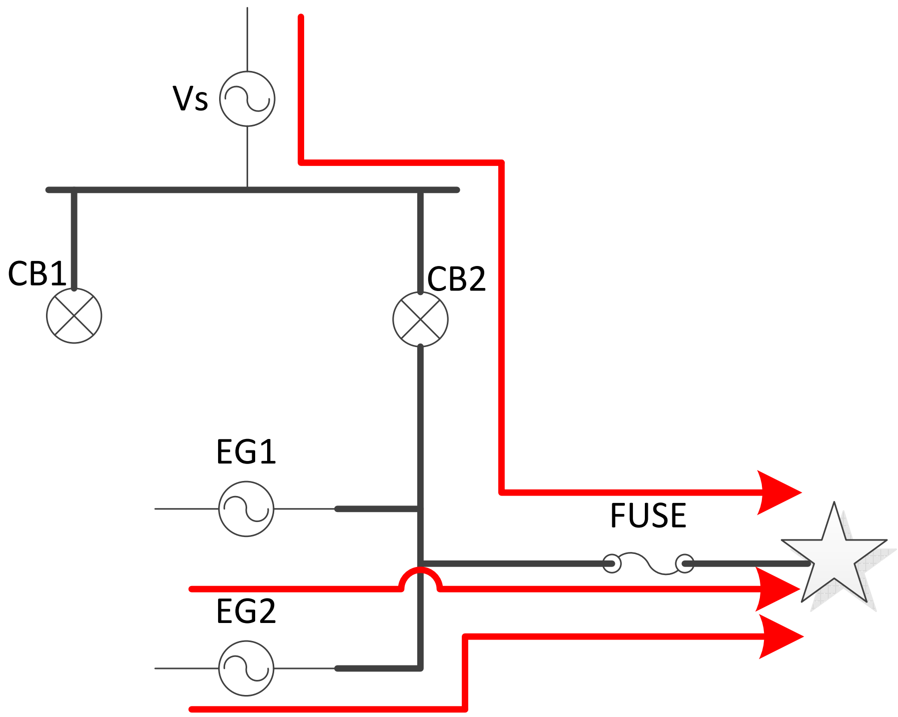

Figure 3: Effects of EG on Recloser-Fuse Coordination

trips after the first reclosure and after then fault has been extinguished for a second time.

However, if the fault current is sustained by the local EG, the current rating of the sectionaliser may be exceeded. Either the sectionaliser would be damaged upon trying to open with a sustained fault current or the sectionaliser may fail to detect an upstream CB operation. In either case, the overall reliability of the DN would be compromised.

2.5. Anti-Islanding Protection

Anti-islanding protection is responsible for preventing instances of unintentional islanding in DNs. Unintentional islanding is any situation where EG continues to supply a subsection of a network despite being isolated from

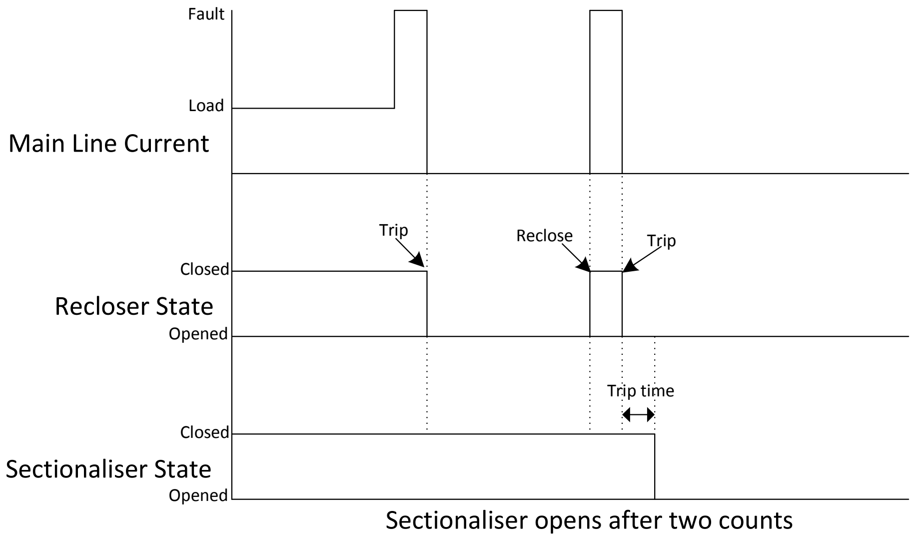

Figure 4: Sectionaliser Operation [15]

the mains supply. There are significant technical and safety issues that might arise from an islanding situation. Consequently, intentional islanding is forbidden by the Australian Standard AS4777.3 [12]. Anti-islanding protection can be broadly classified into three different types: passive, active and communications based. In contemporary applications, anti-islanding protection is limited to passive and active types.

According to comprehensive reports on anti-islanding technology, there is no form of non-communications or utility based anti-islanding protection without a non-detection zone (NDZ) [16, 17]. In practice, however, the risks of most NDZs being realised are very small. However, as EG penetration rises, the risk of anti-islanding protection failure increases. Anti-islanding protection failure can lead to out-of-phase reclosure, decreased reliability and risk of electrocution to utility personnel.

Anti-islanding protection design is not a focus within this paper. A plethora of different anti-islanding methods have been proposed and assessed

[16, 17]. The operational characteristics of an island that are required to prevent islanding detection within two seconds cannot be achieved with contemporary EG penetration sizes and limitations stipulated by utilities [18]. However, if EG restrictions are lifted and EG penetration levels can approach 100% within DNs, the likelihood of anti-islanding protection failure to detect LOM increases significantly. In such a case, traditional DN line protection would be completely inadequate. A significant protection design philosophy reform would be necessary, including the protection of EG units.

When EG penetration levels exceed 100% of DN capacity, a logical evolution of DN operation is the microgrid concept. Within a microgrid, anti-islanding protection is unnecessary, yet the detection of LOM is still vital such that the control and protection schemes employed by an EG unit can change as required. For instance, the control scheme of EG units may change from constant-power control to droop control to ensure proper load following as the microgrid transitions into autonomous mode. It is important to recognise that the protection techniques implemented in microgrids are also valid for grid-connected only operation as a microgrid must be capable of isolating a fault during both grid-connected and autonomous modes of operation. Conversely, grid-connected only protection techniques can be implemented in a microgrid during grid-connected operation.

3. Proposed Protection Schemes for DNs with Grid-Connected EG

The introduction of EG in DNs subverts the premise of radiality central to traditional DN protection philosophy. The non-radiality of DNs can be likened to the power flow observed in transmission networks. The protection philosophy for transmission networks implements distance and directional protective elements to detect and locate faults despite the presence multiple fault current sources. However, the energy resources connected to transmission networks are typically large-scale synchronous machines that are capable of delivering large fault currents. Hence, the principles used in transmission networks could in theory be utilised in DNs with a high EG penetration if EG units were interfaced through synchronous machines and the extra expense of directional and/or distance protection can be justified.

The implementation of directional OC relays is proposed by Bhalja et al. in [19]. All EG units midway through a line have two separate protection devices with directional elements connected on each side of that EG unit's POC. All other DN protective devices are non-directional. There are many concerns with such a protection scheme. There is a significant extra cost as two current transformers, two relays and two circuit breakers are necessary for each EG unit connected midway through a feeder. The scheme also assumes that EG units are interfaced through synchronous machines which is often not the case. Inverter-interfaced EG units would likely be unable to provide enough fault current for adequate protection discrimination during to the limited thermal inertia of power electronics switches. Finally, non-directional relays connected at the upstream end each feeder could trip due to EG feeding faults on adjacent feeders. Hence, it may be appropriate for all OC protective devices to be equipped with directional elements with an EG unit downstream of that protective device.

An adaptive protection scheme that incorporates protection against voltage sag is proposed by Choi et al. in [20]. In the paper, a single end-of-line synchronous generator is the adopted EG interface in the case study. The proposed protection scheme includes both OC and voltage-based methods of fault detection. Protection thresholds of 'critical current' and 'critical voltage' are proposed and can be defined as the expected fault current and voltage at an EG unit's POC during a zero-impedance fault at the nearest upstream protection device. These 'critical values' are thresholds used to determine if a fault is within the inter-tie circuit breaker's zone of protection. An instantaneous trip is implemented for any fault current above the critical current, otherwise IDMT curves are implemented if the measured current at the EG unit is above the pre-determined pick-up current. The proposed protection scheme also uses IDMT curves to determine whether the recorded voltage magnitude is indicative of a fault and, upon detection, will trip the inter-tie circuit breaker. The protection scheme proposed [20] may be inappropriate for schemes with inverter-interfaced EG, particularly during high-impedance faults as fault current flow would be minimal. Furthermore, many Australian DNs cover large distances and substantial voltage drops are frequent. Hence, EG protection using voltage magnitude at the EG unit's POC will likely encounter discrimination issues. Complications for detecting phase-to-earth faults would also arise as the earthing connection and transformer connection can prevent the flow of zero sequence fault current from EG units. There are also unanswered questions regarding the coordination of multiple EG units.

An alternative to OC protection in DNs using distance protection is proposed by Chilvers et al. in [21]. Distance protection is directional in nature and hence is appropriate for non-radial networks. A disadvantage of using distance protection is the connection of a voltage transformer which represents a significant extra cost compared with traditional OC protection. However, it can be argued that the voltage transformer is unnecessary as the voltage sensor can be connected on the low voltage side of the distribution transformer. Contemporary DNs are often separated by normally-open switches or reclosers which can be used to reroute supply during maintenance. In theory, normally-open points could be closed and the network could be protected using distance protection in much the same way as transmission networks are protected [22]. The non-radiality of a DN would increase the reliability of that DN if protection selectivity and discrimination can be achieved. In addition to protection considerations, the voltage profile and thermal loading of the line must also be considered before a normally-open point should be closed. Distance protection also has the advantage of a faster operation time which is important for the overall stability of the DN. A significant complication arises due to delta-wye connected distribution transformers incapable of passing zero sequence current. For a fault on the high voltage side of the distribution transformer, there will be no zero sequence voltage on the low voltage side of the transformer. The protection scheme attempts to compensate for the lack of measurable zero-sequence voltage data using a preset estimate of the impedance behind the distance relay during phase-to-earth faults, including the impedance of the earth return path. The determination of protection settings for distance protection may be a more rigorous process than traditional OC protection to prevent fault under-reach or over-reach during phase-to-earth faults. While preliminary research is promising, more research is necessary to assess the efficaciousness of distance protection in DNs with a high EG penetration.

4. Proposed Protection Schemes for Microgrid Applications

An effective, robust and experimentally verified protection design philosophy for intentional islanding has not yet been developed. Many protection schemes have been proffered by a variety of authors. Arguably, protection is the least understood topic within the realm of microgrid design philosophy largely due to the unusual fault response of inverter interfaced EG. Traditional OC protection alone has been proven to be insufficient for microgrids containing inverter-interfaced generators [23]. Coordinating protection devices across both grid-connected and autonomous modes of operation to maintain adequate redundancy, discrimination and selectivity is a key focus in contemporary protection research.

The simplest method of maintaining a significant fault current during islanded operation is through connection of machines with a significant inherent inertia. The authors of [24] propose the inclusion of a flywheel system to complement inverter-interfaced EG in order to supply a significant current when a fault occurs in an islanded microgrid. Flywheel systems are very useful in applications containing critical load, especially when coupled with dispatchable power such as diesel generators [25]. However, flywheels are expensive and require a sophisticated control scheme for coordination with EG in a microgrid. Due to the high cost of such a scheme, it is unlikely that every inverter-interfaced EG unit will be equipped with a flywheel system. Thus, it is envisaged that a communications medium would be necessary to instigate an inter trip to isolate all non-inertial EG when a relay located at an inertial EG unit detects a fault. There is also no consideration for back up protection for cases of communications or flywheel failure.

Three protection design schemes for microgrids are proffered by Conti et al. [26]. Each scheme assumes the presence of a microgrid central controller and thus communications, which is a subversion of the desirable and well established plug-and-play microgrid design philosophy [27, 28, 29]. Each scheme also employs OC protection and hence cannot be considered appropriate for inverter-interfaced EG.

The first scheme proposed in [26] uses conventional OC protection to isolate the fault at the protection device at the 'satellite centre' (SC) (the circuit breaker immediately downstream of SC in Fig. 5) of the microgrid.

Before the circuit breaker at the SC trips, each protective device determines the direction of the fault. In the example of a phase-to-earth fault, the zero sequence current direction is determined using the zero sequence voltage as a reference. A lagging zero sequence current indicates a forward direction fault and vice versa. The central controller then determines the location of the fault using the information gathered by each relay transmitted over a communications channel and switches, in and out, the appropriate circuit breakers to ensure fault isolation and maximum customer connection. The central controller must be given a data set containing the network topology and protective device locations and identifiers. Any modification of the microgrid requires significant alterations and reprogramming of the protection devices. There is also a significant loss of reliability due to unnecessary tripping of upstream protective devices and the abandonment of recloser operation. Reclosers are essential to maintaining reliability in DNs (though reclosers can be problematic if EG isolation does not occur before the first reclose). It is important to note that for the first proposed scheme, the isolation of a fault is not dependent on communications; merely the appropriate selectivity of the protection is dependent on communications.

The second scheme uses OC and zero sequence current relays to determine the presence and direction of a fault to identify the fault location, much like the first proposed scheme. The difference is that the circuit breaker immediately downstream of the SC no longer necessarily trips first. Upon detecting a fault, each protection device communicates with any adjacent protection devices through a pilot wire. If the OC or zero sequence current direction is the same, no protection trip is necessary. If the directions are different, the relevant circuit breakers will isolate the fault. The advantage of the second proposed scheme is the short duration trip time, reducing the

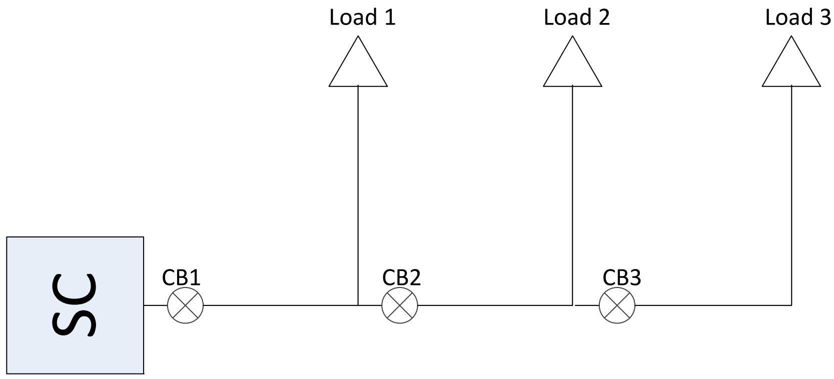

Figure 5: Conti's Microgrid Example

impact of fault current on existing infrastructure and minimising the risk of igniting a bushfire. The disadvantage of the second proposed scheme is the extra cost of the pilot wire and control logic as well as the lack of contingent protection if communications are to fail. The absence of communication response and presence of OC would necessitate a trip signal which would compromise the selectivity and reliability of the protection scheme.

The final scheme contains two sets of CTs, circuit breakers and relays adjacent to every load and EG unit, except at the end of the line where only one set is necessary. Each protective device is directional in nature and 'looks' away from that protective device's load or EG unit as shown in Fig. 6. When a fault current is detected, the protective devices at the end of each line segment compare the direction of the fault. If the paired protection devices observe the same forward fault direction, those protection devices will both trip, isolating the fault. A communications medium is required for the protections scheme to operate as expected; hence, a back-up protection is necessary in the case of communication failure. The extra protection infrastructure represents a significant cost and could only be deemed appropriate

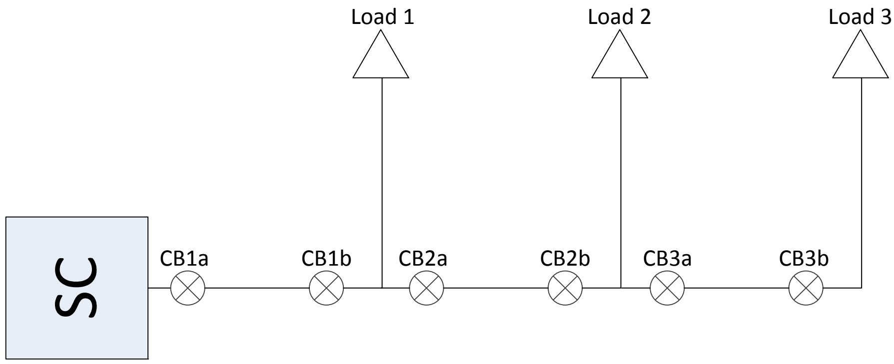

Figure 6: Conti's Final Protection Scheme Example

for large scale EG such as those found in sub-transmission networks.

All three protection schemes rely on the presence of OC during fault response; a premise which is unreasonable in the case of microgrids dominated by inverter interfaced EG. Conti discusses the protection issues concerned with inverter-interfaced EG and recommends use of differential protection which also requires use of a communications medium. The reliance on a communications medium for adequate protection compromises the reliability of the microgrid. It is also preferable for the microgrid to operate in a plug-and-play manner as much as possible to reduce DN planning complexity and eliminating the need for reconfiguration of protection settings each time a modification is made to the DN.

A microgrid protection scheme for inverter-interfaced EG dominated networks is proposed by Loix et al. in [30]. The use of inverter-interfaced EG can have significant benefits from a stability perspective provided the inverter is rated sufficiently to provide adequate fault ride-through. An inverter interface decouples the dynamics of an energy source or machine from the grid [31]; the inverter can be controlled to provide a desirable response to disturbances given that the ratings of the IGBTs are not exceeded and enough short term energy is available from the DC bus. For the protection scheme proposed in [30], a fault current limiter is necessary to ensure an inverter-interfaced EG will aid in fault detection without exceeding current ratings. The proposed protection scheme uses sequence components to identify the fault location and uses time delays to achieve protection coordination. Communications may be used to reduce the trip time, but is not essential to achieve protection adequacy. The major omission of the proposed scheme is a discussion regarding protection discrimination capabilities, particularly during the presence of high impedance faults. The zero sequence fault current may not be significantly different from an unbalanced load current. Furthermore, transformer connections and earthing configurations are not taken into account may provide multiple (or no) zero sequence current paths.

The authors in [32] use directional OC, negative sequence current and zero sequence current protection to detect faults within a microgrid. For high impedance faults, an energy level based protection proposed by [33] is adopted. However, there exist some loads that behave similarly to high impedance faults [33]; hence, discrimination problems may arise. The proposed control scheme includes the provision of blocking signals between protective elements to preclude false trips due to faults in adjacent zones of protection. There are several advantages to using blocking signals to ensure selectivity and redundancy in DNs. Firstly, the use of blocking signals provides back-up protection for circuit breaker failure. Blocking signals will only be transmitted long enough for the fault to be isolated according to the IDMT curve programmed within each relay. If a circuit breaker has failed to isolate the fault, the blocking signal will be removed and the adjacent circuit breaker will trip, providing adequate back-up protection. Secondly, assuming communications infrastructure is healthy, selectivity can be achieved in tandem with fast tripping times, improving the stability of the network. Protective devices no longer have to wait until each upstream device has the opportunity to isolate a fault before tripping. Finally, in the event of communications failure, the protection scheme will still isolate the fault. The disadvantage of communications failure is that selectivity will be compromised which will result in an unnecessary disconnection of supply to some customers. Such a disadvantage can be considered acceptable within the context of safe microgrid operation.

The use of differential protection in microgrids been proposed by Zeineldin et al. in [34] for microgrid application, similarly to Conti in [26]. To accomplish differential protection, the end of each line must be equipped with a current transformer, relay and circuit breaker. A communications link will be necessary between devices on the end of each line such that the end of line currents can be compared. A relay will send a trip signal if the difference in current exceeds a predetermined level. In the proposed scheme in [34], each EG unit is assumed to keep contemporary anti-islanding protection that will inform the central controller and EG unit whether an island has formed. Constant current control is used for grid-connected operation and P-V control is used for autonomous control. The proposed protection scheme offers very effective protection discrimination and selectivity assuming all components are working properly. However, no provision for back up protection during communications or circuit breaker failure is given. Furthermore, the proposed protection scheme is very expensive and only appropriate for sub-transmission level microgrids with limited spurs and loads.

Instantaneous communication based differential protection is proposed as an effective protection scheme for microgrids in [35]. In the event of a circuit breaker failure, adjacent relays would receive an inter-trip signal to isolate a fault. However, provision for communication failure is not given. The authors in [36] investigate the efficacy of differential protection, but only consider three-phase bolted faults which are uncommon. Regardless, differential protection would theoretically provide adequate discrimination and selectivity for any type of fault given the fault current exceeds 10% of nominal current flow [35].

The use of voltage-restrained over-current (VROC) relays in inverter dominated microgrids is proposed by Tumilty et al. in [37]. The feasibility of using solely voltage-based protection techniques for protection adequacy in a network is explored in the paper. The paper concludes that topological selectivity is problematic and impractical for complex microgrids. VROC relays can provide separate OC protection settings depending on the locally measurable voltage. The use of VROC reduces tripping times and reduces the risk of nuisance tripping if protection settings are chosen correctly. However, there still exists complications in coordinating protective devices using VROC; general selectivity for every microgrid configuration cannot be achieved without communications.

A sequence component voltage-based protection scheme for islanded operation is proposed in [38] and [39]. The three-phase voltage waveforms are converted into the direct-quadrature (d-q) axis using a rotating reference frame. The difference between the reference d-q voltages and the measured d-q voltages is calculated and analysed to determine the fault type and location. The models of EG units given in [38] and [39] assume an outer voltage regulation loop and an inner current regulation loop to control the gating signals transmitted to the inverter. Such a control scheme does not allow for load following and hence is inappropriate for use within microgrids.

The sequence component voltage-based protection scheme relies on communications infrastructure to provide fault discrimination. The authors of [36] found that if a significant voltage drop existed during normal operation, fault discrimination could not be achieved even with healthy communications. Fault discrimination is further complicated through the prevalence of very high impedance phase-to-earth faults in DNs, particularly when control schemes such as droop control maintain the voltage within acceptable bounds as stipulated in [40]. Hence, voltage-based protection schemes are deemed inadequate as primary protection within microgrids.

Another protection scheme proposed by Al-Nasseri et al. involves the use of harmonic content of voltage waveforms in inverter-based EG dominated microgrids [4]. A protection relay monitors the total harmonic distortion (THD) of the EG unit's POC voltage and will trip the local circuit breaker if the THD exceeds a predetermined threshold and the fault is proven to be within that protection relay's zone of protection. A communications link is used to compare the THD at various EG unit terminals. There are no considerations for distribution transformer connection which are common in DNs. A delta-wye connected distribution transformer will have a significant impact on the fault current and voltage waveform at the EG unit's POC. In some cases, protection discrimination through THD may be impossible. Furthermore, the proposed scheme is inappropriate for high impedance faults which may only provide a voltage drop similar to significant unbalanced operation. There might also exist complications caused by dynamic loads which could cause nuisance tripping [4]. It is noted in [4] that protection using THD can only be a back-up or complementary form of protection [4].

Li et al. proffer a protection scheme for inverter dominated networks in [41] using transient fault information. Travelling waves are analysed to de-

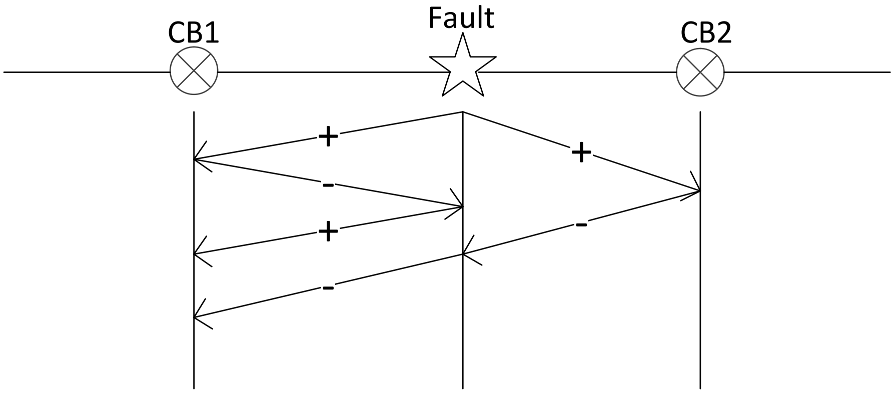

Figure 7: Protection using Travelling Waves [41]

termine the location of the fault using a Rogowski sensor [42]. If the first two wavefronts detected by a protective device have the same polarity, the fault is located within the relay's zone of protection as shown in Fig. 7. If the fault can be located, selectivity is assured and the fault will be isolated much quicker than traditional protection devices. The shortcoming of using wavefronts for protection analysis is the ambiguity of the fault inception angle. If the fault occurs when the voltage is not near peak, the protection performance will be inadequate. A rate of change of current back-up protection is proposed; however, the discrimination between fault events and acceptable disturbances has not been assessed and requires further research to determine the efficacy of the proposed protection scheme.

Distance protection is proposed for microgrid protection in [43] as the recommended form of primary protection. Directional OC and EF elements are used as local back up protection. Distance protection requires measurement of the local voltage as well as current. The voltage is measured at the LV winding of the distribution transformer to avoid the need for a voltage transformer. It is assumed that a delta-wye connected distribution transformer is used. The distance protection relay must incorporate compensation for the voltage drop across the transformer. Detection of earth faults can be particularly challenging as the zero sequence voltage cannot be measured directly due to the connection of the voltage sensor at the LV winding; the zero sequence voltage has to be estimated using an approximate fault impedance behind the distance relay and the measured zero sequence current. Similarly to most proposed protection scheme, distance protection may have discrimination issues when high impedance single line to earth faults occur. However, if adequate impedance compensation and protection discrimination can be achieved, distance protection may be an effective means of microgrid protection.

A similar approach is adopted by Dewadasa et al. in [44] using an admittance-based protection scheme for application in inverter dominated microgrids. Each DN line protective device implements IDMT curves to express the tripping time as a function of normalised admittance Y_r as expressed in (1).

$$Y_r = |\frac{Y_m}{Y_t}| \tag{1}$$

Where Y_m is the measured admittance of the relay and Y_t is the admittance for a zero impedance fault at the end of the protection zone. The scheme is shown to work for a three-phase bolted fault when the microgrid is operating in islanded mode. Further research is needed to identify whether admittance protection is effective for high impedance phase-to-earth faults.

A differential energy based scheme is proposed by Samantaray et al. in [45]. An S-transform is used to analyse the current waveform; the S-transform is a time-frequency transform that is an aggregate wavelet and short-time Fourier transform. The current is measured and modified using the S-transform to find the spectral energy content at each protective device.

The spectral energy is then compared with the data gathered at the other end of each protection zone to find the differential spectral energy. The proposed protection scheme is inherently communication based and thus requires some form of back-up protection for instances of communication failure. Case studies carried out in [45] reveal that differential energy based schemes are effective for both grid connected and islanded modes of operation for a variety of fault types. Doubly-fed induction generator based wind farms were implemented within the case study as the EG type. No provisions for energy storage were made which is impractical for microgrid applications. It is likely that energy storage would be connected through an inverter interface. Further research is required to assess whether protection discrimination is possible for more complicated networks, particularly in the presence of unbalanced loading and significant inverter-interfaced EG penetration.

A microgrid protection scheme based on symmetrical and differential current components is presented by Nikkhajoei and Lasseter in [46]. Nikkhajoei and Lasseter assume that the microgrid can be separated from the main grid by means of a static transfer switch. The adopted protection design philosophy states that the static transfer switch shall be opened for any fault detection within the microgrid. Furthermore, Nikkhajoei and Lasseter assume that microgrid sources are inverter-interfaced and hence limited to 2.0 p.u. of rated current; traditional OC protection is deemed inappropriate for islanded modes of operation. The plausibility of detecting phase-to-earth faults using the differential components of phase currents as shown in (2) is discussed in [46].

$$I_d = \sum_{k=a,b,c,n} |I_k| \tag{2}$$

The differential phase current scheme proved effective for phase-to-earth faults if earth current passed through a protective relay. All EG units are interfaced with the microgrid through a wye(neutral)-delta transformer which does not align with Australian DN transformer connections. All loads are also neutral connected and a single earthing point is connected to the neutral upstream of the static transfer switch. The earthing and neutral connection of the proposed microgrid does not allow earth current to flow through a relay downstream of a phase-to-earth fault. Hence, bi-directional fault current cannot be achieved unless multiple earth points are available throughout the network. However, a multi-earthed system would introduce the possibility of nuisance trips and compromise fault discrimination as zero sequence current would flow from each earthing point during a phase-to-earth fault. Loads are usually unbalanced in DNs, providing earth current during normal operation if an earthing path is supplied, further complicating protection discrimination. A protection scheme based on differential components of phase currents would also be incapable of detecting line-to-line faults and hence cannot be implemented as a complete protection system.

In order to better identify the presence of phase-to-earth and line-to-line faults, Nikkhajoei and Lasseter propose the use of zero sequence and negative sequence currents respectively. The presence of unbalanced loading conditions which are considered when selecting protection settings for relays within the microgrid is also acknowledged. Essentially, protection settings should be chosen such that a nuisance trip will not occur during the extremes of unbalanced loading and a trip should occur for a high impedance fault within a relay's zone of protection. The results of the proposed protection scheme are shown to be very promising in [46]. The main advantage of a sequence component based protection scheme is the absence of the requirement of communications. Time delays are used to ensure selectivity of the protection scheme.

The major complications of sequence-based protection are unfounded assumptions regarding the connection of distribution transformers and earthing points. Australian medium voltage networks are three wire, meaning that there is no neutral return. Neutral points of the customer are earthed at each switchboard by the multiple earth neutral system stipulated in AS/NZS 3000:2007 [47]. The connection of transformer windings and EG unit earthing also dictates the flow of zero sequence current which must be taken into consideration if sequence-based protection is to be implemented in microgrids.

5. Conclusion

The protection of DNs with a high EG penetration is a very complex topic. There are many degrees of entropy including network topology, grid-connected or autonomous modes of operation, EG size and type, transformer connections, earthing connection and protective device locations which have a significant impact on the efficacy of the proposed protection schemes. Furthermore, there is a heightened desire for cost effectiveness for EG proprietors due to the auxiliary costs of protection and control constituting a much higher percentage of the overall cost compared with large-scale generation [27].

Protection adequacy in contemporary networks can be achieved through careful planning and restricting the amount of EG penetration in each feeder. Safe recloser operation can be achieved through setting reclose attempt durations to greater than two seconds, ensuring all EG is isolated and fault arcs are extinguished. Coordination of protection devices such as fuses, reclosers and sectionalisers in a network with a high EG penetration can be achieved through DN simulation and recalibration of protection settings where necessary. However, the paradigm of protection adequacy analysis without precluding EG connection violates the IEEE Standard 1547-2003, suggesting that current standards are not equipped to handle large EG penetrations. The formation of such standards is a topic for considerable future research.

Many protection schemes presume the existence of a communications medium which incurs transmission delays and an increased risk of poor reliability within networks. Further research is necessary to develop and commission a protection scheme that uses communications to improve the speed and selectivity of the protection response, but does not rely on communications for execution of the required trip sequence. The protection scheme must ensure the DN is adequately protected for any mode of operation with N-1 redundancy including the possibility of communication failure. If an autonomous network is deemed to be unprotectable, the protection scheme should isolate all EG units.

There is limited research investigating the probability of protection discrimination and selectivity to be achieved for each proposed protection scheme. The range of plausible microgrid network topologies renders such an exercise impractical, particularly when considering highly modular microgrids.

Rather, a protection system capable of dynamically assessing the protection adequacy of a microgrid with high redundancy is highly desirable. It is very likely that such a dynamic protection scheme would implement sequence component and/or distance protection to minimise the number of required protection and auxiliary devices and provide adequate protection discrimination without communications. Detection of phase-to-earth faults is highly dependent on the transformer and earthing connection of the network. A neutral voltage displacement relay or energy content-based protection are likely candidates for detecting high impedance faults. Communications can be used as a tool to monitor protection adequacy, update protection settings and reduce tripping time where possible.

For every proposed protection scheme (with the exception of differential protection which is prohibitively expensive), there exists the possibility of poor protection discrimination, particularly in networks dominated with inverter interfaced EG. Many authors tend to suggest complex methods of fault protection to compensate for the limited fault current capability of microgrids. However, the stability and fault ride-through requirements of the microgrid are often ignored or considered separately. The requirement for a microgrid to contain a heightened thermal inertia to maintain stability and provide fault ride through in autonomous mode may preclude the anticipated low fault current levels of the microgrid to some extent. Conversely, the characteristics of a microgrid may have to be shaped in order to provide desirable fault characteristics to reduce the cost and complexity of protection systems. Hence, a holistic approach towards a microgrid's robustness during fault conditions is necessary in the development of microgrid protection philosophy.

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7. Appendix

Table 1: Protection Scheme Analysis Table: Grid-Connected EG

Scheme	Cost	Discrimination/Selectivity	Other Notes
Directional OC	Comparatively expensive	Fault identification not achieved for inverter-interfaced EG. Selectivity failure possible during reflected faults	Selectivity issue can be solved with directional element installed in upstream OC device.
OC/Voltage Sag	Comparatively inexpensive	Discrimination problems with long feeders and feeders with multiple EG.	Only appropriate for cases with one synchronous generator in a feeder.
Distance	Comparatively inexpensive	Fault identification may be achieved for all EG interface types. Requires a detailed off-line study to determine protection settings	Requires a more rigorous study for verification. Most likely solution if only locally sourced data is available and EG penetration is high.

Table 2: Protection Scheme Analysis Table: Microgrid Operation

Scheme	Cost	Discrimination/Selectivity	Other Notes
Inertia Wheel	Flywheel and communication systems both expensive	No foreseeable problem if flywheel is active at the fault instant. An inter trip system will be needed for flywheel failure	Communication system will be needed as a local flywheel for all EG is prohibitively expensive.
OC with SC I	Comparatively inexpensive	Discrimination problems with inverter-interfaced EG. Poor selectivity during fault clearance.	A back-up scheme is available if communications fail; however, long term selectivity is lost.
OC with SC II	More expensive than OC with SC I	Discrimination problems with inverter-interfaced EG. Short trip time and high selectivity.	Pilot wire is needed.
OC with SC III	More expensive than OC with SC II	Discrimination problems with inverter-interfaced EG. Short trip time and perfect selectivity.	Prohibitively expensive for DNs.
Current Sequence Components	Comparatively inexpensive	Discrimination of HIF requires a supplementary control scheme, otherwise this protection scheme is effective.	Communications can be used to optimise this scheme but is not mandatory.
Differential	Very expensive	Discrimination and selectivity is always achieved.	Scheme is prohibitively expensive for DN applications.
VROC	Comparatively inexpensive	In general, discrimination and selectivity problems are likely.	This scheme is only plausible with very simple microgrid configurations.
Voltage Sequence Components	Comparatively inexpensive	Discrimination capabilities heavily dependent on earthing and transformer connections.	The controller of the inverter will also have a significant impact on efficacy.
Harmonic Content	Comparatively inexpensive	Discrimination capabilities are dubious and are strongly governed by controllers, filters and load behaviour.	May be used as back-up protection.
Travelling Waves	Comparatively inexpensive	Discrimination capabilities are dependent on fault inception point.	May be used as back-up protection.
Distance	Comparatively inexpensive	Fault identification may be achieved for all EG interface types. Requires a detailed off-line study to determine protection settings.	Requires a more rigorous study for verification. Most likely solution if only locally sourced data is available and EG penetration is high.
S-Transform	Comparatively expensive	Fault identification is achieved Requires fast and reliable communications.	Back-up protection is needed for communications failure. A more detailed study for all EG types (including storage) is needed.
Differential Phase Current	Comparatively inexpensive	Fault discrimination may be lost with multiple earthing points. Hence, applications may not be effective under some earthing schemes.	Not appropriate in Australia.