

Islanding Protection of Distribution Systems with Distributed Generators – A Comprehensive Survey Report

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Abstract-- Anti-islanding protection schemes currently enforce the DGs to disconnect immediately for grid faults through loss of grid (LOG) protection system. This greatly reduces the benefits of DG deployment. For preventing disconnection of DGs during LOG, several islanding protection schemes are being developed. Their main objectives are to detect LOG and disconnect the DGs from the utility. This allows the DGs to operate as power islands suitable for maintaining uninterruptible power supply to critical loads. A major challenge for the islanding protection schemes is the protection co-ordination of distribution systems with bi-directional fault current flows. This is unlike the conventional overcurrent protection for radial systems with unidirectional fault current flow. This paper presents a comprehensive survey of various islanding protection schemes that are being developed, tested and validated through extensive research activities across the globe.

Index Terms-- Islanding Protection, Protection Coordination, Distributed Generation, Loss of grid, Digital Protection

I. INTRODUCTION

WITH growing power demand and increasing concern about the use of fossil fuels in conventional power plants, the new paradigm of distributed generation is gaining greater commercial and technical importance across the globe. Distributed generation (DG) involves the interconnection of small-scale, on-site distributed energy resources (DER) with the main power utility at distribution voltage level [1]. DERs mainly constitute non-conventional and renewable energy sources like solar PV, wind turbines, fuel cells, small-scale hydro, tidal and wave generators, micro-turbines etc. These generation technologies are being preferred for their high energy efficiency (micro-turbine or fuel cell based CHP systems), low environmental impact (PV, wind, hydro etc.) and their applicability as uninterruptible power supplies to power quality sensitive loads. Electric energy market reforms and developments in electronics and

communication technology are currently enabling the control of geographically distributed DERs through advanced SCADA [2]. R.H.Lasseter et. al. [3] have discussed how interconnected DERs can be operated as microgrids both in grid-connected mode and islanded mode.

A high degree of penetration of DG (more than 20%) as well as DER placement and capacity have considerable impact on operation, control, protection and reliability of the existing power utility [3][4][5]. These issues must be critically assessed and resolved before allowing the market participation of DGs. This is necessary for utilising full DG potential for generation augmentation, for enhancing power quality and reliability and for providing auxiliary services such as active reserve, load-following, interruptible loads, reactive reserve, restoration etc. [6].

The area that is critically affected by DG penetration is protection coordination of the utility distribution system. Conventional overcurrent protection is designed for radial distribution systems with unidirectional fault current flow. However, connection of DG into distribution networks convert the singly-fed radial networks to complicated ones with multiple sources. This changes the flow of fault currents from unidirectional to bi-directional [7]. Further the steady state and dynamic behaviour of the DGs also affect the transmission system operation [8]. Various impacts of DG connection on existing utility network protection are listed below:

- i) false tripping of feeders
- ii) nuisance tripping of protective devices
- iii) blinding of protection
- iv) increase or decrease of fault levels with connection and disconnection of DERs
- v) unwanted islanding
- vi) prevention of automatic reclosing
- vii) unsynchronised reclosing

Currently, available technical recommendations viz., G83/1, G59/1, IEEE 1547, CEI 11-20 prescribe that DGs should be automatically disconnected from the MV and LV utility distribution networks in case of tripping of the circuit breaker (CB) supplying the feeder connected to the DG. This is known as the anti-islanding feature. This is incorporated as a mandatory feature in the inverter interfaces for DGs available in the market. As the DGs are not under direct utility control,

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use of anti-islanding protection is justified by the operational requirements of the utilities [9]. Anti-islanding systems are mainly used to ensure personnel safety at the grid end and to prevent any out of synchronism reclosure.

However, with greater DG penetration, automatic disconnection of DGs for LOG situation drastically reduces the expected benefit of DGs for (i) maintaining power quality and reliability, (ii) enhancing system security and (iii) providing several ancillary services. It also leads to unnecessary loss of DG power in the event of utility fault [8][9]. Besides, the islanding detection and anti-islanding protection systems tend to increase the complexity of protection system. For better maximization of DG benefits, the idea of keeping the DERs connected during system disturbances and islanded protection of DGs [9][10][11] is being debated upon by researcher across the globe. Various low cost and efficient digital islanding protection schemes are being developed, tested and validated through extensive research activities [12]. Fast and efficient microprocessor-based islanding protection systems are suitable for operation of the active distribution networks both in stand-alone and grid connected modes. They can also ensure seamless operation of the inter-tie CBs for re-connection of the islanded zones without affecting original protection co-ordination of the utility grid [13]. Improved islanding protection systems are also being developed for hybrid renewable energy power systems. These schemes efficiently combine the passive (U/O Voltage, U/O Frequency) and active (Sandia Frequency Shift and Sandia Voltage Shift) protection methods [14]. Digital protection schemes are also being designed and tested for meshed distribution systems with high penetration of DGs [10].

This paper presents a comprehensive survey of various islanding protection schemes that are being developed, tested and validated through extensive research activities across the globe.

II. LOSS OF GRID PROTECTION

A. Objective and Requirements

The main objective of LOG protection is to detect the condition where the DGs are left connected to a portion of the utility's load network with no main source of utility power. This is commonly known as LOG phenomena. This may occur following a system switching operation caused by fault clearance, scheduled and unscheduled load shedding, maintenance outages and/or equipment failure. The main objective of LOG protection is to detect and disconnect the inter-tie CB between the DG units and the utility network after any LOG occurrence in order to (i) enable an uncomplicated restoration of utility supply and (ii) avoid any out of synchronism reconnection of the two systems that may cause severe damage to the utility grid and the DG units [15]. The typical requirements for this protection are as below:-

1) It should operate within half a second following the isolation of the power island, but faster relaying is attractive.

2) The DG units should maintain the system's voltage and frequency within specified limits.

3) To prevent any out of synchronism reclosure.

LOG detection schemes usually used are :

a) For DGs less than 200 kVA :

For small DGs, LOG is either detected by a reverse power relay that monitors the power flow in the inter-tie circuit or through under voltage and under frequency relays. LOG usually causes severe overloading of the DG unit, causing its output voltage and frequency to fall. In that case, under voltage and under frequency relays will operate and automatically disconnect the DG unit from utility loads.

b) For DGs more than 200 kVA :

Larger DGs are usually fitted with high speed automatic voltage regulators. Therefore their generation may be able to maintain the voltage and frequency at the load bus within specified limits following LOG. Thus, for such DGs, specialised relaying will be needed to detect LOG and trip the inter-tie breaker.

B. Different techniques of LOG detection

The direct method for LOG protection is to monitor auxiliary contacts on all CBs on the utility system between its main generation source and the DG units. When a switching operation produces LOG, a transfer trip scheme can be used to open the inter-tie CB between the two systems. The DG units can then be resynchronised to the utility and reconnected after successful restoration of the utility supply. But when several CBs are involved in creating the LOG condition, then the transfer trip scheme can only be managed through an extensive SCADA system and network automation. Reclosure of the utility supply onto a DG unit can be avoided by using dead circuit pick-up supervision on utility CBs. These would stop the utility CB from closing until the load-side circuit was de-energised and would initiate a transfer trip to open the inter-tie CB between the DG and the utility.

LOG techniques have been classified as active and passive. Active techniques directly interact with the on-going power system operation, namely (i) reactive power export error detection, (ii) system fault level monitoring. Passive techniques detect LOG solely by monitoring the change in power system's behaviour following such occurrence, namely (iii) U/O voltage and U/O frequency, (iv) rate of change of frequency, (v) phase displacement monitoring, (vi) the rate of change of generator power output and (vii) change of rate of change of frequency.

There are some other techniques which are neither active nor passive in nature. These are (viii) Intertripping, (ix) Fault Thrower and (x) Neutral Voltage Displacement.

B-1. Active Techniques

(i) Reactive power export error detection

The reactive power export error detection relay interfaces with the DG control system and forces it to generate a level of reactive power flow in the inter-tie between the DG and the utility. This level can only be maintained when the utility generation is connected. Relay operation is triggered when there is an error between the setting and the actual reactive power being exported for a time period greater than the set value. To avoid spurious operation, the time setting is chosen to be greater than the duration of probable supply fluctuations. With operating times from 2 to 5 seconds, this is a comparatively slow protection and is frequently used as back up to other faster protections. This approach can detect LOG even when there is no change in the generator loading due to the switching operation [15].

(ii) System fault level monitoring

It is a faster acting protection technique. Its tripping is dependent on the power system's source impedance close to the inter-tie. In this scheme, system fault level is monitored by sensing the short circuit current and reduction in supply voltage when a shunt inductor is connected across the supply by using point-on-wave triggered, thyristor switches. The firing of the thyristors occurs just before a current zero. This causes a short pulse of current to flow in the inductor and a voltage glitch. The tripping decision depends on the comparison of the measured system fault level with that corresponding to a network fed from the utility generation. The system is to adequately sense the huge difference between the fault levels of utility generation and that of DG units. Hence it needs not be particularly accurate. This approach provides faster protection with theoretical minimum operating time of about half a cycle. Its tripping depends on the value of the power system source impedance measured close to the inter-tie [15].

B-2. Passive Techniques

(iii) U/O voltage and U/O frequency

Under/Over voltage and Under/Over frequency relaying are effective LOG techniques for small DGs. They usually provide an acceptable level of protection. But they may fail to operate if the change of load associated with LOG can be compensated by the DGs' control system, keeping voltage and frequency more or less stable [15].

(iv) Rate of change of frequency (ROCOF)

Rate of change of frequency (ROCOF) relay utilises the generator swing equation (1) to define rate of change of frequency as below:

$$\frac{\Delta f}{\Delta t} = \frac{\Delta P \cdot f}{2 \cdot H \cdot G} \quad (1)$$

where,

$$\begin{aligned} \Delta P &= \text{change in power output} \\ f &= \text{system frequency} \\ H &= \text{inertia constant of DG system} \\ G &= \text{rated capacity of DG system} \end{aligned}$$

ROCOF relay monitors the voltage waveform and trips the CB when the measured rate of change of frequency exceeds a preset level for longer than a set time period. The settings are chosen such that the relay operates only for fluctuations associated with LOG and with the DG operating independently from the utility, but not for those fluctuations governed by utility time constants. For small and medium sized DG units, a setting of 0.3 Hz/sec is found to be optimum with an operating time from 0.3 to 0.7 seconds. However, for excessive changes in frequency, tripping time less than 4 or 5 cycles may be possible [15].

(v) Phase displacement monitoring

The phase displacement monitoring is generically related to the ROCOF relay operation and operates when there are phase displacements in the voltage waveform. Such relays are sensitive to changes in DG loading and may cause them to operate in 50 ms following a LOG resulting in a load change of greater than 5% of the DG capacity [15].

(vi) Rate of change of generator power output

A LOG condition usually causes a change in DG loading which in turn alters the instantaneous DG power output. This method detects LOG by monitoring changes in the DG output. Instantaneous DG power given by equation (2) :-

$$P_g = v_a \cdot i_a + v_b \cdot i_b + v_c \cdot i_c \quad (2)$$

where, v_a , v_b and v_c are the sampled values of phase voltages and i_a , i_b and i_c are sampled values of the line currents measured at the DG terminals. With these measurements, the protection algorithm monitors the changes in power output and integrates these changes over a defined sample period. Tripping occurs when the integrated signal exceeds the trip setting. This approach can quickly detect out of synchronism reconnection of the utility supply to a power island containing DGs [15].

(vii) Comparison of Rate of Change of Frequency (COROCOF)

COROCOF relay [16] assumes that LOG would cause a change in frequency at the DG but would not normally affect the system frequency as a whole. This also assumes that the power island formed is very small compared to that of the rest of the system. Thus, it discriminates between frequency deviation due to LOG and those due to widespread system disturbances by using a blocking signal. During a change in frequency affecting the entire system, the COROCOF sending relays transmit a blocking signal to all COROCOF DG protection relays to prevent relay operation. In case of LOG

no blocking signal would be generated and the COROCOF protection would therefore trip. However, the relay may fail to operate if a LOG phenomena and a system frequency transient overlap, until the frequency transient in the rest of the system dies out. This may be prevented by encoding or modulating the blocking signal according to the system frequency measured by the COROCOF sending relay. On the contrary, a COROCOF DG protection relay would measure the DG frequency and would operate only if there is a difference between that and the system frequency indicated by the blocking signal.

B-3. Other Techniques

(viii) Intertripping

This technique detects LOG by sensing the contact openings at the point of disconnection. Then it transmits this signal to all DG sites supporting the respective island zones through (a) leased communication channel scheme, (b) radio or microwave intertripping scheme, (c) powerline carrier intertripping scheme or (d) hardwired intertripping scheme. In order to have a compromise between cost and reliability, powerline carrier tripping is used for long HV lines ($\geq 132\text{kV}$) and leased communication channel scheme for MV and LV lines. It is also necessary to consider for remote intertrip signals where the communication media is out of the control of the user, is independence of main supply for ensuring signal's continuity at times of disturbance and network failure [12].

(ix) Fault Thrower

This scheme employs an automatically operated switch to create a short circuit of one line to earth. It is a reliable, low-cost, acceptable option for intertripping of rural lines with several DGs. It is used to trip islanded DGs from the source end and is interlocked with the island initiating CB. It applies a line-to-earth fault which is detected by the neutral voltage displacement relays leading to tripping of all the islanded DGs. This acts as the only earth reference with the interlocking preventing substantial current flowing from the grid source. The device reset time should be coordinated with the network protection and any reclosing facility [12].

(x) Neutral Voltage Displacement (NVD)

It is not a standard LOG protection but may be used in conjunction with LOG protective devices for mitigating the risk associated with their non-operation. NVD reliably and directly protects against the unsafe condition where one line of the islanded system is referenced to earth leading to over voltage condition in the other two phases [12].

One future possibility is the national broadcasting of grid frequency for comparing it with the local frequency of the DG sites. The DG sites around the country will compare their measured local frequencies with the grid frequency broadcast

and use the divergence from the selected level to trip the DG units. However, this method runs the serious risk of widespread common mode tripping.

III. ISLANDING PROTECTION

The most challenging aspect of designing the electrical power system with cogeneration was anti-islanding protection [18]. Major concern of utility grid operation in parallel with DGs is that the DGs do not operate under the direct control of utility grid. The most important operational requirement of the utility is avoiding accidental islanding of any DG site from the utility power source. According to utility, a power island thus formed may complicate the orderly reconnection of the power supply network and may present a potential hazard to the public and utility personnel. Besides, DG power supply can deviate from the required quality standards. Several guidelines have been introduced [18] in G59 to ensure that the presence of the small DGs will not detract from the quality of supply to all customers connected to the system. Several of these guidelines include the need to provide islanding protection.

The principal objective for an islanding protection is to detect the power island condition to trip the inter-tie breaker between the power island and the utility. Thus the power island will not affect the orderly restoration of the utility supply to the rest of the network. Since the inter-tie breaker is used to connect two active systems, hence the power island can be reconnected to the utility after the network supply is established. The tripping time for the islanding protection should be critically decided such that the two systems are successfully separated first before any out-of-synchronism reconnection attempt by automatic reclosure. Currently the maximum separation time has been specified as 0.5 seconds however best target tripping time is 0.125 seconds. The fault level of DG power island is much less than that of conventional grid and short circuit back-up protection needs to be properly coordinated with this target tripping time. Islanding protection is quite complicated since the CB that causes the loss of connection could be any breaker or isolator connecting the main source of supply to the DG site. Besides, it is unlikely that the status of the CB is supervised or fitted with synchronism checking or live line/dead bus and live bus/dead line supervision.

The economics of small DG schemes are such that once the desired level of protection is defined, the protection cost does not vary with the DG's capacity. Besides, the utility grade relays are too costly for DGs. Thus for economic viability there is obvious necessity for low cost, high quality protection packages for the complete protection of the DG system. The use of a single microprocessor based relay with integrated protection functions, including islanding protection, as per the need of the system, is an ideal solution.

IV. PROTECTION SCHEME FOR MESHED DISTRIBUTION SYSTEMS

Disconnecting DGs at every fault inception, even for temporary faults in overhead lines, makes the distribution system unreliable. Viawan, Karlsson, Sannino and Daalder

[10] report, through case studies, that a protection scheme for meshed distribution systems may be employed to prevent disconnection of DGs during utility faults. They emphasize that this meshed operation does not put the DGs or any part of the distribution network in islanding operation. It also ensures that conventional overcurrent protective devices namely, CBs, relays, reclosures, fuses etc. do not lose their properly coordinated functions. Here the distribution systems with high penetration of DGs are operated in loop or mesh. However, this scheme may lengthen the duration of fault affecting system's dynamic behaviour, which need to be further investigated.

The basic scheme connects the DGs to two feeders, which are operated in a loop by closing a normally open (NO) switch. The DG is disconnected from the faulted feeder at the fault inception while it remains connected at the unfaulted feeder for reliable supply to the distribution system. The number of CBs needed and their placement depend on the connection points of the DGs. The protection scheme performs the following tasks:

- (a) Breaks up the loop in order to isolate the DG from the faulted area and puts the faulted feeder into radial operation
- (b) Clears the fault in the faulted section
- (c) Puts the feeders back to meshed operation once a temporary fault is cleared

The above functions may be performed by a microprocessor-based high speed digital line protection relay with the following features - pilot and non-pilot distance protection, phase and ground directional overcurrent protection, synchronism check, reclosing, breaker failure and PLC-based I/O. These relays are available in the market but before application, its cost impact needs to be critically judged.

Celli, Pilo et. al. [20] have also indicated that revolutionary change is needed in the operation and planning of distribution networks with high penetration of DGs through efficient DG placement and adoption of meshed network architecture. They performed steady state and dynamic simulation of a portion of Italian distribution network to analyse the voltage profile, power losses, short circuit currents and grid reliability. They have verified and concluded that closed loop networks can be quite easily implemented. However, for extracting maximum benefits some modifications must be made in protection coordination by limiting short circuit currents and applying a new voltage control. Meshed networks is a valid option to improve networks capability to accommodate DGs, but their development should accompany revolutionary changes in distribution network operation. Though, changing from radial to meshed networks is advantageous from DG diffusion point of view, but for thick meshes, DG placement must be carefully planned to get maximum benefit.

Meshed networks equalise voltage along feeders and help to achieve acceptable voltage regulation. In order to have better voltage regulation, each DG should contribute to

regulation and thus voltage regulator should be modified accordingly. There is a prospective research area on the studies of protection coordination in non-radial networks with DGs. Girgis, Brahma et. al. have proposed [21][22][23] an adaptive scheme to protect distribution systems with DGs. This scheme can easily be implemented in a network but requires enormous effort in modifying a well-consolidated conventional operating practice.

Girgis, Brahma et. al. [23] have concluded the following for microprocessor-based protection coordination of distribution systems with high penetration of DGs.

- a) In case of high DG penetration, coordination between reclosure and fuse is likely to be disrupted
- b) This problem cannot be resolved with available traditional reclosures
- c) Microprocessor-based reclosures are available in the market to resolve this problem completely
- d) Protection coordination with microprocessor-based reclosures is simple

V. LOW COST MICROPROCESSOR-BASED DISTRIBUTION SYSTEM ISLANDING PROTECTION

Islanding protection is quite complicated because the LOG may take place by the operation of any CB or isolator connecting the utility grid to the DGs. Besides, the status of the CB is not normally supervised or fitted with synchronism check or live line/dead bus and live bus/dead line supervision systems. The "fit and forget" approach for connecting DGs to utility distribution system is no more valid and circumstances call for a policy of integrating DGs into power system planning and operation through active management of distribution networks applying suitable concepts.

The utility grid relays are not cost effective for application in DG protection. It is necessary to develop cost effective high quality protection packages for islanding protection. It is reported by Redfern, Usta et. al. that the use of a single microprocessor-based relay with integrated protection functions is the suitable solution to this requirement [13]. Moreover, the most direct and effective method for islanding protection is to take the advantage SCADA system for monitoring auxiliary contacts of all the circuit breaking devices present in the system between DG site and utility grid. A transfer trip signal can be provided to open inter-tie CB [13].

Redfern, Usta et. al. [13][15] have reported a microprocessor-based islanding protection technique to detect power island condition of DGs. After detection, it quickly disconnects the DGs from the utility grid by tripping the inter-tie breakers between the utility grid and the DGs. It does not affect the orderly restoration of the utility supply to the rest of the network. Since the inter-tie breaker is used to connect two active systems, hence, the DGs can be reconnected to the utility grid after the LOG situation is over.

The algorithm in [13][15] detects islanding by monitoring fluctuations in the DG power output caused by disturbances and by differentiating between the DG responses experienced in grid-connected and in islanded mode. This scheme calculates instantaneous power from DGs' site and then derives the rate of change of power which is then limited in amplitude by specific insensitivity function to overcome subtransient responses of the DGs. This clipped signal is integrated over a moving window of a specific length and tripping is initiated when the absolute value of the integrated signal exceeds the trip setting. The tripping time is kept sufficient to allow the two systems to be successfully separated before any automatic reclosing attempts occur. This avoids the chances of any out of synchronism reclosure. Maximum separation time is specified as 0.5 seconds. However, new protection algorithms are being thoroughly reviewed with a target tripping time of 0.125 seconds.

This scheme has been checked for tripping for both islanding and local load changes during independent operation. The algorithm remains stable during large local load changes while utility grid remains connected and also during local power system fault conditions. This scheme optimises the use of relay processing capability under normal conditions enabling it to be included in a low cost microprocessor-based protection scheme.

VI. ISLANDING PROTECTION METHOD FOR HYBRID RENEWABLE DG

Robitaille, Agbossou et. al. [14] reports the development of an islanding protection scheme of a hybrid power system with wind turbine, photovoltaic array and fuel cell in Hydrogen Research Institute, Canada. In the scheme, passive and active protection methods e.g., U/O voltage, U/O frequency, Sandia frequency shift and Sandia voltage shift are judiciously combined together to implement islanding protection. Simulation results for different critical operating conditions indicate that clearing times can surpass those defined by IEEE 1547 standard.

In this scheme, the U/O voltage and U/O frequency techniques have been used as a basic protection for the system. The inverter disconnects from the grid when the voltage or frequency at the Point of Common Coupling (PCC) crosses the predefined minimum and maximum limits. The PCC voltage amplitude should be within 88-110% of the nominal value and its frequency should stay within 59.5Hz to 60.5Hz as per Canadian standard C22.2 No107.1-01.

The Sandia Frequency Shift (SFS) is an improved version of Active Frequency Drift or Frequency Bias. It applies a positive retroaction to the PCC voltage's frequency and it tries to destabilise the grid by modifying the inverter's output current frequency for detecting islanding faster. The inverter's output current frequency is forced to be different from the grid frequency by adding truncations or dead times to the current's waveform. The length of the truncations or the dead times and the current's frequency is determined by the following equations (3)-(5):

$$W = W_0 + K_F (F_{PCC} - F_{Grid}) \quad (3)$$

$$W_t = (W T_{Grid})/2 \quad (4)$$

$$F_{Inverter} = 1/(T_{Grid} - 2 W_t) \quad (5)$$

where,

W = Truncation or dead time length (%)

W_0 = Initial length of the truncation or dead time (%)

K_F = SFS gain (%/Hz)

F_{PCC} = PCC voltage's frequency (Hz)

F_{Grid} = Grid voltage's frequency (60 Hz)

W_t = Truncation or dead time duration (s)

T_{Grid} = Grid voltage's period (1/60 s or 1/50 s)

$F_{Inverter}$ = Frequency of the inverter's output current sine part (Hz)

The inverter's output current waveform is set back to zero at each zero crossing of the PCC voltage for being synchronized with the grid. This way, the current's waveform will be back to zero before the voltage's waveform if the inverter's frequency is more than that of the grid. The current's waveform will thus stay at zero until the next zero crossing of the voltage occurs, where a new sinusoidal half-cycle begins. This behaviour will produce a short dead time in the inverter's output current waveform. If the inverter's frequency is lower than that of the grid, the voltage's waveform will be back to zero before the current's waveform, thus forcing the current back to zero. This produces a truncation of the current's waveform. The current's waveform presents a dead time when

$F_{Inverter} > F_{Grid}$ and it is truncated when $F_{Inverter} < F_{Grid}$.

The Sandia Voltage Shift (SVS) method is similar to the SFS, but it applies a positive retroaction to the PCC voltage's amplitude instead of to its frequency. It then controls the output current according to equation (6).

$$I_{Inverter} = K_v (V_{PCC} - V_{Grid}) \quad (6)$$

Where K_v is gain expressed in A/V which multiplies the difference between the PCC voltage's amplitude and the grid voltage's nominal value.

A combination of Sandia Frequency Shift (SFS) and Sandia Voltage Shift (SVS) methods are also incorporated in the scheme to utilise the benefits of both the schemes. The advantages of SFS or Active frequency drift with positive feedback (AFDPF) are: - (a) very narrow Non-Detection Zone (NDZ), (b) high efficiency, (c) easy implementation and (d) low cost (even when inverters are connected to the same PCC). However, it tends to reduce the quality of output current waveform which may produce instability when the DG is connected to a weak grid. Otherwise, it provides a good compromise between efficiency of detection, the waveform quality and the effect of transient behaviour on the system. The efficiency of SFS method decreases significantly with high quality factor loads. This may be corrected by adding the Sandia Voltage Shift (SVS) method. The main advantage of this method is that its efficiency is independent of load quality factor, thus complementing the SFS method. Though SVS method also slightly degrades waveform quality of the output current, it has been verified that the combination of SFS and

SVS methods is very efficient in detecting islanding with a very small NDZ.

VII. MULTI-AGENT PROTECTION SCHEME FOR DISTRIBUTION SYSTEMS WITH DG PENETRATION

Perera, Rajapakse et. al. [19] have proposed a multi-agent based protection scheme for distribution systems with DGs. The network is divided into several segments. Fault detection and isolation are performed by installing relay agents at points of interconnection between different network segments. The relay agents communicate with the neighbouring agents through synchronous communication networks. This scheme uses a wavelet transform technique to identify the direction of fault current with respect to a node in the network. In case of a fault, the assigned relay agents collaboratively determine the faulted zone by acquiring the feedback signals from CTs, on the interconnected branches, that measure the currents leaving the node. Wavelet Transform Coefficients (WTCs) are calculated after measuring the transient currents in these branches. A fault is designated to be internal or external from the sign of the wavelet transform coefficients (WTC) of the currents measured at all points. When the sign is same, then fault is designated to be internal, otherwise it is external. In case of external faults, the fault direction can also be determined from the fact that WTCs of the currents measured on the faulted branch has a sign opposite to that of the currents measured in the other branches.

For a fault on any designated segment, relay agents determine the direction of the fault current with respect to its location and communicate this information to adjacent relay agents. On the basis of this information, the relay agents determine the faulted segment for issuing correct trip signals to the relevant CBs to isolate the faulted segment. In this algorithm, a relay agent identifies a fault on the busbar at its location as an internal fault. In such a case the fault is immediately cleared by the relay agent tripping all the CB connected to the busbar and communicating its decision to the other relay agents.

Wan, Li, Wong et. al. [24] have also proposed a similar multi-agent protection coordination scheme and verified its application feasibility. The scheme uses the substation as one JADE Agent Container consisting of a substation management agent and a number of relay agents, DG agents and equipment agents. The coordination strategy is embedded in every relay agent. This helps to coordinate the relay agents taking into account all pre-fault, during-fault and post-fault constraints. In the coordination strategy, relay settings and time are not the only parameters that decide the relay coordination. These agents communicate amongst themselves and also with substation management agent, DG agents and equipment agents to obtain a successful coordination.

The validity and effectiveness of this scheme have been demonstrated by applying it to an agent-based platform-“JADE”. Communication simulation shows that successful information communication between agents can be achieved with this scheme. A major advantage of this scheme is its ability to self-check and self-correct. It can also act rapidly

and can provide highly selective fault regions backup function when the primary protection fails. Effort is being given to improve the performance of the multi-agent system to cope with protection coordination in a more complex system.

VIII. CONCLUSION

This paper presents a comprehensive survey of islanding protection of active distribution networks with DG units. The DG paradigm has created widespread interest in power system planning and research in recent years amongst energy planners, policy makers, regulators, generators and researchers. Resolving of technical and economic issues related to interconnection of non-conventional and renewable DERs has been a major thrust of work in this area. The main challenge of DG interconnection is the protection coordination of the distribution system with bi-directional fault current flows. Protection coordination for such systems is quite unlike that for radial systems with unidirectional fault current flow. Further challenges are the impacts of steady state and dynamic behaviour of the DGs on transmission system operation and expansion. Initially, when the degree of DG penetration was low, then anti-islanding feature was imposed worldwide to prevent accidental islanding of DGs. This feature is still in operation for personnel safety at grid end and for avoiding any untoward out of synchronism reclosure. Anti-islanding feature forces the DGs to be disconnected immediately in the event of grid faults by different LOG detection schemes.

In recent years, the rapid growth of DGs has enhanced DG penetration across the globe to a very high level. This is gradually leading to reassessment of the anti-islanding protection as it greatly prevents utilization of DGs for enhancing power quality and reliability. Besides, the islanding detection and anti-islanding protection also increase the complexity of protection systems. In the perspective of rising consciousness about possible benefits of DGs, proposals against anti-islanding protections are being established in the form of DG islanding protection schemes. The aim of research is the development of effective microprocessor based digital schemes for disconnecting the DGs from the utility in case of LOG situation and allowing them to operate as power islands. This research also aims to make these schemes fast, effective, easy to implement and as maintenance-free as possible. Apart from technical soundness, research should also aim at developing low cost schemes which should be cheap enough to attract the attention of the DG owners. The current research leads to utilise of the state-of-the-art communication techniques for islanding protection and control of geographically distributed and remotely located DG units.

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