A Casestudy of Islanding Detection Methods for Distributed Generators

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Abstract -Nowadays, Distributed Generations (DGs) have taken a special role in power systems. Distributed genertions have received significant attention as a means to improve the performance of the electrical power system, provide low cost energy, and increase overall energy efficiency. The advancement in new technology like fuel cell, wind turbine, photo voltaic and new innovation in power electronics, customer demands for better power quality and reliability are forcing the power industry to shift for distributed generations. Hence distributed generation (DG) has recently gained a lot of momentum in the power industry due to market deregulations and environmental concerns. . A problem with such generators is the unwanted islanding phenomenon. Islanding occurs when a portion of the distribution system becomes electrically isolated from the remainder of the power system yet continues to be energized by distributed generators. An important requirement to interconnect a DG to power distributed system is the capability of the DG to detect islanding detection. Failure to trip islanded generators can lead to a number of problems to the generators and the connected loads. The current industry practice is to disconnect all distributed generators immediately after the occurrence of islands. Typically, a distributed generator should be disconnected within 100 to 300 ms after loss of main supply. To achieve such a goal, each distributed generator must be equipped with an islanding detection device, which is also called anti islanding devices like vector surge relay and ROCOF relay. Islanding detection important and challenging issue to power engineers. Islanding detection is a necessary function for grid connected distributed generators. Islanding methods can be classified into two 1)Remote islanding Method and 2) Local islanding method. In this, new techniques to detect islanding condition also has been proposed for distributed generation.

Index Terms – DG-Distributed Generators,NDZ- nondetection zones ,PCC- point of common coupling,PMU-Phase Measurement Unit,

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1 INTRODUCTION

1.1 General

Distributed generation is an approach that employs small-scale technologies to produce electricity close to the end users of power. DG technologies often consist of modular (and sometimes renewable-energy) generators, and they offer a number of potential benefits. Conventional power stations, such as coal-fired, gas and nuclear powered plants, as well as hydroelectric dams and large-scale solar power stations, are centralized and often require electricity to be transmitted over long distances. By contrast, DG systems are decentralized, modular and more flexible technologies , that are located close to the load and they serve capacities of only 10 megawatts (MW) or less. Distributed generation (DG) refers to power generation at the point of consumption. Generating power on-site, rather than centrally, eliminates the cost, complexity, interdependencies, and inefficiencies associated with transmission and distribution but problem with such generators is the unwanted islanding phenomenon.Islanding occurs when a portion of the distribution system becomes electrically isolated from the remainder of the power system yet continues to be energized by distributed generators. An important requirement to interconnect a DG to power distributed system is the capability of the DG to detect islanding detection. **Islanding** is a critical and unsafe condition in which a distributed generator, such as a solar system, continues to supply power to the grid while the electric utility is down. Islanding is a critical and unsafe condition, which may occur in a power system. This condition is caused due to an excessive use of DG in the grid.

1.2 Islanding Detection

"Islanding" refers to the condition in which a distributed generator (DG) continues to power a location even though electrical grid power from the electric utility is no longer present. Islanding can be dangerous to utility workers, who may not realize that a circuit is still powered, and it may prevent automatic re-connection of devices. For that reason, distributed generators must detect islanding and immediately stop producing power; this is referred to as "anti-islanding".The common example of islanding is a grid supply line that has solar panels attached to it. In the case of a blackout, the solar panels will continue to deliver power as long as irradiance is sufficient. In this case, the supply line becomes an "island" with power surrounded by a sea of unpowered lines. For this reason, solar inverters that are designed to supply power to the grid are generally required to have some sort of automatic anti-islanding circuitry in them. In intentional islanding , the generator disconnects from the grid, and forces the distributed generator to power the local circuit. This is often used as a power backup system for buildings that normally sell their excess power to the grid. Electrical inverters are devices that convert direct current (DC) to alternating current (AC). Grid-interactive inverter have the additional requirement that they produce AC power that matches the existing power presented on the grid. In particular, a grid-interactive inverter must match the voltage, frequency and phase of the power line it connects to. There are numerous technical requirements to the accuracy of this tracking. Normally, even when the load and production are exactly matched, the so-called "balanced condition", the failure of the grid will result in several additional transient signals being generated. For instance, there will almost always be a brief decrease in line voltage, which will signal a potential fault condition. However, such events can also be caused by normal operation, like the starting of a large electric motor. Methods that detect islanding without a large number of false positives is the subject of considerable research. Each method has some threshold that needs to be crossed before a condition is considered to be a signal of grid interruption, which leads to a "non-detection zone" (NDZ), the range of conditions where a real grid failure will be filtered out. . Generally speaking, the reasons for anti-islanding are given as 1) Safety concerns: if an island forms, repair crews may be faced with unexpected live wires2)End-user equipment damage: customer equipment could theoretically be damaged if operating parameters differ greatly from the norm. In this case, the utility is liable for the damage.3)Ending the failure: Reclosing the circuit onto an ac-

tive island may cause problems with the utility's equipment, or cause automatic reclosing systems to fail to notice the problem.4)Inverter confusion: Reclosing onto an active island may cause confusion among the inverters.Figure1.21 shows an isolated system
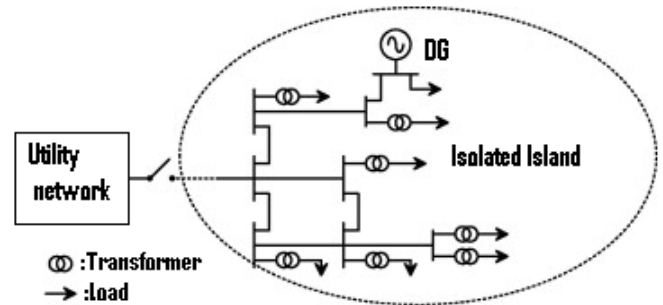

Figure 1.21 An isolated system during Islanding

1.3 Classification of Islanding Detection Methods

Generally, islanding detection methods can be classified into following two categories:1)Remote Islanding Method and 2)Local Islanding Method

Remote islanding Methods are also calledCommunication based methods.Communication based methods do no harm to the power quality of the power system and have no nondetection zones (NDZs) in the theory.However, the cost is much high because of the need of communication infrastructure and the operations are more complex as well . In addition, the effectiveness cannot be guaranteed with the risk of communication breakdown. Therefore, passive and active methods have been well developed.

Local islanding Methods can be grouped into two categories Active and Passive .Passive methods determine the islanding condition by measuring system parameters such as the magnitude of the voltage at the PCC, the PCC voltage frequency, and phase jump. Accordingly, over/under frequency protection (OFP/UFP),over/under voltage protection (OVP/UVP) and phase jump detection (PJD) are the most widely used passive islanding detectionmethods. These passive methods are easy to implement and do no harm to the power quality, but they may fail to detect islanding when the local load's power consumption closely matches the DG's power output.

In order to reduce or eliminate the NDZ, active methods rely on intentionally injecting disturbances, negative sequence components or harmonics into some DG parameters to identify whether islanding has occurred. The active frequency drift, slip-mode frequency shift, and Sandia frequency shift methods are three classical active methods by creating a continuous trend to change the frequency during islanding. Though active methods suffer smaller NDZs, they sacrifice power quality and reliability of the power system during normal operation. Moreover, some active methods have difficulty in maintaining synchronization of the intentional disturbances. Therefore, they may not work owing to the averaging effect when applied in multiple-DG operation.
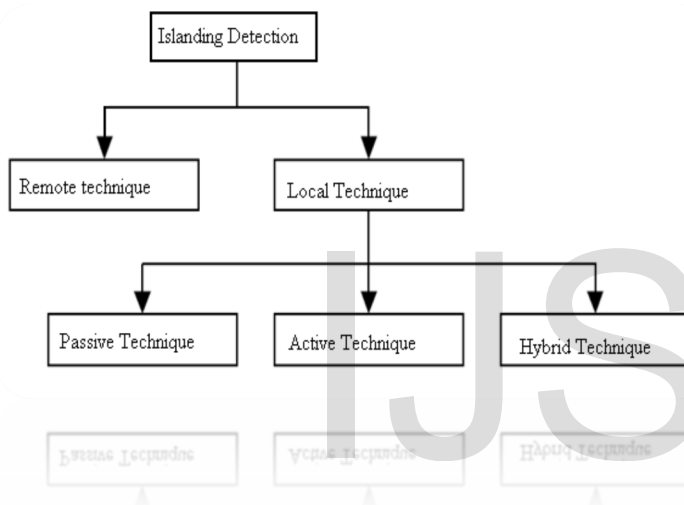
1.4 Types of Passive Methods

Passive methods include any system that attempts to detect transient changes on the grid, and use that information as the basis as a probabilistic determination of whether or not the grid has failed, or some other condition has resulted in a temporary change.

1.41 Under/over voltage Detection

According to Ohm's law, the voltage in an electrical circuit is a function of electric current (the supply of electrons) and the applied load (resistance). In the case of a grid interruption, the current being supplied by the local source is unlikely to match the load so perfectly as to be able to maintain a constant voltage. A system that periodically samples voltage and looks for sudden changes can be used to detect a fault condition.Under/over voltage detection is normally trivial to implement in grid-interactive inverters, because the basic function of the inverter is to match the grid conditions, including voltage. That means that all grid-interactive inverters, by necessity, have the

circuitry needed to *detect* the changes. All that is needed is an algorithm to detect sudden changes. However, sudden changes in voltage are a common occurrence on the grid as loads are attached and removed, so a threshold must be used to avoid false disconnections.The range of conditions that result in non-detection with this method may be large, and these systems are generally used along with other detection systems.

1.42 Under/over frequency Detection

The frequency of the power being delivered to the grid is a function of the supply, one that the inverters carefully match. When the grid source is lost, the frequency of the power would fall to the natural resonant frequency of the circuits in the island. Looking for changes in this frequency, like voltage, is easy to implement using already required functionality, and for this reason almost all inverters also look for fault conditions using this method as well.Unlike changes in voltage, it is generally considered highly unlikely that a random circuit would naturally have a natural frequency the same as the grid power. However, many devices deliberately synchronize to the grid frequency, like televisions. Motors, in particular, may be able to provide a signal that is within the NDZ for some time as they "wind down". The combination of voltage and frequency shifts still results in a NDZ that is not considered adequate by all.

1.43 Rate of change of frequency

In order to decrease the time in which an island is detected, rate of change of frequency has been adopted as a detection method. The rate of change of frequency is given by the following expression:

$$\text{ROCOF}, \frac{df}{dt} = \frac{\Delta p}{2HG} \times f$$

Where, ΔP is power mismatch at the DG side

H is the moment of inertia for DG/system

G is the rated generation capacity of the DG/system

1.44 Voltage phase jump detection

Loads generally have power factors that are not perfect, meaning that they do not accept the voltage from the grid perfectly, but impede it slightly. Grid-tie inverters, by definition, have power factors of 1. This can lead to changes in phase when the grid fails, which can be used to

detect islanding.Inverters generally track the phase of the grid signal using a phase locked loop (PLL) of some sort. The PLL stays in sync with the grid signal by tracking when the signal crosses zero volts. Between those events, the system is essentially "drawing" a sine-shaped output, varying the current output to the circuit to produce the proper voltage waveform. When the grid disconnects, the power factor suddenly changes from the grid's (1) to the load's (~1). As the circuit is still providing a current that would produce a smooth voltage output given the known loads, this condition will result in a sudden change in voltage. By the time the waveform is completed and returns to zero, the signal will be out of phase. The main advantage to this approach is that the shift in phase will occur even if the load exactly matches the supply in terms of Ohm's law - the NDZ is based on power factors of the island, which are very rarely 1. The downside is that many common events, like motors starting, also cause phase jumps as new impedances are added to the circuit. This forces the system to use relatively large thresholds, reducing its effectiveness.

1.45 Harmonics detection

Even with noisy sources, like motors, the total harmonic distortion (THD) of a grid-connected circuit is generally unmeasurable due to the essentially infinite capacity of the grid that filters these events out. Inverters, on the other hand, generally have much larger distortions, as much as 5% THD. This is a function of their construction; some THD is a natural side-effect of the switched-mode power supply circuits most inverters are based on. Thus, when the grid disconnects, the THD of the local circuit will naturally increase to that of the inverters themselves. This provides a very secure method of detecting islanding, because there are generally no other sources of THD that would match that of the inverter. Additionally, interactions within the inverters themselves, notably the transformers, have non-linear effects that produce unique 2nd and 3rd harmonics that are easily measurable. The drawback of this approach is that some loads may filter out the distortion, in the same way that the inverter attempts to. If this filtering effect is strong enough, it may reduce the THD below the threshold needed to trigger detection. Systems without a transformer on the "inside" of the disconnect point will make detection more difficult. However, the largest problem is that modern inverters attempt to lower the THD as much as possible, in some cases to unmeasurable limits.

1.5 Types of Active Methods

Active methods generally attempt to detect a grid failure by injecting small signals into the line, and then detecting whether or not the signal changes.

1.51 Negative-sequence current injection

This method is an active islanding detection method which can be used by three-phase electronically coupled distributed generation (DG) units. The method is based on injecting a negative-sequence current through the voltage-sourced converter (VSC) controller and detecting and quantifying the corresponding negative-sequence voltage at the point of common coupling (PCC) of the VSC by means of a unified three-phase signal processor (UTSP). The UTSP system is an enhanced phase-locked loop (PLL) which provides high degree of immunity to noise, and thus enable islanding detection based on injecting a small negative-sequence current. The negative-sequence current is injected by a negative-sequence controller which is adopted as the complementary of the conventional VSC current controller. The negative-sequence current injection method: • detects an islanding event within 60 ms (3.5 cycles) under UL1741 test conditions; • requires 2% to 3% negative-sequence current injection for islanding detection; • can correctly detect an islanding event for the grid short circuit ratio of 2 or higher; • is insensitive to variations of the load parameters of UL1741 test system. For more details about this method, the reader is referred to: "Negative-Sequence Current Injection for Fast Islanding Detection of a Distributed Resource Unit",

1.52 Impedance measurement Detection

Impedance Measurement attempts to measure the overall impedance of the circuit being fed by the inverter. It does this by slightly "forcing" the current amplitude through the AC cycle, presenting too much current at a given time. Normally this would have no effect on the measured voltage, as the grid is an effectively infinitely stiff voltage source. In the event of a disconnection, even the small forcing would result in a noticeable change in voltage, allowing detection of the island.The main advantage of this method is that it has a vanishingly small NDZ for any given single inverter. However, the inverse is also the main weakness of this method; in the case of multiple inverters, each one would be forcing a slightly different signal into the line, hiding the effects on any one inverter. It is possible to address this problem by communication between the inverters to ensure they all force on the same schedule, but in a non-homogeneous install (multiple

installations on a single branch) this becomes difficult or impossible in practice. Additionally, the method only works if the grid is effectively infinite, and in practice many real-world grid connections do not sufficiently meet this criterion.

1.53 Measurement at a Specific Frequency

Although the methodology is similar to Impedance Measurement, this method, also known as "harmonic amplitude jump", is actually closer to Harmonics Detection. In this case, the inverter deliberately introduces harmonics at a given frequency, and as in the case of Impedance Measurement, expects the signal from the grid to overwhelm it until the grid fails. Like Harmonics Detection, the signal may be filtered out by real-world circuits.

1.54 Slip mode frequency shift

This is one of the newest methods of islanding detection, and in theory, one of the best. It is based on forcing the phase of the inverter's output to be slightly mis-aligned with the grid, with the expectation that the grid will overwhelm this signal. The system relies on the actions of a finely tuned phase-locked loop to become unstable when the grid signal is missing; in this case, the PLL attempts to adjust the signal back to itself, which is tuned to continue to drift. In the case of grid failure, the system will quickly drift away from the design frequency, eventually causing the inverter to shut down. A SMS curve is given by the equation:

$$\theta = \theta_m \sin\left(\frac{\pi}{2} \frac{f^{(k-1)} - f_n}{f_m - f_n} \right)$$

Where θm is the maximum phase shift that occurs at frequency fm . fn is the nominal frequency and f $(k-1)$ is the frequency at previous cycle. The major advantage of this approach is that it can be implemented using circuitry that is already present in the inverter. The main disadvantage is that it requires the inverter to always be slightly out of time with the grid, a lowered power factor. Generally speaking, the system has a vanishingly small NDZ and will quickly disconnect, but it is known that there are some loads that will react to offset the detection.

1.55 Frequency bias Detection

Frequency bias forces a slightly off-frequency signal into the grid, but "fixes" this at the end of every cycle by jumping back into phase when the voltage passes zero. This creates a signal similar to Slip Mode, but the power factor remains closer to that of the grid's, and resets itself every cycle. Moreover, the signal is less likely to be filtered out by known loads. The main disadvantage is that every inverter would have to agree to shift the signal back to zero at the same point on the cycle, say as the voltage crosses back to zero, otherwise different inverters will force the signal in different directions and filter it out.There are numerous possible variations to this basic scheme. The Frequency Jump version, also known as the "zebra method", inserts forcing only on a specific number of cycles in a set pattern. This dramatically reduces the chance that external circuits may filter the signal out. This advantage disappears with multiple inverters, unless some way of synchronizing the patterns is used.

1.6 Utility-based methods

The utility also has a variety of methods available to it to force systems offline in the event of a failure.

1.61 Manual disconnection

Most small generator connections require a mechanical disconnect switch, so at a minimum the utility could send a repairman to pull them all. For very large sources, one might simply install a dedicated telephone hotline that can be used to have an operator manually shut down the generator. In either case, the reaction time is likely to be on the order of minutes, or hours.

1.62 Automated disconnection

Manual disconnection could be automated through the use of signals sent though the grid, or on secondary means. For instance, power line carrier communications could be installed in all inverters, periodically checking for signals from the utility and disconnecting either on command, or if the signal disappears for a fixed time. Such a system would be highly reliable, but expensive to implement.

1.63 Transfer-trip method

As the utility can be reasonably assured that they will always have a method for discovering a fault, whether that be automated or simply looking at the recloser, it is possible for the utility to use this information and transmit it down the line. This can be used to force the tripping of properly equipped DG systems by deliberately opening a series of recloser in the grid to force the DG system to be isolated in a way that forces it out of the NDZ. This method can be guaranteed to work, but requires the grid to be equipped with automated recloser systems, and external

communications systems that guarantee the signal will make it through to the reclosers.

1.64 Impedance insertion

A related concept is to deliberately force a section of the grid into a condition that will guarantee the DG systems will disconnect. This is similar to the transfer-trip method, but uses active systems at the head-end of the utility, as opposed to relying on the topology of the network. A simple example is a large bank of capacitors that are added to a branch, left charged up and normally disconnected by a switch. In the event of a failure, the capacitors are switched into the branch by the utility after a short delay. This can be easily accomplished through automatic means at the point of distribution. The capacitors can only supply current for a brief period, ensuring that the start or end of the pulse they deliver will cause enough of a change to trip the inverters. There appears to be no NDZ for this method of anti-islanding. Its main disadvantage is cost; the capacitor bank has to be large enough to cause changes in voltage that will be detected, and this is a function of the amount of load on the branch. In theory, very large banks would be needed, an expense the utility is unlikely to look on favourably.

1.65 SCADA

Anti-islanding protection can be improved through the use of the Supervisory Control and Data Acquisition (SCADA) systems already widely used in the utility market. For instance, an alarm could sound if the SCADA system detects voltage on a line where a failure is known to be in progress. This does not affect the anti-islanding systems, but may allow any of the systems noted above to be quickly implemented.

1.8 Hybrid detection schemes

Hybrid methods employ both the active and passive detection techniques. The active technique is implemented only when the islanding is suspected by the passive technique. Some of the hybrid techniques are discussed as follows:

(a) Technique based on positive feedback (PF) and voltage imbalance (VU):

This islanding detection technique uses the PF (active technique) and VU (passive technique). The main idea is to monitor the three-phase voltages continuously to determinate VU which is given as

$$VU = \frac{v + sq}{v - sq}$$

$V+ Sq$ and $V-Sq$ are the positive and negative sequence voltages, respectively. Voltage spikes will be observed for load change, islanding, switching action, etc. Whenever a VU spike is above the set value, frequency set point of the DG is changed. The system frequency will change if the system is islanded.

(b) Technique based on voltage and reactive power shift:

In this technique voltage variation over a time is measured to get a covariance value (passive) which is used to initiate an active islanding detection technique, adaptive reactive power shift (ARPS) algorithm $T_{av'}$ is the average of the previous four voltage periods.

$$\text{Co-variance}(T_{av'}, T_v) = E \left[T_{av'}^{(n)} - U_{av'} \right] \left[T_v^{(n)} - U_v \right]$$

$T_{av'}$ is the average of the previous four voltage periods.

U_{av} is the mean of $T_{av'}$

T_v is the voltage periods

U_V is the mean of T_V

The ARPS uses the same mechanism as ALPS, except it uses the d-axis current shift instead of current phase shift. The d-axis current shift, **idk** or reactive power shift is given as

$$i_d^k = k_d \left(\frac{T_{av'} - T_v^{'(k)}}{T_v^{(k)}} \right)$$

kd is chosen such that the d-axis current variation is less than 1 percent of q-axis current in inverter's normal operation. The additional d-axis current, after the suspicion of island, would accelerates the phase shift action, which leads to a fast frequency shift when the DG is islanded

1.9 Remote islanding detection techniques

Remote islanding detection techniques are based on communication between utilities and DGs. Although these techniques may have better reliability than local techniques, they are expensive to implement and hence uneconomical. Some of the remote ID techniques are as follows

3.1 Power line signaling scheme:

These methods use the power line as a carrier of signals to transmit islanded or non-islanded information on the power lines. The apparatus includes a signal generator at the substation (25+ kV) that is coupled into the network where it continually broadcasts a signal as shown in figure (2.2). Due to the low-pass filter nature of a power system, the signals need to be transmitted near or below the fundamental frequency and not interfere with other carrier technologies such as automatic meter reading. Each DG is then equipped with a signal detector to receive this transmitted signal. Under normal operating conditions, the signal is received by the DG and the system remains connected. However, if an island state occurs, the transmitted signal is cut off because of the substation breaker opening and the signal can not be received by the DG, hence indicating an island condition.
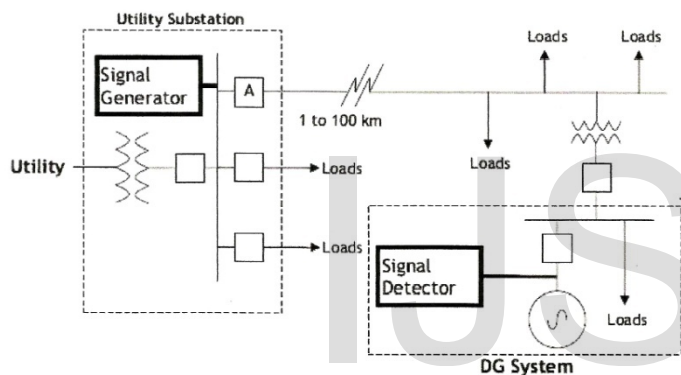

Figure 2.2: Distibuted Generation power line Signaling Islanding Detection

This method has the advantages of its simplicity of control and its reliability. In a radial system there is only one transmitting generator needed that can continuously relay a message to many DGs in the network. The only times the **16** message is not received is if the interconnecting breaker has been opened, or if there is a line fault that corrupts the transmitted signal. There are also several significant disadvantages to this method, the fist being the practical implementation. To connect the device to a substation, a high voltage to low voltage coupling transformer is required. A transformer of this voltage capacity can have prohibitive cost barriers associated with it that may be especially undesirable for the first DG system installed in the local network. Another disadvantage is if the signaling method is applied in a non radial system, resulting in the use of multiple signal generators. This scenario can be seen in Figure 2.3 where the three feeder busses connect to one island bus. The implementation of this system, opposed to a simple radial system, will be up to three times the cost. Another problem for power line communication is the

complexity of the network and the affected networks. A perfectly radial network with one connecting breaker is a simple example of island signaling; however, more complex systems with multiple utility feeders may find that differentiation between upstream breakers difficult.
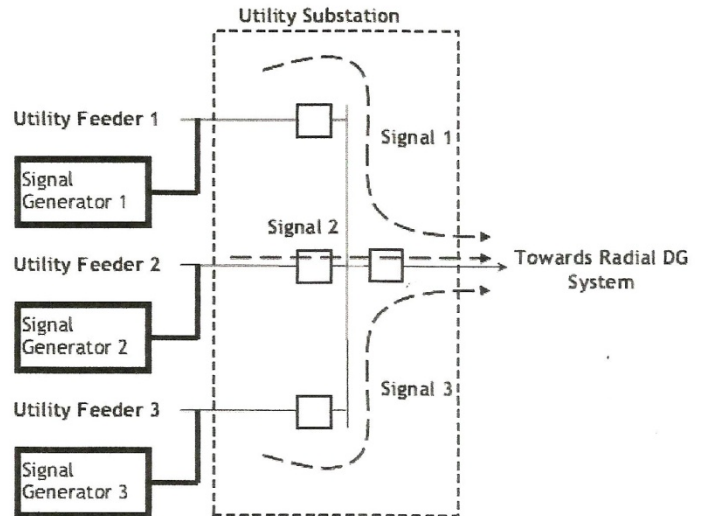
3.2 Transfer trip scheme:

The basic idea of transfer trip scheme is to monitor the status of all the circuit breakers and reclosers that could island a distribution system. Supervisory Control and Data Acquisition (SCADA) systems can be used for that. When a disconnection is detected at the substation, the transfer trip system determines which areas are islanded and sends the appropriate signal to the DGs, to either remain in operation, or to discontinue operation. Transfer tip has the distinct advantage similar to Power Line Carrier Signal that it is a very simple concept. With a radial topology that has few DG sources and a limited number of breakers, the system state can be sent to the DG directly from each monitoring point. This is one of the most common schemes used for islanding detection

The weaknesses of the transfer trip system are better related to larger system complexity cost and control. As a system grows in complexity, the transfer trip scheme may also become obsolete, and need relocation or updating. Reconfiguration of this device in the planning stages of DG network is necessary in order to consider if the network is expected to grow or if many DG installations are planned. The other weakness of this system is control. As the substation gains control of the DG, the DG may lose control over power producing capability and special

agreements may be necessary with the utility. If the transfer trip method is implemented correctly in a simple network, there are no non-detection zones of operation.   Figure 2.11 express the structure of synchronous measurement which sually implemented by phasor measurement unit(PMU) in electric power system.GPS Timing receiver automatically acquires and track s satellite ,providing GPS Time(or Co-ordinated Universal Time) for the PMU which accomplich calculation on measured voltage/current.As from the figure calculated frequency from node A and B can be transmitted to centram mangment unit through communication net-work.When the power system is in stability and con
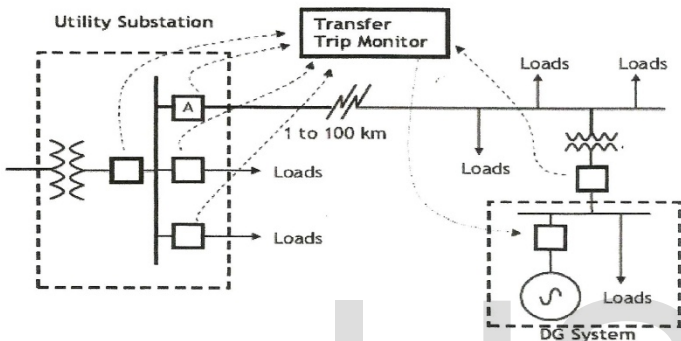

Figure 2.4: Distributed Generation Transfer Trip Islanding Detection

1.7 PMU-based islanding detecting method

Figure 2.11 express the structure of synchronous measurement which sually implemented by phasor measurement unit(PMU) in electric power system.GPS Timing receiver automatically acquires and track s satellite ,providing GPS Time(or Coordinated Universal Time) for the PMU which accomplich calculation on measured voltage/current.As from the figure calculated frequency from node A and B can be transmitted to centram mangment unit through communication network.When the power system is in stability and connected,both frequency of node A and B are the same.While the PV station(A side) di-sonnected with the grid B side,frequency of the PV station generally becomes different from that of the grid.The frequency diffence between node A and B can be taken as an index to distinguish betweenA-B connection status,which is the basic principle to identify islanding condition nect-ed,both frequency of node A and B are the same.While the PV station(A side) disonnected with the grid B side,frequency of the PV station generally becomes differ-ent from that of the grid.The frequency diffence between node A and B can be taken as an index to distinguish be-

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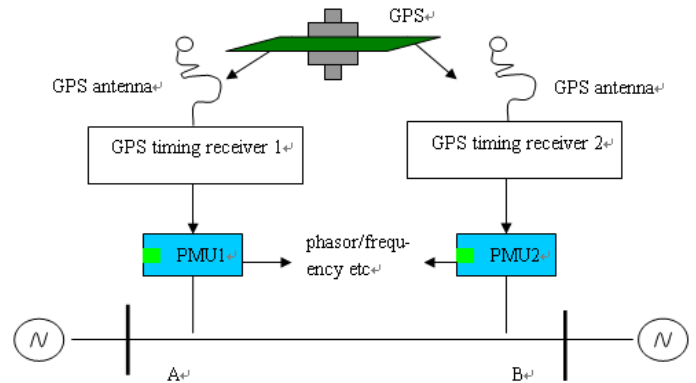
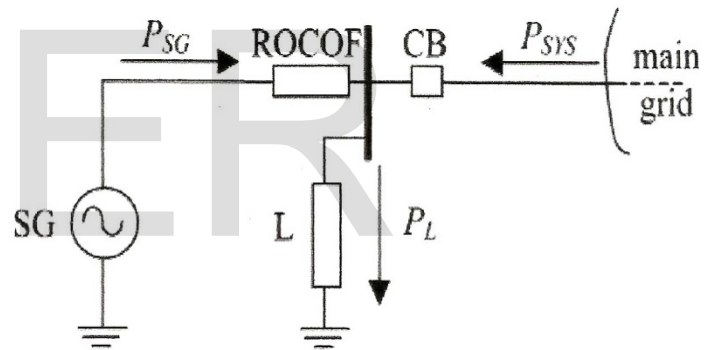## 1.8 Types of Relay Used:
1.81 ROCOF Relay

Figure presents an equivalent circuit of a synchro-nous generator equipped with a ROCOF relay operating in parallel with a distribution network. In this figure, a syn-chronous generator (SG) feeds a load (L). The difference between the electrical powers PSG supplied by the genera-tor and PL consumed by the load is provided (or con-sumed) by the main grid. Therefore, the system frequency remains constant. If the circuit breaker (CB) opens, due to a fault for example, the system composed by the generator and the load becomes islanded. In this case, there is an elec-trical power imbalance due to the lost grid power . This power imbalance causes transients in the islanded system and the system frequency starts to vary dynamically. Such system behavior can be used to detect an islanding condi-tion. However, if the power imbalance in the islanded sys-tem is small, then the frequency will change slowly. Thus, the rate of change of frequency can be used to accelerate

the islanding detection for this situation. [45] The rate of change of frequency is calculated considering a measure window over a few cycles, usually between 2 and 50 cycles.

1.82 Vector Surge Relay
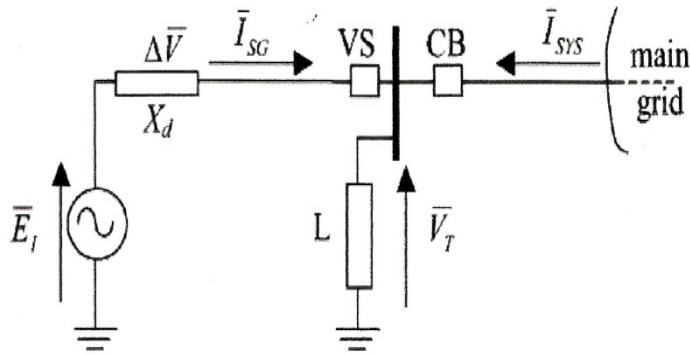
A synchronous generator equipped with a VS relay operating in parallel with a distribution network is depicted in Fig. 3.2. There is a voltage drop V between the terminal voltage VT and the generator internal voltage EI due to the generator current ISG passing through the generator reactance Xd . Consequently, there is a displacement angle between the terminal voltage and the generator internal voltage, whose phasor diagram is presented in Figure. In Figure, if the CB opens due to a fault, for example, the system composed by the generator and the load L becomes islanded. At this instant, the synchronous machine begins to feed a larger load (or smaller) because the current ISYS provided (or consumed) by the power grid is abruptly interrupted. Thus, the generator begins to decelerate (or accelerate). Consequently, the angular difference between VT and EI is suddenly increased (or decreased) and the terminal voltage phasor changes its direction, as shown in Fig. Analyzing such phenomenon in the time domain, the instantaneous value of the terminal voltage jumps to another value and the phase changes the phase position changes as depicted in Fig. 3.4, where the point A indicates the islanding instant.

Additionally, the frequency of the terminal voltage also changes. This behavior of the terminal voltage is called vector surge. VS relays are based on such phenomena. VS relays available in the market measure the duration time of an electrical cycle and start a new measurement at each zero rising crossing of the terminal voltage. The current cycle duration (measured waveform) is compared with the

last one (reference cycle). In an islanding situation, the cycle duration is either shorter or longer, depending on if there is an excess or a deficit of active power in the islanded system, as shown in Fig. 3.4. This variation of the cycle duration results in a proportional variation of the terminal voltage angle, which is the input parameter of VS relays. If the variation of the terminal voltage angle exceeds a predetermined threshold, a trip signal is immediately sent to the CB. Usually, VS relays allow this angle threshold to be adjusted in the range from 2 to 20. The relay is also disabled if the magnitude of the terminal voltage drops below a threshold value to avoid false operation. To avoid false operation, ROCOF and VS relays are disabled if the terminal voltage decreases below a determined voltage threshold. Showed that ROCOF relays require a smaller active power imbalance level than VS relays for successful islanding detection. On the other hand, ROCOF relays are much more susceptible to false operation than VS relays.
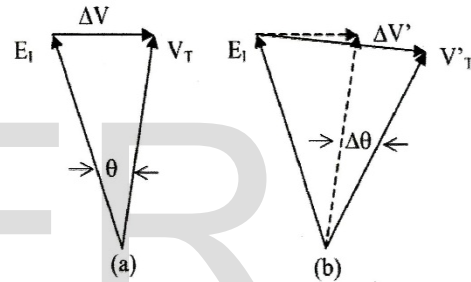

Figure 3.3: Internal and terminal voltage phasors (a) before opening with CB (b) after opening with CB
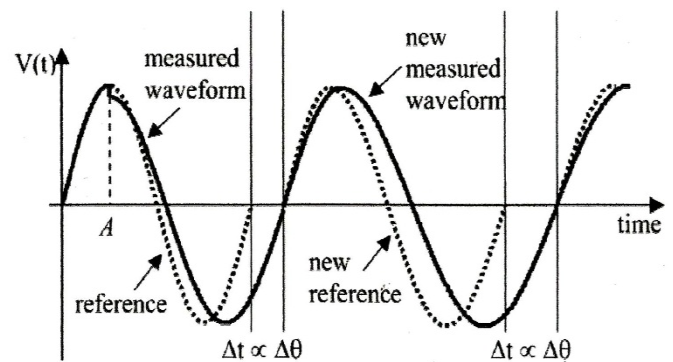

Figure 3.4: Voltage Vector Surge

Conclusion

Fast and accurate detection of islanding is one of the major challenges in today's power system with many distribution systems already having significant penetration of DG as there are few issues yet to be resolved with islanding. Islanding detection is also important as islanding operation of distributed system is seen a viable option in the future to improve the reliability and quality of the supply There is no single islanding detection technique which will work satisfactorily for all systems under all situations. The choice of the islanding detection technique will largely depend on the type of the DG and system characteristics. Recently, hybrid detection techniques have been proposed and it seems that the hybrid detection technique is the way to go with passive technique detecting the islanding when change in system parameter is large and initiating the active technique when the change in system parameter is not so large for the passive technique to have an absolute discrimination.

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