An Assessment of Distributed Generation Islanding Detection Methods and Issues for Canada

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An Assessment of Distributed Generation Islanding Detection Methods and Issues for Canada

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DISCLAIMER

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LIST OF ACRONYMS

CSA:	Canadian Standards Association
CSI:	Current source inverter
DG:	Distributed generation
ENS:	(German inverter anti-islanding device method)
IEC:	International Electrotechnical Commission
IEEE:	Institute of Electrical and Electronic Engineers
IGBT:	Insulated Gate Bipolar Transistor
MOSFET:	Metal Oxide Semiconductor Field Effect Transistor
NDZ:	Non-detection zone
PLL:	Phase locked loop
PWM:	Pulse width modulated
Q_f:	Quality factor
ROCOF:	Rate of change of frequency
THD:	Total harmonic distortion
UL:	Underwriters Laboratories
VSI:	Voltage source inverter
VSR:	Vector surge relay

EXECUTIVE SUMMARY

As Distributed Generation (DG) gains in popularity in Canada a number of safety issues are raised in the electrical industry. Among the most commonly cited ones is islanding. However, while DG is still in its infancy stage in Canada, a number of countries have led the development of safe anti-islanding protection means and adopted them.

There are a number of islanding detection techniques available, which fall into these two categories: remotely controlled (communication based) or locally built-in detection schemes. Since no islanding detection scheme can serve all DG source types equally, the method will normally be selected according to its very nature (synchronous vs. static-inverter based) in order to maximize its efficiency/reliability. In addition, it is necessary to balance the costs and safety risks of non-intentional islanding events. In some DG installations, simple and low cost inverter technologies are already available and have shown to reduce safety risks to an industry accepted level.

This report presents a review on the status and performance of all major anti-islanding techniques. Anti-islanding protection for synchronous generators is a more challenging problem in comparison with the inverter-based generators. Options are limited for synchronous generators. Among them the passive frequency-based relays are the most attractive option. Unfortunately, information on the probability and risk associated with the applications of frequency-based relays is almost non-existent.

The main issues faced by Canadian utility companies and DG industry are related to the anti-islanding protection of synchronous generators. This document proposes two complementary strategies to address the problems. The first strategy is to develop a Canadian application guide on anti-islanding protection of distributed generators. This guide would recommend methods to apply commercially available anti-islanding technologies to existing electricity distribution systems in Canada. The second and more important strategy is to change some of the practices in current distribution systems, such as modifying recloser practises. This proactive approach of making distribution systems work in harmony with distributed generator can be a very effective way to reduce the barrier caused by anti-islanding protection requirements.

In reviewing the issues pertaining to islanding and developing the above strategies, the authors bring to the forefront a number of measures that should be undertaken in support to the implementation of DG in the long term, including:

- A program to assess the actual likelihood and magnitude of the problems and to identify solutions relating to potential problems with interference of active anti-islanding schemes with each other as DG penetration increases, degraded power quality and system stability.

- A program to investigate how DGs can help support the grid and improve grid stability while maintaining adequate protection against unintentional islanding.

- A program to conduct work on DG anti-islanding protections vis-à-vis the Canadian systems to:

    - Understand the probability of islanding formation for typical Canadian distribution systems and the associated risks.

    - Understand the performance characteristics of key anti-islanding schemes when applied to typical Canadian systems.

    - Establish the basis for developing new or adopting existing anti-islanding schemes for Canadian DG industry based on results obtained from the above two steps.

SOMMAIRE EXÉCUTIF

Depuis quelques années, la production distribuée gagne en popularité au Canada mais non sans soulever certaines craintes au sein de l'industrie électrique. De celles-ci, l'îlotage est certainement la situation qui soulève le plus de questions. Toutefois, bien que la production distribuée en soit au stade embryonnaire au Canada, plusieurs autres pays ont déjà fait faces à ces questions et ont développé et mis en application des méthodes de détection d'îlotage considérées sécuritaires.

Il existe plusieurs méthodes de contrôle d'îlotage; toutes se résument cependant en deux approches : contrôle à distance (gérée par communication) et contrôle embarqué (intégré aux systèmes locaux de production distribuée). Puisqu'aucune méthode ne sert adéquatement toutes les technologies de production distribuée, le choix de la méthode est guidé par la nature des technologies de production distribuée (à savoir s'il s'agit de générateurs synchrones ou encore à base d'onduleurs statiques) afin de maximiser son efficacité et sa fiabilité. Il est aussi nécessaire d'évaluer le coût de ces dispositifs en fonctions des risques réels liés à l'îlotage involontaire. À cet effet, il existe déjà des technologies d'onduleurs simples et peu coûteuses qui assurent un niveau de sécurité acceptable et reconnue par l'industrie.

Ce rapport présente une revue de l'état et de la performance des diverses méthodes de détection d'îlotage. Les méthodes de protection (anti-îlotage) sont davantage problématiques pour les systèmes à base de générateurs synchrones que ceux à base d'onduleurs et les options limitées. Parmi les options disponibles, les méthodes passives à relais basées sur la fréquence sont les plus prometteuses. Malheureusement, les informations sur les risques et probabilités associés à l'application des ces méthodes sont pratiquement inexistantes à ce jour.

Les principales préoccupations auxquelles font face les compagnies de distribution d'électricité et l'industrie de la production distribuée sont liées à la problématique de contrôle d'îlotage des générateurs synchrones. Ce document propose deux stratégies complémentaires pour y faire face : La première stratégie consiste à développer un guide canadien d'application des méthodes de détection d'îlotage des systèmes de production distribuée. Ce guide recommanderait des façons d'appliquer des méthodes de détection aux systèmes actuels utilisant les technologies disponibles sur le marché. La deuxième stratégie (d'importance supérieure) vise plutôt à changer certaines pratiques de l'industrie au niveau des systèmes de distribution d'électricité, tel que les méthodes de réalimentation des circuits. Des approches proactives, qui amènent les systèmes de distribution d'électricité à faciliter l'intégration des systèmes de production distribuée, pourraient s'avérer plus efficaces pour éliminer la barrière que représente la problématique d'îlotage.

En réalisant cette revue des problématiques et stratégies touchant l'îlotage, les auteurs mettent en avant-plan certaines mesures qui devraient être mises en place pour faciliter l'intégration de système de production distribuée à long terme, dont :

- Un programme permettant d'évaluer la probabilité et l'ampleur des problématiques et d'identifier des solutions potentielles qui s'y rapporte en matière d'interférence des méthodes actives de détection d'îlotage (sujet à s'accentuer avec l'augmentation du niveau de pénétration des systèmes de productions distribuée) et de dégradation de la qualité de l'onde et de la stabilité des systèmes.

- Un programme visant à évaluer comment les systèmes de production distribuée peuvent contribuer à supporter le réseau et amélioré sa stabilité tout en maintenant un niveau de protection adéquat contre l'îlotage involontaire.

- Un programme réalisant des travaux sur les méthodes de détection d'îlotage dans le cadre d'opération au sein des réseaux canadiens et permettant de :

    - Comprendre la probabilité de formation d'îlots dans les réseaux de distribution canadiens typiques et les risques qui y sont inhérents.

    - Comprendre les caractéristiques propres à l'efficacité des différentes méthodes de détection d'îlotage appliquées dans un contexte canadien.

    - Établir des bases nécessaires au développement ou à l'adaptation de méthode de détection d'îlotage pour l'industrie canadienne à lumière des travaux réalisés tel que mentionné ci-haut.

CHAPTER 1 : INTRODUCTION

The integration of Distributed Generation (DG) into the main electricity networks is currently changing the paradigm we used to live with, where the electric power industry was generated in large power plants, sent to the consumption areas through transmission lines, and delivered to the consumers through a passive distribution infrastructure. While numerous benefits are associated with this change and Distributed Generation is gaining interest in Canada, as it is worldwide, such a transition also represents many challenges for all stakeholders (Utilities, independent power producers, manufacturers, researchers, governments and regulators). Expertise in integrating DG into the electricity network, and consensus on standard codes and practises, are still being developed by the industry.

This is especially true of anti-islanding protection methods and their implementation which remains one of the most frequent issues raised when DG interconnection to the distribution grid is discussed. Islanding is a situation that occurs when part of the network is disconnected from the remainder of the power system but remains energized by a distributed generator. An issue with safety is raised when such an un-planned island occurs.

As discussed in an International Energy Agency (IEA) report [18], the views on the importance of this issue tend to be very polarized, as some people focus on the very low probability of such events while others simply contemplate the issue itself and its potential impacts. Nevertheless a number of techniques have been developed to mitigate such occurrences by detecting an islanding condition and then re-energizing or disconnecting the distributed generator.

This report presents and compares the methods used to mitigate the issues pertaining to islanding in accordance with the nature of the DG. These methods and techniques are constantly improved; however, many are intrinsically limited. This is why there is a need to compromise between cost and simplicity, or between maximizing reliability of islanding detection methods and maximizing DG power availability (for example, limiting nuisance tripping). Therefore, several strategies to address the islanding protection issue for the integration of Distributed Generation to the electricity network in Canada are recommended.

CHAPTER 2 : RATIONALE FOR ANTI-ISLANDING PROTECTION

Anti-islanding capability is an important requirement for distributed generators. It refers to the capability of a distributed generator to detect if it operates in an islanded system and to disconnect itself from the system in a timely fashion. 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. Failure to trip islanded generators can lead to a number of problems for the generator and the connected loads. The current industry practice is to disconnect all distributed generators immediately after the occurrence of islands. The objective of this chapter is to provide background information on the operation of power distribution systems and to explain the importance of anti-islanding protection. A classification of different types of anti-islanding techniques is also provided.

2.1 Electric Island Formed by Distributed Generators

A typical power distribution system in North America is shown in Figure 2.1. The substation steps down transmission voltage into distribution voltage and is the sending end of several distribution feeders. One of the feeders is shown in detail. There are many customer connection points in the feeder. Large distributed generators are typically connected to the primary feeders (DG1 and DG2). These are typically synchronous and induction generators at present. Small distributed generators such as inverter based PV systems are connected to the low voltage secondary feeders (DG3).

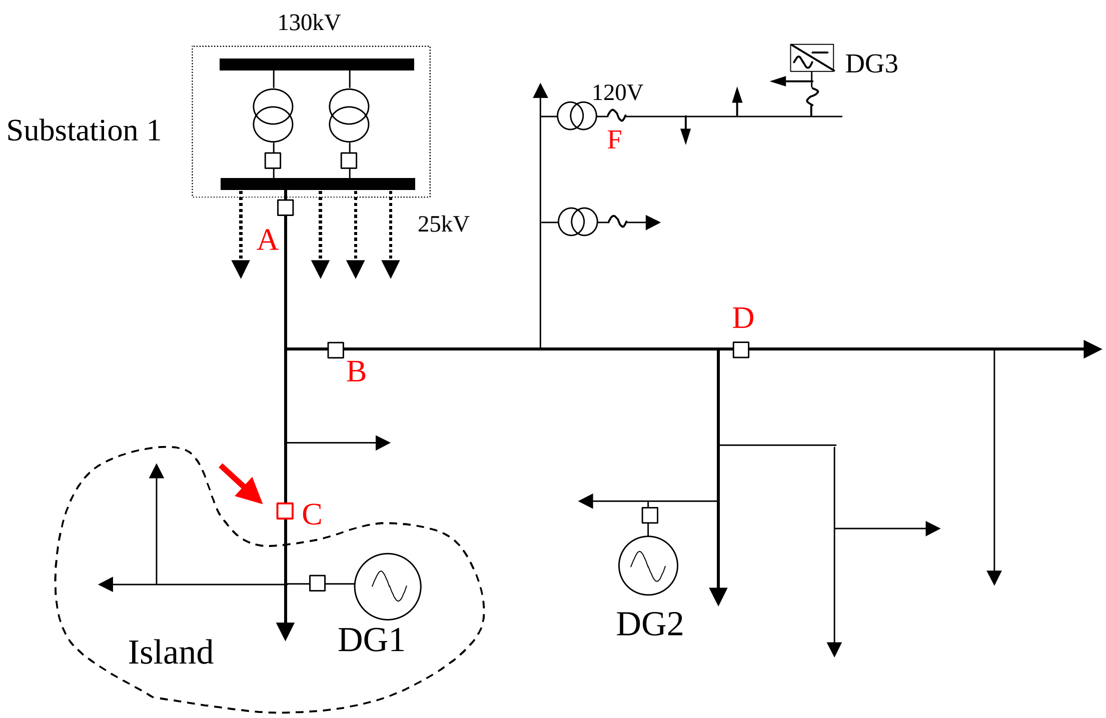


Figure 2.1: Typical distribution system with distributed generators.

An island situation occurs, for example, when recloser C opens. DG1 will feed into the resultant island in this case. The most common cause for a recloser to open is a fault in the downstream of the recloser. A recloser is designed to open and re-close two to three times within a few seconds. The intention is to re-connect the downstream system automatically if the fault clears by itself. In this way, temporary faults will not result in the loss of downstream customers. An island situation could also happen when the fuse at point F melts. In this case, the inverter based DG will feed the local loads, forming a small islanded power system.

The island is an unregulated power system. Its behaviour is unpredictable due to the power mismatch between the load and generation and the lack of voltage and frequency control. The main concerns associated with such islanded systems are:

- The voltage and frequency provided to the customers in the islanded system can vary significantly if the distributed generators do not provide regulation of voltage and frequency and do not have protective relaying to limit voltage and frequency excursions, since the supply utility is no longer controlling the voltage and frequency, creating the possibility of damage to customer equipment in a situation over which the utility has no control. Utility and DG owners could be found liable for the consequences.

- Islanding may create a hazard for utility line-workers or the public by causing a line to remain energized that may be assumed to be disconnected from all energy sources.

- The distributed generators in the island could be damaged when the island is reconnected to the supply system. This is because the generators are likely not in synchronism with the system at the instant of reconnection. Such out-of-phase reclosing can inject a large current to the generators. It may also result in re-tripping in the supply system.

- Islanding may interfere with the manual or automatic restoration of normal service for the neighbouring customers.

The current industry practice is to disconnect all DGs immediately so that the entire feeder becomes de-energized [1,2]. It prevents equipment damage and eliminates safety hazards. To achieve this goal, each DG must have the capability to detect islanding conditions and to automatically disconnect itself from the system.

2.2 Detection of Islanded Power Systems

An islanding situation should be detected soon after the island is formed. The basic requirements for a successful detection are:

- The scheme should work for any possible formations of islands. Note that there could be multiple switchers, reclosers and fuses between a distributed generator and the supply substation. Opening of any one of the devices will form an island. Since each island formation can have different mixture of loads and distributed generators, the behaviour of each island can be quite different. A reliable anti-islanding scheme must work for all possible islanding scenarios.

- The scheme should detect islanding conditions within the required time frame. The main constraint here is to prevent out-of-phase reclosing of the distributed generators. A recloser is typically programmed to reenergize its downstream system after about 0.5 to 1 second delay. Ideally, the anti-islanding scheme must trip its DG before the reclosing takes place.

Many anti-islanding techniques have been proposed and a number have been implemented in actual DG projects [3] or incorporated into the controls of inverters used in utility-interactive DG applications. When selecting an anti-islanding scheme, it is important to consider the characteristics of the distributed generators. Almost all distributed generators can be grouped into the following three types:

- Synchronous generator: This type of DG is typically connected to the primary feeder. Its size can go as high as 30MW. Synchronous generators are highly capable of sustaining an island. Due to its large power rating, options are limited to control the generators for the purpose of facilitating islanding detection. As a result, anti-islanding protection for synchronous generators has emerged as the most challenging task faced by the DG industry.

- Induction generator: This type of DGs is typically connected to the primary feeder as well. Its size can also be quite large, for example 10 to 20 MW. Induction generators are not capable of sustaining an island due to their need for reactive power support from the electricity network. As a result, anti-islanding protection is not considered as an issue for induction generators[1].

- Inverter-based generator: This type of DG is commonly connected to the secondary feeder due to its relatively small size (typically in the range of a few hundred watts to 1 MW). The inverter is actually an interface between

[1] If there is enough reactive support in an island, an induction generator can become self-excited. This is a form of islanded operation. It is rare, however, that the operating point of self-excitation has a frequency close to 60Hz. As a result, a frequency relay can be used to detect the self-excitation situation.

the system and the generator. The generator can be photovoltaic panels, fuel cells, micro-turbines etc. Since it is the inverter that interacts with the supply system, all inverter-based DGs have operating characteristics with respect to grid interaction primarily determined by the inverter topology and controls. The inverter-based DGs are capable of sustaining an island; however, the utility-interactive inverters can be designed to detect and control islanding conditions. As a result, many inverter specific anti-islanding techniques have been proposed.

This report will review all major islanding detection techniques published or developed. These techniques can be broadly classified into two types according to their working principles. This classification is shown in Figure 2.2. The first type consists of communication-based schemes and the second type consists of local detection schemes. The communication-based schemes use telecommunication means to alert and trip DGs when islands are formed. Their performance is independent of the type of distributed generators involved.

The second type is local detection schemes that rely on the voltage and current signals available at the DG site. An islanding condition is detected if indices derived from the signals exceed certain thresholds. A representative example is the frequency relay. The local detection schemes can be further divided into two sub-types. One is the passive detection method, which makes decisions based on measured voltage and current signals only. Another type is the active detection method. Such methods inject disturbances into the supply system and detect islanding conditions based on system responses measured locally. The active method is widely used by inverter-based DGs due to its ease of implementation on such systems. Although some of the local detection schemes can be applied to both types of DGs, their performances can differ as they are dependent on the operating characteristics of the DGs involved.

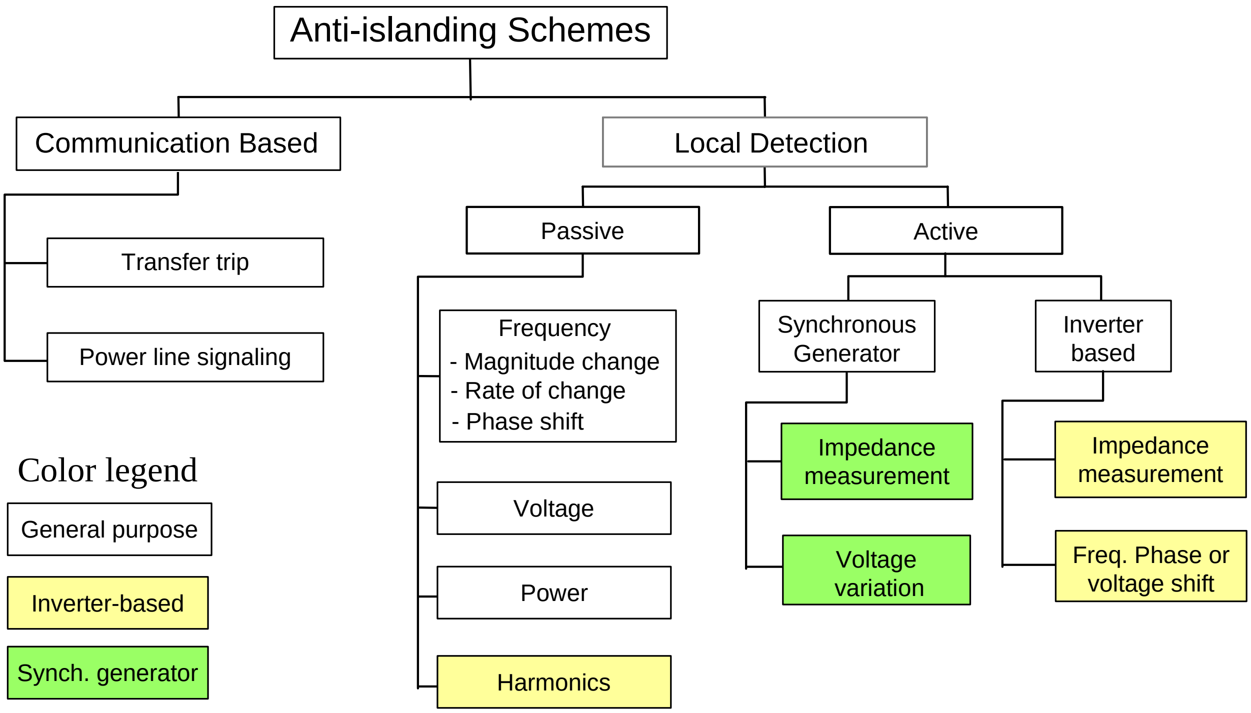


Figure 2.2: Classification of anti-islanding schemes.

The anti-islanding techniques shown in Figure 2.2 are presented in three chapters in this report. Chapter 3 deals with the telecommunication-based techniques. These techniques are applicable to both the synchronous generator type and the inverter-based distributed generators. Chapter 4 reviews the location detection techniques with application to the synchronous generators as the focus. Chapter 5 discusses the local detection techniques associated with the inverter-based units.

2.3 Non-Detection Zone and Associated Risks

All anti-islanding schemes have some limitations which may include:

- high implementation cost;
- need for coordination between the DG operator and the utility;
- susceptibility to false detection of islanding (nuisance tripping);
- possible non-detection of islanding under some conditions; and
- possible reduction of utility power quality and voltage and frequency stability.

Since anti-islanding schemes are not perfect and may impose financial or performance costs, it is necessary to understand the actual probability that an island will occur and what risks this unintentional island will present to human safety and the electrical network. This allows the benefits of further risk reduction from better anti-islanding schemes to be balanced against the costs imposed by these schemes. If a simple and low cost anti-islanding scheme reduces risk to a level below other electrical safety risks that are currently considered acceptable, it is debatable whether a scheme with better detection performance, but higher costs (in financial or performance terms), is necessary. This is particularly true when the DG reduces other hazards, such as air pollution.

One of the main limitations with local detection schemes is that each scheme has an operating region where islanding conditions cannot be detected in a timely manner. This region is called the non-detection zone (NDZ). The impact of the non-detection zone can be negligible in some cases and can be significant in other cases. The frequency-based anti-islanding methods, which are the most commonly employed schemes for synchronous generators, are used here as an example to illustrate the risks associated with the non-detection zone.

The frequency-based anti-islanding scheme uses locally measured frequency as a criterion to decide if an island is formed. It is known that when a feeder is connected to the utility supply, the feeder frequency is almost constant. On the other hand, the frequency of an islanded feeder can have various values depending on the power mismatch between the load and generation in the island. Excess generation will drive up the frequency and deficit generation will result in the decline of frequency. Accordingly, if there is a large power mismatch in an island, the frequency-based anti-islanding scheme will be able to detect islanding condition quickly. If the power mismatch is small, however, it will take longer time to detect islanding condition. In the extreme case where the load and generation in the islanded system are very close, the devices could fail to detect an islanding situation within the allowed time period. Thus, the non-detection zone can be specified using the power mismatch level in an island.

Two factors can significantly affect the power mismatch levels in an island. The first factor is the daily variation of feeder loads. Depending on their operating characteristics, feeder loads could have ±20% variation around its daily average. The second factor is that different islands could be formed with a DG. Each island will have different load levels. Both factors will work together to create more situations where small power mismatch levels could be encountered, leading to increased risk of non-detection. This situation is illustrated in Figure 2.4.

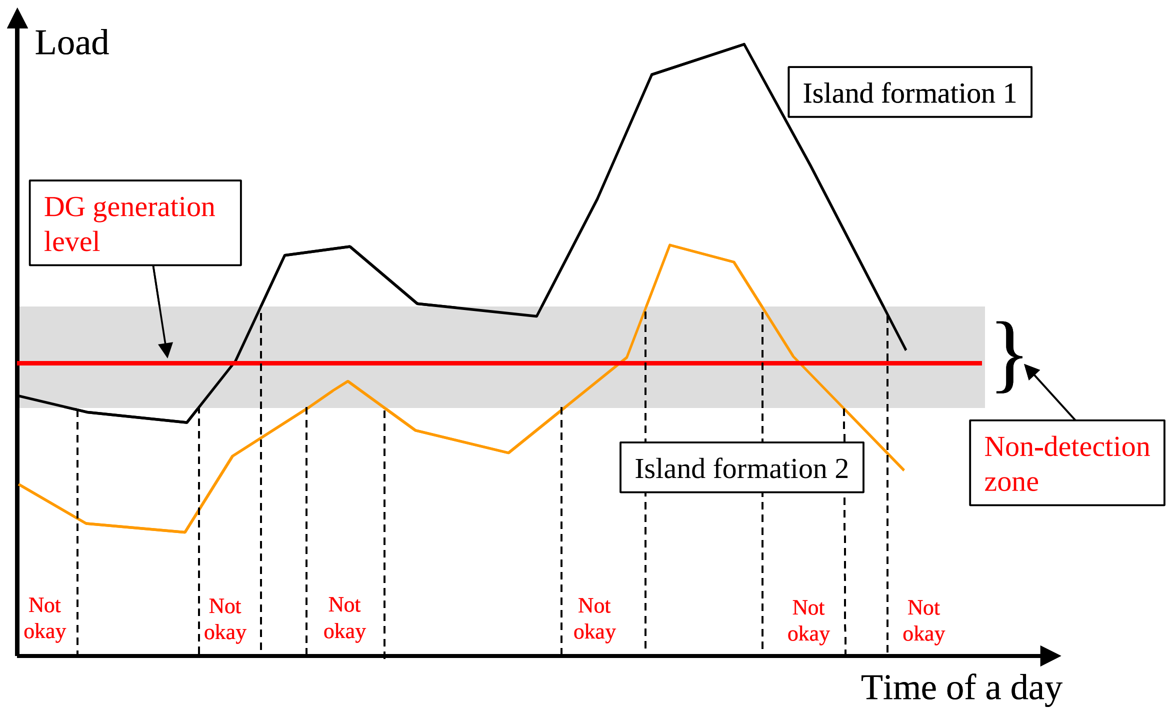


Figure 2.4. The impact of non-detection zone for islanding detection.

The figure shows the variation of load level during a 24-hour period. Two load variation curves are shown. Each curve corresponds to a different island formation scenario. The power output of the DG is assumed as constant during the 24-hour period. So it is a horizontal line. The intersections of the DG curve and the load variation curves represent the cases where there is a zero mismatch between load and generation. The non-detection zone is shown as a shaded band. Any load values that fall into the band will result in poor detection of islanding conditions (marked as 'not okay' in the figure). It can be seen that there are a number of operating periods during which poor or no detection of islanding conditions can occur. If more islanding scenarios are added (i.e. if there are more load variation curves), such periods will increase further. This analysis shows that the risk associated with none-detection zone is real and can be significant. A frequency-based relay can be used reliably only if the distributed generator is less than about half of the smallest load in any possible island formations.

Both the probability of islanding and the risks associated with the formation of an island are typically less for inverter based DGs than for synchronous generator based DGs. Considering risks first, the commonly cited risks or hazards of an unintentional island are:

1. The utility cannot control voltage and frequency in the island, creating the possibility of damage to customer equipment in a situation over which the utility has no control. Utilities, along with the DG owner, can be found liable for electrical damage to

customer equipment connected to their lines that results from voltage or frequency excursions outside of the acceptable ranges;

2. Reclosing into an island may result in re-tripping the line or damaging the distributed resource equipment, or other connected equipment, because of out-of-phase closure;

3. Islanding may interfere with the manual or automatic restoration of normal service by the utility; and

4. Islanding may create a hazard for utility line-workers or the public by causing a line to remain energized that may be assumed to be disconnected from all energy sources.

In North-America, inverters that are type approved to the updated (2001) standards, such as UL1741 or CSA C22.2 NO. 107.1-01, for grid tie DG applications universally have built-in voltage and frequency limits and will cease to energize if the island makes excursions outside of acceptable ranges. Therefore, inverter based DGs do not contribute to the first commonly cited risk associated with an island.

The actual level of risk associated with automatic reclosure into an island created by an inverter based DG is controversial and appears to depend on national or local practices with regard to use of automatic reclosure. Some European countries (e.g. the Netherlands) use automatic reclosure primarily on medium and high voltage overhead transmission lines and do not believe that inverter based DGs, which are normally connected to the low voltage distribution network, are likely to create islands extending up to the transmission level. Therefore they do not consider automatic reclosure into an island to be a substantial hazard. The current North American position, which is reflected in anti-islanding testing standards for DG inverters, is that automatic reclosure is a potential risk. At the very least, damage to the DG inverter, itself, is a possibility.

The risk that islanding may interfere with automatic or manual restoration of service depends in part on the probability that an island will be sustained long enough to be present when the utility is reconnected. An island is sustained only while there is a relatively close match between the power output of the DG and the power consumption of the load within the island. Long duration islands are much less likely than short duration islands since both DG power output and load power consumption change with time. Most studies on the risks associated with islanding of inverter based DGs (discussed below) have found that islands lasting more than a few minutes are very unlikely. Therefore this risk is more of an issue with automatic service restoration techniques, such as automatic reclosing (discussed above), than with manual reconnection.

The hazard to utility line-workers or other personnel by causing a line to remain energized that may be assumed to be disconnected from all energy sources is commonly viewed as the most serious risk of islanding since it involves human safety rather than potential equipment damage or malfunction. As a result, this risk has had the most extensive analysis. The risk to utility line workers can be mitigated by following established rules for line maintenance and repairs. With line workers operating under established hot-line rules or dead-line rules, an islanding situation will not increase the probability for line-worker hazards if those rules are followed. However, other personnel, especially emergency responders, such as firefighters, may not have the time or the capability to follow such procedures. Therefore there is a potential personnel hazard if an island persists beyond a few seconds. North American standards on DG islanding detection reflect this concern in their short trip time requirements.

As with the synchronous generator DG equipped with a frequency-based relay, an inverter based DG will only island if there is a relatively close match between the active and reactive power output of the DG and the active and reactive power consumption of the local loads within the isolation boundary. If there is a significant mismatch, the island voltage or frequency will shift outside the protective function's preset limits and the inverter will cease to energize or the protective relay will cause the DG to disconnect. The non-detection zone for island detection based on inverter voltage or frequency limits is discussed in Chapter 5. Inverters will usually be equipped with additional islanding detection functions that reduce the non-detection zone further.

The personnel safety risk associated with islanding can be analyzed using the fault tree shown in Figure 2.5

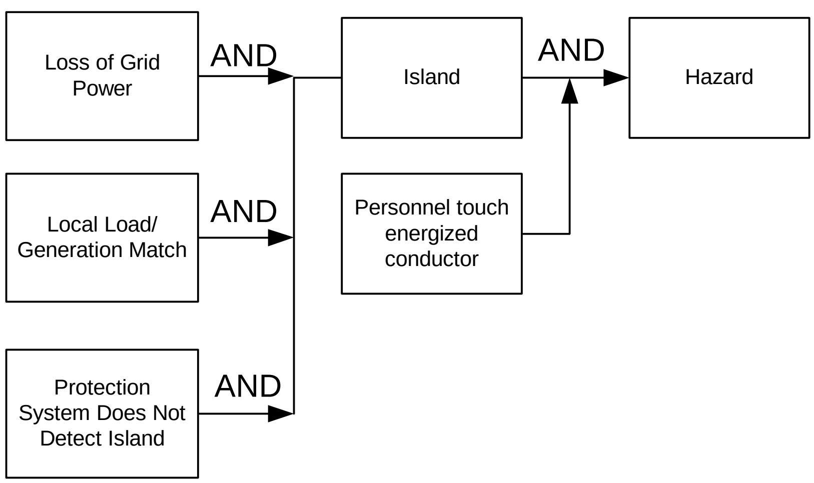


Figure 2.5: Islanding risk analysis fault tree

In order for a hazard to occur, the following events must occur simultaneously:

1. Network (grid) power must be disconnected because of a fault, opening of protective devices, or for maintenance and service;

2. The DG power output (active and reactive) must closely match the power consumption of the local loads within the isolation boundary;

3. The DG must fail to detect the island because the operating condition is within the non-detection zone of the island detection scheme or because the island detection mechanism has failed; and

4. Personnel must touch an uninsulated conductor without using live wire safety practices.

Researchers in Japan [20], USA [21], and the Netherlands [18] have analyzed the probability that there will be a match between DG power output and local load consumption for the case of PV based DGs. A British study [22] has calculated the overall risk level of a personnel hazard, taking into account all four factors listed above. The results of these studies can be summarized as follows:

1. The probability of a power match is negligible with low penetration of DG in the distribution network (DG capacity less than 30% of averaged maximum demand) but increases significantly when penetration is higher;

2. Overall risk of electric shock due to islanding, using British data for probability of outages, a high DG penetration scenario, and reasonable assumptions about island detection capabilities of inverters, is on the order of 10^{-9} per year. This is much less than the baseline risk of electric shock in Britain, which is on the order of 10^{-6} per year.

Thus, the additional personal safety risk presented by islanding, even with high penetration of inverter based DGs, does not materially increase the risk that already exists as long as the risk is managed properly. In particular it is probably wiser to choose an islanding detection scheme that is unlikely to fail completely rather than a less reliable scheme that has a smaller theoretical non-detection zone (NDZ).

There is now considerable field experience with relatively large numbers of PV based DGs in Germany, Japan and the USA, although penetration rates are not yet very high. The authors have been unable to find any reports of injuries to humans ascribed to islanding of these DGs, nor have they found any reports that indicate islanding operation of these DGs has been observed in the field (as opposed to laboratory tests which deliberately try to create an island). This suggests that the theoretical analysis of islanding risk is matched by actual field experience. These islanding risk studies have focused on inverter based DG technologies. The work should be extended to examine situations where rotating machine DGs or a mix of DG technologies are employed.

CHAPTER 3 : COMMUNICATION-BASED ANTI-ISLANDING TECHNIQUES

Communication based schemes rely on telecommunication to alert and trip DGs when islands are formed. Their performance is generally independent of the type of distributed generators involved. This Chapter reviews two basic schemes implemented or proposed for anti-islanding applications. Other communication-based schemes are essentally minor variations of these two basic schemes.

3.1 Transfer Trip Scheme

The basic idea of transfer trip scheme is to monitor the status of all circuit breakers and reclosers that could island a DG in a distribution system [4,5]. When a switching operation produces a disconnection to the substation, a central algorithm determines the islanded areas. A signal is then sent to trip DGs in the islanded areas. Figure 3.1 illustrates the basic idea of this scheme.

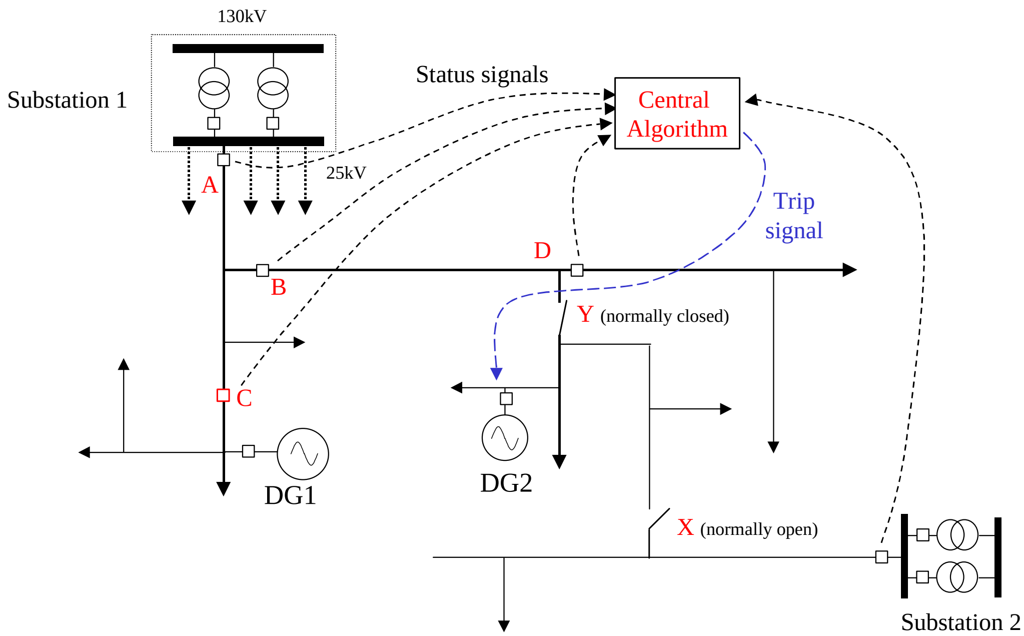


Figure 3.1: Transfer trip scheme.

The transfer trip scheme is very simple in concept. If a DG is connected to a substation with a fixed topology and through a limited number of reclosers, the above transfer trip scheme can be simplified significantly. The status signals can be send to the DG directly from each monitoring point (reclosers) and the central processing algorithm can be avoided. This is the most common adaptation of the scheme nowadays for islanding detection [1,2].

If there are many reclosers and the feeder topology varies, a transfer trip scheme can become quite complicated. Firstly, all reclosers between a DG and the supply substation must be monitored. Secondly, the reclosers between the DG and the supply could be different for different network topologies. A common situation of topology change is the feeder reconfiguration as shown in Figure 3.1. Some operating scenarios may require opening the disconnect switch Y and closing the disconnect switch X. If this happens, DG2 will be transferred to substation 2. As a result, reclosers associated with substation 2 should also be monitored to decide the islanding status of DG2. One can see that a reliable implementation of a transfer trip scheme for multiple network topologies requires a central processing algorithm to determine the formation of islands and the DGs affected by a particular formation. In addition, the algorithm needs to have the most up-to-date information on the topology of the distribution system. Such situations will render the transfer trip scheme quite unattractive.

It is clear that a transfer trip scheme requires extensive communication support. Radio communication or leased telephone lines are the most common method for the scheme. In order to be fail-safe, radio signals are send to DGs or the central unit continuously. Absence of a signal is treated as the opening of the associated breaker. If radio coverage or telephone lines are not available, the scheme cannot be used or can be very expensive to set up.

Transfer trip scheme can be an effective and simple method for islanding prevention for distribution feeders with fixed topology. Utility companies have years of experiences on this scheme for various protection applications so it can be easily accepted. This method would allow additional control of the distributed generators by the utility, increasing the coordination between distributed generators and utility resources. The same system can also be used to provide a signal for reconnecting DG units after fault clearance.

The main disadvantages of the transfer scheme are the cost and potential complexity. This is because signal transmitters are needed for all possible disconnecting points in the system and they must have communication coverage for the DG locations. The scheme can become very complicated if scenarios of feeder reconfiguration exist.

3.2 Power Line Signaling Scheme

This scheme utilizes the power line as a signal carrier and is shown in Figure 3.2. The main device of the scheme is a signal generator connected to the secondary side of the substation bus. The device broadcasts a signal to all distribution feeders continuously. Each DG is equipped with a signal detector. If the detector does not sense the signal (caused by the opening of any breakers between the substation and the DG), it is an island condition and the DG can be tripped immediately. If the 25kV bus loses power, which is another islanding condition, the signal generator also loses power and it stops broadcasting so that downstream DG will also trip. The signal generator has several auxiliary inputs. Any one of the inputs can stop the broadcast, resulting in tripping all DGs in the system. This feature is particularly useful since the utility company can use it to disconnect DGs should an island be formed in transmission systems.

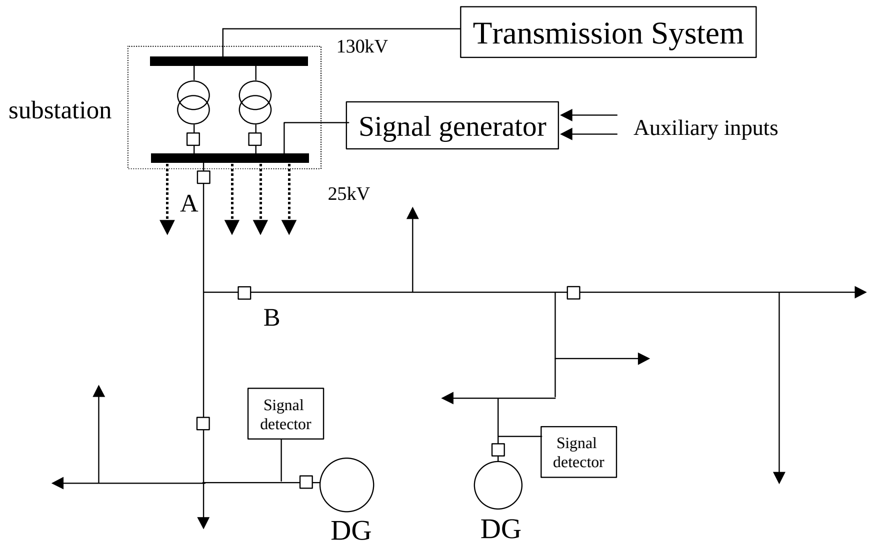


Figure 3.2: Power line signaling scheme.

This scheme has several advantages, especially with increased connection density of distributed generators. The scheme can be quite reliable since there is only one signal transmitter (generator) involved and the signal serves as a continuity-checking tool. The DG owners can share the cost of the transmitter. There is no need to worry about feeder topology change with this scheme. As a result, it can be implemented easily.

The scheme has two main disadvantages. The first one is the cost of the signal generator. This is a medium voltage device. A step down transformer is required to connect it and it has to be installed in a substation. This cost may be hard to justify if there are only one or two DGs using the service. The second concern is the possible interference of the signal with other power line communication applications such as automatic meter reading. This is a promising technology but there is no field application experience of this technology yet.

CHAPTER 4 : LOCAL DETECTION SCHEMES FOR SYNCHRONOUS DISTRIBUTED GENERATORS

Local detection schemes detect islanding situations based on the voltage and current signals available at the DG site. They can be further divided into two sub-types. One is the passive detection method, which makes decisions based on measured voltage and current signals only. Another type is the active detection method. Such methods inject disturbances into the supply system and detect islanding conditions based on system responses measured locally. The performance of these local detection schemes can be significantly affected by the type of distributed generators involved. This Chapter focuses on the application of the scheme to synchronous generators.

4.1 Frequency-Based Passive Schemes

The frequency-based schemes are the most widely used passive scheme for islanding detection involving synchronous generators. It is known if the generation and load have a large mismatch in a power system, the frequency of the system will change. In view of the fact that the frequency is constant when the feeder is connected to the transmission system, it is possible to detect the islanding condition by checking the amount and rate of frequency change. Several commercial products based on this idea have been developed and are available for use at present.

4.1.1 Operating principles

There are three types of frequency-based relays commercially available for islanding detection [7-9], as follows:

- Frequency relay
- Rate of change of frequency (ROCOF) relay
- Vector surge (or shift, jump) relay

The frequency relays calculate the frequency of the DG terminal voltage waveform. A DG is tripped based on over-frequency or under-frequency criteria. In Alberta, the under frequency threshold is 59.5 Hz and the over-frequency threshold is 60.5 Hz. The DG shall be tripped within 0.5 seconds. The ROCOF relays go one step further. It determines the rate of frequency change. DG trip is initiated when the rate exceeds certain threshold. Typical ROCOF settings installed in 60 Hz systems are between 0.10 Hz/s and 1.20 Hz/s. Another important characteristic available in these relays is a blocking function based on minimum terminal voltage. If the terminal voltage drops below an adjustable level V_{min}, the trip signal from the ROCOF relay is blocked. This is to avoid, for example, the actuation of the ROCOF relay during generator start-up or short-circuits.

The vector surge relays measure the phase angle shift of the voltage waveform with respect to a reference waveform, as shown in Figure 4.1. It can be shown that the shift, $\Delta\theta$, is an indirect measurement of the waveform frequency. As a result, this type of relay has a performance characteristic similar to that of the frequency relay.

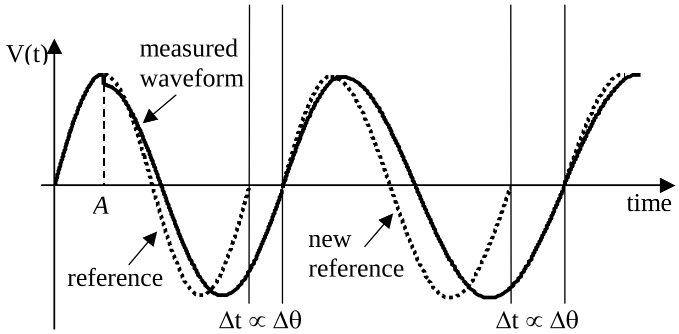


Figure 4.1: Principle of vector surge relay.

4.1.2 Performance characteristics

As discussed earlier, a large power imbalance will cause fast deviation of frequency in an island and it will take less time to detect the islanding condition. An approach to evaluate the performance of frequency-based anti-islanding relays is, therefore, to understand the relationship between the tripping (or detection) time and power imbalance. This relationship can be represented with a detection-time versus power-mismatch curve as shown in Figure 4.2.

In this figure, the x-axis is the power mismatch level of the islanded system referred to the rated MVA of the DG. The y-axis is the time needed by the relay to operate, since it takes time for the islanded system to exhibit detectable frequency variation. If it is required to trip the distributed generator within 300ms after islanding, one can draw a horizontal line of 300ms. The intersection of this line with the relay curve of 10 degrees gives 33% power mismatch level. If an islanded system has a power imbalance greater than 33%, it would take less than 300ms to detect the islanding condition. So the relay can be used with confidence. One the other hand, the relay will take longer than 300ms to operate if the power imbalance level is less than 33%. Consequently, the relay is not suitable for such cases. The 33% power mismatch level is called the non-detection zone for the frequency-based relay. The relay can use different settings to reduce the non-detection. In the figure, curves associated with 3 relay settings have been plotted.

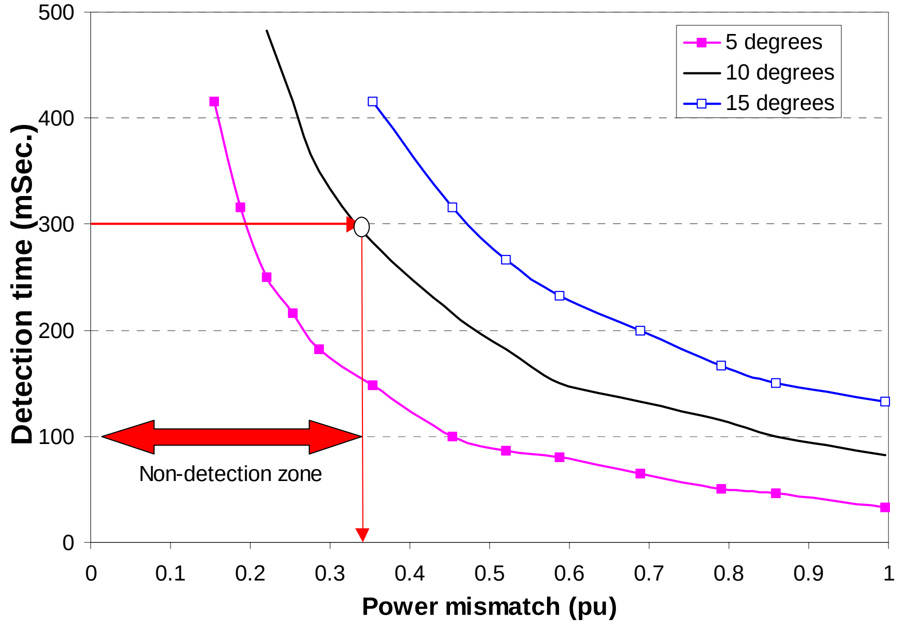


Figure 4.2: Detection-time versus power-mismatch characteristics of frequency relays.

The detection-time versus power-mismatch curves for the frequency, ROCOF and vector surge relays are shown in Figure 4.3 [10] for islands consisting of one synchronous generator. It can be seen that the VSR and frequency relays have similar performance. The ROCOF relay has the best performance since its non-detection zone is the smallest. The results also reveal that a non-detection zone of 10% to 30% power mismatch exists for all relay types. Reducing the trip threshold can reduce the non-detection zone. This approach, however, could make the relays too sensitive, resulting in more opportunities for nuisance trips. Because of this reason, the ROCOF relay is more prone to nuisance trips.

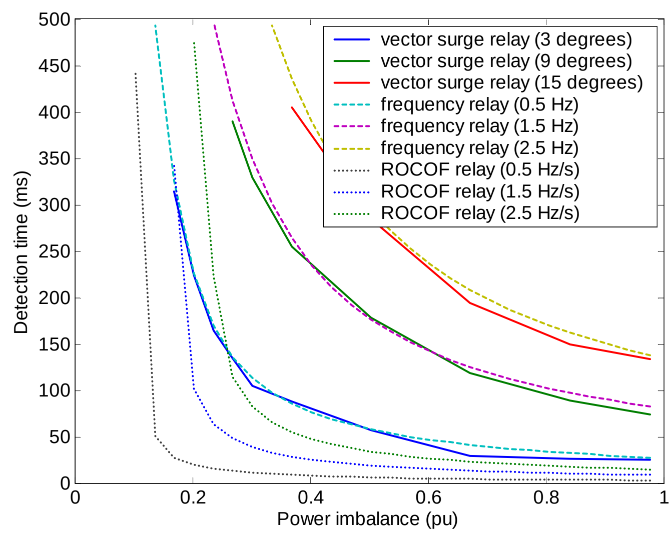
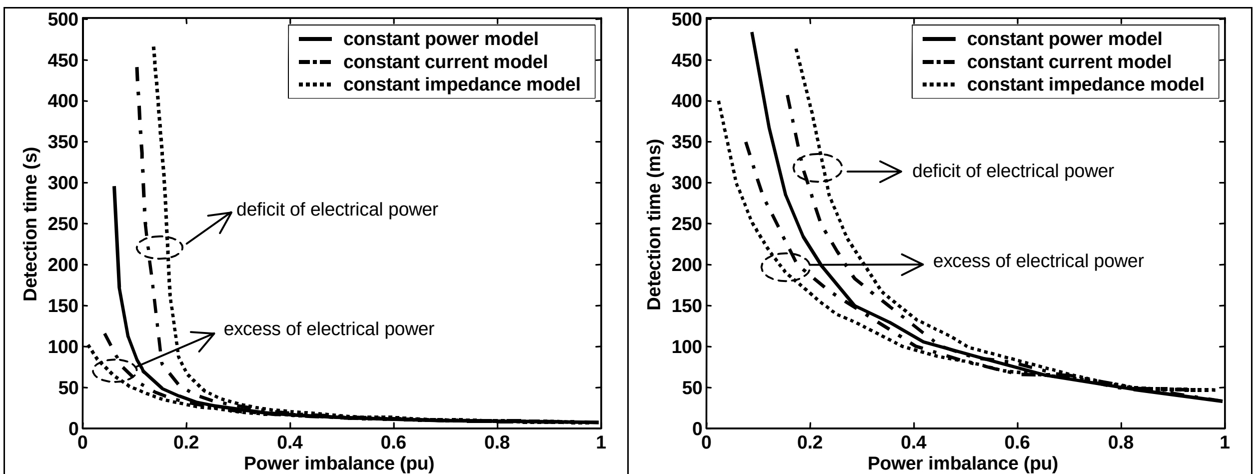


Figure 4.3: Characteristics of three types of frequency-based anti-islanding relays.

It is important to note that Figure 4.3 is an illustration of the typical characteristics of frequency-based relays. A number of factors can affect the curves. Research results show that the following factors have significant impact on the relay performance:

- Inertia constant of the distributed generator;
- Voltage and frequency dependency of the feeder loads; and
- Excitation control of the generator.

As an example, the impact of voltage dependency of the feeder loads is shown in Figure 4.4. The constant power load model represents a load characteristic that is independent of voltage. The constant current model represents a load characteristic whose power consumption varies linearly with the supply voltage. The constant impedance model represents a load characteristic whose power consumption varies with the square of the supply voltage. It is clear that the constant impedance load can create a large power surplus or deficit in an islanded system if the system voltage changes a lot. Research results also show factors such as feeder length and load power factors have little impact on the relay performance curve.



(A) ROCOF Relay (Setting = 1.20 Hz/S).	(b) Vector surge relay (setting = 10 degrees).

Figure 4.4: Impact of load to voltage dependency on the relay performance characteristics.

Equations to predict the performance of the vector surge relays have been developed [10]. The relay detection time can be estimated using the following equation:

$$t = \frac{-(2\omega_0 K(\alpha - \pi)) - \sqrt{\mathrm{D}}}{2K^2(\alpha - 2\pi)}$$

where $K = \omega_o \Delta P^{\frac{1}{1\pm 0.1k}} / 2H$;

$D = (2\omega_0 K(\alpha - \pi))^2 - 4K^2(\alpha - 2\pi)(\omega_0{}^2\alpha + 2\pi^2 K);$

H is the machine inertia constant;
ω_o is the synchronous speed;
α is the relay trip setting;
$\Delta P=(P_{gen}-P_{load})/P_{gen\text{-}rated}$ is the per-unit power mismatch between generation and load at the instant of islanding;
k is the voltage dependency parameter of the load. If $\Delta P>0$, "+" sign is used and $\Delta P<0$, "-" sign is used.

The voltage dependency parameter of a load is defined as

$$P = P_o \left(\frac{V}{V_o} \right)^k$$

where subscript o stands for nominal value, k is the load characteristic parameter. $k=0$ represents constant power load, $k=1$ represents constant current load, and $k=2$ represents constant impedance load.

One of the results derived from the above equation is shown in Figure 4.5 as a general-purpose curve to predict the relay performance. The curves are derived using constant power load model *(k=0)*. Note that the normalized power mismatch, defined as $\Delta P_n=\Delta P/H$ is shown in the figure. Because of the normalization, the curves can be applied to generators of any size. Similar curves for the ROCOF relay have not been developed at present.

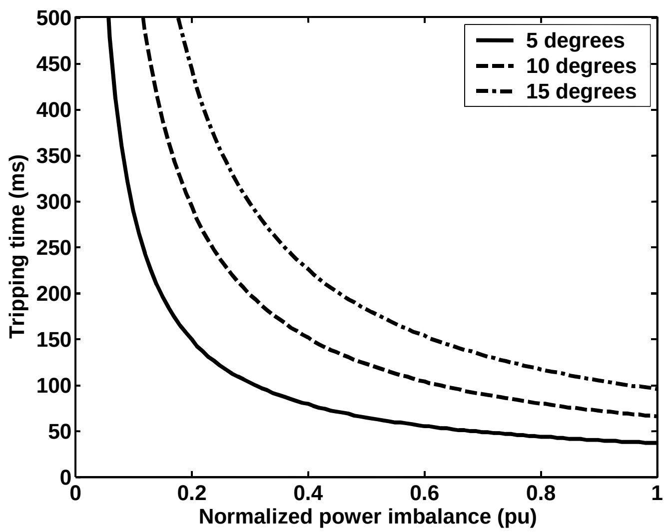


Figure 4.5: General characteristics of the vector surge relay (assuming constant power load).

If there are multiple DGs in an island, the frequency-based relays could interact with each other. This is because the tripping of one generator will change the power mismatch level in the island, which in turn affects the variation of system frequencies. The relay behaviours can be difficult to predict under such circumstances [11]. Research results also show that the ROCOF relay can cause more nuisance trips than the vector surge relay.

4.1.3 Comments

The frequency-based relays are probably the most viable local-detection option available at present for synchronous generator anti-islanding applications. The methods are simple and reliable for almost all cases where power imbalance is significant. They have been widely used for anti-islanding purposes and many application experiences have been accumulated. Research results show that the ROCOF relay has the smallest non-detection zone and is, therefore, a more attractive alternative for anti-islanding application. A frequency relay is also needed since the supply utility has requirements to trip DGs for under- or over- frequency conditions. As a result, a relay that has the combined features of ROCOF and frequency relays is the most desirable device for anti-islanding applications.

The main weakness of the frequency-based relay is its non-detection zone. The relay cannot provide effective anti-island protection if the load-generation mismatch in an island is less than 10% to 30%. This disadvantage could be mitigated to some extent if the reactive power mismatch in the island is also used as a detection criterion. Delaying the reclosing operation of feeder reclosers will also help since it gives the relay more time to detect frequency variations.

4.2 Other Passive Schemes

Besides frequency, other power quantities can also be used to help detecting island situations. The most common one used in industry is the under- and over-voltage relay. The relay operates on the principle of reactive power mismatch in an island. Excessive reactive power will drive up the system voltage and deficit reactive power will result in voltage decline. By determining the change or rate of change of the voltage at the DG terminal, it is possible to detect islanding conditions that cannot be detected by frequency-based relays. Note that a voltage relay is needed for other protection purposes in a DG installation. For example, it is used to prevent over-voltage stress to the DG unit. A voltage relay is, therefore, always available in a DG installation and can be utilized to support islanding detection at no extra cost.

The performance characteristics of voltage-based relays for islanding detection is not clear at present since no research work has been reported on this subject. What is certain is that a voltage change can occur much faster than a frequency change. This is because there is no mechanical 'inertia' associated with voltage change. So a voltage relay can operate with shorter delay. A power distribution system typically has small reactive power mismatch due to the need for feeder loss reduction. As a result, the reactive power mismatch and its associated voltage change in an islanded system can be small. On the other hand, there are other disturbances that can cause voltage change. In view of these factors, voltage-based relays cannot be used as a primary device for anti-islanding protection.

Research work has been reported on the use of other indices derived at the DG site for islanding detection. Examples are:

- Change of active power output [12]: This scheme monitors the change of DG's active power output. Since frequency change is a direct consequence of active power change, the performance of this method is likely to be similar to that of frequency-based relays. On the other hand, other disturbances (e.g., from the prime mover) could also change the power output level. So it is difficult to establish a reliable anti-islanding criterion for active power change based methods.

- Change of reactive power output [12]: This scheme monitors the change of DG's reactive power output. It could have a better performance than the voltage-based relays. This is because it takes a lot of reactive power change to cause detectable voltage change in a low penetration application. The reactive power change is a more sensitive index. To be effective, this method requires the generator to operate at the voltage control mode, which is often prohibited by the utility. The method also experiences similar problems faced by voltage-based relays.

- Power factor (*P/Q*) and (*df/dP*) indices [13,14]: The power factor is affected by both active and reactive power of the generator. There is no convincing technical reason to suggest that the power factor index will exhibit significantly different behaviour before and after islanding. The same conclusion applies to the *df/dP* index. So such indices are unlikely to result in improved anti-islanding schemes.

In summary, the voltage relay can be used as a complementary device for anti-islanding protection. There is no evidence that other indices or schemes can provide performance better than that of the frequency-based relays. Furthermore, these schemes can be sensitive to disturbances other than islanding. Even if they were commercially available, it could be difficult to establish tripping thresholds that can differentiate islanding conditions from other disturbances.

4.3 Active Schemes

Active detection schemes inject disturbances into the supply system and detect islanding conditions based on system responses measured locally. Active methods are highly dependent on the DG units involved. For synchronous generators, options to inject disturbances are limited since the voltage is high and the generators are not easy to control. The review undertook by the authors of this report found that two active methods have been reported in literature.

4.3.1 Method of impedance measurement

One of the active methods is to measure the system impedance seen at the DG terminals. It is known that if a DG is connected to the main grid, the system impedance seen by the DG will be very small. On the other hand, if it loses connection with the system, the impedance will be large. A possible way to detect an islanding condition, therefore, is to monitor the impedance on a continuous basis.

Unfortunately, determining system impedance is not an easy task. It requires to inject disturbance into the system. One obvious choice is to inject low frequency inter-harmonic current, as shown in Figure 4.6. Harmonic current cannot be used since the system has harmonic sources that will corrupt the results. Reference [15] is the only known impedance based method for synchronous generators according to this survey. The method uses a shunt-connected thyristor connected at the DG terminal to inject disturbance into the system. Impedance is calculated from the voltage and current responses. Since there is a large difference between impedances with and without the supply system, accurate impedance measurement is not necessary for this scheme.

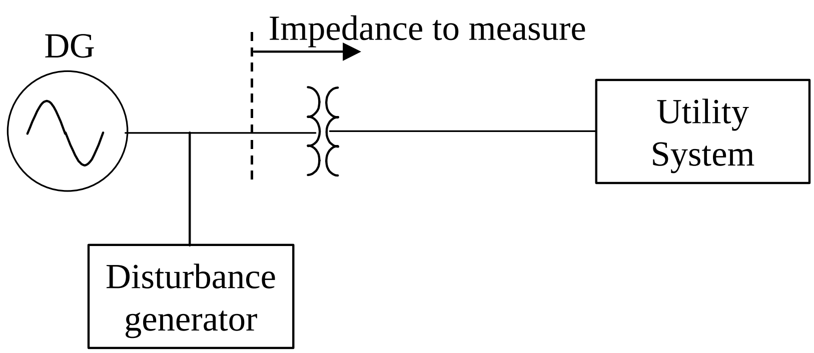


Figure 4.6: Method of impedance measurement.

One significant advantage of this scheme is that the power mismatch level in the island will not affect its performance. The main disadvantage of this scheme is the interference among the disturbances injected when there is more than one DG. This interference can make it very difficult to obtain reasonably accurate impedance measurement so the effectiveness of the scheme will suffer. Cost is also a factor since it requires a dedicated disturbance generator at each DG site. Finally, some loads may have a frequency response that prevents the disturbed parameter from sufficiently impacting the sensed parameter to adequately detect the loss of supply.

4.3.2 Method of varying generator terminal voltage

A variation of the impedance measurement scheme is to measure the change of reactive power flow when the terminal voltage of the DG unit is varied [16]. Due to the difference on the impedances, the change of the DG's reactive power output can be quite different between the case of connected system versus the case of islanded system. If the system is connected to the grid, the variation will be small. Based on this observation, one can let the Automatic Voltage Regulator of the DG unit make small variations on its voltage setting and monitor the var output variation of the unit to detect the island condition. This scheme is more practical than the scheme of direct impedance measurement. Its implementation needs to change the excitation system of the generator only.

Another reported active method also varies the generator terminal voltage [17]. The setting changes periodically with a frequency of 1 to 5Hz. The magnitude of variation is around 1%. Reference [17] shows that such a voltage change will accelerate the change of the waveform frequency if the generator is islanded. Thus, the frequency-based relays will be able to detect islanding conditions more easily, including the cases where the power mismatch is very small. In fact, the technique was proposed to reduce the non-detection zone of the frequency-based anti-islanding schemes.

Like the impedance measurement method, the above schemes are also more complicated than the passive schemes. It could result in other side effects such as power quality deterioration and rotor vibration. The main concern for any active methods is, however, on the potential interference if there is more than one DG. When multiple DGs are injecting similar disturbances to the system, it can become very difficult and even impossible to measure the system impedance and the generator responses are hard to determine. No work has been done to investigate the impact of multiple disturbances on the effectiveness of islanding detection. As a result, the reliability of active schemes cannot be assured for systems with multiple DGs.

4.4 Summary

This Chapter has reviewed key anti-islanding schemes associated with synchronous distributed generators. The following conclusions are drawn:

- The frequency-based passive detection method is the simplest option that can work for most cases. It is the most effective local detection scheme for anti-islanding protection at present. The risk associated with small power mismatch is small for cases involving small distributed generators. Voltage relays are good complementary anti-islanding protection devices for the frequency-based relays.

- The active methods are promising. But many technical problems need to be solved before one can use them with confidence. One of the main problems of the active methods is the interference of disturbances introduced by multiple DGs. No research has been conducted on such issues.

CHAPTER 5 : LOCAL DETECTION SCHEMES FOR INVERTER BASED DG APPLICATIONS

5.1 Introduction

Inverter interfaced distributed generation systems differ from rotating machine interfaced distributed generation systems in several ways that influence the approach taken to islanding detection and protection.

Typically, inverter interfaced systems are relatively low power by utility standards, ranging from under one kilowatt up to a few megawatts. In addition they often interface generation resources that are non-dispatchable, such as photovoltaic arrays. As a result it is usually not cost-effective, and there is little incentive, to communicate with utility control systems. Therefore, islanding detection and protection schemes for inverter interfaced systems have focused on local detection techniques rather than communication based techniques.

Also, for cost reasons, smaller inverter interfaced systems cannot support utility interconnect requirements for larger systems that may include an engineering study, use of utility approved protective relays, and witness testing of the installation. Instead, it is desirable to have:

- Standardized interconnection guidelines and protection settings;
- Integration of the protection functions in the inverter rather than in a separate protective relay; and
- Type approval of the inverter's protection functions, with any required testing performed during manufacturing rather than by witness testing in the field.

Therefore, there has been considerable activity devoted to developing acceptable standards for island detection and subsequent protective actions and to developing testing and certification methods for islanding protection functions in inverters.

5.2 Influence of Inverter Topology and Control Structure on Islanding Risk and Protection Techniques

Different inverter topologies and control structures may be employed depending on the specific requirements of the distributed generation system. The choice of inverter topology and control structure can affect the nature of the islanding risk and the type of detection and protection techniques employed.

5.2.1 Inverter operation

The inverter interface converts electricity from the distributed generation source to a form that can be supplied to the distribution network. Often the "inverter" is a complex power electronic system whose structure depends on the characteristics of the distributed generation source as shown in Figure 5.1. If the source is a rotating machine operating at variable speed, such as those found in wind turbines, microturbines and some engine-generators, the variable frequency ac voltage at the terminals of the generator is rectified and regulated to dc and then inverted to a fixed frequency ac current that is fed to the distribution network. If the distributed generation source has a varying dc voltage output, such as a photovoltaic array or fuel cell, the voltage may first be stepped up or down and pre-regulated by a dc/dc converter, or it may be fed directly to the dc to ac inverter. The inverter interface decouples the generation source from the distribution network and the islanding characteristics of the distributed generator are primarily determined by the inverter.

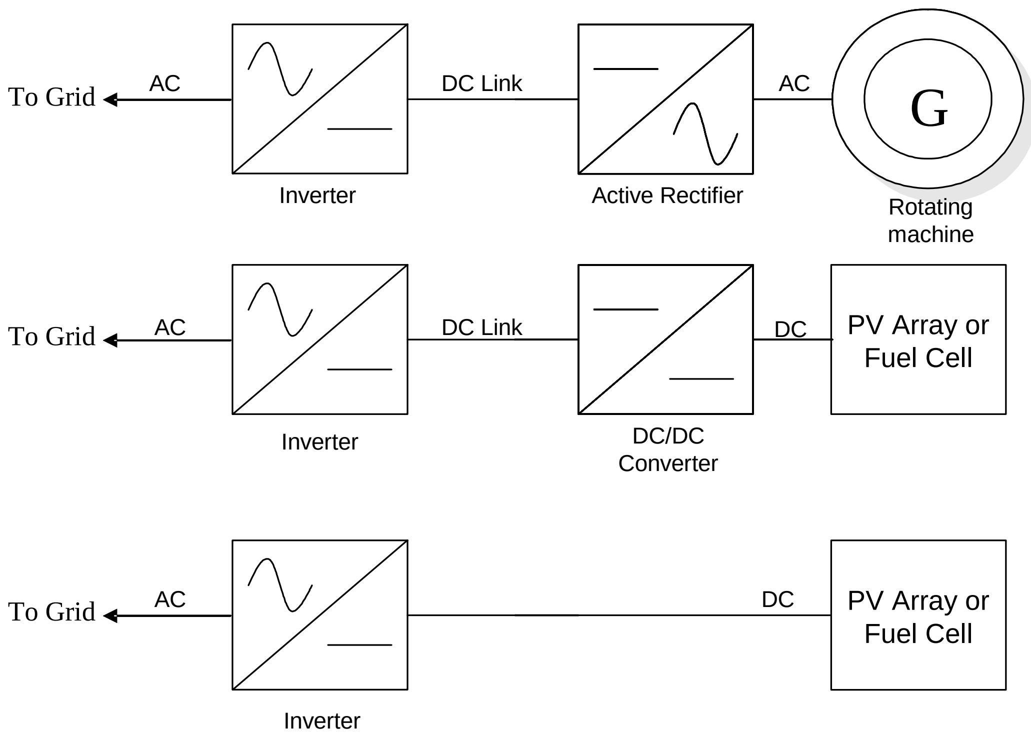


Figure 5.1: Inverter interface configurations

5.2.2 Inverter classification

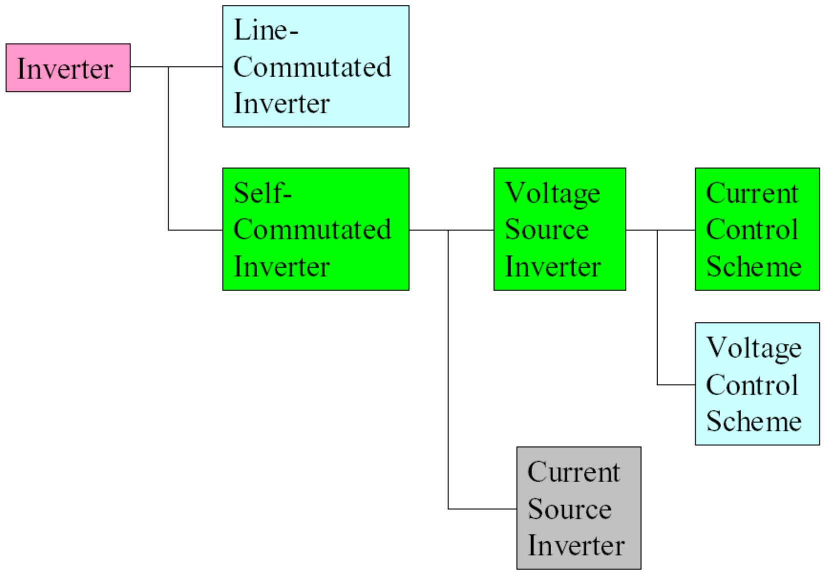


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Figure 5.2: Inverter classification (Source: [23])

A variety of dc to ac inverter topologies and control techniques may be applied in inverter interfaces for distributed generation sources. Figure 5.2 shows the topologies and control techniques that may be employed.

5.2.3 Line commutated inverter

The line (or load) commutated inverter uses switching devices, such as thyristors, that can be turned on with a control signal but require an external circuit or source to commutate them (turn them off) by reducing circuit current to zero. In the line commutated inverter, the distribution network acts as the source to turn off the switching devices. There may be an erroneous perception that a line commutated inverter cannot island because it will have a commutation failure when the distribution network voltage is not available and its protection circuits will shut it down. In fact, a line commutated inverter can be commutated by external capacitive reactance within the island, or by another distributed generator within the island, and it may continue to operate unless islanding detection and shutdown measures are implemented.

Line commutated inverters are limited in their ability to control the voltage and current waveform on the ac side and commonly require extensive filtering to meet power quality requirements. However, thyristors are capable of high voltage and high current operation and so line commutated inverters using thyristors still find application in high power systems.

5.2.4 Self commutated inverter

The self-commutated inverter uses switching devices that can control both the on-state and the off-state, such as IGBTs and MOSFETs. The self-commutated inverter can precisely control the voltage and current waveform at the ac side, allowing it to control the power factor and limit harmonic currents with moderate sized filters. It is also resistant to utility system disturbances that would cause a line commutated inverter to shut down. Most inverter interfaces for distributed generation now employ a self-commutated inverter topology since IGBTs are now available that allow design of inverters with multi-megawatt ratings.

Self commutated inverter topologies can be classified by the nature of the dc link at the input of the dc to ac inverter section.

Current source inverter (CSI)

A current source inverter has a dc link that can be characterized as a controlled current source. Typically the dc link employs a large series inductor to maintain a constant current in the link. The switches in the inverter bridge conduct current in one direction when turned on but must be able to block voltage in both directions when turned off.

Voltage source inverter (VSI)

A voltage source inverter has a dc link that is characterized as a controlled voltage source. Typically the dc link employs a large parallel capacitor to maintain a constant voltage across the link. The switches in the inverter bridge must conduct current in both directions when turned on but only have to block voltage in one direction when turned off.

A current source topology appears to be a natural choice for an inverter interface for a distributed generation source since the inverter output is connected to the distribution network, which has the characteristics of a fairly stiff voltage source. It is easier to control power flow between a directly connected current source and voltage source than between directly connected voltage sources. Indeed, current source inverter topologies are employed in some inverter interfaces for distributed generation sources. However, voltage source inverters can also be used with appropriate control strategies. They are used more commonly than current source inverters, probably because switching devices such as IGBTs and MOSFETs meet the requirements of voltage source inverters more readily and because distributed generation sources resemble voltage sources more than current sources.

5.2.5 Inverter control structures

A simplified circuit diagram of a single phase voltage source inverter interface for a distributed generation source is shown in Figure 5.3.

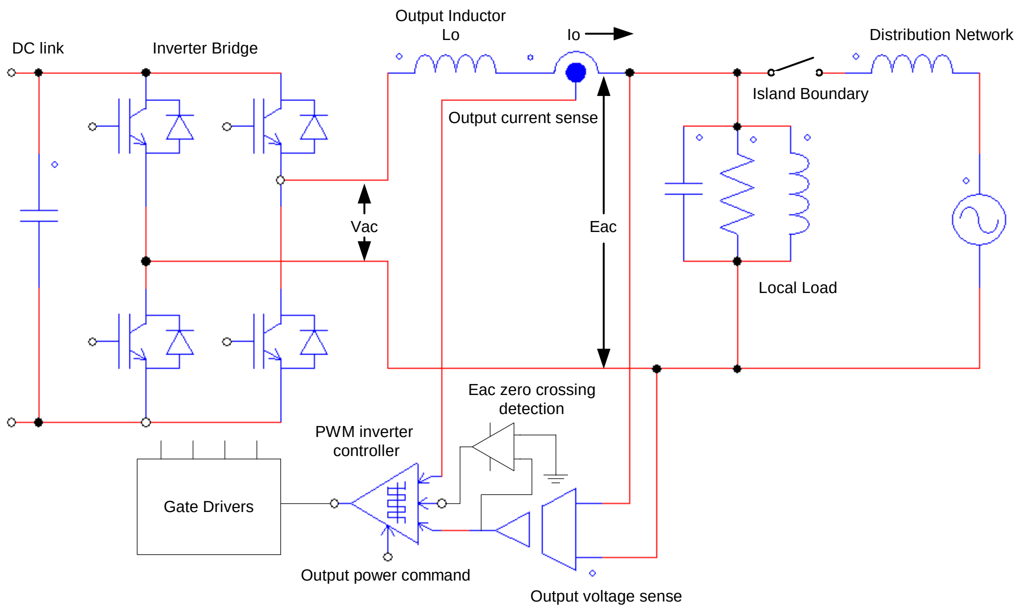

Figure 5.3: Voltage source inverter connected to local load and distribution network

The distribution network can be modeled as a voltage source behind a small line impedance. It imposes a voltage Eac on the output terminals of the inverter. A local load, modeled as a parallel RLC network, remains connected to the inverter if an island is connected. The inverter switches are gated using a pulse width modulated (PWM) switching scheme to directly control the average output voltage of the inverter bridge (Vac) [24]. The inverter switching frequency is normally many times greater than the line frequency, so a relatively small output inductor, Lo, can be used to remove the PWM carrier frequency component of the inverter output. The high switching frequency also allows sufficient control bandwidth to allow the inverter to generate a high quality, low distortion ac waveform.

The inverter controller senses terminal voltage Eac and output current (Io), and uses this information, plus a power command, which may be internally calculated or received from an external source, to control the output current and active and reactive power.

Current controlled

In a current controlled inverter, the controlled variable is the output current. A feedback loop is closed around the output current Io and the inverter output Vac is adjusted based on the error between the measured output current and a reference current command. Figure 5.4 shows a simple implementation of a current controller. In this implementation, the inverter terminal voltage Eac serves as a current waveform reference that is multiplied by a current magnitude command to create the output current reference.

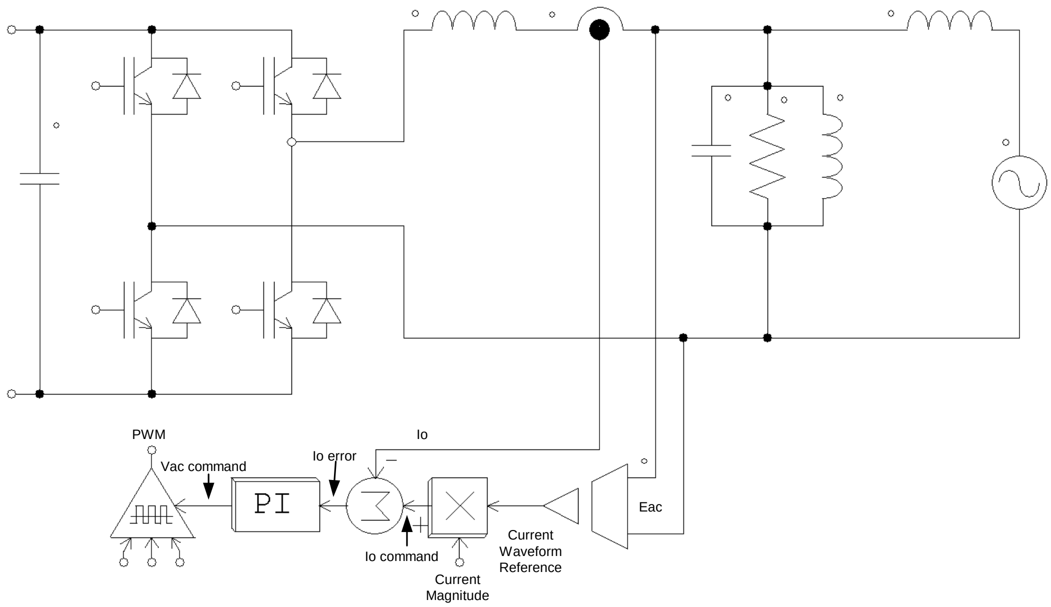

Figure 5.4: Current controlled voltage source inverter

Since Eac is imposed on the inverter terminals by the distribution network, the inverter output current will be in phase with, and have the same waveform as, the distribution network voltage. Power output can be controlled by adjusting the current magnitude command.

The use of the output terminal voltage Eac as the current waveform reference is advantageous to islanding detection since it creates positive feedback that destabilizes an island but it has the disadvantage that the output current reflects any voltage distortion on the network. An alternative approach that eliminates this issue is to use an internal low distortion sine wave current reference that is synchronized to the zero crossings of the output voltage with a phase locked loop (PLL).

Power angle controlled

In the power angle controlled inverter, power flow through the output inductor (Lo) of the inverter is the controlled quantity.

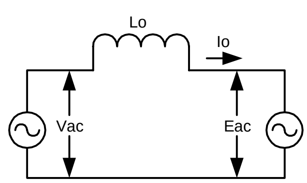

Figure 5.5: Power angle control equivalent circuit

Active and reactive power flow through Lo can be expressed as

$$P = \frac{V_{ac} E_{ac} \sin\delta}{\omega L_o} \quad Q = \frac{E_{ac}\left(V_{ac}\cos\delta - E_{ac}\right)}{\omega L_o}$$

where δ is the phase angle (called the power angle) between the inverter bridge voltage (V_{ac}) and the distribution network voltage (E_{ac}) and ω is the line frequency in radians/sec [25]. L_o is normally relatively small on a per-unit basis and the power angle δ is small even at rated power output. As a result, cos δ is close to unity. Therefore the power angle δ is normally controlled to regulate active power flow (P) through the filter inductor (L_o) and the magnitude of V_{ac} is controlled to regulate reactive power flow (Q).

Neither the current controlled or phase angle controlled inverters have independent internal frequency or output voltage control – they follow the frequency and voltage measured at the output terminals and control the output current or power. Since the inverter controls are trying to maintain output current or power at a constant level, there is a rapid shift in output frequency and/or voltage if an island occurs and there is a mismatch between the power output (active and reactive) of the inverter and the power draw of the local load. This can be understood by considering the relationships between power, voltage and frequency for the RLC load shown in Figure 5.3

$$P = \frac{E_{ac}^2}{R_{load}} \qquad Q = E_{ac}^2 \left(\frac{1}{\omega L_{load}} - \omega C_{load} \right)$$

If there is an active power mismatch between the inverter output and the load, the inverter output voltage load must change to achieve a balance. If there is an active power match, but a reactive power mismatch, the frequency (ω) must change to achieve a balance.

Since inverters monitor the voltage and frequency at their output terminals for control purposes, it is relatively easy to implement a passive islanding detection technique based on detecting whether the inverter voltage or frequency shifts outside a window centered around the nominal line voltage and frequency setpoints. However, if the local load is closely matched to the inverter's output power (active and reactive) at the time the island occurs, the voltage and frequency shift may be small or nonexistent and the island will not be detected.

The size of this non detection zone depends on the sizes of the voltage and frequency windows and on the design of the inverter controller. Current controlled inverters that use the control topology shown in Figure 5.4 have small non detection zones. They are constrained to operate at unity power factor and the output current follows changes in inverter output voltage, both of which are destabilizing factors that cause large excursions in frequency or voltage even with relatively well matched loads. Power angle controlled inverters, particularly if they have slow or loosely regulated reactive power control, have been shown to have larger non-detection zones [26]. However, tests on power angle controlled inverters that implement additional active islanding detection schemes have shown that they can meet stringent islanding detection standards [27].

Multi-mode control

Distributed generation systems may have more complex operating modes than simply supplying power to the distribution network. They can supply power to local loads when power from the distribution network is unavailable or expensive (stand-alone operation), they can store electricity from the distribution network for use at another time, or they may provide local power quality improvement through voltage regulation, reactive power compensation or active filtering to remove harmonics.

Power angle controlled inverters are attractive in applications where the inverter operates in both grid-tie and stand-alone modes, or where reactive power compensation of local loads is desired, since they can operate bidirectionally (inverter and rectifier operation) simply by changing the power angle, and reactive power control is built into the control scheme. Alternatively, control loops can be switched between current control and voltage control for grid-tie and stand-alone application [28, 29].

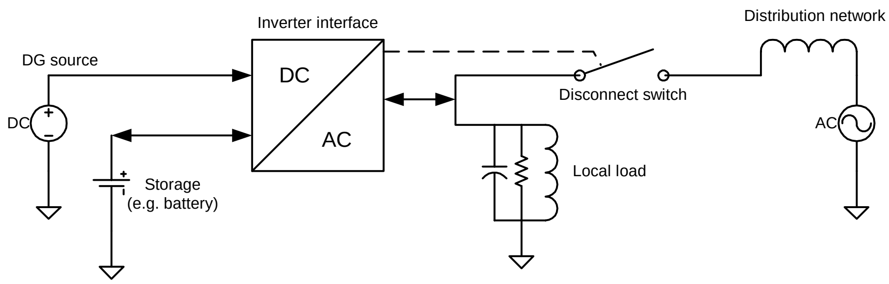

Figure 5.6: Multi-mode distributed generation system

The inverter control logic must ensure that appropriate protection functions are enabled, depending on the operating mode. This is relatively straightforward when the operating modes are either stand-alone or pure grid-tie. In stand-alone operation, the distribution network is physically disconnected at the point of common coupling from the local loads by an inverter controlled switch and the inverter operates in voltage control mode to supply local loads using internally generated voltage and frequency references. The disconnect switch provides protection against energizing the distribution grid and it may need to meet regulatory requirements for fail-safe operation.

When operating in grid-tie mode (i.e. inverter controlled switch connects the distribution network), the inverter is acting either as an inverter with normal anti-islanding protection enabled, selling power to the distribution network, or as a high power factor active rectifier, buying power from the distribution network to charge its storage system. Since operating modes are distinct (inverter or rectifier), application of islanding detection techniques is straightforward.

However, if the inverter is controlled to condition the grid power, the situation is more complex. For example, if the inverter provides reactive power to the local load so that the power factor at the point of common coupling is unity (no reactive power draw from the distribution network), then islanding is more difficult to detect since there will be no reactive power imbalance to force a change in inverter frequency if an island occurs and there are no other loads within the island. Similarly, inverter control schemes that provide local grid voltage support can make islanding more difficult to detect. Current standards for DG interconnect usually forbid voltage support and may also require that the DG operate at a fixed power factor close to unity. These requirements simplify the island detection problem and reduce the perceived risk of unintentional islanding with DG sources.

5.3 Inverter Resident Islanding Detection Techniques

Inverter resident islanding detection techniques have been an active topic of research for the past 15 years. Much of the research has focused on inverters for grid-tied solar power applications but the results are applicable to inverters used with other distributed generation technologies. The International Energy Agency Photovoltaic Power Systems Program has recently published a comprehensive survey of islanding detection methods for utility interactive photovoltaic power systems [30] that provides additional details on the methods briefly discussed herein.

5.3.1 Passive methods

Definition

Inverter resident passive islanding detection methods are similar to local passive methods used with synchronous generators. They monitor the voltage at the output of the inverter seeking to detect changes in a parameter, such as voltage or frequency, when an island is created. Since the inverter already monitors the terminal voltage for its own control purposes, adding passive islanding detection usually requires little additional hardware and can be implemented at low cost. A separate protective relay is not required.

Under/over voltage and under/over frequency detection

Inverter output voltage and frequency limits are universally required in grid-connected inverters to provide protection for customer equipment if the inverter voltage or frequency drifts. However these limits also provide islanding detection because the voltage or frequency will shift if there is a mismatch between the inverter output power (active and reactive) and the power consumption (active and reactive) of the local load when the island occurs. If the voltage or frequency shift drives the inverter to its detection limits, the inverter shuts down and the island has been detected. Many active islanding detection methods also attempt to drive the inverter voltage or frequency up or down when an island occurs and thus ultimately rely on these limits to detect the island and shut the inverter off.

However, this method will not detect an island if the local load is closely matched to the inverter output power, and the voltage and frequency shift is not sufficient to exceed the inverter voltage and frequency limits. These limits must be sufficiently wide so that the inverter can track normal fluctuations in grid voltage and frequency without shutting down. Typical standards for grid-tie inverters in North America (including Canada) require the lower and upper voltage limits to be set at 88% and 110% of the nominal grid voltage, and require the lower and upper frequency limits to be set at 57 - 59.3 Hz and 60.5 Hz [31].

The size of the non-detection zone (NDZ), in terms of active power mismatch (ΔP) and reactive power mismatch (ΔQ) between the inverter output (P,Q) and the local load ($P+\Delta P$, $Q+\Delta Q$), will vary depending on the inverter control strategy. Assuming a control strategy that maintains constant output power and synchronizes output current with output voltage (unity power factor), then the following relationships can be derived [32] :

$$\left({V}/{V_{\max}}\right)^2 - 1 \le \frac{\Delta P}{P} \le \left({V}/{V_{\min}}\right)^2 - 1$$

$$Q_f \cdot \left(1 - \left({f}/{f_{\min}}\right)^2\right) \le \frac{\Delta Q}{P} \le Q_f \cdot \left(1 - \left({f}/{f_{\max}}\right)^2\right)$$

where

V_{max}, V_{min}, f_{max} and f_{min} are the over/under voltage and frequency limits respectively, and

Q_f is the quality factor of the local load circuit and, if the load is modelled as a parallel RLC circuit, can be defined as

$$Q_f = R\sqrt{{C}/{L}}$$

For typical North American limits as given above (assuming f_{min} = 59.3 Hz), and assuming a Q_f of 2.5, the NDZ for under/overvoltage and under/over frequency detection is

$$-17.36\% \le \frac{\Delta P}{P} \le 29.13\%$$

$$-5.94\% \le \frac{\Delta Q}{P} \le 4.11\%$$

The results show that the NDZ is relatively large for active power mismatch. This detection method, with the usually prescribed voltage and frequency limits, has a smaller NDZ for reactive power mismatch. The reactive power mismatch NDZ is even smaller if Q_f is reduced. A Q_f of 2.5 was chosen for this example because that is the value specified by North American regulatory standards as a test condition for islanding detection circuits but it is considerably higher than would be expected for typical loads. These regulatory standards are currently undergoing revision, and the requirement for Q_f of the test load is being reduced from 2.5 to 1.0, to be more representative of actual conditions expected on a typical distribution network.

Voltage phase jump detection

This method is similar to the ROCOF and vector surge relay techniques used for islanding detection with synchronous generators. The inverter control system monitors the phase relationship of the inverter terminal voltage and output current for sudden changes. The inverter control system normally controls the output current to keep a very small phase difference between the voltage and current (unity power factor operation). A sudden change indicates that the distribution network is no longer maintaining the voltage at the inverter terminals and it has shifted in phase to match the phase angle of the local load.

A load with the same phase angle as the inverter at the time the island occurs (i.e. a matched load) will not produce a phase jump and islanding will not be detected. In practice, the non-detection zone is larger since a threshold for the magnitude of the phase jump must be set to avoid nuisance tripping of the inverter. Unfortunately the threshold must be relatively small (less than a few degrees) if the phase jump method is to have a smaller NDZ than that provided by over/under voltage and frequency detection. Phase jumps of this magnitude can occur due to transient conditions on the distribution network or in the local load (e.g. motor starting transient). Therefore it is difficult to achieve both effective islanding detection and a low incidence of nuisance tripping.

Detection of change in harmonics

In this method, the inverter controller monitors the total harmonic distortion (THD) of the inverter terminal voltage and shuts down the inverter if the THD exceeds a threshold. The rationale is that, in normal operation, the distribution network acts as a stiff (low impedance) voltage source, maintaining a low distortion voltage (THD $\approx$ 0) on the inverter terminals. Two mechanisms are expected to cause an increase in voltage THD when an island occurs. First, the impedance at the inverter terminals increases because the low impedance distribution network is disconnected and only the local load remains. As a result, current harmonics in the inverter output current will cause increased levels of voltage harmonics in the terminal voltage. Second, non-linear loads within the island, particularly distribution step-down transformers [33], will be excited by the output current of the inverter. The voltage response of the non-linear loads to the current excitation can be highly distorted.

This method has the advantage that it does not have a non-detection zone when the local load matches the inverter output power. However, it suffers from the same problem as the phase jump method: it is difficult to set a THD trip threshold that provides good islanding protection but does not cause nuisance shutdowns. Power quality standards require grid connected inverters to have relatively low current THD (< 5%) and the inverters are usually designed to have lower distortion than the standard to allow some margin. However, the distribution network voltage may have voltage THD of 5% or more if there are significant local non-linear loads on high impedance lines (such as long lines). In addition the distortion level may change rapidly as non-linear loads are switched on and off. Therefore it may not be possible to set a THD detection threshold that accommodates both the relatively low THD of the inverter current and the range of voltage THD that may be expected on the distribution network. An additional practical issue is that current testing standards for islanding detection specify use of linear RLC loads and do not allow for the effects of non-linear loads that might increase the voltage THD in an island situation.

5.3.2 Active methods

Definition

Inverter resident active islanding detection methods use the ability of the inverter to adjust its output current, voltage, or frequency to perturb the load circuit and then monitor the response to detect a change that indicates that the distribution network, with its stable voltage and frequency, and low impedance, has been disconnected.

Impedance measurement

Impedance measurement techniques attempt to detect the change in inverter output circuit impedance that occurs when the low impedance distribution network is disconnected. For example, some European anti-islanding standards require detection of a change in impedance $\Delta Z = 0.5$ ohm, which is regarded as the threshold for detection of an island. Several different techniques may be employed [34].

1. *Power variation*. The inverter perturbs its output current, which will cause a change in output power, and monitors the change in output voltage that results. Since it is monitoring dv/di, it is effectively measuring the load circuit impedance. The detection strategy may rely on driving a voltage change sufficient to trip the under/overvoltage limit, in which case relatively large changes in output current are required. Alternately, the detection strategy may look for smaller changes in voltage but it must then correlate them with the changes in output current so that it doesn't trip on random fluctuations in the distribution network voltage.

   Some drawbacks of this method that have been noted include the following:

   - Detection sensitivity is diluted if there are multiple inverters in the island and their output variations are not synchronized.

- Large variations in output power, particularly if there are multiple synchronized inverters, may cause noticeable voltage flicker and grid instability, particularly if the distribution feeder has relatively high impedance.

2. *Signal injection* The inverter periodically or continuously injects a known signal into the output current and monitors the terminal voltage response. For example, a current at a frequency different than the line frequency may be injected and signal processing techniques are then used to extract the voltage response. This has similarities to the passive harmonic detection method but has the advantage that it can be made less sensitive to noise and distortion on the grid.

   Some drawbacks of these methods that have been noted include the following:

   - Multiple inverters injecting the same signal may cause false trips or otherwise interfere with each other. It is possible to design the scheme to inject the signal periodically when no other inverter is detected injecting a signal in order to avoid this problem.

   - The local load may have very low impedance at higher frequencies, limiting the choice of signals that are effective.

   - To maintain power quality the injected signal must be relatively low amplitude, which then requires sophisticated signal processing techniques to extract the circuit response. This can be cost-prohibitive for inexpensive lower power inverters.

3. *Load insertion* The inverter can periodically connect a load impedance across its output terminals and monitor changes that occur. For example, a capacitor can be inserted across the output to increase the reactive current and the resulting phase shift in terminal voltage can be measured to calculate the effective line impedance [35]. This has similarities to the passive phase jump detection method but since detection of the phase jump can be correlated with the insertion of the impedance, it is more resistant to false trips due to random phase jumps in the grid voltage. As with other impedance measurement techniques, there are concerns about interference among multiple units and the ability to reliably detect impedance changes with practical values of the inserted load.

Frequency and phase shift techniques

These techniques apply positive feedback to the control loops that control inverter phase, frequency, or reactive power to cause the inverter frequency to rapidly shift to the under/over frequency detection threshold if the distribution network is not present to maintain the frequency.

Without this positive feedback, the inverter's frequency changes to a new stable operating point, largely determined by the resonant frequency of the local load, when an island occurs and the distribution network is disconnected. This operating point may be within the under/over frequency limits of the inverter if the load is closely matched to the inverter's active and reactive power output and the natural frequency of the load falls within the over/under frequency limits. The positive feedback introduces instability that drives the inverter frequency away from the resonant operating point towards one of the frequency limits.

These techniques can be very effective at detecting islanding. They typically have small non-detection zones (NDZ) and are relatively easy to implement within the inverter controls. Further, if the gains in the feedback loop are chosen in a consistent manner from inverter to inverter, interference among multiple inverters in a single island may be avoided.

These techniques have greatest difficulty detecting islanding when load quality factor Q_f is high, since a high Q resonant circuit is more resistant to attempts to force the operating frequency away from the resonant frequency. Considerable development work has been focused on analyzing the NDZ for these techniques and improving the techniques so they are effective with high Q_f loads [36,37,38,39,40].

Voltage shift techniques

Voltage shift techniques apply positive feedback to the current or active power regulation control loop of the inverter to cause the inverter terminal voltage to rapidly shift to the under/over voltage detection threshold if the distribution network is not present to maintain the voltage. Without this positive feedback, the terminal voltage changes to a new stable operating point, largely determined by the resistance of the local load, when an island occurs and the distribution network is disconnected. This operating point may be within the under/over frequency limits of the inverter if the load is closely matched to the inverter's active and reactive power output. The positive feedback introduces instability that drives the inverter terminal voltage towards one of the voltage limits.

The simple current controller shown in Figure 5.4 inherently has this positive feedback, since the output current reference is created by multiplying the measured output voltage by a current magnitude command. If the output voltage changes, the output current changes in the same direction. During normal operation, the low impedance distribution network controls the output voltage and reduces the effective gain of the positive feedback so that the inverter is stable. When an island is created, the effective gain of the positive feedback depends on the impedance of the local load, which is much higher than the distribution network impedance. A small fluctuation in the inverter output current will cause a change in terminal voltage that will drive the output current further in the same direction as the initial fluctuation, resulting in a larger change in terminal voltage. This will eventually drive the terminal voltage to the upper or lower limit. In practice, it is desirable to insert disturbances that reduce output current and drive the voltage towards the lower limit so that the inverter does not encounter power limits. As with the frequency shift technique, coordination of gains in the feedback loop from inverter to inverter can avoid anti-islanding interference effects in a multi-inverter island.

5.3.3 Current industry practice and trends

The islanding detection techniques adopted by inverter manufacturers are driven primarily by the need to comply with certification standards (see Section 5.4) in the jurisdictions where the products are sold, and by a desire to use techniques that are cost effective and not subject to nuisance tripping. Some jurisdictions, Germany for example, mandate a specific detection method (e.g. impedance detection). North American jurisdictions specify a test procedure for certification but do not mandate any particular detection method.

Inverter manufacturers typically specify compliance to islanding detection standards but do not normally disclose details of the techniques employed. Therefore it is difficult to make categorical statements about current industry practice. However, based on discussions with engineers familiar with current design practices, and on a recent survey of PV inverter technology [23], the authors believe that

a) Passive detection based on frequency and voltage limits is commonly employed and usually supplemented by other passive or active measures.

b) North American manufacturers generally employ various active techniques based on frequency, phase, or voltage shift.

c) European manufacturers, to gain access to the German market, use the ENS mains monitoring device mandated by German standards, or offer it as an option. This is supplemented by passive means such as rate of change of frequency detection or by active means, such as frequency shift.

d) Japanese manufacturers, to meet Japanese certification requirements, incorporate one passive method (beyond simple frequency and voltage limits), such as rate of change of frequency or phase jump detection and one active method, such as frequency shift or phase (reactive power) perturbation.

In general, as more experience is gained with islanding detection techniques, and standards are harmonized, it appears likely that standards requiring use of specific detection techniques will be replaced with performance based standards, allowing manufacturers more freedom to select cost-effective approaches and adopt newer technology.

5.4 Islanding Detection Standards and Testing Techniques

Common standards for performance of islanding detection techniques and testing procedures to verify the performance of the detection means in detecting islands are needed to reduce the obstacles to grid connection of distributed energy resources. National and international standards bodies have developed such standards and test procedures, initially for photovoltaic inverters but more recently for all DG sources that connect to low voltage portions of the distribution network.

5.4.1 Overview of issues

Standards developed in the early and mid 1990's often specify use of a specific detection method or the use of more than one detection method. For example the German standard [41] requires use of a "Mains Monitoring Unit" that incorporates both active impedance detection and passive over/under voltage and frequency detection as well as redundant disconnect means. Similarly, Japanese standards have required the use of at least one passive and one active method. However the current trend, led by North American standards activity, is to performance based standards that specify the performance of the islanding detection and disconnect means and the test procedure to verify performance, but do not call for use of any particular technique.

The performance standard normally specifies that the DG source must detect and disconnect within a specified time after an island is created, and that it can only reconnect after the grid reconnects to the island, and voltage and frequency have remained within normal limits for a specified time. The allowable time intervals vary among standards, depending on differing assumptions about the importance of rapid detection and disconnection to avoid interfering with the action of automatic reclosers.

Determining an appropriate test procedure to verify performance requires difficult trade-offs between the desire to provide adequate coverage for all possible application modes and types of islands and the need to have a repeatable test procedure that limits the time and cost required for testing. In order to gain consensus on a procedure and avoid requirements for time consuming and costly tests, such as simultaneously testing multiple inverters (not currently addressed by any standards), worst-case test conditions, that are unlikely to be encountered in real life, have often been chosen in the past. As more experience is gained with DG in the field and with actual rather than theoretical incidences of islanding, the trend in developing test procedures is towards more realistic test conditions that still provide a high degree of assurance that the DG will detect an island and disconnect.

5.4.2 North American standards

IEEE standards

The Institute of Electrical and Electronic Engineers has led the development of performance and test standards for islanding detection methods in North America. Its standards [42, 43] have been adopted by many utility DG interconnect standards, and by equipment safety standards for grid-tie inverters, used in North America.

The standards are performance based and define a "non-islanding" inverter as one that

> "will cease to energize the utility line in ten cycles or less when subjected to a typical islanded load in which either of the following is true:
>
> a) There is at least a 50% mismatch in real power load to inverter output (that is, real power load is < 50% or > 150% of inverter power output).
>
> b) The islanded-load power factor is <0.95 (lead or lag).
>
> If the real-power-generation-to-load match is within 50% and the islanded-load power factor is > 0.95, then a non-islanding inverter will cease to energize the utility line within 2 s whenever the connected line has a quality factor of 2.5 or less[2]."

This performance standard requires quick detection and disconnection for islands where there is a large mismatch between inverter output and load but allows more time for the case where load and inverter output are closely matched since islanding is more difficult to detect.

The test procedure makes use of a worst case condition in which the islanded circuit has a high quality factor (Q_f = 2.5) and is operated at resonance (unity power factor). The procedure requires a test in which inverter active and reactive power output matches the islanded circuit load when the utility source is disconnected.

UL/CSA standards

North American electrical equipment certification agencies, such as the Canadian Standards Association and Underwriters Laboratories, are harmonizing their standards [44, 45] for grid-tie inverters and are following the IEEE performance and test standards for islanding detection methods.

[2] IEEE is currently planning to lower this value to 1.0

5.4.3 Standards in other countries

A survey of national grid connection standards for photovoltaic inverters was published by the International Energy Agency in 2001 [46]. It shows considerable variation in standards for performance and testing of islanding detection methods. Standards range from requiring only basic passive over/under frequency detection and disconnection (Netherlands) to specifying specific active detection methods, test, and performance requirements (Germany). Some countries do not consider interference with automatic reclosers to be an issue and allow up to 5 seconds to detect an island and disconnect. Minimum reconnection delay times vary widely, from 5 minutes in North America to 20 seconds in Germany.

The lack of harmonization in the standards makes it more costly and time-consuming for manufacturers to develop and certify inverters or other DG equipment that can be sold into multiple markets. As a result, costs for inverters and other DG equipment are higher than they need to be.

5.4.4 Harmonization activities

Draft IEC standard

The first step towards international harmonization of islanding detection standards is an International Electrotechnical Commission draft standard for test procedures for inverter based systems [47]. It builds on North American, European, and Japanese procedures to define a standard test circuit and procedures that are similar to, but less demanding, than the North American circuit and procedure. Informative Annexes cover alternative procedures that match current German and Japanese practices.

5.4.5 Testing techniques

The test procedure for the IEC test requires an ac power source to emulate the grid (or the grid may be used) and a test load that remains connected to the inverter when the island is created by disconnecting the grid source. The procedure requires that the active and reactive power output of the inverter be matched to the test load so that no current at the line frequency flows in or out of the grid source prior to disconnection. Much of the IEC working group’s discussion centered on defining the test load circuit. It is generally agreed that a parallel RLC load tuned to the line frequency (resonant load) can be used as a worst case representation of an island load. It is believed that other loads are either less likely to create a non-detectable island (e.g. transformers and non-linear loads) or their effects can be duplicated with an RLC load with high quality factor. However, opinions on an appropriate value of quality factor Q_f for the RLC load vary.

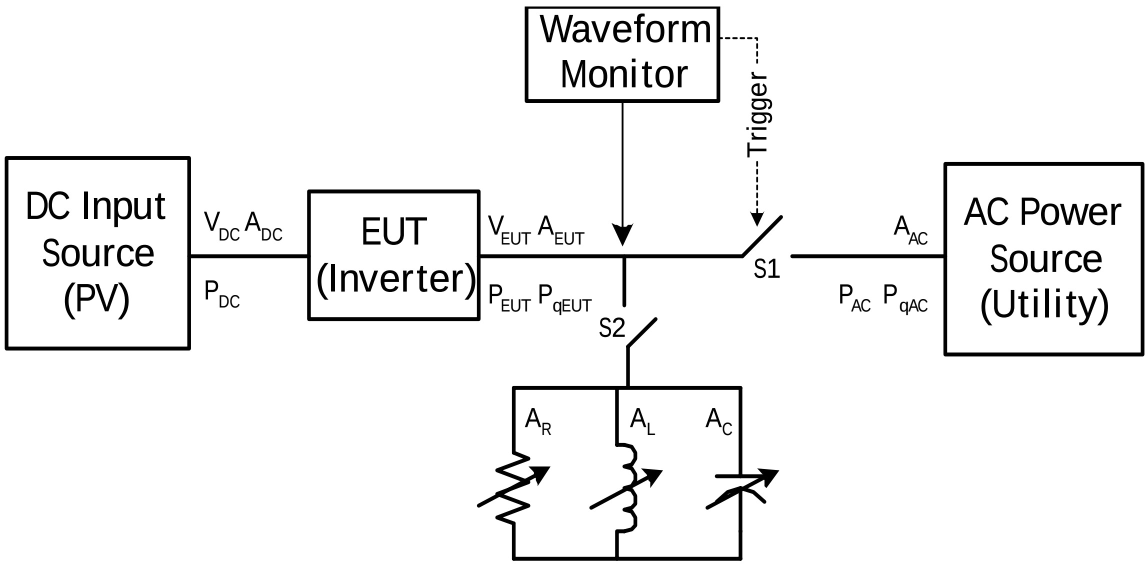

Figure 5.7: Test circuit for islanding detection function in an inverter (from draft IEC 62116)

Resonant load

The Q_f of 2.5 used in North America was originally proposed as the maximum realistic quality factor for a distribution grid that is completely power factor corrected with a compensation capacitor. It corresponds to an uncompensated power factor of about 0.37. This is viewed as overly conservative by many engineers involved in distributed generation [48] who believe a quality factor value below 1 is more realistic.

The proposed IEC test circuit shown above is similar to the test circuit specified in IEEE Standard 929-2000 but the required Q_f of the RLC circuit proposed in the draft standard is 0.65. The proposed IEC value for quality factor is closer to the quality factor of 0.5 required by the British islanding test standard. Lower load quality factor decreases the size of the non-detection zone of most islanding detection methods, therefore the proposed IEC test procedure should be easier to pass than the IEEE test procedure. Also, since it is easier to tune lower quality factor circuits, the test should be easier and quicker to perform.

Motor load

The parallel RLC load is generally accepted as an adequate model for the worst case island load. However, a controversy continues about the additional use of single-phase induction motors in the test circuit. Some engineers, particularly in Japan, claim that capacitor compensated single-phase induction motors with a high-inertia, lightly damped mechanical load (a bench grinder is a typical example) represent a load that is significantly worse for islanding detection. The Japanese islanding detection test circuit incorporates a motor load. Other engineers believe that the motor load can be modeled as a special case of the RLC load and have published studies to support their position [49]. A practical problem with including a motor load in the test circuit is that it becomes much more difficult to get repeatable results since even the proponents of motor loads admit that results are dependent on the make of motor and the characteristics of the mechanical load.

5.5 Multi-inverter and High Penetration Issues

Most research, development, and standards work on islanding detection methods for inverters has focused on single inverters. Often islanding detection methods were developed assuming that it was unlikely that other inverter connected DG sources would be within the same island since penetration of distributed generation was quite low. However there is now recognition that the islanding detection systems of multiple inverters within an island could interact unfavourably and that the likelihood of multiple inverters within an island increases as penetration of distributed generation increases. It is also recognized that the disturbances to the grid created by active islanding detection techniques may reduce power quality, reduce voltage stability, create voltage flicker, or create other problems as penetration increases.

At present there are few or no field reports, experimental results, or analytical studies to support the generalized concerns that are frequently expressed. However research projects on multi-inverter and high penetration issues are being initiated and concrete results that can be used to improve islanding detection methods can be expected in the next year or two.

5.6 Specific Research Needs

Research is needed to determine exactly what problems, if any, do occur with multiple inverter systems using identical or diverse islanding detection techniques. Possibilities that multiple inverters may reduce island detection sensitivity should be investigated. The effects of high penetrations of certain active detection methods on the grid should also be investigated.

There is a need to consider new islanding detection techniques that are effective, inexpensive to implement, and can be shown to work well in multi-inverter, high penetration scenarios. Current implementation of islanding detection schemes in products still relies on considerable experimentation, adjustment, and testing to make schemes work properly. Research on theory, design techniques and computer simulation methods that would allow straightforward implementation of islanding detection methods is needed. This will have to take into account real world effects of noise, quantization effects, and measurement errors.

Although considerable progress has been made on test standards for verification of islanding detection methods, the test procedures are time consuming, subject to differing interpretation, and require test loads that can be difficult to obtain for large DG sources. Test results are often difficult to replicate because results are sensitive to small differences in the test procedure or the characteristics of the test set-up. Further research and development of test procedures is needed.

CHAPTER 6 : DISCUSSIONS AND CONCLUSIONS

The various anti-islanding schemes have been reviewed in Chapters 3 to 5. It can be seen that none of the schemes is fully effective for a large number of applications. In particular, anti-islanding schemes for DGs using rotating machines to interface to the grid are less developed and currently less effective than anti-islanding schemes for DGs using inverters. Since rotating machine based systems will remain popular for many DG applications, particularly at higher power levels, anti-islanding protection may become a significant barrier for DG interconnection across the country. A national strategy is needed to address the problem. This subject is discussed in the following sections.

6.1 Anti-islanding Issues Significant to Canadian Systems

The characteristics of power systems have a significant impact on the requirements for, and the performance of, anti-islanding schemes. They should be taken into account when formulating the strategies to develop and apply various anti-islanding schemes. The Canadian power distribution systems and DG industry have the following distinctive characteristics:

- There are many renewable energy sources in Canada, such as small hydro, biomass, and others, which are relatively concentrated and suitable for large rotating machine distributed generators. As a result, synchronous and induction generators will remain the primary form of distributed generation for the foreseeable future.

- Many distributed generators will be located in remote areas due to the vast geography of Canada and the locations of renewable energy sources. This will limit the applications of schemes that rely on 3rd party telecommunication means such as radio since telecommunication coverage may not be readily available for remote locations.

- The majority of Canadian primary distribution systems operate with a radial network configuration. It is very important to explore this unique characteristic to reduce the cost of anti-islanding protection. On the other hand, many large municipalities use meshed secondary distribution systems due to historical reasons. The main issue for such systems is how to export power from distributed generators[2] in a meshed electricity distribution network.

- Anti-islanding technology for inverter based DG systems is much better developed, and published risk assessments suggest that the current technology and standards provide adequate protection while penetration of DG into the distribution system remains relatively low. However it is desirable to verify this risk assessment in the Canadian

[2] This problem is caused by the characteristics of the network protector.

context and ensure that utility safety engineers and others having influence on interconnect decisions are aware of these assessments and concur with the analysis. This will help ensure rational, low cost, and common interconnect standards in Canada. In the longer term, the following issues will need to be addressed:

- Active anti-islanding schemes may interfere with each other and become ineffective when DG penetration becomes higher. They may also degrade power quality and system stability as DG penetration becomes higher since many techniques inject a disturbance into the network in order to detect the island. These concerns have not actually been verified through experiment, analysis, or simulation. A program to assess the actual likelihood and magnitude of these problems and to identify solutions is needed.

- Current local islanding detection methods virtually guarantee that the DG will be unable to provide grid support or improve grid stability when the grid is stressed since the anti-islanding protection disconnects the DG when it detects voltage and frequency excursions on the grid. Communications based anti-islanding schemes that would allow disconnection decisions to be made by the system operator rather than by the DG controls would allow better use of DGs to support the grid and improve grid stability. A program to investigate how DGs can help support the grid and improve grid stability while maintaining adequate protection against unintentional islanding is needed.

The above characteristics suggest that anti-islanding protection for synchronous distributed generators is still the primary short-term concern for Canadian DG industry and supply utilities. Unfortunately, little information is available on the performances of the synchronous DG anti-islanding schemes. There is also a lack of knowledge on the probability of islanded operation. In comparison, a lot of work has been done for the anti-islanding protection of inverter-based generators including testing schemes [3] and risk assessment [18, 22]. After reviewing various works on the subject areas, this project considers the following issues are important for DG anti-islanding protections in Canadian systems:

- Understand the probability of islanding formation for typical Canadian distribution systems and the associated risks. Such systems have the following characteristics: long radial feeders with limited possibility of reconfiguration. Feeder reclosing is often used. The distributed generators, consisting of mainly synchronous and induction generators, are sparse but tend to have relatively large sizes.

- Understand the performance characteristics of key anti-islanding schemes when applied to typical Canadian systems. The work presented in reference [10] and cited in Section 4.1.2 is an example on how this could be achieved. It could be a starting point to cover other commercially available anti-islanding schemes such as voltage relays. The performance resulted from combined use of two or three schemes should also be assessed and quantified.

- Results obtained from the above two steps will help to establish the basis for developing new or adopting existing anti-islanding schemes for Canadian DG industry. If existing technologies are sufficient, an application guide could be developed. If they are not sufficient, the problems identified through this process will help to define research strategies to improve existing anti-islanding techniques.

6.2 Canadian Strategies to Reduce Barrier Caused by Anti-islanding Protection

Anti-islanding protection has become the single largest technical barrier for DG interconnection in Canadian distribution systems at present. The high cost associated with anti-islanding protection has made various environment-friendly DG proposals unattractive. It is the time to form a national strategy to deal with the barrier and to identify a low cost solution for Canadian DG industry.

Two complementary strategies are proposed to address this barrier. One is to develop a "Canadian Application Guide for Anti-islanding Protection of Distributed Generators". The guide would focus on the subject of <u>how to apply available anti-islanding technologies to existing systems</u>. The guide should cover the three issues outlined in the previous section and address additional issues such as verification of product performance and compliance to electrical codes. In summary, the application guide is expected to contain, but not to be limited to, the following materials:

- Probability and risk associated with the formation of DG islands;
- Performance characteristics of commercially available anti-islanding devices;
- The characteristics of Canadian systems that have important impacts on the performance of anti-islanding protection schemes;
- Industry experiences and application examples;
- Methods and procedures to evaluate and select proper anti-islanding schemes; and
- Test methods for performance verification.

The second strategy is to investigate if changes can be made to the existing distribution systems to reduce the barrier for anti-islanding protection. This proactive approach of <u>making distribution systems work in harmony with distributed generator</u> can be very effective to lower the cost of anti-islanding protection. It is also visionary in the sense that this could be one of the steps to create "DG-friendly" distribution systems. Here, the utility fault clearing practice is used as an example to illustrate this strategy.

As discussed in Section 2.2, feeder reclosing is a widely practiced fault clearing method in Canadian (and US) distribution systems. The method opens and re-closes specific breakers (reclosers) two to three times during a short-circuit fault. The intention is to re-connect the downstream system automatically if the fault can clear by itself. In this way, temporary faults will not result in the permanent lost of downstream customers. Because of the reclosing practice, anti-islanding techniques must trip DGs within about 200 milliseconds before the breaker is reclosed. Failure to do so will lead to out-of-phase re-energization of the DG. The reclosing practice will also result in many unnecessary trips of DGs due to temporary faults, leading to reduce utilization of renewable energy resources. One can easily see that if this practice is modified to fit the needs of distributed generators, it is possible to significantly reduce the technical challenge faced by anti-islanding protection schemes. The following are two example strategies to revise the practice:

- Eliminating the reclosing practice. In this approach, the faulted feeder segments will be disconnected by fuses or breakers once and for all. Consequently, there is no reclose to distributed generators. In this way, a lot more time will be available for anti-islanding protection. It is important to note that this strategy is not farfetched. Eliminating feeder reclosing has become an effective option to improve power quality in distribution systems [19].

- Single pole operation of reclosers. This scheme will only open and reclose the faulted phases. As a result, the DGs can maintain some connections to the system for the majority (70% to 80%) of fault conditions. The probability of islanded operation can be significantly reduced in this way.

The authors believe that the strategy of making utility systems DG-friendly will have more potential to bring significant benefits to Canadian DG and utility industries. In addition to complementing the first strategy, this strategy will promote a change on the perspectives of DG interconnection. The current distribution system has a lot of constraints to accept distributed generators. The various DG interconnection standards developed so far are focused on such constraints. Their goal is to make the DGs work in harmony with the existing systems. In the authors' view, this is a passive approach to the DG opportunity and it is time to deal with the constraints from an alternative and proactive perspective. This perspective is to create distribution systems that embrace distributed generators and work in harmony with them.

6.3 Conclusions

This report has presented a review on the status and performance of all major anti-islanding techniques. It appears that anti-islanding protection for synchronous generators is a more challenging problem in comparison with the inverter-based generators. Options are limited for synchronous generators. Among them the passive frequency-based relays are the most attractive option. Unfortunately, information on the probability and risk associated with the applications of frequency-based relays is almost non-existent.

The main issues faced by Canadian utility companies and DG industry are related to the anti-islanding protection of synchronous generators. This document has proposed two complementary strategies to address the problems. The first strategy is to develop a Canadian application guide on anti-islanding protection of distributed generators. This guide will recommend methods to apply available anti-islanding technologies to existing systems. The second and more important strategy is to change some of the practices in current distribution systems. This proactive approach of making distribution systems work in harmony with distributed generator can be a very effective way to reduce the barrier caused by anti-islanding protection.

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