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Status and Prospect of Islanding Detection in Active Distribution Network

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Abstract: A large number of distributed power sources are injected to the distribution network, which can cause island operation in planned or unplanned situations. The islanded operation caused by the fault will cause the inverter to go off the grid in serious fault conditions such as short circuit between phases and disconnection. After the island is formed, if the common connection point before the island exchanges more power, a sudden change in the voltage within the island occurs. The frequency and phase angle changes of the voltage in the island are closely related to the characteristics of the inverter phase-locked loop, and the frequency mutation generally does not cause sudden changes in frequency due to a certain inertia of the phase-locked loop. Due to sudden changes in load power angle, input fault ride-through, etc., sudden changes in the phase angle of voltage in islands may occur. In order to solve the possible problems of power quality deterioration in islands, passive, active, and remote islanding detection schemes can be adopted, and the three schemes have their own advantages and disadvantages. In actual operation, it is necessary to consider the cooperation relationship between island detection, protection, safe automatic control and fault ride through.

1 Introduction

With the rapid development of clean energy, a large number of inverter-type distributed energy sources, represented by photovoltaics (PV), are penetrating into the distribution grid, making the grid more active. After a substantial amount of distributed PV is integrated, the operation of the system can easily go into an islanding mode when it loses external power, a phenomenon that is frequently observed in field operations.

The reasons for islanding vary, and the mechanisms for changes in frequency and phase angle within the island after it's formed are complex[1,2]. Moreover, there's a lack of simple, dead zone-free, low-cost island detection principles and configuration methods that have minimal impact on existing secondary equipment. According to the standard 《GB/T 37408-2019 Technical Requirements for Grid-Connected PV Inverters》, PV based on the grid connection voltage level, can be divided into: Class A inverters connected to the public grid at 35kV and 10kV, and Class B inverters connected on the user side at 380V and through the 10(6) kV voltage level[3,4]. Class A inverters may not have islanding protection capabilities, while Class B inverters should have the ability to quickly detect and immediately disconnect from the grid, with the islanding protection action time not exceeding 2 seconds. This highlights the importance of island detection for inverter grid connection. However, there's currently a lack in the industry of a comprehensive summary and analysis regarding the causes of islanding, its operating mechanisms, detection methods, and their impact on protection systems, which hinders the further development of clean energy.

This paper first analyzes the causes of islanding, discussing both planned and unplanned reasons for its occurrence and their effects on island detection. It examines the changing mechanisms of voltage amplitude, frequency, and phase angle within the island. Building on this, it introduces the mainstream island detection methods and their coordination with existing protection and automatic systems, finally summarizing and looking forward to current island detection technology and configurations.

2 Causes and Issues of Islanding

As shown in Figure 1, in a typical 10kV distribution system with PV, based on different grounding methods of 10kV, it can be categorized into Low Current Grounding Systems (LCGS) and High Current Grounding Systems (HCGS). Taking the most widely used passive islanding protection as an example: islanding detection can be configured as an independent protection device that collects voltage at the Point of Common Coupling (PCC) and trips during islanding. The conventional criteria are line/phase over/under voltage, over/under frequency. It can also be integrated into the PV inverter, collecting AC side voltage. In addition to the conventional criteria, it generally also judges negative sequence over-voltage,

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and when conditions are met, it sends a pulse before tripping the contactor, commonly referred to as "machine tripping." Due to the presence of negative sequence suppression control, the PV inverter mainly outputs positive sequence components.

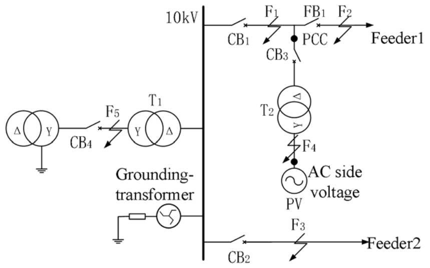

Fig. 1 Typical active distribution network structure

2.1 Causes of Islanding Formation

2.1.1 Planned Islanding

Planned islanding primarily occurs during maintenance when switch CB4 is isolated. Users expect the 10kV busbar to be de-energized. If, after disconnecting CB4, the PV on the feeder continues to back-feed power, then an energized 10kV busbar could endanger the safety of maintenance personnel. Users generally hope that after the switch CB4 is disconnected, all PV would automatically trip and not operate in island mode.

2.1.2 Unplanned Islanding

Unplanned islanding typically occurs due to faults leading to tripping, resulting in the loss of connection with external systems. Possible faults include single-phase grounding, phase-to-phase short circuit, three-phase short circuit, line breakage, etc. The fault may occur on the current line or on neighboring lines, among other locations.

2.2 Changes in Voltage Amplitude, Frequency, and Phase Angle within the Island

Whether it is planned or unplanned islanding, after the PCC is disconnected from the grid and the island is formed, the changes in voltage amplitude, frequency, and phase angle within the island are critical issues related to island detection and power quality. As shown in Figure 2 of a typical photovoltaic power generation system, after the formation of the island, the photovoltaic inverter, being the only power source within the island, dictates the changes in voltage amplitude, frequency, and phase angle.

During islanding, according to Figure 2, the voltage at the PCC $\dot{U}_{PCC}$ is equivalent to the voltage formed by the inverter's output current $\dot{I}_{inv}$ on the equivalent load impedance G(jω).

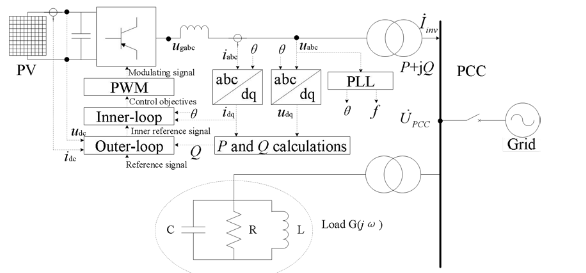

Fig.2 Typical PV power generation system

Ignoring the load branch circuit, transformer impedance, and only considering the fundamental frequency, we have the following formula:

$$\dot{U}_{PCC} = \dot{I}_{inv} \cdot G(j\omega) \tag{1}$$

$$\dot{I}_{inv} = \frac{u_{gabc}}{Z_g + G(j\omega)} \tag{2}$$

In the formula, $\boldsymbol{u_{gabc}}$ represents the fundamental frequency voltage output of the inverter, and $\boldsymbol{Z_g}$ represents the impedance from the inverter output to the PCC.

2.2.1 Voltage Amplitude Variation

Based on equation (1), The amplitude variation of $\boldsymbol{U_{pcc}}$ is closely related to the load characteristics. If there is a significant power exchange at the PCC before the islanding, a sudden change in $\dot{U}_{PCC}$ is very likely after islanding occurs. Even if the power exchange at the PCC is minimal or even zero before islanding, due to the fluctuations of photovoltaic and load, there might still be a possibility of sudden increase or decrease in voltage amplitude.

2.2.2 Frequency Variation

Based on formulas (1) and (2), the steady-state frequency of $\boldsymbol{U_{pcc}}$ is determined by the frequency of $\boldsymbol{u_{gabc}}$, and its phase angle is jointly determined by the phase angle of $\boldsymbol{u_{gabc}}$ and the load angle of G(jω). To determine the frequency and phase angle variations of $\boldsymbol{U_{pcc}}$, it's essential first to discuss the variations in the inverter output voltage $\boldsymbol{u_{gabc}}$.

The frequency and phase angle of the photovoltaic inverter's output voltage and current are closely related to the Phase-Locked Loop (PLL). PLL utilizes synchronization technology to ensure that its phase is in sync with the voltage at the sampling point, which is typically either the PCC or the low-voltage side of the isolation transformer. A commonly employed synchronization method is the Synchronous Reference Frame PLL (SRF-PLL). Its fundamental principle involves controlling uq to be zero in the dq coordinate system to achieve phase-locking. As illustrated in Figure 3, $\boldsymbol{R_g}$, $\boldsymbol{L_g}$, and $\boldsymbol{X_g}$ respectively represent the resistance, inductance, and reactance from the inverter outlet to the PCC, $\boldsymbol{I_{invd}}$ and $\boldsymbol{I_{invq}}$ are the direct-axis and quadrature-axis components of the inverter's output current, ω and θ are the angular speed and phase angle generated by the SRF-PLL, and $\boldsymbol{k_p}$ and $\boldsymbol{ki}$ denote the proportional and integral coefficients, respectively.

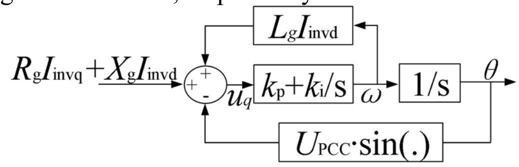

Fig. 3 Principle of SRF-PLL

Based on the SRF-PLL principle, when the tracking error of the reactive angle $\boldsymbol{u_q}$ enters the PI control, it inherently exhibits inertia characteristics. After the occurrence of an islanding event, an abrupt change in the external voltage UPCC will not immediately lead to a significant shift in the phase angle θ of $\boldsymbol{u_{gabc}}$. This suggests that the synchronization frequency and phase angle of the SRF-PLL change gradually, analogous to the trend in frequency and phase angle changes observed when a synchronous machine encounters an external fault. As illustrated in Figure 4, within the current inner-loop control, $\boldsymbol{i_{dref}}$ and $\boldsymbol{i_{qref}}$ represent the control target values generated by the outer loop, with $\boldsymbol{T_d}$ and $\boldsymbol{T_q}$ as the filtering constants, and $\boldsymbol{u_{gabc}}$ denotes the output voltage of the inverter. The phase angle θ produced by the SRF-PLL serves as the reference phase angle for generating the voltage $\boldsymbol{u_{gabc}}$ within the current inner loop. Based on Equations (1) and (2), it can be inferred that the steady-state frequency of $\boldsymbol{U_{pcc}}$ will not undergo abrupt changes. It's worth noting that, since the impedance angle of G(jω) correlates with the frequency, when the power factor of the inverter's output deviates significantly from the impedance angle of G(jω) at the fundamental frequency, a relatively large frequency offset from the fundamental frequency is required within the islanding area to achieve the control target.

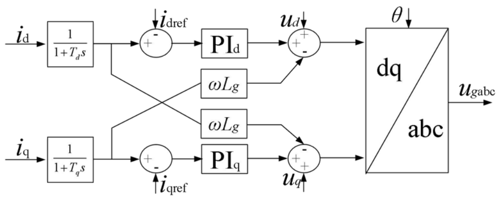

Fig. 4 Current inner loop control

2.2.3 Phase Angle Variation

Before the occurrence of islanding, the inverter operates according to the rated power factor, which implies that G(jω) in Equations (1) and (2) is close to being purely resistive. Once islanding takes place, G(jω) transforms into a local load. This could potentially result in a sudden change in the load power angle, subsequently leading to a sudden change in the phase angle of $\boldsymbol{U_{pcc}}$. Figure 5 illustrates the simulated waveforms of $\boldsymbol{U_{pcc}}$ and $\boldsymbol{I_{inv}}$ after islanding occurs at 0.8s. The figure contrasts the cases where the load power factor remains unchanged (as represented by $\boldsymbol{U_{pcc}}$ and $\boldsymbol{I_{inv}}$) and where it varies (as represented by $\boldsymbol{U_{pcc}}$-PFChg and $\boldsymbol{I_{inv}}$-PFChg). As evident, if there's a change in the load power factor following the onset of islanding, a noticeable sudden change in the voltage phase angle will occur.

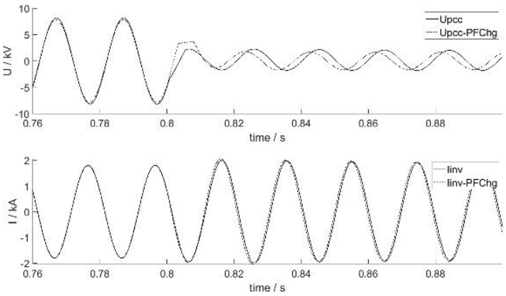

Fig.5 Effect of power factor change on the phase of PCC voltage and inverter output current

Moreover, the phase angle of $\boldsymbol{I_{inv}}$ is influenced not only by θ but also by the proportion of $\boldsymbol{i_{dref}}$ and $\boldsymbol{i_{qref}}$ (i.e., the power factor). If the inverter's output power factor remains unchanged after islanding, the phase angle of the output current won't undergo a sudden change. Otherwise, in scenarios such as low voltage ride through (LVRT), high voltage ride through (HVRT), and changes in the load power angle, alterations in the power factor can result in sudden shifts in the phase angle of the output current.

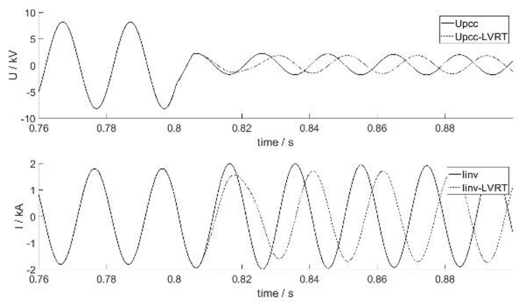

Fig.6 Effect of LVRT on the phase of PCC voltage and inverter output current

For inverters equipped with fault ride-through capabilities, upon entering fault ride-through mode, the target for voltage outer loop control gets locked by the LVRT/HVRT characteristic, and the current inner loop has minimal inertia[5]. As a result, the output current phase angle might undergo a sudden shift due to abrupt changes in the power factor. When the frequency remains constant, as per formula (1), it's easy to deduce that $\boldsymbol{U_{pcc}}$ will also exhibit a phase angle shift. Figure 6 illustrates the simulated waveforms of $\boldsymbol{U_{pcc}}$ and $\boldsymbol{I_{inv}}$ after islanding occurs at 0.8s, contrasting between scenarios without LVRT activation (as seen with $\boldsymbol{U_{pcc}}$ and $\boldsymbol{I_{inv}}$) and with LVRT activation (as represented by $\boldsymbol{U_{pcc}}$-LVRT and $\boldsymbol{I_{inv}}$-LVRT). It's evident that upon activating LVRT after islanding, there's a marked shift in both the voltage and current phase angles.

2.2.4 Conclusions on Voltage Amplitude, Frequency, and Phase Angle Changes within the Island

From the analysis, it is clear that after the onset of an island, there might be abrupt shifts in the voltage amplitude and phase angle within the island. The phase angle and frequency might either oscillate or diverge, leading to a deterioration of power quality within the island and posing threats to the safety of the power supply. Even under conditions like stable sunlight and fewer sensitive loads for consumers, there's a possibility that the island could operate stably for a certain duration. In such instances, while there might not be significant variations in voltage, frequency, or phase, there remains a risk of damaging consumers' electrical appliances.

3 Islanding Detection Scheme

From the previous analysis, it's clear that islanding operation can pose several challenges to operation, maintenance, and electrical safety. Therefore, it's essential to implement a reliable islanding detection scheme. The three primary islanding detection methods in the mainstream are passive, active, and remote.

3.1 Passive Detection Method

During an islanding event, electrical parameters such as frequency, phase angle, voltage, and harmonics within the island might undergo sudden changes. Passive islanding detection identifies islanding based on these observed shifts in electrical parameters. Common criteria for detection include over/under-voltage, over/under-frequency, Rate of Change of Frequency (ROCOF), Rate of Change of Power (ROCOP), sudden voltage phase shifts, and harmonic distortion rate.

3.1.1 Detection Principle

The principle behind passive islanding detection is straightforward and cost-effective. It has been widely employed in distribution networks integrated with Distributed Generation (DG). However, a significant drawback of this method is the potential for a non-detection zone. If, during islanding, the load is in equilibrium with the DG power output, the frequency, voltage, and phase angle within the island could remain stable for a certain duration. This stability leads to a failure in detection. The non-detection zone of passive islanding detection is associated with the load power factor[6-9]. Passive islanding detection becomes ineffective when conditions described by formulas (3) and (4) are met:

$$(U_{PCC0}/U_{\max})^2-1\le \Delta P/P_{inv0}\le (U_{PCC0}/U_{\min})^2-1 \quad (3)$$

$$M[1-(f_0/f_{\min})^2]\le \Delta Q/P_{inv0}\le M[1-(f_0/f_{\max})^2] \quad (4)$$

$$M=R\sqrt{\frac{C}{L}} \quad (5)$$

In the formula, ΔP and ΔQ represent the active and reactive power differences after the PCC is disconnected, and they can be considered as the active and reactive power transmitted by the PCC before the islanding. P_{inv0} is the active power output of the PV before islanding. $U_{\min}$ refers to the under-voltage protection threshold; $U_{\max}$ refers to the over-voltage protection threshold; $f_{\min}$ indicates the under-frequency protection threshold; $f_{\max}$ indicates the over-frequency protection threshold. U_{PCC0} is the PCC voltage before the islanding, and f_0 is the PCC frequency prior to islanding. M denotes the power quality factor of the load, with the load impedance being represented by the parallel model $G(j\omega)=R//j\omega L//1/j\omega C$. The IEEE expert group believes that the actual power distribution network load's power quality factor will not exceed 2.5. According to the IEEE Std.929-2000, the power quality factor of the islanding protection test circuit is set to 2.5, while both IEC62116-2008 and Q/GDW618-2011 require the power quality factor of the islanding protection test circuit to be 1.

3.1.2 Impact of Various Faults on Detection

Faults of different types and locations can have varied effects on islanding detection. The general process of islanding occurrence is illustrated in Figure 7.

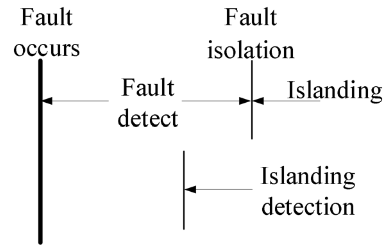

Fig. 7 Islanding process

Based on the various fault scenarios occurring at different locations in Figure 1, the islanding detection situation before fault isolation is shown in Table 1[10].

Table 1 Island detection before fault isolation

Fault Scenario	Islanding Detection Situation before Fault Isolation
F1, F2, F3 Single Phase Grounding	**LCGS**: Due to the isolation transformer T2, PV is unaffected by zero-sequence voltage; PCC might detect over-voltage in the non-faulty phase and trip. **HCGS**: Both PV and PCC might detect low line or phase voltage, resulting in trip-off and circuit breaker tripping.
F1, F2 Phase-to-Phase Short Circuit	PV might detect negative sequence voltage and trip; PCC might detect low voltage in the faulted line or phase and trip.
F1, F2 Three Phase Short Circuit	Both PV and PCC might detect considerably low line or phase voltage, eventually leading to trip-off and circuit breaker tripping.
F1 Line Break	During single or double phase line breaks, PCC might trip due to low line or phase voltage. For Δ/Y isolation transformer, PV might detect negative sequence voltage and trip. Three-phase line break equates to islanding; whether to trip or not depends on voltage and frequency changes within the island.
F2 Line Break	During single or double phase line breaks, the system might experience certain over phase voltage. Due to the existence of the isolation transformer, PV operates normally unless the PCC downstream line is too long or heavily loaded; otherwise, PCC is generally unaffected. A three-phase line break means

	PV loses contact with the load, having no impact on PV or PCC, but it might reverse the current flow of the main line.
F3, F4 Phase-to-Phase or Three Phase Short Circuit	Both PV and PCC might detect negative sequence voltage or low line or phase voltage, leading to erroneous circuit breaker tripping and machine trip-off.
F3 Line Break	Regardless of single, double, or three-phase line breaks, PV remains unaffected. If feeder 2 is lengthy or heavily loaded, it might cause certain over line or phase voltage. However, the possibility of PCC line or phase over-voltage is relatively low.
F4 Single Phase Grounding	**LCGS**: After single-phase grounding, the non-faulty phase rises to line voltage, leading to phase over-voltage trip-off; PCC remains unaffected. **HCGS**: Both PV and PCC might detect low line or phase voltage, resulting in trip-off and circuit breaker tripping.
F4 Line Break	Regardless of single, double, or three-phase line breaks, they all lead to trip-off; PCC remains unaffected.

It can be observed that, in the event of a severe fault on this line (two-phase, three-phase short circuit, line break, etc.), the PV will disconnect in a short time. In case of severe faults on other lines or within the PV itself, the PV might disconnect erroneously. Under LCGS, when a single phase is grounded, the PV does not disconnect.

3.2 Active Detection Method

To address the blind spots of passive islanding detection, some researchers have proposed active islanding detection by injecting small disturbance signals into the distribution grid. During grid-tied operation, these disturbances are absorbed by the system, with minimal impact on power quality. However, during islanding, the effect of these disturbances is amplified, and the passive islanding detection can then determine the islanding situation based on the magnitude of the disturbances. There are various active islanding detection methods, including Active Frequency Drift (AFD), Slide-mode Frequency Shift (SMS), and Reactive Power Disturbance method, etc[11,12]. The following introduces the principle of active islanding protection using the most typical Reactive Power Disturbance method, illustrated using a typical system in Figure 2.

The Reactive Power Disturbance method detects islanding by injecting imbalanced reactive power to disturb the system frequency. In Figure 2, based on the dq-axis transformation theory, the inverter voltage $\dot{U}_{PCC}$ and current $\dot{I}_{inv}$ are transformed to the *dq-axis* coordinate system to obtain U_d, U_q, I_d, and I_q, with $\dot{U}_{PCC}$ set in the direction of the *d-axis*. The relationship between I_d, I_q, and the PCC voltage frequency f during islanding is as follows[13, 14]:

$$\frac{I_q}{I_d}\cdot\frac{1}{2M}=\frac{f-f_n}{f_n} \tag{6}$$

In the formula, M represents the quality factor of the load impedance, and f_n stands for the resonance frequency of the load impedance. It is evident that when Id remains constant, the change in PCC voltage frequency (f) linearly correlates with I_q. Under normal operation of the inverter, the power factor is typically required to be close to 1.0, implying that I_q is set to zero. However, if I_q is not zero, indicating a demand for the inverter to produce reactive power, an islanding situation may lead to a system frequency offset due to unbalanced reactive power, thus detecting the island. In regular grid-connected conditions, the grid absorbs the imbalanced reactive power, preventing any frequency shift. The extent of frequency disturbance relates to the ratio of I_q/I_d and the quality factor M. When M is larger, a significant reactive power is needed to cause a noticeable frequency deviation, analogous to the meaning of formula (4).

Additionally, differing control strategies might lead to injecting disturbances into the grid connection point in opposing directions, causing a dilution effect where disturbances cancel each other out, resulting in a larger detection blind spot.

3.3 Remote Detection Method

The remote method for islanding protection involves islanding detection from the grid side. This primarily uses methods like the power line carrier communication method and topology identification method[15, 16].

The power line carrier communication method entails the installation of a signal generator on the grid side that continuously sends a weak signal. On the PV side, a local receiver captures this signal. If islanding occurs and the signal disappears, it is judged as an islanding event. Given the condition of achieving a certain signal strength, only one signal generator is required to detect islanding in high-density photovoltaics without any blind spots. Just like general carrier communication, this method has challenges, such as the signal being largely affected by the characteristics of load impedance and the continuity of power line impedance. There are adaptations where the power line carrier communication is transitioned to wireless communication, effectively sidestepping the limitations of carrier communication, but this comes at a significantly increased cost.

The topology identification method constructs a wide-area network using communication methods like optical fibers and wireless to collect information about switch positions, current, and voltage. A remote central processing unit, based on the topology identification algorithm, determines the occurrence of islanding. Common algorithms for topology identification include depth or breadth-first searches and the self-multiplication of full connection matrices. The topology identification method does not have dead zones or power quality issues. However, the response time and reliability are contingent on establishing a high-reliability and low-latency communication network, which can be quite expensive.

3.4 Comparison of Approaches

Table 2 compares the advantages and disadvantages of three islanding detection methods:

Table 2 Comparison of three islanding detection schemes

Method	Response Speed	Cost	Reliability
Passive	Average, depends on the rate of voltage frequency deterioration	Low, protection functions can be integrated into new energy interface devices or inverter controllers	Average, with dead zones present
Active	Fast, depends on load quality factor, etc.	Low, only requires changes to inverter control strategy, but significant impacts on power quality with large numbers of PVs	High, with smaller dead zones; multiple PVs might affect each other
Remote	Fast, depends on communication delay	High, requires communication channels	High, completely without dead zones

If PV inverters integrate both active and passive islanding detection methods, they can meet the islanding detection requirements in most cases. However, when the load quality is high or the load has complex nonlinear characteristics, there might be issues like prolonged islanding detection time and low sensitivity. Additionally, with the massive integration of PV and inconsistent controller control strategies, problems such as interference offsetting each other and decreased power quality may arise.

4 Integration of Islanding Detection with Other Secondary Functions

In an active distribution network equipped with islanding detection, it is essential to consider the coordination with existing line protection, transformer protection, reclosing, automatic-standby-switching, and other secondary devices. The general principle is that the integration of islanding detection should not impact the existing protection logic and actions. It is generally believed that inverters have a smaller current loop control inertia, meaning that after a fault, the inverter quickly enters a steady state, and the transient process only lasts a few milliseconds.

4.1 Coordination with Line and Component Protection

Based on the various fault scenarios that occur at different positions in Figure 1, it can be observed that during faults, PV might induce issues like external extraction, augmentation, and reverse fault currents. This requires validation of protection configurations and adjustment of set values. For the commonly used three-segment overcurrent protection in feeders: For overcurrent segments I and II, settings are typically based on short-circuit current in the minimum operational mode. The fault current provided by PV is limited and doesn't have a substantial impact; Overcurrent segment III might be set based on the load current under the maximum operational mode and a reliability coefficient. This setting might be affected by PV. However, considering that the overcurrent segment III generally acts as backup protection with a significant delay, augmentation generally wouldn't trigger overstepping actions. External extraction might cause non-operation under I and II segment failure scenarios, but the probability is low. Hence, island detection and overcurrent protection don't need special coordination.

In weak grid systems, if the load side of the line differential protection contains a high proportion of PV, the initiation of a phase-to-phase short circuit might lead to a lag in the phase angle of the fault current at both ends. This can affect the sensitivity of the differential protection and might even cause it to refuse operation. Given that fiber-optic differential protection serves as the primary protection and its action time is usually within 30ms, the low voltage ride-through time of PV generally exceeds this duration. Therefore, relying solely on island detection cannot address this issue.

For lines where reverse power protection is installed at the starting point, upon islanding, there's a possibility of power from within the island being fed back to the external load. In this situation, the island detection time should be shorter than the action time of reverse power protection to avoid expanding the power outage scope due to the operation of reverse power protection.

In small current grounding systems, single-phase grounding is the main type of fault. Grounding line selection devices based on transient principle are usually configured. Since the effect of inverter-type distributed power generation on transient processes is akin to that of large-capacity loads, PV won't influence grounding line selectors based on the transient principle.

For the issue where PV might cause over-voltage at the neutral point of the Y-side of the transformer, it's generally more severe in distribution networks with higher penetration rates. The island detection time should be less than the action time of transformer gap protection.

4.2 Coordination between PCC and Inverter's Built-in Islanding Detection

If an islanding detection device is installed at the PCC, there needs to be a coordination mechanism with the inverter's built-in islanding detection. Common coordination methods include segmented setting coordination, disabling the inverter's islanding detection, and no protection coordination. Here, not having protection coordination is recommended: in most actual sites, PCC islanding detection devices and inverter islanding detection do not employ coordinated measures. The rationale for not having protection coordination is that, during islanding, whether the inverter is disconnected first or the PCC switch is not crucial. Either disconnection doesn't affect the other islanding detection's judgment: if the PCC switch disconnects first, an island forms, and then the inverter's islanding detection acts, cutting off each inverter; if the inverter trips first, the PCC loses voltage, activating the low-voltage protection of the PCC islanding detection device.

4.3 Coordination with Low/High Voltage Ride-Through

According to the standard 《GB/T 37408-2019 Technical Requirements for Grid-Connected Photovoltaic Inverters》, Class A inverters must be equipped with a low/high voltage ride-through function (hereinafter referred to as **fault ride-through**). Inverter fault ride-through can maintain reliable grid-connected operation during system low/high voltage conditions without disconnecting from the grid (usually for the duration of fault reclosure), providing reactive power support for grid voltage stability. Since the electrical quantities of fault ride-through and islanding operation are hard to distinguish (fault ride-through might also experience frequency changes), inverters usually activate only one of either fault ride-through or islanding detection.

When the inverter engages in fault ride-through and the PCC has islanding detection, the islanding detection duration should exceed the fault ride-through duration. Otherwise, when islanding detection trips, the inability to output reactive power renders the fault ride-through ineffective. In this scenario, reclosure and backup auto-switching should adopt a no-check method. If a no-voltage check method is used, it becomes impossible to simultaneously satisfy the relationship of islanding detection being shorter than reclosure time, islanding detection duration being longer than fault ride-through duration, and fault ride-through duration exceeding reclosure time. It's worth noting that fault ride-through only makes sense before fault isolation. In islanding scenarios, injecting reactive power is similar to reactive power disturbance-based anti-islanding protection, only increasing frequency deviation. However, this indirectly boosts the sensitivity of islanding detection.

5 Conclusion and Outlook

The large-scale integration of distributed energy resources can lead to planned or unplanned islanding operations. Within these unplanned islanding scenarios, aside from the single-phase grounding in low current grounding systems, other severe faults could result in islanding detection actions or false triggers. After islanding occurs, the internal voltage, frequency, and phase angle may experience significant distortion. Specifically, if there's a considerable power exchange voltage magnitude at the Point of Common Coupling (PCC) before the fault, there will be a sudden change. The voltage frequency might gradually shift due to the inertia of the phase-locked loop, and the voltage phase angle could abruptly change because of variations in the load angle, fault ride-through, and other reasons. This underscores the potential deterioration in the power quality within the island. To address the above challenges, there are three islanding detection methods: Passive detection methods, which are straightforward in principle but have issues like detection dead zones and setting adjustments. The size of these dead zones relates to the power deficit at the PCC before islanding and load power factor; Active detection methods can reduce the dead zone to some extent, but they can also be influenced by different control strategies and interactions between inverters; Remote detection methods can overcome the aforementioned challenges, but due to their high costs, they are less commonly implemented in practice.When utilizing passive or active islanding detection principles, coordination with protection and automation systems is essential. This minimizes the impact on distributed energy sources related to transformer neutral over-voltage, reclosing synchronization, and fault self-healing. Additionally, the coordination with fault ride-through needs consideration. In such cases, if reclosing is configured, it should be set to unchecked, and the islanding detection time should be slower than fault ride-through.

Given the existing challenges in islanding detection, the following areas warrant further exploration: Adaptive passive islanding detection methods that can dynamically adjust settings based on the power deficit at the PCC before islanding, thus reducing the protection dead zone; Coordinated control strategies for active anti-islanding after a vast integration of distributed energy resources, aiming to synchronize interference injection across a wide area of distributed sources, resolving the problem of one diminishing as another increases; Research on islanding detection schemes based on weak communication, which can account for the impact on communication channels under fault conditions and reduce the construction and maintenance costs of remote islanding detection; Studies on the coexistence mechanism between fault ride-through and islanding detection on the inverter side. This involves considering the longest fault isolation time from the external grid and transitioning from fault ride-through to islanding detection, achieving an integrated local configuration of both fault ride-through and islanding detection.

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