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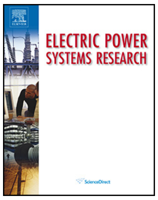

Fault current contribution scenarios for grid-connected voltage source inverter-based distributed generation with an LCL filter

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ABSTRACT

Inverter-based distributed generation (IBDG) is characterized by its negligible fault current contribution compared with synchronous generators due to its inherent non-overload capabilities. Thus, IBDG hardly affects the fault current level; this shadows the conventional protection schemes resulting in improper system protection especially with a high penetration of IBDGs at high power levels and/or in island operation mode. This paper presents an experimental investigation of two scenarios for IBDG fault current contribution under different fault conditions. In the first scenario, the inverter is controlled to produce zero output current or is disconnected upon fault occurrence, which is the case for most commercial grid-connected inverters. In the second scenario, the inverter contributes its rated current to the fault. The practical selection may be questionable and is affected by the fault level, employed protection scheme, and the penetration level of IBDGs. The introduction of double-loop proportional-resonant (PR) current controller is investigated using three case studies applying the previously described fault current contribution scenarios. The double-loop PR controller is found favorable when the inverter is designed to contribute its rated current to the fault. This conclusion is verified experimentally in this work.

1. Introduction

The number of grid-connected distributed generation (DG) units is gradually increasing in modern distribution grids. This corresponds to an increase in the amount of power delivered by these units. DG systems are typically connected to the public grid through power converters [1]. For example, strings of PV arrays require a DC–AC conversion stage to meet the grid voltage and frequency requirements. Similarly, the variable nature of wind energy systems implies that grid frequency and voltage requirements are not automatically met, therefore, an AC–DC–AC energy conversion unit is needed [2]. Current regulated voltage-source inverters (CR-VSI) are commonly used for parallel operation of VSI-to-grid and VSI-to-VSI. If properly designed, full control of both active and reactive power can be obtained in addition to acceptable total harmonic distortion of the injected grid current [3]. The use of power converters with switching frequencies in the range of 1–20 kHz produces harmonics that may trigger protection devices and disturb sensitive loads [4,5]. This is typically mitigated by the use of an output filter between the power converter and the grid. An LCL filter is an attractive solution to overcome the harmonics problem, as it introduces high attenuation with small-sized passive elements. This enables relatively low switching frequency converters to meet the IEEE 519-1992 standards [5,6]. Compared to a simple L filter, an LCL filter also provides better dynamics. However, the third order nature of the LCL filter introduces control design challenges due to obstacles related to filter resonance phenomena and the corresponding stability limitations [7–10]. Hence, the employed control system will significantly affect the overall system behavior during healthy and abnormal conditions. The connection of DG onto the low and medium voltage electricity supply networks can result in raised fault current levels leading to increased stress on network components [11]. This issue has been identified as a potential limit to the level of installed DG that may be integrated into existing networks. Fault current limiting (FCL) devices offer a means of managing this issue without the need for extensive network reinforcement [12,13]. The contribution of DG to network fault levels depends heavily on the employed technology [14]. In the case of directly connected rotating machines, the fault behavior is well established; with synchronous generators contributing higher fault levels than induction generators [14]. The synchronous generator passes through three stages during faults: sub-transient (0–50 ms), transient (50 ms to 1 s), and steady state (>1 s) [15]. The transient and steady state short circuit currents depend on the

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excitation system. Solid state excitation can be used for controlling and limiting the fault current. In induction generators, the magnetic excitation of the induction generator (IG) is fed from the power system. Short-circuiting the induction generator terminals causes loss of excitation, which results in a rapid collapse of the fault current. Currents decrease to an insignificant value after 100–400 ms, thus, IGs do not contribute to the steady state fault current [14]. The contribution of Inverter Based Distributed Generation (IBDG) to the system's fault current level is the lowest. The effect is, however, dependent on control design, which is one of the objectives of this work. The current of the IBDG depends mainly on the output power of renewable source at steady state. However, the output current of the IBDG in transient depends mainly on the voltage difference between the inverter and the grid voltage as well as the reactance of the LCL filter. Consequently, the controller bandwidth is responsible for the transient overshoot of the output current. Practically, the controller bandwidth is restricted by the measurement delays, noise, and the speed of the Digital Controller itself. Improper controller design could lead to malfunctioning of the distribution network's protection system, which is typically based on over-current protection devices [14]. The limited fault current contribution of IBDG coupled with a high penetration rate for these systems, can however, lead to an intolerable scenario from the power system perspective, as it may not be able to discriminate between healthy and faulty conditions during transients [1]. There is a body of literature exploring this problem and its solutions. In [15], dual-connection of FCLs is proposed when a new DG plant is connected to the electric grid. The proposed connection limits its fault currents to avoid disturbing the original protection relay schemes of the utilities. In [16], digital relays with a communication network are used to protect the micro-grid system and a new method for modeling high impedance faults is presented. This method requires a central controller to monitor the current and voltage differences and remotely operate the switching devices at the substation. Authors in [17] present a computational tool for determining the adjustments of all protection devices in the distribution network in the presence of DG. In [18], an agent-based protection scheme for distribution networks with distributed generators is proposed. Here, the distribution network is divided into several network segments. The direction of fault currents can be determined from the transients generated by the fault. In [19], an algorithm has been proposed for analyzing distribution networks containing IBDG. The proposed technique identifies which inverter goes into a current limit mode and predicts the fault currents and voltages in the network for both balanced as well as unbalanced faults. However, centralized communication and complex calculations are also required. In [20], the inverters are capable of terminating power delivery within the first few cycles subsequent to a fault by utilizing very sensitive, high precision, instantaneous over-current protection schemes supported by an under-voltage detection scheme. In [21], some possible control strategies, which an IBDG can adopt when running on fault conditions are discussed. This work targets compensation of active and reactive power oscillations, however it neglects the effect of multiple connected inverters. In [23], the fault current contribution of the IBDG has been discussed. Low voltage ride-through capability of IBDG showed that it could produce 1.2 times peak current for a period of approximately 7 cycles. But the effect on the distribution system protection scheme has been investigated. In [24], designing a robust DG interface featuring a fault-ride-through capability was considered. The IBDG's reaction to faults is highlighted in IEEE standard 929 [22], where voltage drop measurement due to a short circuit, rather than sensing the short circuit current, is recommended for short circuit protection. However, asymmetrical faults are difficult to be detected through a voltage drop measurement especially if the IBDG is interfaced to the grid through a delta/star transformer [1]. Moreover, faults on adjacent feeders create very similar voltage changes to faults on the IBDG feeder, hence, adding to the discrimination difficulty. The typical consequence is that IBDG is tripped out too often, which is a common criticism, especially when the IBDG is situated close to the substation. Protection devices and their coordination would need to be reconsidered to address this challenge. Moreover, establishing high-speed communication between generators and possibly central control may also be required. This is a costly endeavor that has motivated significant research into this topic. Appropriate control of IBDG is promoted in this work as an alternative, while maintaining current protection strategies. Fast and stable current control can be an alternative to hardware solutions such as additional directional relays or communication lines between sources to help resolve the discrimination difficulty and limit the fault current contribution during transients. In this paper, an experimental investigation into IBDG fault current contribution under different fault conditions is introduced. Two current controllers, namely, single loop and double loop PR controllers are compared. The comparison is done through three case studies that represent some problematic cases associated with power system protection. Two scenarios are proposed. Firstly, the inverter is controlled to produce zero output current or is disconnected upon fault occurrence. Alternatively, the inverter's current contribution to the fault is limited to its rated current.

Table 1
Experimental system parameters.

Grid line-to-line voltage	$E_n = 380\,\mathrm{V}$
Inverter output power	$S_n = 10\,\mathrm{kV\,A}$
Nominal DC-link voltage	$V_{dc} = 650\,\mathrm{V}$
DC-link capacitance	$1000\,\mu\mathrm{F}$
Frequency of the grid	$f = 50\,\mathrm{Hz}$
Switching frequency	$f_{sw} = 6\,\mathrm{kHz}$
Inverter side inductor	$L_i = 3\,\mathrm{mH}$
Grid side inductor	$L_g = 1\,\mathrm{mH}$
Filter capacitor	$C = 29.8\,\mu\mathrm{F}$
Filter resonance frequency	$f_{res} = 1\,\mathrm{kHz}$

2. Power system protection challenges associated with DG generation

With the proliferation of IBDGs in distribution networks, the impact of the IBDG fault current on the power system protection will be higher. Introducing DG units into a distribution grid affects its operation and negatively affects its protection schemes due to some problematic scenarios which are briefly described below [11–26].

2.1. Prevention of automatic reclosing

When a short duration fault occurs on a power line, as shown in Fig. 1(a), permanent line disconnection is not necessary. The automatic re-closer disconnects the line for a short period of time to allow for arc extinguishing, and then it re-connects again after a certain period. This process is repeated a specified number of times, after which the line is permanently disconnected if the fault still exists. However, with DG installed, the inverter may continue to energize the fault and the developed arc, which may convert the temporary fault to a permanent one even with the re-closer open. Hence, unnecessary line disconnection would occur [27].

2.2. Undesirable islanding

Islanding occurs when a portion of the distribution system is electrically disconnected due to maintenance or a permanent fault. In this case, the remaining loads are powered only from the DG units when present [28,29]. This raises concerns about the safety of