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Impact of the Penetration of Inverter-Based Systems on Grid Protection

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SUMMARY

Protection systems are designed to detect and isolate faults from power systems. Protection engineers are very comfortable with designing the protection systems for the grid and have been protecting a grid that has been dominated by synchronous machines for years. Today, the increased use of renewable energy resources such as wind and solar, which supply power via inverters, are being added to the grid. These types of resources are known as Inverter-Based Resources (IBR), and they add a new challenge to the protection of power systems. The fault contribution from a small percentage of IBRs may not have substantial impact on the grid and its protection, but a larger penetration will. The paper mainly focuses on the impact of IBRs directly connected to the Bulk Power system (BPS). The paper is organized to provide its audience with an awareness of the issues with low fault current contribution due to high penetration of IBRs and its impact on protection schemes. The first section of the paper presents the brief background of IBRs, including its fault current characteristics, inverter power electronics and controls, and the challenges associated with low fault currents on the system. The second section presents the analysis of grid protection schemes. Reduced fault current due to IBRs and their positions in the network will present challenges to protection elements, by requiring fault detectors to be set to very sensitive settings, if they are to operate at all. Such settings may then cause mis-operations on load currents. Each of the traditional protection schemes, including directional/non-directional phase and ground overcurrent, phase and ground distance (impedance), pilot and differential protection schemes is evaluated in terms of its effective application on low fault current systems caused by IBRs. Several unconventional protection schemes which can perform in IBR fed low fault current conditions, such as traveling wave protection, voltage-based detection techniques, and setting-less protection schemes, are evaluated. Devices to enhance fault currents, like synchronous condensers and uprated voltage source inverters, are also discussed.

KEYWORDS

Inverter based resources (IBR), Distributed Energy Resources (DER), Grid protection, Overcurrent, Low fault current, Impedance relay, Line differential, Voltage-Based Fault Detection, Synchronous condenser

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INTRODUCTION

Typical power systems consist of power plants, transmission systems, sub transmission systems, and distribution systems. The function of a power system is to deliver safe and reliable power to the customer, including residential, commercial, and industrial users. Protection systems are designed to detect and isolate faults from power systems. New generating sources, particularly renewable sources, mostly have inverters that convert the power from the energy source to the grid [1]. This is true for both Distributed Energy Resources (DER) that are connected close to the customer, and for large renewable projects, such as wind farms, solar projects, and battery storage systems connected directly to the Bulk Power System. Both are called Inverter-Based Resources (IBR). Generator types used with renewable sources include synchronous generators, induction machines, and inverter interfaced solar arrays. This paper will discuss, in depth, the impact of IBRs on fault currents and the protection system. These resources are rapidly replacing conventional generators. Most jurisdictions have goals for 100% renewable generation in 10, 20, or 30 years [2].

Inverter-Based Resources

Inverter-Based Resources (IBR) insert a power electronics interface between energy sources and the utility grid. Resources such as full ac-dc-ac inverter (type 4) wind turbine generators, photovoltaic (PV) generation, and battery storage type generation are common IBRs. To minimize the rating of the power electronics, and therefore the costs, IBRs are typically designed to limit current flow. Current flow limits are accomplished by the inverter controls. This means that IBRs provide minimal fault current contributions. The IBRs generally produce low fault current between 1.1 to 1.5 times the rated output current of the inverter or, for the power engineer, simply 1.1 to 1.5 per unit currents [1], [3]. The fault contribution from a small percentage of IBRs may not have substantial impact on the grid. However, a high penetration of IBRs adds more challenges to existing transmission system protection schemes. Unlike synchronous generators, IBRs have negligible or fast decaying fault current envelopes, as they lack magnetic characteristics of synchronous generators. Also, IBRs do not have a significant rotating mass component which prevents them from providing inertia to support the grid.

Fault current characteristics of IBR

The dynamic behaviors of IBRs are different from synchronous machines in terms of fault currents. IBRs do not have a stored electro-magnetic flux (EMF) and do not create a large fault current. IBRs also have negligible or fast decaying fault current envelopes, because they lack magnetic characteristics of synchronous generators and must limit fault currents quickly to avoid damage to themselves. Unlike synchronous machines they do not provide an inherent path for negative or zero sequence currents. The inverter can be designed (programmed) as voltage source inverter or current source inverter. However, in practice, voltage source inverters are used in utility scale inverter-based generators [1]. During faults, these voltage source inverters are seen as current source by the network since the inverter controls actively limit current output under such conditions [4].

The control strategy of the inverter system regulates the fault response of the IBRs. This control method varies among the manufacturers. They are basically designed to produce only positive sequence current during normal and fault (balanced/unbalanced) conditions. In [1], as shown in Figure 1, a simplified positive sequence, negative sequence and zero sequence equivalent of an IBR is presented for steady state fault level calculation. In the figure, IBRs can inject positive sequence current, negative sequence depending upon the switch control, and do not provide a path for zero sequence current.

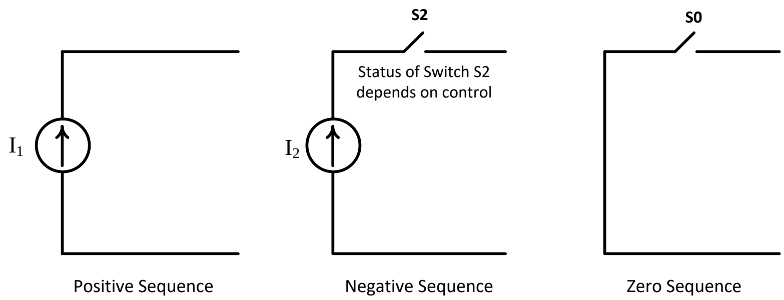

Figure 1: Simplified Sequence Diagram for IBR

Traditional Short Circuit Programs

Short circuit modelling assumes that the voltage source (EMF) is behind an impedance [5]. However, inverters cannot be represented as a voltage source behind the impedance [6]. Inverters are basically voltage controlled current sources during system faults. Reference [1] shows that most installed inverters provide a high impedance path to negative sequence currents. Furthermore, the short circuit algorithms used in commercial analysis assume that fault currents are much higher than load currents and, therefore, ignore load currents altogether. In North America, fault current calculations are most frequently made by one of two available commercial programs. At least one of these programs is also in widespread use internationally. From our experience, one of these programs is more advanced than the other in its progress toward accurate fault modelling that can be used by protection engineers [7]. However, at this writing its ability to provide quality fault current calculations in the presence of largescale penetration remains untested. According to reference [8]:

- Zero and negative sequence currents are suppressed
- The program assumes a particular structure for the low voltage to medium voltage transformers that may not be universally used
- There are no benchmarks tests for large cases. The main testing has been done on a small network consisting of a single IBR and a single synchronous machine equivalent
- Without infeed between the generator and the fault, the iterative solution may not converge
- Generators that do not converge are “disconnected.” The program uses a wide variety of heuristics to account for limits, like the controls in power flows. However, without the years of experience engineers have with power flow, there is no guarantee these will converge reliably

Finally, these models have yet to be widely integrated into existing utility scale short circuit models. Detailed studies of short circuit behaviors of IBRs can also be completed with Electro-Magnetic Transients (EMTP) type software. This is feasible for a small study area. However, inverter manufacturers have proprietary EMTP models which are not being provided to protection engineers on a scale necessary to complete system studies. Protection engineers are left to design protection systems without reliable knowledge of fault currents.

Inverter Power Electronics and Control System

An inverter is a power electronics device used to convert direct current to alternating current of desired magnitude and frequency. The main building blocks of the inverters are switching devices including Metal-Oxide Field-Effect Transistors (MOSFETs), Thyristors, and Insulated Gate Bi-Polar Transistors (IGBTs). Figure 2 shows a general structure of IBR. It consists of source side converter (SSC) and grid side converter (GSC). The GSCs are also called inverters. The SSC collects power from the source and generates dc voltage (V_{dc}) across the capacitor. The inverter draws dc power from the capacitor and converts it to AC power. In the figure, the inverter is connected to the grid via a transformer that meets the inverter and medium voltage system requirements.

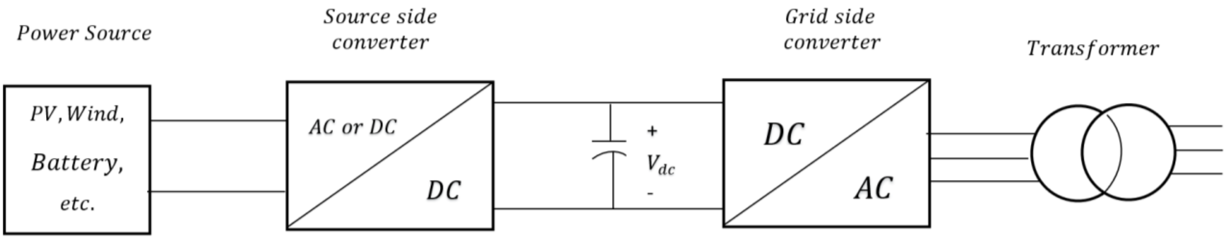

Figure 2: Typical IBR Structure

The output of the grid-tie inverter is controlled to match the phase of the grid and maintain the output voltage slightly higher than the grid voltage at any instant. If the inverter supply power is in parallel with the utility grid, it is called Utility-Interactive or grid connected Inverter [4]. Utility scale inverters use high DC input voltage in the range of 900 to 1000 V and AC output voltage up to 35 kV to reduce losses and the costs of the equipment [9]. To maintain the voltage and frequency to the grid, a multi-loop control method is applied as shown in Figure 3. The outer loop or the voltage control loop maintains the dc capacitor voltage and sets the reference for inner current loop. G_V and G_C are voltage and current regulators, respectively. The operation of the controls in dq0 and abc coordinates are explained in detail in case studies given in [10].

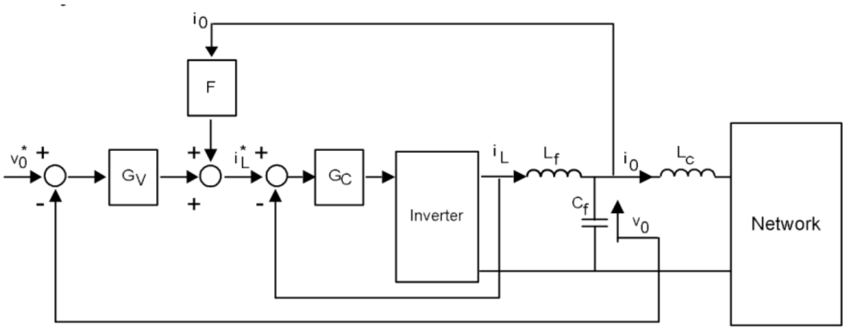

Figure 3: Multiloop Controls of Stand-alone Inverters [10]

ANALYSIS OF TRANSMISSION GRID PROTECTION SCHEMES IN RESPONSE TO LOW AND HIGH FAULT CURRENT

Short circuit currents and voltages are the basis (main input) for the relay to decide to send a signal to trip the circuit breaker (CB) or another kind of isolating device. The input for the relays is the measured data, such as voltage, current, and frequency acquired via secondary devices, such as current transformers (CT) and potential transformers (PT). Irrespective of the relay type (electromechanical or micro-processor based), the input data is processed and decision to trip (close or open of CB) is made based on the relay algorithm. Such algorithms are developed by the relay manufacturer and the setting engineer. In some cases, the relay needs to be set with delay to achieve relay coordination.

<u>Overcurrent Scheme</u>

In overcurrent protection schemes (directional/non-directional), the fault current magnitude is used by the relay to detect faults. If the magnitude of current seen by the relay is above a set value, the relay operates. Typically, the overcurrent element is set low enough that it can detect the minimum fault and high enough that it will not operate under full load conditions. For a phase fault, suppose a phase overcurrent element is set to pick up at 75% of the minimum fault current, which is above the full load condition, and if the same setting is applied to the element in the IBR dominated system with phase fault current levels around 1.1 – 1.5 per unit, the current pickup would be (=1.1*0.75), which is 0.825 per unit. This would cause the overcurrent element to pick up below load currents (1.0 per unit). Since the fault current contribution by the IBR is small, it is difficult for relay to differentiate between normal load or fault current. Hence, the phase overcurrent scheme is not dependable where there is high penetration of IBRs.

Setting negative and zero sequence overcurrent elements to detect unbalanced faults can be a challenge in systems with widespread IBRs. The typical IBR blocks negative and zero sequence currents [1] during unbalanced faults (Single-Line-Ground [SLG], Line-Line [LL], etc.) Thus, negative sequence elements would not be able to detect LL fault fed by IBRs. For SLG faults, a delta/wye grounded transformer near the relay position may provide a path for zero sequence fault currents, but due to low fault currents, ground currents will be small making the fault difficult to detect. Hence, the zero and negative sequence overcurrent schemes are not reliable in IBR dominated systems.

Directional Elements

Directional Elements are set in the relay to determine the direction of the fault in the system and provide security and selectivity. They are used to provide supervision for overcurrent and distance elements. Directional relays compare the phase shift between an operating quantity and a polarizing quantity [11]. To illustrate the basic principle of directional elements, for a symmetrical fault, if the current lags the fault voltage, then it is a forward fault. Otherwise if current leads, then it is a reverse fault. Here, the fault voltage is the polarizing quantity, and the fault current is operating quantity. Directional elements can use positive, negative, or zero sequence quantities to determine the direction of the fault.

In a network with mostly IBRs, the negative sequence currents will be low during faults. This will make operation of negative sequence directional elements difficult. Even with grounded transformers close to the relay to provide a ground current path, the zero sequence directional elements may face issues with insufficient zero sequence voltage and current magnitudes.

Impedance (Distance) Relay

Impedance relays work on the principle of sensing voltage and current at the relay position to determine the impedance to the fault and performing phase comparisons to ascertain if the measured impedance to fault lies within relay reach [12]. There are two types of distance relays in popular use – mho relays and reactance (quadrilateral) relays. Reactance relays require directional supervision from phase or ground directional elements, whereas mho relays are inherently directional [11], [12]. To determine the location of the fault, the mho impedance relays use a polarizing quantity and compares it with an operating quantity comprised of both fault current and voltage signals [12]. For self-polarized mho relays, the polarizing quantity is the voltage of the faulted phase. The drawback of this method is that for close-in faults, the voltage will be zero, and thus the relay will not work in the absence of polarization quantity. To get around this problem, different types of other polarization techniques, like memory polarization and cross polarization [12], [13] are employed. In memory polarization, the relay is polarized with the help of memorized pre-fault voltage. A side effect of memory polarization is that it causes expansion of the mho circle [12]. For a traditional system, the memory voltage vector lags the measured fault voltage by a small angle for forward power flows, and the reverse is true for backward power flows. This characteristic determines the resistive coverage of the relay during expansion, since it shifts the mho circle left or right depending on the direction of the power flow. In systems with a high penetration of IBRs, the angle between memory voltage and the measured fault voltage will be variable, since the phase angle relation will depend on the controls of the inverter instead of the inductive nature of synchronous sources [1]. Also, due to low system inertia associated with inverter-based sources, the frequency slip between the pre-fault system and faulted system may render use of memory voltage vector invalid. Self-polarized mho relays, on the other hand, will determine the direction of the fault correctly in systems with renewable sources, if fault voltage and current are of sufficient magnitude to make phase comparisons [1]. However, mho relays most probably will find the polarizing voltage magnitude to be too small to reliably process for comparison in the relay. This is because an IBR dominated system will have low short circuit strength (weak system) which will present a high source impedance behind the relay compared to impedance of the protected zone.

Most of the phase and ground distance relays are supervised by phase and ground fault detectors, respectively, which are set to pick up under fault currents. The fault detectors will face the same issues as overcurrent elements. This may cause load encroachment on the phase distance elements, which is undesirable. For ground distance elements, the unbalanced current magnitude may be close to the minimum current that the ground fault detectors can detect due to low negative sequence currents from IBRs.

Finally, since the inverter-based sources cannot be represented by a voltage source behind an impedance, like in traditional synchronous sources-based systems [5], [6], the assumption of the phase angle relationships between voltage and current used in distance relay logic to identify faults and its location on the impedance plane may not hold. The fault current from IBRs can lag the voltage at any angle, depending on the control settings of the inverter in contrast to the inductive nature of fault currents in traditional systems. Distance protection employing impedance-based relays will be unreliable in IBR dominated systems.

Pilot Schemes

Pilot protection schemes provide high speed detection of phase and ground faults for 100% of the transmission line, in contrary to step distance scheme, where it detects the fault around 80 to 90% of the line [14]. These schemes use a communication channel between the terminals to provide near instantaneous clearing of the fault. Some common pilot schemes applied to protect transmission lines are Directional Comparison Blocking (DCB), Directional Comparison Unblocking (DCUB), Permissive Over-reaching Transfer Trip (POTT) schemes, and Permissive Under-reaching Transfer Trip (PUTT). In all these schemes, the local relay will obtain the response of the distance relay at the remote end to speed up the process of decision making. Since the distance scheme is still the mainstay of the pilot schemes, they still face the issues related to polarization and fault detection, as mentioned in the preceding impedance relays section.

Differential Protection Scheme

Line differential protection schemes operate for phase and ground fault on the in-section fault quantity. The relay will still see enough fault current, even if the line terminals are weak sources due to IBRs. If the communication channels exist and are secure, this protection scheme will trip both the line terminal for any in section line fault and restrain for external fault [15]. The differential protection scheme is reliable and sensitive compared to other schemes.

REVIEW OF UNCONVENTIONAL PROTECTION SCHEMES TO ACCOMODATE LOW FAULT CURRENTS

As discussed in preceding sections, the fault currents in IBR dominated networks would be close to nominal load currents. Traditional transmission protection schemes, like time overcurrent, and impedance relays may not work properly under such conditions. There have been several alternative or unconventional protection schemes proposed to detect faults using various other system parameters in the absence of high short circuit currents [16], [17]. Furthermore, synchronous condensers have been put forward as likely candidate to improve the fault current level in a bulk electric system dominated by IBRs [18].

Traveling Wave Based Protection Scheme

Faults and other disturbance, like lightning produce traveling waves on transmission lines [5]. Travelling wave-based fault location and protection technique (TWFL&P) is a time domain technique, in which the characteristics and the timings between successive traveling waves can be utilized for locating the fault on a line and protecting it [19]. It can also differentiate between the characteristics like polarity of the traveling waves to make tripping decisions [20]. The traveling waves generated due to faults depends on the pre-fault voltage at fault point, characteristic impedance of the line and the wave propagation velocity [1]. As such, TWFL&P will be independent of the changes in the system parameters, like decreases in magnitude of fault currents and variable phase angle relationship introduced by large scale inverter-based generation. Thus, TWFL&P technology is uniquely suited for differential-type transmission line protection applications in systems even with 100% IBR penetration.

Voltage-Based Fault Detection Techniques

A fault in the system will cause depression of voltage on buses around the fault location. This would be true even in low fault current systems [16]. The basic idea of this detection technique is to convert the phasor voltages into two DC voltage signals on a synchronously rotating dq coordinate axis system using Clarke or Park transformations [21]. The converted DC voltage terms are then squared and summed to obtain a square of a constant voltage value. This voltage is then compared with a reference voltage to produce an error signal. If this error signal is greater than a predefined tolerance, then it would indicate the presence of a disturbance. Symmetrical voltage components can also be used to detect both balanced and unbalanced faults with this method [21]. Application of such methods require studies to understand the behavior of voltage across the system during various types of faults. This will help in setting a proper threshold voltage to detect a fault correctly and determine the zones of protection.

Synchronous Condensers

Synchronous condensers are synchronous machines without prime movers (i.e. unloaded synchronous motors). They produce high short circuit currents during faults [18] and contribute to voltage regulation and inertial frequency response which are difficult for IBRs to provide [22]. Voltage regulation and healthy system inertia is critical for maintaining system stability. As such, application of synchronous condensers in a transmission grid that is being increasingly penetrated by renewable resources has been gaining traction. They can also be modeled in traditional short circuit programs with a voltage source behind machine impedance unlike IBRs [5], [6], [22]. Optimal placement of synchronous condensers in a network with majority inverted based sources can improve the short circuit ratios at inverter terminals [22]. Thus, conventional system protection, like overcurrent and distance protection, and the short circuit study required for their settings, will be aided by the presence of synchronous condensers. The cost implications of installing and operating synchronous condensers in a power network is given in [23].

Setting-Less Protection

Traditional protection schemes have settings against which to make comparisons with monitored system parameters to determine fault conditions. These settings are sensitive to low fault current magnitudes. Setting-Less protection does not require any settings [17]. In this scheme, the data collected, like terminal voltages associated with the protected device, are fed into a dynamic state estimator to predict the state of the equipment. Under normal conditions, the data will satisfy the model equations and the equipment will be considered healthy. However, under fault conditions, the continuity of the physical laws like Kirchhoff Voltage Law (KVL) or rate of change of flux, will be violated. This would indicate a presence of fault in the monitored element and necessary tripping decisions can be made. This protection scheme can be considered as an extension of the differential protection scheme. Since this scheme looks for divergence in the predicted dynamic state and the measured parameters to declare fault condition, it will be immune to the low fault current effects and unconventional phase angle relationships between fault currents and voltages during faults in IBR dominated grids. There are several issues associated with Setting-Less protection scheme [17]. Some of the major ones are the high computation power requirement to implement dynamic state estimation calculations, availability of accurate models of the power component under protection, and the time required to make tripping decision. A limited field demonstration showcasing the scheme's capability was carried out in the New York Power Authority (NYPA) system [24].

Uprating of Power Electronics in the Inverter Circuits

A method to increase the magnitude of fault currents in systems with high penetrations of IBRs is using inverters with uprated power electronics capable of providing 3-5 times the nominal current [25]. Some inverters, like synchronverters, which implement synchronous generator equations in the control, can provide fault currents of up to 3.5 times load current for short time durations [26]. This solution can help overcurrent elements which are non-directional to function satisfactorily for protection of radial lines. Drawbacks include the high cost of manufacturing the uprated power electronics, and not addressing the polarization issues for directional elements and impedance relays in inverter dominated systems.

Modification of Inverter Controls

Inverter manufacturers could be required to program inverters to produce negative or zero sequence currents during faults [1]. Requiring grid connected inverters to have this capability have appeared in German grid code as a precondition to interconnection [27]. However, this scheme requires the inverter controls to recognize a fault and begin injecting appropriate currents. If the control can recognize a fault, a protective device might as well, trigger breakers and clear faults without adding to the inverter control.

CONCLUSION

Focusing on IBRs and their impact on grid protection, we reviewed and analyzed a variety of technical resources, including: technical papers, seminar presentations, transaction papers, conference papers, white papers, and user manuals. The behavior of IBRs are different from synchronous machines during faults on the system. The control strategy of IBRs regulates the contribution of the fault current. Presently, the control of IBRs generate limited positive sequence current during faults and block negative sequence and zero sequence components. This adversely affects the working of traditional protection schemes in terms of polarization, fault detection, and signal magnitudes. From our review and analysis, differential protection schemes and its variants are the only schemes which can work reliably in BES with a high penetration of IBRs, since they only need to see the fault current differences, provided that the communication channels are secure and reliable. The assumptions and the shortcomings of the commercially available short circuit models of IBRs are discussed in the paper. IBR models that can be widely integrated into existing utility scale short circuit models are still an ongoing research topic. Because protection engineers cannot rely on fault current calculations or the proper operation of many common relay schemes, a conservative approach is to specify differential protection whenever feasible.

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