Review and Evaluation of Control-Based Protection Solutions for Converter-Dominated Power Systems

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***Abstract*—With the rapid and massive increase of converter-interfaced resources (e.g. renewable generation, HVDC systems, etc.), the dynamic behavior of future power systems is expected to change significantly and will be predominantly determined by converters' control strategies. As a result, the performance of conventional protection schemes can be severely compromised due to the new and different fault characteristics introduced by converters. Recent studies reveal that, converter control could be designed in a manner, e.g. to intentionally inject certain fault signature or sequence components, that can effectively facilitate the protection operation, offering a promising solution to address the aforementioned protection challenges. While the control-based protection solutions have increasingly been investigated by the research community, there is no comprehensive comparison and evaluation of different proposed approaches. Therefore, this paper presents a comprehensive state-of-the-art review and evaluation of converter control-based solutions for addressing protection challenges, which covers approaches based on active signal injections, symmetrical component control, and integrated control and protection. Case studies of selected control-based solutions are presented, where the virtual impedance-based Grid-Forming (GFM) control is compared with dual-sequence current-based Grid-Following (GFL) control for distance protection, and it was found that GFM control can more effectively support the distance protection operation.**

***Keywords*—power system protection, converter control, grid codes, distance relay, converter-dominated power systems**

I. INTRODUCTION

Power systems are experiencing rapid transformation with a wide variety of new resources and technologies being integrated, e.g. Renewable Energy Sources (RES), High Voltage Direct Current (HVDC) transmission systems, Battery Energy Storage Systems (BESS), etc. [1]. As a result, power electronic converters will gradually replace Synchronous Generators (SGs), and conventional power systems are expected to evolve from SG to converter-dominated power systems. The massive integration of converter-interfaced resources can present unprecedented challenges for future power system protection due to the converters' different and diverse fault characteristics, which are typically dependent on the control strategies implemented. Therefore, it is crucial to understand the emerging protection issues in converter-dominated power systems, thus proposing effective solutions to address them.

As shown in Fig.1, the major challenges in the protection of converter-dominated power systems can be summarized and analyzed from the perspectives of fault characteristics, protection issues and system performance. In terms of fault characteristics, converters cannot produce large fault currents as SGs, owing to its limited over loading capability. Therefore, conventional protection strategies (e.g. overcurrent protection) dependent on the magnitude of fault currents will no longer be effective. The impact of different converter control schemes on impedance measurement in distance protection is thoroughly discussed in [2]. It is found that in certain converter control modes (e.g. constant reactive power and balanced current control), the fault impedance locus has discontinuous features, leading to a refuse-to-trip failure of distance relays. The negative-sequence component from fault current injected by converters is typically lower in amplitude and diverse in phase depending on different control modes of converters compared with SGs, which could also contribute to compromised protection operation [3].

Furthermore, for the distance protection applied in lines connecting converters with the main power systems still with many SGs, there will also be a large phase difference between the fault currents from both ends, resulting in large apparent impedance measurement errors and the false/sympathetic tripping [4]. Therefore, the apparent impedance cannot precisely reveal the fault distance between the relay measurement point and the fault location, so it can further cause loss of coordination between distance relays in transmission networks [5].

As a result of the potential compromised protection operation, the overall performance and security of future systems with large-scale integration of converters can be severely affected and challenged. For example, the failure in timely protection operation and low fault current could lead to severe wide-spread voltage depression [6], which can subsequently lead to undesirable resources tripping [7]. These also cause prominent damage to system-wide stability, e.g. control system stability, voltage stability and frequency stability [8].

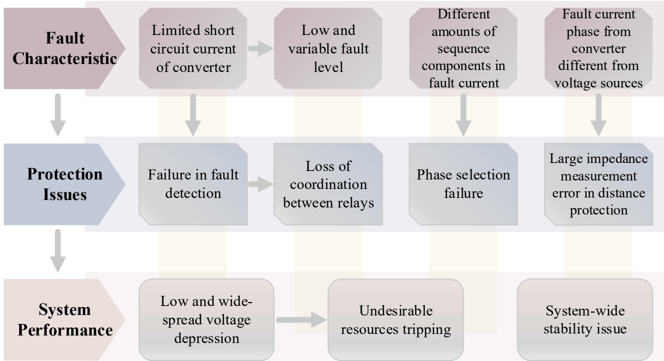

Fig. 1. Protection challenges in converter-dominated power systems

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As discussed previously, the different fault characteristics introduced by converters' control is one of the main causes for the risk of compromised protection performance. Therefore, there have been increasing research activities, focusing on the refinement of the converter control in order to support protection operation, which is referred to as control-based protection solutions [4, 9-14]. Recent studies have revealed that, converter control can be designed and implemented in a manner that can effectively facilitate the protection operation, offering a promising solution to address the aforementioned protection challenges [2-8]. While the control-based protection solutions have increasingly been investigated by the research community, there is no comprehensive comparison and evaluation of different proposed approaches. Therefore, this paper presents a comprehensive review and evaluation of converter control-based solutions for addressing protection challenges, which covers approaches based on active signal injections, symmetrical component control, and integrated control and protection.

The rest of the paper is organized as follows: Section II provides an overview of European grid code requirements for converters during faults; Section III presents a comprehensive review and evaluation of the state-of-the-art of control-based protection solutions; In Section IV, case studies are presented to illustrate the converter's impact on the conventional distance protection performance and how improved control can help to mitigate the negative impacts; Section V provides conclusions of the paper where the research gap and future trends on control-based protection solutions are also discussed.

II. Comparative Analysis of Grid Code Requirements for Converters during Faults

As discussed previously, fault currents contributed by converters are significantly lower than SGs, i.e. typically in the range of 1-2 p.u [15]. This could have major impact on the gird voltage support and protection activation. Furthermore, the control systems utilized in converters could have a strong sensitivity of grid voltage fluctuations. Therefore, a set of requirements for converters' behaviour during faults are typically imposed by system operators, which include Low-Voltage Ride-Through (LVRT), High-Voltage Ride-Through (HVRT), Fast Fault Current Injection (FFCI). In this section, a number of existing European Grid Codes are analyzed and compared [16-21].

A. Low-Voltage Ride-Through Requirements

LVRT refers to the capability of power generation modules and HVDC systems to withstand the voltage dip and remain connected to the grid for a specified period of time during grid faults. Therefore, LVRT capability is critical to minimize the risks of undesirable losses of power caused by grid faults. Different countries set out different LVRT requirements on basis of various factors, e.g. the penetration level of renewable generation, power quality and security standards. A summary of voltage sag and duration required in the LVRT curves of 6 European countries is listed in Table I and Fig.2.

TABLE I. LVRT / HVRT requirements in different grid codes

Country	LVRT (During Fault)		LVRT (After Fault)		HVRT (Voltage Swell)	
	T_{max}(s)	V_{min}(p.u.)	T_{min} (s)	V_{min}(p.u.)	T_{sw}(s)	V_{sw}(p.u.)
UK	0.14	0.15	2.5	0.85	-	-
Denmark	0.5	0.2	1.5	0.9	0.2	1.2
Germany	0.15	0	1.5	0.9	0.1	1.2
Ireland	0.625	0.15	3	0.9	-	-
Spain	0.5	0.2	1	0.8	0.25	1.3
Italy	0.5	0.2	2	0.85	0.1	1.25

For example, German grid code requires to ride through grid faults with the voltage depressed to zero for the maximum duration of 150 ms, followed by the voltage recovery to 0.9 p.u. after 1.5 s. The LVRT requirements in UK grid code are relatively less strict than Germany, where it demands to withstand the voltage drop to 0.15 p.u. for 140ms, and stay connected while the voltage level recovering to 0.85 p.u. after 2.5s .

B. High-Voltage Ride-Through Requirements

In recent years, HVRT requirements are gradually being included in the grid codes, particularly for new grid interconnection standards. Some serious condition can result in the grid overvoltage and voltage instability. For example, the short-term overvoltage might occur during single line to ground faults, variations in loads or generation units. Therefore, HVRT requirements are critical to ensure system stability during the aforementioned transient events.

Table I also presents the HVRT capability specified in 6 European country grid codes. The HVRT requirements imposed by Spain are the most stringent, which requires withstanding the voltage swell to 1.3 p.u. for 250 ms. Following by this, Italy grid code stipulates any power generation modules should accept the increase of voltage to 1.25 p.u. and be able to withstand this voltage level for a duration of 100 ms. Denmark and Germany grid codes require the same voltage swell of 1.2 p.u., but for different specific durations. However, some countries (such as UK and Ireland) that enforce LVRT standards have not implemented relevant HVRT requirements.

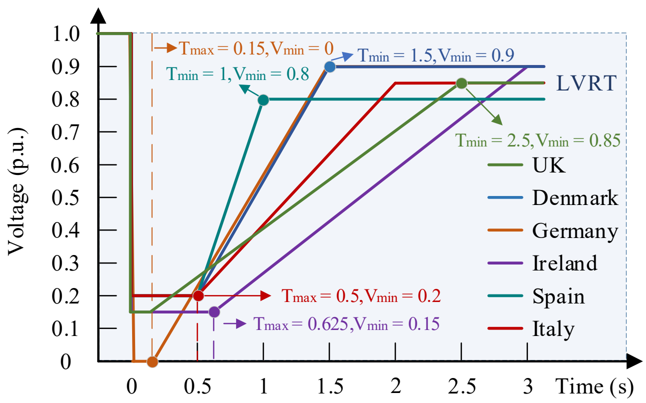


Fig. 2. LVRT requirement curves for different grid codes

C. Fast Fault Current Injection Requirements

FFCI is another vital requirement in the grid codes, which facilitates protection systems to detect fault and support system voltage during the faults and system voltage recovery following the fault clearance. Existing grid code requirements on FFCI vary significantly across European countries, which are summarized in Table II. In these grid codes, a dead zone setting is typically adopted, which is in the range of 0.9-1.1 p.u. of the Point of Common Coupling (PCC) voltage. When the system voltage drops below 0.9 p.u., power generation modules are typically required to inject reactive current proportional to the level of voltage depression. With respect to the injection proportion, for example, UK and Denmark require 2.5% reactive current injection for 1% PCC voltage depression, while German grid code requires 2% reactive current injection for 1% PCC voltage reduction.

The grid code also regulates the response time, including rise time and settling time. As shown in Table II, the longest response time duration of FFCI is 300 ms from Ireland grid code, followed by Spain, which has a requirement of 150 ms. However, UK and Germany grid codes require reaching 90% of steady-state value within 60 ms. It should be noted that, except for Germany, most grid codes are presently lack of specific requirements of negative-sequence current injection. Existing research has revealed that the lack of negative sequence component in most existing grid code requirements can lead to risk of protection failure [22] and issues with overvoltage in healthy failure during unbalanced faults [13]. Therefore, it is expected that wider and more detailed requirements for negative sequence current injection will be more common in different countries' grid codes.

III. Review of Control-based Protection Solutions for AC Grids

While researchers have put significant efforts in developing new protection methods suited for converter-dominated system, there has been increasing research activities, focusing on the improvement/refinement of the control of converters to facilitate the protection operation. In this section, a comprehensive review of the existing control-based protection solutions for AC grids is provided, which can be categorized in three main types: 1) active signal injections; 2) symmetrical component control; 3) integrated control and protection. Table III and IV individually summarize the aforementioned different types of control-based protection schemes, as well as their main features, applicable scenarios and systems.

A. Active Signal Injections

Currently, most of the existing protection schemes utilize the dynamic grid measurements to detect and identify fault occurrences, which can be considered as passive methods as they are purely dependent on measurements from the grid, e.g. voltage and/or current features during faults and there is no active control of converters involved. In contrast, active signal injection protection schemes, as presented in [9-11] and summarized in Table III, intentionally control the converters to inject specific signals when faults are detected (typically based on the depressed voltage level), with which protection systems can analyze the signals injected in order to understand the fault types, locations, etc. For AC grids, single or multiple harmonics have been typically used as the injected signals.

A harmonic time-current-voltage directional relay for protection coordination without the need for communication in inverter-based islanded microgrids is proposed in [10]. Once detecting faults, a third harmonic voltage generator is superimposed on the droop controller of Inverter-Interfaced Distributed Generators (IIDGs). Then, two decoupled layers (i.e. harmonic and fundamental layers) are introduced in the proposed relay during faults, so as to measure harmonic components as the trip condition. Similarly, [11] utilizes the fifth harmonic injection and detects faults in accordance with harmonic components. However, relay coordination issues determined by bidirectional power flows in microgrids are not fully considered.

In addition to the aforementioned research activities, multiple harmonic injection represents new developments for the active signal injection method. Injecting a specific and assigned harmonic to each IIDG individually is implemented in [9], in order to identify faults without communication between relays in the islanded microgrid. However, it is inevitable to deploy with harmonic injection modules in IIDGs control loops and harmonic component analysis algorithm in relays. Active signal injection-based protection methods can be intentionally developed with unique fault signatures generated by converters, independent of the fundamental fault current and voltage [23]. These features can potentially defend against low and variable fault levels. However, injecting single or multiple signals during faults might introduce risk of damage to sensitive loads in power systems [24]. Furthermore, this method will require an aligned approach for design of converter control and protection, which is not always easy in practice.

B. Symmetrical Component Control

In three-phase AC power systems, voltages and currents can be represented by positive, negative and zero-sequence components. These symmetrical components provide intuitive way for understanding and analyzing power system dynamic behaviour. During different types of fault, different combination of sequence components will typically present. Therefore, in recent years, many researchers have been focusing on development of controllers that inject specific symmetrical components during faults to facilitate protection operation.

An active phase control strategy to address the large phase difference between the fault currents from both ends is proposed in [4], in order to avoid the mal-operation of the distance relay. It only utilizes local measurements to calculate the phase difference, and then aims to eliminate it via the adjustment of the positive-sequence current in the converter side. However, the influence and applicability of different control strategies are not taken in consideration. Similarly, [12] presents a dual current control strategy, in order to emulate the current angle feature of SGs during all types of faults. This method can enhance the performance of distance protection against fault resistance in the power systems dominated by converters, but converter controllers fail to meet the local grid code requirements due to the need to adjust the power factor during faults.

Furthermore, an enhanced control scheme that injects negative-sequence currents during unbalanced faults via exploit the induced negative-sequence voltages is proposed in [13]. This method facilitates the system voltage recovery after fault clearances and effectively refrain from protection mal-operations. Additionally, it can avoid replacing or upgrading a large number of existing relays in case of using appropriate symmetrical component control schemes of converters. However, the issue associated with balancing the requirements between protections and grid stabilities (e.g. voltage support/recovery) still remains unresolved.

C. Integrated Control and Protection

The foregoing control-based protection solutions mainly focus on different signal injections and symmetrical component features, whereas the other control-based protection can utilize the modification of the power references of the control system to achieve multiple-stage control strategy and improve protection performance in converter-dominated power systems. For example, [14] presents a two-stage control strategy to enable precise phase selection. In stage 1, the converter controllers will switch to balanced current control in the event of fault occurrences. After the system enters fault steady state, the converter controller will transfer to stage 2 via changing the power references. Then, a novel superimposed control network is created based on the subtraction of control networks under stage 1 and stage 2. Therefore, the phase angle characteristics of sequence superimposed currents and voltages are analyzed in the proposed control network, and the phase selection criteria is built according to these components. The proposed phase selection scheme is not ruled by converter natural features and directly reflects fault characteristics of the transmission lines. Furthermore, it also provides a novel perspective to address these protection challenges in converter-interfaced sources. However, this control strategy can merely be implemented and tested in the Type IV wind turbines currently.

TABLE II. FFCI REQUIREMENT IN DIFFERENT GRID CODES

Country	PCC Voltage (p.u.)	Response Time (ms)	Current type	Injection amount
UK	0.5-0.9	Rise time≤20 Settling time ≤60	Positive-sequence	2.5% injection for 1% PCC voltage dip
Denmark	0.5-0.9	Rise time≤100	Positive-sequence	2.5% injection for 1% PCC voltage dip
Germany	0.5-0.9	Rise time≤30 Settling time ≤60	Positive-sequence Negative-sequence	2% injection for 1% PCC voltage dip
Ireland	0-0.9	Rise time≤100 (0.9 p.u.) Settling time ≤300	Positive-sequence	At least proportional to the voltage dip
Spain	0-0.9	Rise time≤150	Positive-sequence	0.2% injection for 1% PCC voltage dip during 0 – 0.5 p.u. of PCC voltage 0.857% injection for 1% PCC voltage dip during 0.5 – 0.85 p.u. of PCC voltage 6% injection for 1% PCC voltage dip during 0.85 – 0.9 p.u. of PCC voltage

TABLE III. PROTECTION SCHEMES BASED ON ACTIVE SIGNAL INJECTION

Ref.	Type	Main Feature	Test System	
			Voltage / Capacity	Achieved Fault Clearance Time
[10]	Single harmonic	• Generate the third harmonic voltage by IIDGs during faults • Develop harmonic time-current-voltage characteristics of overcurrent relays	12.47 kV 2 MVA	0.292 s - 1.653 s
[11]	Single harmonic	• Inject fifth harmonic and identify faults by harmonics • Be independent of high fault current magnitudes	380 V 13.6 kVA	0.110 s - 0.285 s
[9]	Multiple harmonic	• A communication-free active unit protection • Inject assigned harmonics into individual IIDGs • Detect and isolate faults by harmonic analysis	11 kV 500 kVA	0.6 s - 0.92 s

TABLE IV. PROTECTION SCHEMES BASED ON ACTIVE SYMMETRICAL COMPONENT CONTROL

Ref.	Type	Main Feature	Test System	
			Voltage / Capacity	Achieved Fault Clearance Time
[4]	Positive sequence current	• Calculate phase differences between fault currents from both ends using local measurements • Regulate positive-sequence currents to eliminate phase difference	35 kV 6 MW	25 ms
[12]	Negative sequence current	• Propose a dual current control scheme • Emulate the current angle signature of SGs during faults in the positive- and negative-sequence circuits	138 kV 80 MVA	-
[13]	Negative sequence voltage	• Exploit the induced negative sequence voltages • Facilitate controlled injection of negative sequence currents during asymmetric AC faults	320 kV 1200 MW	-

IV. CASE STUDIES

A. Overview of the Case Studies

This section presents case studies to further evaluate the impact of converters on the conventional distance protection performance, and illustrated how refined control strategy can facilitate protection operation. The test system used in the case studies are shown in Fig. 3. Two cases are investigated: 1) the fault infeed from one end is a GFL converter that uses the dual-sequence current control strategy [25], which allows the independent control of the positive-sequence and negative-sequence components; 2) the converter control is replaced by the virtual impedance-based GFM control scheme [15], which aims to emulate voltage source behaviour by virtually controlling the source impedance of GFM converter. It should be noted that, the aforementioned cases can be classified into the symmetrical component control-based protection.

The details of the test system are presented in Table V, and the key settings of the modelled distance protection are provided in Table VI. Furthermore, Table VII presents the list of case studies under different fault conditions, including fault types, fault locations, and fault resistance values. It should be noted that, the fault level at converter PCC and the capacity of converters studied in GFL case and GFM case are individually installed at 1500MVA and 500MVA. Therefore, Short Circuit Ratio (SCR) of the test system is equal to 3. In general, it can be regard as a weak system [25], so that the above cases are conduced to evaluate converters' performance in weak power systems.

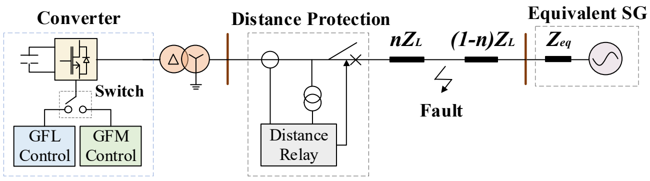


Fig. 3. Schematic of the test system investigated in case studies

TABLE V. PARAMETERS OF THE TEST SYSTEM

Parameters	Description	Values
V_s	Nominal system voltage (kV)	275
P_s	Converter rated capacity (MVA)	500
L	Protected line length (km)	12.1
K_v, K_c	Voltage/Current Transformer (CT/VT) rations	2500:1, 1200:1
R_1, R_0	Per-unit positive/zero sequence resistance (Ω/km)	0.0378, 0.159
L_1, L_0	Per-unit positive/zero sequence inductance (mH/km)	1.324, 3.202
C_1, C_0	Per-unit positive/zero sequence capacitance (nF/km)	8.964, 6.48

TABLE VI. SETTINGS OF THE DISTANCE RELAY

Parameter Description	Relay Settings
Protection characteristic	QUAD
Reach setting	Zone 1: 80%, Zone 2: 120%
Residual compensation factor	$K_0 = 0.48\angle{-6.4°}$
Time delay	Zone 1: 0 ms, Zone 2: 400 ms
Right/Left resistive reach (primary side of CT/VT)	14 Ω, 3.5 Ω
Directional/Tilt angle	30°, -3°

TABLE VII. INFORMATION OF THE TESTED FAULT CONDITIONS

Fault Conditions	
Fault resistances	2 Ω, 6 Ω
Fault locations	Zone 1: 15%, 30%, 50%, 70%, 80%
	Zone 2: 85%, 90%, 95%
Fault types	AG, AB, BCG, ABC
The above fault conditions are tested in all cases	

B. Simulation Results and Analysis

a) Overview of distance protection performance:

The test system as shown in Fig.3 has been implemented in MATLAB Simulink to conduct systematic tests of the fault scenarios presented in Table VII for all cases. In total, there are 128 tests conducted for evaluating the distance protection performance. Among these, Table VIII and IX individually demonstrate the simulation results of the distance relay performance in the investigated cases during 2 and 6 ohms. Furthermore, the detailed criteria for evaluating the distance protection performance based on whether the fault is detected successfully in the correct zone. The overall performance of the distance relay during all the tested fault conditions in the investigated cases is shown in Table. X. It's shown that 46.88% of the tested cases can correctly detect faults in the protective zone. Compared with the overall performance of GFL and GFM control, GFM control seems to effectively facilitate the distance protection. The ratio of correct fault detection in GFM control can reach to 62.5%, rather than 31.25% in GFL control.

TABLE VIII. SIMULATION RESULTS OF THE DISTANCE RELAY PERFORMANCE IN THE INVESTIGATED CASES DURING 2 OHMS

Fault type	Fault location	GFL	GFM	Fault location	GFL	GFM
AG	15%	√	√	80%	√	√
	30%	√	√	85%	●	●
	50%	√	√	90%	●	√
	70%	√	√	95%	●	√
AB	15%	×	√	80%	×	√
	30%	×	√	85%	×	●
	50%	×	√	90%	×	●
	70%	×	√	95%	×	●
BCG	15%	√	√	80%	√	★
	30%	√	√	85%	●	√
	50%	√	√	90%	●	√
	70%	√	★	95%	●	√
ABC	15%	×	√	80%	×	√
	30%	×	√	85%	×	●
	50%	×	√	90%	×	●
	70%	×	√	95%	×	●

"√" represents the fault detection in the correct zone;
"×" represents the fault detection failure in the protective zone;
"●" represents the issue of fault detection in zone 1 for zone 2 fault;
"★" represents the issue of fault detection in zone 2 for zone 1 fault.

TABLE IX. SIMULATION RESULTS OF THE DISTANCE RELAY PERFORMANCE IN THE INVESTIGATED CASES DURING 6 OHMS

Fault type	Fault location	GFL	GFM	Fault location	GFL	GFM
AG	15%	√	√	80%	√	√
	30%	√	√	85%	●	●
	50%	√	√	90%	●	●
	70%	√	√	95%	●	●
AB	15%	×	×	80%	×	√
	30%	×	×	85%	×	●
	50%	×	×	90%	×	●
	70%	×	√	95%	×	●
BCG	15%	√	√	80%	√	★
	30%	√	√	85%	●	√
	50%	√	√	90%	●	√
	70%	√	★	95%	●	√
ABC	15%	×	×	80%	×	√
	30%	×	√	85%	×	●
	50%	×	√	90%	×	●
	70%	×	√	95%	×	●

TABLE X. THE OVERALL PERFORMANCE OF THE DISTANCE RELAY DURING ALL THE TESTED FAULT CONDITIONS IN THE INVESTIGATED CASES

Types of distance protection performance	GFL case (all tested fault conditions)	GFM case (all tested fault conditions)	All the investigated cases (all tested fault conditions)
Correct fault detection	31.25%	62.5%	46.88%
Fault detection failure	50%	6.25%	28.12%
Fault detection in the false zone	18.75%	31.25%	25%

As shown in Table VIII and IX, the distance relay in GFL case and GFM case have compromised performance in some fault conditions. Overall, with the increase of fault resistance values, there are fault detection failures of the distance relay in the protective zone, especially for phase-to-phase faults and three phase faults. For example, in the event of 6 ohms AB fault, the faults at different locations cannot be correctly detected in the protective zone of the distance relay in GFL case, whereas the relay in GFM case can complete the correct fault detection in the 70% and 80% of the protected line. However, for zone 2 faults, there is one case with the fault being detected in false zone, i.e. the measured impedance locus appeared in zone 1. For zone 2 faults, the percentage of fault detection failure or moving to the false zone is higher than zone 1 faults. Among these, 50% of the tested GFL cases are faced by the issue of fault detection failure in the distance relay. For GFM cases, the measured impedance locus cannot move to the correct zone in the 31.25% of tests.

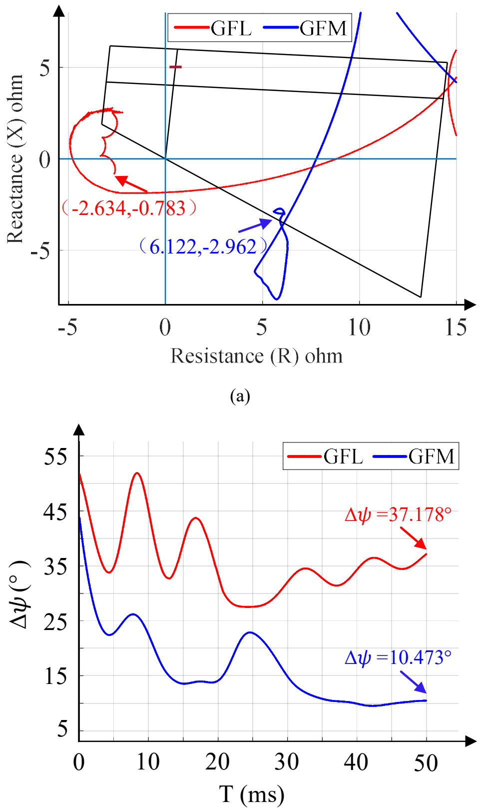
b) Comparative analysis of the distance protection performance in GFL/GFM control:

To evaluate the impact of GFL/GFM control strategies on the distance protection performance for zone 1 and zone 2 faults, a group of the cases are shown and analyzed in details as shown in Table XI.

TABLE XI. THE INFORMATION OF THE STUDIED CASES

Cases	Types of converter control schemes	Fault conditions	Fault types
1	GFL	6 Ω, 70%, AB	Zone 1
2	GFM	6 Ω, 70%, AB	
3	GFL	6 Ω, 95%, BCG	Zone 2
4	GFM	6 Ω, 95%, BCG	

The impedance locus measured by the distance relay of Case 1 and Case 2 are plotted in Fig. 4 (a). It is shown that, for zone 1 faults, the distance relay in Case 2 can detect faults as the measured impedance locus moves into zone 1, whereas the measured impedance locus in Case 1 is on the reverse side of zone 1 area. As shown in Fig.4 (b), there is the larger angle deviation of the infeed currents from both sides of the protected line in case 1 rather than case 2. As discussed in [25], the under-reach issues can be found in the distance protection, when the angle deviation (i.e. $\Delta\psi$) is between 0° and 180°. On the contrary, there are the over-reach issues in the distance protection as the angle deviation is from 180° to 360°. Therefore, the distance relay in case 2 fails to detect faults due to the under-reach issue introduced by the large angle deviation of the infeed current.

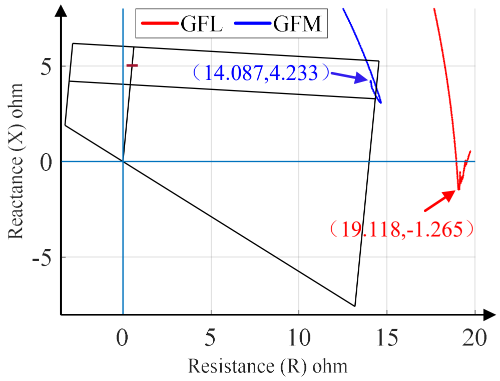


(a)

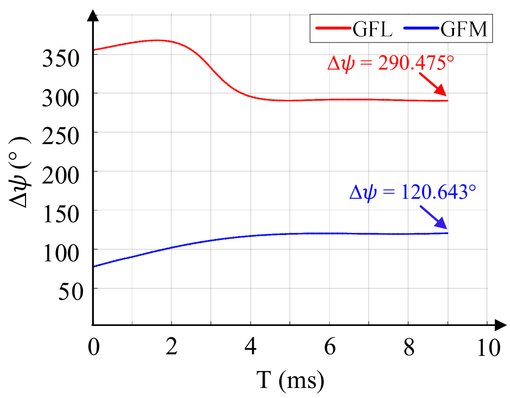
(b)

Fig. 4. Simulation results of case 1 and case 2, (a) the measured impedance locus by the distance relay, (b) the angle deviation of the infeed currents from both sides of the protected line

For zone 2 faults, Fig. 5 (a) presents the measured impedance locus on the 95% of the protected line in Case 3 and Case 4. The measured impedance locus in Case 4 is located at Zone 2 protective area, but the measured impedance locus in Case 3 is far beyond the protection zone border. As shown in Fig.5 (b), the large angle deviation causes the over-reach issue in Case 3, resulting in the fault detection failure. However, for Case 4, there might be the under-reach issue because the value of $\Delta\psi$ reaches to 120.643°. As shown in Fig. 5 (a) and (b), as a result of this angle deviation, the measured impedance locus in Case 4 moves beyond the right resistance reach border at the beginning of fault occurrence, then quickly moving to the zone 2 protective area. Therefore, the virtual impedance-based dual current GFM control scheme seems to more effectively facilitate the distance protection.



(a)



(b)

Fig. 5. Simulation results of case 3 and case 4, (a) the measured impedance locus by the distance relay, (b) the angle deviation of the infeed currents from both sides of the protected line

V. Conclusions

Different fault characteristics generated by converters' control is one of the main factors for the compromised protection performance. Appropriate converter control strategies can effectively facilitate the protection operation, and address the aforementioned protection challenges. This paper has presented a comprehensive review and evaluation of converter control-based solutions for addressing protection challenges, which covers methods on a basis of active signal injections, symmetrical component control, and integrated control and protection. Case studies of selected control-based solutions are presented, where the virtual impedance-based GFM control is compared with dual-sequence current-based GFL control for distance protection, and it was found that GFM control can more effectively support the distance protection operation.

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