Received: 28 September 2024 | Revised: 7 November 2024 | Accepted: 14 November 2024

IET Generation, Transmission & Distribution

DOI: 10.1049/gtd2.13338

The Institution of Engineering and Technology WILEY

ORIGINAL RESEARCH

Advanced voltage relay design for distance relay coordination in power networks equipped with low-inertia areas

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Funding information
Deanship of Research and Graduate Studies at King Khalid University, Grant/Award Number: RGP2/238/45

Abstract

In modern power systems with high levels of distributed generation (DG), traditional protection schemes face challenges in ensuring reliable and efficient fault detection due to the complexities introduced by DG, particularly low-inertia sources such as wind power. This paper presents an advanced protection scheme that integrates voltage relays (VRs) rather than overcurrent relays (OCRs) to improve coordination with distance relays (DRs) and enhance fault detection across multiple protection zones. By utilizing voltage measurements instead of conventional current-based methods, the proposed scheme addresses issues such as low fault currents and mis-coordination, which are common in DG-integrated systems. The VR-DR coordination improves system reliability by increasing fault detection sensitivity and selectivity, reducing the risk of mis-coordination, and minimizing reliance on potentially inconsistent current measurements. VRs trigger faster fault isolation by operating before backup DRs, thus improving overall response times and system resilience. The VR scheme significantly outperforms traditional overcurrent relay schemes, with tripping times ranging from 0.002 to 0.956 s, compared to 0.035 to 1.184 s in the traditional scheme for three-phase faults in a CIGRE power network. Additionally, the total tripping time is reduced from 10.5 s in the traditional scheme to 3.2 s with the VR scheme in networks with DGs under line to line to ground fault. The study demonstrates that no mis-coordination events occurred with DRs in zone two, further emphasizing the effectiveness and reliability of the VR scheme. This innovative approach offers substantial improvements in fault management, ensuring quicker fault resolution and enhanced system stability in modern, DG-integrated power grids.

1 | INTRODUCTION

1.1 | Motivation

The reliability and stability of transmission lines in modern power systems are essential, requiring advanced protection strategies to ensure rapid fault detection and clearance. Distance relays (DR) serve as the primary protection for transmission lines due to their fast response times, while directional overcurrent relays (OCR) act as backup protection. Proper coordination between DR and OCR is crucial to maintain the integrity of the system, especially at critical fault points where time margins are narrow. However, the integration of distributed generation (DG), such as solar and wind energy, introduces new challenges. DG can reduce fault current levels, particularly with inverter-based systems, complicating the coordination of protection devices and potentially triggering unnecessary outages. This complexity necessitates frequent adjustments to relay settings to address changing grid conditions, as failure to do so can disrupt coordination and compromise system reliability. As DG continues to play a growing role in modern grids, maintaining proper coordination between DR and OCR becomes increasingly difficult but essential. Ensuring the sensitive and reliable operation of these relays at critical locations is key to preserving the effectiveness and efficiency of power system protection [1, 2].

1.2 | Literature review

The integration of DG has a significant impact on the coordination timing of protection schemes within the electric grid by changing fault current levels, complicating OCR and DR coordination efforts, and requiring adjustments to relay settings. This highlights the need for advanced adaptations and new schemes to develop more effective protection strategies in today's electrical networks. As DG penetration continues to rise, addressing these challenges is essential to maintaining the reliability of the power system operation [1]. Recent approaches have made considerable progress over traditional relay coordination methods used in transmission line protection. Modern optimization techniques, adaptive strategies, and thorough validation processes have been proposed to more effectively address the complexities introduced by DG, particularly for OCR and DR. These advancements improve the overall reliability of protection systems, which is increasingly necessary as the industry shifts toward greater integration of renewable energy and DG sources [3, 4]. Studies in [5, 6] explored how the integration of DG affects fault current levels, leading to changes in relay settings and coordination times. Moravej at el. emphasized how the increased fault currents from DG impact the coordination of DR and directional OCRs [7].

Perez and Urdaneta [8] involved the use of adaptive protection coordination schemes to modify the zones of DRs for enhanced performance. Furthermore, by increasing the flexibility of Zone-2 operations in DRs and adding selectivity constraints, it becomes possible to optimize the coordination between DRs and OCRs, thereby improving protection across the zone-2 range of these devices [8]. This adaptive strategy facilitates the integration of user-defined time-inverse overcurrent relays, which enhances the operating times of backup directional OCRs and increases the overall system performance. In addition, a study [9] proposed a non-standard operating characteristic for DRs aimed at reducing the overall operating time of the protection system. This new characteristic divided the second zone of DRs into two segments, significantly decreasing the operating times for both primary and backup protection. Such a modification contributes to improved stability in power systems and mitigates the risks of equipment damage. In another research [10], authors addressed the staggered tripping characteristic of DRs to improve coordination with standard time-inverse OCRs, leading to a reduction in overall operating time. By decreasing the zone-2 operating time of primary relays, the coordination between DRs and OCRs can be optimized for enhanced performance during fault conditions. However, authors in [4] highlighted that the optimal minimum time delay for DRs and OCRs has not been adequately explored. In addition, utilizing artificial intelligence for coordinating DR and OCR presents challenges, including inaccuracies in fault detection, difficulties in adapting to changing conditions, and potential security risks. For effective coordination, both OCRs and DRs must be synchronized, ensuring that the time interval between the primary relay and its backup relay is no less than the coordination time interval (CTI) [11, 12]. In relay coordination challenges, the goal is to minimize the time between the main and backup relays. This coordination issue can be framed as an optimization problem, which can be addressed using advanced computational techniques [13]. The optimal coordination of OCRs and the second zone of DRs was analysed by [14] using linear programming techniques to determine the time setting multipliers (TSMs). In [15], a new objective function was introduced to optimize the coordination of both OCRs and DRs using genetic algorithms (GA), allowing selection of the TSMs and characteristics of the overcurrent relays. However, in these studies, the pickup currents were still considered as fixed values and the coordination was affected the second zone of DR.

The integration of DGs with low-inertia into power systems presents several challenges that create significant gaps in the existing literature on protection coordination for DRs. One major issue is that low fault current contributions from DG can lead to ineffective operation of OCRs, resulting in mis-coordination with DRs. This mis-coordination can cause backup OCRs to trip before primary DRs during fault events, leading to unnecessary service interruptions. Additionally, the presence of DG complicates the coordination process, necessitating frequent adjustments to relay settings due to the dynamic nature of system conditions. The variability in fault current levels produced by DGs makes it increasingly difficult to establish reliable coordination between OCRs and DRs. Furthermore, in systems with significant DG penetration, traditional OCR schemes may lack the reliability needed for highly sensitive and selective protection systems or prevent equipment damage and ensure safety. Therefore, Assouak and Benabid [10] and Alasali et al. [16] proposed the incorporation of a voltage variable into the OCR framework, resulting in a time–current–voltage characteristic aimed at minimizing overall tripping times and enhancing coordination among OCRs. Additionally, Alasali et al. developed a non-standard logarithmic and hybrid tripping coordination scheme that utilizes current–voltage characteristics specifically for power networks with DG. However, these studies primarily focus on OCRs and do not address coordination with distance relays (DR). Moreover, the implementation of the time–current–voltage characteristic presents complexities that complicate the attainment of optimal settings within an adaptive framework.

1.3 | Contributions

In modern power systems characterized by the integration of DG, the reliability and efficiency of protection schemes have become increasingly critical. Traditional protection methods often face challenges in adapting to the complexities introduced by DG, necessitating innovative approaches that enhance coordination and fault detection. This section outlines the key contributions of our proposed framework, which focuses on utilizing voltage relays (VRs) in coordination with DRs. By utilizing voltage measurements, our approach aims to improve coordination across various protection zones while mitigating the risks associated with low fault currents. Addressing the limited research on developing VRs to coordinate with DRs is crucial for achieving higher sensitivity and selectivity compared to OCRs. Effective coordination between OCR and DR is crucial for quick fault detection and isolation, ensuring minimal delay in response times and preventing unnecessary outages across network zones. As discussed in the previous section, current research generally recommends extending the tripping time for zone 2 to deal with delays from OCRs. However, this adjustment introduces further delays in zone 3′s distance protection response. To address this, our study introduces a VR protection approach that bypasses the need to extend zone 2′s tripping time, thereby improving coordination without compromising response times in adjacent zones. The following contributions detail how this framework enhances system performance, reduces mis-coordination, and ultimately fosters a more resilient electrical network.

- VR scheme: Although studies mention optimal OCR for optimized coordination between OCR and DR, there is a lack of in-depth research on comprehensive VR schemes. The integration of VRs with DRs enhances system coordination and reliability, ensuring effective fault detection even at low fault currents. The proposed method emphasizes a scheme that utilizes voltage measurements to optimize coordination among different protection zones of DRs.
- VRs contribute to more stable operations in systems with DGs with low-inertia (wind and PV systems), significantly reducing the risk of mis-coordination.
- This approach minimizes dependency on current measurements, which can be inconsistent in systems incorporating DG. The proposed VR scheme emphasizes the operation of VRs before activating backup DRs, effectively improving fault isolation and reducing the impact of faults on the transmission system. Consequently, this leads to quicker response times and enhanced reliability, especially during fault events.

1.4 | Outline of the paper

This article is structured as follows: Section 2 presents a description of the mis-coordination problem between DRs and OCRs in power networks with DG. Section 3 details the methodology used to develop innovative dual VR protection schemes. Section 4 shows the results obtained from the proposed VR scheme and includes a comparison with OCR. Finally, Section 5 concludes the study and offers suggestions for future research in this area.

2 | PROBLEM STATEMENT AND OCRS AND DRS COORDINATION CHALLENGES

The integration of DG with OCRs significantly complicates protection strategies. Variations in fault current contributions from DG can result in mis-coordination and overlapping protection zones, making it imperative to frequently update relay settings [10, 16]. To ensure that the protection system remains efficient and dependable within the changing topology of power generation, network operators need to invest in comprehensive analysis and protection modelling. Coordinating OCRs such as "OCR1, OCR2, and OCR3" with distance relays (DRs) "DR1, DR2, and DR3" is vital to avoid mis-coordination, as shown in Figure 1. In the event of a fault, if the OCRs react more quickly than the DRs due to a lack of proper coordination, it can lead to unnecessary outages or damage to equipment. It is crucial to acknowledge the potential risks associated with treating OCRs and DRs as independent systems. This may lead to situations where backup OCRs trip before the primary DRs during a fault, which could undermine the overall effectiveness of the protection scheme. Therefore, establishing a time-based coordination between the OCRs and DRs is essential. Each relay must be configured to operate within a defined time interval (CTI), ensuring that primary protection (DRs) acts first, with backup protection (OCRs) engaging only if the primary fails.

Figure 2 presents an examination of the mis-coordination issues faced by OCRs "OCR1, OCR2, and OCR3" and DRs "DR1, DR2, and DR3" in transmission systems, especially in the context of DG. The incorporation of DG complicates protection schemes by changing fault current dynamics, which affects the coordination between OCRs and DRs. Inverter-based distributed generation (IBDG) systems, such as solar photovoltaic (PV) and wind energy installations, are increasingly important in contemporary electrical grids. However, their integration introduces specific challenges regarding fault detection and relay performance. Typically, IBDGs produce lower fault currents compared to traditional synchronous generators due to the control strategies utilized by inverters, which restrict the current injected into the grid during fault events. For example, the fault current occurring between bus stations B and C may reach only the predetermined levels necessary to trigger "OCR2," as illustrated in Figure 2. This limitation may delay the relays' ability to respond adequately to high fault currents, potentially leading to failures in protection. The reduced fault current can cause "OCR2" and "DR2" to become less responsive to fault conditions, which may result in these relays not activating as intended, ultimately compromising system reliability and protection. Ineffective fault detection can increase the risk of equipment damage and safety issues. Furthermore, contributions from DG can cause overlapping protection schemes between OCRs and DRs during fault conditions. Figure 2 shows that the presence of DG can raise the fault current detected by DR1 in its third stage, thereby extending its operational reach beyond the desired parameters. As a result, DR1 might activate before the downstream OCR2 when faults occur between buses C and D. This scenario undermines the selectivity and reliability of both the overcurrent and distance protection systems within networks that integrate DG.

3 | PROPOSED VR PROTECTION SCHEME TO SOLVE MIS-COORDINATION CHALLENGES WITH DRS

In Section 1, many studies highlighted the necessity for integrated protection schemes that reduce the risks of mis-coordination between OCRs and DRs. The coordination of

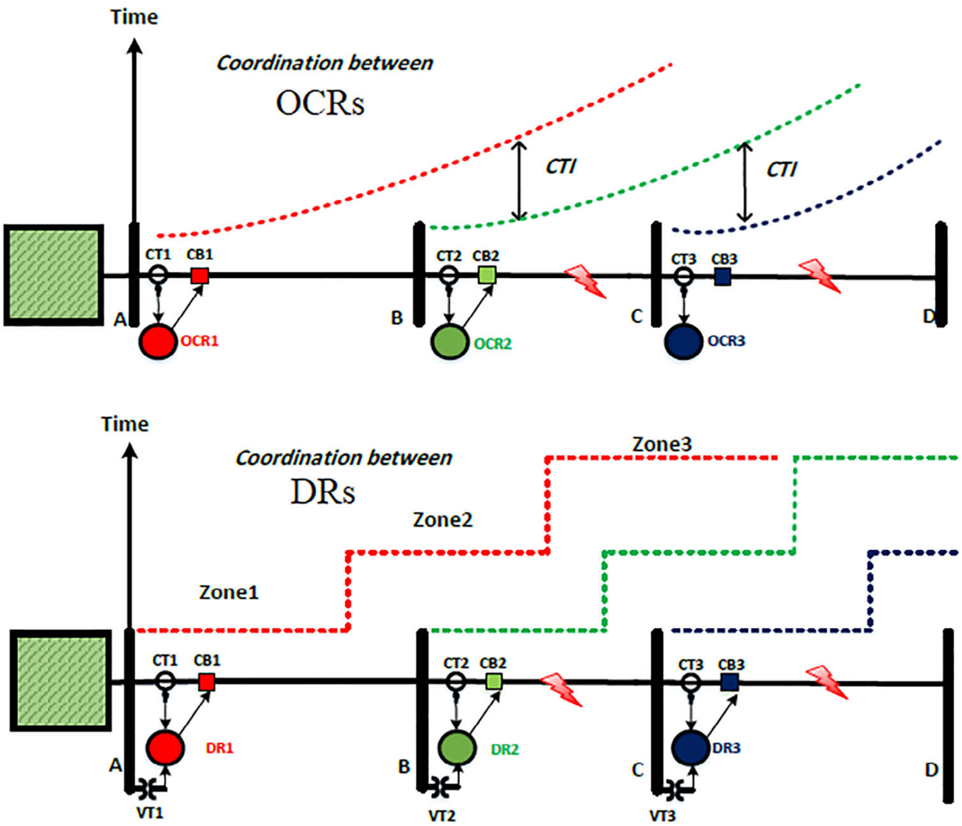

FIGURE 1 OCR and DR schemes coordination in transmission systems.

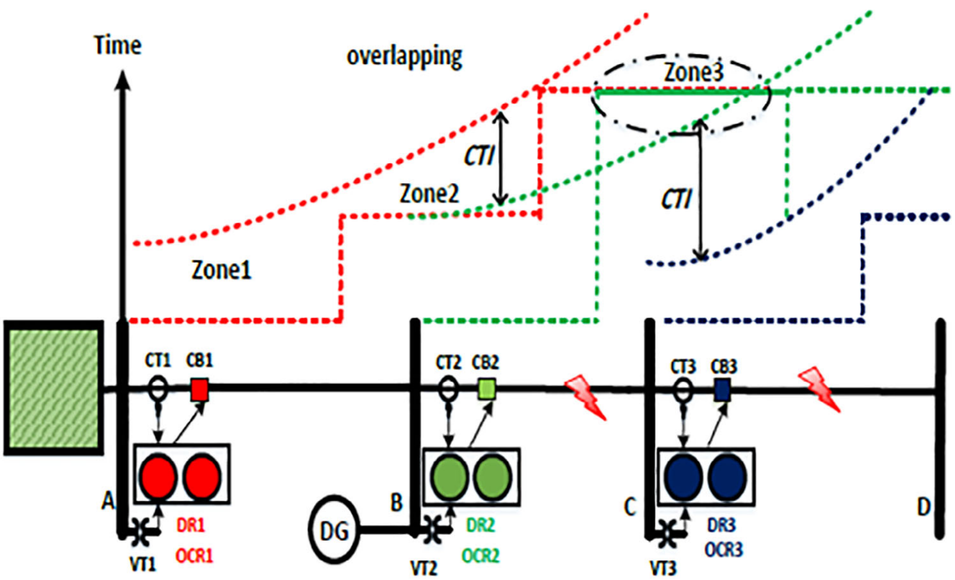

FIGURE 2 OCRs and DRs coordination mis-coordination and challenges.

OCRs and DRs in the context of DGs presents considerable challenges that complicate the overall coordination process and calculations, as illustrated in Figure 2. The coordination of OCRs and DRs in the context of DGs presents considerable challenges that complicate the overall coordination process and calculations. The presence of DG can result in fluctuating fault current contributions. Different from conventional generation sources, DGs, especially those based on inverters, may deliver limited fault currents during fault events. This variability complicates the determination of relay settings, as the anticipated fault current levels can change depending on the operational status of the DG. Such mis-coordination can create overlapping

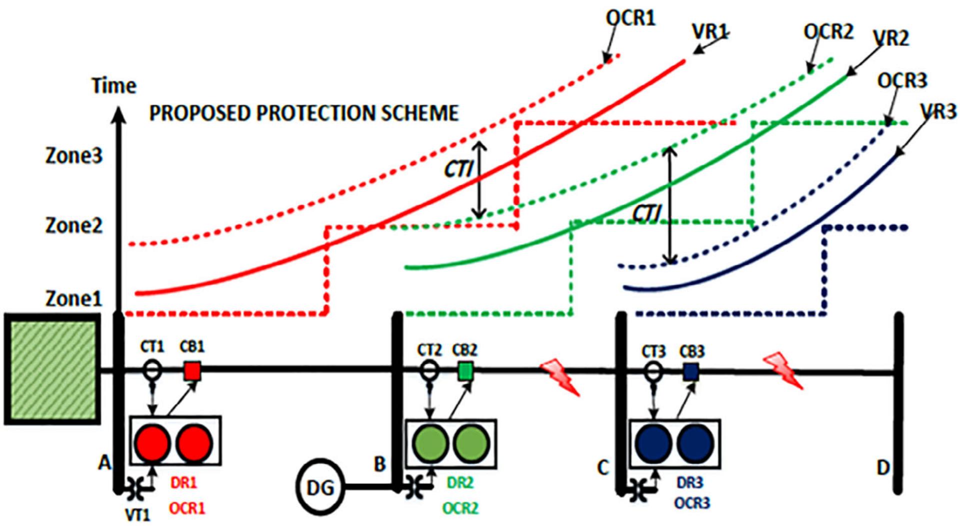

FIGURE 3 Proposed voltage-based protection for transmission line protection.

protection zones, leading to situations where both OCRs and DRs react to the same fault. This overlap can complicate fault isolation efforts and may result in unnecessary outages. In addition, it has been highlighted the importance of regular testing and updates to relay settings to adapt to evolving system conditions, particularly with the increasing integration of DG sources [10, 16].

The operational characteristics of DG can fluctuate frequently due to changes in generation output, grid conditions, and load demands. Consequently, relay settings need to be updated regularly to accommodate these dynamic conditions. This involves continuous analysis and recalibration of both OCR and DR settings to maintain effective coordination. Operators must take into account not only fault characteristics but also the influence of DG on system impedance, fault current levels, and relay tripping times. In a scenario where a fault occurs between bus stations C and B, standard procedures dictate that DR2 should operate quickly to clear the fault; OCR2 is intended to serve as a local backup if DR2 fails to trip the fault in zone 1, ensuring that only the affected line is disconnected from the network, as shown in Figure 3. In case of both DR2 and OCR2 fail to respond, DR3 is designed to trip the fault in zone 2, which covers the line between bus stations C and B as remote backup protection. However, the contribution from DG during a fault can lead to mis-coordination between DR2 and OCR2, as well as with DR3 in zone 2 for the line between substations C and D. This mis-coordination might result in DR3 activating in zone 2 before OCR2, triggering unnecessary tripping and undermining the selectivity of the protection schemes within the transmission system, as illustrated in Figure 3.

Given the difficulties associated with low fault current contributions, there is growing interest in employing voltage measurements as an alternative or supplementary approach for fault detection. This trend is gaining traction as it presents a potential solution to the limitations of current measurements. By monitoring voltage fluctuations during fault events, protection systems can identify faults more reliably, even when current measurements fall short. This shift towards utilizing voltage measurements highlights the demand for innovative solutions to address the evolving challenges faced by modern electric grids. This study introduces a novel approach that employs new characteristics for VR to address coordination issues with DR protection schemes. As illustrated in Figure 3, voltage-based protection facilitates improved coordination among the various zones of the DRs installed within the transmission system. This highlights the advantages of using VR in conjunction with DRs for achieving enhanced accuracy and reliability in coordinating transmission line protection schemes. The proposed voltage characteristics are outlined in Equation (1), providing a clear framework for understanding how these parameters function in VR. By establishing specific voltage thresholds, the equation serves as a guideline for the optimal operation of voltage relays. This framework allows for a systematic assessment of how voltage measurements can enhance protection strategies, particularly in environments where DG influences fault current levels. Moreover, the equation facilitates the integration of voltage characteristics into protection schemes based on voltage data, short circuit voltage (V_{SC}) and pickup voltage (V_{P}) and the voltage-time multiplier setting, TMS_v.

$$\mathbf{t} = \mathbf{TMS}_v \left(\frac{\boldsymbol{V}_{\mathbf{SC}}}{\boldsymbol{V}_{\mathbf{P}}}\right)\left(\frac{0.14}{1-\left(\frac{\boldsymbol{V}_{\mathbf{SC}}}{\boldsymbol{V}_{\mathbf{P}}}\right)^{0.02}}\right) \tag{1}$$

As shown in Figure 3, using voltage relays (VR2) offers several key benefits compared to OCR2 relays when coordinating with DRs. VR2 rely on voltage measurements, making them less susceptible to the influence of DG than relays that depend on current measurements. This enhances the reliability of fault detection, particularly in cases where the fault current is low. By incorporating VR2 relays into the protection scheme alongside DRs, the system becomes less reliant on current-based measurements, ensuring better coordination between DRs and backup protection mechanisms. This reduces the risk of mis-coordination often associated with OCR2 relays. In addition, the use of VR2 relays ensures that voltage-based backup protection engages before the second zone of the remote backup DRs. This approach helps mitigate the effects of faults and allows for quicker isolation of the affected portion of the transmission system, improving overall system stability and protection reliability. The VR2 voltage relay offers superior performance for protecting transmission lines when compared to the OCR2 current relay. It provides more reliable fault detection, better coordination with DRs, and faster activation of backup protection, especially in networks with distributed generation.

3.1 | DR protection setting

The design of a distance protection scheme involves dividing the system into three distinct zones, each with its own tripping time. The first zone acts as the primary protection, while the second and third zones serve as backup protections in case the downstream relays fail to respond as intended. This arrangement is depicted in Figure 3. In a digital environment at terminal substations, as shown in Figure 3, the concept can be applied where the first zone, $Z_{1,\,\mathrm{DR1}}$ for DR1, is set to cover 80% of the impedance of line AB, Z_{AB}, as described in Equation (2). The tripping time for this primary zone is configured to operate almost instantaneously, with a minimal delay set at zero seconds for faster response [17, 18].

$$Z_{1,\,\mathrm{DR1}} = 0.8Z_{\mathrm{AB}} \tag{2}$$

To ensure coordination between DRs, the second zone for DR1, $Z_{2,\,\mathrm{DR1}}$, should be configured, as in Equation (3), so that it does not overlap with the first zone at substation B and the impedance of line BC, Z_{BC}. The tripping time for the second zone is typically set with a minimum delay of 0.4 s to maintain proper selectivity and ensure backup protection functions as intended.

$$Z_{2,\,\mathrm{DR1}} = 0.8(Z_{\mathrm{AB}} + 0.8Z_{\mathrm{BC}}) \tag{3}$$

The third zone is generally designed to protect 80% of the shortest outgoing line from substations B and C for the impedance of line CD, Z_{CD}, as described in Equation (4), with its tripping time usually set to a minimum of 0.7 s for backup protection.

$$Z_{3,\,\mathrm{DR1}} = 0.8(Z_{\mathrm{AB}} + 0.8\,(Z_{BC} + 0.8Z_{\mathrm{CD}}) \tag{4}$$

3.2 | The objective function of the VR coordination with DR

Effective coordination between VRs and DRs is crucial for reliable power system protection, particularly with the integration of DG. The goal is to align VR activation times with DR second-zone tripping times to ensure fast fault clearance without unnecessary disconnections. By integrating both relay timings into a unified coordination strategy, the system can handle various fault conditions, improving overall reliability and safety. The objective function, total tripping time (t_{of}) for this coordination balancing VR and DR timings for optimal performance is

$$t_{\mathrm{of}} = \sum_{v=1}^{V} t_v + \sum_{d=1}^{D} t_{d,Z2} \tag{5}$$

where t_v is the tripping time for voltage relay v, $t_{d,\,Z2}$ is the tripping time of the distance relay (d) at the second zone. In this study, the coordination between VR and DR is optimized using the water cycle algorithm (WCA), a nature-inspired metaheuristic that excels at solving complex optimization problems. WCA models the natural flow of water through streams and rivers to efficiently explore the search space and find optimal solutions. When applied to VR and DR coordination, WCA is particularly effective at managing the timing of both primary and backup protection, ensuring fast and reliable fault detection and isolation [19, 20]. The integration of DG into modern power systems introduces new challenges, such as reduced fault currents and variable operating conditions, which complicate relay coordination. VRs, which rely on voltage variations rather than current measurements, offer a more reliable solution in such scenarios, as they are less affected by low fault current contributions. However, coordinating these VRs with distance relays requires precise optimization to prevent mis-coordination, especially under varying fault conditions. By applying WCA to VR and DR coordination problems to minimize the total tripping time, t_{of}, the algorithm ensures that the protection system responds effectively to faults, providing faster and more selective isolation of affected sections. This optimization balances the operation times of VRs and DRs, minimizing unnecessary trips and enhancing overall system stability.

As shown in Figure 4, this study develops and implements the WCA within the MATLAB environment to optimize the coordination of relays. The performance of relays coordination methods is compared with the proposed approach to determine the minimum trip settings for all OCRs and VRs. To validate the relays settings and assess the coordination strategies, the study utilizes ETAP, an industry-standard software used for power system analysis and simulation. ETAP's advanced features enable precise modelling of real-world grid operations and the evaluation of protection schemes under various operating scenarios. This robust tool ensures that the coordination methods developed are not only theoretically optimal but also applicable in practical, real-world grid environments. The use of ETAP provides a high level of confidence in the reliability and effectiveness of the proposed protection coordination approach, making it suitable for implementation in modern power systems.

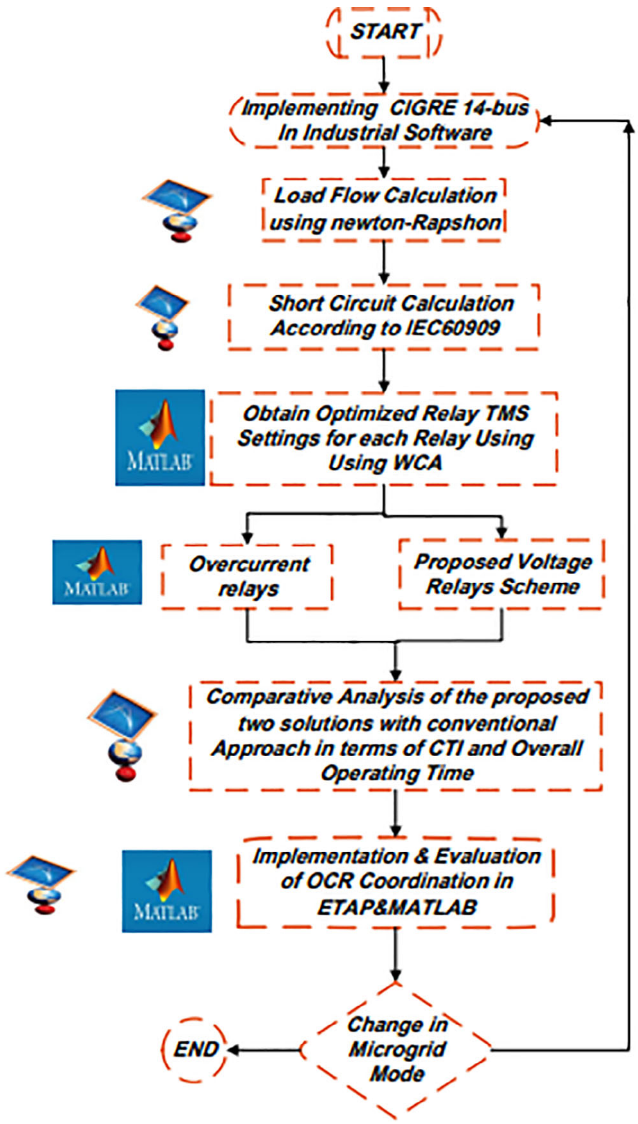

FIGURE 4 Flowchart of developing the proposed VR and OCR protection scheme.

4 | SIMULATION RESULTS AND DISCUSSION

This section presents a comprehensive assessment of the performance of the newly developed VR scheme, featuring modern relay capabilities aimed at optimizing coordination between DR compared to OCRs. The evaluation begins by testing the scheme's effectiveness using a reference power network, specifically the CIGRE network, under three-phase fault conditions at different locations. These tests provide a detailed comparison between the proposed VR scheme and conventional OCR applied to the second zone of distance relays. The key metrics for comparison include total tripping time and the CTI, both of which are critical to assessing the scheme's ability to clear faults quickly and maintain system stability. The enhanced performance of the proposed scheme stems from its ability to respond to changing network conditions, ensuring optimal coordination between relays. This flexibility is particularly important in modern power grids, which are increasingly characterized by DG and varying fault scenarios. The VR approach responds more effectively to faults, improving the overall reliability and protection of the network.

4.1 | Power system network

The proposed dual-setting settings for the OCR scheme applied to a CIGRE network, aim to optimize OCR coordination with DR and minimize tripping time. The CIGRE grid configuration, shown in Figure 6, is based on a 14-bus feeder powered by a high-voltage/medium-voltage utility source and protected by 16 OCRs and DRs. Additionally, the grid incorporates two wind units, each rated at 5 MVA as detailed in [21, 22]. The CIGRE network initiates three-phase faults at various lines (L1–L9), representing both near-end and far-end fault locations. The proposed VR scheme is designed to enhance coordination with DRs while minimizing tripping times to improve the overall protection and stability of the power network. This approach is applied to the CIGRE network, which serves as a standard framework for power system analysis. The network configuration, as illustrated in Figure 5, is a 14-bus feeder powered by a high-voltage/medium-voltage utility source, representing a realistic grid structure. The protection system includes 16 VR or OCRs and DRs, strategically placed to ensure effective fault detection and isolation. In this study, the most widely used and robust control method for DERs, guided by the German grid code requirements is used [23–27]. This standard for inverter-interfaced distributed generators (IIDGs) includes low voltage ride through (LVRT) capabilities, ensuring that they remain connected to the grid during voltage sags. LVRT requirements enhance grid stability during disturbances but also introduce added complexity to fault analysis, as IIDGs must respond to faults while meeting control and regulatory expectations. However, this work specifically focuses on relay tripping times and the coordination of protection systems.

A key feature of this study is the integration of two types of DGs: a wind power system and a photovoltaic (PV) system. Each of these systems presents unique challenges for relay coordination due to their intermittent and variable nature. The wind power system consists of two wind units, each rated at 5 MVA, while the PV system provides additional complexity, as it operates under varying sunlight conditions [17, 18]. These DG units are critical components of the test network, reflecting the increasing penetration of renewable energy sources in modern grids. Both wind and PV systems are tested in this work to assess their impact on the performance of the proposed OCR scheme. The inclusion of these DG units highlights the scheme's adaptability in low-inertia areas, regions where renewable energy sources such as wind and PV dominate. In a power network with DGs, the system's inertia is significantly reduced, making protection coordination more challenging due to the fluctuating fault current contributions from DG sources. These low-inertia conditions demand highly advanced protection schemes, as traditional methods may struggle to deal with the rapid changes

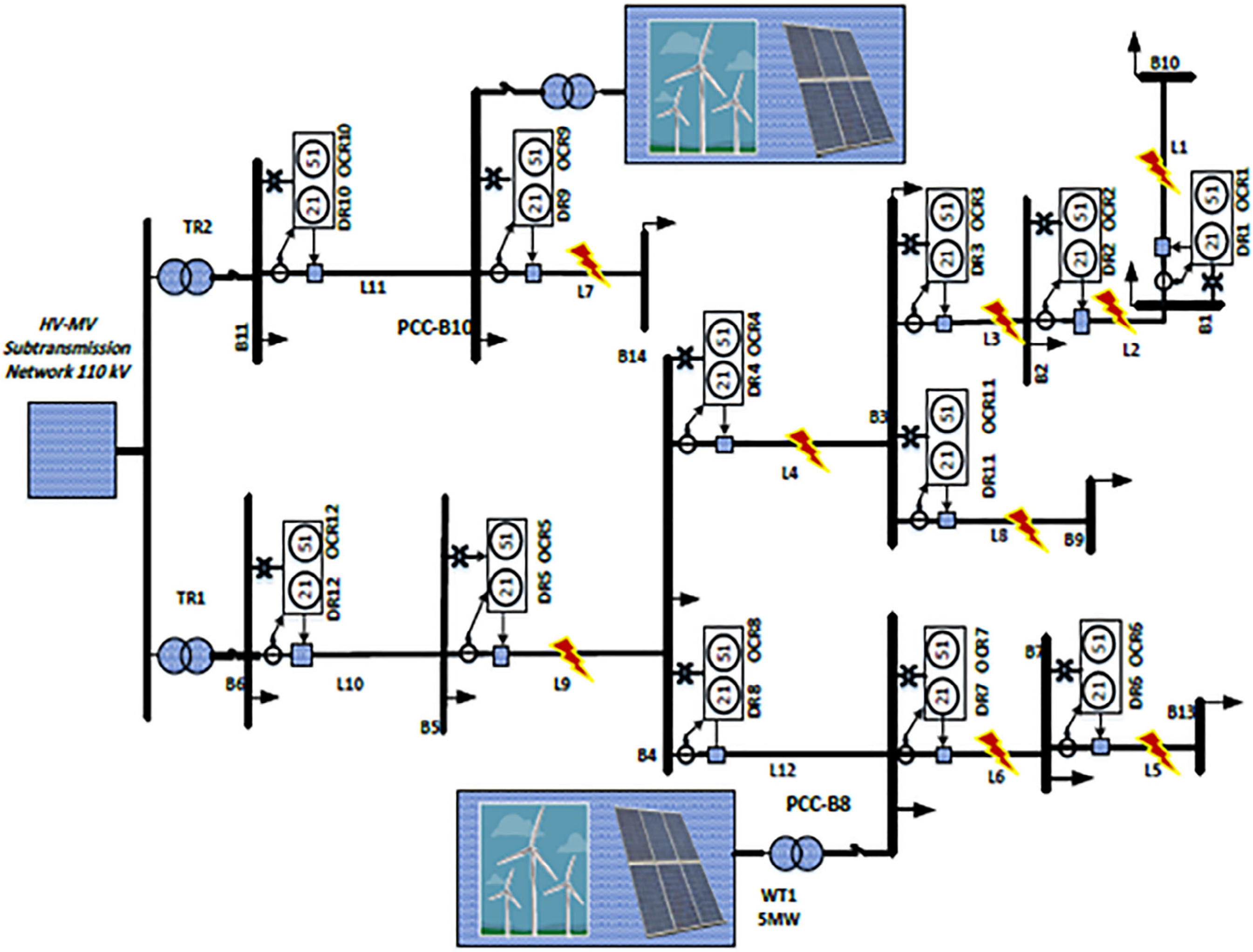

FIGURE 5 CIGRE network with DGs.

in system dynamics. The network is subjected to three-phase faults at various locations along lines L1 to L12, capturing a wide range of fault scenarios. These fault locations include both near-end faults, which are closer to the utility source and require faster tripping times, and far-end faults, which are located further along the feeder and cause greater challenges in detection and isolation. This study considers the following power grid configurations for analysis:

- Power network model 1 (CIGRE-1): CIGRE grid without DGs: This case study assesses the protection schemes in a CIGRE grid without the presence of DG units, allowing for a comparison to understand the impact of DG on the system's protective mechanisms.
- Power network models 2 and 3(CIGRE-2 and CIGRE-3): CIGRE grid with PV and wind systems, respectively: in these cases, the protection schemes are evaluated on a CIGRE grid that includes two PV or wind units, each with a capacity of 5 MVA. The aim is to assess how the integration of DG affects relay coordination and overall system protection.

These scenarios and fault locations offer a detailed evaluation of the power grid's performance under varying configurations, emphasizing the impact of DGs on the effective coordination of DR and VR compared to OCR. The time multiplier setting (TMS) for each OCR and VR, under all power network models, are outlined in Table 1. Initially, a load flow analysis is conducted to establish the appropriate current transformer ratios for each OCR. Following this, a three-phase short-circuit analysis, adhering to IEC-60909 standards, is carried out across multiple fault locations (L1–L9). This analysis is executed using ETAP software, with data extracted to model the CIGRE network accurately.

4.2 | The VR scheme testing results

This section assesses the performance of the proposed VR scheme in comparison to the conventional OCR approach within different CIGRE grid models. The evaluation of the total tripping time and the tripping times for the primary and backup

TABLE 1 TMS settings for VR and OCRs under three models of the CIGRE network.

Time multiplier sitting OCR				Time multiplier sitting VR			
Relay	**CIGRE-1**	**CIGRE-2**	**CIGRE-3**	**Relay**	**CIGRE-1**	**CIGRE-2**	**CIGRE-3**
OCR1	0.010	0.01	0.01	VR1	0.01	0.01	0.01
OCR2	0.080	0.09	0.089	VR2	0.29	0.22	0.24
OCR3	0.168	0.190	0.184	VR3	0.21	0.155	0.155
OCR4	0.263	0.30	0.294	VR4	0.15	0.09	0.09
OCR5	0.258	0.315	0227	VR5	0.045	0.04	0.038
OCR6	0.01	0.01	0.01	VR6	0.01	0.01	0.01
OCR7	0.086	0.110	0.11	VR7	0.22	0.11	0.1
OCR8	0.18	0.182	0.205	VR8	0.15	0.125	0.105
OCR9	0.01	0.01	0.010	VR9	0.01	0.01	0.01
OCR10	0.130	0.130	0.152	VR10	0.01	0.01	0.01
OCR11	0.01	0.01	0.01	VR11	0.01	0.09	0.01
OCR12	0.346	0.43	0.315	VR12	0.060	0.1	0.1

TABLE 2 Fault currents, fault voltages and tripping times for primary and backup OCRs and VRs at various fault locations CIGRE-1.

	OCR scheme			VR scheme		
Fault current	**Current fault**	**OCR**	**Time**	**Voltage fault**	**VR**	**Time**
L1	609	OCR1	0.038	1.49	VR1	0.002
	609	OCR2	0.304	4.46	VR2	0.306
L2	712	OCR2	0.280	1.77	VR2	0.076
	712	OCR3	0.587	5.33	VR3	0.300
L3	858	OCR3	0.535	2.20	VR3	0.075
	858	OCR4	0.838	6.59	VR4	0.315
L4	1079	OCR4	0.756	2.86	VR4	0.079
	1079	OCR5	1.054	11.34	VR5	0.317
L5	712	OCR6	0.035	1.77	VR6	0.003
	712	OCR7	0.301	5.33	VR7	0.314
L6	858	OCR7	0.274	2.19	VR7	0.078
	858	OCR8	0.525	6.58	VR8	0.314
L7	1847	OCR9	0.303	3.62	VR9	0.008
	1847	OCR10	0.606	15.48	VR10	0.301
L8	858	OCR11	0.032	2.19	VR11	0.032
	858	OCR4	0.838	6.59	VR4	0.956
L9	1486	OCR5	0.883	5.74	VR5	0.256
	1486	OCR12	1.184	9.37	VR12	0.558
Total tripping time	9.373			4.29		

relay at each fault occurring at various points along the grid (L1 to L9). Table 2 details the total tripping times and tripping times of primary and backup VRs and OCRs under various fault locations for CIGRE-1 (CIGRE grid without DGs). The results highlight the improvements in response times achieved by the VR approach under different fault conditions compared to OCR. Across all analysed fault locations, the VR scheme consistently delivers faster tripping times for both primary and backup OCRs. For example, the tripping times range from 0.002 to 0.956 s for VR schemes, compared to the traditional OCR scheme's range of 0.035 to 1.184 s. The tripping time at fault at L2 was 0.076 and 0.3 s for the primary and backup relay of the VR scheme, while for the OCRs scheme was 0.28 and 0.587 s.

TABLE 3 Fault currents, fault voltages and tripping times for primary and backup OCRs and VRs at various fault locations- CIGRE-2.

	OCR scheme			VR scheme		
Fault current	**Current fault**	**OCR**	**Time**	**Voltage fault**	**VR**	**Time**
L1	725	OCR1	0.035	1.76	VR1	0.003
	725	OCR2	0.312	5.30	VR2	0.311
L2	924	OCR2	0.277	2.16	VR2	0.076
	924	OCR3	0.585	6.49	VR3	0.316
L3	1150	OCR3	0.531	2.77	VR3	0.078
	1150	OCR4	0.839	8.32	VR4	0.301
L4	1517	OCR4	0.751	3.74	VR4	0.071
	1603	OCR5	1.038	11.72	VR5	0.309
L5	1071	OCR6	0.029	2.51	VR6	0.004
	1071	OCR7	0.317	7.55	VR7	0.301
L6	1340	OCR7	0.289	3.13	VR7	0.066
	838	OCR8	0.587	7.22	VR8	0.313
L7	2372	OCR9	0.021	4.29	VR9	0.010
	1851	OCR10	0.303	15.60	VR10	0.311
L8	1150	OCR11	0.022	2.76	VR11	0.036
	1150	OCR4	0.649	8.32	VR4	0.725
L9	1992	OCR5	0.937	3.85	VR5	0.173
	1992	OCR12	1.280	8.72	VR12	0.476
Total tripping time	8.802			3.88		

Table 3 presents the total tripping times, along with the primary and backup tripping times, for VRs and OCRs under various fault locations for the CIGRE-2 configuration, which represents a CIGRE grid with PV. The findings emphasize the notable improvements in system response times achieved by the VR scheme compared to the traditional OCR approach, especially under different fault conditions. Across all analysed fault locations, the VR scheme consistently exhibits faster tripping times for both primary and backup relays. For instance, the VR scheme demonstrates total tripping times equal to 3.88 s, outperforming the traditional OCR scheme, which displays a slower time of 8.802 s. At fault location L3, the tripping times for the primary and backup relays in the VR scheme were recorded as 0.078 and 0.301 s, respectively, whereas in the OCR scheme, these times were significantly slower at 0.531 and 0.839 s.

In grids incorporating wind turbines (CIGRE-3), the VR scheme consistently outperforms the OCR scheme by delivering faster tripping times for both primary and backup relays under different fault conditions, as shown in Table 4. This performance improvement is particularly crucial in wind-integrated grids, where the variable nature of wind energy can lead to fluctuations in fault current levels and power system stability. For example, the VR scheme demonstrates a total tripping time of 3.961 s, which is significantly faster than the traditional OCR scheme's total time of 8.294 s. Such a reduction in response time is vital for limiting fault propagation and ensuring minimal disruption to power system operations.

The findings highlight the significant improvements in response times achieved by the VR approach compared to the traditional OCR scheme, particularly when analysing fault scenarios involving PV and wind-based DG, as shown in Figure 6. When PVs and wind turbines are added to the grid, they introduce additional complexity due to the intermittent nature of PV and wind energy. The VR scheme outperformed the OCR scheme and recorded the minimum total tripping time for all power CIGRE network models, as shown in Figure 5. This shows the improvement in the performance of the VR scheme and highlights its enhanced speed and reliability, making it more effective in reducing fault impacts and maintaining the grid's operational stability. The ability to rapidly detect and clear faults is critical for reducing the risk of equipment damage and minimizing power interruptions, ensuring a more resilient protection system.

4.3 | Coordination with DR results

In power systems, effective coordination between protection devices, such as OCR and DR, is essential for ensuring the reliable operation and fault management of the grid. With the increasing integration of DG sources, such as wind turbines and PV systems, maintaining coordination becomes even more critical due to the dynamic nature of fault currents introduced by these energy sources. This section presents the results of an

TABLE 4 Fault currents, fault voltages and tripping times for primary and backup OCRs and VRs at various fault locations- CIGRE-3.

	OCR scheme			VR scheme		
Fault current	**Current fault**	**OCR**	**Time**	**Voltage fault**	**VR**	**Time**
L1	735	OCR1	0.034	1.69	VR1	0.002
	735	OCR2	0.306	5.08	VR2	0.316
L2	892	OCR2	0.279	2.10	VR2	0.080
	892	OCR3	0.576	6.31	VR3	0.300
L3	1132	OCR3	0.518	2.77	VR3	0.078
	1132	OCR4	0.816	8.31	VR4	0.301
L4	1548	OCR4	0.721	4.02	VR4	0.080
	923	OCR5	1.023	11.90	VR5	0.306
L5	1112	OCR6	0.028	2.65	VR6	0.005
	1112	OCR7	0.312	7.96	VR7	0.305
L6	1507	OCR7	0.276	3.79	VR7	0.081
	1507	OCR8	0.578	7.75	VR8	0.303
L7	2370	OCR9	0.021	4.84	VR9	0.012
	2370	OCR10	0.300	15.86	VR10	0.303
L8	1132	OCR11	0.022	2.76	VR11	0.036
	1132	OCR4	0.631	8.31	VR4	0.724
L9	1488	OCR5	0.776	5.75	VR5	0.216
	1488	OCR12	1.077	9.39	VR12	0.513
Total tripping time	8.294			3.961		

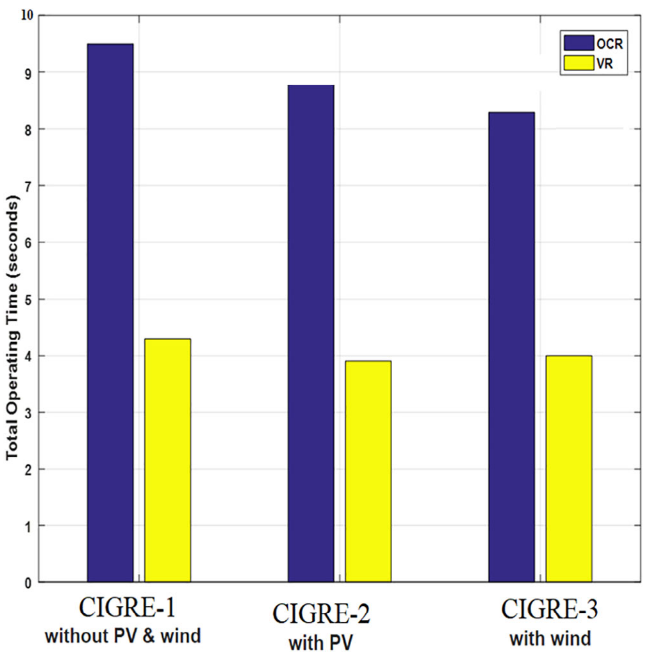

FIGURE 6 Total tripping time of VR and OCR over the three CIGRE network models.

extensive evaluation of coordination between OCRs, VRs and DRs, specifically focusing on the performance of a proposed VR scheme in comparison to a traditional OCR scheme. The analysis is carried out using three CIGRE grid models, which have been adapted to incorporate without DGs, PV and wind generation systems. Fault scenarios are simulated at different locations along the grid's lines, including fault at the second zone at the backup DR, which is a critical zone for observing the interaction between the VR, OCR and DR.

Firstly, Table 5 displays the simulation results for the tripping times at various fault locations for OCRs and VRs, and at the second protection zone for the backup DR, with a focus on the coordination between them at CIGRE-1. The tripping times are compared across three different protection schemes: the traditional OCR scheme, the DR scheme, and the proposed VR scheme. This analysis aims to assess the effectiveness of the VR scheme in improving coordination and reducing tripping times. The OCR scheme recorded two mis-coordination events at L3 and L4, which required to increase in the tripping time of zone 2 more than 0.4 s. While the VR scheme successfully did not record any mis-coordination events with DR.

Secondly, a detailed evaluation of the coordination between OCRs and VRs with DRs in the CIGRE network with an integrated PV system. This analysis aims to compare the performance of different protection schemes, focusing on tripping times and the coordination between the relays at fault locations across the grid. Specifically, we investigate coordination at the second zone for the backup DR relays, which represents a critical point for evaluating relay interaction and fault-clearing performance. Table 6 illustrates the simulation results of the tripping times for various fault locations in the CIGRE-2 model.

TABLE 5 Fault currents, fault voltages and tripping times for primary OCRs and VRs coordinated with DR as backup relay at various fault locations- CIGRE-1.

	Relay No.		Fault current		Tripping time	
Fault location	**OCR—primary**	**DR—backup**	**Primary (A)**	**Backup (A)**	**OCR—primary**	**DR—backup**
L1	OCR1	DR2	609	609	0.038	0.4
L2	OCR2	DR3	712	712	0.28	0.4
L3	OCR3	DR4	858	858	0.535	0.635
L4	OCR4	DR5	1079	1079	0.756	0.856
L5	OCR6	DR7	712	712	0.035	0.4
L6	OCR7	DR8	858	858	0.274	0.4
L7	OCR9	DR10	1847	1847	0.023	0.4
L8	OCR11	DR4	858	858	0.032	0.4
L9	OCR5	DR12	1992	1992	0.883	0.99
	Relay No		**Fault Voltage**		**Tripping time**	
Fault location	**VR—primary**	**DR—backup**	**Primary (V)**	**Backup (V)**	**VR—primary**	**DR—backup**
L1	VR1	DR2	1.49	4.46	0.002	0.4
L2	VR2	DR3	1.77	5.33	0.076	0.4
L3	VR3	DR4	2.20	6.59	0.075	0.4
L4	VR4	DR5	2.86	11.34	0.079	0.4
L5	VR6	DR7	1.77	5.33	0.003	0.4
L6	VR7	DR8	2.19	6.58	0.078	0.4
L7	VR9	DR10	3.62	15.48	0.008	0.4
L8	VR11	DR4	2.19	6.59	0.032	0.4
L9	VR5	DR12	3.85	8.72	0.19	0.4

The traditional OCR scheme and the proposed VR scheme are assessed to determine their effectiveness in enhancing the coordination of protection systems under different fault conditions. The proposed VR scheme consistently demonstrates improved performance, with faster tripping times and better coordination between the relays, as shown in Table 6. In contrast, the traditional OCR scheme showed two instances of mis-coordination at fault locations L3 and L4, where it required the DR to respond with delay, potentially leading to extended fault-clearing times. These delays can cause unnecessary outages and increased stress on the power system, particularly in grids with high PV penetration.

Thirdly, this section evaluates the coordination between OCRs, VRs and DRs in the CIGRE network with integrated wind systems, focusing on tripping times and relay coordination at fault locations. Table 7 shows the tripping times for various fault locations in the CIGRE-3 model, comparing the traditional OCR scheme with the proposed VR scheme. The VR scheme consistently outperforms the OCR scheme, showing faster tripping times and better coordination. While the traditional OCR scheme experienced mis-coordination at fault locations L3 and L4, the VR scheme recorded no such issues. This improvement is particularly crucial for low-inertia, wind-integrated grids, where rapid fault isolation is essential to maintaining stability and preventing outages.

The backup tripping times for DR 4 in zone 2 are consistently set to 0.4 s, leading to frequent mis-coordination events in the traditional OCR scheme, as illustrated in Figure 7. In addition, the experimental DR results at fault location L2 (DR2 and DR3) is shown in Figure 8. While the VR scheme reduces these mis-coordination events. The study evaluates the VR scheme's effectiveness in reducing tripping times and improving coordination in grids integrated with DGs. Results show that this approach leads to quicker response times, ensuring greater grid stability and minimizing potential damage during faults. The experimental data closely aligns with the simulation outcomes, validating the VR scheme's performance in practical settings. Compared to the traditional OCR, the VR scheme consistently delivers faster tripping times and superior reliability.

4.4 | Enhanced fault protection for unsymmetrical faults

This study evaluates the VR and OCR scheme's performance during an unsymmetrical fault. Firstly, line-to-line (LL) fault is applied in a CIGRE grid integrated without DGs (CIGRE-1). Secondly, the protection schemes are investigated under the line-line-ground (LLG) fault at CIGRE-2 network. Faults are tested at various locations (L1 to L9) assessing tripping time

TABLE 6 Fault currents, fault voltages and tripping times for primary OCRs and VRs coordinated with DR as backup relay at various fault locations- CIGRE-2.

	Relay No		Fault current		Tripping time	
Fault location	**OCR—primary**	**DR—backup**	**Primary (A)**	**Backup (A)**	**OCR—primary**	**DR—backup**
L1	OCR1	DR2	725	725	0.035	0.4
L2	OCR2	DR3	924	924	0.277	0.4
L3	OCR3	DR4	1150	1150	0.531	0.631
L4	OCR4	DR5	1517	1603	0.751	0.851
L5	OCR6	DR7	1071	1071	0.029	0.4
L6	OCR7	DR8	1340	838	0.289	0.4
L7	OCR9	DR10	2372	1851	0.021	0.4
L8	OCR11	DR4	1150	1150	0.022	0.4
L9	OCR5	DR12	1992	1992	0.67	0.77

	Relay No		Fault voltage		Tripping time	
Fault location	**VR—primary**	**DR—backup**	**Primary (V)**	**Backup (V)**	**VR—primary**	**DR—backup**
L1	VR1	DR2	1.76	5.30	0.003	0.4
L2	VR2	DR3	2.16	6.49	0.076	0.4
L3	VR3	DR4	2.77	8.32	0.078	0.4
L4	VR4	DR5	3.74	11.72	0.071	0.4
L5	VR6	DR7	2.51	7.55	0.004	0.4
L6	VR7	DR8	3.13	7.22	0.066	0.4
L7	VR9	DR10	4.29	15.60	0.010	0.4
L8	VR11	DR4	2.76	8.32	0.036	0.4
L9	VR5	DR12	3.85	8.72	0.173	0.4

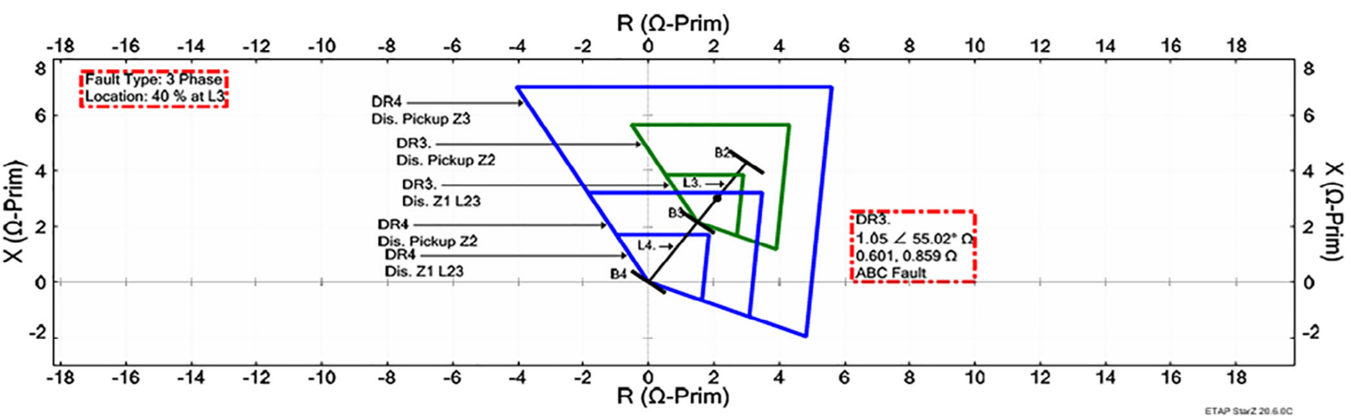

FIGURE 7 The experimental DR results at fault location L3 (DR3 and DR4).

of OCRs and VRs. Table 8 displays the total, primary, and backup tripping times for VRs and OCRs under various LL fault locations in the CIGRE-1 configuration, which simulates a CIGRE grid without DG systems. The results highlight significant enhancements in system response times with the VR scheme compare to the traditional OCR approach across multiple fault location. The VR recorded minimum total tripping time with 2.8 s compared to OCR with 13.6 s. For every fault location analysed, the VR scheme consistently achieves faster tripping times for both primary and backup relays. For example, the VR scheme records a tripping time of 0.162 and 0.269 s for primary and backup relays at fault located at L2, notably faster than the traditional OCR scheme's 6.13 and 7.11 s. Table 9 examines tripping times for VRs and OCRs under various LLG fault locations in the CIGRE-3 configuration, which simulates a CIGRE grid with wind systems. In the traditional scheme, total tripping time recorded 10.5 s compared to VR scheme recorded 3.2 s This is showed the powerful of VR scheme compared to

TABLE 7 Fault currents, fault voltages and tripping times for primary OCRs and VRs coordinated with DR as backup relay at various fault locations- CIGRE-3.

	Relay No		Fault current		Tripping time	
Fault location	**OCR—primary**	**DR—backup**	**Primary (A)**	**Backup (A)**	**OCR—primary**	**DR—backup**
L1	OCR1	DR2	735	735	0.034	0.4
L2	OCR2	DR3	892	892	0.279	0.4
L3	OCR3	DR4	1132	1132	0.518	0.61
L4	OCR4	DR5	1548	923	0.721	0.82
L5	OCR6	DR7	1112	1112	0.028	0.4
L6	OCR7	DR8	1507	1507	0.276	0.4
L7	OCR9	DR10	2370	2370	0.021	0.4
L8	OCR11	DR4	1132	1132	0.022	0.4
L9	OCR5	DR12	1995	1995	0.675	0.77
	Relay No		**Fault voltage**		**Tripping time**	
Fault location	**VR—primary**	**DR—backup**	**Primary (V)**	**Backup (V)**	**VR—primary**	**DR—backup**
L1	VR1	DR2	1.69	5.08	0.002	0.4
L2	VR2	DR3	2.10	6.31	0.080	0.4
L3	VR3	DR4	2.77	8.31	0.078	0.4
L4	VR4	DR5	4.02	11.90	0.080	0.4
L5	VR6	DR7	2.65	7.96	0.005	0.4
L6	VR7	DR8	3.79	7.75	0.081	0.4
L7	VR9	DR10	4.84	15.86	0.012	0.4
L8	VR11	DR4	2.76	8.31	0.036	0.4
L9	VR5	DR12	3.85	8.73	0.164	0.4

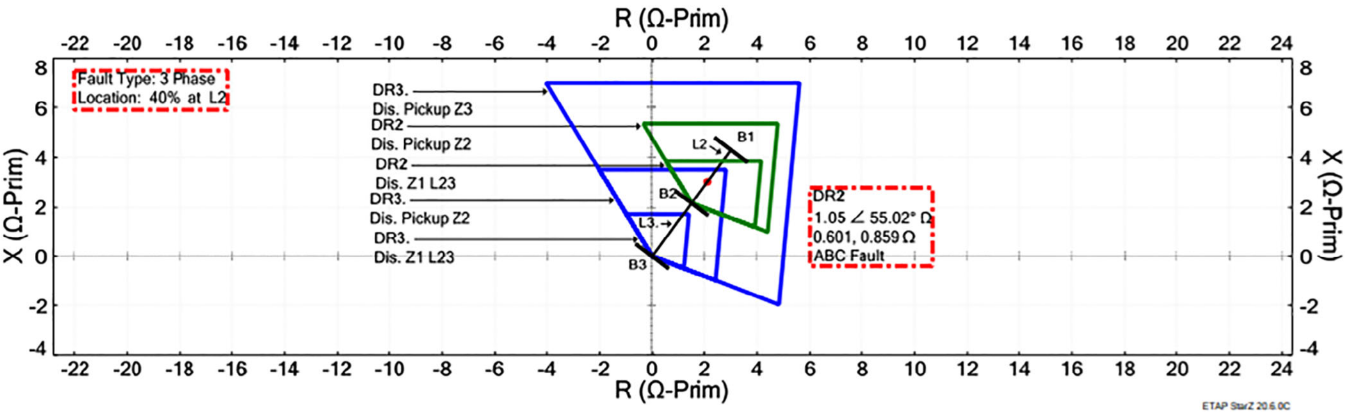

FIGURE 8 The experimental DR results at fault location L2 (DR2 and DR3).

OCR scheme. In addition, at each fault location, the VR scheme consistently achieves faster tripping times for both primary and backup relays. For example, the VR scheme records a tripping time of 0.159 and 0.288 s for primary and backup relays at fault located at L3, while the traditional OCR scheme's records 5.51 and 7.26 s.

Figure 9 demonstrates the advantages of the VR scheme over the traditional OCR approach in terms of faster fault response times across various fault types and network configurations (CIGRE-1 and CIGRE-3). The results highlight how the VR scheme consistently achieves shorter total tripping times, showing potential to improve fault isolation speed, which is especially valuable in modern grids that include distributed generation. In the CIGRE-1 network, the VR scheme significantly reduces tripping times for all fault types, with the most improvement seen in managing LL faults. While the OCR approach records a tripping time of 13.6 s for LL faults, the VR scheme reduces this to approximately 2.8 s. This shows that OCRs may struggle

TABLE 8 LL fault currents, fault voltages and tripping times for primary and backup OCRs and VRs at various fault locations- CIGRE-1.

	OCR scheme			VR scheme		
Fault current	**Current fault**	**OCR**	**Time**	**Voltage fault**	**VR**	**Time**
L1	304	OCR1	0.062	5.96	VR1	0.005
	304	OCR2	0.498	6.78	VR2	0.301
L2	356	OCR2	0.435	6.13	VR2	0.162
	356	OCR3	0.914	7.11	VR3	0.269
L3	429	OCR3	0.796	6.38	VR3	0.148
	429	OCR4	1.246	7.57	VR4	0.248
L4	540	OCR4	1.073	6.73	VR4	0.140
	540	OCR5	1.800	9.04	VR5	0.143
L5	356	OCR6	0.054	6.15	VR6	0.006
	356	OCR7	0.468	7.12	VR7	0.282
L6	429	OCR7	0.407	6.38	VR7	0.154
	429	OCR8	0.853	7.56	VR8	0.247
L7	924	OCR9	0.031	7.34	VR9	0.012
	924	OCR10	0.400	10.23	VR10	0.052
L8	429	OCR11	0.047	6.36	VR11	0.007
	429	OCR4	1.246	7.56	VR4	0.247
L9	726	OCR5	1.383	8.33	VR5	0.104
	726	OCR12	1.855	10.26	VR12	0.294
Total tripping time	13.6			2.8		

TABLE 9 LLG fault currents, fault voltages and tripping times for primary and backup OCRs and VRs at various fault locations-CIGRE-3.

	OCR scheme			VR scheme		
Fault current	**Current fault**	**OCR**	**Time**	**Voltage fault**	**VR**	**Time**
L1	414	OCR1	0.049	4.93	VR1	0.004
	414	OCR2	0.389	6.03	VR2	0.304
L2	518	OCR2	0.335	5.16	VR2	0.236
	518	OCR3	0.703	6.52	VR3	0.333
L3	660	OCR3	0.612	5.51	VR3	0.159
	660	OCR4	0.957	7.26	VR4	0.288
L4	921	OCR4	0.811	6.11	VR4	0.168
	921	OCR5	1.165	8.66	VR5	0.142
L5	653	OCR6	0.037	5.23	VR6	0.007
	653	OCR7	0.315	6.96	VR7	0.388
L6	462	OCR7	0.387	5.66	VR7	0.218
	462	OCR8	0.811	6.97	VR8	0.272
L7	1365	OCR9	0.026	7.35	VR9	0.015
	1365	OCR10	0.339	10.13	VR10	0.052
L8	648	OCR11	0.037	5.50	VR11	0.008
	648	OCR4	0.967	7.25	VR4	0.287
L9	1045	OCR5	1.074	7.35	VR5	0.090
	1045	OCR12	1.441	9.88	VR12	0.277
Total tripping time	10.5			3.2		

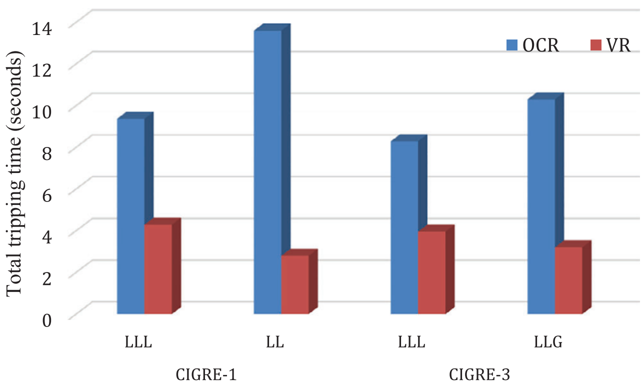

FIGURE 9 Total tripping time of VR and OCR over different faults and CIGRE network models.

to quickly clear certain fault types and raising the risk of instability. In contrast, the VR scheme's quicker response minimizes delays, improving overall network reliability and reducing the chance of faults spreading. For the CIGRE-3 network, which includes distributed generation sources, the VR scheme continues to show faster response times, particularly for LLL and LLG faults.

5 | CONCLUSIONS AND RECOMMENDATIONS

Effective coordination with DR is essential for rapid fault detection and isolation, minimizing response delays and preventing unnecessary outages across network zones. Recent research often suggests extending tripping times in zone 2 to address OCR-induced delays. However, this approach may compromise the speed and efficiency of the protection system, highlighting the need for alternative methods to enhance relay coordination without prolonging response times. The results of this study demonstrate that the proposed VR scheme significantly outperforms traditional OCR schemes in modern power systems. By utilizing voltage-based fault detection and integrating it with DRs, the VR scheme achieves faster fault isolation, reducing total tripping times. This reduction in tripping time is essential for minimizing system downtime and preventing fault escalation, which can lead to widespread disturbances in the grid. This performance improvement is especially critical in wind-integrated grids, where the variable nature of wind energy can cause fluctuations in fault current levels, affecting power system stability. For instance, the VR scheme at CIGRE-3 network achieves a total tripping time of 3.961 s, significantly faster than the traditional OCR scheme, which has a total time of 8.294 s. This reduction in response time is essential for minimizing fault propagation and ensuring minimal disruption to power system operations. The enhanced coordination provided by the VR scheme proves to be vital in maintaining the reliability and efficiency of grids that incorporate renewable energy sources such as wind. Moreover, the VR scheme maintained or enhanced the CTI, ensuring precise coordination across protection zones. Importantly, the OCR scheme recorded two mis-coordination events at locations L3 and L4, where it required an increase in tripping time by more than 0.4 s in zone 2. In contrast, the VR scheme successfully avoided any mis-coordination events with the DR, further demonstrating its superior reliability and performance. In general, the evaluation confirms that the VR-DR coordination scheme offers substantial improvements in both speed and coordination over traditional protection methods. Its ability to minimize tripping times while maintaining robust fault clearance enhances system stability and resilience during fault events. These advantages make the proposed scheme a highly effective solution for modern power grids, where more responsive and adaptable protection strategies are increasingly necessary. Future research should investigate adaptive relay settings or hybrid schemes could enhance fault management in increasingly complex networks.

AUTHOR CONTRIBUTIONS

Feras M. Alasali: Data curation; formal analysis; methodology; software; supervision; validation; writing—original draft; writing—review and editing. **Naser Naily**: Data curation; formal analysis; investigation; methodology; resources; software; validation; writing—original draft. **Haytham Mustafa**: Conceptualization; data curation; formal analysis; investigation; methodology; resources; software; writing—original draft. **Hassen Loukil**: Funding acquisition; investigation; software; supervision; validation; visualization; writing—original draft. **Saad M. Saad**: Data curation; formal analysis; investigation; methodology; software; validation; writing—original draft. **Abdelaziz Saidi**: Data curation; investigation; methodology; resources; software; supervision; validation; writing—original draft. **William Holderbaum**: Data curation; methodology; project administration; software; supervision; validation; visualization; writing—review and editing.

ACKNOWLEDGEMENTS

The authors would like to thank The Hashemite University and University of Salford for their support in publishing this article.

CONFLICT OF INTEREST STATEMENT

The authors declare no conflicts of interest.

DATA AVAILABILITY STATEMENT

Derived data supporting the findings of this study are available from the corresponding author on request.

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How to cite this article: Alasali, F., El-Naily, N., Mustafa, H.Y., Loukil, H., Saad, S.M., Saidi, A.S., Holderbaum, W.: Advanced voltage relay design for distance relay coordination in power networks equipped with low-inertia areas. IET Gener. Transm. Distrib. 19, e13338 (2025). https://doi.org/10.1049/gtd2.13338