Intelligent Coordination of Directional Relays for Protection of Radial Distribution Systems with Integrated Distributed Generation

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Abstract-- The integration of Distributed Generation (DG) into radial distribution networks introduces significant challenges for traditional overcurrent protection schemes, particularly with respect to relay–fuse coordination and fault selectivity. Variations in both the direction and level of fault currents caused by DG units can compromise the reliability of conventional recloser-based protection strategies. To address these challenges, this paper proposes an alternative protection approach in which directional overcurrent relays are deployed along the feeder, eliminating the dependence on a single recloser at the substation. The proposed scheme ensures selective fault isolation under different DG operating conditions and supports both fuse-saving and fuse-blowing protection philosophies. Unlike conventional approaches, the coordination logic remains effective regardless of the connection or disconnection status of DG units. The effectiveness of the proposed protection strategy is demonstrated through detailed time-domain simulations carried out on a representative radial distribution network using DIGSILENT PowerFactory. Simulation results confirm that the proposed method enhances coordination robustness and fault selectivity while maintaining compatibility with existing distribution protection infrastructure.Keywords: Distributed Generation, Distribution Systems, Overcurrent Protection, Protective Coordination.

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I. Introduction

Conventional overcurrent protection schemes in radial distribution systems are generally based on the installation of a recloser at the feeder head, coordinated with downstream protective devices such as overcurrent relays, sectionalizers, and lateral fuses. In certain network configurations, a circuit breaker at the feeder origin or additional reclosers installed at intermediate and terminal points of the feeder are also used. However, achieving proper coordination between reclosers and lateral fuses becomes particularly challenging when Distributed Generation (DG) units are connected to the feeder. To overcome these coordination issues, adaptive microprocessor-based reclosers have been proposed in [2] to enhance protective performance in active distribution networks. Despite their widespread application, these schemes typically require the disconnection of DG units prior to the first reclosing operation. Alternatively, non-adaptive microprocessor-based reclosers installed at DG interconnection points or schemes employing directional elements have been introduced in [3]; however, these approaches are unable to effectively evaluate relay coordination once DG units are reconnected to the network. Measurement-based coordination methods combined with feeder design considerations have also been investigated in [4] to improve recloser–fuse coordination in radial distribution systems. In [5], the replacement of lateral fuses with numerical reclosers or protective relays was proposed as a means to preserve overcurrent protection coordination in distribution systems with Distributed Generation (DG). The effectiveness of this approach was verified through simulations on two test distribution networks, demonstrating satisfactory performance even under conditions of fuse aging that could otherwise lead to miscoordination. Directional overcurrent relays have traditionally been applied in meshed or ring distribution systems; however, with the increasing penetration of DG, their application has been extended to radial distribution networks as well [6], [7]. To further enhance protection performance, communication-assisted directional overcurrent relays have been implemented in radial feeders to reduce the number of DG units that must be disconnected and to achieve faster fault isolation [8]. In addition, reclosing functions are commonly employed to restore the system to its normal operating state following temporary faults. For more advanced protection objectives, distance relays have been utilized in distribution networks to provide inherent fault detection and location capabilities, as reported in [9], [10]. Recently, protection schemes based on neural network algorithms have been proposed for distribution systems with Distributed Generation (DG) [11], [12]. Although these approaches can enhance fault detection accuracy, their computational complexity and response speed often limit their suitability for practical

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protection applications. In addition to data-driven methods, several current-based techniques have been investigated for protection design in active distribution networks. Analytical approaches relying on steady-state current calculations for balanced operating conditions have been presented in [13], while phase angle comparison methods have been employed as decision criteria in pilot protection schemes [14]. Furthermore, differential protection concepts have been extensively studied and successfully applied as unified protection solutions in microgrids [15]–[17]. Similar differential protection principles have also been implemented in advanced urban distribution systems using IEC 61850 communication standards [18]. In addition, a differential pilot protection scheme was evaluated on the IEEE 34-bus distribution system in [19].

The objective of this paper is to propose a novel overcurrent protection scheme for radial distribution systems with integrated Distributed Generation (DG). Unlike conventional approaches that rely on a recloser installed at the feeder head, the proposed scheme employs directional overcurrent relays installed on both sides of each line section. This configuration enhances protection coordination and fault selectivity under varying DG operating conditions, independent of the connection or disconnection status of DG units. Moreover, the proposed scheme is capable of operating in accordance with both Fuse Saving and Fuse Blowing protection philosophies. The proposed protection scheme differs from existing studies in several important aspects. Unlike most previous works that rely on reclosers as the primary device for protection coordination, this paper replaces conventional reclosers with directional overcurrent relays, providing a more effective solution for addressing the protection challenges introduced by Distributed Generation (DG). In addition, the proposed approach enhances coordination between protective relays and lateral fuses by employing directional elements and communication-assisted logic, ensuring reliable operation under various network configurations and DG operating conditions. Furthermore, a distinctive feature of the proposed scheme is its ability to support both Fuse Saving and Fuse Blowing protection philosophies within a unified framework, a capability that has received limited attention in prior studies.

The remainder of this paper is organized as follows. Section II presents a detailed description of the proposed protection scheme and its operating principles. Section III discusses the application of the proposed method to a radial distribution system and analyzes the simulation results. Finally, Section IV concludes the paper.

II. TWO PROPOSED OVERCURRENT PROTECTION SCHEMES

This paper introduces an overcurrent protection scheme that employs numerical directional overcurrent relays to protect radial distribution networks with integrated Distributed Generation (DG), eliminating the need for a recloser at the feeder head. The proposed scheme can be implemented using modern intelligent electronic devices equipped with standard communication capabilities. Furthermore, the protection strategy is designed to operate in accordance with both fuse-blowing (FB) and fuse-saving (FS) protection philosophies.

A. Logic of Protection Scheme Design

The proposed protection scheme is based on the deployment of directional overcurrent relays installed at both ends of each line section, as illustrated in Fig. 1. Each relay is denoted by the symbol R, where the subscripts specify the assumed direction of fault current flow. For a directional overcurrent relay Rjk, the fault current is considered to flow from bus j toward bus k. To ensure correct operation of the directional elements, accurate measurements of both voltage and current are required at each relay location. Consequently, appropriate current transformers (CTs) and voltage transformers (VTs) must be installed at these points along the feeder.

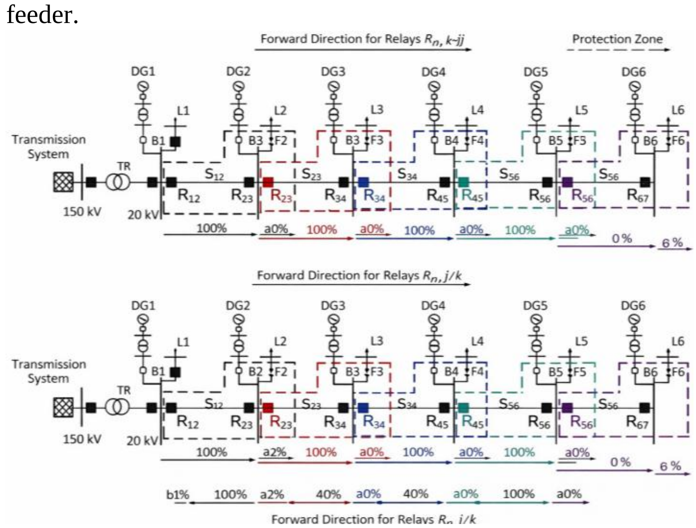

Fig. 1. Primary Protection Zones.

To properly set the directional elements of the relays, the proposed protection design requires the determination of the expected ranges of fault current angles and pre-fault voltage angles at all possible fault locations along the feeder [20]. Based on this information, each directional overcurrent relay Rjk is configured to detect faults occurring in the intended direction within its designated primary protection zone. Accordingly, coordination among relays is achieved through the appropriate definition of these primary protection zones. Specifically, the primary protection zone of relay Rjk is designed to include the entire line section Sjk, along with an additional portion extending into the adjacent line section Sk+1,j+1 in the direction of the relay. For instance, relay R23 is set to protect line S23 and an additional α% of line S34, whereas relay R32 covers line S23 and an α% extension of line S12 in the same direction. As a result, the primary protection zones of the relays partially overlap with the protection zones of adjacent lateral fuses. These bidirectional overlapping zones are illustrated on the network layout.

It should be noted that such overlapping cannot be uniformly applied at all locations, particularly at terminal buses such as B1 and B6. For example, in the case of relay

R21, the maximum overlap percentage b% is determined based on the defined protection boundaries to ensure that the transformer and bus B1 are fully covered by the primary protection zone. Similarly, for relay R56, the maximum allowable overlap percentage e% is selected to guarantee complete coverage of the protection zone associated with fuse F6. Furthermore, each relay is equipped with two time-delay stages (DT) for phase overcurrent elements and two corresponding DT stages for ground overcurrent protection. The first time-delay stage (DT) of each relay is configured to detect phase and ground faults occurring within the relay's primary protection zone. The second DT stage functions as a delayed backup element, which operates only if the primary relay fails to clear the fault. Accordingly, when a relay identifies a phase or ground fault within its primary protection zone or in close proximity to the fault location, the corresponding backup relay monitoring the same fault direction is required to operate after a predefined coordination time interval (CTI) to ensure proper selectivity.

B. Relay Settings

A detailed analysis is required to properly determine the settings of the phase and ground overcurrent elements of the relays at each location along the feeder. This process involves calculating the maximum and minimum short-circuit currents detected by each relay under all possible phase and ground fault conditions. To ensure accurate evaluation, simulations of common fault types—including three-phase, two-phase, two-phase-to-ground, and single-phase faults—are performed within both the primary and backup protection zones of each relay. These simulations account for the full range of short-circuit conditions resulting from balanced and unbalanced faults, as well as different DG connection scenarios and fault resistance values. To illustrate the proposed setting procedure, relay R34 is considered as an example. Short-circuit currents are first calculated for faults occurring within its primary protection zone, where the operating range of relay R34 is designed to extend by α% into line section S45. All relevant fault types and network operating conditions described above are incorporated into this analysis. Based on the calculated results, the maximum and minimum phase fault currents, denoted as Imaxpf,R34 and Iminpf,R34, are obtained to define the effective short-circuit current range for relay setting purposes. The calculated current ranges are then used to assess the performance of the phase overcurrent element of relay R34 under all possible network operating conditions. In a similar manner, the maximum and minimum ground fault short-circuit currents, denoted as Imaxef,R34 and Iminef,R34, are determined for faults occurring within the primary protection zone of relay R34. For instance, the highest phase fault current within this zone corresponds to a three-phase fault occurring in close proximity to the relay when two DG units are connected to bus B3. In contrast, significantly lower fault current levels are observed for a single-phase fault located at a distance of α% along line S45, with two DG units connected at buses B1 and B4. If notable differences in short-circuit current levels or overall network behavior are identified between grid-connected and islanded operating modes, separate relay settings must be defined. In such cases, the relays switch between the corresponding setting groups based on signals received from the islanding detection relay or the breaker status indicator [21]. Consequently, two distinct overcurrent time settings are specified for each phase and ground element: one for grid-connected operation and another for islanded mode.

C. Coordination Issues

The time settings of the phase and ground overcurrent elements must be carefully selected to ensure proper coordination between protective relays and lateral fuses. In a Fuse Blowing (FB) protection scheme, the time delays of the first and second stages, denoted as tRJK,1 and tRJK,2, are adjusted to allow sufficient time for the lateral fuse to operate prior to relay tripping. Consequently, when a fault occurs on a lateral branch, the fuse clears the fault before the upstream relay is activated. In contrast, under a Fuse Saving (FS) protection philosophy, the relays are required to operate faster than the fuses. In this case, reduced time-delay settings or instantaneous elements are applied to the first-stage phase and ground overcurrent functions. Accordingly, the timing of the relays installed at high- or medium-voltage levels must be properly coordinated to maintain overall system selectivity. In practical distribution networks, each DG unit is typically equipped with multiple protective devices [22]. Among these, voltage and frequency relays, overcurrent relays, and differential protection relays play a critical role in maintaining protection coordination. In accordance with international standards [23] and established industry practices, these devices are essential for the prompt disconnection of DG units during fault conditions. In islanded operating mode, system operation without DG units is generally not feasible, whereas in grid-connected mode, a variety of operating scenarios must be considered at different penetration levels.

D. Economic Evaluation

The deployment of protection equipment entails considerable investment, which is closely linked to the required level of reliability of the protection system. Even when high reliability is desired, installing relays along with voltage and current transformers (VTs/CTs) at multiple locations throughout the feeder inevitably increases the overall implementation cost. If such expenditures are viewed solely as network reinforcement costs, the investment may appear unjustifiable. However, a comprehensive economic assessment must take into account the operational and maintenance benefits expected by both the distribution system operator (DSO) and DG owners [24]. In this context, costs associated with service interruptions, increased system losses, forced disconnection of DG units, degradation of power quality, and potential regulatory or legal penalties represent critical factors for both DSOs and DG operators. These cost components should therefore be incorporated into the economic evaluation of protection schemes. It should be emphasized that all of these factors are strongly influenced by the performance and reliability of the protection system itself [25], [26]. From a broader perspective, regulatory bodies and policymakers increasingly encourage stakeholders to invest in modern power systems. Under current operating practices, many distribution system operators (DSOs) require the immediate disconnection of Distributed Generation (DG) units following the occurrence of faults. However, as the penetration level of DG continues to increase, this approach becomes progressively less viable, since DG owners are unlikely to invest in generation resources if frequent production curtailment is imposed due to network faults. The implementation of communication infrastructure involves relatively high capital costs, and its performance requirements must be aligned with the desired level of protection and control functionality. Nevertheless, communication networks in distribution systems are not solely deployed for protection purposes; they also serve as a fundamental enabler for various automation applications. In particular, distribution automation has the potential to significantly reduce operational and maintenance costs, thereby enhancing the overall economic efficiency of distribution networks [27].

III. THE STUDIED NETWORK

A. Description of the Test System

The effectiveness of the proposed overcurrent protection scheme was evaluated using the radial distribution network illustrated in Fig. 1. The test system operates at a nominal voltage of 20 kV and a frequency of 50 Hz and consists of a 50 km overhead feeder divided into five equal line sections. Line sections S12, S23, and S34 are constructed using ACSR conductors with a cross-sectional area of 95 mm², whereas sections S45 and S56 employ ACSR conductors with cross-sectional areas of 50 mm² and 35 mm², respectively. The total system load is 7.5 MW and 1.48 MVAR, with load L1 connected at bus B1 representing the aggregate feeder demand supplied from the substation. The upstream transmission network is modeled as a balanced voltage source with a maximum short-circuit capacity of 435 MVA and a minimum of 250 MVA. A synchronous generator with a cylindrical rotor, rated at 4.08 MW, 10.5 kV, and 50 Hz with a nominal power factor of cosϕn = 0.85, is considered as the DG unit. In grid-connected operation, the DG units are assumed to operate at unity power factor, whereas in islanded mode, voltage regulation is provided by one of the DG units. The DG units are connected to the distribution network through a 25 MVA, 20 kV (YN)/10.5 kV (D) step-up transformer operating at 50 Hz. Standard component models available in the DIgSILENT PowerFactory software are used to represent the studied system.

B. Fuse-Recloser Coordination

The main feeder is protected by an R-351 SEL recloser relay installed at the feeder head, operating with a reclosing sequence of 10 s, 5 s, and 0.5 s. Since no Distributed Generation (DG) units are connected to the downstream sections in this configuration, downstream monitoring is not required, and faults are assumed to occur only within the main feeder. The lateral branches are protected by fuses with a nominal current rating of 25 A. As the R-351 SEL recloser model is not available in the current version of DIgSILENT PowerFactory, a standard inverse-time overcurrent relay or an equivalent recloser model is used for simulation purposes. The coordination between the relay and the lateral fuse, based on a time–overcurrent protection scheme, is illustrated in Fig. 2. The upper and lower portions of the fuse characteristic curve correspond to the TC and MM fuse types, respectively. In this case, the Fuse Saving (FS) protection philosophy is applied. In the absence of DG units, proper coordination between the recloser and fuses ensures effective fault clearing for faults occurring at any location along the feeder.

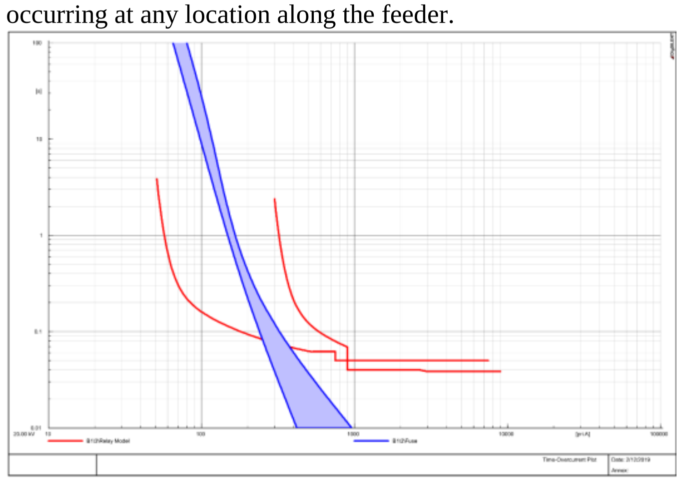

Fig. 2. Coordination diagram for the Recloser-Fuse scheme without DG.

As illustrated in Fig. 2, the simulation results confirm that proper coordination between the recloser and the lateral fuse is achieved. The dynamic response of the recloser under fault conditions is further examined in Fig. 3, which depicts its operation during a single-phase-to-ground fault with a fault resistance of 5 Ω occurring at bus 6. In this scenario, the phase overcurrent element of the recloser operates after approximately 1.42 s, whereas the ground overcurrent element responds in about 0.28 s. The recloser settings are selected based on the most severe operating condition, corresponding to a single-phase fault at bus 6. For fault locations closer to the recloser or the upstream network, the operating time of the recloser decreases accordingly. Since the fault is located outside the protection zone of the lateral fuse, the fuse does not operate in this case.

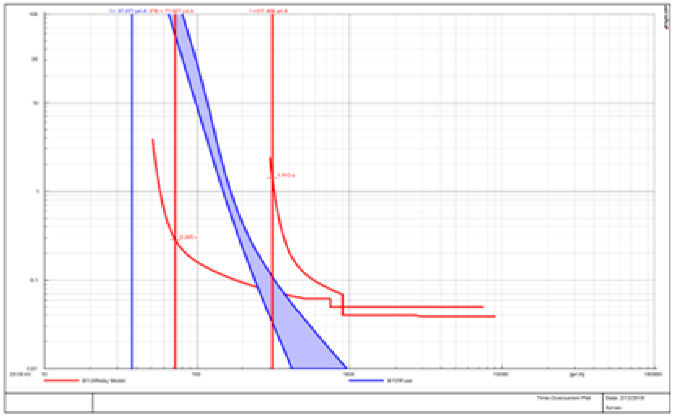

Fig. 3. Recloser performance for a single-phase fault under minimum short-circuit conditions.

Figure 4 illustrates a case in which the recloser fails to operate when a Distributed Generation (DG) unit connected at bus 4 is in service and a single-phase-to-ground fault with a resistance of 5 Ω occurs on the feeder. Under this condition, the contribution of the DG alters the fault current characteristics, resulting in the loss of proper protection coordination. Consequently, the recloser is unable to identify the fault condition and incorrectly interprets the fault current as normal load current.

$$t_{Rjk,1} = t^{max}{}_{TCFi} + CTI_{min}$$
$$t_{Rjk,2} = t^{max}{}_{TCFi} + CTI_{min}$$
$$t_2 = t^{max}{}_{Rjk,1} + CTI_{min} \quad (1)$$
$$t_4 = t^{max}{}_{Rjk,2} + CTI_{min}$$

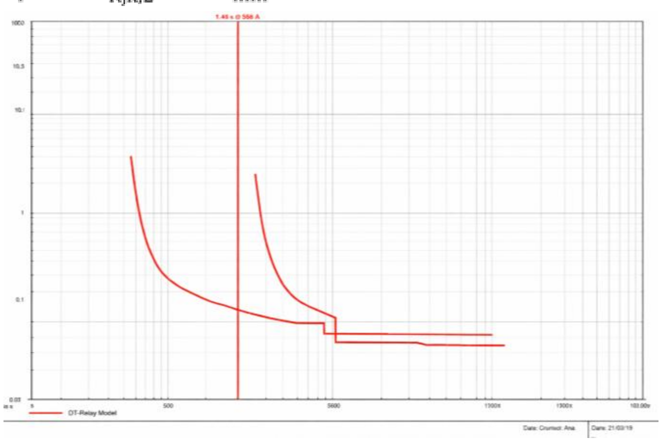

Fig.4. Failure of the recloser to operat for a single-phase fault under minimum short-circuit conditions with the presence of DG.

C. Application of the Proposed Protection Scheme

The proposed protection strategy replaces the recloser installed at the feeder head with directional overcurrent relays positioned at both ends of each line section. The total active load of the system is 7.5 MW, which allows the simultaneous connection of up to two DG units when the penetration level approaches 100%. Tables 1,2 presents the minimum phase current (Iϕ) and the ground return current (3I0) measured by the relays for faults occurring at the remote end of the feeder within the primary protection zone, considering both grid-connected and islanded operating modes. All possible DG connection scenarios are taken into account in these calculations. Owing to space limitations, the results corresponding to relays monitoring the opposite direction toward the upstream grid are not included in this section.

TABLE I

MINIMUM SHORT-CIRCUIT CURRENT AT THE FARTHEST POINT FOR PHASE IΦ AND GROUND 3I0, MEASURED BY THE RELAYS IN THE PRIMARY SIDE OF THE NETWORK ISLANDED MODE (ID/3I0) KA

DG location	R12	R23	R34	R45	R56
none	No LF	No LF	No LF	No LF	No LF
B1	No LF	No LF	No LF	No LF	No LF
B2	No LF	No LF	No LF	No LF	No LF
B3	No LF	No LF	No LF	No LF	No LF
B4	No LF	No LF	No LF	No LF	No LF
B5	No LF	No LF	No LF	No LF	No LF
B6	No LF	No LF	No LF	No LF	No LF
B1&B2	0.44/0.11	0.64/0.33	0.54/0.32	0.34/0.15	0.34/0.20
B1&B3	0.44/0.46	0.35/0.06	0.46/0.54	0.21/0.21	0.30/0.29
B1&B4	0.45/0.59	0.36/0.30	0.25/0.04	0.43/0.28	0.36/0.23
B1&B5	0.46/0.59	0.38/0.36	0.25/0.35	0.21/0.04	0.20/0.39
B1&B6	0.52/0.59	0.38/0.36	0.50/0.26	0.23/0.15	0.16/0.02

TABLE II

MINIMUM SHORT-CIRCUIT CURRENT AT THE FARTHEST POINT FOR PHASE IΦ AND GROUND 3I0, MEASURED BY THE RELAYS IN THE PRIMARY SIDE OF THE NETWORK GRID-CONNECTED MODE (ID/3I0) KA

DG location	R12	R23	R34	R45	R56
none	1.12/0.75	0.84/0.40	0.43/0.40	0.31/0.15	0.25/0.15
B1	1.14/0.76	0.64/0.40	0.52/0.30	0.30/0.19	0.26/0.15
B2	1.40/0.20	0.94/0.72	0.52/0.39	0.35/0.25	0.26/0.19
B3	1.26/0.70	0.85/0.05	0.50/0.65	0.60/0.62	0.33/0.35
B4	1.15/0.76	0.69/0.40	0.52/0.25	0.35/0.03	0.28/0.51
B5	1.12/0.78	0.95/0.65	0.45/0.04	0.32/0.39	0.39/0.15
B6	1.15/0.76	0.67/0.41	0.48/0.27	0.36/0.15	0.24/0.02
B1&B2	1.17/0.77	0.85/0.58	0.56/0.08	0.45/0.39	0.38/0.15
B1&B3	1.39/0.73	0.64/0.35	0.51/0.62	0.49/0.39	0.36/0.15
B1&B4	1.17/0.79	0.83/0.39	0.56/0.27	0.66/0.39	0.43/0.15
B1&B5	1.17/0.79	0.78/0.41	0.53/0.39	0.33/0.39	0.29/0.15
B1&B6	1.16/0.73	0.33/0.59	0.19/0.63	0.35/0.39	0.39/0.15

It should be noted that, since the trip delays of the overcurrent relays installed on opposite sides of the same line section Rjk are already taken into account, the relays facing the upstream grid (i.e., Rjk with k > j) do not need to be set for grid-connected operation. Under the Fuse Blowing (FB) protection philosophy, the first step is to determine the maximum clearing time of each lateral fuse, denoted as tmaxTCFi (i = 2, …, 6). Subsequently, for each corresponding relay–fuse pair, the first-stage operating time of the relay is selected such that it exceeds the sum of the maximum fuse clearing time TC and the minimum coordination time interval CTImin, which is typically set to 0.3 s. Based on this requirement, the time-delay settings DT for both operating stages, t1 and t2, are calculated by incorporating CTImin into the maximum total operating time of the first stage. In this manner, the coordination constraint is satisfied, ensuring proper selectivity between the relay and the fuse.In addition to relay–fuse coordination, appropriate coordination among the relays installed along the main feeder must also be ensured. The maximum fuse clearing time TC is obtained by simulating a wide range of short-circuit scenarios at the most downstream location of each fuse under various operating conditions. The simulation results indicate that, in grid-connected mode, the highest fuse clearing time occurs under minimum short-circuit current conditions and when no DG units are connected to the network. Tables 3 and 4 summarize the results obtained from simulations performed under islanded operating conditions. As shown, lower fault current levels are observed for different combinations of DG connection and disconnection. For example, in the case of relay R12, the minimum fault current associated with a single-phase fault at the remote end of its primary protection zone occurs when two DG units are connected at buses B1 and B2, as highlighted in the tables. Similar trends can be observed for the remaining relays, where higher fault current values are obtained under other operating scenarios.

TABLE III
THE FAULT CURRENTS OBTAINED FROM THE SIMULATION IN ISLANDED MODE FOR RELAYS FORWARD.

DG CONNECTION	R21 (IΦ/3I₀)	R32 (IΦ/I₀)	R43 (IΦ/I₀)	R54 (IΦ/3I₀)	R65 (IΦ/I₀)
NONE	NO LF	NO LF	NO LF	NO LF	NO LF
B1 & B2	0.32 / 0.12	0.80 / 0.15	0.05 / 0.6	0.34 / 0.06	0.33 / 0.05
B1 & B3	0.28 / 0.06	0.42 / 0.5	0.05 / 0.1	0.31 / 0.03	0.35 / 0.51
B1 & B4	0.25 / 0.04	0.31 / 0.3	0.22 / 0.04	0.33 / 0.6	0.35 / 0.55
B1 & B5	0.21 / 0.03	0.19 / 0.03	0.31 / 0.3	0.42 / 0.48	0.37 / 0.55
B1 & B6	0.18 / 0.02	0.19 / 0.12	0.28 / 0.21	0.30 / 0.30	0.40 / 0.56

TABLE IV
THE FAULT CURRENTS OBTAINED FROM THE SIMULATION IN ISLANDED MODE FOR REVERSE RELAYS.

DG AT	R21	R32	R43	R54	R65
NONE	NO LF	NO LF	NO LF	NO LF	NO LF
B1 & B2	0.32/0.12	0.80/0.15	0.05/0.6	0.34/0.06	0.33/0.05
B1 & B3	0.28/0.06	0.42/0.5	0.05/0.1	0.31/0.03	0.35/0.51
B1 & B4	0.25/0.04	0.31/0.3	0.22/0.04	0.33/0.6	0.35/0.55
B1 & B5	0.21/0.03	0.19/0.03	0.31/0.3	0.42/0.48	0.37/0.55
B1 & B6	0.18/0.02	0.19/0.12	0.28/0.21	0.30/0.30	0.40/0.56

Table 5 presents the fault currents obtained from simulations conducted in grid-connected mode for the forward relays. Owing to the large number of evaluated operating scenarios, only the most critical cases are emphasized and highlighted in the table. Specifically, these highlighted values correspond to the minimum fault current levels observed for each relay. Based on this analysis, the lowest fault current associated with each forward relay is extracted and summarized in Table 6. These minimum current values represent the critical operating conditions considered for relay setting and coordination studies.

TABLE V
The fault currents obtained from the simulation in grid-connected mode for forward relays.

DG at	R12	R23	R34	R45	R56
none	1.06/ 0.75	0.61/ 0.42	0.41/ 0.24	-	-
B2	1.47/ 0.16	-	-	-	-
B3	-	0.85/ 0.07	-	-	-
B4	-	-	0.52/ 0.04	-	-
B5	-	-	-	0.35/ 0.03	-
B6	-	-	-	-	0.24/ 0.02
B5(2)	-	-	-	0.29/ 0.04	-
B2 & B5	-	-	-	-	0.18/ 0.02

TABLE VI
Overcurrent-time settings

Relay	Isl: (Iφ1/3I0) A	Isl: (Iφ2/3I0) A	Isl: tRjk1 (s)	Isl: t2 (s)	Grid: (Iφ1/3I0) A	Grid: (Iφ2/3I0) A	Grid: tRjk1 (s)	Grid: t2 (s)
R12	394/99	312/54	0.41	2.10	954/146	549/62	0.35	1.75
R23	312/54	234/36	0.61	2.10	549/62	369/36	0.44	1.75
R34	234/36	198/27	0.87	2.10	369/36	261/27	0.64	1.75
R45	198/27	135/18	1.21	2.10	261/27	158/18	0.96	1.75
R56	135/18	-	1.73	-	158/18	-	1.42	1.75
R21	162/18	-	0.45	0.80	153/81	-	0.35	0.75
R32	171/27	162/18	0.45	0.80	180/54	153/81	0.35	0.75
R43	198/36	171/27	0.48	0.80	216/54	180/54	0.39	0.75
R54	279/300	198/36	0.48	0.80	252/72	216/54	0.41	0.75
R65	297/450	279/300	0.50	0.80	324/126	252/72	0.41	0.75

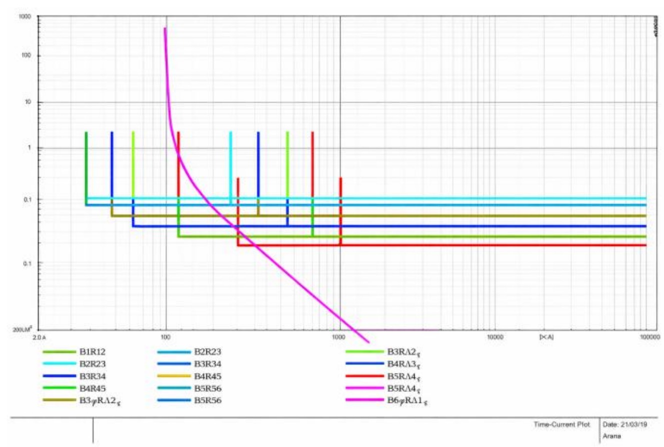

Fig.5. Fuse-relay coordination for grid-connected operation.

Figure 5 illustrates the relay–fuse coordination obtained from simulation results under grid-connected operation using the Fuse Blowing (FB) protection scheme. As shown, proper coordination between the relays and the lateral fuse is achieved, confirming the correct operation of the proposed protection settings.

Figure 6 presents the corresponding coordination results under islanded operating conditions. As indicated in both figures, the FB protection philosophy is successfully implemented, with the fuse operating prior to the associated relays. In addition, adequate coordination among the relays themselves is maintained, ensuring selective and reliable fault isolation in both operating modes.

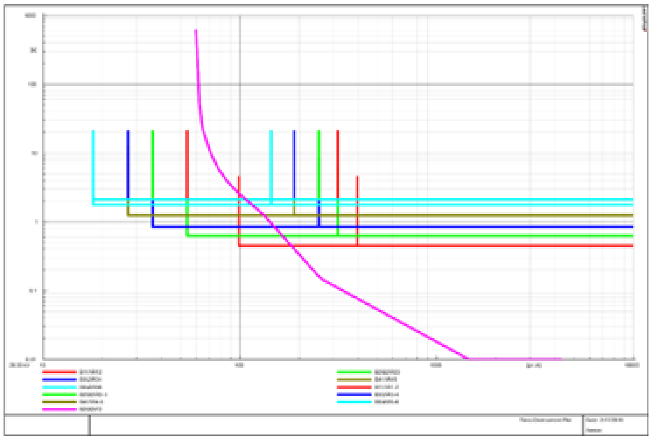

Fig.6. Fuse-relay coordination for islanded operation.

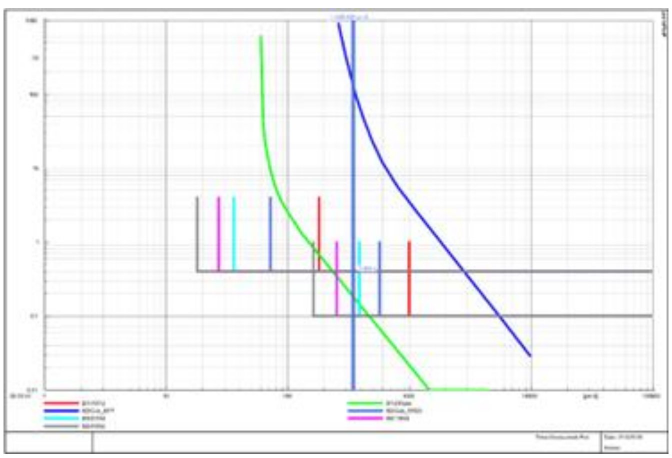

Fig.7. Fuse-relay coordination for grid-connected operation in the FS scheme.

The coordination problem associated with the Fuse Blowing (FB) scheme is addressed by replacing the 25 A lateral fuses with 125 A fuses. Figure 7 illustrates the minimum fault current resulting from a single-phase fault evaluated across all fuse locations in the network, together with the characteristic curve of the 125 A fuse. As shown, this replacement improves coordination by ensuring that the minimum fault current intersects the fuse characteristic under most operating conditions. However, the use of a 125 A fuse introduces a specific limitation. In the event of a fault occurring at fuse 6, the resulting fault current is approximately 242 A, which does not intersect the operating characteristic of the 125 A fuse. Consequently, the fuse fails to operate under this condition, as demonstrated in Fig. 8.

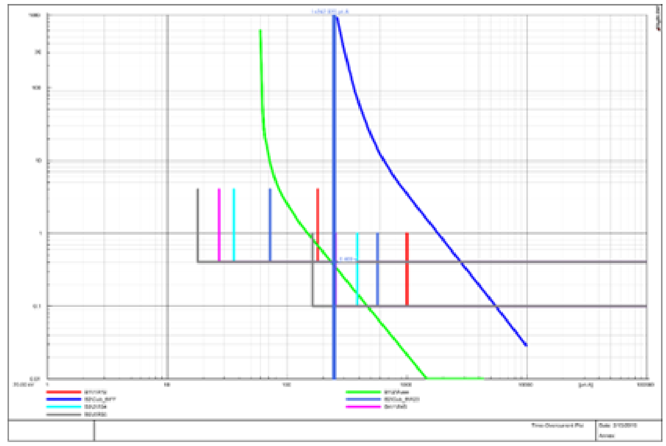

Fig.8. Fuse-relay coordination for islanded operation in the FS scheme.

IV. CONCLUSION

This paper presented a communication-assisted protection scheme for radial distribution networks with Distributed Generation (DG). The proposed approach employs shared directional overcurrent relays to enhance protection coordination and selective tripping performance within the main feeder as well as at the lateral branches. By improving relay selectivity, the scheme ensures reliable operation under both grid-connected and islanded operating conditions. Furthermore, the results indicate that replacing lateral fuses with relays can significantly improve the overall reliability of the protection system. Extensive simulation studies conducted using DIgSILENT PowerFactory confirm the effectiveness and robustness of the proposed method across a wide range of operating scenarios and fault conditions.

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