Electrical Power and Energy Systems 172 (2025) 111119

Contents lists available at ScienceDirect

International Journal of Electrical Power and Energy Systems

journal homepage: www.elsevier.com/locate/ijepes

Multi-path routing based intelligent fault detection strategy for microgrids

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ARTICLE INFO

Keywords:
IEC 61850
Microgrid
Multi-path routing
Overcurrent relay
Protection coordination

ABSTRACT

The increasing integration of renewable energy sources (RES) and frequent topological changes in modern power systems pose significant challenges to overcurrent protection. These include non-selective tripping, protection miscoordination, and fault detection failures. This paper proposes a novel routing-based protection strategy that leverages multiple communication paths, classified as Main, Reserved, Source, and Reference, to enhance fault localization and coordination. Faults are mapped across routing areas (RAs), and information is exchanged via Intelligent Electronic Devices (IEDs) using the IEC 61850 protocol. Each path comprises Flow Areas (FAs) with neighboring IEDs that dynamically contribute to fault clearing based on their role in the path. Unlike conventional methods, the proposed strategy does not require changes to relay settings during faults. It ensures effective operation regardless of the location or penetration level of distributed generation (DG) units. Additionally, it addresses challenges related to fault current direction changes caused by topology shifts, and it enables IEDs to detect and learn new connection points in real time. The strategy is validated through simulations in ETAP, demonstrating improved selectivity, coordination, and reliability under diverse fault scenarios.

1. Introduction

1.1. Background and challenges

The increasing integration of distributed generation (DG) units, such as solar photovoltaic and wind turbines, into distribution grids has transformed conventional power systems into more flexible and decentralized structures. This transformation not only enhances energy efficiency and reliability but also contributes to reducing greenhouse gas emissions and mitigating environmental pollution [1]. The emergence of microgrids — small-scale power grids capable of operating both in grid-connected and islanded modes — offers additional benefits, including improved energy security, better utilization of renewable energy resources, and reduced transmission losses. However, these advantages come with new technical challenges, particularly in the protection of distribution grids.

Overcurrent relays are fundamental protection devices in distribution grids, designed to operate based on the magnitude of current without considering its direction. As a result, they are classified as non-directional relays. The integration of DG units into modern distribution grids introduces bidirectional power flows, which significantly complicate fault detection and isolation. In cases where fault currents originate from multiple directions, non-directional relays are unable to precisely identify the fault location, leading to incorrect relay operations. Proper coordination among relays is essential to ensure that the nearest protective device isolates the fault without unnecessary intervention from backup devices [2]. One of the primary challenges in distribution grids is the coordination of overcurrent relays with other protective devices. The complexity of this task increases in large-scale distribution grids, where numerous protective devices are deployed. Inaccurate relay settings can result in malfunctions, such as the failure to trip, unnecessary tripping of backup relays, or equipment damage [3–5]. Another critical issue is sympathetic tripping, in which relays operate erroneously in response to disturbances on adjacent feeders, even in the absence of faults in their designated zone. Moreover, selectivity — the ability of protective devices to isolate only the faulted section while maintaining the operation of the rest of the system — becomes particularly challenging in the presence of DGs. This issue arises when fault currents exceed predefined thresholds or when multiple power sources feed the fault point from different sections of the grid [6].

The widespread deployment of microgrids further exacerbates these challenges due to their flexible configurations and dynamic operational modes. Two key protection challenges in microgrids are as follows:

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https://doi.org/10.1016/j.ijepes.2025.111119
Received 15 March 2025; Received in revised form 19 August 2025; Accepted 8 September 2025
Available online 16 September 2025

- **Multi-Directional Current Flow:** The presence of numerous protection devices in the grid, combined with bidirectional power flows, makes it difficult to accurately determine the fault location. This issue becomes more severe in looped grid topologies, where fault currents may circulate, causing relays to misoperate. Consequently, some relays may detect large fault currents with sudden directional changes, resulting in incorrect tripping.
- **Miscoordination of Protective Devices:** When fault currents exceed predefined thresholds, backup protections may operate incorrectly. Two scenarios can occur: (1) The operating curves of the main and backup relays overlap, leading to simultaneous tripping and (2) the time delay between the main and backup relay settings is insufficient, causing the backup relay to operate before the main relay.

Conventional protection schemes in microgrids face significant limitations due to the distinctive characteristics of these grids. During islanded operation, inverter-based DGs generate limited fault currents, which may be insufficient to activate overcurrent relays. Consequently, fixed relay settings designed for grid-connected modes become ineffective in islanded conditions [7]. Additionally, the variability in fault current paths and magnitudes caused by DGs may result in sympathetic tripping or failure to trip. The looped topology commonly found in microgrids further complicates fault detection, reducing the effectiveness of protection devices in isolating faults.

1.2. Literature review

The challenges in protection systems arising from DG integration can be categorized into two main groups: operational changes and structural modifications. The widespread deployment of DGs throughout the grid complicates the selective coordination of protective devices due to bidirectional power flows and fluctuating fault current magnitudes. Achieving optimal coordination settings to minimize unnecessary tripping while ensuring fault isolation remains a critical issue. Under certain operating conditions, DGs may induce reverse power flows, rendering conventional overcurrent protection schemes ineffective [8]. Conventional overcurrent protection systems, originally designed for centralized power generation, may not accurately respond to altered fault currents at different distribution grid locations [9]. Consequently, the time-current characteristics of protective devices often require recalibration to accommodate the changing fault behavior introduced by DGs. These challenges become more pronounced in grids with higher DG penetration levels, where the complexity of coordination tasks increases.

One approach to mitigate excessive fault currents involves controlling the fault current contributions from DGs by strategically placing generation units within the grid. Proper DG placement helps maintain both the original relay coordination and the maximum DG penetration level. Additionally, limiting the fault current contribution of inverter-based resources has been proposed to reduce miscoordination risks [10]. However, managing these resources presents operational challenges for both system operators and resource owners. Identifying fault location and direction is essential to preserve coordination, with distance relays and differential relays being two common solutions. Distance protection strategies, such as those proposed in [11,12], offer fault detection based on impedance measurements along the line. Protection and fault management in distribution networks face increasing complexity due to the presence of high impedance faults (HIFs), which are difficult to detect using conventional strategies. As highlighted in [13], enhancing HIF detection requires advanced strategies such as harmonic analysis and experimental validation. These approaches improve detection accuracy and reinforce the reliability of protection schemes in modern distribution systems. Differential protection schemes are widely employed in microgrids due to their fast fault detection capability, often supported by communication-based pilot protection systems [14]. Communication systems play a crucial role in enhancing protection system performance. Depending on the type of protection scheme, these systems can operate using either centralized or decentralized architectures [15,16]. The timely exchange of measurement data is critical for fault clearance and coordination. Several studies propose adaptive protection strategies that dynamically update relay settings in real time to accommodate changes in operating conditions caused by DG integration [17]. However, the effectiveness of these systems relies heavily on accurate measurements and reliable communication channels. Agent-based protection systems have been introduced to improve the intelligence and adaptability of protection schemes [18]. These systems utilize self-decision-making algorithms and standardized communication protocols, such as IEC 61850, to enhance coordination efficiency [19].

In microgrids, coordination challenges arise not only from the integration of DG and fluctuations in fault current levels but also from the geographical placement of DG units, which directly affects the operation of primary and backup relays [20]. The flexible configurations and operational strategies of microgrids frequently alter grid topologies, complicating the definition of protection zones and coordination strategies. These topological changes introduce new current-carrying paths to fault points, increasing the likelihood of overcurrent relay miscoordination. Consequently, multiple relays may trip simultaneously, or relays on unaffected feeders may mistakenly operate, jeopardizing system reliability. Additionally, grid reconfigurations may cause line currents to surpass the rated capacity of protective devices, triggering unnecessary trips and leading to power interruptions. Failure to appropriately adjust protection coordination settings in response to these dynamic changes can result in mismatches between primary and backup relays, ultimately causing inadequate fault isolation, false trips, or failure to trip. Despite the growing need for adaptive protection systems, many grid operators avoid frequent modifications to protection schemes due to cost and operational complexity. However, while DG integration enhances power loss reduction and voltage profiles, it simultaneously increases the probability of protective device malfunctions and unintended outages. Effective fault detection and isolation in microgrids require the prompt identification of faults, both within the microgrid and at its boundaries with the external grid. Achieving this requires protection systems capable of balancing selectivity and operational speed while ensuring high reliability against device malfunctions [21].

To address these challenges, advanced intelligent protection schemes are being developed to maintain the reliable operation of overcurrent relays in dynamic microgrid environments. These schemes leverage the impact of DG on fault current behavior, enabling adaptive relay coordination that enhances both stability and efficiency. Information theory (IT)-based methods play a pivotal role in modern protection systems by facilitating real-time monitoring, adaptive protection settings, and seamless coordination among protection devices. These innovations not only improve fault detection and isolation but also optimize the overall performance, robustness, and reliability of the protection system.

1.3. Aims and contributions

In this paper, a routing-based protection strategy is proposed to enhance the reliability and selectivity of distribution grids in the presence of DG units. The solution aims to accurately detect faulty feeders while preventing the disconnection of non-faulty feeders. The proposed strategy utilizes the identification of multiple fault current paths leading to the fault point within the microgrid. Each path consists of one or more Flow Areas (FAs), where Neighboring Intelligent Electronic Devices (IEDs) are strategically positioned along the route. Depending on their designated roles in the operating path, the IEDs within each FA actively contribute to fault detection and clearing. To the best of our knowledge, it is the first time that the multi-path routing technique has been employed in power system protection studies.

The primary contributions of the proposed strategy are as follows:

Table 1
Comparison of the proposed strategy with some existing smart protection strategies.

Reference	Current direction detection scheme	Topological detection scheme	Centralized/ Decentralized	Supported topology	Advantages
[22]	Using central controllers	Mapping the grid by the all agent's types information	Centralized	Radial and loop	Using multi-agent system to protect the grid
[23]	Failure to detect reverse current	Failure to detect grid reconfiguration	Centralized	Radial	Less latency rather than conventional multi-agent system to maintain the coordination
[24]	Necessity to have bi-level protection	Failure to detect grid reconfiguration	Decentralized	Radial	Having protection redundancy scheme to keep the coordination
[25]	Using directional relays	Failure to detect grid reconfiguration	Decentralized	Radial	Using a directional relay to keep the selectivity
Current work	Using routing area tables	Knowing the topological changes by multi-path detection method	Decentralized	Radial and loop	Using FAs to prevent unexpected trip and finding new connection points during the fault

- Fault clearing performance is independent of DG location and penetration levels;
- Challenges associated with fault current direction due to topological changes are effectively mitigated;
- Protection settings remain fixed during fault conditions, eliminating the need for frequent setting updates; and
- New connection points introduced during faults are automatically detected and learned by protection IEDs, enhancing the adaptability of the protection system.

Table 1 presents a comparison between various smart protection strategies and the proposed solution. The evaluation highlights significant differences in fault current direction detection and topological recognition capabilities. The centralized strategy in [22] employs multi-agent systems to protect the grid by mapping the entire system, supporting both radial and loop topologies. However, centralized methods typically involve higher latency and communication overhead. The solution in [23] demonstrates lower latency but struggles to detect reverse currents and grid reconfigurations. In [24], a decentralized bi-level protection strategy improves redundancy but fails to detect dynamic topological changes. Similarly, the solution in [25] utilizes directional relays to maintain selectivity but does not effectively handle grid reconfigurations. In contrast, the proposed decentralized strategy leverages routing area tables and a multi-path detection mechanism to dynamically identify topological changes. This approach supports both radial and loop topologies, enhancing fault isolation by defining FAs. The key advantage of this solution lies in its ability to prevent unexpected trips and automatically identify new connection points during faults, significantly improving the reliability and adaptability of the protection system.

1.4. Paper organization

The remainder of this paper is organized as follows. Section 2 describes the impact of fault current direction on protection performance. An overview of the multi-path routing technique is presented in Section 3. Section 4 introduces the routing based proposed protection strategy. Section 5 evaluates the effectiveness of the solution. Finally, the conclusion is presented in Section 6.

2. Assessment of microgrid fault current flow

The reliability of overcurrent protection schemes in power systems is significantly influenced by the direction and path of fault current. With the integration of DG and the increasing complexity of grid topologies, traditional assumptions about unidirectional current flow no longer hold. This shift introduces challenges in relay coordination, potentially leading to protection failures or false operations. This section addresses this issue by analyzing two critical aspects: the direction of fault current and its path. Fig. 1 shows the decision-making process involved in fault current analysis and how it impacts relay operation and coordination strategies.

2.1. Fault current direction

In conventional distribution grids, electricity typically flows in one direction, from the grid to the loads. However, this unidirectional current flow can be altered, primarily due to the integration of DG units. Such alterations can significantly affect the operation of overcurrent relays, influencing both the magnitude and the direction of fault currents, depending on the location of the relays. In the event of a fault, two potential current flow states arise, each having a distinct impact on protection coordination:

(i) **Forward Current Flow (FCF):** In this scenario, the fault current flows in the conventional direction, from the grid side towards the fault point. As shown in Fig. 2a, this type of fault typically involves the disconnection of only one faulty area from the grid. Effective coordination between the main and backup relays is critical in this case. When relay R2 operates, the fault is cleared, ensuring the grid returns to a stable state.

(ii) **Backward Current Flow (BCF):** In contrast, during a BCF scenario, the current flows from another part of the grid back towards the fault point. This condition can result in multiple faulty areas, requiring careful attention to prevent the misoperation of relays located in healthy regions. Fig. 2b demonstrates a case where a fault occurs between relays R2 and R3. In such a situation, relay R4 may operate faster than relay R3 due to reverse current injection into the grid from DG sources.

Mathematically, the total fault current I_f at the fault location is the algebraic sum of contributions from all available sources as

$$I_f = \sum_{i=1}^{q} I_i, \tag{1}$$

where I_i represents the current contribution from the ith source, such as the main grid or DG units.

In a FCF condition, where the grid is the only fault current source, one can write

$$I_f = I_{\text{Grid}} \text{ and } I_{\text{DG}} = 0, \tag{2}$$

where I_{Grid} and I_{DG} are the fault current contribution from the grid and DG unit, respectively.

In a BCF scenario especially in systems with active DGs, the total fault current is expressed as

$$I_f = I_{\text{Grid}} + \sum_{j=1}^{m} I_{\text{DG}_j} \tag{3}$$

where m is the number of DG units feeding the fault.

This leads to complex directional current flows and possible miscoordination. The current measured by relay R, I_R, is determined by the direction and path of I_f as

$$I_R = \begin{cases} +I_f, & \text{Forward Current} \\ -I_f, & \text{Backward Current.} \end{cases} \tag{4}$$

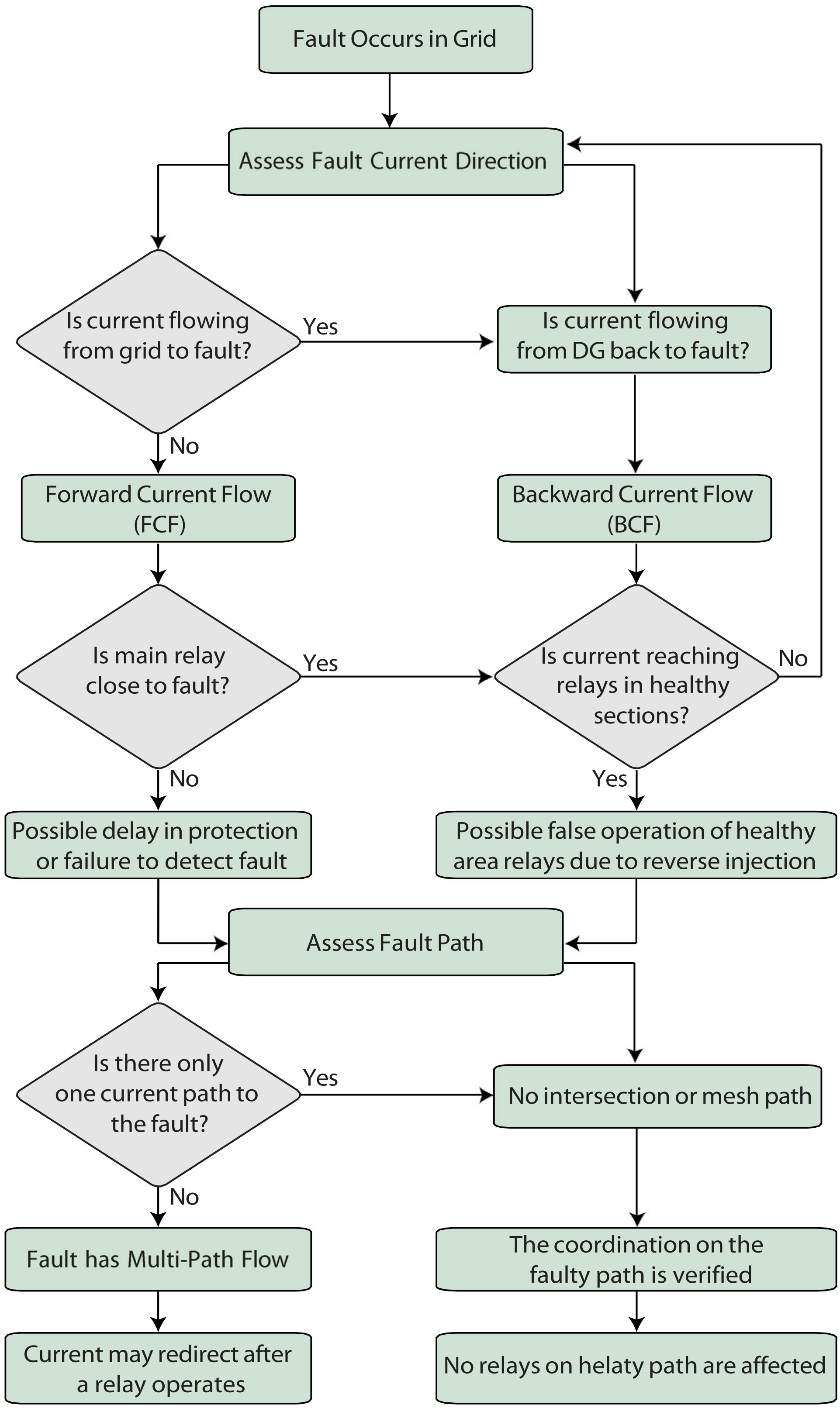
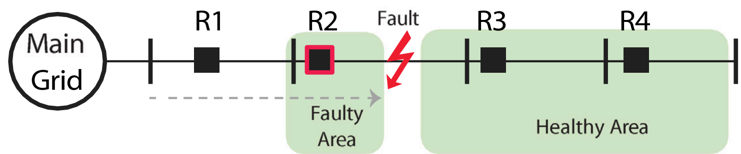
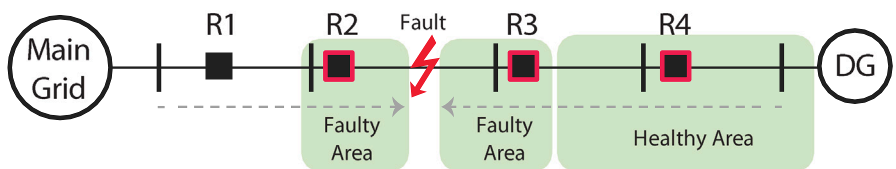


Fig. 1. Relay coordination strategy based on fault current direction and path.

The occurrence of various fault conditions can lead to performance failures in protective relays, necessitating a comprehensive evaluation of both FCF and BCF scenarios. Grid modifications — such as the introduction of DGs and changes in topology — can alter the direction of the current flow, thereby affecting the relay's operation. Consequently, relays may need to be reconfigured to account for these changes and ensure proper operation during fault conditions. To guarantee the optimal functioning of each protective relay, appropriate settings must be applied within the designated protection zones. In the event of a fault, the relay(s) closest to the fault point must operate when a fault



(a)



(b)

Fig. 2. Fault current flow in the microgrid. (a) Forward current flow and (b) backward current flow.

current is detected. The grid's fault current state is generally described as follows.

2.2. Fault current path

When no intersection exists between busbars, the fault current follows a single path to the fault point. However, the path of fault current can be altered due to grid reconfigurations or changes in the grid from a radial to a looped or meshed topology. Such alterations can impact the sequence of relay operations, leading to the categorization of fault current paths into two distinct states:

- **Single-path Current:** Fig. 3a shows a single-path fault, where the fault current flows solely through one path towards the fault point. In this situation, certain grid areas may not experience fault current, especially if no DGs are injecting fault current. The primary protection system can efficiently clear the fault, with straightforward coordination between the main and backup relays. The backup relay is activated after an appropriate time delay. Relay R2 serves as the primary relay, with no additional current paths to the fault point. Once R2 operates, the system returns to normal, with load current resuming and healthy feeders remaining connected and operational. Relay R1 serves as a backup to ensure the fault is cleared if necessary.
- **Multi-path Current:** Fig. 3b shows a scenario in which the fault current direction changes in two stages—before and after the operation of the protection system. Initially, coordination between relays R1 and R2 is essential. In the second stage, if relay R2 operates, the fault current, which is sufficiently large to trigger other relays, changes its direction to seek a new path towards the fault location. The presence of a multi-directional current can lead to the misoperation of relays on healthy feeders. In this scenario, relays R4, R5, and R6 may operate more quickly than relay R3 due to reverse current injection.

To ensure proper coordination between two directional overcurrent relays (main and backup), the IEC standard recommends a minimum coordination time interval (CTI) of 300 ms. This means that the operating time of the upstream relay (backup) should be delayed enough so that the downstream relay (main) has time to operate first. The fundamental coordination condition is given by

$$\Delta t = t_{\mathrm{BR}} - t_{\mathrm{MR}} > t_m, \tag{5}$$

where t_{MR} and t_{BR} are the operating times of main and backup relays, respectively. t_m is the required coordination time interval, typically 300 ms. To satisfy this inequality, the time multiplier setting (TMS) of backup relay must be selected appropriately. The standard IEC inverse time current characteristic is used for this derivation. The equation derived for ensuring this coordination is expressed as

$$\frac{A_{\mathrm{BR}} \times \mathrm{TMS}_{\mathrm{BR}}}{(I_f/I_{p_{\mathrm{BR}}})^{n_{\mathrm{BR}}} - 1} - \frac{A_{\mathrm{MR}} \times \mathrm{TMS}_{\mathrm{MR}}}{(I_f/I_{p_{\mathrm{MR}}})^{n_{\mathrm{MR}}} - 1} \geq \Delta t \text{ (ms)}, \tag{6}$$

where A is the constant from the IEC characteristic curve (dependent on relay type). $I_{p_{\mathrm{MR}}}$ and $I_{p_{\mathrm{BR}}}$ are the pickup currents of main and backup relays, respectively. n is the curve exponent based on IEC standard.

Using the IEC standard CTI of 300 ms, (6) is rearranged as

$$\mathrm{TMS}_{\mathrm{BR}} \geq \frac{(I_f/I_{p_{\mathrm{BR}}})^{n_{\mathrm{BR}}} - 1}{A_{\mathrm{BR}}} \times \left[300(\mathrm{ms}) + \frac{A_{\mathrm{MR}}}{(I_f/I_{p_{\mathrm{MR}}})^{n_{\mathrm{MR}}} - 1} \times \mathrm{TMS}_{\mathrm{MR}}\right]. \tag{7}$$

This final equation is critical in relay coordination planning because it explicitly shows how the TMS of the main relay must be chosen to ensure selective operation in the presence of fault current I_f, taking into account the backup relay's settings and network parameters.

3. Multi-path routing technique based fault isolation

This section provides a structural explanation of the multi-path fault isolation logic by focusing on how communication paths are defined and utilized within the protection framework. While mathematical modeling is not the primary focus here due to the nature of routing-based design, the interactions between nodes, routing tables, and IEDs are systematically discussed to justify how the scheme operates in a real-world communication network.

3.1. Basics of path definition

In computer networks, a "path" refers to the route that data follows from the source to the destination, passing through various network devices, known as nodes. When multiple paths exist between the source and destination, it becomes crucial to select the optimal route. Typically, the path with the fewest "hops" — intermediate points through which the data passes — is preferred. For example, as shown in Fig. 4, node A may choose the path with fewer hops to reach node B. Paths are classified into two categories: Main and reserved paths. The main path is the primary route designated for data transmission, whereas reserved paths act as backups in the event of disruptions to the main path. Reserved paths typically involve more hops but ensure the network's reliability. As the network scales, the importance of selecting the most efficient main and reserved paths becomes more significant. To effectively manage routing and guarantee reliable data transfer, nodes maintain a routing table, which records various routes to each destination. In a meshed network, the existence of multiple

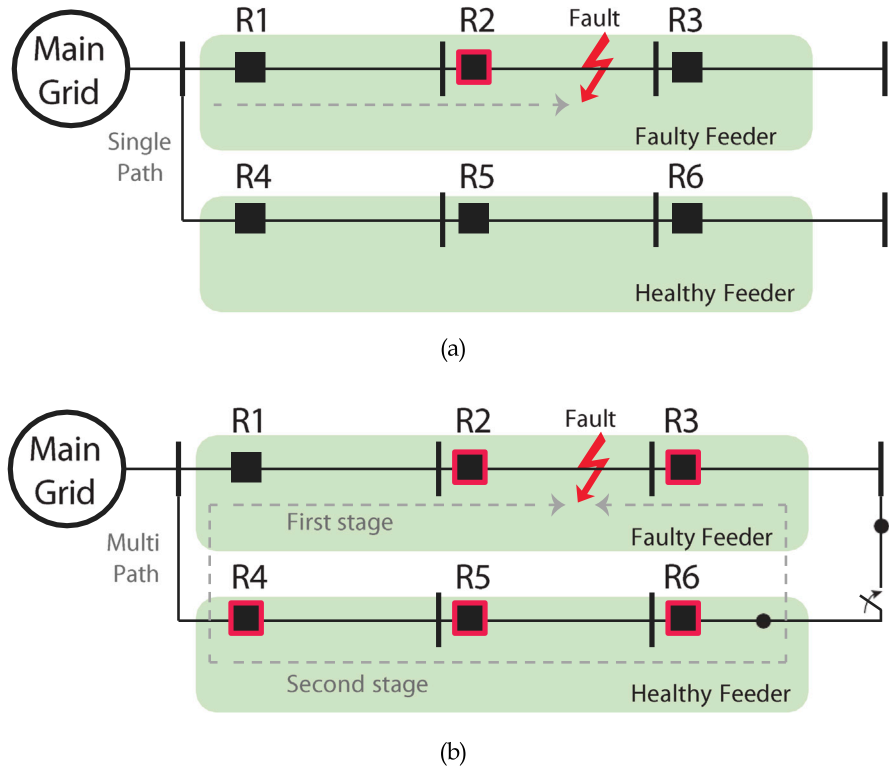


Fig. 3. Fault current path in the microgrid. (a) Single-path fault and (b) multiple-path fault.

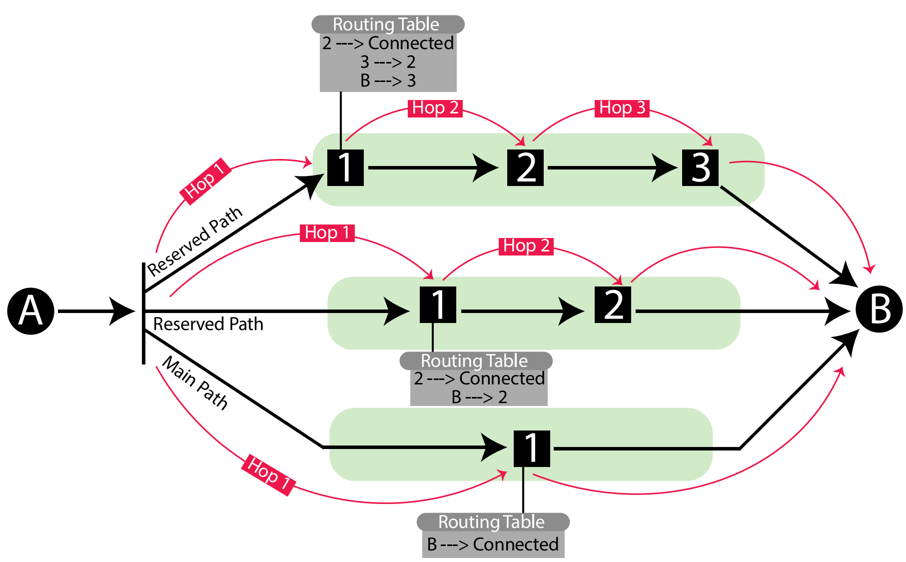


Fig. 4. Data transmission path between two nodes A and B.

paths between nodes enhances reliability. The routing table assists nodes in determining the next hop in the transmission process, ensuring that data can reach its destination, whether via the main path or an alternative reserved route. For instance, in Fig. 4, node A's routing table includes both the direct path (main) and alternative routes through nodes 2 and 3 (reserved paths) to reach node B.

3.2. Fault clearing

In distribution grids, the occurrence of a fault necessitates the immediate isolation of the faulted section by the nearest protective device. If this protective relay fails to clear the fault, two potential scenarios may arise:

(i) The relay may fail to trip due to malfunction or other issues. In this case, the backup relay for the same path should operate.

(ii) If fault current is injected from a different path, the relays corresponding to that path must be identified and activated.

IEDs have been proposed as an effective means of diagnosing and addressing issues within communication networks. Protection IEDs function as network elements, detecting the correct path to the fault and selecting the appropriate IED responsible for isolating the fault via a communication link. The communication environment is based on the IEC 61850 standard, operating over TCP/IP, allowing IEDs to establish communication between each other. The multi-path based isolation logic relies on real-time communication and routing strategies among

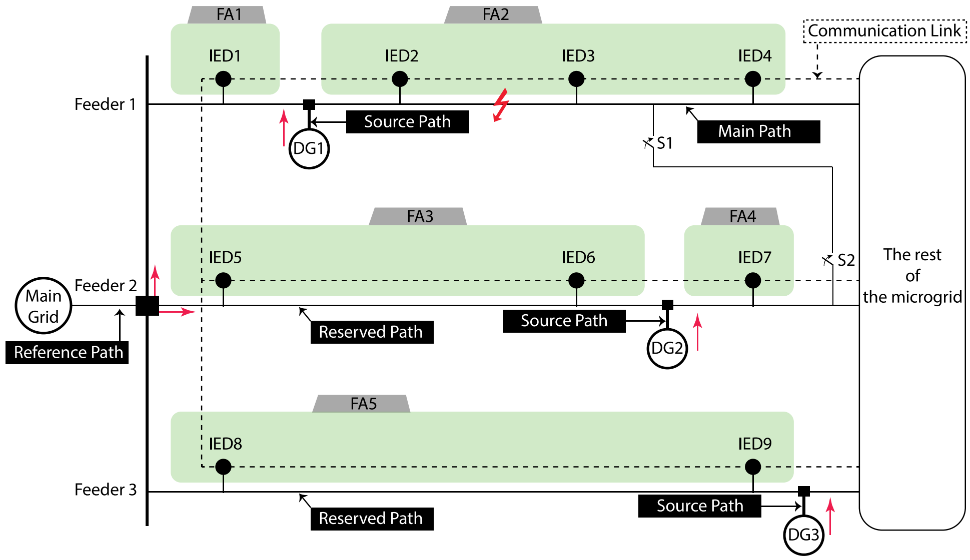


Fig. 5. Multi-path fault current clearing strategy.

IEDs. Each IED evaluates fault direction, current magnitude, and location through information received from adjacent nodes. The scheme dynamically adapts based on topological relationships and real-time data exchange, ensuring correct fault isolation. This approach mimics real-world distributed decision-making in intelligent power systems where topological awareness is more crucial than static calculation. Fig. 5 shows the communication links between IEDs in a sample grid, where nine IEDs are distributed throughout the microgrid and exchange data across different feeders. A point-to-point connection is established between the IEDs, enabling direct communication.

3.3. Multi-path fault

A multi-path fault occurs when current flows through multiple paths to reach the fault point. Typically, one of these paths carries a significantly higher current, as the current flows through the path with the lowest impedance, usually the one closest to the fault. Two primary factors contribute to multi-path faults: (1) Intersections between busbars create multiple paths leading to the fault and (2) DGs can inject fault current from various paths within the network, contributing to multiple fault current paths. In Fig. 5, the connection between two feeders (Feeder 1 and Feeder 2) via S1 and S2 creates an additional path to the fault.

3.4. Operating paths

The proposed strategy introduces four distinct operating paths:

- **Main Path:** This is the primary path where the fault occurs. It includes both the main and backup IEDs that clear the fault. In Fig. 5, Feeder 1 is identified as the main path, and IED 2 and IED 1 are designated as the main and backup IEDs for this path, respectively. The fault is cleared if there is no fault current in the grid by the operation of the IEDs in the Main path.
- **Reserved Path:** This is an alternative path that can lead to the fault point. It involves reserved IEDs that can be used to clear the fault. Depending on the grid configuration, one or more paths may feed the fault. In Fig. 5, two reserved paths (Feeder 2 and Feeder 3) contribute to the fault. In this condition, the likelihood of IED 9 malfunctioning increases because it is downstream of IEDs sensing BCF.
- **Source Path:** This is the path through which current is injected via a generation source. This path divides the microgrid into different FAs, which experience both FCF and BCF during the fault. In Fig. 5, DGs and the main grid contribute to the formation of five distinct FAs, each with a different direction of fault current. For example, FA3 and FA4 are formed due to DG3, which leads to both FCF and BCF during the fault condition.
- **Reference Path:** The reference path starts from the main grid and shares the fault current between the main path and the reserved paths. This path can carry significant fault current, which in turn impacts the flow of current in the FAs.

3.5. Information flow area

In the proposed strategy, the microgrid is divided into FAs to identify primary and backup paths. The segmentation criterion for these FAs is that each area extends from the Reference path to the point where a DG unit is present. Beyond this point, the next segment is defined as a separate FA, and this process continues until another DG source is encountered. For example, in Fig. 5, there are five FAs: FA1 and FA2 initiated by DG1, FA3 and FA4 defined by DG2, and FA5 created by DG3. Each FA contains IEDs that can communicate and exchange data with each other. Within each FA, the current observed is uniform, and the IEDs generate identical tables that represent the connections between them. This enables the IEDs to locate each other geographically. For instance, IED1 belongs to FA1, while IED2 and IED3 are part of FA2, both of which are defined by DG1.

Each FA generates a table that includes "Nodes" and "Learned Area". A Node refers to an IED, and the Learned Area identifies the FA from which the information for the corresponding node has been obtained. This table can be shared with other FAs, allowing all IEDs to learn the paths from one another. These tables are then used to route data through the network. Tables 2, 3, and 4 present the results of sharing routes and paths across three feeders. Connections within the network are either directed or undirected. For example, in FA2, IED2 has a direct connection to IED1 in FA1, while the paths to other nodes outside FA2 are learned from IEDs in other FAs. In this case, IED2 learns the path to IED5 through IED1 and IED9.

The division of the network into FAs supports localized decision-making and fault direction analysis. While mathematical expressions are not directly applied here, the logic is based on network segmentation principles similar to subnetting in computer networks. Each IED learns the network structure via routing tables and acts accordingly

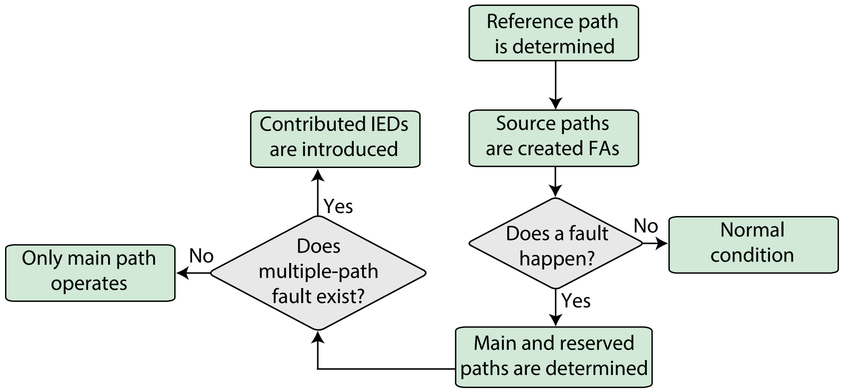


Fig. 6. Flowchart of the proposed protection strategy.

Table 2
Learned Area of Feeder 1.

IED1 (FA1)		IED2 (FA2)		IED3 (FA2)		IED4 (FA2)	
Node	Learned Area	Node	Learned Area	Node	Learned Area	Node	Learned Area
IED2,IED5,IED8	Direct connected	IED1	Direct connected	IED2	Direct connected	IED3	Direct connected
IED3,IED4	FA2	IED5,IED6	FA1	IED1	FA1	IED1	FA1
IED6	FA3	IED7	FA1	IED5,IED6	FA1	IED5,IED6	FA1
IED7	FA3	IED8,IED9	FA1	IED7	FA1	IED7	FA1
IED9	FA5	–	–	IED8,IED9	FA1	IED8,IED9	FA1

Table 3
Learned Area of Feeder 2.

IED5 (FA3)		IED6 (FA3)		IED7 (FA4)	
Node	Learned Area	Node	Learned Area	Node	Learned Area
IED1,IED8	Direct connected	IED5,IED7	Direct connected	IED6	Direct connected
IED2,IED3,IED4	FA1	IED1	FA1	IED5	FA3
IED7	FA4	IED2,IED3,IED4	FA1	IED1	FA3
IED9	FA5	IED8, IED9	FA5	IED2,IED3,IED4	FA3
–	–	–	–	IED8, IED9	FA3

Table 4
Learned Area of Feeder 3.

IED8 (FA5)		IED9 (FA5)	
Node	Learned Area	Node	Learned Area
IED1,IED5	Direct connected	IED8	Direct connected
IED6	FA3	IED1	FA1
IED7	FA3	IED2,IED3,IED4	FA1
IED2,IED3,IED4	FA1	IED5,IED6	FA3
–	–	IED7	FA3

in the event of a fault. This structure-centric design aligns with how real-world distributed agents operate in IEC 61850 environments using GOOSE and SV messages for protection coordination.

4. Proposed protection strategy

Fig. 6 shows the flowchart of the proposed strategy. In the first step, the Reference path, where the main grid begins supplying power to the feeders, is identified. Next, DG connection points are used to create Source paths. Based on the Reference and Source paths, FAs are defined. When a fault occurs, both the Main and Reserved paths are labeled. If a multi-path fault is detected, the involved IEDs are identified; otherwise, the main IED in the main feeder isolates the affected area. A critical aspect of the protective algorithm is selecting the appropriate Reserved paths for the Main path. In multi-path fault scenarios, not all Reserved paths should contribute to feeding the fault point. Therefore, it is crucial to correctly identify and select the Reserved paths to ensure proper protection coordination.

4.1. Main path

In the proposed strategy, each feeder can have one or more FAs. Under fault conditions, it is initially assumed that the IEDs within an FA observe equal fault currents. The criterion for selecting the Main path is based on the highest fault current reported by the IEDs. Through communication between IEDs, the feeder reporting the highest fault current forms the Main path, and the area experiencing the highest fault current is defined as the Main Fault Area (MFA). Consequently, other paths are designated as Reserved, and the remaining areas are considered Reserved Fault Areas (RFAs). Fig. 7 shows the block defined for the Main path in Fig. 5. Blocks are created after determining the IED responsible for clearing the fault, which is designated as the main IED. The area of the main IED is labeled as Block 1, and the other areas are categorized as Block 2.

Blocks are defined with two primary tasks: (1) Assigning FCF or BCF to each IED and (2) assisting in finding the Reserved path connection points. The basis for classifying each block as either FCF or BCF is determined at the time of fault occurrence. When a fault occurs in the Main path, the fault-clearing process follows the Algorithm 1.

Fig. 8 shows the flowchart of the fault detection and isolation process within a microgrid using IEDs. The process starts with the identification of the main IED within the MFA. If both BCF and FCF are detected, the main IED in Block 1 is activated to isolate the fault. In the absence of both BCF and FCF, the last downstream IED on the MFA is triggered. Following the tripping of the main IED in Block 1, the system verifies whether the fault current continues to flow through Block 1. If the current persists, the backup IED is activated according to the learned area table. If there is no current flow, the main IED in Block 2

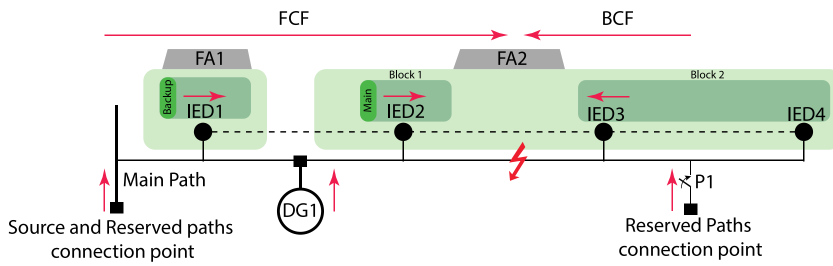


Fig. 7. Flowchart of the main path fault clearness.

Algorithm 1 Main Path Fault Clearness Algorithm

Require: IEDs Current: $I_j \mid I_j$ in Main path ($j = 1, \ldots, k$)
Find $\max(I_j$ for $j = 1, \ldots, k)$
Define MFA as the area where the IED$_j$ is located
for IEDs in MFA **do**
  if There is a current difference in MFA **then**
    There are FCF and BCF
    Block 1 and Block 2 are created
    In FCF and BCF blocks, the last downstream and upstream IEDs should operate as main IEDs
    In FCF and BCF blocks, IEDs have current differences exists the connection point
  end if
end for

is tripped. After the activation of Block 2, the system checks Block 1 once again. If the current is still present, the backup IED is triggered, and if not, the fault was cleared. Additionally, if no fault current is detected, IEDs in the Reserved path are considered to ensure complete protection. This step is crucial to account for alternate fault paths that may bypass the primary protection mechanism. If a fault current is detected in the Reserved path, the backup IED is triggered based on the learned area table. This comprehensive methodology ensures effective fault isolation, adaptability to various fault conditions, and improved system reliability by providing multiple layers of protection.

4.2. Reserved path

In the proposed strategy, the number of hops represents the distance between two nodes in the network, with fewer hops indicating a closer path to the endpoint. This principle is used to measure the distance to the fault point, where a higher current indicates that the path is closer to the fault. Fig. 9 shows a fault condition in which IED 3 fails to isolate the grid properly, and current attempts to flow through the connection point to Feeder 1. In this case, Feeder 2 and Feeder 3 serve as Reserved paths. Based on the information in Tables 2 and 3, the MFA, which is FA2, is closer to FA5 than to FA3 and FA4. This means, from a communication perspective, IED 3 is closer to Feeder 3, requiring only three hops to reach IED 3. Therefore, Feeder 3 is designated as a Reserved path contributing to fault isolation.

When the current flows entirely through Feeder 2, IED 7 observes the highest fault current compared to other IEDs in the grid, due to topological changes in the system. This suggests an unknown path exists, connecting Feeder 2 to IED 3 in FA2. In this scenario, FA4, where the highest current is flowing, is considered as an RFA, and IED 7 is responsible for clearing the fault. Given this condition, which contradicts the routing information in Tables 2 and 3, it is necessary for new areas to be learned, and the routing tables should be updated accordingly. Once the tables are updated, the fault can be cleared according to the procedure outlined in the flowchart of Fig. 10.

Step 1 → **Identify the IED with the Highest Fault Current:** The process begins by identifying the IED that measures the highest fault current, indicating that it is the closest device to the fault point.

Step 2 → **Select the Nearest Area:** The system then selects the area with the shortest communication path, measured by the fewest hops, to the fault point. This area is prioritized for fault isolation.

Step 3 → **Verify Area Belonging:** A verification process is carried out to determine if the IED with the highest fault current belongs to the selected area. If the IED is within the area, the path associated with the fault is designated as a Reserved path. If the IED does not belong to the area, multiple paths to the fault location are identified.

Step 4 → **Handle Multi-Path Fault Scenarios:** In cases where multiple paths lead to the fault point, the communication flow in the network is updated. The system designates the primary fault-clearing region, referred to as the Responsible Fault Area, which will be responsible for isolating the fault.

Step 5 → **Fault Clearing by Assigned IED:** The IED assigned to the Responsible Fault Area attempts to clear the fault by disconnecting the faulty section from the microgrid.

Step 6 → **Check for Remaining Fault Current:** After the fault-clearing attempt, the system checks whether the fault current is still present in the Reserved path. If no fault current remains, the process ends successfully. If the fault current persists, further action is required, as stated in Step 7.

Step 7 → **Activate Neighboring IED:** If a fault current still exists, the system activates a neighboring IED from an adjacent area to assist in fault isolation and ensure the complete removal of the fault current from the microgrid.

5. Performance evaluation

To verify the effectiveness of the proposed strategy, a microgrid is simulated using ETAP software. As shown in Fig. 11, this microgrid operates fully in grid-connected mode and consists of ten IEDs. It is powered by one wind turbine and two PV systems, with its protection system designed to protect four sub-feeders. Sub-feeders 1.2 and 2.1 are interconnected through switches S1 and S2, while Sub-feeders 2.1 and 2.2 can be connected via switches S3 and S4. IED 1 provides protection for Sub-feeders 1.1 and 1.2, while IED 2 is responsible for the protection of Sub-feeders 2.1 and 2.2. Each Sub-feeder is equipped with two IEDs arranged in a main-backup configuration. The communication and power flow zones are shown in Fig. 11, with detailed information provided in Tables 5, 6, 7, and 8. It is important to note that Sub-feeder 2.1 does not have any source paths, while Sub-feeder 2.2 has a single source path and is assigned to only one area. According to the data in Tables 5∼8, IED 1 and IED 6 are located in two different areas: IED 1 in areas 1 and 3, and IED 6 in areas 5 and 6. This configuration indicates that these two IEDs play a shared role in fault isolation. Fig. 12 shows the network topology, emphasizing the communication relationships between IEDs, while Tables 5∼8 provide a comprehensive overview of the connections among the IEDs. In the following sections, two case studies are presented to assess the performance of the proposed protection strategy.

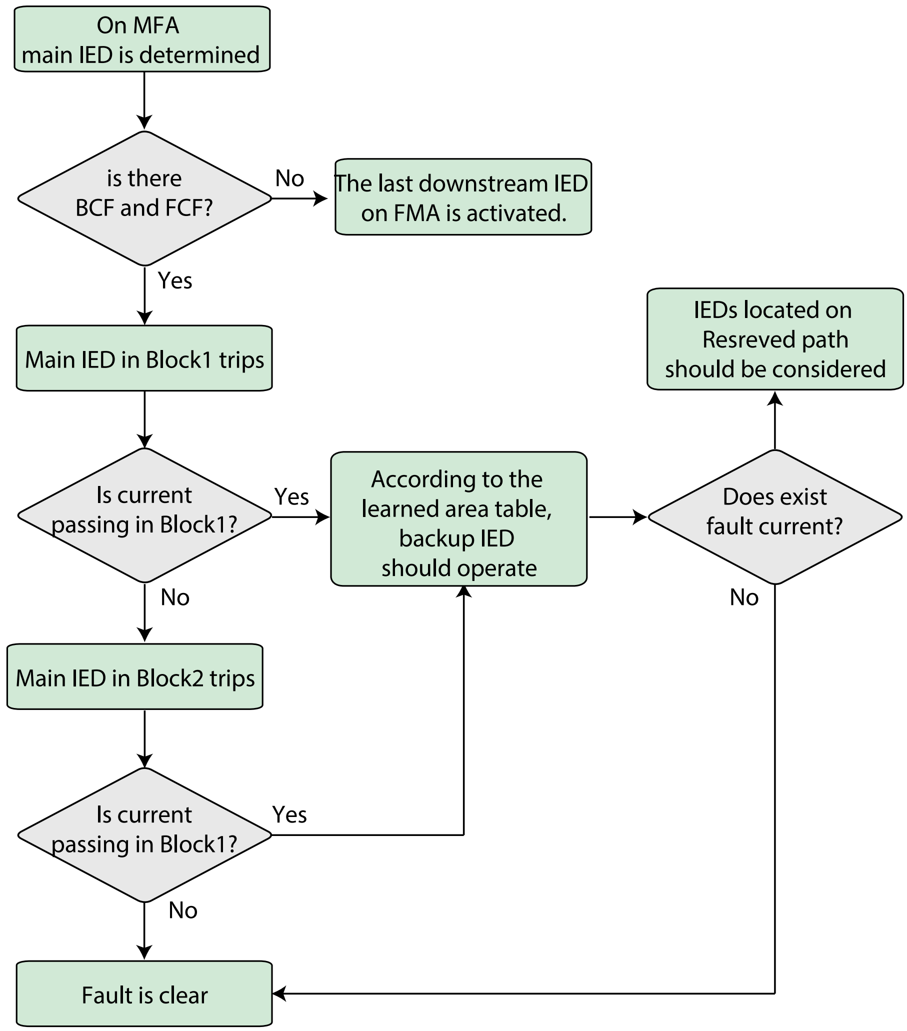


Fig. 8. Flowchart of the fault clearing strategy in the main path.

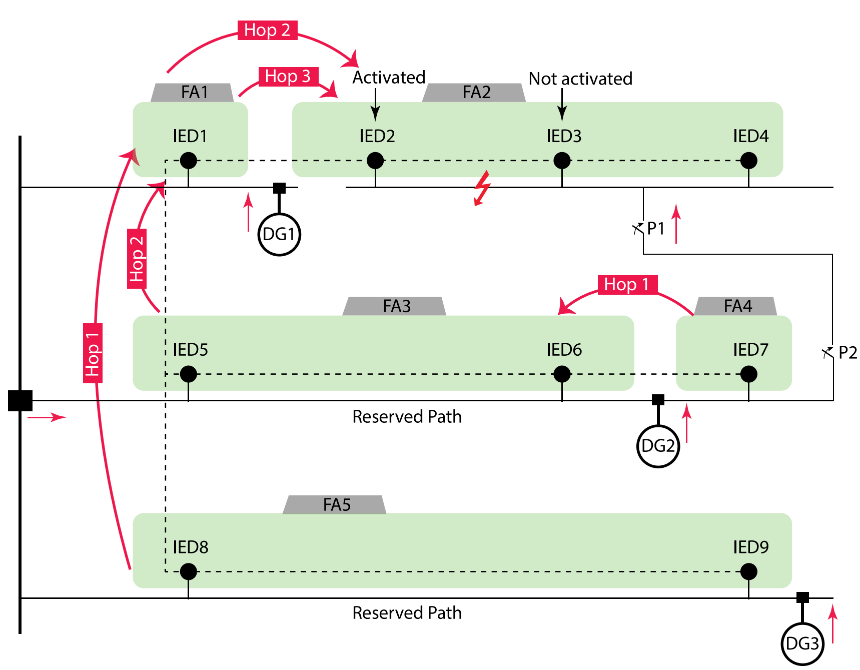


Fig. 9. Reserved path fault clearing.

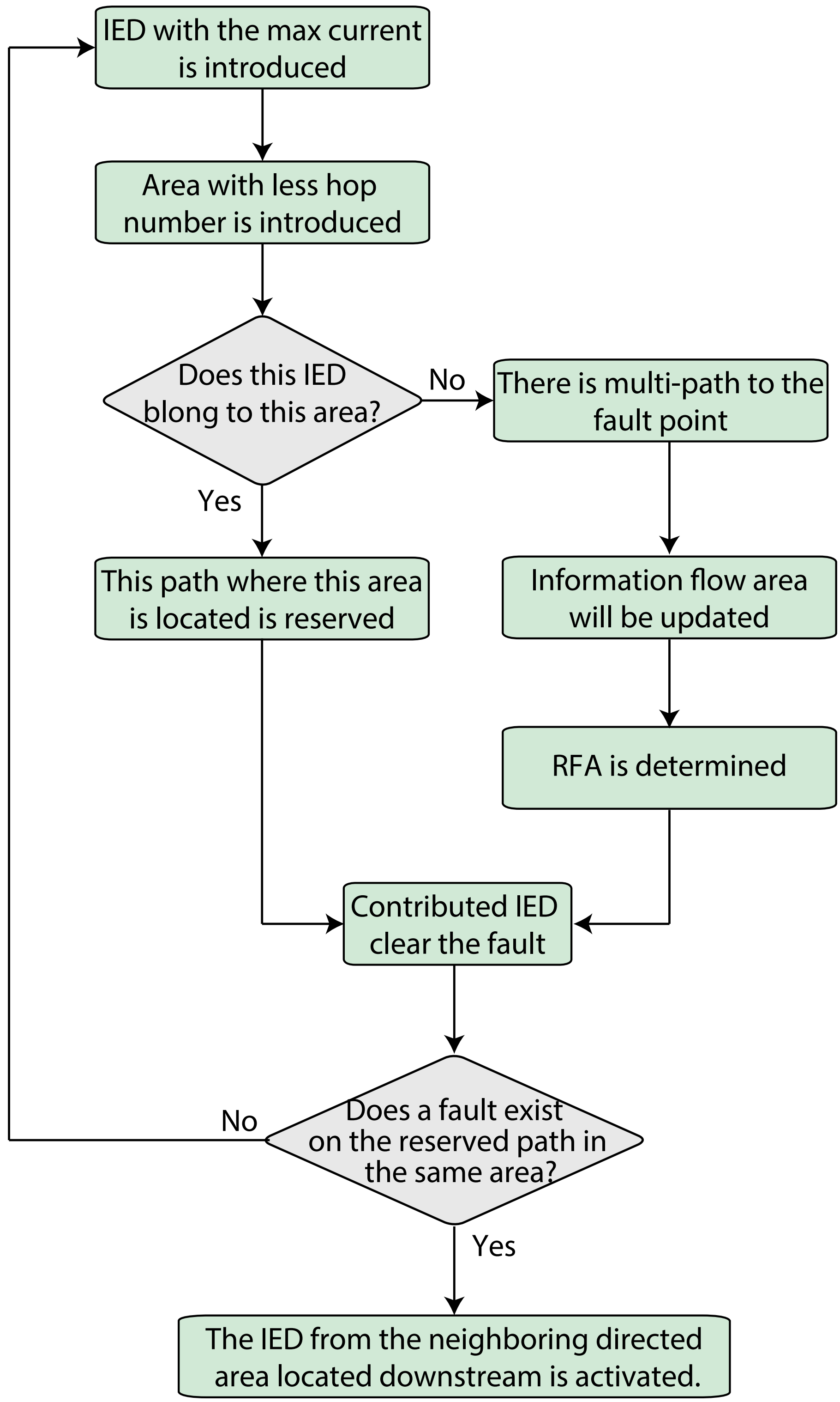


Fig. 10. Flowchart of the fault clearing strategy in the Reserved path.

5.1. Case 1 → fault: F1; S1 & S2: Open; S3 & S4: Closed

In this case study, an increase in current causes miscoordination among the protection IEDs in both Sub-feeder 1.2 and Sub-feeder 2.2 with Sub-feeder 1.1. Fig. 13 shows the time-current curve for IED4, IED5, and IED10. It shows that IED10 and IED5 operate faster than IED4, even though IED4 is closer to the fault point and should be the first to respond. Based on the fault's location, the correct response should involve isolation by IED4 alone. However, the incorrect operation of unrelated IEDs due to BCF causes the protection system to fail.

From the perspective of the proposed strategy, there is one Reference path and three Source paths, creating six flow areas. When a fault occurs, as shown in Fig. 6, it is crucial to determine the main and backup paths to identify how many IEDs should be involved in the fault-clearing process. FA3 is designated as the MFA, with IED4 acting as the

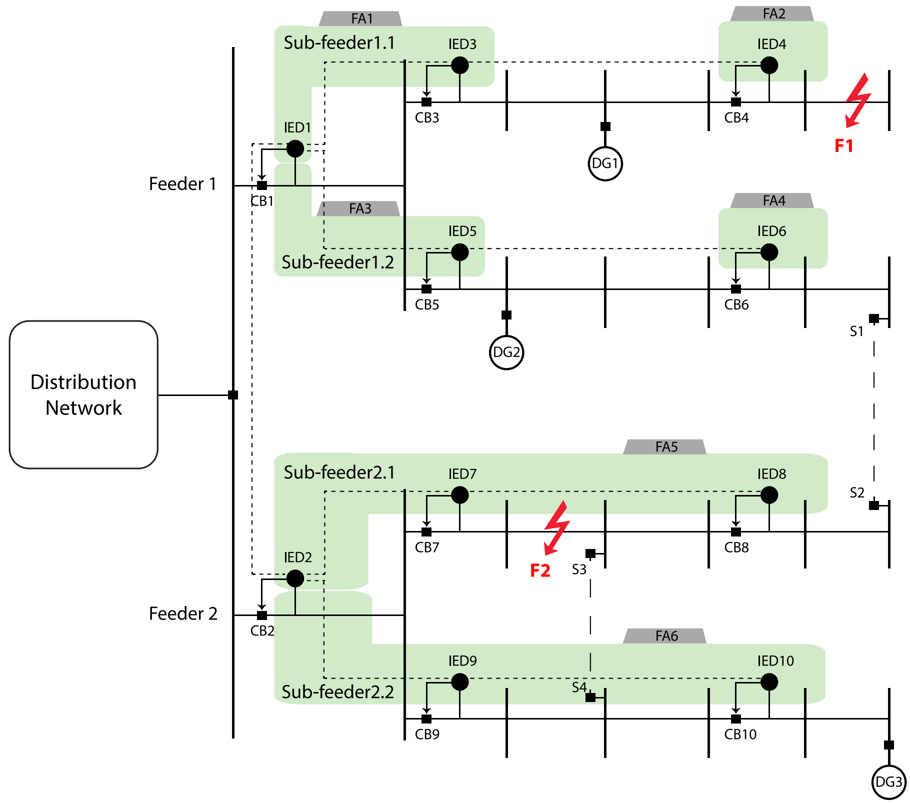


Fig. 11. The test-bed microgrid.

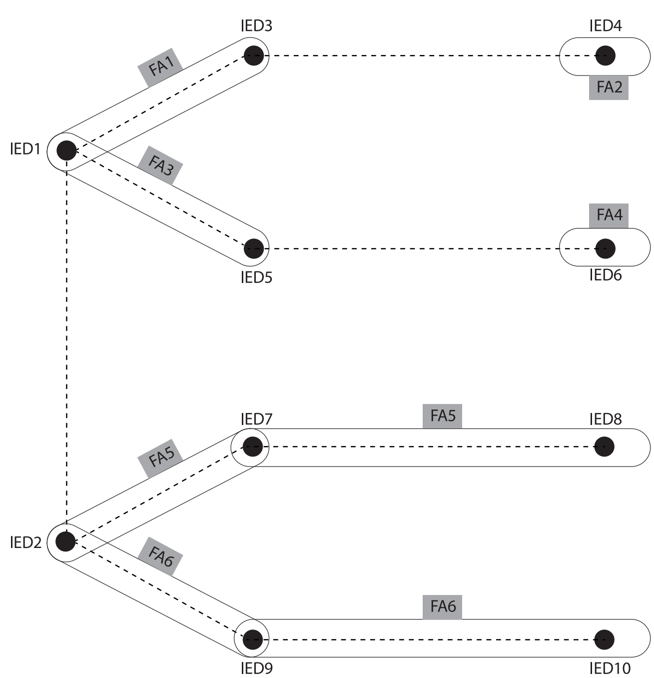


Fig. 12. Network mapping topology.

main IED in this area. According to Table 5 and the network map in Fig. 12, FA3 contains only one IED, which is directly connected to FA1. As a result, BCF and FCF do not exist in this path, meaning that IED4 must operate. Since IED4 is the last downstream IED in this area, it is designed to respond faster. If IED4 operates and clears the fault current from the microgrid, it confirms that the fault was located in a single path. However, if IED4 fails to operate during the fault, the neighboring area with the highest observed fault current should take over the fault-clearing process. In this case, FA1 is the closest neighboring path to the fault, with fewer hops, and IED3 is directly connected to the main IED. Fig. 14 shows the operating times of the breakers within the microgrid.

5.2. Case 2: Fault: F2; S1~S4: Closed

Due to the interconnections between feeders, the protection system cannot function properly because of changes in the protective areas. In this case, IED6 must protect the area originally assigned to IED8, and for Feeder 2, both sub-feeders must serve as backups for one another during a fault. These reconfigurations lead to miscoordination among the relays, as they have not been updated to reflect these changes. When fault F2 occurs, IED7, IED8, IED9, and IED10 are expected to trip their breakers. However, an analysis of the protection system reveals several issues. Sub-feeder 1.1 fails to activate as configured, and there is no BCF on FA2. In Sub-feeder 1.2, IED6 malfunctions due to the increased current flowing through this path from both the Reserved and Source paths (1 and 2). This increased current causes IED6 to operate faster than IED8, disrupting the intended protection sequence. Similarly, in Sub-feeder 2.2, both IED9 and IED10 must operate to fully isolate the fault. In the event of a malfunction, IED2 should act as a backup for both IED7 and IED9. Fig. 15 shows the miscoordination between IED6 and IED8, highlighting their operating times.

To resolve these issues, it is crucial to first identify the Main and Reserved paths. Fig. 16 shows the connection states among IEDs during this fault. As per Algorithm 1, the currents of all IEDs in the Main path are analyzed to determine the MFA. Consequently, the main path is identified as Sub-feeder 2.1, with FA5 being the MFA because IED7, which has a maximum current of 1470 A, belongs to this area. Given the significant difference in current magnitude between IED7 and IED8, both FCF and BCF are present in this feeder. Next, it is necessary to create Block1 and Block2. As a result, IED7 and IED8, being the last

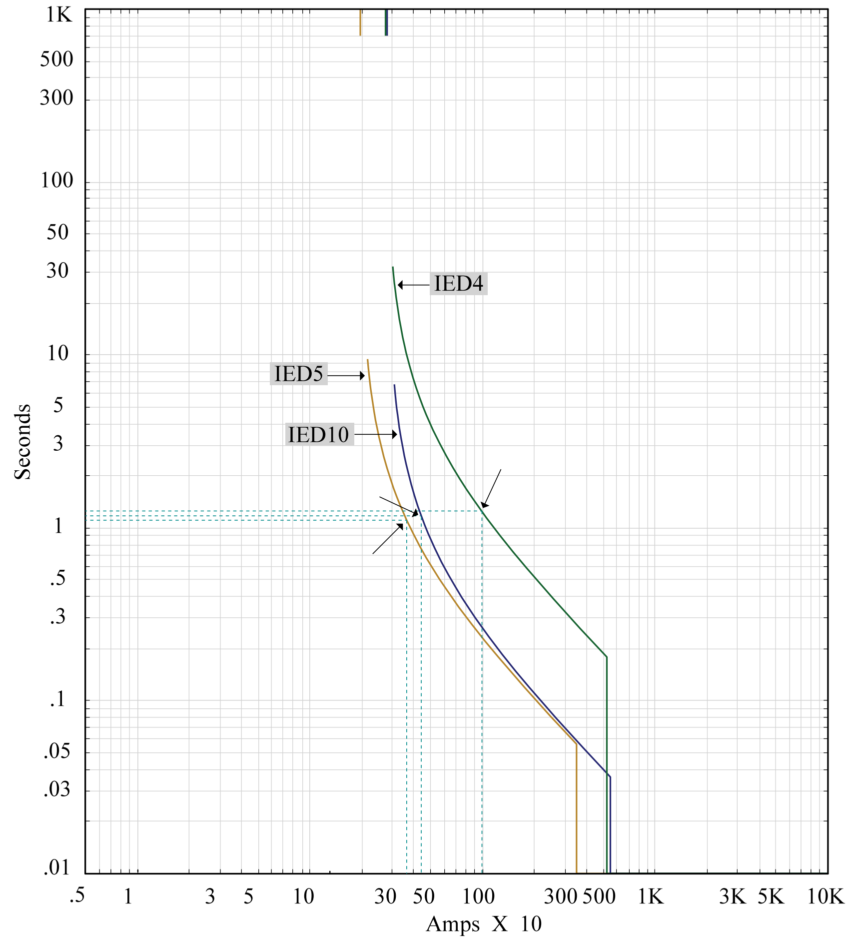


Fig. 13. Miscoordination among IED4, IED5, and IED10 in the case of fault F1.

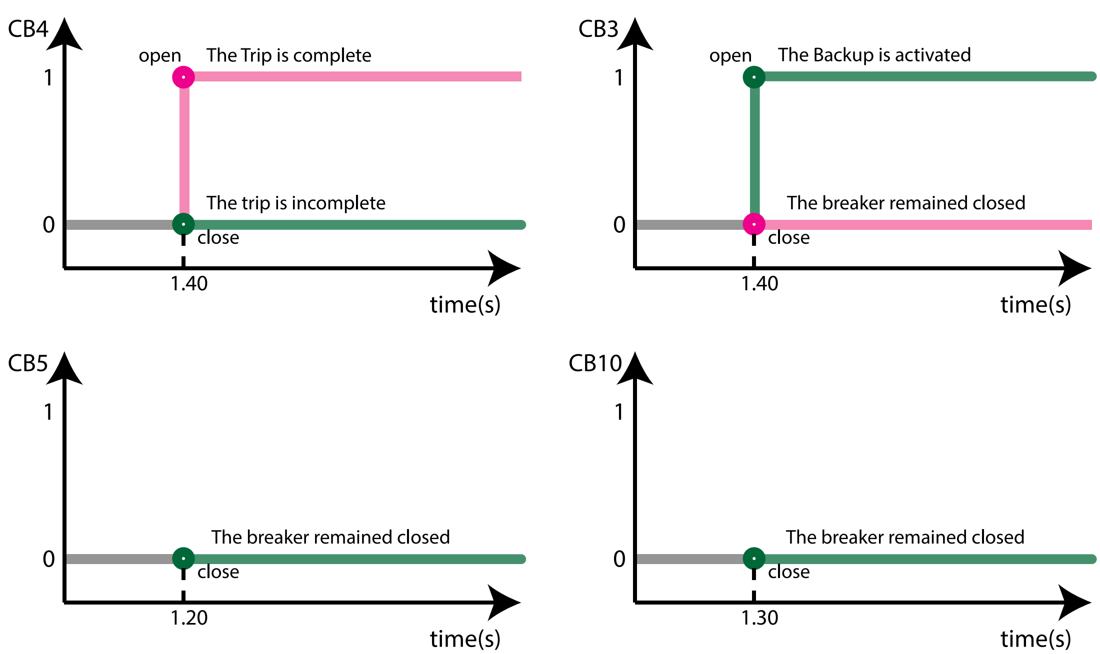


Fig. 14. The breakers status during fault F1.

upstream and downstream devices in this FA, will operate. In this Sub-feeder, there is a connection point to the BCF block where IED8 is located, indicating that Sub-feeder 2.1 is connected to another feeder. According to Fig. 8, IED7 in Block1 will trip. If IED7 fails to operate, as specified in Table 7, IED1 should act as a backup. If Block1 clears the fault, IED8 in Block2 will trip. However, if the fault persists, the

Table 5
Learned Area for Sub-Feeder 1.1.

IED1 (FA1)		IED3 (FA1)		IED4 (FA2)	
Node	Learned Area	Node	Learned Area	Node	Learned Area
IED2,IED5	Direct connected	IED1,IED4	Direct connected	IED3	Direct connected
IED4 IED6	FA2 FA3	IED5,IED6	FA3	IED1,IED2, IED5,IED6, IED7,IED8, IED9,IED10	FA1
IED7,IED8 IED9,IED10	FA5 FA6	IED2,IED7,IED8 IED9,IED10	FA5 FA6		

Table 6
Learned Area for Sub-Feeder 1.2.

IED1 (FA3)		IED5 (FA3)		IED6 (FA4)	
Node	Learned Area	Node	Learned Area	Node	Learned Area
IED2,IED3	Direct connected	IED1,IED6	Direct connected	IED5	Direct connected
IED4 IED6	FA2 FA4	IED3,IED4	FA1	IED1,IED2, IED3,IED4, IED7,IED8, IED9,IED10	FA3
IED7,IED8 IED9,IED10	FA5 FA6	IED2,IED7,IED8 IED9,IED10	FA5 FA6		

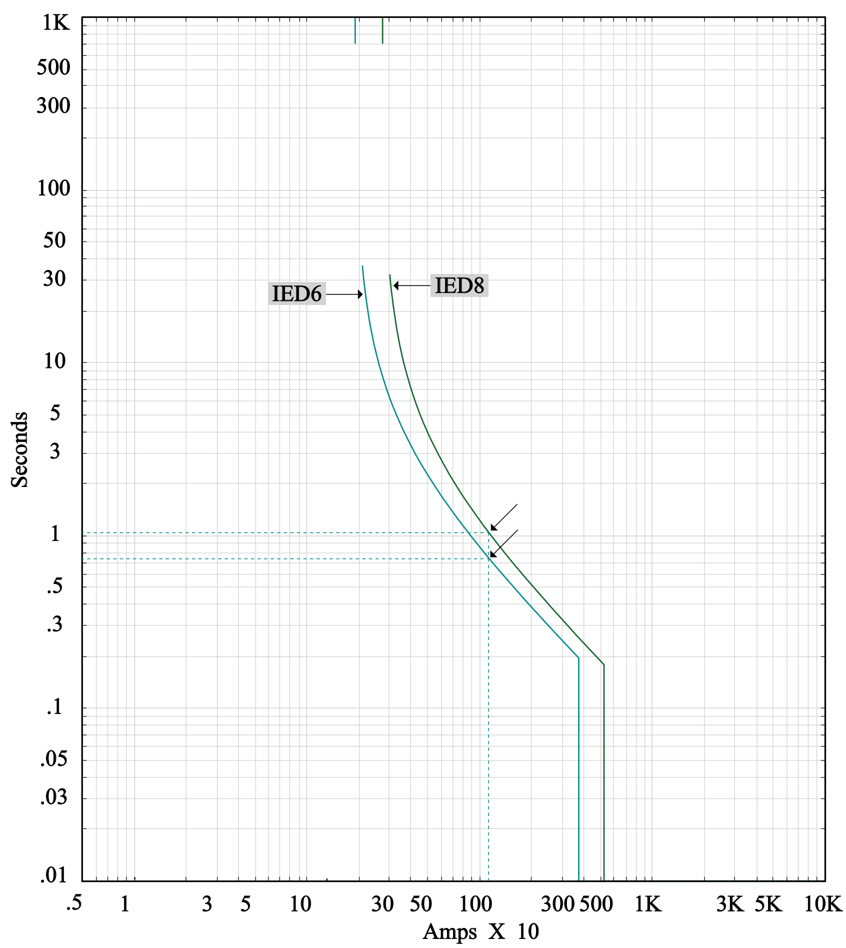


Fig. 15. Miscoordination between IED6 and IED8 in the case of fault F2.

backup relay for IED8 should operate. Although no backup relay for IED8 is listed in Table 7, one must be identified. Referring to Fig. 8, the IEDs in the Reserved paths should be marked and configured accordingly.

In the Reserved paths (Sub-feeder 1.1/1.2 and Sub-feeder 2.2), IED6 is identified as the device with the maximum current. In Sub-feeder 2.2, areas FA1, FA3, and FA6 have fewer hops to IED7; however, IED6 is not included in these areas. As a result, there are multiple paths to the fault point. FA4 is designated as the RFA, and IED6 will trip. Since fault current is observed in Sub-feeder 2.2, IED9 is identified as the IED with the maximum fault current. Given that IED9 has already learned from IED7 in FA5 and now detects the fault in this path, it indicates another connection point to the area. Consequently, IED9 will operate. The RFA continues to observe the fault, and IED10, as the downstream IED directly connected to this area, will operate to fully clear the fault. Fig. 17 shows the status of the breakers during this fault-clearing process.

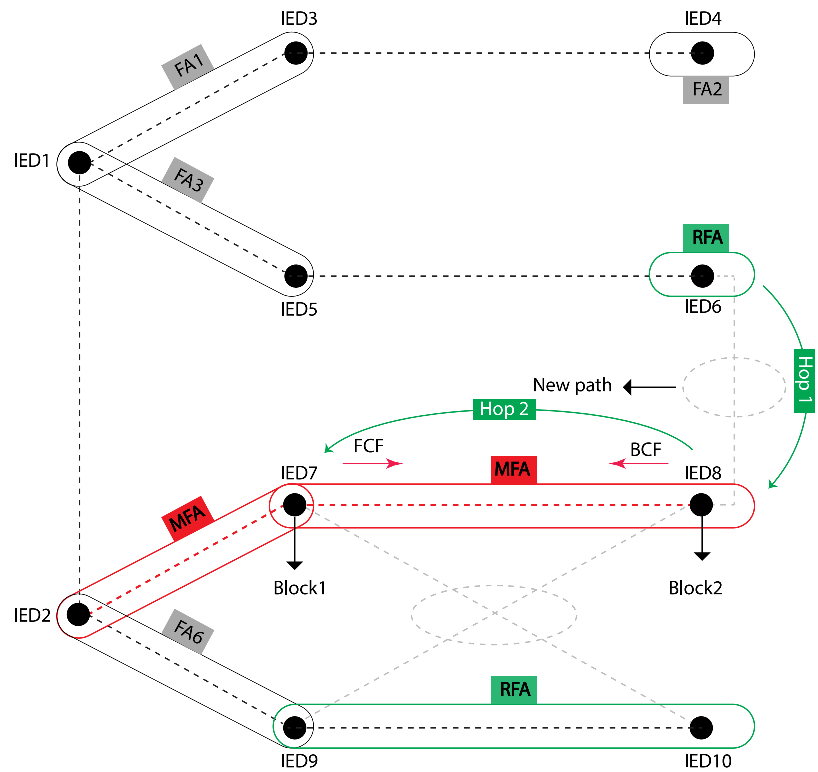


Fig. 16. Determination of MFA and RFA for fault F2.

Table 7
Learned Area for Sub-Feeder 2.1.

IED2 (FA5)		IED7 (FA5)		IED8 (FA5)	
Node	Learned Area	Node	Learned Area	Node	Learned Area
IED1,IED9	Direct connected	IED2	Direct connected	IED7	Direct connected
IED3	FA1	IED1 IED5 IED6	FA3	IED1,IED5, IED6	FA3
				IED3,IED4	FA1
IED4,IED5, IED6	FA3	IED3 IED4	FA1	IED9, IED10	FA6
IED9,IED10	FA6	IED9, IED10	FA6		

Table 8
Learned Area for Sub-Feeder 2.2.

IED2 (FA6)		IED9 (FA6)		IED10 (FA6)	
Node	Learned Area	Node	Learned Area	Node	Learned Area
IED1,IED7	Direct connected	IED2	Direct connected	IED7	Direct connected
IED3	FA1	IED1,IED5, IED6	FA3	IED1,IED5, IED6,	FA3
				IED3,IED4,	FA1
IED4,IED5, IED6	FA3	IED3,IED4	FA1	IED7, IED8	FA5
IED7,IED8	FA5	IED7,IED8	FA5		

5.3. Case 3: IEEE 33 bus test system

In this case study, the IEEE-33 bus system is modeled using ETAP software. Nine IEDs are deployed across the network to protect the system. Additionally, four PV units (PV1 to PV4) are connected to the grid to provide support. Fig. 18 shows the locations of the IEDs and PVs within the network. From the perspective of multi-path fault analysis, the network is divided into five FAs: IED1 and IED6 are placed in FA1; IED2, IED3, and IED4 are located in FA2; IED5 is in FA3; IED7 and IED8 are situated in FA4; and IED9 resides in FA5. Fig. 19 shows the FAs and their inter-IED connections. Identifying the main and reserved paths is essential for determining which IEDs should participate in the fault-clearing process. When Fault 3 occurs, IED2 is the only IED with the highest FCF and should operate faster than the others, while maintaining selectivity. However, there is a risk of potential misoperations by IED6 in FA1, IED8 in FA4, and IED4 due to BCF.

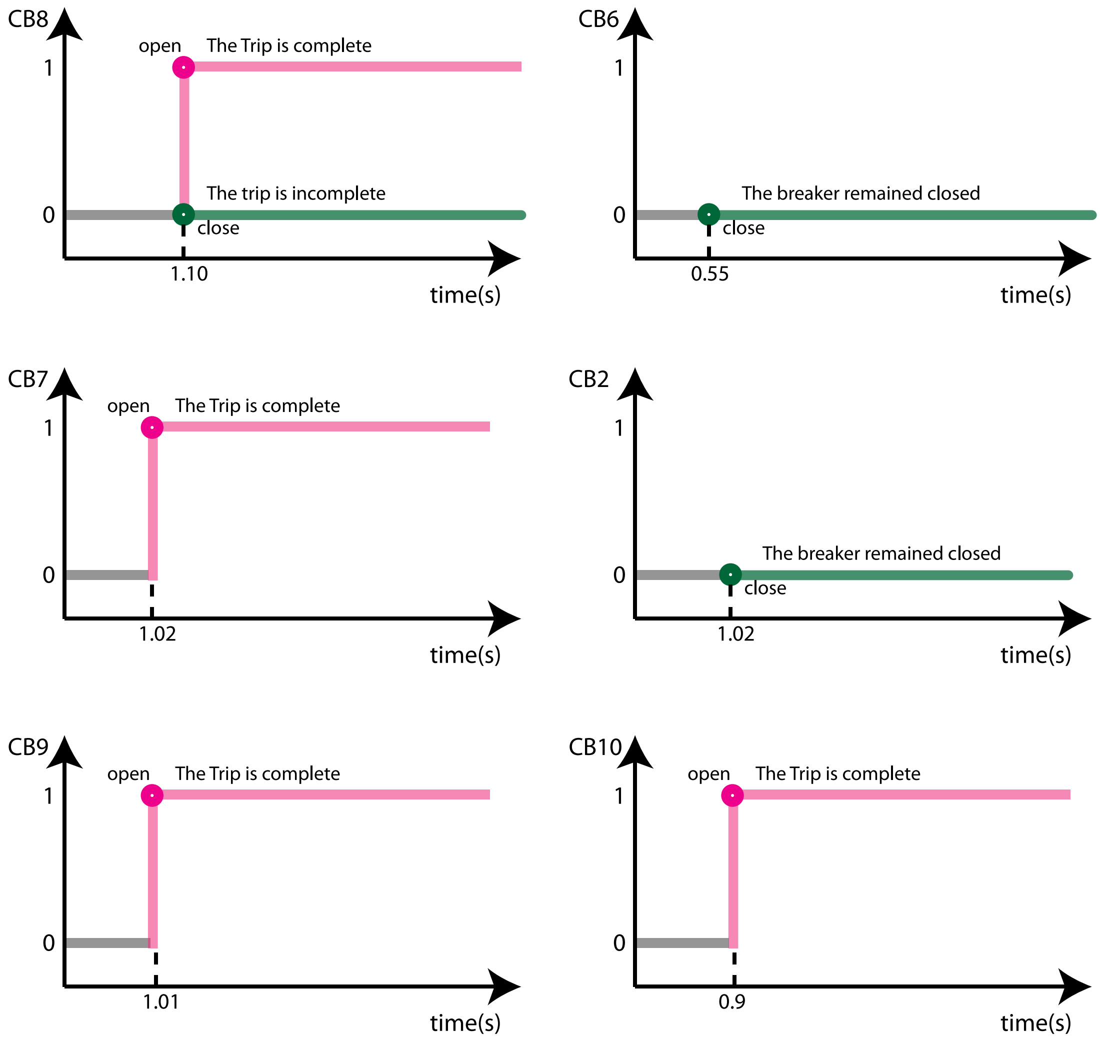


Fig. 17. The breakers status during fault F2.

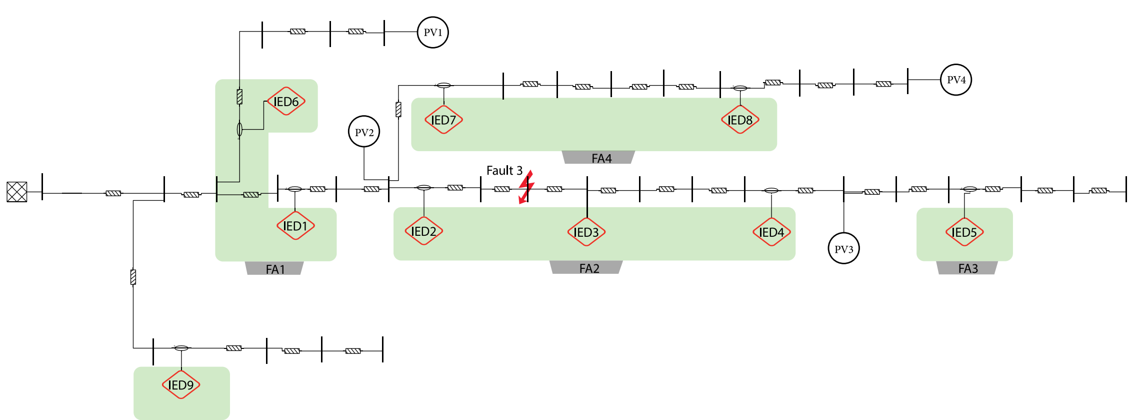


Fig. 18. Single-line diagram of the IEEE 33-bus test system.

The first step involves identifying the main and reserved paths to determine how many IEDs should participate in the fault-clearing process. Next, current measurements from all IEDs along the main path are analyzed to identify the MFA. Based on the fault location, FA2 is designated as the MFA. Within this area, IED2 observes the highest current and is the closest device with FCF, based on the learned path topology. If IED2 successfully operates, the FCF fault will be cleared. Otherwise, additional actions are required. Fig. 20 shows the communication status and coordination among FAs during the fault-clearing process. If IED2 in Block 1 fails to isolate the fault, FA1 and FA4 act as backup areas. In this case, IED1 (backup for IED2 on the main path) and IED7 (backup on the reserved path) will both participate in clearing

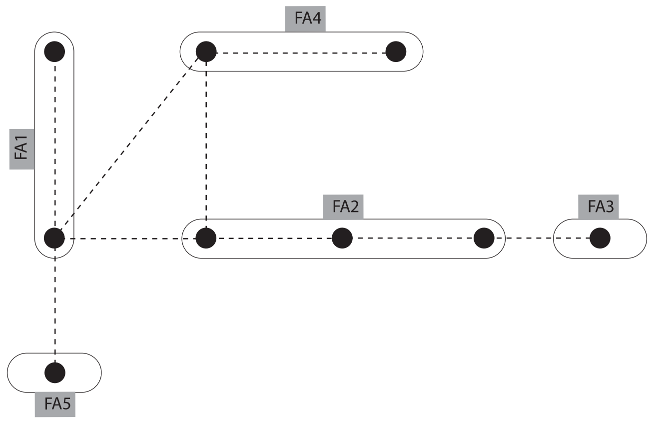


Fig. 19. Network mapping topology for Case 3.

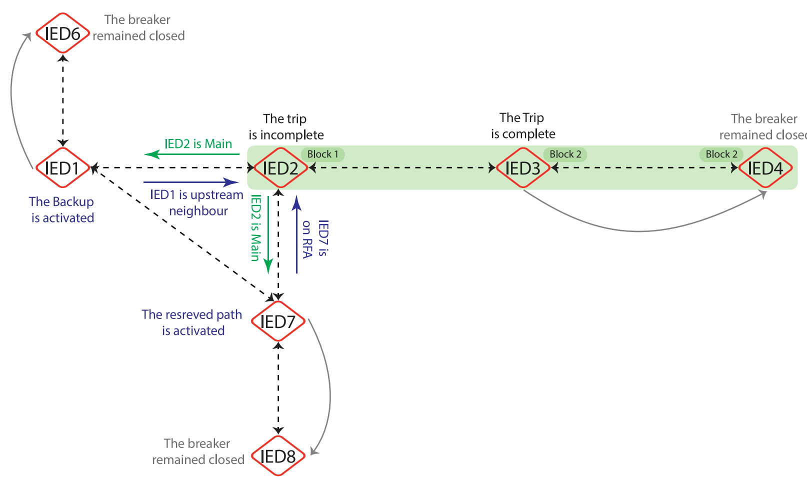


Fig. 20. Established connections among FAs for Case 3.

the fault. In Block 2, IED3 experiences a BCF and should operate faster than IED4. According to the coordination strategy shown in Fig. 8, this ensures that the fault is cleared on the affected feeder.

6. Conclusion

The dynamic changes in microgrid topology, driven by factors such as the integration of DG sources, significantly affect the efficiency and reliability of microgrid protection systems. As microgrids evolve, it becomes increasingly important to implement protection strategies that adapt to these changes. The strategy introduced in this paper leverages the IEC 61850 standard, coupled with a multi-path routing technique, to offer an advanced fault detection solution. By utilizing the concept of RAs, the proposed strategy enables fault identification in a short time, allowing relays to be prepared promptly for protective actions. One of the main advantages of this strategy is its incorporation of both Main and Reserved paths, enhancing the overall reliability of the protection system. Unlike traditional strategies, where fault detection is limited to the Main path, the proposed strategy ensures redundancy through the use of Reserved paths. If the fault is not detected via the Main path, the Reserved path automatically takes over, ensuring continuous fault detection and minimizing the risk of protection system failure. Future research will focus on quantitatively evaluating the reliability, dependability, and security of the proposed method using established formulas, such as those presented in [26], to provide a numerical comparison with existing protection strategies. Additionally, the strategy can be tested on different network sizes and configurations-such as IEEE-14 and IEEE-57 bus systems-to assess its scalability and flexibility. Another potential extension is the development of a simplified, dynamic learning mechanism that allows IEDs to identify Main and Reserved paths in real-time, reducing the need for predefined configurations and improving adaptability in evolving grid structures.

CRediT authorship contribution statement

Mohammad Hossein Afshari: Writing – original draft, Visualization, Software, Investigation. **Bahador Fani:** Writing – review & editing, Visualization, Supervision, Conceptualization. **Iman Sadeghkhani:** Writing – review & editing, Supervision, Methodology. **Hadi Saghafi:** Writing – review & editing, Supervision, Methodology.

Declaration of competing interest

The authors of this paper state that there is no conflict of interest.

Data availability

Data will be made available on request.

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