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Adaptive Overcurrent Protection in Inverter-Dominated Microgrids Considering Fault Ride-Through and Dynamic Operating Modes

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Abstract - The increasing penetration of inverter-based distributed energy resources (IBDERs) in microgrids significantly alters short-circuit behavior, often resulting in fault currents that are comparable to nominal load levels. Combined with frequent transitions between grid-connected and islanded modes, this renders conventional overcurrent protection (OCP) schemes unreliable, leading to mis-operations, loss of selectivity, and delayed fault clearing. Additionally, Fault Ride – Through (FRT) requirements allow IBDERs to sustain limited current contribution for a defined time window before tripping, which further complicates protection settings.

This paper introduces an adaptive OCP framework that dynamically adjusts protection thresholds based on both the microgrid operating mode and time intervals aligned with expected IBDER current response. By incorporating FRT-driven time segmentation, the proposed approach allows reliable discrimination between transient and permanent faults, while preserving system stability. Preliminary simulation case studies demonstrate promising improvements in detection sensitivity and coordination when compared to fixed OCP settings, suggesting a viable foundation for implementation in future real-time microgrid protection schemes.

Index Terms – Overcurrent protection, IBDER, Microgrids, FRT requirements, Adaptive protection in microgrids

I Introduction

The increasing penetration of IBDERs is fundamentally altering short-circuit behavior and protection coordination principles in modern distribution networks. Unlike traditional radial systems with high short-circuit strength and unidirectional power flow, microgrids with high DER penetration exhibit bidirectional currents and significantly reduced fault levels, particularly during islanded operation. Furthermore, Grid Code requirements such as FRT mandate that DER units remain connected during voltage disturbances for a specified duration, causing short-circuit currents to vary dynamically over time.

To address these challenges, adaptive relay protection methods have been developed. Time-segmented coordination approaches based on DER disconnection intervals have demonstrated improved selectivity in grid-connected networks with high DER penetration. However, their applicability in islanded microgrids remains limited due to reduced short-circuit magnitudes and altered inverter dynamics. Additionally, transitions between grid-connected and islanded modes require real-time adaptation of protection parameters.

This paper proposes an enhanced adaptive relay protection framework for microgrids that integrates operating-mode detection at the point of common coupling (PCC) with dynamic switching of relay protection setting groups. In grid-connected mode, established adaptive short-circuit and FRT-based coordination methods are applied. In islanded mode, relay parameters are adjusted through predefined setting groups to maintain sensitivity under reduced fault current conditions.

Simulation results obtained on the Case Western Reserve University campus microgrid demonstrate that the proposed framework preserves selectivity and improves protection reliability across both operating modes.

II Grid Code Standard

Traditional distribution networks were historically designed with radial topology, where a slack bus supplied downstream feeders and power flowed unidirectionally toward end consumers. Relay protection coordination in such systems was performed according to IEC 60909 and other established conventional methods.

With the increasing integration of DERs, distribution networks are evolving into microgrids. A microgrid is defined as a group of interconnected loads and DERs within clearly defined electrical boundaries that can operate both in grid-connected and islanded modes. As DER penetration grows, their influence on short-circuit behavior becomes increasingly significant.

DERs are typically connected through power electronic interfaces, most commonly inverters. Two dominant types are used: Doubly Fed Induction Machines (DFIMs), which are partially interfaced through converters, and Inverter-Based DERs (IBDERs), which are fully converter-interfaced. According to IEC 60909, DFIMs are modeled as induction machines if the fault is electrically close, while IBDERs are represented as constant current sources limited by inverter capability. These assumptions are acceptable in networks with low DER penetration. However, in microgrids with high shares of IBDERs, such simplified representations may lead to significant deviations from actual short-circuit currents [1,2]. Consequently, conventional IEC 60909-based coordination becomes insufficient for accurate protection design.

To address these challenges, modern Grid Code requirements have been introduced. Among them, FRT and Reactive Current Injection (RCI) are particularly relevant [3].

During short-circuit events, voltage magnitudes at network nodes drop significantly, especially near the fault location. The FRT requirement specifies the duration for which a DER must remain connected during voltage dips. This duration is inversely proportional to the voltage drop—deeper voltage sags correspond to shorter permitted connection times. In earlier systems, DERs were typically disconnected immediately after disturbances. However, in highly penetrated networks, widespread disconnection of IBDERs during faults could threaten system stability. Therefore, FRT requirements are essential to ensure grid resilience [4, 5]. Among existing standards, the German Grid Code is considered one of the most stringent [1, 6-11].

In addition to FRT, the RCI requirement defines the amount of reactive current that must be injected based on the voltage deviation at the point of common coupling. The larger the voltage drop, the higher the reactive current component that must be provided. These requirements are especially critical in islanded microgrids, where DERs are the primary generation sources and their dynamic response directly affects system stability.

The FRT and RCI standards are illustrated in the figures below.

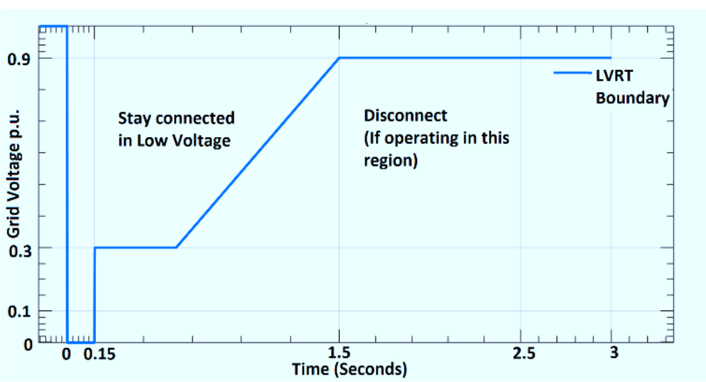

Figure 1. FRT requirement [12]

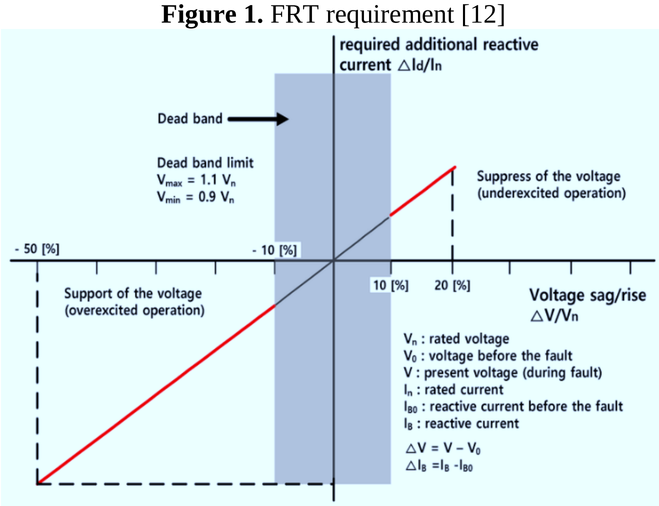

Figure 2. RCI requirement [13]

The increasing penetration of converter-interfaced DERs, combined with FRT and RCI requirements, significantly alters short-circuit current characteristics and protection coordination principles. As a result, traditional relay protection approaches based on fixed settings and IEC 60909 assumptions face serious limitations in modern microgrids. The following section analyzes these challenges in detail and reviews an adaptive relay protection method that serves as the foundation for the enhancements proposed later in this paper.

III Protection Challenges and Adaptive Relay Protection Method

This Section will be displayed in two separate subsections. The first one will address the challenges when integrating DERs into the radial distribution network, while the second subsection will analyze existing method for adaptive relay protection, resolving those challenges.

III-1 Protection challenges in DER – integrated distribution networks

The integration of DERs introduces fundamental changes in fault behavior and protection performance within distribution networks. Unlike traditional radial systems, where short-circuit currents originate from a single upstream source, DER-connected feeders may experience fault currents supplied from multiple locations. This effectively creates double-fed fault conditions, altering both the magnitude and distribution of fault currents.

In feeders containing DERs, fault current may consist of contributions from both the upstream grid and locally connected generation. Such additional current contributions can lead to unintended relay operation, reduced selectivity, or improper sensitivity margins. In contrast, certain fault scenarios may result in reduced current levels at upstream protection devices compared to conventional systems, potentially leading to insufficient pickup and loss of sensitivity. Therefore, relay coordination must account for variable fault contributions and different operating configurations.

Another critical challenge is the impact of DERs on protection selectivity in parallel feeder configurations. A fault on one feeder may receive current contribution from a DER located on an adjacent feeder. If this contribution exceeds the pickup setting of protection devices on the healthy feeder, non-selective tripping may occur, often requiring the implementation of directional overcurrent protection schemes [4].

DER integration also affects coordination between reclosers and fuses. In conventional radial systems, coordination is arranged so that reclosers operate before downstream fuses during transient faults. However, when DERs are present upstream of a fuse, their fault contribution may cause the fuse to operate before the recloser, disrupting the intended protection hierarchy and leading to unnecessary outages.

Overall, DER integration significantly alters protection behavior and may compromise the reliability, selectivity, and coordination of traditional overcurrent protection schemes. While DERs improve supply reliability from a generation perspective, their influence on fault currents and relay operation requires careful reassessment of protection philosophy and coordination principles.

The following subsection presents an adaptive relay protection method designed to address the identified challenges. The method is analyzed in detail, and its advantages and limitations are critically evaluated.

3.2. Adaptive relay protection method

In the previous subsection, the conventional overcurrent relay protection method and its main limitations were discussed. In what follows, an adaptive relay protection approach intended for DER-dominated distribution networks is described in detail.

First, it should be emphasized that this method relies on a generalized Δ-circuit algorithm for calculating short-circuit current values. The approach is absolute in nature and has been proven reliable for both grid-connected and islanded operating modes, as well as for all types of short circuits. A comprehensive presentation of this algorithm can be found in [2, 6, 11].

Due to the shortcomings of traditional protection schemes in networks with a high penetration of DERs, a relatively new adaptive relay protection method has been proposed in [14, 15]. Unlike the conventional approach, the adaptive method introduces a set of time intervals defined from the instant of fault occurrence up to the relay tripping time. These intervals are determined according to the DER disconnection times specified by applying FRT requirement, as shown in Figure 3. Although the method can be implemented using the FRT requirements of any country, the German FRT is often considered since it represents one of the most stringent criteria.

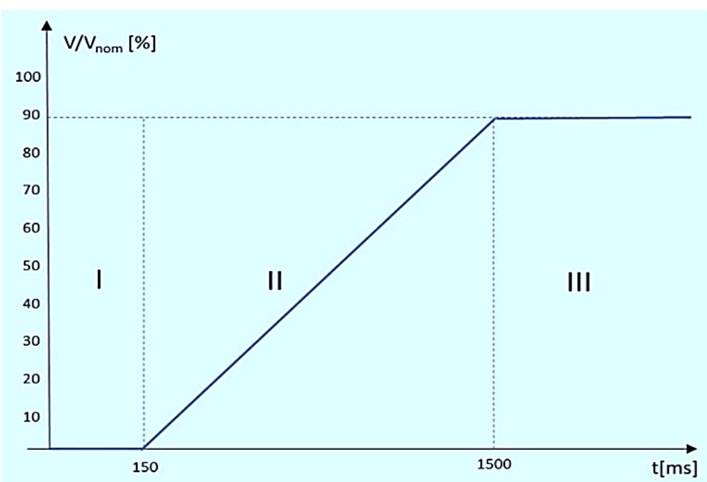

Figure 3. German FRT requirement presented in three time intervals [15]

From Figure 4, it can be observed that for a fault at Bus 2, the operating time of relay R2, acting as the primary protection, is shorter than the operating time of relay R1, which serves as backup protection. In this case, proper selectivity between the relays is achieved.

However, the presence of DER significantly alters fault behavior. When a short circuit occurs, DER units also contribute to the fault current, affecting both its magnitude and direction. This bidirectional current flow contradicts the traditional assumption of unidirectional fault current in radial distribution systems and directly impacts relay coordination and selectivity.

For example, in the case of a fault at the transformer bus, both the main transformer and the DER inject fault current from opposite directions. Under such conditions, relays may not detect the fault accurately or may fail to operate in the intended sequence, which can lead to reduced sensitivity and compromised selectivity. In the event of a downstream fault, the current measured by relay R1 may be significantly lower than expected because part of the fault current is supplied upstream by the DER. This changes the current distribution in the network and disrupts the originally designed coordination margins based on predefined current ratios.

To overcome these challenges, the adaptive method described in [14] proposes a modified procedure for relay setting and coordination in distribution systems with high DER penetration. Instead of assuming constant short-circuit conditions, the method accounts for the dynamic behavior of DER units during fault events. The defined time intervals correspond to the periods in which different numbers of DER units remain connected to the grid, in accordance with the selected FRT requirement (Figure 3).

Within each interval, the sensitivity and coordination of the protection system are evaluated using short-circuit current values calculated for the specific network configuration at that moment. As DER units disconnect in compliance with FRT requirement, the short-circuit current level changes over time. Consequently, the relay operating time is recalculated for every interval to ensure that protection performance—both in terms of sensitivity and selectivity—remains satisfactory under varying system conditions.

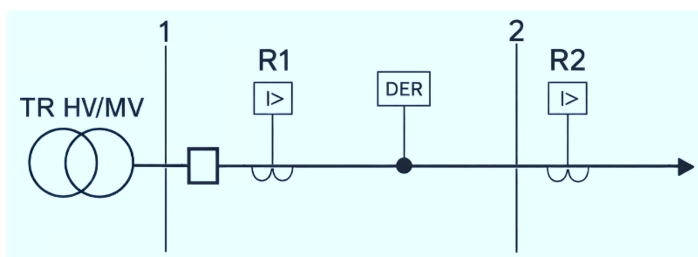

Figure 4. Single line diagram of main – backup relay pairs

As shown in Figure 3, after the fault occurs, all DERs must stay connected to the grid at least 150 ms, which is labeled as Interval I. The same approach is used to determine time intervals for any FRT requirement. Within this interval, the complete short-circuit current calculation [2,6,11] is performed.

The fault current through relay R2 in this interval is $\hat{I}_{R2}^{1}$, and through R1 is $\hat{I}_{R1}^{1}$. Their tripping times are t_{R2}^{1} and t_{R1}^{1}, respectively.

If t_{R2}^{1} is less than 150 ms, R2 trips before DER disconnection, and the calculation ends. If t_{R2}^{1} exceeds 150 ms, a second time interval is defined—from 150 ms to t_{R2}^{1} (Interval II in Figure 3). During this period, DER disconnection times are calculated based on the voltage profile using equation below which is based on the FRT characteristic:

$$t_i^h = 150 + \frac{1500-150}{0.9} r_{VTi}^h \ [ms],\ i = 1, \dots, N_{DER}. \qquad (1)$$

Where r_{VTi}^h represents the relative voltage deviation and is calculated as the ratio of the positive-sequence voltage component at the DER connection node to the nominal voltage value of that node using the equation:

$$r_{VTi}^h = \frac{V_{Ti}^{+h}}{V_{Tnomi}^{+}},\ i = 1, \dots, N_{DER}\ . \qquad (2)$$

If at least one DER disconnects during this interval, a second short-circuit calculation is carried out, excluding those DERs.

New short-circuit currents $\hat{I}_{R1}^2$ and $\hat{I}_{R2}^2$ are determined, and corresponding relay operating times $t(\hat{I}_{R1}^2)$ and $t(\hat{I}_{R2}^2)$are calculated. Since relays were already exposed to current during the first interval, corrected relay times are calculated using the following equations:

$$t_{R2}^2 = 150\text{ms} + t(\hat{I}_{R2}^2) - 150ms\ \frac{t(\hat{I}_{R2}^2)}{t(\hat{I}_{R1}^2)} \qquad (3)$$

$$t_{R1}^2 = 150\text{ms} + t(\hat{I}_{R1}^2) - 150ms\ \frac{t(\hat{I}_{R1}^2)}{t(\hat{I}_{R2}^2)} \qquad (4)$$

This calculation must be repeated for each main-backup relay pair in the network and is also applicable for recloser-fuse coordination [14].

This is where the calculation ends. In [14], the robust method was tested on the IEEE 37 and verified on the real-life distribution network. Based on the results obtained in the research, it was concluded that the method is useful and applicable for real-life distribution networks with high DER penetration.

As for the applicability to microgrids, the next section will present the calculation results obtained from the short – circuit and relay protection coordination study conducted in ETAP (Electrical Transient Analyzer Program) software.

IV Calculation Results

This section presents and discusses the results obtained from the research reported in [11]. The original study comprised two main parts: a short-circuit analysis and a relay protection analysis.

The short-circuit study focused on validating the generalized Δ-circuit calculation method under different operating conditions. In parallel, the relay protection study was conducted to verify the practical applicability and effectiveness of the proposed adaptive relay protection method in distribution networks with a high penetration of DERs, only now, on the real-time microgrid.

The microgrid in question is the Case Western Reserve University (CWRU) campus microgrid, located in Cleveland, Ohio [16]. Single line diagram of the CWRU campus microgrid is presented in Figure 5.

Two yellow lightnings indicate that on those Buses (2 and 5) three – phase short circuit was simulated.

The microgrid consists of 28 three-phase nodes, and Bus 1 being the source node which is connected to the Utility grid at the PCC. Three voltage levels exist within the microgrid, and these are: 11.2 kV, 0.48 kV and 0.207 kV.

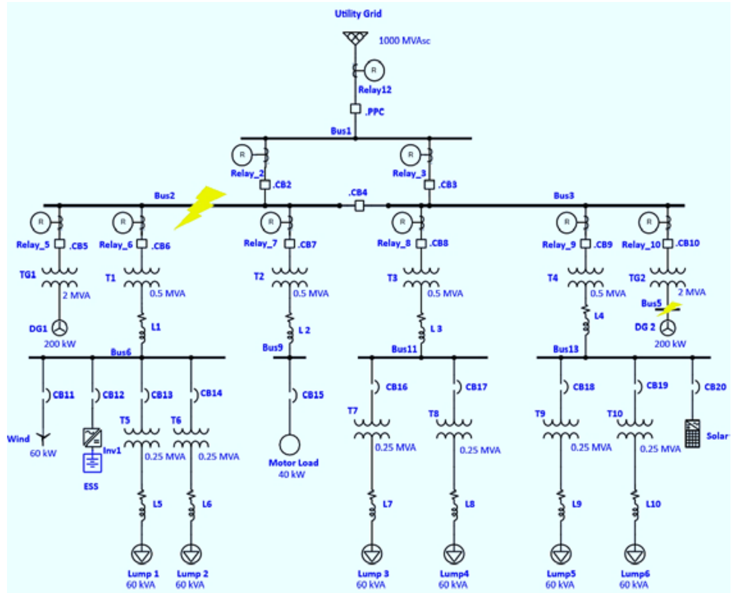

Figure 5. CWRU campus microgrid

The Utility grid has a three-phase short-circuit power of 1000MVA and X/R=22. Two identical diesel generators are connected in Bus 4 and 5. Their rated power is 200 kVA.

Wind turbine with rated power and the Energy Storage System, with rated powers of 60 and 40 kVA, respectively are connected to the Bus 6. PV Array with the rated power of 40 kVA is connected to the Bus 13.

Line impedance of cables L1, L2, L3, and L4 is $(0.049 + j0.027)\Omega/kft$, while L1 and L2 being 150 ft long and L3 and L4 200 ft. Line impedance of L5, L6, L7, L8, L9, and L10 is $(0.06 + j0.03)\Omega/kft$. The length of these cables is 400 ft. At the end of these cables Lump loads are located, each having a rated power of 60 kVA. Single Motor load is connected to the Bus 9 with the rated power of 40 kW.

Transformers TG1 and TG2 have parameters: 0.48/11.2 kV, Δ/Y, 2 MVA, Z=5.75%, X/R=6.

Transformers T1-T4 have parameters: 11.2/0.48 kV, Δ/Y, 0.5 MVA, Z=5.75%, X/R=6.

Transformers T5-T10 have parameters: 0.48/0.207 kV, Δ/Y, 0.25 MVA, Z=5.75%, X/R=3.

For the purpose of this paper, short – circuit study, as well as the results will not be discussed. They are thoroughly displayed and discussed in [11]. However, applicability of the adaptive relay protection method will be addressed in the following text.

The study was conducted in ETAP software using the Star-Protection and Coordination mode, which is specialized in relay protection coordination. In this case, three-phase faults were simulated at Buses 2 and 5. However, this study was conducted only in grid-connected mode, due to certain limitations of the method used for relay protection settings and coordination. These limitations will be discussed after presenting the results.

It is very important to note that ETAP Star does not have an option to integrate certain mathematical functions and perform the calculations based on them. Instead, an official standard is chosen (IEC, ANSI, IEEE, etc.), and relay protection coordination is conducted accordingly. In Tables 1 and 2, relay reaction times were listed for a three-phase fault in Buses 2 and 5, respectively. These reaction times were calculated using the IEC standard and the traditional relay protection method for radial distribution networks, where selectivity is set solely based on the relay location in the network and the short-circuit current magnitude at that location. In this method, relays are set according to their time-current characteristic curves, which determine operating time as a function of the fault current magnitude. The closer a relay to the slack bus, the later should it operate (serving as backup protection for relays in the lower network layers) in order to avoid immediate disconnection of larger parts of the network that are not affected by the fault. On the other hand, the chosen method for relay protection coordination in distribution networks with high DER penetration takes into account DERs' disconnection times according to the FRT standard and calculates relay reaction times in separate time intervals, based on those disconnection times. Discussion will be carried out in the following text and a comparison will be made regarding those two approaches.

Tables 1 and 2 present the results for three-phase faults at Buses 2 and 5, respectively, showing the sequence and timing of relay and associated circuit breaker operations. The relevant data are marked with a green rectangle. The left column shows the reaction time (ms), while the right column identifies the device that operated at that instant.

From Table 1 and the relay positions in Figure 5, the results demonstrate proper selectivity. For a fault at Bus 2, Relay 2 operates first and trips HVCB2, which is the closest breaker to the fault location. If HVCB2 fails, Relay 12 provides backup protection by tripping the breaker at the PPC and isolating the faulty section. The remaining breakers are LVCBs on the 0.48 kV side, supplying DERs and local loads, and their later operation is consistent with their downstream position.

Table 1. Result table generated by ETAP for a three-phase short-circuit in grid-connected mode simulated on Bus 2.

Protection device	Reaction time [ms]
Relay_2	20.1
CB2	70.1
Relay_3	227
CB3	277
Relay12	680
PPC	780
CB11	3350
CB15	6074
CB16	9506
CB17	9506
CB18	9562
CB19	9562
CB13	10536
CB14	10536

A similar pattern is observed for the fault at Bus 5, shown in Table 2. Relay 10 operates first and trips HVCB10, as expected due to its proximity to the fault. In case of failure, Relay 3 acts as backup by tripping HVCB3, followed by Relay 12 as the final backup at the PPC.

Overall, the results for the grid-connected mode confirm correct operation of the traditional relay protection scheme, with primary and backup devices operating selectively and in the intended sequence for both fault locations.

Table 2. Result table generated by ETAP for a three-phase short-circuit in grid-connected mode simulated on Bus 5.

Protection device	Reaction time [ms]
Relay_10	390
CB10	400
Relay_3	1837
CB3	1887
Relay12	2451
PPC	2551
Relay_2	4467
CB2	4517

Unlike the previous method, this approach takes into account the FRT standard, displayed in Figure 3, thereby considering the period of time during which all DERs must remain connected to the grid depending on the relative voltage drop at the point of connection. Based on these time intervals, the relay operating times are calculated accordingly. DER disconnection times are calculated using equation (1).

Calculated disconnection times are displayed in Tables 3 and 4. In the left colums, Buses with associated DER, and in the right disconnection times in ms are displayed.

Firstly, the results of the three-phase fault at Bus 2 will be discussed, followed by a discussion of the results on Bus 5.

According to the adaptive relay protection method and based on the FRT requirement shown in Figure 3, if the relay protecting the bus operates during the first interval, meaning it trips while all DERs are still connected to the network, the calculation process stops at that point. In this case, as shown in Table 1, Relay_2 operates at 20 ms, which falls within the first interval while all DERs are still connected. Therefore, no further calculation is required.

Table 3. DER disconnection times for a three-phase short-circuit simulated on Bus 2 in grid-connected mode.

Buses with connected DERs	Disconnection time [ms]
Bus 2 (DG1)	150
Bus 5 (DG2)	212.55
Bus 6 (Wind + ESS)	334.95
Bus 13 (Solar)	262.05

In contrast to the previous scenario, a three-phase short circuit was simulated at Bus 5. Relay_10, which provides protection for this bus, operates at 390 ms (see Table 2). As this operating time exceeds 150 ms, additional calculations are necessary. Table 2 summarizes the DER disconnection times, while the same table also presents the relay response times within the first time interval. To proceed with the analysis, the corrected relay time equations are applied again, corresponding to Equations (3) and (4).

Both equations are required, as the method is implemented for a coordinated main–backup relay pair. In the considered case of a fault at Bus 5, Relay_10 operates as the primary protection device, while Relay_3 provides backup protection.

Following the application of the adaptive relay protection scheme and the recalculation using the two referenced equations, revised operating times were obtained for the main–backup pair. The original operating time of 390 ms for Relay_10 was adjusted to 508 ms, whereas the backup relay, Relay_3, exhibited a corrected operating time of 1280 ms instead of the initial 1837 ms reported in Table 2.

Both updated operating times are positioned within Interval II of the FRT requirement. This confirms that the adaptive relay protection approach yields a more precise assessment of relay response times compared to the conventional method, as it incorporates FRT constraints together with real-time network conditions, enabling dynamic and more realistic coordination of protection devices.

Table 4. DER disconnection times for a three-phase short-circuit simulated on Bus 5 in grid-connected mode.

Buses with connected DERs	Disconnection time [ms]
Bus 5 (DG2)	150
Bus 1 (DG1)	1671.45
Bus 6 (Wind + ESS)	1672.05
Bus 13 (Solar)	1672.65

As presented above, the adaptive relay protection method operates in the grid – connected environment with ease. Moreover, the method has a clear limitation when it comes to coordinating relay protection in the islanded microgrids, due to the low short – circuit current magnitudes and different dynamic DER behavior. These limitations are especially visible in the more complex scenarios such as transitioning between two operating modes of the microgrid, where whole protection scheme must adapt in real – time to achieve selectivity and proper relay tripping.

Consequently, next section will propose the enhanced method for adaptive relay protection in microgrids based on the foundation of methods for short – circuit calculation [2,6,11] and adaptive relay protection [14,15].

V Proposition of Enhanced Adaptive Relay Protection Framework in Microgrids

Since the previous section pointed out technical drawbacks regarding the applicability of the method in islanded mode of operation as well as in transitioning between two operating modes, this section will introduce enhanced adaptive relay protection framework for microgrids.

Let us consider the microgrid with DERs and loads and one PCC connecting it to the wider distribution grid. This microgrid can operate in both, grid – connected and islanded mode. In the event of short – circuit the proposed algorithm should operate as follows:

Firstly, it must be determined whether the microgrid operates in grid – connected or in islanded mode, via the sensor on the PCC indicating the state of the circuit breaker (opened / closed). Secondly, whether the circuit breaker is closed, meaning the microgrid operates in grid – connected mode, methods for adaptive relay protection [14,15] and short – circuit calculation [2,6,11] should be used. The reason for that is, topologically speaking, grid – connected microgrid acts like a part of the radial distribution network with high DER penetration, in which those two algorithms work efficiently.

On the other hand, whether the circuit breaker is opened, and the microgrid operates in the islanded mode, algorithm for relay protection coordination should be different.

Before discussing the algorithm for islanded mode of operation, it is necessary to introduce the concept of relay protection setting groups in numerical relays [17,18].

Modern microprocessor-based relays allow the implementation of multiple predefined setting groups. Each setting group represents a complete and independent set of protection parameters, including pickup current tripping values, time delays, directional elements, voltage and frequency limits, and logic coordination settings. Only one setting group is active at a given time (or change in topology of the system), while others remain stored and can be activated either manually or automatically. In the case of a microgrid, manual would consider SCADA surveillance and manual setting from the control room, while automatic activation would happen when the relay receives an input indicating a change in the circuit breaker state at PCC, changing the setting group of the relay.

The primary purpose of setting groups is to enable adaptive protection behavior under different system operating conditions. In microgrids with high DER penetration, system characteristics such as short-circuit level, fault current contribution, and power flow direction may significantly vary depending on whether the microgrid operates in grid-connected or islanded mode [7,10,11]. Consequently, a single fixed set of protection parameters may not ensure proper sensitivity and selectivity in all operating scenarios.

In grid-connected operation, fault currents are typically supported by the upstream distribution network, resulting in higher short-circuit levels. Therefore, higher pickup thresholds and conventional coordination settings can be applied. However, during islanded operation, IBDERs often limit fault current contribution, leading to substantially reduced short-circuit currents. Under such conditions, conventional overcurrent settings may become insufficiently sensitive, potentially preventing correct fault detection.

By utilizing protection setting groups, relay parameters can be dynamically adjusted according to the detected operating mode of the microgrid. This enables the proposed framework to maintain adequate protection performance in both grid-connected and islanded states.

Development of the entire methodology, that would be able to adaptively adjust and protect the microgrid regardless of operating condition and location and type of the fault, based on the above discussion, will be the subject of authors' future research.

VI CONCLUSION

The increasing penetration of IBDERs significantly alters short-circuit characteristics and protection coordination principles in modern microgrids. Conventional overcurrent protection schemes based on fixed settings and IEC 60909 assumptions are no longer sufficient, particularly under conditions of bidirectional power flow, current-limited inverter behavior, and mandatory Fault Ride-Through requirements.

The adaptive relay protection method analyzed in this paper, based on time-segmented coordination aligned with DER disconnection intervals, demonstrates improved accuracy in grid-connected microgrids. Simulation results obtained using the CWRU campus microgrid model confirm that the method enhances selectivity and provides more realistic relay operating times compared to traditional coordination approaches.

However, the study also highlights a critical limitation: reduced short-circuit levels and dynamic inverter behavior in islanded operation restrict the direct applicability of existing adaptive methods. Furthermore, transitions between operating modes require real-time modification of protection parameters to ensure reliable fault detection.

To overcome these limitations, an enhanced adaptive relay protection framework has been proposed. The approach integrates operating-mode detection at the PCC with dynamic switching of relay protection setting groups.

Development of the entire methodology, that would be able to adaptively adjust and protect the microgrid regardless of operating condition and location and type of the fault, based on the above discussion, will be the subject of authors' future research.

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Adaptivna prekostrujna zaštita u mikromrežama sa dominantnim inverterskim izvorima uz razmatranje Fault Ride-Through i dinamičkih režima rada

Rezime - *Sve veći udeo distribuiranih energetskih resursa (DER) zasnovanih na invertorima (IBDER) u mikromrežama značajno menja prirodu i ponašanje sistema tokom trajanja kratkog spoja, pri čemu su struje kvara bliske nominalnim vrednostima. Pored toga, česti prelazi između režima povezanog na mrežu i ostrvskog režima rada, to čini tradicionalne šeme prekostrujne zaštite (Over Current Protection – OCP) nepouzdanim, što dovodi do nepravilnog delovanja zaštite, gubitka selektivnosti i kasnom uklanjanju kvarova. Dodatno, Fault Ride – Through (FRT) zahtevi omogućavaju IBDER jedinicama da tokom tačno definisanog vremenskog intervala održavaju ograničen doprinos struji kvara pre isključenja sa mreže, što dodatno komplikuje podešavanje zaštite.*
U ovom radu se predstavlja adaptivna struktura prekostrujne zaštite koja dinamički prilagođava vrednosti za koje će zaštita da reaguje u zavisnosti od radnog režima mikromreže, kao i vremenskih intervala usklađenih sa očekivanim strujnim odzivom IBDER jedinica. Uvođenjem vremenskih intervala zasnovanih na FRT zahtevima, predloženi pristup omogućava pouzdano razlikovanje prolaznih i trajnih kvarova, uz očuvanje stabilnosti sistema. Preliminarne simulacione studije pokazuju značajna poboljšanja u osetljivosti detekcije i koordinaciji u poređenju sa fiksnim podešavanjem prekostrujne zaštite, što ukazuje na održivu osnovu za primenu u budućim šemama zaštite mikromreža u stvarnom životu.

***Ključne reči* -** *prekostrujna zaštita, IBDER, mikromreže, FRT zahtevi, adaptivna zaštita u mikromrežama*

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