New overcurrent relay coordination method to enhance microgrid protection

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ABSTRACT This paper presents a method to protect microgrids (MGs) through coordination of directional overcurrent relays (DOCRs). The new formulation is subjected to restrictions of pre-established time intervals to guarantee the primary and backup functions of each relay. This coordination criterion has advantages over the conventional coordination because functional independence between the relays is achieved. It is only necessary to update the setting in the relays affected by contingencies, topological changes, or during the formation of islands. The use of non-conventional curves is considered to give the flexibility necessary to meet the time intervals at each required location. Based on the results, the proposed coordination method reduces the operation time of the relays compared with that under the conventional coordination method in the power systems studied. Further simplification in the relay adjustment process under the different contingencies studied was obtained, which improved under the various operating conditions in the test systems.

INDEX TERMS Directional overcurrent relays, microgrids, non-conventional curves, power system protection, relay coordination algorithms

I. INTRODUCTION

Owing to the increase in fossil energy costs, the development of electricity generation in recent decades has been oriented toward environmental conservation and greater efficiency [1]. As a result, the vertical structure of electrical networks, mainly medium- and low-voltage networks, has been modified toward systems either isolated or with weak connections to the electrical network [2]. These microgrids (MGs) present a very wide diversity regarding their operation [3], and the connection of non-dispatchable sources [4] significantly influences load flows and faults due to topology changes or to the intermittency of generation sources [5]. However, MGs have operational benefits [6] as they reduce the congestion problems of the main network, provide generation closer to the consumption centers, and reduce energy losses, demand peaks, and, therefore, operating and generation costs [7].

One of the problems to consider in the implementation of an MG is the design of the protection scheme [8]. Integration of the MG into electrical networks has promoted the development of control and protection systems; for this purpose, local or distributed architectures have been considered [9]. The scheme must be capable of satisfying basic protection needs [10], such as selectivity, sensitivity, and reliability, either in a mode connected to the main network or in an island operation mode [11].

A. LITERATURE REVIEW

MG protection systems must contemplate highly dynamic operating conditions [12]. The protection scheme must be adaptable [13], consider the MG's operating modes, and guarantee an online coordination system. Which should also incorporate the necessary configurations in the protection relays according to load variations, the penetration of renewable generation [14], topology changes, and weak sources, thus resulting in better fault detection, reduction of false trips, and shorter operating times [15]. Differential protection is used to address the limitations of DOCRs under dynamic MG operating conditions [16]. The identification of poor operation of DOCRs through the connection of inverter-based distributed generation units (IBDG) is described in [17], where a harmonic DOCR is proposed for the detection of harmonic contamination of IBDGs during fault conditions.

The application of time overcurrent relays in MGs has limitations in terms of sensitivity [18]. Highly dynamic load conditions combined with minimal faults owing to the
distributed energy resources (DERs) compromise fault detection; a lack of sensitivity can be very common in these networks [19]. The overcurrent relay configuration is engaged mainly because the pickup current is calculated using the maximum values of the load current [20]. A contingency analysis of \( n-1 \) should be considered to avoid false operations under power-transfer conditions. Minimal fault currents can be very common if the utility contribution is small under a poor MG connection or under isolated operation [21]. A high connection of the MG with the utility does not represent general sensitivity problems, and the fault currents are often similar for all MG buses.

The implementation of the protection scheme in a MG was evaluated using a scheme based on directional overcurrent relays (DOCRs) [22]. Various deterministic [23,24] and metaheuristic methods [25,26,27] have been explored. The considered metaheuristic models are effective because they do not require initial conditions for their execution and have the capacity to conduct a global search and are therefore capable of greater exploration. In addition, the robustness necessary to solve complex nonlinear problems was demonstrated. A combination of phase and ground protection is formulated with a unique objective function, using an evaporation rate water cycle algorithm [28]. The search for new protection functions was advanced through the design of new characteristics for the time curve of overcurrent relays. In [29], an optimal coordination method was proposed based on a dual adjustment using different time curves. A non-conventional curve was presented that took into consideration the limited variation in the coefficients of the time curve [30, 31]. A new time curve to reduce the operating time of DOCRs was presented in [32].

**B. CONTRIBUTIONS**

In this study, the MG coordination problem is presented as an optimization problem with time restrictions for overcurrent relays. The differential evolution (DE) algorithm was selected and used for optimal configuration of the relays [33]. The time curve model is very important in order to ensure proper coordination [34]. Time curves with more degrees of freedom are more flexible, and offer an alternative for overcurrent coordination [31]. The key contributions of this study are as follows. The proposed formulation is subjected to restrictions of pre-established time intervals to guarantee the primary and backup functions of each relay, with that functional independence between the relays is achieved. The use of non-standardized time curves reduces violations and improves the operating times. This proposed method applied in an online protection has advantages because it does not require the re-coordination of all the relays to a dynamic topology or to operational changes, but only of the affected relays. The proposed method was compared with the conventional coordination; the proposed method resulted in lower relay operating times for the different contingencies analyzed.

This paper is presented as follows: Section II focuses on the problem statement of directional overcurrent relay coordination. In Section III, the methodology of the proposed scheme is described in detail. Section IV the optimization algorithm is described. In Section V, the test systems used are described. In Section VI, the simulation results and discussion are presented and analyzed. Finally, the section VII shows the general conclusions.

**II. DIRECTIONAL OVERCURRENT RELAY COORDINATION PROBLEM**

Overcurrent relays have a highly dynamic protection zone because they are very affected by the operating conditions of the electrical network, such as topological changes, current demand variation, and operating states that modify the fault current contributions. However, owing to their functional simplicity, they respond appropriately according to the fault conditions of the system and their tolerance to temporary overloads. They are applied at all voltage levels of the electrical network.

The DOCR coordination is formulated to guarantee the safety of the protection scheme, and backup relays are established to guarantee that the fault is released when the primary relay does not operate. Inverse time curves are commonly used so that the primary protection and backup functions coordinate correctly. Given the divergence of the time curves, the sequence of operation is obtained using a coordination time interval (CTI) for the maximum value of the fault current seen by both relays, as shown in Figure 1. Because DOCRs use the same curve for the primary and backup functions, the crossing of curves is avoided; however, in meshed electrical networks, this is not always ensured, because the load current may be higher downstream.

Distributed generation (DG), such as that with small conventional generators, must be considered in the fault current [35] because it is possible that the time of the relays decreases with the additional fault current contribution, and simultaneous trips occur. Loss of coordination can occur between relays \( R_1 \) and \( R_2 \) in \( F_{PC} \), as shown in Figure 1. Because \( R_3 \) does not see the contribution of the DG, its time will not be affected \( (F_3) \), and thus, coordination will be maintained between \( R_2 \) and \( R_3 \) but with a higher CTI. It is necessary to evaluate the true impact of DG on coordination because the increase in the fault current may be in the asymptotic region of the time curve with little effect on relay timing. In the case of non-controlled sources connected by converters, such as wind power or photovoltaics, it may not
Relay coordination is a complex process because the coordination requirements present a functional dependency between relays, because the backup time relay is computed with the primary time relay plus the CTI, and because the number of coordination pairs is proportional to the electrical network interconnection. It is advisable to formulate coordination as an optimization problem.

A. TRADITIONAL OPTIMIZATION FORMULATION

The purpose of this section is to establish the traditional optimization formulation for the relay coordination solution that serves as a comparative framework with the proposed coordination method.

The objective function (OF) is commonly formulated to minimize the operation time of each relay and to ensure the CTI between the primary and backup relays. Because each coordination problem is different and the diverse configurations and operating conditions of the electrical networks result in different relay settings. Many formulations have been proposed, and some have been compared [36]. The objective of this paper is the evaluation of the proposed coordination method with conventional methods; thus, the comparison between different OFs or optimization algorithms is not considered. In this paper, the formulation for the conventional coordination method is:

\[
OF_{\text{conv}} = \min \left\{ \frac{NV}{NCP} + \omega_1 \left( \frac{\sum tp}{NCP} - 1 \right) + \omega_2 \left( \frac{\sum tb}{NCP} - 1 \right) + \omega_3 \left( \frac{NCP}{pB} - 1 \right) \right\} \tag{1}
\]

where \( NCP \) is the number of coordination pairs present in the system, \( NV \) is the number of coordination pairs violated, \( tp \) is the operating time of the primary, \( tb \) is the operating time of the backup relay, and \( CTI_{pb} \) is the \( CTI \) that is interpreted as a soft-constrained \( CTI \) error of the \( pbth \) coordination pair. The variables \( \omega_1 \), \( \omega_2 \), and \( \omega_3 \) are the weighting factors used to determine the importance of each objective. The best weights were obtained using the Pareto frontier through parametric variations of the overcurrent coordination.

The operating time of each relay is defined as follows by taking as reference the conventional curves (CCs) of the IEEE standard [34]:

\[
tp, b(s) = \left[ \frac{A}{I_{sc}} \left( \frac{I_{sc}}{PSM \cdot I_{load}} \right)^{\varphi - 1} + B \right] \cdot TDS \tag{2}
\]

where \( TDS \) is the time dial setting, \( I_{sc} \) is the maximum near-end fault current, \( PSM \) is the plug setting multiplier, and \( I_{load} \) is the protected line load current. Thus, the pickup current is computed as \( I_{\text{pickup}} = PSM \cdot I_{load} \), where parameters \( A, B, \) and \( \varphi \) are the characteristic curve parameters, which are defined as constants according to the standardized equation and specify the type of curve to be used.

The variables used for the optimization algorithms were \( TDS \) and \( PSM \). This results in different settings for each DOCR to meet the coordination constraints, as follows:

\[
(t_b - t_p \geq CTI)_{\theta} \tag{3}
\]

\[
(PSM_{\text{min}} \leq PSM \leq PSM_{\text{max}})_{\beta} \tag{4}
\]

\[
(TDS_{\text{min}} \leq TDS \leq TDS_{\text{max}})_{\beta} \tag{5}
\]

where \( \theta \) is the total number of relays considered in the coordination, and \( \beta \) is the total number of relays. For example, the 14 IEEE test system has 50 pairs and 40 relays, and the 30 IEEE test system has 120 pairs and 82 relays. For good coordination, the relay must operate immediately after a fault occurs in its protected line; however, it is also necessary to have a sufficient time delay to provide backup for the adjacent line in the forward direction when the primary relay does not operate. Because of the functional dependence in the coordination process, the setting
modification in one relay has a domino effect, affecting all relay coordination (3).

III. PROPOSED COORDINATION METHOD

In this paper, the coordination of DOCRs is proposed in a non-conventional way, each relay is adjusted stand-alone without needing the adjustment of the neighboring relay. In traditional coordination, the operation of the backup relay depends on the time of the primary relay. This functional dependence means that during some topological or operational changes, the readjustment of a relay will affect the coordination of the entire electrical network. In addition, a slow relay, either due to its high pickup current or because of its coordination commitments, may affect other nearby relays, causing their operating times to also increase.

In the proposed method, the relay operating time is bounded at the desired time intervals. This enables independent adjustments between relays because only the compliance with the operating times within the time intervals must be obtained. This benefits the setting of the relays, as they are not affected by the timing of the neighboring relays. The three-time intervals used in the proposed method are displayed in Figure 2. The time intervals were defined based on expected time criteria for the operation of relays of some electric companies; however, following the proposed methodology, these may be different, as shown in section VI. It is only necessary to define a CTI time between these intervals to avoid loss of coordination and to guarantee the functions of primary protection and backup protection but avoiding functional dependency (3).

Each relay must meet the defined times in the time intervals with a unique time curve, in Figure 2 two relays are shown and as with the fulfillment of each relay within the intervals, the coordination between them is obtained independently without the need for the time of the backup relay depends on the time of the primary relay. The time defined in the intervals can be lower, but safety during operation of the relay must be weighed.

The use of non-conventional curves (NCCs) is considered to obtain the flexibility of the time curve necessary to meet the time intervals at each required location. However, there is the possibility of violations with smaller interval margin because the time curve must be more flexible, even though it is possible to relax the third interval because it is affected by the pickup of the relay. In the cases studied, there were no violations with an interval of 0.1, Figure 2. The fault currents are different for each relay location; thus, the optimization coordination algorithm searches the NCC to guarantee the time intervals. Thus, the optimization algorithm computes a different time curve for each relay. This condition is favorable for the coordination algorithms because the search process will only consider the degrees of freedom of the curve for each relay to comply with the times established in each interval, avoiding functional dependence with other relays.

When considering relay coordination as a minimization problem, it is intended that the operating times become close to the lower limit of each interval. To determine the time curve of each relay, the fault currents at three points are required for the relay R2 to determine the times in each interval (Isca, Iscb, and Iscc in Figure 2), unlike the conventional method, which requires only two fault currents for R2 (F1 and F2 in Figure 1). However, for the proposed coordination method these fault currents are known values, and no modification of the fault study is required.

A. PROPOSED OBJECTIVE FUNCTION

The objective of the coordination problem is to minimize the operation time of each relay with compliance with the three intervals, as follows:

$$OF_{pro} = \min \left\{ \sum_{\mu=1}^{N} \left( T(I_{sc\ a})_\mu + T(I_{sc\ b})_\mu + T(I_{sc\ c})_\mu \right) + NV \right\}$$

(6)

where $N$ is the number of relays in the system, $t(I_{sc\ a})$ is the operating time for a close-in fault, $t(I_{sc\ b})$ is the operating time for a bus-end fault, $t(I_{sc\ c})$ is the operating time for a fault in the remote line-end, and $NV$ is the number of recorded violations when the operation time is not fulfilled within each interval, which is included with the objective of minimizing the number of violations to zero (avoiding convergence to the local minimum). These are included in the proposed $OF_{pro}$ to further improve the results while maintaining selectivity.
B. COORDINATION CONSTRAINTS

The time curve model considers each coefficient as a degree of freedom to obtain the generalized formulation of the overcurrent relay, and the design obtained is individual for each relay. Thus, the resulting adjustment increases the possibility of complying with the relay restrictions. This implementation allows greater flexibility in the generation of NCC.

The variables $A$, $B$, and $p$ determine the shape of the time curve. The variability of the time curve ranges from a moderately inverse to an extremely inverse curve, and it is possible to obtain a wide diversity of time curves with the parametric constraint. The inequality constraints (2) and (3) are not used in this coordination proposed method. TABLE I lists the intervals considered for the time curves [34].

| Parameter | Minimum range | Maximum range |
|-----------|---------------|---------------|
| $TDS$     | 0.1           | 3             |
| $PMS$     | 1.4           | 1.6           |
| $A$       | 0.05          | 28.2          |
| $B$       | 0.11          | 0.49          |
| $p$       | 0.02          | 2.00          |

The restrictions of the time intervals of the relays were established for each point of interest, and the time curve was evaluated at each fault current value. Thus, the same curve must satisfy all three regions in a minimum time, as follows:

\[
 t(I_{sc}a)^{min} \leq t(I_{sc}a) \leq t(I_{sc}a)^{max}
\]

\[
 t(I_{sc}b)^{min} \leq t(I_{sc}b) \leq t(I_{sc}b)^{max}
\]

\[
 t(I_{sc}c)^{min} \leq t(I_{sc}c) \leq t(I_{sc}c)^{max}
\]

The time intervals can be different following the protection criterion for each utility, and voltage sags or indices that weigh the unavailability per customer in minutes per year must be evaluated. The time intervals used in this work were defined following the common criteria of relay operating times of the Federal Electricity Commission (CFE). However, different time intervals were evaluated in case of having different time criteria in the operation of relays, and the results are displayed in the Results section.

The proposed method can be implemented with any CC, but NCCs provide better results because they have more flexibility to accomplish the time intervals. There is the possibility of crossing curves when the pickup current of the primary relay is greater than the pickup current of the backup relay, which occurs frequently in mesh systems. Given the operating conditions of the electrical network, the lack of compliance in the interval $t(I_{sc}c)$ is probable. This condition occurs in relay coordination because the lack of sensitivity is an intrinsic problem in the overcurrent protection principle; as a possible solution in the proposed method is relax the third interval because it is not used for coordination. Other solution mechanisms, such as distance relays or adaptive relay settings via online protection, can be implemented.

IV. DIFFERENTIAL EVOLUTION FORMULATION VIA INTERVAL METHOD

The DE algorithm is one of the evolutionary algorithms, and it performs a metaheuristic search based on natural evolution for the selection of genes. It is performed through genetic operators (Figure 3), altering the members of the current generation population with scaled differences from members of the randomly chosen population, through a probability distribution. This characteristic causes the algorithm to have fewer mathematical operations and less computational execution time.

1) Initial population ($P$) An initial population is created in which the genes of the individuals start at a certain number within the probable range corresponding to the relay configuration. Each row is an individual, and each column has a gene/variable/relay setting configuration. The population size is $(NP, D * N)$, where $NP$ represents the number of individuals, $D$ is the number of control variables, and $N$ is the number of relays. For example, for a system that has 10 relays with five degrees of freedom ($TDS, PSM, A, B,$ and $p$), the population size for 80 individuals will be (80,50). The initial population is as follows:

\[
 P = \begin{bmatrix}
 TDS_{(1,1)} & \cdots & TDS_{(1,N)} & PSM_{(1,1)} & \cdots & PSM_{(1,N)} \\
 \vdots & \ddots & \vdots & \vdots & \ddots & \vdots \\
 TDS_{(NP,N)} & \cdots & TDS_{(NP,N)} & PSM_{(NP,1)} & \cdots & PSM_{(NP,N)} \\
 A_{(1,1)} & \cdots & A_{(1,N)} & B_{(1,1)} & \cdots & B_{(1,N)} & P_{(1,1)} & \cdots & P_{(1,N)} \\
 \vdots & \ddots & \vdots & \vdots & \ddots & \vdots & \vdots & \ddots & \vdots \\
 A_{(NP,1)} & \cdots & A_{(NP,N)} & B_{(NP,1)} & \cdots & B_{(NP,N)} & P_{(NP,1)} & \cdots & P_{(NP,N)} 
\end{bmatrix}
\]

(10)

2) Mutation. The mutation consists of an arithmetic difference between pairs of randomly selected vectors. A mutant vector is reached, which is computed as the scaled difference between two vectors ($r_2, r_3$) of three randomly chosen vectors, added to the value of the third vector ($r_1$), called the base vector. $F$ is the mutation factor.

\[
 X'_{i,G+1} = X'_{r_1,G} + F(X'_{r_2,G} - X'_{r_3,G})
\]

(11)
where:
\[
\begin{align*}
\bar{X}_{r1G} &= \text{Best } P \, (\text{TDS, PSM, A, B, p}) \\
\bar{X}_{r2G} &= P_{\text{old}} \, [\text{Rand permutation (NP)}] \\
\bar{X}_{r3G} &= P_{\text{old}} \, [\text{Rand permutation (NP)}]
\end{align*}
\]

And \( r_1, r_2, r_3 \in \{1, 2, ..., NP\} \). \( F \) is a constant user defined from \([0, 2]\), \( \bar{X}_{LG+1} \) is called the donor vector of generation \( G + 1 \).

3) Crossover. To benefit the variety of the population, a crossover operation is performed after forming the mutant vector mid-mutation. The mutant vector exchanges its elements with the parent vectors \( \bar{X}_{LG} \) to form the child vector. The crossover is performed on each \( D \) variable as long as a randomly generated number between 0 and 1 is less than or equal to the value of \( CR \).

\[
U_{j,LG} = \begin{cases} V_{j,LG} & \text{if } (\text{rand}_i,j \leq CR) \text{ or } (j = j_{\text{rand}}) \\ X_{j,LG} & \text{otherwise} \end{cases}
\]
(12)

where:
\[
V_{j,LG} = P_{\text{old}} (\text{rand}(NP, D) < CR) + V_{j,LG} (\text{rand}(NP, D) < CR)
\]

And \( \text{rand}_{i,j} [0,1] \) is a uniformly distributed random number. This random function is executed for each \( i \)th component of the \( i \)th parameter vector. Then, a randomly chosen index \( j_{\text{rand}} \in [1, 2, ..., D] \) ensures that the test vector \( \bar{U}_{LG} \) obtains at least one component of the donor vector \( \bar{V}_{LG} \).

4) Selection. To keep the population size constant in successive generations, the next step of the algorithm sets the selection to determine whether the parent vector or the child vector survives to the next generation, which refers to \( G = G + 1 \). The selection operation is as follows:

\[
\bar{X}_{LG+1} =
\begin{cases} 
\bar{U}_{LG} & \text{if } f(\bar{U}_{LG}) \leq f(\bar{X}_{LG}) \text{ if competitor is better than value in "cost array"} \\
\bar{X}_{LG} & \text{if } f(\bar{U}_{LG}) > f(\bar{X}_{LG}) \text{ otherwise the target vector is kept in the population}
\end{cases}
\]
(13)

And:
\[
P(NP, D) = U_{i, LG} (NP, D) \text{ Replace old vector with new one (for new iteration)}
\]

where \( f(\bar{X}) \) is the fitness of the target vector, and \( f(\bar{U}) \) is the fitness of the trail vector. If a lower or equal value of fitness is obtained from the new trial vector, then the target vector will be replaced in the next generation; otherwise, the target vector is kept in the population. By doing so, the . each relay was analyzed using:

\[
Sb = \frac{I_{SC} \geq 1.5}{P_{SM} + I_{load}}
\]
(14)

where \( I_{SC} \) is the minimum fault current in the remote line end detected by the backup relay. It is considered to have a lower limit of 1.5, because between multiples of current from 1 to 1.5, the times resulting from the operation of relays are large and useless for protection purposes.

In conventional coordination, the topological change in the electrical network or the change in the load/fault current forces an update to all coordination owing to the functional dependence between the relays. This adjustment update includes all relays, even though many of them may not notice any variation in the magnitudes. In contrast, in the proposed interval method, the adjustment update will only be in the relays involved; those that do not have an appreciable change in currents will not have to be adjusted, which reduces the computing and communication times.

The optimization algorithm that will be selected for on-line execution must show the robustness necessary for protection systems. To carry out the proposed coordination and the correct operation of the protections in the pre-established times, the adjustment update system must be implemented in centralized mode with continuous real-time measurement processing and monitoring of the system topology. The time updating before any topological change must be almost in real time, and the update by variation of the demand can be carried out in intervals of no more than 15 min, similar to the times used for the calculation of the demand. The latency of communication available in the electricity grid must be considered. The \( l_{\text{lookup}} \) is updated with the measured load current within the time interval considered, and the \( L_o \) will be modified in case of a topological change or the connection of generation sources.

V. TEST SYSTEMS

The test system used for the analysis and evaluation of the proposed method is the 9-bus IEEE (modified). An interconnected system is used to obtain more complex scenarios for the comparison of the coordination methods. Different DERs are incorporated (PV1.2 = 10 MW, WPP = 10 MW, Energy storage = 5 MW, Diesel = 50 MW), various loads are determined (Load1 = 20 MW, Load2 = 20 MW, Load3 = 10 MW, Load4 = 20 MW, Load5 = 10 MW), the branch reactance of the test system are shown in Table A1 of the Appendix, and the transient impedance values of each of the generation sources are as shown in Figure 4. Thus, we sought to form and evaluate a microgrid with a high degree of complexity. The selected voltage is 34.5 kV and the scheme has 22 relays. Each relay is assigned a name derived from the local bus and the remote bus. The system presented 32 coordination pairs. The three-phase currents and the
minimum two-phase faults on each bus are calculated in the fault analysis, based on the assumption that the remote end open fault current values are updated in case of any topological or generation change. The results of this power flow and fault analysis are shown in TABLE A2 of the Appendix.

Two cases were studied. Case 1 with MG connected to the utility, in this condition the fault current is mainly provided by the utility. In case 2, the MG disconnects from the utility, a substantial reduction in fault currents is expected. In both scenarios, a comparison is made between the proposed coordination method and the conventional method.

VI. RESULTS AND DISCUSSION

We defined the initial data for the optimization algorithm. For the optimization process, 80 individuals were considered. The method included 1,000 iterations, and the runtime was evaluated as a feasibility code for online applications. A minimum TDS of 0.1 was used for each case, which provided the required time ranges. The MATLAB software was used for the simulation, and DigSILENT was used for n−1 contingency for the calculation of \( I_{\text{pickup}} \) and for dynamic operative conditions. Relays that did not meet the sensitivity filter were excluded and are not shown in the results. In the tests conducted, the time intervals shown in Figure 2 were used as the base case.

Case 1. Microgrid Connected to the Utility

The conventional coordination method with NCCs and the interval coordination method are also evaluated, with the objective of comparing and analyzing the performance of the methodologies in the protection scheme. As presented in TABLE II, the use of NCCs guarantees better operating times for both the primary element and backup using conventional coordination. Using the proposed coordination method, it is possible to reduce or eliminate the violations considerably because the search for the solution is independent for each relay. As observed in the results of the interval method, the algorithm guarantees the operating times in the preset intervals according to the faults that occur in the system. Compared to the conventional coordination, better operating times can be observed, which guarantees better coordination between each element. This can be observed, for example, in the times of the coordination methods for relay number 39.

Table II includes statistical data for the results obtained here, such as the sum of the operating times of the relays, which indicates that our results achieve a minimum value for the OF. The number of violations indicates which restrictions were not met. Finally, the computation time is indicated to allow for a comparison of the execution times for both the conventional and the proposed algorithms. Based on all these indicators, the proposed method achieves better results.
The average operation time of each of the three methods that were analyzed, conventional coordination with CC and NCC and the interval method, is shown in Figure 5. It is evident that the interval method provided the best results. Both the primary and backup times are lower with the proposed method, and the average CTI is closer to 0.2, giving the best coordination. The conventional coordination with CCs is presented in Table A3.

Different time intervals were evaluated; this brings the benefit of a coordinated system with operating times depending on the need for protection, which is evaluated according to the elements to protect and the problems of the network. This condition has the risk of violations in the proposed method, and in the cases studied, there were no violations. Figure 6 shows the reduction in the operating times obtained using three different intervals. In the cases studied, the computational demand of the proposed interval method was lower than that of conventional coordination methods. Table III lists the operation times for intervals: 0.1–0.15, 0.35–0.4, and 0.6–0.65.

Different contingencies were simulated to evaluate the behavior of the coordination methods according to the operational dynamics of the electrical network. Faced with a contingency in the electricity grid, the coordination problem is different. Thus, the evaluation of the performance of the coordination methods will be subjected to new restrictions. It is considered that the coordination is updated for each contingency.

In the conventional method of coordination, the adjustment change of the affected relays impacts a greater number of relays owing to their functional dependence (3). In the proposed method, the independence of operation between relays results in a new operation curve for each affected relay, thereby improving the operation times. Figure 7 includes some contingencies, and the three-time intervals used in the proposed method are presented in Figure 2. In all of them, the execution time of the algorithm was less in the proposed method. Likewise, there was a smaller number of affected relays, and the total operation time of the relays were lower in the proposed method.

The simulated contingencies were used to establish the operating conditions of the electrical network in which the protection could be affected. The output of a diesel generator and the disconnection of the utility were simulated, which involved modifying the profiles of the short-circuit current. In order to modify the power flows in the electrical network, the output of lines 4-5 and 1-7 were simulated. Under these conditions, the simulations were performed using the proposed method.

| Relay | \( t_{(Isc_a)} \) | \( t_{(Isc_b)} \) | \( t_{(Isc_c)} \) | Violations (NV) | Computation Time (s) |
|-------|----------------|----------------|----------------|----------------|---------------------|
| 36    | 0.149          | 0.367          | 0.604          | 0               | 17.83               |
| 39    | 0.143          | 0.351          | 0.649          | 0               |                     |
| 45    | 0.150          | 0.350          | 0.629          | 0               |                     |
| 46    | 0.148          | 0.350          | 0.605          | 0               |                     |
| 57    | 0.147          | 0.350          | 0.619          | 0               |                     |
| 69    | 0.125          | 0.351          | 0.616          | 0               |                     |
| 78    | 0.149          | 0.368          | 0.607          | 0               |                     |
| 89    | 0.140          | 0.360          | 0.602          | 0               |                     |

**TABLE III**

**OPERATION TIMES DEFINING DIFFERENT PRE-ESTABLISHED INTERVALS**

**Figure 5.** Average of relay operation times of the applied coordination methods.

**Figure 6.** Average of time relays for different time intervals.
conditions, the proposed method resulted in a shorter execution time of the algorithm, as fewer relays needed to be coordinated and the total operating time of the relays was lower.

**Case 2. Island Mode.**

In case 2, we studied the MG disconnected from the main network and operating in island mode. Under these operating conditions, the contribution of the sources to the fault is considerably reduced. It is expected that the operation time of the protection scheme will increase. Many relays can lose sensitivity if they maintain their pickup current in the connected mode. This is a condition that reveals the advantage of changing the setting of the relays in topological changes.

The results in Figure 8 show that the operating time of the relays complies with the time intervals defined in the proposed coordination method (Figure 2). This confirms the validity of the interval coordination method and its suitability for online applications in complex networks with dynamic topological changes. TABLE A4 of the Appendix shows the adjustments obtained by the algorithm for this case.

**TABLE IV**

**CONVENTIONAL COORDINATION WITH NON-CONVENTIONAL CURVES, LINE 7-8 OUTPUT.**

| Relay Primary-Backup | tp  | tb  | CTI_c | Relay Primary-Backup | tp  | tb  | CTI_c |
|----------------------|-----|-----|-------|----------------------|-----|-----|-------|
| 39 - 63              | 0.147 | 0.460 | 0.313 | 71 - 57              | 0.674 | 0.021 | -0.654 |
| 45 - 64              | 0.175 | 0.476 | 0.301 | 63 - 46              | 0.226 | 0.526 | 0.300 |
| 46 - 54              | 0.385 | 0.693 | 0.307 | 63 - 96              | 0.226 | 0.526 | 0.300 |
| 57 - 45              | 0.020 | 0.432 | 0.413 | 93 - 69              | 0.159 | 0.484 | 0.324 |
| 69 - 46              | 0.188 | 0.494 | 0.306 | 64 - 36              | 0.321 | 0.625 | 0.304 |
| 69 - 46              | 0.188 | 0.526 | 0.338 | 64 - 96              | 0.321 | 0.746 | 0.425 |
| 51 - 45              | 0.130 | 0.432 | 0.302 | 96 - 39              | 0.345 | 0.654 | 0.309 |

Number of Violations (NV) 1
Computation Time DE (s) 13.27

In Figure 4, the output of line 7–8 is simulated. TABLE IV indicates the necessary changes in the configuration of the relay with the conventional method (3), which shows that the relays that are presented require configuration to maintain the fully coordinated scheme. We observed a reduction in the time of the relays and the advantage of the number of relays that need to change configurations during this condition with the interval coordination proposal, for which a change in $Isc$ ($\pm$10%) was considered to change the setting of relays (TABLE V). Furthermore, because of the

![FIGURE 7. Contingency analysis and comparison between both methods.](image7.png)

![FIGURE 8. Comparison between relay times during islanding condition: a) primary relays, b) backup relays.](image8.png)
re-coordination with the conventional method (TABLE IV), a violation occurred in the pair of relays 71–57.

In Figure 9, a comparison between both methods is presented with the output of lines 7–8; the number of relays to reconfigure and the computation time are evaluated, along with the average of the backup time of the relays. The protection scheme is evaluated using the interval coordination method, which guarantees the settings for each relay independently. In the case of topological variations or contingencies, the algorithm updates the configuration of the affected relays without having to act on the rest of the relays in the scheme, unlike the conventional method, which must reconfigure the network to maintain the coordination of each relay.

TABLE V
RESET OF THE RELAYS AFFECTED BY THE OUTPUT
FROM LINE 7–8 WITH THE PROPOSED INTERVAL METHOD

| Relay | t (Isc_a) | t (Isc_b) | t (Isc_c) |
|-------|-----------|-----------|-----------|
| 39    | 0.104     | 0.436     | 0.701     |
| 46    | 0.190     | 0.403     | 0.793     |
| 57    | 0.192     | 0.405     | 0.740     |
| 96    | 0.166     | 0.417     | 0.705     |

| Num. of Violations (NV) | Computation Time DE (s) |
|-------------------------|--------------------------|
| 0                       | 9.16                     |

VII. CONCLUSIONS

The dynamic condition of MGs makes it necessary to find new strategies so that the electricity grid provides reliable and secure power to users. In this study, an interval coordination method was proposed. The presented formulation guarantees the coordination of the DOCR through pre-established time intervals for the primary and backup functions. The functional independence between relays is obtained because each time curve is computed to comply with the time intervals. The non-conventional time curves obtained with the proposed algorithm provide the flexibility necessary to comply with the pre-established operating ranges. From the results, the proposed coordination method shows less operation time for the relays than the conventional coordination method in the power systems studied, and the resulting operating times between the relays have a flat profile, indicating similar operating times for the primary and backup protection functions. The proposed coordination method is very advantageous for network dynamic operations such as topological changes and island formation, as it is necessary to update the setting only in the affected relays, obtaining lower operating times than conventional methods of coordination in the cases studied. The proposed coordination method was applied to MG networks because of their highly dynamic operating conditions, but it can be applied to other electrical systems, such as sub-transmission or distribution systems.

Future work: Most existing papers on relay coordination focus on phase protection, since this stage involves the greatest complexity in the adjustment process. However, coordination in zero sequence networks is extremely important. This topic will be addressed in future work, considering negative sequence and zero sequence relays.

Limitations: Actual relays use curves that are standardized or defined by the manufacturer, and it is not feasible to have an implementation in the current times of the proposed method. Our proposal assumes that the user or computer program can define the coefficients of the non-conventional time curves for the relays, due to the advantages that this approach offers in terms of coordination. The implementation of our proposed method involves a modification only of the relay firmware.

APPENDIX

TABLE A1
BRANCH REACTANCES OF THE TEST SYSTEM

| Bus | Bus | X(p.u.) |
|-----|-----|---------|
| 1   | 5   | 0.371   |
| 1   | 7   | 0.292   |
| 2   | 4   | 0.365   |
| 3   | 6   | 0.312   |
| 3   | 9   | 0.381   |
| 4   | 5   | 0.335   |
| 4   | 6   | 0.292   |
| 5   | 7   | 0.255   |
| 6   | 9   | 0.377   |
| 7   | 8   | 0.356   |
| 8   | 9   | 0.352   |
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