A Framework for Optimal Operation of Overcurrent Relays in Microgrids Using a Modified Tripping Formulation

Reza Farhadi Koutenaei [a], AmirAli Nazari[b], Reza Keypour[b]

Abstract— **This paper presents a method which is capable of satisfying the optimal protection coordination of relays in Microgrids (MGs) in both islanded and grid-connected modes. While the tripping times are minimized, the requirement of having multiple setting groups for relays is alleviated. Non-linear constrained programming is formulated in firefly algorithm (FA) and static penalties are considered for constraints handling. The goal is to obtain the optimal coordination between the directional overcurrent relays (OCRs). The formulation includes a framework to satisfy coordination constraints for both connectivity modes of MG operation and yield the least tripping times, while maintaining an appropriate time interval between the primary and the backup relays. A 9-bus IEEE test system is simulated as the MG in DIgSILENT software and the achieved results are compared with a similar study where the genetic algorithm has been applied for optimization. The comparative results verify the capability of the current method and its superiority.**

Index Terms— **Microgrid, Firefly Algorithm, Distributed generation, Directional over current relays, Short circuit fault.**

I. Introduction

Protection against faults is essential to ensure the continuity of power system operation. A coordinated and ideal protection scheme is the one capable to isolate the fault affected parts in the system under fault conditions in order to avoid unnecessary outages in other areas not exposed to fault. Distribution systems are usually radial in which the power flow is unidirectional from one main post towards the loads [1]. For such systems, the OCRs and fuses are employed as the main protectors [2]. The magnitude of fault currents is considered in unidirectional pass to reduce the complexity of the protection coordination scheme. In other words, the schemes are based on non-directional OCRs. The emergence and increased popularity of distributed generations (DGs) in distribution systems have turned the configuration into a system with multiple generation sources, thus raising the protection coordination complexity. Basically, the OCRs trip the connected DGs on the occasion of a fault [3,4]. The presence of DGs causes some variations in the short circuit currents (SCCs) magnitude and direction. Therefore, the existing protection schemes may not be capable to carry out the coordination function correctly. The aggregation of DGs within the distribution system forms MGs. Considering MGs importance, it seems critical to develop various protection approaches proposed specific for MGs [5,6]. In designing a MG protective system suitable for both grid-connected and isolated operations, the following properties have to be taken into account [7]:

First, the system has to be able to respond to both the distribution system and MG faults. Second, the MG has to be isolated as quickly as possible for a fault in the external grid. Third, for the internal MG fault, the smallest part of radial system which contains the fault has to be isolated to minimize the fault incurred damage. Fourth, the protection scheme has to provide an effective protection function for the customers. Unusual conditions (faults, overload, overvoltage, and etc.) can cause additional contingencies in more parts of the distribution system. Thus, to avoid damage to the equipment and prevent a widespread outage, the fault-affected equipment must be rapidly identified and isolated to guarantee energy generation and transmission for the maximum number of customers and maintain the system stability. Other detailed tests concerning MG protection are discussed in Refs. [8-11]. Therefore, the protection system has to be designed and tuned in such a manner that could ensure the highest speed and reliability of the grid. In cases, where the primary protection system runs into error or other equipment like the switch does not work properly, there has to be the backup protection system in order to ensure the grid stability. Considering the aforementioned challenges and requirements, the directional OCRs must be used for protection. Ref. [12] proposes such protective relays along with their optimal settings for a distribution network consisting of DGs. The needed optimization has been carried out using the interior point method.

Similarly, the study in [13] uses a branch and bound algorithm to operate OCRs and proves that such a method is less likely to be trapped in local optima. In order to coordinate these relays in looped systems such as the MGs, optimization methods are applied for the primary and backup relays coordination. In Ref. [14], a proposed scheme is implemented

a : Managing Director of Protection Office, Radin Sanat Co. Qaemshahr, Iran
b : Faculty of Electrical and Computer Engineering, Semnan University, Semnan, Iran

Corresponding Author: Reza Farhadi Koutenaei, r.farhadi57@yahoo.com, +989113262600).

that uses dual setting directional OCRs that are capable of operating in both connectivity modes with different settings. A similar dual setting method for the operation of OCRs has also been introduced in [15]. Other than the optimal settings of OCRs, the required number of them is also determined in that work using the epsilon constraint method. In Ref. [16], a modified 14-bus IEEE network was simulated to find the optimum coordination of OCRs along the value of Fault Current Limiter (FCL) at the Point of Common Coupling (PCC). Concerning the fact that an MG operates in two different operating modes, i.e., grid-connected and islanded, it is obvious that the current faults will have various values in these two modes. Then, different solution representations must be proposed due to this variation in fault currents depending on the MG operation mode. The MGs operate in either grid-connected to lower energy loss of the system and peak shaving or in islanded mode to increase reliability and backup power during an outage. Their goal of protective relay coordination is to achieve the capability to operate without overlooking the sensitivity and time of rapid fault clearing (debugging). The most common method addressed in many studies is using relay setting groups for each operation mode. The mode is recognized by the external grid connection switch through communication platforms. In Ref. [17], the differential protection method has been employed as a different way to protect the MG due to its differential nature in identifying fault. The functionality is independent from SCC level. Adaptive MG protection with modified relay settings have been proposed in [18]. A hybrid protection method is also proposed in [19] that incorporates both traditional differential protection and a new adaptive MG protection. Some protection methods which utilize data mining approach to calculate the delay between relays have been proposed in [20,21]. The papers mentioned above did not propose solutions for the problem of multiple settings for different operation modes of MGs. Therefore, it yet remains a gap in the literature. Hence, in this paper, an MG protection scheme is proposed for two connectivity modes, including the optimal setting adjustment of OCRs. The method enables the relays to operate with a fixed setting and avoids using multiple setting groups. Moreover, comparative studies on the performance of different optimization methods are not present in the mentioned studies. Most papers have stopped at implementing algorithms like GA without justification. Here, the FA is used as the optimization tool to find the best setting and least tripping times. Its performance is compared with the GA and its superiority is shown. The analysis is implemented on a 9-bus IEEE test system in DIgSILENT software.

The rest of the paper is organized as follows. Section II is devoted to explaining the MG protection issues. In section III, the FA procedure is described. In section IV the proposed protection model is explained. Results have been gathered in section V and conclusions are in section VI.

II. Protection of MG

Incorporating small scale generations and energy storage devices into low or average voltage systems forms up practical MG. These systems vary in size and shape. Good examples are real power systems existing in natural islands. Designing the components has to be done in such a way that their reliability is guaranteed in both operating modes. According to [1], having both grid-connected and islanded applications is effective and very useful, first because it increases customers' confidence, second due to creating the possibility to perform programmed repair and maintenance, and third, for supplying reliable power for essential and critical loads. MG systems rely on common DG technologies including renewable resources such as solar, wind, hydraulic energies and etc. Non-renewable resources such as diesel generator and gas turbine are also essentially present to counterbalance the varying nature of wind and solar generations. The merit of utilizing renewable resources is that accessing such energy is not dependent on pollutant fuels. In contrast, non-renewable resources require using fossil fuels which produce adverse greenhouse gasses. Moreover, their available sources are in danger of depletion. DGs are geographically close to the customer and directly connected to MG management center [22]. A DG categorization based on generation size has been illustrated in Fig.1.

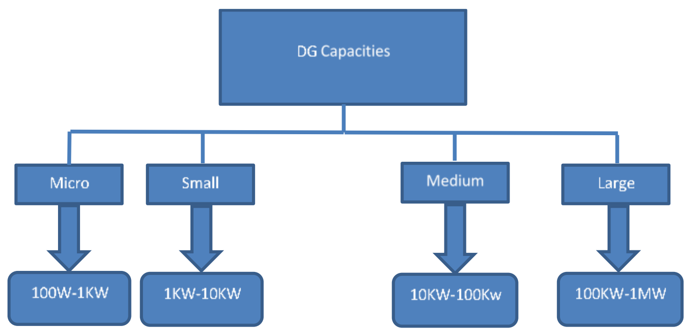

Fig. 1. A comprehensive DG categorization

Despite knowing that using DG can potentially reduce the requirement of traditional systems development, controlling many DGs leads to a new challenge in reliability and economic control and function. Since using these generation units is increasing, to boost and raise the efficiency of distribution networks, the voltage and active power of this part of the power system has to be analyzed. In radial distribution systems, in design step, the possibility of having a generator beside the load has not been considered. In fact, the whole network after substation has been taken as a passive circuit. Thus, installing DG at the side of load or along the feeder will significantly affect the current, power, and voltage of various points.

The initial design of MGs has to be done in such a manner that when operating in islanded mode, equilibrium is kept between power generation and consumption. The load flow analysis has to be done for diverse scenarios to ensure appropriate voltage regulation and the capability to tackle large loads and rush currents. In islanded mode, balancing the level of generation with load is highly important. There is also the PCC that links the MG with the rest of the network. Different technologies are required for suitable switching function, encompassing measurement, protection relays, communication devices and etc. When a breaker opens, the power generation sources in the MG have to be able to feed their load with apt frequency and voltage level. Depending on the switch technology, instant outages may occur during the transition from grid-connected mode to islanded mode. In these cases, it is imperative for generators to be re-triggered after breaker opening. When tripping occurs, the control system has to maintain the frequency and voltage level by resupplying the instant active and reactive power shortage [23]. In hybrid MGs that possess fueled generators, diesel generators do frequency-voltage control. In wind-hydro hybrid systems, this task will be performed by a hydro-generator.

III. Firefly Algorithm

FA is a recent intelligence-based optimizer introduced by Yung in 2008 for the first time. There are two reasons behind the light being produced by a Firefly. First to attract its mate and then bait. In addition to these, maybe it uses its light as a defensive mechanism. This algorithm operates similarly to the particle swarm optimization (PSO) algorithm in some ways. By selecting appropriate values for the parameters used in FA, it is possible to make it function similar or better than common particle-based algorithms. Though so far, FA has been mainly applied to solve non-constrained continuous problems, it simply can be used for solving constrained and/or continuous problems [24].

The way FA operates is that first, several artificial fireflies are randomly distributed in the decision area. Then, each firefly emits light whose luminance is proportional to the firefly location's optimality. Thereafter, the light luminance of the firefly is regularly compared with that of other fireflies and the faint fireflies are attracted to brighter ones. Yet, the brightest firefly also moves randomly, increasing the optimal global solution in the problem magnitude.

Given the flowchart in Fig. 2, it is observed that the initial population of fireflies is generated as a set of vectors ($X_i, i = 1, 2, \dots n$) in the problem space. The luminance of i^{th} firefly (I_i) is determined via the value achieved for the objective function at point X_i. The firefly movement equation on the condition that $I_j > I_i$ holds, leads the i^{th} firefly to j^{th} firefly as the following equation suggests:

$$X_i \rightarrow X_i + \beta\left(X_j - X_i\right) + \alpha(rand - .5) \tag{1}$$

$$\beta = \frac{\beta_0}{1 + \gamma r^2} \tag{2}$$

In the above equation, α is the randomization parameter. $rand$ is a random number generator uniformly distributed in [0, 1]. β is called the attraction factor and is a function of the distance between the two fireflies. Generally speaking, the expression ($X_j - X_i$) indicates the i^{th} firefly attraction level toward the j^{th} firefly. In fact, this statement implies this reality that like nature, here each fainter firefly is attracted to the brighter ones with a certain probability. Having calculated

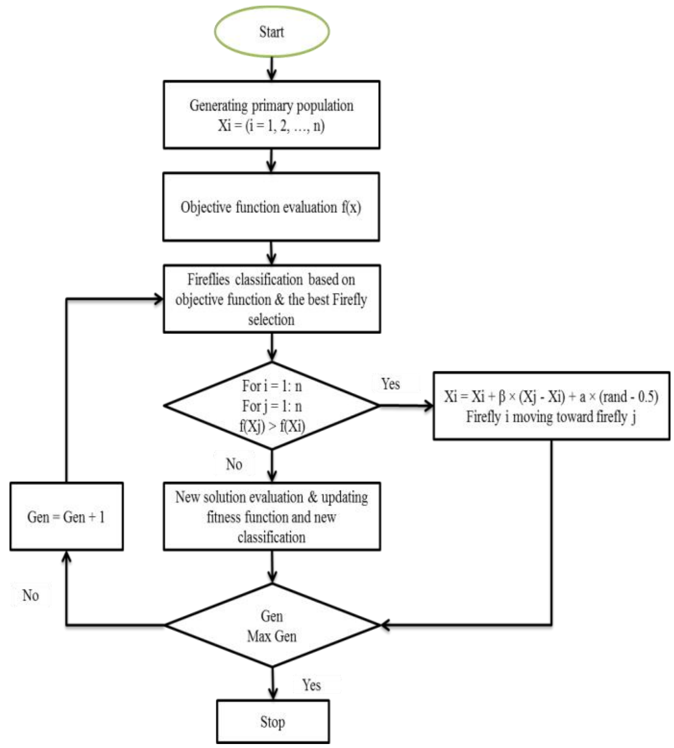

Fig. 2. The flowchart of FA operation process

the new position of the i^{th} firefly, its light luminance is updated. In optimization problems, the light luminance can be considered proportional with the inverse of the objective function (for instance: $I(x) = 1/(1 + F(X))$. The problem must converge to higher luminance values steadily as each solution moves towards better locations.

This algorithm has desirable convergence potential. Each firefly is able to improve itself separately considering the founded new position. The third term in position updating formula is a random displacement. Therefore, the FA owns the capability to exit the local optimal points and find a near global one.

IV. Proposed Model

There are two types of an inverse time directional OCR which include the instant or the fixed time type and the continuous time type. The second one has the potential for tripping defined by test curves that portrait switching delay vs SCC intensity. In this paper, continuous OCR with normal inverse characteristic has been used. The OCR has two values that have to be set, pickup current (I_p) and time division switching (TDS). Pickup current value is the minimum current value for which the relay is triggered [25]. In Fig. 3, the switching curves for different TDS values have been drawn.

In Eq. (3) a formulation equivalent to Fig. 3 curves has been shown.

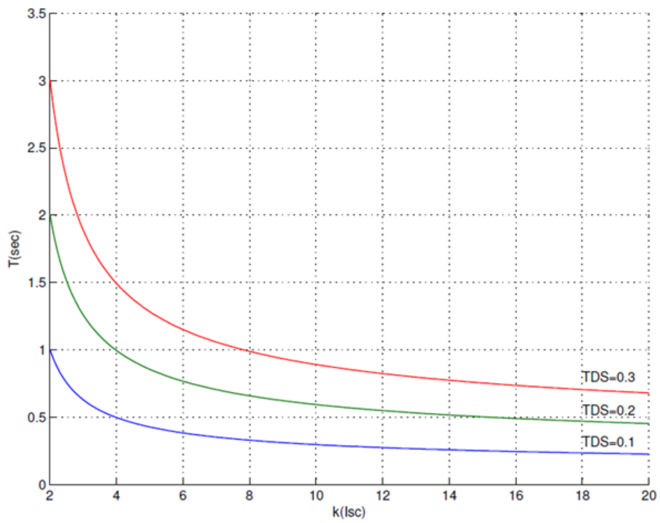

Fig. 3. OCR switching time for a specified SCC range

$$T_i = \frac{k_1.TDS_i}{M^{k_2} + k_3} \qquad \forall i = 1, \dots, n \tag{3}$$

$$M = \frac{I_{sc}^i}{I_p^i} \qquad \forall i = 1, \dots, n \tag{4}$$

k_1, k_2 and k_3 are constants that have been taken as -1, 0.02 and 0.14 respectively and n is the total number of relays. I_{sc}^i is SCC value passing through the i^{th} relay. In Ref. [1], a fault FCL has been used at the point of common coupling (PCC) to decrease fault current in grid-connected mode. Its value has been optimized so that the SCC in grid-connected and islanded modes has approximately equal values. Therefore the relays do not need additional setting groups for grid-connected mode. However, this paper has introduced an approach to omit FCL presence and still avoid requiring various setting groups. The method is able to ensure correct and timely operation of all relays for both connectivity modes. In the absence of FCL, the SCC values can differ significantly depending on the connection mode for the same fault location. Because of current flow into the MG, SCC value rises in the grid-connected mode operation. So, a relay setting for one connection mode is unsuitable for the other. If TDS and I_p calculations and setting are set for grid-connected mode, the tripping time (T) increases according to Eq. (3) and the coordination between primary and backup relays are lost. The rise of relay tripping time can damage MG equipment and switches. When the tripping time exceeds 3s, it is more probable because most power equipment can maximally tolerate SCCs for 3s. In addition to damaging the equipment, the SCC persistence can lead to DGs trip that is basically inconsistent with the fundamental goals of developing MGs. In order to prevent the aforementioned shortcomings, some variations are proposed to the tripping time formulation so that for fixed TDS and I_p values, the modified equation is able to yield a tripping time suitable for both connection modes. Moreover, the coordination between the relays is still maintained.

For this purpose, Eq. (3) has been changed as it follows:

$$T_i = \frac{k_1.TDS_i}{M_i^{k_2} + k_3}.K_d^i \tag{5}$$

$$K_d^i = V_i^{\left(1 - \frac{I_{sc}^i}{I_{sc,max}^i}\right)} \tag{6}$$

In the above equation, V_i stands for a line per unit voltage for which the i^{th} relay acts as primary. $I_{sc,max}^i$ is the maximum SCC value in the grid-connected mode which passes through i^{th} relay. The expression K_d is defined as a time reduction factor. In grid-connected mode, the I_{sc} and $I_{sc,max}$ are equal, then K_d will be equal to 1. This matter can be inferred from Fig. 4 curve.

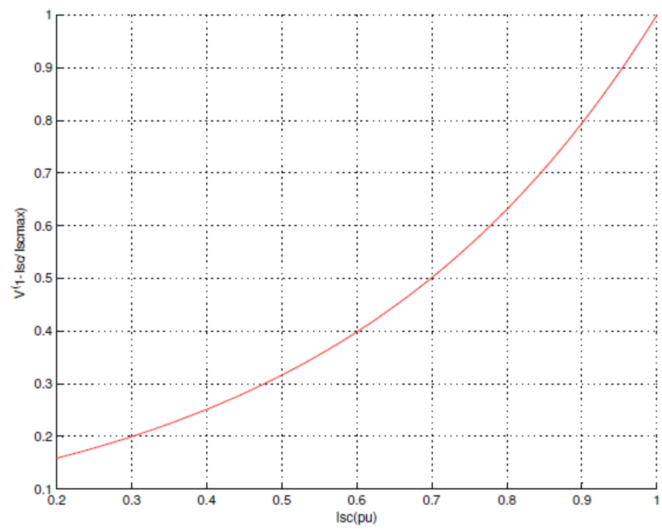

Fig. 4. K_d factor variation vs SCC intensity

As illustrated in the figure, the time reduction factor declines exponentially as fault current drops and is multiplied as a coefficient smaller than 1 in the fraction of Eq. 3. Thus, in islanded mode operation, the tripping time decreases and the performance of relays is boosted. Moreover, in the case of a fault occurrence, the line voltage quantity is higher for the backup relays. Then according to Eqs. (5-6), the tripping time is yielded higher for backup relays than that of primary ones, which is another advantage of the new setting and helps to satisfy the coordination time interval constraint which is explained later.

A. *Constraints*

Generally, there are some constraints related to I_p and TDS values. i_p^{min} should be considered higher than rated load currents with a remarkable margin. It avoids improper operation of relays under normal increment of load flow. Also, given the normal inverse curves, TDS values are adjustable in the range of 0.01-1. These two constraints are shown in the following equations.

$$TDS_{min} \leq TDS_i \leq TDS_{max} \qquad \forall i = 1, \dots, n \tag{7}$$

$$I_p^{min} \leq I_p^i \leq I_p^{max} \qquad \forall i = 1, \dots, n \tag{8}$$

A backup protection system is considered in an electric power system to guarantee reliability and primary protection. The primary and backup protection systems have to be coordinated with each other. Coordination

TABLE I
System Parameters

Parameter	Value
Number of relays	21
Apparent power of DGs	5 MVA
Rated voltage of DGs	480 V
Apparent power of T1	20 MVA
Conversion ratio of T1	115 KV / 12.47 KV
Conversion ratio of T2-T5	12.47 KV/480 V
Apparent power (MVA) of the external network (grid)	500 MVA
X/R ratio of the external network	6 H / Ω
Transmission line length	500 km

Time Interval (CTI) is a test requirement to be taken into account in coordination. In order to make sure of the protective system reliability, the backup system gets into operation only when the primary action delay exceeds the CTI value. This case is expressed as the following:

$$T_{backup} - T_{primary} \geq CTI \quad (9)$$

Where T_{backup} is the backup relay tripping time and $T_{primary}$ is the primary relay tripping time.

B. Objective formulation

The goal behind protection is to operate as fast as possible and maintain fast fault clearing time. Here the total operation time of relays is considered as the objective function. As stated previously, the time interval between the primary and backup relays is taken as a constraint. A 9-bus IEEE test system is selected for analysis. In the beginning, the grid is modeled as a graph. The connecting electrical lines are viewed as the graph branches in this graph. In order to state the branches direction, the conventional directions have been arbitrarily taken into account. The objective function can be expressed in the following formula:

$$OF = \min \left[\sum_{j=1}^{m} \sum_{i \in S_j^p} T_{ij}^p + \sum_{j=1}^{m} \sum_{k \in S_j^b} T_{ik}^b \right] \quad (10)$$

m stands for the number of fault locations. S_j^p is the set of relays considered as primary for the j^{th} fault and S_j^b are the relays considered as backup for the j^{th} fault. With regard to two unknown variables (I_p,TDS) for each relay, there are $2 * n$ decision variables to take into account. Yielding the least cost or the highest fitness means achieving the minimum operation time for relays. FA is employed for minimization. In the algorithm, first the coordination constraints for each of the primary and backup relays are determined. The program starts and continues until a predetermined number of iterations is reached. Then suitable operation times for the primary and backup relays of branches are determined. The overall procedure of proposed optimization is shown as a flowchart in Fig. 5.

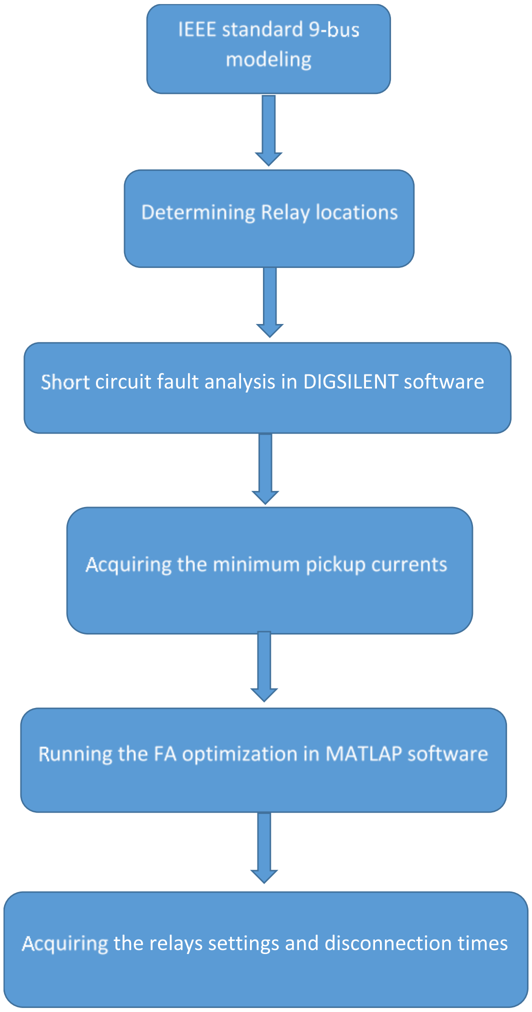

Fig. 5. The suggested framework for the problem optimization.

V. Results and Discussion

The 9-bus IEEE test grid is analyzed as the MG in both connectivity modes. Figure 6 depicts the aforementioned grid. As it can be seen from the figure, the grid consists of 9 buses, 8 lines, 4 DGs, 21 directional OCRs and one optional FCL which connects the MG to the external network. Each unit features some rated value known from its manufacturer. Such Characteristics for the MG have been mentioned in Table 1.

In each branch where short circuit occurs, two relays have been taken into account as the primary relays and two backup relays are also accounted for regarding the current direction. For example, if we assume that in islanded operation mode, the short circuit occurs in branch 10, relays R1 and R2 are the primary relays. Moreover, for R1, the R10 and for R2, the R4 operate as backup relays. The maximum delay between primary and backup relay tripping is taken equal to 0.2 seconds. For experimentation, three-phase short circuit faults are applied based on IRC60909 test in DIgSILENT software.

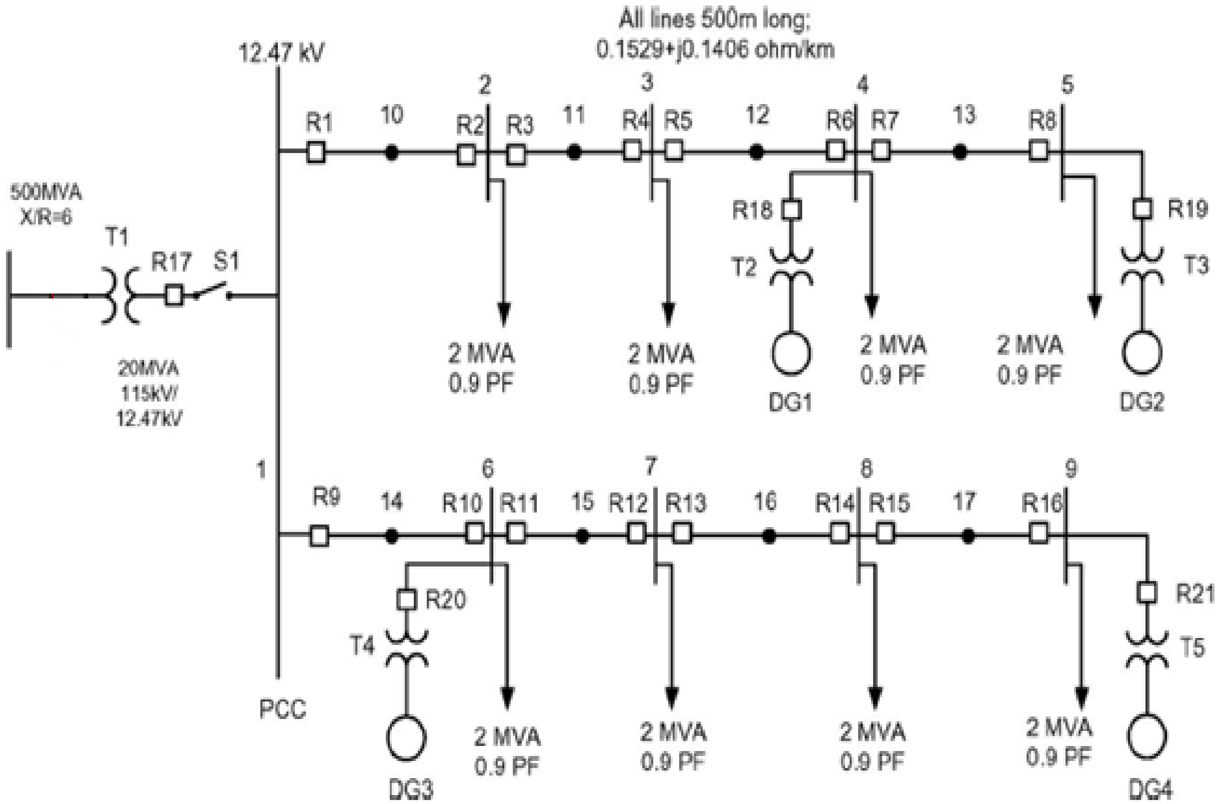

Fig. 6. IEEE 9-bus Schematic.

All generators have ground-connected nodes with star configurations. According to the discussion in section IV, by utilizing the modified tripping formula, having FCL at the PCC point is unnecessary and omitted here.

The optimization is implemented with the modified tripping equation (Eq. (5)). After running the FA, it was found out that in grid-connected mode, the results of relay settings and tripping times are not meaningfully different from the ones obtained in Ref. [1]. However, the results obtained for the islanded mode operation are comparable. For example, the tripping times yielded for the faults in branches 10 and 11 are presented in Tables II-III along with those of the paper [1].

TABLE II
Relays Operations for a Fault in Branch 10

Relay	Voltage	I_{sc}	T	
			Eq. (5)	Ref. [1]
R1	0.1	0.4256	0.32685	1.301217
R2	0.1	0.2505	3.13037	4.500091
R4	0.2	0.563456	1.51466	1.779154
R10	0.2	0.56645	1.10993	1.30374
Total Time			6.08181	8.884202

As expected, the times of the third column are shorter than those of the fourth column. It means that relays react faster to short circuits in our model than in Ref. [1] in which the standard formula for tripping was used. Table IV compares the summation of tripping times for both connectivity modes with Ref [1] results. As it can be deduced from the table, the difference in grid connected mode is almost negligible.

TABLE III
Relays Operations for a Fault in Branch 11

Relay	Voltage	I_{sc}	T	
			Eq. (5)	Ref. [1]
R3	0.1	0.4047	0.28587	1.13805
R1	0.2	0.909945	0.68024	0.799022
R4	0.1	0.581115	1.34464	1.692807
R6	0.2	0.581232	1.56559	1.838969
Total Time			3.87634	5.468848

TABLE IV
The Summation of Tripping Times in Both Connectivity Modes

Method	Runtime		
	Islanded	Grid-connected	Total
Eq. (5)	39.39984	43.0381	82.43794
Ref. [1]	43.31	43.46	86.78

Meanwhile there is a 3.91s performance boost for the islanded mode which accounts for a 9.02% improvement.

VI. Conclusions

The importance of proper operation of protection equipment is inevitable for a power system. OCR settings need fine tuning, so as to be able for proper operation under the occurrence of system faults. In MGs, the SCC values can differ depending on the MG connectivity with the external network. Therefore, multiple setting groups are needed for relays. In this paper, an approach was introduced to determine optimized settings for directional OCRs which is consistent for both islanded and grid-connected operation modes and enables the relays to operate with only a fixed setting group. Moreover, the final results indicate that the system's response is boosted by 9% in total. Therefore, the probability of unwanted outages and equipment damage is reduced. The FA which is an intuitive optimization algorithm with great search capability was incorporated to yield the best relay settings which minimize the total tripping times. The studies on 9-bus IEEE test grid were presented with practical data in both connectivity modes. The SCC values of all branches were calculated using DIgSILENT software. Future studies on this subject can work on other relay technologies and involve uncertainties regarding relays operations. The proposed modification to the tripping approach in this paper can be valuable for researchers in the MG protection area in a way that they will be able to suggest similar solutions for other protective equipment and different relays. Moreover, the FA algorithm proved superior to GA and can be counted as a benchmark for future studies, so they can compare their optimization approaches with the one presented in this paper.

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