An Adaptive Protection Scheme for Distribution Networks with Distributed Generation Sources in Various Operational Modes

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ABSTRACT:
Distributed Generation (DG) is a common technology in today's distribution networks due to its exclusive benefits. However, DG units introduce a series of new issues to distribution network beside their benefits. Adding a DG unit to the network can change the direction and magnitude of the power flow and fault currents through branches. It may cause the failure of the original protection system or false tripping of some existing relays. In this paper, a new adaptive approach is introduced for classification of different DG topologies in distribution network using the existing setting groups in over current relays. This method determines those settings such that maximum number of the possible scenarios for different operations in distribution system are covered including grid-connected mode, autonomous mode, and DGs capacity changes. In order to verify the performance of the new method, two simulation studies are performed on 14-node and IEEE 33-node distribution network test systems. DIgSILENT software has been employed to simulate the network in various operational modes.

KEYWORDS: Protection Coordination, Distribution Network, Distributed Generation (DG).

1. INTRODUCTION

The fast growing of demands, reliability challenges, emission concerns and electricity loss due to long transmission lines highlight the role of the microgrids in today's power systems. It is very important to consider harmful effects of new technologies used in microgrids in design level to obtain a more cost efficient solution compared to other approaches. A common technology used in micrograds with a high penetration is Distributed Generation (DG) units. DGs bring about many benefits by generating electricity near load sites, such as more reliability, less emission and energy losses, fast development and energy production for remote communities [1]. However, adding DG units to the power delivery network will cause several issues. An important problem is the change in magnitude and direction of the current in both fault and normal conditions which can lead to failure of the original protection scheme of the power delivery network, especially in distribution systems with high penetration of DG units [2].

Several researches have been conducted to solve this issue. The simplest way is to recalculate and change the protection setting of relays after adding every new DG unit to the power delivery network [3], [4]. According to [5], this method is effective when directional overcurrent relays are used, considering the bidirectional nature of networks which include DGs. However, this approach is inefficient in some cases. Any changes in original protection system may result in high costs or even technical limits.

Another technique is introduced in [6] that suggests disconnecting all DG units once a fault is detected in the microgrid. Therefore, there is no need to change original protection system after adding every new DG unit. However, the transient issue may be significant, especially in the case of high penetration of DGs in the network. This method has different benefits, such as simplicity and low cost, but it can cause some issues for networks, including repetitive synchronization of DG with network. Moreover, this approach cannot be implemented in islanded mode.

Another method introduced in [7], [8] makes limitations on DG capacities. In this approach, DG sizes are limited via protection coordination constraints. Therefore, it is not possible to obtain full capability of

DGs and operation is not optimal. In addition, the total sizes of DGs may not meet the total demand of microgrid in islanded mode.

Application of Fault Current Limiter (FCL) technology is another state-of-the-art approach. Fault Current Limiter is a device used for limiting the short circuit current during fault occurrence. FCL is typically a high impedance branch fitted in parallel with a low impedance branch. When system is in normal mode, the low impedance branch is connected and once a fault is detected, the present branch will be switched to high impedance. The best location of FCLs for the purpose of reducing the negative impact of DG units is the point where DG unit is connected to the microgrid [9]. There are several disadvantages for FCLs, i.e. there are some issues with using FCL in microgrid in islanded operation mode [10]. Though, [11] introduces an approach that uses FCL in islanded mode. In [12], [13], first the protection coordination of the network is determined before connecting DGs, and after connecting DGs, the FCLs are added to keep the original protection scheme.

The ultimate solution to this issue is to use adaptive protection systems that are classified into On-line and Off-line types. An On-line adaptive protection system monitors the power delivery network in real time and sets a new protection coordination to existing relays with any changes in network topology or power generation/consumption size [14]. In [15], a new approach is introduced that monitors the protection scheme and if any changes occur in the network, a suitable protection setting will be applied to the protection scheme. In addition, in [16], [17] the protection coordination is determined adaptively by signals released through any connecting or disconnecting of DGs in network. The most significant challenge about these approaches is complex and time-consuming process, so if a new fault occurs while determining the protection coordination, the system is vulnerable.

In off-line adaptive protection, all operational modes of network are considered and saved in a database. In [18], authors determined the protection scheme for islanded and grid-connected modes based on local data. For this purpose, some algorithms for detecting the operating states are employed to select the trip specifications of the relays. In this paper, the islanding mode detection is based on [19]. A similar work was presented in [20], [21], where the islanding mode is detected when main circuit breaker connects the microgrid to the network. In [22], the protection coordination is determined by digital relays with multiple setting groups and a central control system. This control system monitors the connection status of DGs and the connection mode of the microgrid. The protection setting of each topology is determined off-line and saved in a memory. The approach employed by [18], [20-22] does not cover every possible mode.

In [23], given that the existing relays have several setting groups, first a protection scheme is determined for network without DGs; then the protection coordination is analyzed after adding each DG unit to the network and during this process, again the protection setting is determined for relays that failed. This process is performed off-line. The maximum settings each relay accepts is based on the number of available relay setting groups embedded in the relay which is assumed 6 in [23]. Since adding or removing DG units may result in coordination failure of some relays, the protection coordination for those relays should be determined again which makes this method non-optimal. In [24], a method is introduced that classifies all existing modes including connecting and disconnecting DGs in 6 setting groups. It, then, determines the optimal protection scheme for each setting group and the FCL is employed for the modes in which the protection coordination has failed.

In [23], [24] relay coordination does not include islanded mode. In addition, the impact of changing DG capacities is not considered. Therefore, these methods do not cover all operational modes.

In this paper, based on the fact that existing protection relays include several setting groups, possible modes of DG connected and disconnected to the network are considered. In every existing mode, the protection coordination is performed and protection current pairs are determined. Then, given that the available relays include limited setting groups, each possible operation mode of the network including grid-connected, islanded, DG connected or disconnected modes must be classified into setting groups. For this purpose, different operational modes are combined and the modes that minimize the total operation time, could be classified in the same group. Thus, after creating each group, the optimal protection scheme is determined and the impact of DG capacity changing is applied in protection coordination. Since the groups combination technique is used for modes that cause protection scheme failure, the protection scheme is valid for every possible operation mode. The main advantage of the group combination is that in each functional mode, it is possible to use a suitable combination of different existing setting groups instead of using a single setting group. This capability makes a competitive flexibility by covering more functional modes in comparison with other approaches. Therefore, the need for FCLs is reduced.

The structure of this article is as follows. In section 2, a new design for protection coordination is proposed. Simulation studies are proposed in section 3, and finally, section 4 concludes the paper.

2. PROPOSED METHOD

In this paper, to design valid protection coordination in all operational states of the network, the network states' classification approach is employed based on the fact that the existing microprocessor relays have more than one setting group. For this purpose, each possible state of DGs being connected and disconnected are grouped in maximum relays setting, and finally, the protection coordination is determined for each group for worst cases (conditions). The impact of changing DG sizes is considered during the protection coordination process of each group.

2.1. Classification of Different Topologies

To classify all operational states in maximum relay settings, some states must be combined and embedded in one group. The grouping principals employed in this paper are the same as [24], except that, in this paper, the classification is based on total operation time minimization. The islanded mode and impact of changes in DG sizes are considered, too. Unlike [24], in this paper the protection coordination has been made robust using a combination of different setting groups instead of using FCLs. To do this, different setting groups are combined, and those combinations that result in minimum operation time are considered as optimum groups. The maximum number of network topologies is obtained as follows:

$$S = 2^{N_{DG}} + 1 \tag{1}$$

Where, N_{DG} is the number of existing DGs in the network. Since the islanding mode is included in groupings, an offset is added to (1). The total operational states can be obtained from [24]:

$$C = \sum_{n=1}^{S} \binom{S}{n} \tag{2}$$

During combination of different modes to determine the protection coordination, minimum short circuit currents are used for determining the upper limit of IDMT. On the other hands, if three presumptive modes are embedded in a group, the minimum current is selected between these three modes. The value of this current is shown in (3). In addition, to set the lower limit, the maximum load current for combined modes is used which is shown in (4). For protection coordination of backup relays, the maximum short circuit current for all modes of a group is assumed. Equation (5) shows this current.

$$I_m = \min\{I_{m1}, I_{m2}, ..., I_{mn}\} \tag{3}$$

$$I_L = \max\{I_{L1}, I_{L2}, ..., I_{Ln}\} \tag{4}$$

$$I_b = \max\{I_{b1}, I_{b2}, ..., I_{bn}\} \tag{5}$$

Where, n is number of possible states in a node, I_m is the short circuit currents flow through main relays, I_L is load currents flow through main relays and I_b is the short circuit currents flow through the backup relay.

As mentioned previously, protection coordination considering desired current pairs is the worst case, so the protection coordination in this case is valid for all states.

According to presented approach, it is possible to model the classification process of relays as an optimization problem. The objective function of this algorithm is minimizing the total operation time of each group. In this paper, the Genetic Algorithm (GA) is employed to solve this optimization problem and obtain the optimal classification.

The operation time of each relay is presented below [24]:

$$t_i = \frac{0.14 \times TDS}{\left(\frac{I_{SC,i}}{I_{pickup}}\right)^{0.02} - 1} \tag{6}$$

Where, TDS is time dial setting, I_{sc} is short circuit current and I_{pickup} is pickup current.

The total operation time in each operational state is:

$$T_j = \sum_{i=1}^{R} t_i \tag{7}$$

So the total operation time of each group is obtained from:

$$T(SG_k) = \sum_{j=1}^{n} T_j \tag{8}$$

Where, SG_i is the k[th] setting group. According to the presented equations, the objective function can be written as follows:

$$T = \sum_{k=1}^{SG_{max}} T(SG_k) \tag{9}$$

The constraints of this problem are the same as constraints of the protection coordination problem and are [23]:

$$\begin{gathered} t_{i,j}^{b} - t_{i,j}^{m} \geq CTI \\ I_l \leq I_{pickup} \leq I_u \\ TDS_{\min} \leq TDS \leq TDS_{\max} \end{gathered} \tag{10}$$

Where, CTI is the coordination time interval that is assumed 0.3 s, I_l is minimum pickup current that is 1.3

times greater than the maximum load current that may flow through the branch. I_u is maximum pickup current that is 0.9 of the minimum short circuit current that may flow through the branch. TDS_{max} and TDS_{min} are maximum and minimum allowed coordination factors, which are assumed 2 and 0.1, respectively.

2.2. Protection Coordination for Each Group

After classifying different states into groups, the protection coordination for each group is determined considering capacity variation of DGs. At this step, given that any changes in DG capacities may result in protection coordination failure, the failed relays are detected and the coordination is set for them using a combination of different setting groups. The process of optimal protection coordination is defined as an optimization problem for each group. The objective function of this optimization problem is to minimize the total operation time of each group and the problem is solved using Genetic Algorithm. The objective function of this problem is presented in (8). The constraints of this problem are presented in (10).

By combining groups, not only all setting criteria are limited to allowed values, but also more groups can be generated. In [24], just 6 setting tables are used to classify operational modes. For the modes in which the protection scheme fails, FCL is employed to maintain protection coordination. Utilizing the proposed approach, it is possible to cover more operational modes without FCL. Fig. 1 shows the flowchart of the approach proposed in this paper.

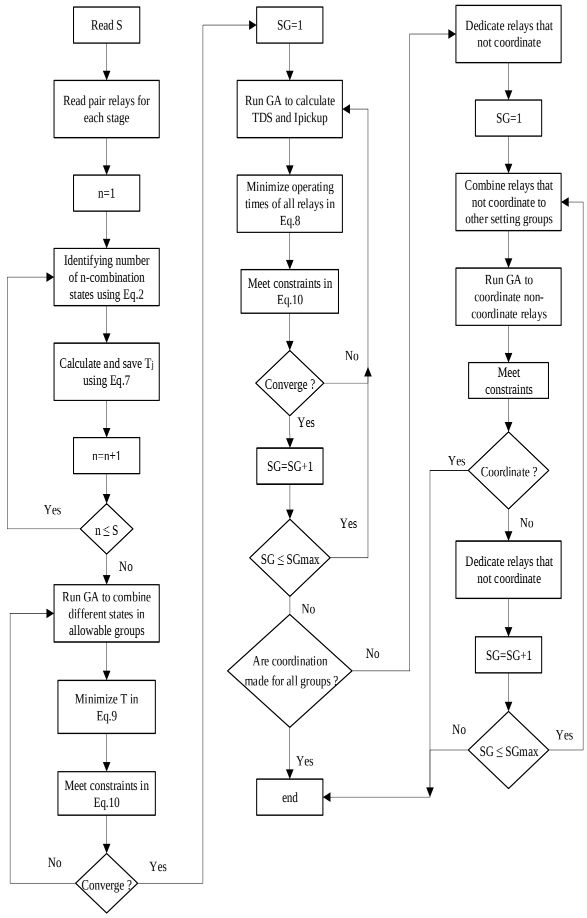

Fig. 1. Flowchart of the proposed method.

3. SIMULATION STUDIES

3.1. Studied Network

The simulation studies were carried out with two different scenarios using DIgSILENT software. The first scenario is a 14-node distribution network [25], with 28.7 MW and 5.9 MVar total active and reactive power, respectively, and is shown in Fig. 2. In this scenario, the DG units are connected on nodes 2, 3 and 8. Tables 1 and 2 show the sizes of DG unites and different operational modes of this network, respectively.

In the second scenario, IEEE 33-node test system is studied [26] and is shown in Fig. 3. The total active and reactive power of this network are 3.715 MW and 2.3 MVar, respectively. DG units are connected on nodes 2, 6, 12 and 30 and their capacities are presented in Table 3. Table 4 illustrates different operational states of the network.

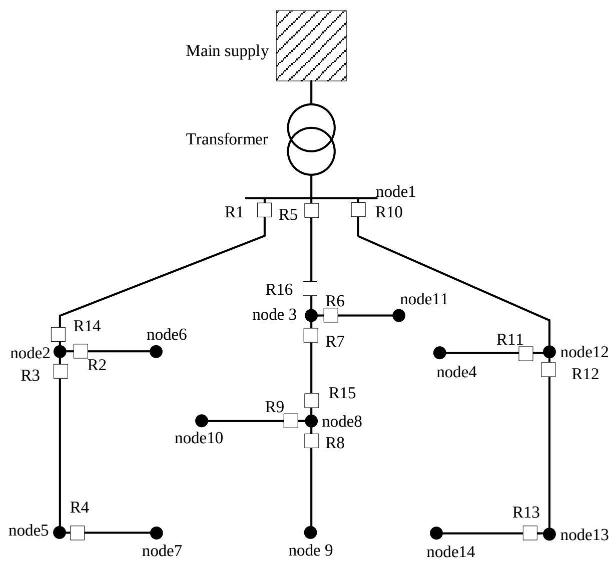

Fig. 2. 14-node distribution network.

3.2. Result and Discussion

The simulations were carried out using a 14-node radial distribution network and IEEE 33-node test network, and the results are presented in this section. According to [23], [24], classification of maximum setting states is distributed into six setting groups. The optimal classification of first scenario is presented in Table 5. The convergence of GA is shown in Fig. 4 where the population size is set to 300 and the maximum number of iteration is set to 100.

Table 1. Capacity and location of DGs in scenario 1.

Number	Location	P (MW)	Q (MVar)
1	node 2	8.5	2.8
2	node 3	10.1	3.1
3	node 8	10.1	0

Table 2. Operational modes in scenario 1.

Stage	Operation mode	Stage	Operation mode	Stage	Operation mode
1	Islanding	4	DG2	7	DG1+DG3
2	Without DG	5	DG3	8	DG2+DG3
3	DG1	6	DG1+DG2	9	DG1+DG2+DG3

Table 3. Capacity and location of DGs in scenario 2.

Number	Location	P (MW)	Q (MVar)
1	node 2	1.39	0.65
2	node 6	0.63	0.31
3	node 12	1.075	0.51
4	node 30	0.62	0.81

Table 4. Operational modes in scenario 2.

Stage	Operation mode	Stage	Operation mode	Stage	Operation mode
1	Islanding	7	DG1+DG2	13	DG1+DG2+DG3
2	Without DG	8	DG1+DG3	14	DG1+DG2+DG4
3	DG1	9	DG1+DG4	15	DG1+DG3+DG4
4	DG2	10	DG2+DG3	16	DG2+DG3+DG4
5	DG3	11	DG2+DG4	17	DG1+DG2+DG3 +DG4
6	DG4	12	DG3+DG4		

Table 5. Optimal setting groups in scenario 1.

Stage	group	Stage	group
1	1	6	5
2	2	7	4
3	3	8	3
4	4	9	6
5	5		

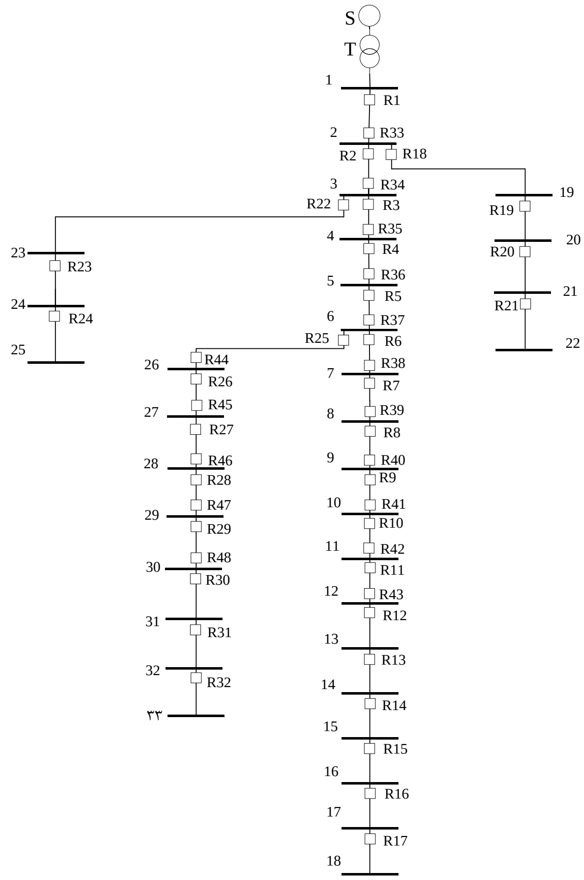

Fig. 3. IEEE 33-node distribution network.

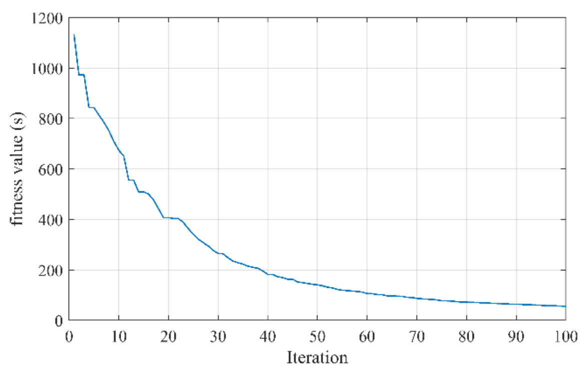

Fig. 4. Convergence of GA in scenario 1.

After applying the classification, the impact of variation of DG sizes is considered to perform the optimal protection coordination. According to the proposed algorithm, if the protection coordination of some of the relays fails, the setting group combination algorithm is used. So in this scenario, the present protection coordination is valid. Tables 6 and 7 show the optimal protection coordination for this scenario. In order to show the validation of protection coordination, coordination time interval for main and backup relay pair are shown in Fig. 5 for mode 3. As shown in Fig. 5, the coordination time interval of each relay pair is more than minimum allowable time, 0.3 s. The convergence of GA for protection coordination of group 3 in scenario 1 is shown in Fig. 6.

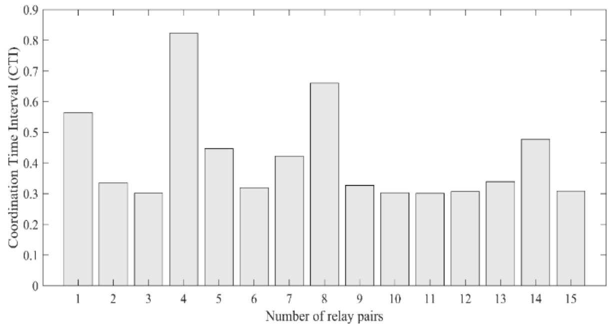

Fig. 5. Coordination time interval for each relay pairs in scenario 1.

Table 6. Optimal protection settings for groups 1 to 3 in scenario 1.

Relay	SG 1		SG 2		SG 3	
	$I_{pickup}(A)$	TDS	$I_{pickup}(A)$	TDS	$I_{pickup}(A)$	TDS
R1	11.12	0.65	4035.75	0.10	1435.76	0.17
R2	179.45	0.10	209.96	0.10	182.00	0.10
R3	220.09	0.21	215.80	0.22	216.38	0.23
R4	114.40	0.10	115.70	0.10	115.70	0.10
R5	1.01	0.94	2861.35	0.10	942.50	0.26
R6	79.30	0.10	547.88	0.10	81.90	0.10
R7	22.10	0.40	1151.43	0.13	1076.32	0.13
R8	284.70	0.10	633.68	0.10	293.81	0.10
R9	45.51	0.10	48.10	0.10	48.10	0.10
R10	308.56	0.30	3380.27	0.10	304.21	0.37
R11	88.40	0.10	88.40	0.10	88.40	0.10
R12	188.17	0.23	750.60	0.16	185.90	0.25
R13	133.90	0.10	494.96	0.10	133.90	0.10
R14	1.12	1.27	-	-	145.28	0.43
R15	3.61	1.23	-	-	193.17	0.42
R16	303.60	0.37	-	-	305.30	0.37

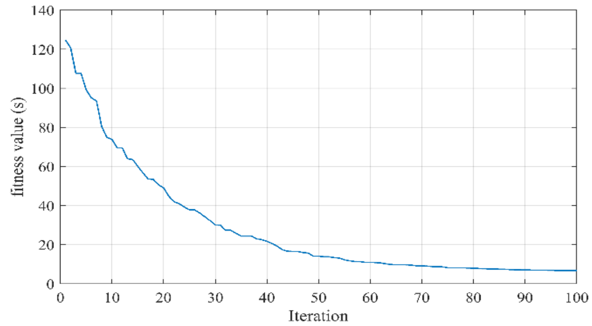

Fig. 6. Convergence of GA for protection coordination of group 3 in scenario 1.

Table 7. Optimal protection settings for groups 4 to 6 in scenario 1.

Relay	SG 4		SG 5		SG 6	
	$I_{pickup}(A)$	TDS	$I_{pickup}(A)$	TDS	$I_{pickup}(A)$	TDS
R1	536.90	0.28	537.18	0.28	536.90	0.29
R2	182.00	0.10	182.00	0.10	182.00	0.10
R3	215.80	0.24	215.80	0.24	215.80	0.24
R4	115.70	0.10	115.70	0.10	115.70	0.10
R5	943.95	0.23	942.50	0.24	942.50	0.23
R6	81.90	0.10	81.90	0.10	81.90	0.10
R7	617.50	0.18	617.50	0.18	617.50	0.18
R8	293.80	0.10	293.80	0.10	293.80	0.10
R9	48.10	0.10	48.10	0.10	48.10	0.10
R10	304.20	0.37	311.83	0.37	304.20	0.39
R11	88.40	0.10	88.40	0.10	88.40	0.10
R12	187.65	0.25	185.90	0.25	966.98	0.14
R13	133.90	0.10	133.90	0.10	133.90	0.10
R14	105.63	0.45	197.92	0.35	200.10	0.33
R15	22.10	1.21	22.10	1.28	203.50	1.42
R16	0.35	1.49	1.86	1.18	300.30	0.38

The classification and optimal settings for second scenario are presented in Tables 8 and 9-12, respectively. As shown in table 8, the coordination between some relays is mismatch, so for these relays, the coordination is obtained from combining other setting groups. In other words, to realize the validation of protection coordination, coordination time interval for main and backup relay pairs are shown in Fig. 7 for the 17^{th} mode.

The convergence of GA in scenario2 is shown in Fig. 8. The convergence of GA for protection coordination of group 1 in scenario 2 is shown in Fig. 9.

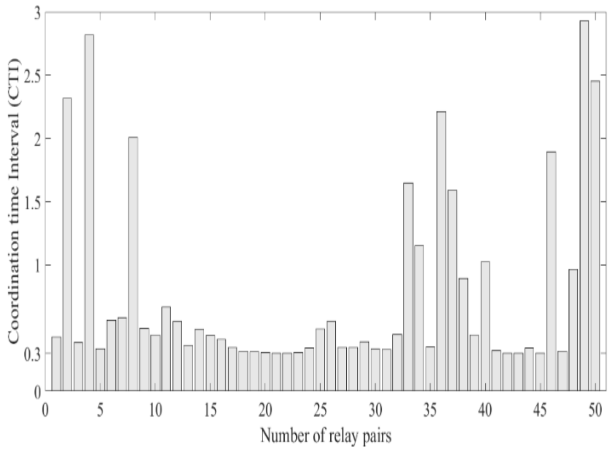

Fig. 7. Coordination time interval for each relay pairs in scenario 2.

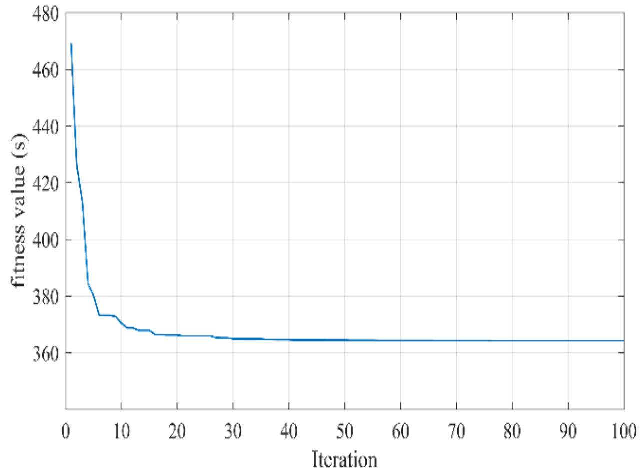

Fig. 9. Convergence of GA for protection coordination of group 1 in scenario 2.

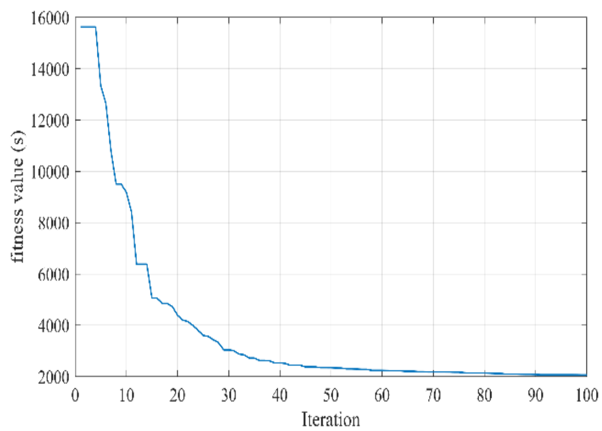

Fig. 8. Convergence of GA in scenario 2.

Table 8. Optimal setting groups in scenario 2.

Stage	Relay	group	Stage	Relay	group
1	all	1	11	R1-R44, R46-R48	3
2	all	2	11	R45	4
3	all	2	12	R2-R48	6
4	all	2	12	R1	2
5	R2-46, R48	3	13	all	4
5	R1, R47	2	14	all	1
6	R1-42, R44-48	5	15	R1-R37, R39-R48	6
6	R43	4	15	R38	4
7	all	5	16	R2-R48	6
8	all	4	16	R1	2
9	all	4	17	R1-R26, R28-R46, R48	3
10	all	1	17	R27, R47	2

Table 9. Optimal protection settings for group 1 in scenario 2.

Relay	$I_{pickup}(A)$	TDS	Relay	$I_{pickup}(A)$	TDS
R1	275.88	1.77	R25	84.53	1.00
R2	243.10	1.54	R26	80.60	0.82
R3	176.37	1.58	R27	78.00	0.68
R4	166.40	1.47	R28	74.10	0.52
R5	162.96	1.37	R29	66.30	0.41
R6	75.41	1.68	R30	29.90	0.38
R7	63.41	1.57	R31	19.50	0.24
R8	48.68	1.53	R32	5.20	0.10
R9	44.21	1.41	R33	0.01	0.20
R10	218.76	0.57	R34	0.02	1.73
R11	36.41	1.12	R35	5.21	1.06
R12	32.50	0.96	R36	13.00	1.35
R13	27.30	0.82	R37	19.34	2.00
R14	18.21	0.73	R38	24.68	1.90
R15	14.30	0.58	R39	24.86	1.99
R16	10.40	0.44	R40	27.43	2.00
R17	6.50	0.12	R41	30.99	1.98
R18	30.26	0.62	R42	33.86	1.98
R19	19.50	0.48	R43	40.00	1.91
R20	13.20	0.30	R44	25.50	1.86
R21	6.50	0.10	R45	32.28	1.74
R22	62.77	0.55	R46	38.37	1.66
R23	57.20	0.29	R47	29.50	2.00
R24	28.60	0.14	R48	32.24	2.00

Table 10. Optimal proection settings for groups 2 and 3 in scenario 2.

SG 2	$I_{pickup}(A)$	TDS	SG 3	$I_{pickup}(A)$	TDS
R1	3969.48	1.10	R1	273.11	1.82
R2	243.10	2.00	R2	243.10	1.74
R3	175.55	1.64	R3	175.51	1.77
R4	166.41	1.51	R4	166.40	1.66
R5	162.51	1.40	R5	162.50	1.48
R6	75.41	1.61	R6	75.40	1.79
R7	62.41	1.51	R7	62.41	1.66
R8	48.11	1.46	R8	48.10	1.60
R9	45.20	1.33	R9	44.20	1.34
R10	40.30	1.21	R10	40.33	1.12
R11	36.41	1.09	R11	36.40	0.99
R12	33.50	0.96	R12	32.54	0.86
R13	27.31	0.83	R13	27.30	0.70
R14	18.56	0.74	R14	18.20	0.57
R15	14.33	0.60	R15	14.31	0.42
R16	10.42	0.48	R16	10.40	0.27
R17	6.54	0.24	R17	6.50	0.10
R18	326.79	0.27	R18	31.82	0.62
R19	19.50	0.48	R19	19.50	0.48
R20	12.14	0.30	R20	12.50	0.30
R21	6.51	0.10	R21	6.50	0.10
R22	63.38	0.47	R22	62.40	0.41
R23	57.20	0.24	R23	57.25	0.25
R24	28.60	0.10	R24	28.60	0.10
R25	84.50	1.08	R25	84.51	0.78
R26	80.60	0.86	R26	711.15	0.17
R27	78.00	0.71	R27	635.71	0.14
R28	74.16	0.58	R28	74.11	0.56
R29	66.61	0.47	R29	66.31	0.44
R30	29.90	0.47	R30	29.91	0.42
R31	19.50	0.24	R31	19.50	0.29
R32	5.20	0.10	R32	5.20	0.14
R33	0.20	0.40	R33	0.01	0.10
R34	0.01	1.95	R34	0.01	2.00
R35	0.04	2.00	R35	5.20	1.05
R36	0.50	2.00	R36	13.00	1.33
R37	3.43	2.00	R37	18.69	1.40
R38	4.86	2.00	R38	29.06	0.97
R39	6.60	2.00	R39	23.90	2.00
R40	8.68	2.00	R40	27.34	1.99
R41	11.00	2.00	R41	29.94	2.00
R42	13.59	2.00	R42	33.93	1.97
R43	16.82	2.00	R43	37.70	1.96
R44	14.72	1.42	R44	34.47	1.01
R45	7.21	1.96	R45	36.57	1.21
R46	12.27	1.83	R46	139.94	0.43
R47	21.17	2.00	R47	69.79	1.62
R48	17.98	2.00	R48	56.54	1.36

Table 11. Optimal protection settings for groups 4 and 5 in scenario 2.

SG 4	$I_{pickup}(A)$	TDS	SG 5	$I_{pickup}(A)$	TDS
R1	210.16	1.88	R1	273.07	1.97
R2	187.00	1.79	R2	243.11	1.90
R3	135.01	1.78	R3	176.10	1.92
R4	128.00	1.64	R4	166.40	1.79
R5	685.80	0.54	R5	162.50	1.64
R6	74.18	1.69	R6	75.45	1.97
R7	62.43	1.48	R7	62.47	1.85
R8	48.10	1.42	R8	48.17	1.78
R9	44.20	1.21	R9	44.24	1.39
R10	40.30	1.08	R10	40.31	1.23
R11	36.40	0.96	R11	36.40	1.09
R12	32.50	0.82	R12	32.50	0.95
R13	28.20	0.65	R13	27.30	0.75
R14	18.21	0.56	R14	18.29	0.62
R15	14.30	0.41	R15	14.30	0.46
R16	10.42	0.26	R16	10.43	0.30
R17	6.50	0.10	R17	6.51	0.11
R18	27.36	0.62	R18	42.15	0.61
R19	20.79	0.47	R19	20.74	0.49
R20	14.11	0.29	R20	12.05	0.31
R21	6.50	0.10	R21	6.50	0.10
R22	62.44	0.39	R22	62.40	0.60
R23	57.87	0.23	R23	847.64	0.10
R24	28.60	0.10	R24	28.60	0.10
R25	84.50	1.10	R25	84.51	1.09
R26	81.28	0.90	R26	81.09	0.90
R27	78.39	0.73	R27	78.00	0.73
R28	74.10	0.56	R28	74.11	0.59
R29	66.31	0.43	R29	66.31	0.46
R30	29.90	0.40	R30	31.15	0.40
R31	19.50	0.27	R31	19.50	0.26
R32	5.20	0.11	R32	5.20	0.10
R33	0.01	0.10	R33	0.01	0.10
R34	0.01	2.00	R34	0.01	2.00
R35	16.29	0.78	R35	0.14	2.00
R36	3.89	2.00	R36	1.33	2.00
R37	18.57	2.00	R37	7.91	2.00
R38	21.16	2.00	R38	10.46	2.00
R39	23.88	2.00	R39	14.28	1.95
R40	28.00	1.95	R40	17.96	2.00
R41	29.91	1.99	R41	21.67	1.98
R42	33.82	1.96	R42	25.60	1.97
R43	37.70	1.95	R43	41.06	2.00
R44	22.02	1.98	R44	14.72	1.78
R45	25.12	2.00	R45	13.59	1.96
R46	29.68	2.00	R46	16.76	1.96
R47	34.95	2.00	R47	20.62	1.93
R48	44.11	2.00	R48	141.09	0.58

Table 12. Optimal protection settings for group 6 in scenario 2.

Relay	$I_{pickup}\,(A)$	TDS	Relay	$I_{pickup}\,(A)$	TDS
R1	273.03	1.70	R25	84.50	0.96
R2	243.10	1.62	R26	80.85	0.79
R3	175.51	1.64	R27	78.00	0.64
R4	166.40	1.52	R28	74.29	0.52
R5	491.56	0.78	R29	66.30	0.41
R6	75.41	1.76	R30	29.90	0.38
R7	62.40	1.66	R31	19.99	0.24
R8	48.10	1.50	R32	5.20	0.10
R9	44.21	1.30	R33	0.01	0.10
R10	40.30	1.12	R34	0.01	2.00
R11	36.42	0.99	R35	5.20	1.05
R12	32.54	0.88	R36	13.02	1.34
R13	27.32	0.68	R37	18.88	2.00
R14	18.34	0.57	R38	26.34	1.82
R15	14.31	0.42	R39	24.10	2.00
R16	10.40	0.26	R40	27.32	1.99
R17	6.50	0.10	R41	30.73	1.97
R18	27.21	0.64	R42	33.83	1.97
R19	18.67	0.48	R43	39.93	1.90
R20	12.33	0.30	R44	24.62	1.87
R21	6.50	0.10	R45	28.86	1.83
R22	62.40	0.39	R46	31.62	1.83
R23	57.25	0.24	R47	36.02	1.79
R24	28.60	0.10	R48	43.36	1.69

Table 13 shows the coordination time interval for each relay pairs for two-phase faults in mode 9 of scenario 1.

Table 13. The coordination time interval for two-phase faults in mode 9 of the scenario 1.

Fault location	Main relay	backup relay	CTI (s)
Node 6	R2	R1	0.746
Node 5	R3	R1	0.457
Node 7	R4	R3	0.347
Node 11	R6	R5	1.053
Node 8	R7	R5	0.563
Node 9	R8	R7	0.423
Node 10	R9	R7	0.528
Node 4	R11	R10	0.793
Node 13	R12	R10	0.361
Node 14	R13	R12	0.427
Node 1	R16	R15	1.893
Node 3	R5	R14	0.630
Node 12	R10	R16	0.664
Node 12	R10	R14	0.781
Node 2	R1	R16	0.652

To illustrate the sensitivity of proposed protection coordination, Tables 14 and 15 show fault current of main and backup relays for fault locations in the middle of the lines in 17th mode, respectively.

As can be seen in these tables, the fault currents is greater than the pickup current and thus the fault is detectable. The time difference between the operation of the main and backup relays is shown in Table 16.

Table 14. Fault current of primary relay for fault locations in the middle of the lines in 17th mode.

Fault location	Main relay	Fault current (A)	Fault location	Main relay	Fault current (A)
1-2	R1 R33	8830 967	17-18	R17	622
2-3	R2 R34	7355 606	2-19	R18	8552
3-4	R3 R35	5389 621	19-20	R19	4055
4-5	R4 R36	4298 634	20-21	R20	2128
5-6	R5 R37	3082 663	21-22	R21	1919
6-7	R6 R38	2619 268	3-23	R22	5554
7-8	R7 R39	2180 273	23-24	R23	3554
8-9	R8 R40	1737 278	24-25	R24	2372
9-10	R9 R41	1366 287	6-26	R25 R44	2809 249
10-11	R10 R42	1216 292	26-27	R26 R45	2579 250
11-12	R11 R43	1167 293	27-28	R27 R46	2025 255
12-13	R12	1179	28-29	R28 R47	1544 263
13-14	R13	982	29-30	R29 R48	1337 268
14-15	R14	891	30-31	R30	1320
15-16	R15	814	31-32	R31	1146
16-17	R16	705	32-33	R32	1063

By comparing the obtained results with the ones obtained from methods presented in the literature, it is clear that the setting factors in the present work are more than other approaches. It is because just a few possible modes were considered by other works, so the determined protection scheme is just valid for those limited modes. In this paper, all possible operational modes of the network are considered, so a higher value of setting factor must be selected to make it possible. Like the present paper, [24] considers too many modes that include high values for setting factors. In addition, the performed study in [24] does not cover all possible modes, therefore, the FCL is employed to cover all states. In this paper, there is no need to FCLs, because it is possible to create more modes. Table 17 compares the proposed method with the method presented in [24].

Table 15. Fault current of backup relay for fault locations in the middle of the lines in 17th mode.

Fault location	Backup relay	Fault current (A)	Fault location	Backup relay	Fault current (A)
1-2	- R34	- 595	17-18	R16	622
2-3	R1 R35	7045 606	2-19	R1 R34	7978 537
3-4	R2 R36	5389 621	19-20	R18	4055
4-5	R3 R37	4298 634	20-21	R19	2128
5-6	R4 R38, R44	3082 256, 240	21-22	R20	1919
6-7	R5, R44 R39	2305, 224 268	3-23	R2, R35	5062, 509
7-8	R6 R40	2180 273	23-24	R22	3554
8-9	R7 R41	1737 278	24-25	R23	2372
9-10	R8 R42	1366 287	6-26	R5, R38 R45	2461, 256 249
10-11	R9 R43	1216 292	26-27	R25 R46	2579 250
11-12	R10	1167	27-28	R26 R47	2025 255
12-13	R11	984	28-29	R27 R48	1544 263
13-14	R12	982	29-30	R28 -	1337 -
14-15	R13	891	30-31	R29	1136
15-16	R14	814	31-32	R30	1146
16-17	R15	705	32-33	R31	1063

Table 16. Coordination time interval for fault locations in the middle of the lines in 17th mode.

number	Pair relay	CTI (s)	number	Pair relay	CTI (s)
1	r1-r2	0.342	26	r26-r27	0.352
2	r1-r18	2.855	27	r27-r28	0.363
3	r2-r3	0.315	28	r28-r29	0.321
4	r2-r22	2.98	29	r29-r30	0.306
5	r3-r4	0.3	30	r30-r31	0.3
6	r4-r5	0.448	31	r31-r32	0.313
7	r5-r6	0.396	32	r48-r47	0.681
8	r5-r25	2.205	33	r47-r46	0.5
9	r6-r7	0.445	34	r46-r45	0.835
10	r7-r8	0.367	35	r45-r44	0.826
11	r8-r9	0.595	36	r44-r37	0.926
12	r9-r10	0.513	37	r37-r36	0.381
13	r10-r11	0.323	38	r36-r35	0.852
14	r11-r12	0.416	39	r35-r34	0.342
15	r12-r13	0.388	40	r34-r33	1.084
16	r13-r14	0.371	41	r43-r42	0.3
17	r14-r15	0.312	42	r42-r41	0.296
18	r15-r16	0.296	43	r41-r40	0.296
19	r16-r17	0.297	44	r40-r39	0.306
20	r18-r19	0.298	45	r39-r38	2.664
21	r19-r20	0.296	46	r38-r37	0.404
22	r20-r21	0.295	47	r34-r18	0.417
23	r22-r23	0.297	48	r35-r22	0.920
24	r23-r24	0.301	49	r38-r25	1.549
25	r25-r26	0.631	50	r44-r6	0.3

Table 17. Comparing proposed method with the method presented in [24].

	Proposed method	[24]	pros and cons
Considering all topology of network	✓	✓	-
Islanded mode	✓	×	The proposed approach considers the islanded mode
variation of DG sizes	✓	×	The variation of DG sizes can cause the method presented in [24] to fail
Using FCL	×	✓	In the proposed method there no need to use FCL. Short circuit level in proposed method is more than [24]

4. CONCLUSION

In this paper, a new approach is introduced to classify different network operational modes into existing relay setting groups, while the protection coordination is valid for each operational mode. This approach considers the changes of capacities of DG units. Operational modes include each possible connecting and disconnecting of DG units, microgrid islanding/grid connected modes and variation of DG capacities. For this purpose, the over-current relays with several setting groups are used. In the proposed approach, all operation modes are classified into existing setting groups. Then the protection coordination is determined for each group. After classification, the impacts of capacity variation of DG units are considered and, again, optimal setting of each group is determined. For the operational modes in which the protection coordination failed, combination of setting groups is used to recover group's coordination. Thanks to the new classification approach, the need for FCL and thus costs are reduced. In order to investigate the performance of the proposed approach, simulations were carried out on 14-node and 33-node test distribution networks. DIgSILENT software has been employed to simulate the network in various operational modes. All possible scenarios are considered in classifications, and optimal protection coordination is performed for each of them. The results show better performance of the proposed approach compared to other existing approaches, so the designed protection system is more efficient while costs are reduced.

5. NOMENCLATURE

VARIABLES:

S	Maximum number of network topologies
N_{DG}	Number of existing DGs in the network.
C	Total operational states.
I_m	Short circuit currents flow through main relays.
I_L	Load currents flow through main relays.
I_b	Short circuit currents flow through backup relays.
t_i	Operation time of each relay.
TDS	Time Dial Setting.
I_{SC}	Short circuit current.
I_{pickup}	Pickup current.
T_j	Total operation time in each operational state.
SG_k	k^{th} setting group.
$T(SG_k)$	Total operation time of each group.
T	Total operation time.
$t_{i,j}^{b}$	Backup relay operating time.
$t_{i,j}^{m}$	Main relay operating time.
I_l	Minimum pickup current.
I_u	Maximum pickup current.
TDS_{max}	Maximum allowed TDS.
TDS_{min}	Minimum allowed TDS.

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