

DEVELOPMENT OF AN OPTIMIZED DUAL RELAY SETTING COORDINATION SCHEME FOR DISTRIBUTION NETWORK WITH DISTRIBUTED GENERATION



Babatunde Lambo, Yusuf Jibri, Boyi Jimoh, A.S Abubakar
Department of Electrical Engineering, Ahmadu Bello University, Zaria - Nigeria.
tundelambo@yahoo.com.

Keywords: –

time dial setting.
Directional overcurrent relays.
Distributed Generation.
Bat Algorithm.
Relay Coordination.

Article History: –

Received: July, 2021
Reviewed: August, 2021
Accepted: August, 2021
Published: September, 2021

ABSTRACT

In Distributed Generation systems (DG), the fault current through a relay in forward direction is mostly higher than in the reverse direction. Thus, it is desirable to have dual setting directional over current relay (DOCR) which can operate for both forward and reverse direction of fault current with two independent relay settings. The presence of DGs gives additional fault current contribution to the fault location. In this work, the coordination problem was formulated as a nonlinear optimization problem with the aim of minimizing the operation times of the relays using bat algorithm. The protection setting consists of two time-dial settings and one pickup current setting for each relay. The algorithm was used to obtain the time dial setting (TDS) with the objective of minimizing the TDS and constraint of satisfying CTI for network topologies and DGs operation. The performance of the presented coordination strategy was tested on distribution part of IEEE 30 bus system with synchronous DGs. In the case of TDS for without DG penetration for the relay at maximum/minimum category, the two cases I, II appreciated significantly with 99.96%, and 99.98% respectively. At the maximum/minimum operation for cases I, II with DG penetration result 99.98% and 99.99% respectively when compared with the base case. This show that the relay response fast to clear out the fault current in the network. Also, a reduction in cases I and II of fault current at maximum/minimum level without DG represent 25.12% and 14.47% respectively. At maximum/minimum fault current for cases I, II scenario with DG result to 29.33% and 14.94% respectively. The result illustrates that the algorithm used within dual setting protection scheme is significantly reaching the optimized coordination and the relay coordination is certain for all simulation scenarios with remarkable performance.

1. INTRODUCTION

In modern power systems, generating stations are now used to feed a high voltage network. These networks are connected to millions of equipment, whenever there is fault in the network the consequence may be devastating [1]. In order to secure the network from such kind of abrupt circumstances, protective relays are infused into the system. These relays ensure that the part of the system malfunctioning is disconnected from the network by tripping the circuit [2]. Protection relay plays a vital role for effective operation within the power system. In distribution networks, inverse time

overcurrent relay is considered as the backbone of the protection strategies where the overcurrent relays settings are chosen to achieve coordination [3]. This guarantees fast, selective and reliable relay operation to isolate the power system faulted section [4]. For proper protection of interconnected systems, Directional overcurrent relays (DORs) are an attractive, economic and technical choice. DORs measure the magnitude of the fault current in each phase and issue a trip signal after a specific operating time [5]. This operating time depends on the setting values and fault current magnitude. Nowadays, distributed generation are been integrated into the

distribution system due to the increasing interest in smart grids [6-8]. This has led to the distribution system transforming from the commonly radial nature toward a meshed and looped structure and this increases the short circuit levels of the system. Generally, the integration of distributed generation (DG) has different impacts on the distribution systems and one of the major challenges is its effects on the protection system [4]. The impact of the DG integration on the protection scheme depends on the type of DG as well as the nature of the distribution system (radial or meshed) [9]. There are mainly two types of distributed generations which include: inverter based distributed generation and synchronous based distributed generation [10, 11]. Synchronous based DGs inject high fault currents and result in significant changes in the fault current level [12]. Radial distribution systems are typically protected by fuses, reclosers and over-current relays [13]. The impacts of the inverter based distributed generation in terms of the protection coordination on such system is almost negligible [14]. In the presence of synchronous based distributed generation (SBDG), the fuse might operate before the recloser's first operation and this will affect the fuse saving strategy [9]. The SBDG can also impact the coordination between the fuse and the overcurrent resulting in unnecessary tripping of the whole feeder [15]. Mitigating such problems would require either fuse replacement or optimizing the settings of the over-current relay [16].

In line with the problems identified (minimizing the operating time of the overcurrent relay and ensuring coordination between the relays) with the distribution

system whenever SBDG is integrated into it, literatures have used trial and error method for the selection of the settings of the relays, however, this method requires a lot of computation time. Metaheuristic techniques such as genetic algorithm [17] which has high tendency of getting trapped in local optimum and particle swarm optimization [18] have also been used to optimize the relay settings. However, the operating time of the relays still needs to be minimized in order to ensure that equipment connected to the distribution system do not malfunction [11]. Sajjad Dadfar and Majid Gandomkar, (2020). Proposed and presented an optimal dual characteristic for enhancing coordination index in protecting forward and reverse fault currents. The result was remarkable however, the approach acknowledged a failure in responding a proper solution bounded with specified bound. Therefore, this research used a bat algorithm for optimizing the relay settings considering fault analysis in the distribution network with DG. This algorithm is chosen based on its favorable echolocation properties (ability to orientate its environment). This will ensure proper coordination between the main relay and back up relay and also minimize the operation time of the relays.

2. METHODS

The system was used in implementing the developed method. This system is a standard IEEE-30 bus test system as detailed. The system used is as shown in Figure 1.

2.1 Standard IEEE 30-bus power system

The IEEE 30-bus test system is 33kV meshed network. The single line diagram of this system is shown in figure 1. The system is equipped with 109 directional overcurrent relays. The SBDG units is modeled with each, rated at 2 MVA and sub transient impedance of 9.67%. Each SBDG is integrated into the network using a step-up 0.415/33 kV transformer with the rated capacity of 2.5 MVA, and 5% impedance. The buses for the DG units connected to the meshed DN are place at bus 1, 2, 13, 22, 23, and 27.

2.1.1 Performance of Load flow analysis

Load Flow Analysis which is also refer to as power flow analysis is an important tool in power system analysis which aids in the determination of the steady state behavior of a system. A number of power flow algorithms has been developed over the years to help solve power flow problems for both balanced and unbalanced distribution networks. Some of the algorithms were capable of finding solution even after inclusion of DG sources in the network.

2.1.2 Short Circuit Analysis

The majority of faults in power systems are asymmetrical, as such, to analyze an asymmetrical fault, an unbalanced three phase was used. The direct solution to handling such networks are usually very difficult. These methods produce excellent results for balanced electric power systems. However, the MGs configuration is unbalanced, but with the method of symmetrical components application to fault analysis, it was transformed arbitrarily and then, computation of the system response is carried out by straightforward circuit analysis. Then, the results

obtained are transform back to the original phase variables.

2.1.3 Objective Function

The use of abbreviations in both paper title and the other titles should be avoided as much as possible. Define all the terms and put the abbreviations in parenthesis.

2.2.1 Equations

In distribution system, the primary relays have to clear fault as fast as possible to avoid mal-operation of the equipment connected to the network. To ensure this, the time dial settings and the plug settings of the relay need to be optimized. In this work, the summation of the operating times of all the primary and backup relays, responding to clear close-in and far bus faults will be taken as the objective function.

Given the operating time (t) of a DOCR, an inverse function of the short circuit current flowing through it. The relay time-current characteristic can be expressed as follows [9].

$$t_{ij} = TDS_i \frac{A}{\left(\frac{I_{scij}}{I_{pi}}\right)^B - 1} \quad (1)$$

Where i is the relay identifier and j is the fault location identifier, The parameters A and B are constants that vary with the type of OCR which are commonly set at 0.14 and 0.02 respectively. The term I_{scij} represents the relay Fault Current and I_{pi} represents the relay

pickup current. Each DOCR has one pair of setting for both primary and backup operation. The optimization objective is to minimize the times of all the relays (primary and backup) while maintaining the conditions of protection coordination.

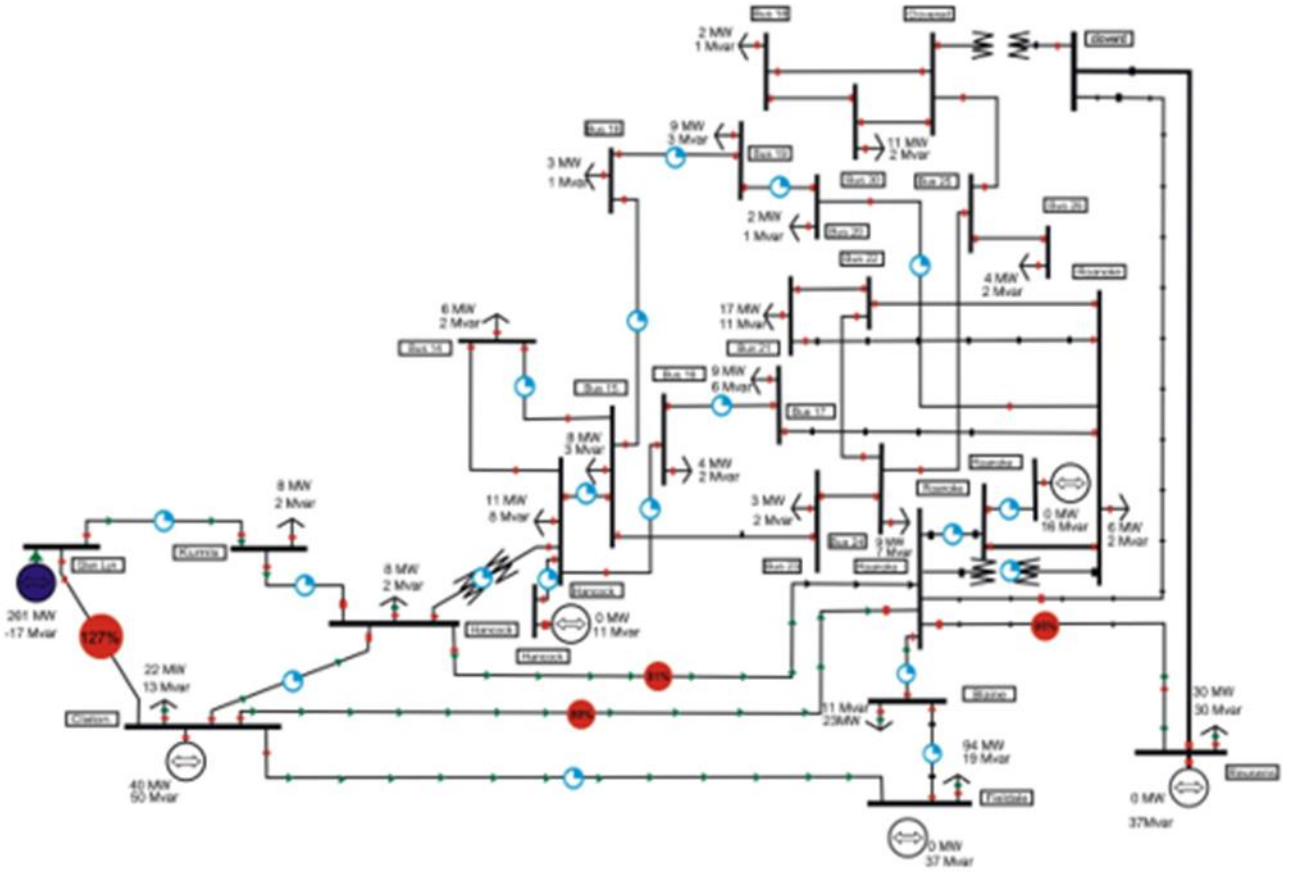


Figure 1: Standard IEEE 30 Bus Network

The objective function taken to be the sum, T can be expressed as:

$$T = \sum_{j=1}^M \left(\sum_{i=1}^N t_{fw_{ij}} + \sum_{k=1}^N t_{rv_{kj}} \right) \forall (i, k) \in \Omega \quad (2)$$

Where Ω is the set of primary/backup pairs of the relays, N represents the total number of relays, and M denotes the total number of fault locations across all feeders. $t_{fw_{ij}}$ and $t_{rv_{kj}}$ denote the operation times for the forward/primary and reverse/backup relays, respectively. The variables $t_{fw_{ij}}$ and $t_{rv_{kj}}$ are the

time of operation of relay i , and k for a fault at location j during forward (primary) and reverse (backup) operation, respectively.

The coordination constraints must be satisfied while solving the protection coordination problem which can be represented as follows:

$$t_{rv_{kj}} - t_{fw_{ij}} \geq CTI \quad \forall i, k, j \quad (3)$$

$$I_{pi_min} \leq I_{pfi}, I_{prvi} \geq I_{pi_max} \quad (4)$$

$$TDS_{i_min} \leq TDS_{fwi}, TDS_{rv} \leq TDS_{i_max} \quad (5)$$

where coordination time interval (CTI) indicates the minimum time between the primary and the backup relay. The CTI usually takes values between 0.2 and 0.5 s and in this work, it was set to 0.3 s. In addition, there are upper and lower bounds on the relay settings which can be represented as follows:

Where I_{pi_min} and I_{pi_max} represent the lower and upper bounds on relay i pickup current setting. The parameters TDS_{i_min} and TDS_{i_max} represent the lower and upper bounds on the TDS for relay i . The main variables, to be optimized, for the protection coordination problem, are the TDS and I_p in both forward and reverse

directions. The short circuit current is considered a parameter within the optimization but the DG location and size will have an effect on FCL. For each study, prior to optimizing the relay settings, fault analysis is conducted to determine the Fault Currents passing through each relay [3]. As can be seen from (4) and (5), the relationship between the relay operating time and the pickup current setting is nonlinear. Thus, the model is formulated as a constrained NLP problem, integrated with a primary/backup pair scheme such that the relays closest to the fault are consider.

3. RESULTS

The analysis preformed on the IEEE-30 bus were done using the method outline from the section 3.3. In the analysis, two case scenarios of fault were considered, which involved fault between bus 4 and 6 and fault between bus 15 and 23. The fault current, Set- I_p , Set-TDS and operating time were determined and the results obtained are shown.

3.1 Case I: Fault Between Bus 4 and 6

For the case I scenario, it is assumed that a fault occurred between the mid of bus 4 and 6 which create

Table 1: Fault Current and Relay Operating Time

S/N	Relay No	Bus No		Fault Current Without DG	Operating Time	Fault Current With DG	Operating Time
1	431	4	P	0.171721	0.130115	0.27904695	0.109236135
2	42	4	B	0.064475	0.300024	0.104771393	0.300000717
3	24	2	P	0.064475	0.300001	0.104771393	0.300004839
4	431	4	P	0.171721	0.130115	0.27904695	0.109236027

5	43	4	B	0.061392	0.300007	0.099761989	0.300002829
6	34	3	B	0.061392	0.300014	0.099761989	0.300001748
7	431	4	P	0.171721	0.130113	0.27904695	0.109240015
8	412	4	B	0.050413	0.300001	0.08192115	0.300002898
9	124	1	B	0	0.300001	0	0.300020506
10	631	4	P	0.171721	0.183879	0.131546113	0.145237008
11	62	4	B	0.061392	0.300009	0.084939355	0.300058131
12	26	3	B	0.061392	0.300068	0.084939355	0.300008507
13	631	6	P	0.026984	0.451391	0.026983818	0.451360131
14	67	6	B	0.020285	0.719481	0.020284682	0.719477468
15	76	7	B	0.020285	0.719507	0.020284682	0.719520958
16	631	6	P	0.026984	0.451357	0.026983818	0.451354596
17	68	6	B	0.028572	0.41989	0.028572344	0.419896834
18	86	8	B	0.028572	0.419899	0.028572344	0.419905383
19	631	6	P	0.026984	0.451349	0.026983818	0.451369223
20	69	6	B	0.015652	1.553162	0.015651733	1.553151244
21	96	9	B	0.015652	1.553244	0.015651733	1.55311398
22	631	6	P	0.026984	0.451	0.026983818	0.451396416
23	610	6	B	0.005173	1000	0.005173278	1000
24	106	1	B	0	1000	0	1000
25	631	6	P	0.026984	0.451	0.026983818	0.451366716
26	628	6	B	0.006124	1000	0.00612372	1000
27	286	28	B	0.006124	1000	0.00612372	1000

a virtual bus called bus 31. The buses connected to bus 4 and 6 are: bus 1, bus 4 and bus 5.

Each of these buses have relay connected to them and the results obtained when a fault occurred between the 4 and 6 is shown on table 1 and 2. From Table 1, it shows the fault current and the operating time obtained when the fault occurred while Table 2 shows the set_ Ip and set TDS of the relays. The simulation was done without and with DG on the network. For the fault between bus 4 and 6, we have 9 primary relays and 18 back up relays connected within the fault zone. The primary relays are label as relay No 431 and 631 while the relay No 24, 42, 34, 43, 124, 412, 26, 62, 67, 76, 68, 86, 69, 96, 610, 106,

286 and 628 serves as the backup relays which are shown on Table 1 with their respective buses.

From Table 1, the maximum fault current without DG occurred at bus 4 and was seen by the two primary relay. The fault current obtained without DG on the network is 0.1717A. The maximum fault current with DG on the network occurred at bus 4 with 0.2790A fault current. It is seen by the primary relay No 431.

The minimum fault current for both without and with DG is zero (0) indicated by relay No 124 and 106 respectively at bus 1.

The maximum operating time of the relay for without and with DG is 1000s located at buses 28, 6 and 1

and is indicated by relay No 610, 106, 286 and 628. However, the minimum operating time of the relay for network without and with DG differs, which is 0.1301s and 0.1092s respectively. Also, all the operating time falls within the CTI value of 0.3s.

The maximum Set Ip for without and with DG both occurred at bus 4 as seen on table 2 which occurred between line 2 and 6 at bus indicated by the backup relay 62 with values of 1.4976A and 1.4897A respectively.

The minimum Set Ip for without and with DG occurred at bus 6 which were indicated by relay No 631 and 69 with values of 1.25A and 1.2500A between line 6 to the point of the fault and line 6 and 9 respectively.

Also, the maximum SET_TDS for without DG occurred at bus 6 between line 6 to 1 which was indicated by the backup relay No 610 with values of 0.9829s while the maximum SET_TDS with DG on the network is 0.8768s located at bus 28 which was indicated by relay No 286.

The minimum SET_TDS for with and without DG both occurred at bus 4, which were indicated by relay 431 with values of 0.0500s and 0.0500s and all

between line 4 to the point where the fault occurred. As depicted in the table, all the operating time falls within the CTI value of 0.3s.

3.2 Case II: Fault Between Bus 15 and 23

For the case II scenario, it was assumed that the fault occurred between the mid-point of bus 15 and 23 which create a virtual bus called bus 31. The buses connected to bus 15 and 23 are bus 12, 14, 15, 18, 21, 23 and 24.

Each of these buses have relay connected to them and the results obtained when a fault occurred between the 15 and 23 is shown on table 3 and 4. Table 3 shows the fault current and the operating time obtained as the result of the fault while table 4 shows the set Ip and set TDS of the relays. The simulation was done without and with DG on the network.

Table 2: Fault Current and Relay Operating Time

S/N	Relay No	Bus No		Set_Ip Without DG	Set_TDS	Set_Ip With DG	Set_TDS
1	431	4	P	1.250029	0.050000964	1.250048916	0.050000325
2	42	4	B	1.291102	0.070048408	1.291671282	0.091615675
3	24	2	B	1.355437	0.067892078	1.487301705	0.085323311
4	431	4	P	1.25002	0.050001139	1.250039228	0.050000405
5	43	4	B	1.300987	0.06754004	1.454128379	0.084144927
6	34	3	B	1.280995	0.068226295	1.384567092	0.086329022
7	431	4	P	1.250033	0.050000132	1.250171985	0.050000467

8	412	4	B	1.297901	0.058950113	1.253912636	0.081968333
9	124	1	B	1.42396	0.054871894	1.376437785	0.077828314
10	631	4	P	1.250003	0.050000911	1.250018455	0.050000715
11	62	4	B	1.497609	0.054247162	1.489752138	0.075931822
12	26	3	B	1.296491	0.06060518	1.344453104	0.08047799
13	631	6	P	1.250002	0.050005009	1.250014162	0.050000975
14	67	6	B	1.250007	0.050002201	1.25000234	0.050002342
15	76	7	B	1.250006	0.05000406	1.250029835	0.050003082
16	631	6	P	1.250006	0.050001081	1.250001163	0.050001043
17	68	6	B	1.250006	0.050001568	1.250040158	0.050000731
18	86	8	B	1.250025	0.050001747	1.250055288	0.050001011
19	631	6	P	1.250008	0.050000139	1.250036832	0.050000795
20	69	6	B	1.250011	0.050000903	1.25000061	0.050002345
21	96	9	B	1.250022	0.050001473	1.250003903	0.050000559
22	631	6	P	1.25	0.0500011	1.250010467	0.050005188
23	610	6	B	1.359	0.982904	1.303378111	0.492278609
24	106	1	B	1.429	0.633496	1.429848869	0.480544626
25	631	6	P	1.25	5.00E-02	1.250020197	0.050001388
26	628	6	B	1.323	0.216323	1.320786907	0.457918605
27	286	28	B	1.359	0.344186	1.462837551	0.876807701

Table 3: Fault Current and Relay Operating Time

S/N	Relay No	Bus No		Fault Current	Operating Time	Fault Current	Operating Time
				Without DG		With DG	
1	1531	15	P	0.00806	0.184336	0.013096878	0.145517974
2	1512	15	B	0.005697	0.300007	0.009257033	0.300004263
3	1215	12	B	0.005697	0.300008	0.009257033	0.300009392
4	1531	15	P	0.00806	0.184332	0.013096878	0.145515004
5	1514	15	B	0.001459	2.260296	0.002371099	0.543252172
6	1415	14	B	0.001459	2.259095	0.002371099	0.543274182
7	1531	15	P	0.00806	0.000184	0.013096878	0.14552046
8	1518	15	B	0.000947	1	0.001539207	1.678445239
9	1815	18	B	0.000947	1	0.001539207	1.678419434
10	2331	23	P	0.00209	0.67715	0.003396972	0.346620216
11	2321	23	B	0.006179	0.300002	0.010040824	0.300000645
12	2123	21	B	0.006179	0.300021	0.010040824	0.300010272
13	2331	23	P	0.000697	1000	0.000696815	1000
14	2324	23	B	0.000555	1000	0.000555017	1000
15	2423	24	B	0.000555	1000	0.000555017	1000

Table 4: Fault Current and Relay Operating Time

S/N	Relay No	Bus No		Set_Ip Without DG	Set_TDS	Set_Ip With DG	Set_TDS
1	1531	15	P	1.250171	0.050001	1.250039918	0.050001229
2	1512	15	B	1.448994	0.059484	1.405769158	0.082320069
3	1215	12	B	1.359183	0.062304	1.396387809	0.082619494
4	1531	15	P	1.250141	0.050001	1.250002403	0.050000862
5	1514	15	B	1.250113	0.050001	1.250027176	0.050002826
6	1415	14	B	1.250005	0.050003	1.250026248	0.05000491
7	1531	15	P	1.250001	0.050001	1.250141034	0.050000321
8	1518	15	B	1.358365	0.591161	1.250001135	0.050007221
9	1815	18	B	1.389836	0.378803	1.250019601	0.050002895
10	2331	23	P	1.250016	0.05	1.250033462	0.050001228
11	2321	23	B	1.305667	0.067666	1.346489355	0.087860407
12	2123	21	B	1.401201	0.06455	1.428957141	0.085212649
13	2331	23	P	1.283759	0.630372	1.462210376	0.74535543
14	2324	23	B	1.27846	0.708485	1.338688197	1.062657432
15	2423	24	B	1.253354	0.936212	1.303112669	0.894128785

For the fault between bus 15 and 23, there are 5 primary relays connected within the fault zone, which are relay No 1531 located at bus 15 and relay No 2331 located at bus 23. The backup relays within this fault zone are relay No 1215, 1512, 1415, 1514, 1815, 1518, 2123, 2321, 2324 and 2423. These relays are shown on table 3 with their respective bus.

From Table 3, the maximum fault current with and without DG both occurred at Bus 15 which all were indicated by relay No 1531, with fault current of 0.0130A and 0.0080A respectively. Also, the minimum fault current for both with and without DG occurred at bus 23 and 24 with a fault current value of 0.0005A and 0.0005A respectively, all indicated by relay No 2324 and 2423.

The maximum operating time of the relay for both with and without DG is 1000s and were both located

at bus 23 and 24 which were indicated by relay No 2331, 2324 and 2423.

Also, the minimum operating time of the relay for the network with and without DG are 0.1455s and 0.0002s respectively and were both indicated by 1531 at bus 15. Furthermore, most or all the operating time falls within the CTI value of 0.3s.

From table 4, the maximum Set Ip for network without DG is 1.4489A and was indicated by relay No 1512 at bus 15 which occurred between line 12 and 15 while the maximum set Ip for network with DG is 1.4622A and was indicated by relay No 2331 at bus 23 between line 23 to the point where the fault occurred.

The minimum Set Ip for with and without DG both occurred at bus 15 and were indicated by relay No 1518 and 1531 with values of 1.2500A and 1.2500A

respectively, between line 15 to 18 and line 15 to the point where the fault occurred.

The maximum SET_TDS for network with DG is 1.0627s and was indicated by relay No 2324 at bus 23 which occurred between lines 23 to 24 while the maximum SET_TDS for network without DG is 0.9362s and was indicated by relay No 2423 at bus which occurred between lines 23 to 24 in opposite direction.

The minimum SET_TDS for network with DG is 0.0500s and was located at bus 15 and was indicated by relay 1531 and this occurred between line 15 to the point of the fault while the minimum SET_TDS for network without DG was indicated by relay No 2331 at bus 23 with values of 0.05s and this occurred between line 23 to the point where the fault occurred. It is also good to know and observe that the CTI value fall within the set value.

4. CONCLUSION

The research work has presented a Dual Relay Setting Coordination Scheme for Distribution Network with Distributed Generation Using Bat Algorithm. The method based on bat algorithm is presented to obtain the optimal protection coordination of DOCR in a meshed distribution network. The strategy works by minimizing the total operating time of primary and backup OCR, with consideration to the CTI between relay pairs. From the summary of 30 bus test system, it observed a reduction in cases I and II of fault current at maximum/minimum level without DG represent 25.12% and 14.47% respectively. At maximum/minimum fault current for cases I and II

scenario with DG result to 29.33% and 14.94% respectively. Also, TDS for without DG penetration for the relay at maximum/minimum category, the two cases I, II appreciated significantly with 99.96% and 99.98% respectively. At the maximum/minimum operation for cases I, II with DG penetration result 99.98% and 99.99% respectively when compared with the base case. This show that the relay response fast to clear out the fault current in the network.

REFERENCES

- [1] T. A. Short, *Electric power distribution handbook*: CRC press, 2014.
- [2] M. Thakur and A. Kumar, "Optimal coordination of directional over current relays using a modified real coded genetic algorithm: A comparative study," *International Journal of Electrical Power & Energy Systems*, vol. 82, pp. 484-495, 2016.
- [3] H. M. Sharaf, H. Zeineldin, D. K. Ibrahim, and E. Essam, "A proposed coordination strategy for meshed distribution systems with DG considering user-defined characteristics of directional inverse time overcurrent relays," *International Journal of Electrical Power & Energy Systems*, vol. 65, pp. 49-58, 2015.
- [4] C. J. Mozina, "Impact of smart grid and green power generation on distribution systems," in *Innovative Smart Grid Technologies (ISGT), 2012 IEEE PES*, 2012, pp. 1-13.
- [5] N. Sharma, *Novel Directional Protection Scheme for the FREEDM Smart Grid System*: Arizona State University, 2015.
- [6] I. Abdulwahab, Y. Jibril, G. A. Olarinoye, A. S. Abubakar, A. A. Olaniyan, and M.

- Mohammed, "A Cuckoo Search Optimized Control of Dual Stator Induction Generator in Wind Energy Conversion System," 2021.
- [7] A. S. Abubakar, A. A. Olaniyan, A. Ibrahim, and S. H. Sulaiman, "An Improved Analytical Method For Optimal Sizing And Placement Of Power Electronic Based Distributed Generation Considering Harmonic Limits," in *2019 IEEE PES/IAS PowerAfrica*, 2019, pp. 122-127.
- [8] J. Ehrenberger and J. Švec, "Directional Overcurrent Relays Coordination Problems in Distributed Generation Systems," *Energies*, vol. 10, p. 1452, 2017.
- [9] H. H. Zeineldin, H. M. Sharaf, D. K. Ibrahim, and E. E.-D. A. El-Zahab, "Optimal protection coordination for meshed distribution systems with DG using dual setting directional over-current relays," *IEEE Transactions on Smart Grid*, vol. 6, pp. 115-123, 2015.
- [10] I. Abdulwahab, A. A. Olaniyan, A. S. Abubakar, U. Musa, and O.-o. Ajayi, "An Optimized Droop Control Scheme for Power Quality Improvement in Microgrid," 2020.
- [11] T. S. Aghdam, H. K. Karegar, and H. Zeineldin, "Transient Stability Constrained Protection Coordination for Distribution Systems with DG," *IEEE Transactions on Smart Grid*, 2017.
- [12] N. Nimpitiwan, G. T. Heydt, R. Ayyanar, and S. Suryanarayanan, "Fault current contribution from synchronous machine and inverter based distributed generators," *IEEE Transactions on power delivery*, vol. 22, pp. 634-641, 2007.
- [13] T. K. Abdel-Galil, A. E. Abu-Elanien, E. El-Saadany, A. Girgis, Y. A.-R. Mohamed, M. Salama, *et al.*, "Protection coordination planning with distributed generation," *Qualsys Engco. Inc*, 2007.
- [14] H. B. Funmilayo, J. A. Silva, and K. L. Butler-Purry, "Overcurrent protection for the IEEE 34-node radial test feeder," *IEEE Transactions on Power Delivery*, vol. 27, pp. 459-468, 2012.
- [15] P. P. Barker and R. W. De Mello, "Determining the impact of distributed generation on power systems. I. Radial distribution systems," in *Power Engineering Society Summer Meeting, 2000. IEEE*, 2000, pp. 1645-1656.
- [16] B. Hussain, S. Sharkh, S. Hussain, and M. Abusara, "An adaptive relaying scheme for fuse saving in distribution networks with distributed generation," *IEEE transactions on power delivery*, vol. 28, pp. 669-677, 2013.
- [17] W. K. Najy, H. H. Zeineldin, and W. L. Woon, "Optimal protection coordination for microgrids with grid-connected and islanded capability," *IEEE Transactions on industrial electronics*, vol. 60, pp. 1668-1677, 2013.
- [18] M. M. Mansour, S. F. Mekhamer, and N. El-Kharbawe, "A modified particle swarm optimizer for the coordination of directional overcurrent relays," *IEEE transactions on power delivery*, vol. 22, pp. 1400-1410, 2007.