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Online adaptive protection scheme for electrical distribution network with high penetration of renewable energy sources

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ABSTRACT

Incorporation of distributed energy resources (DERs) in power distribution networks makes the system combined and lively. Presence of DER with variable generating capacity at different locations converts protection coordination problem (PCP) to a very challenging one. In this paper, authors have proposed an online adaptive protection scheme based on relay coordination to tackle PCP, when renewable energy based distributed generators penetrate power in the system with conventional generators. Directional overcurrent relays (DORs) are one of the main elements of protection schemes in power systems. The PCP is formulated as nonlinear programming problem with DORs for different operating combinations. The adaptive algorithm uses an afresh published optimization technique, namely, Symbiotic Organism Search (SOS) installed at SCADA computers. The program is coded in MATLAB to find the optimal settings of relay parameters, time dial setting (*TDS*) and pickup current (I_p) setting, which gives minimum operating time during any fault. Operational ability of the algorithm is validated on IEEE 14 bus distribution system by varying generation arrangements of DER in different combinations. Every time for slight variation in the system fault current level may be due to variation in line parameters or incorporation of new DERs; new relay settings are communicated to corresponding relays. The proposed protection scheme is highly flexible to sustain the protection coordination among DORs, maintaining reliable coordination margin for each primary/backup relay pair for every combination.

Keywords: Distributed Energy Resources; directional overcurrent relay; protection coordination; SOS optimization technique; adaptive relay protection.

INTRODUCTION

Nowadays a trend arises to renovate and modernize everything in a smarter way, mainly in the power sectors to improve efficiency, safety, security, and reliability. Normally radial distribution systems are protected by overcurrent relays (OCRs) because of unidirectional flow of current. But with the insertion of distributed generators (DGs) or DERs, they are no longer radial. The flow of current may be bidirectional, which require directional and non-directional element both. Increased fault current level enhances the chances of mis-coordination and false tripping tendency in protective devices. Considering DER penetration, the PCP had been discussed in Saleh *et al.* (2015); Ojaghi *et al.* (2013); El-khattam and Sidhu (2009). Different solutions of accepting DER installation in the system were proposed in Yazdanpanahi *et al.* (2014); KAMEL *et al.* (2013). The sole feature of all the studies is increased value of fault currents. That may not satisfy all the protection constraints like coordination criterion, minimum operating time and predefined coordination time interval, etc. Use of FCL in DG connected system is a widely used method to reduce fault current [Lim *et al.*, 2012; Lim, S.H. & Kim, J.C. 2012; Najy *et al.*, 2013]. In a distribution system, coordination of DORs at different topological conditions was addressed in Noghabi *et al.* (2009); Urdaneta *et al.* (1997); Noghabi *et al.* (2010). Ghadiri Anari *et al.* proposed a Mixed-integer programming (MIP) approach for solving unit commitment

(UC) problem with Demand Response Resources (DRR) and gridable vehicles (Ghadiri Anari *et al.,* 2014). In adaptive protection scheme, under different topological conditions, the optimal set of relay settings are computed first. For every possible topology change in season and network change, DOR settings are rearranged. Adaptive relaying approach for saving fuses in the changed scenario of higher fault current level in the presence of DERs maintaining recloser-fuse coordination was deliberated in Hussain *et al.* (2013); Naiem *et al.* (2012); Shah *et al.* (2014). Adaptive methods had been proposed to solve PCP with DORs during topological changes in the grid without any telecommunication infrastructure [Ojaghi *et al.,* 2013; Zamani *et al.* 2011]. Adaptive protection schemes had been suggested for relay coordination for fast fault isolation at different operational modes of DG units comparing with conventional structure [Ates *et al.,* 2016; Chen and Lee, 2014]. In the process of the adaptive relaying scheme, optimization techniques would be helpful for choosing proper settings.

Different nature-inspired heuristic methods had been applied for solving relay coordination problem [Ojaghi *et al.,* 2013; Hussain *et al.,* 2013; Mansour *et al.,* 2007; Zeineldin *et al.,* 2006; Saha *et al.,* 2016]. Nowadays, coordination problems are also solved by hybrid methods [Noghabi *et al.,* 2009]. Their key attention is to reduce execution time, to minimize search space, and to reduce the number of iterations necessary to attain optimal solutions. SOS algorithm is a nature-inspired optimization technique developed by Min-Yuan Cheng and Doddy Prayogo in 2014. It mimics the natural give and takes policies. To survive in the ecosystem properly, organisms opt these policies. No living being can live alone on the earth. All are dependent on one another directly or indirectly. This type of relationship of dependency on one another is termed as symbiosis [Cheng, and Prayogo, 2014]. This algorithm uses three phases of symbiosis: mutualism, commensalism, and parasitism. Main attractive features of SOS over other metaheuristic algorithms, while solving relay coordination problem, are as follows: SOS algorithm operations require no algorithm-specific parameters, SOS shares characteristics similar to most population-based algorithms (GA, DE, PSO, TLBO, etc.) and performs specific operators iteratively on a group of candidate solutions to achieve a global solution, SOS does not reproduce or create children, and unlike GA, DE, and numerous other evolutionary algorithms, SOS adapts through individual interactions. Although similar in this respect to PSO and DE, the SOS strategy differs significantly. SOS uses three interaction strategies, mutualism, commensalism, and parasitism, to gradually improve candidate solutions. SOS optimization technique proved its effectiveness in the computation of optimum relay settings compared to other algorithms in interconnected power systems [Saha *et al.,* 2016b].

The continuous signal will be received from every nook and corner of the system with advanced Supervisory Control and Data Acquisition (SCADA) systems in control rooms. In the advanced technology, microcontroller based protective relays and Disturbance Fault Recorders (DFRs) are integrated into the SCADA system, which receives continuous signal of voltage and current magnitude, phase angles, etc. Adaptive protection scheme for variation in loading condition for few cases had been discussed in Chen and Lee (2014). During any operational or topological change, the signal will be received continuously, irrespective of whether power is feeding from a particular DER(s) in the system or not. Power transaction from a DER or any change in loading condition will be clearly sensed by modern advanced devices. To tackle the continuous parameter change, further research is needed to implement new protection schemes in power system. At different topological conditions to avoid mis-coordination, protective relay settings need to adjust adaptively.

In this paper, authors have proposed an online adaptive algorithm, which can be integrated into the supervisory control unit. In the present work, small DER power injection is considered at different topological conditions in the distribution system. Optimal relay settings under various conditions are achieved using SOS optimization technique.

The paper is arranged as follows: section 2 describes relay coordination in presence of DER injection. Section 3 describes an implementation of the proposed adaptive algorithm. System investigated and results are discussed in section 4. Section 5 concludes the paper.

RELAY COORDINATION IN PRESENCE OF DER INJECTION

DORs are mostly used for the primary and secondary protection of a distribution system. Formulation of PCP for DOR is a very complex task in a multisource mesh or radial network. The objective of PCP is the minimization of total operating time of all the relays (primary and backup) while fulfilling the constraints. Integration of DERs modifies the PCP because direction and magnitude of current coming out from DER modifies the fault scenario. Formulation of PCP in a distribution system including DER power injection is discussed below.

A. Protection coordination in distribution system without considering DER power injection

For any faulted condition in the system, relays should send a signal as early as possible to isolate the circuit. Moreover, coordination of primary and backup relays should be maintained. The operating time (T) of a relay varies inversely with the short circuit current. T of DOR as a function of time dial setting (TDS) and plug setting (PS) is expressed in (1). PS is the division of fault current and pick-up current (I_p). For any type of fault in a known system, fault current can be obtained using Thevenin's theorem [Ustun *et al.,* 2013].

T can be expressed as a non-linear equation in terms of TDS and I_p and is presented in (1) [Pandi *et al.*, 2013]:

$$T = \left(\frac{y}{(PS)^x - 1} \right).TDS = \left(\frac{y}{\left(\frac{I_{fault}}{I_p} \right)^x - 1} \right).TDS \tag{1}$$

where I_{fault} is the fault current, and x and y are the constants. The values of x and y for different kinds of IDMT characteristics are shown in **Table 1**[Pandi *et al.*, 2013].

Table 1: Values of x and y for different kinds of IDMT characteristics.

Type	x	y
Standard inverse (SI)	0.02	0.14
Very inverse (VI)	1	13.5
Extremely inverse (EI)	2	80

Objective function to be minimized can be formulated as in (2) subject to satisfying all the constraints:

$$Minimize\ OT = \sum_{i=1}^{N} \sum_{j=1}^{M} \left(T_{p_{ij}} + T_{b_{ij}} \right).W_i \tag{2}$$

where N is the total number of relays; M is the total number of fault locations; i is relay identifier; j is the fault location identifier; $T_{p_{ij}}$ is the primary relay operating time; $T_{b_{ij}}$ is the backup relay operating time; W_i is the weight factor for line length. W_i is assumed 1 considering all lines as short and of equal length.

Constraints of the problem are given as below: [Zeineldin *et al.,* 2006]

i. Coordination criterion: $T_b - T_p > CTI$ (3)

CTI is the coordination time interval. Typically CTI values are taken as 0.2 sec.

ii. Bounds on relay settings: $TDS_{min} \leq TDS \leq TDS_{max}$; (4)

TDS_{min} and TDS_{max} are the lower and upper values of TDS. In a conventional electromechanical relay, the variation of TDS becomes discrete. But in today's digital relay, TDS may vary smoothly within a small range of values.

iii. Limits on relay operating time: $T_{min} \leq T \leq T_{max}$; (5)

T_{max} and T_{min} are the upper and lower limits of the relay operating times, respectively.

iv. Limits of pickup currents: $I_{p_{min}} \leq I_p \leq I_{p_{max}}$ (6)

$I_{p_{min}}$ and $I_{p_{max}}$ are the lower and upper limits of the pickup current. In a conventional electromechanical relay, the variation of *Ip* becomes discrete. But in today's digital relay, *Ip* may vary continuously within a small range.

In conventional electromechanical relays both the relay settings, *TDS* and I_p, are discrete. Continuous settings are available with digital relays.

B. Protection coordination in a distribution system including DER power Injection

In the existing power system, conventional sources are mainly used. To limit the abandon use of natural resources, renewable energy-based small DERs are being installed. But solar or wind energy-based generators mainly depend on weather, and operators do not have any control over them. So, when power is available from these sources, use of conventional sources can be reduced to some extent subject to satisfaction of the protection and stability issues. Fault current magnitude and direction may vary anywhere in the system owing to DER or distributed generation (DG) injection. So, conventional protection coordination may fail.

Due to DG inclusion, fault current analysis needs modification in the formulation part. Formulation of the objective function can be done similarly as the earlier one, i.e., minimization of the sum of the total operating time of all the primary and backup relays. However, the calculation of short circuit current in presence of DG injection involves more computational burden than earlier. Operating time (T_{DG}) of a relay in presence of DG can be expressed as (7).

$$T_{DG} = \left(\frac{y}{\left(\frac{I_{fdg}}{I_{pdg}} \right)^x - 1} \right) .TDS_{dg} \tag{7}$$

where I_{fdg} is the total short circuit current contribution in the system including DG power injection.

$$I_{fdg} = \left(I_{fault} \times Op.\text{mode} \right) + \sum_{i=1}^{ndg} I_{dg} \times st.bit_{dgi} \tag{8}$$

I_{fault} is the short circuit current contribution in the conventional system without DG insertion.

Op. mode is used to represent whether DG is connected to normal grid-connected mode (*Op. mode*= 1) or islanding mode (*Op. mode* = 0). n_{dg} is the total number of DGs connected the system, I_{dg} is the maximum fault current contribution due to DG, and $St.bit_{dgi}$ is used to represent the DG connection status. If DG is ON, $St.bit_{dgi}$ is '1', otherwise, $St.bit_{dgi}$ is '0'.

With DG ON, direction and magnitude of I_{fdg} can be calculated before the occurrence of a fault. T_{DG} of a relay is the function of fault current, time dial setting, and pickup current setting in presence of DG. Mathematically, T_{DG} can be expressed as (9).

$$T_{DG} = f\left(I_{fdg,} TDS_{dg,} I_{p_{dg}} \right) \tag{9}$$

where TDS_{dg} and $I_{p_{dg}}$ are the new settings of *TDS* and I_p in the new environment.

Objective function remains the same as mentioned in (2). Relay coordination constraints are the same as discussed in section (A).

IMPLEMENTATION OF PROPOSED ADAPTIVE ALGORITHM

To sustain the relay coordination problem due to the installation of DERs or DGs, proposed online adaptive relaying algorithm needs to be integrated into the computers of SCADA control unit. Once a DG(s) is feeding power, system operator receives instant information of that, from advanced devices. Steps of the proposed algorithm are given below:

Step I: Receive input data, i.e., operating status of connected DGs, existing relay settings, etc.

Step II: Adjust the bus type of connected DG, PV, or PQ bus.

Step III: Perform load flow analysis.

Step IV: Perform the short circuit analysis considering fault at all the buses.

Step V: Set the limit values of *TDS* and I_p.

Step VI: For applying SOS optimization technique, select initial ecosystem, i.e., relays parameters, the size of the ecosystem (number of organisms), convergence criteria, and design variables considering constraints.

Step VII: Identify the fittest organism.

Step VIII: Calculate optimal relay settings following mutualism phase, commensalism phase, and Parasitism Phase.

Step IX: Calculate fitness value and reject/accept the modified organism based on the fitness value.

Step X: Follow the step **VII** if the current organism is not the last organism in the ecosystem.

Step XI: Receive the optimal value of relay settings if convergence criterion is satisfied, else, move to step **VII**.

Step XII: Compare the new settings with the existing one and check whether any change is required in the existing system or not.

Step XIII: Send a signal to do the corresponding changes in the relay settings of the system.

Flowchart of the proposed algorithm is given in **Fig.1**.

SYSTEM INVESTIGATED

Wind energy is the most recent development among other renewable, which is present throughout the day free of cost. The recent development of wind energy conversion system attracts the use of Doubly Fed Induction Generator (DFIG) based wind farms.

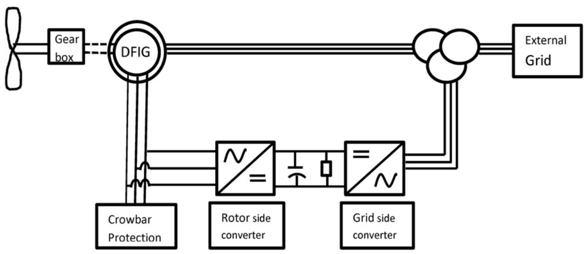

Fig. 1. Grid connected DFIG based wind energy system.

Fig. 1 shows the basic arrangement of a DFIG based wind farm. The induction generator (IG) and wind turbine are connected via a mechanical shaft system, consisting of a low-speed and a high-speed shaft. A gearbox is connected in between them. The IG is fed from both the stator side and the rotor side. Stator of the IG is joined to the grid directly, whereas a variable frequency convertor (VFC) is used to feed the rotor. To provide quality power (constant voltage and frequency) at the grid end, power flow needs to be controlled between the rotor circuit and the grid both in magnitude and in direction. VFC consists of two converters (a rotor-side converter (RSC) and a grid-side converter (GSC)) linked end-to-end by a dc-link capacitor. During transient conflicts, to protect RSC from over-current producing inside the rotor circuit, a crow-bar circuit is connected. The controlling process of DFIG is done by VFC, i.e., controlling of RSC and GSC.

The target of this paper is to propose an online adaptive algorithm to determine optimal relay settings in order to reduce the total relay operating time (primary and backup relays) in a distribution system including DER power injection subject to satisfaction of constraints under different topological conditions. The objective function is formulated in terms of relay settings: *TDS* and I_p. Relays with standard inverse characteristic are considered. In this work, authors have considered DFIG based DERs to study its effect on protection studies. Inverter-based DER units have less effect on fault current levels (fault current levels are approx. 1 p.u.), the short circuit contribution of inverter-based DER unit is ignored by modeling the inverter-based DG as an open circuit in the fault analysis, and synchronous-based DER units are modeled using the sub-transient reactance. Fault analysis in presence of DFIG based DER is done similar to fault study of induction motors.

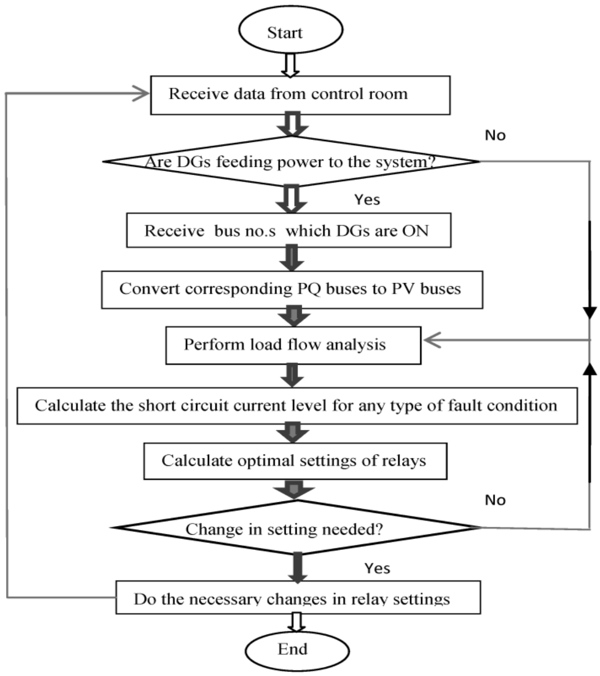

Fig. 2. Flowchart of the proposed algorithm.

MATLAB coding is developed for steady-state analysis, fault analysis and for relay coordination using SOS optimization technique. Fault Analysis is performed considering bolted fault on all the buses.

RESULT SECTION

The single-line diagram of the IEEE 14-bus distribution system is shown in **Fig. 3**. The detailed data for the IEEE 14-bus test system has been obtained from Saleh *et al.*, 2015; washington.edu. The study has been done on IEEE 14-bus system, which consists of both transmission and distribution part. DERs are installed at low voltage buses of the distribution system. For this reason, from IEEE 14 buses only the low voltage buses (≤ 33kv) have been considered for DER installation and the rest were neglected. The number of low voltage buses is 7. The low voltage part of the IEEE 14 bus system is called IEEE14-bus distribution system. The distribution system is fed through two 60 MVA, 132 kV/33 kV transformers connected at buses 1 and 2. 4.25 MW DFIG farm is connected through 480 V/33 kV step-up transformers. The system is equipped with 16 directional over-current relays (R_1, R_2, ----- R_{16}), two on each side of a line. DERs can be connected at 5 buses having 32 combinations.

SOS optimization technique is adopted for finding optimal relay settings in order to get reduced total relay operating time (primary and backup relays) subject to satisfaction of coordination and boundary constraints for every combination. Relay coordination is simulated for all the possible combinations of IEEE 14-bus distribution system with DGs. To coordinate all relays, settings of all the sixteen relays are to be optimized. Consequently, there are 32 decision variables; i.e., TDS_1 to TDS_{16} and I_{p1} to I_{p16} are considered for IEEE 14-bus system. Primary and backup relay coordination pairs for different fault locations are shown in **Table 2**.

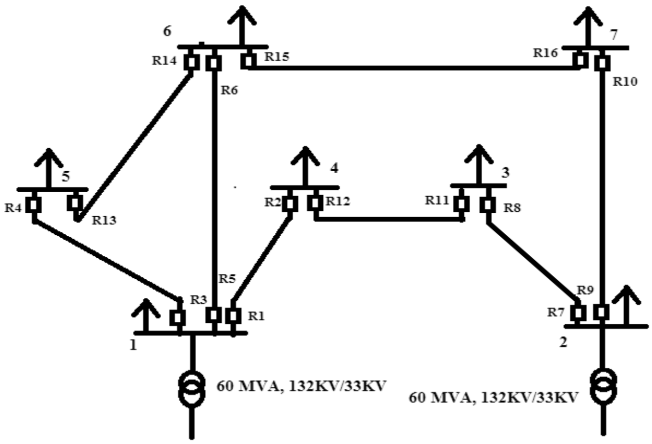

Fig. 3. IEEE 14 bus Distribution System.

Table 2. Relay coordination pair.

Fault point	Primary Relay	Backup Relay	
Bus 1	R_1	R_4	R_6
	R_3	R_2	R_6
	R_5	R_2	R_4
Bus 2	R_9	R_8	
	R_7	R_{10}	
Bus 3	R_8	R_{12}	
	R_{11}	R_7	
Bus 4	R_{12}	R_1	
	R_2	R_{11}	
Bus 5	R_4	R_{14}	
	R_{13}	R_3	
Bus 6	R_6	R_{13}	R_{16}
	R_{14}	R_5	R_{16}
	R_{15}	R_5	R_{13}
Bus 7	R_{10}	R_{15}	
	R_{16}	R_9	

Three-phase symmetrical short-circuit currents have been calculated for a fault at all the buses for different combinations:

Case I. When no DER is present in the system

In the test system, steady state voltage and currents are tabulated in **Table 3 and Table 4**. Fault study has been done at all the buses shown in **Table 5**. Optimal values for *TDS* and I_p using SOS without considering DER power injection are calculated based on steady-state and minimum fault currents. Based on the optimal values of *TDS* and I_p, operating times of primary and backup relays are calculated. Relay settings (*TDS,* I_p), T_p *and* T_b all are tabulated in **Table 6**. Calculated values of TDS_{min}, TDS_{max}, $I_{p_{min}}$ *and* $I_{p_{max}}$ are 0.0150s, 0.1590s, 0.0884 p.u., and 0.5823 p.u. respectively. Average values of T_p *and* T_b are obtained as 0.1521s and 0.4211s, respectively.

Table 3. Bus voltages in IEEE 14-bus distribution system.

Bus	**Voltage (pu)**	**Angle (°)**
1.	1.07	0
2.	1.0685	-7.2165
3.	1.0636	-6.3461
4.	1.0624	-3.4189
5.	1.0624	-1.4346
6.	1.0575	-2.0675
7.	1.0517	-6.1546
8.	1.09	-6.6753

Table 4. Steady-state line currents in IEEE 14-bus distribution system.

Bus to	**Bus from**	**Line current (p.u.)**
1	4	0.2907
1	5	0.0978
1	6	0.2763
8	2	0.2162
2	3	0.1876
3	4	0.26
2	7	0.0865
6	7	0.1945
5	6	0.0426

Table 5. Fault currents in IEEE 14-bus distribution system without any DG penetration.

Fault point	**From bus – to bus**							
Bus	2 - 3	1 – 4	1 – 5	1 – 6	2 – 7	3 – 4	5 - 6	6 - 7
1		1.0355	0.1636	0.5488				
2	1.233				0.7879			
3	3.01					1.495		
4		2.443				1.773		
5			1.97				1.4345	
6				2.81			1.77	3.98
7					1.92			1.409

Table 6. When no DER is ON- relay settings (*TDS*, I_p), primary and backup relay operating time in seconds.

Relay	***TDS (Sec)***	I_p***(p.u.)***	**Primary Relay operating Time *(Sec)***	**Backup Relay operating Time*(Sec)***
1	0.1024	0.5814	0.1504	0.4999
2	0.0209	0.5819	0.1005	
3	0.1253	0.2995		0.4567
4	0.0152	0.2162	0.1400	
5	0.0150	0.5823		0.4727
6	0.0275	0.5526	0.1163	
7	0.1590	0.4354	0.1836	0.4643
8	0.1081	0.4684	0.1999	0.4774
9	0.0656	0.2274	0.1365	0.3187
10	0.0280	0.2740	0.1917	0.4836
11	0.0548	0.5269	0.1638	0.3123
12	0.1561	0.5200	0.1799	0.4232
13	0.1104	0.0903	0.1718	0.3639
14	0.1290	0.0884	0.1208	0.3151
15	0.0812	0.3892	0.1309	0.4361
16	0.0826	0.3890	0.1440	0.4506
Objective function				7.6046
Elapsed time in seconds				0.061552

Case II. When Single DER is present in the system (at buses 3, 4, 5, 6, and 7, one at a time)

Single DER is connected to the system at a time. Fault current in all the lines has been calculated considering fault at all the buses separately. Steady-state load current and fault currents have been tabulated for all the lines. Maintaining all the limits and constraints, SOS optimization technique is applied to find optimal values of relay settings (*TDS* and I_p). From these optimal values of *TDS* and I_p, relay operating times (primary and backup) are calculated. For example, the values of steady-state load current and fault current in line 1-4 are shown graphically in **Fig. 4**. It is found from **Fig. 4** that pickup current settings of relay R_1 and R_2 of line 1 - 4 are in between load current and minimum fault current for the optimal operating time. **Table 7** shows the actual values of *TDS* and I_p in presence of single DER in the system at various locations. At no DER condition, I_p setting of R_1 is 0.5814 p. u., which is in between steady-state load current (0.2907 p. u.) and minimum fault current (1.0355 p. u.). Similarly, I_p setting of R_2 is 0.5819 p. u. When DER at bus 3 is in ON condition, I_p setting of R_1 is 0.5272, which is in between steady-state load current (0.2596 p. u.) and minimum fault current (2.175 p. u.).

Similarly, I_p setting of R_2 is 0.5216 p. u. Average values of load current, fault current, I_p setting of R_1 and R_2 are 0.27535 p. u., 1.59945 p. u., 0.55056 p. u., and 0.53692 p. u., respectively.

Table 7. Values of *TDS* (Sec) and I_p (p.u.) in presence of single DER in the system.

Relay	DER at bus 3		DER at bus 4		DER at bus 5		DER at bus 6		DER at bus 7	
	TDS (Sec)	I_p *(p.u.)*	*TDS (Sec)*	I_p *(p.u.)*	*TDS (Sec)*	I_p *(p.u.)*	*TDS (Sec)*	I_p *(p.u.)*	*TDS (Sec)*	I_p *(p.u.)*
1	0.1908	0.5272	0.0387	0.5072	0.0678	0.5875	0.0768	0.5777	0.1655	0.5532
2	0.2814	0.5216	0.1419	0.5267	0.1725	0.5823	0.0852	0.5314	0.1287	0.5226
3	0.2562	0.1910	0.1618	0.1982	0.2757	0.2186	0.1243	0.1882	0.1146	0.2439
4	0.0804	0.1996	0.0612	0.2031	0.2414	0.3726	0.0255	0.2770	0.0915	0.1804
5	0.1258	0.5918	0.0823	0.5014	0.1983	0.5140	0.1672	0.5152	0.1081	0.5195
6	0.1949	0.5493	0.1000	0.5108	0.1751	0.5673	0.2884	0.4999	0.1991	0.5289
7	0.1003	0.4793	0.1122	0.4052	0.1676	0.4702	0.0733	0.4324	0.1417	0.4369
8	0.2804	0.4145	0.0324	0.3258	0.2200	0.4657	0.2802	0.4604	0.0422	0.3841
9	0.0445	0.4263	0.0469	0.1945	0.0301	0.2771	0.1571	0.2263	0.0172	0.3143
10	0.0172	0.4747	0.1290	0.1762	0.0934	0.2854	0.0714	0.2699	0.1537	0.3757
11	0.0854	0.3103	0.0948	0.5003	0.1775	0.5452	0.0624	0.5196	0.0196	0.4996
12	0.1152	0.3716	0.1209	0.5540	0.1276	0.5102	0.1424	0.5998	0.0418	0.4926
13	0.2255	0.3745	0.1128	0.4861	0.1972	0.2276	0.0264	0.2294	0.1182	0.2375
14	0.1402	0.3441	0.2132	0.0826	0.1167	0.2840	0.2182	0.1702	0.2194	0.2197
15	0.1111	0.3724	0.1780	0.3993	0.1739	0.3792	0.1159	0.3972	0.1657	0.3981
16	0.1737	0.4623	0.1239	0.4203	0.1859	0.4307	0.0736	0.4413	0.1743	0.3487

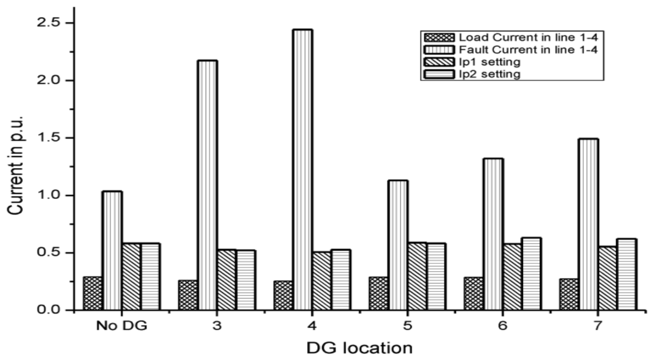

Fig.4. Variation of current setting with DER location for Relays 1 & 2.

Case III. When two DERs are present in the system (at buses 3&4, 4&5, 5&6, 6&7, 7&3, 3&5, 3&6, 4&6, 4&7, and 5&7)

Two DERs are being in ON condition in the system at a time. Fault currents are calculated considering fault at all the buses separately. Steady-state load current and fault current has been tabulated for all the lines. Maintaining all the limits and constraints, SOS optimization technique is applied to find optimal values of relay settings (*TDS* and I_p). From these optimal values of *TDS* and I_p, relay operating times (primary and backup) are calculated. For example, the values of steady-state load current and fault current in line 1- 4 for different DERs at two buses are shown graphically in **Fig. 5**. It is found from **Fig. 5** that pickup current settings of relays R_1 and R_2 of line 1 - 4 are in between load current and minimum fault current for the optimal operating time. **Table 8** shows the actual values of *TDS* and Table 6 shows actual I_p values in the presence of two DERs in the system at various locations. When DERs of bus 3 and bus 4 are in ON condition, I_p setting of R_1 is 0.5432 p. u., which is in between steady-state load current (0.2218 p. u.) and minimum fault current (2.634p. u.). Similarly, I_p setting of R_2 is 0.4534p.u. Average values of load current, fault current, I_p setting of R_1 and R_2 are 0.25375 p. u., 2.3001 p. u., 0.56812 p. u., and 0.53792 p. u., respectively.

Case IV. When three DERs are present in the system(at buses '3,4,5', '4,5,6', '5,6,7', '6,7,3', '7,3,4', '3,4,6', '3,5,6', '3,5,7', '4,6,7', and '4,5,7')

When three DERs are in ON condition at a time in the system, load current, fault current, and optimal values of *TDS* and I_p are calculated. Average values of TDS_1, TDS_2, TDS_3, TDS_4, and TDS_5 are 0.16305s, 0.13983s, 0.129s, and 0.13499s, respectively. $I_{p_{min}}$ *and* $I_{p_{max}}$ are 0.1749 p. u. and 0.6395 p. u., respectively. For a fault at bus 1, when DERs of buses 4, 5, and 6 are ON, R_1, R_3 and R_5 take 0.1733s, 0.1314s, and 0.168 s as primary protection relay. If they fail to operate R_2, R_4 and R_6 take 0.386s, 0.4201s, and 0 .7412s, respectively. At that time, corresponding CTI values are greater than 0.2 sec.

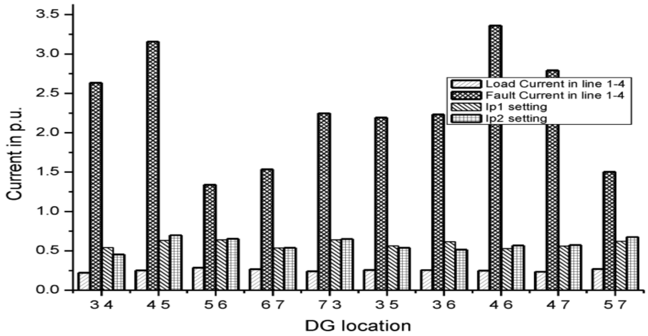

Fig. 5. Variation of current setting with DER location for Relays 1 & 2.

Case V. When four DERs are present in the system (at buses '3, 4, 5 & 6', 'bus 4, 5, 6 & 7', 'bus 5, 6, 7 & 3, 'bus 6, 7, 3 & 4', and 'bus 7, 3, 4 & 5')

When four DERs are in ON condition at a time in a different combination in the system, load current, fault current, and optimal values of *TDS* and I_p are calculated. From this optimal relay settings, optimum operating time of relays are also calculated. For example, for a fault at bus 5, when DERs of bus 3,4,5 and 6 are ON, R_4, and R_{13} take 0.1009s and 0.1378s as primary protection relay. If they fail to operate R_{14} and R_3 take 0.4121s and 0 .4837s, respectively. In this case, CTI values are 0.3112s and 0.3459s, respectively.

Table 8. Values of *TDS* (Sec) in presence of double DERs in the system.

DG location	3&4	4&5	5&6	6&7	7&3	3&5	3&6	4&6	4&7	5&7
Relay										
1	0.0631	0.1994	0.0815	0.0988	0.2718	0.0760	0.1697	0.1396	0.1816	0.1692
2	0.1726	0.1547	0.1542	0.2202	0.2842	0.1168	0.1242	0.1777	0.1845	0.2050
3	0.1151	0.0394	0.1194	0.1385	0.1038	0.0792	0.1113	0.0985	0.0468	0.0194
4	0.1439	0.1318	0.0812	0.0386	0.1750	0.1946	0.0518	0.1559	0.2078	0.1968
5	0.1556	0.0150	0.0698	0.1676	0.3398	0.1846	0.2526	0.2779	0.1695	0.0490
6	0.0270	0.3017	0.1849	0.0837	0.0763	0.1981	0.1855	0.1605	0.3838	0.0251
7	0.3034	0.1234	0.0877	0.0621	0.0671	0.0260	0.2443	0.2340	0.1670	0.0805
8	0.1378	0.1573	0.0603	0.1176	0.3031	0.2947	0.2019	0.0203	0.2144	0.1875
9	0.1699	0.0340	0.2434	0.0300	0.1432	0.0200	0.0997	0.1175	0.0777	0.1287
10	0.0517	0.0537	0.1308	0.0697	0.1595	0.0349	0.0498	0.0469	0.1017	0.2208
11	0.1280	0.2603	0.1155	0.1460	0.1694	0.2596	0.2331	0.0399	0.2505	0.2067
12	0.1651	0.1882	0.2778	0.0798	0.2062	0.1962	0.0515	0.0988	0.1677	0.2144
13	0.0863	0.1416	0.3700	0.1586	0.1799	0.1245	0.2638	0.1968	0.1111	0.0822
14	0.1435	0.0150	0.3341	0.0974	0.1884	0.0715	0.1228	0.1836	0.2993	0.3045
15	0.2780	0.0393	0.1733	0.1848	0.0848	0.1200	0.2934	0.1234	0.2809	0.0784
16	0.0966	0.1946	0.0655	0.1277	0.0325	0.2982	0.1214	0.1635	0.1719	0.2003

Table 9. Values of I_p (p. u.) in presence of double DGs in the system.

DG location	3&4	4&5	5&6	6&7	7&3	3&5	3&6	4&6	4&7	5&7
Relay										
1	0.5432	0.5680	0.6395	0.5476	0.5397	0.5639	0.6161	0.5331	0.5589	0.5712
2	0.4534	0.5998	0.6027	0.5378	0.5505	0.5395	0.5163	0.5167	0.4749	0.5876
3	0.2039	0.2318	0.1749	0.1705	0.4961	0.1782	0.2502	0.2718	0.1819	0.2233
4	0.1950	0.3227	0.2742	0.1839	0.4409	0.2324	0.1777	0.2607	0.2442	0.3243
5	0.5224	0.5647	0.5246	0.4449	0.1409	0.5741	0.5212	0.5334	0.5354	0.5932
6	0.5350	0.5126	0.5102	0.4262	0.1848	0.6094	0.4728	0.5240	0.5722	0.6457
7	0.4500	0.3958	0.4109	0.3850	0.4475	0.4376	0.4478	0.3937	0.4190	0.4079
8	0.4190	0.3888	0.4019	0.3429	0.4239	0.4544	0.4544	0.4225	0.4155	0.4220
9	0.2857	0.2219	0.3201	0.2615	0.2422	0.1739	0.1967	0.2245	0.2093	0.3126
10	0.1493	0.1746	0.2576	0.2697	0.2706	0.1881	0.2494	0.1843	0.2122	0.3708
11	0.5471	0.6104	0.5758	0.5154	0.4476	0.4739	0.5034	0.6096	0.5475	0.5617
12	0.5248	0.6178	0.5774	0.4964	0.4320	0.5341	0.4895	0.5895	0.5565	0.5860
13	0.1715	0.2173	0.2243	0.1763	0.1017	0.3635	0.1586	0.1806	0.1433	0.1824
14	0.1846	0.2700	0.2753	0.0911	0.1886	0.1794	0.1859	0.2054	0.1869	0.1530
15	0.3615	0.4266	0.4849	0.3921	0.3186	0.4409	0.3950	0.4335	0.3459	0.4668
16	0.4301	0.4002	0.4440	0.4432	0.3192	0.4396	0.4353	0.4842	0.4183	0.4033

Case VI. When DGs are present in all the load buses

When all the connected DGs are in ON condition, optimal values of relay parameters (*TDS* and I_p) have been calculated. From these optimal values of *TDS* and I_p, operating times of all the individual relays have been calculated. Relay parameters are found within their limits. Calculated operating times of primary and backup relay are also acceptable. CTI values satisfy the coordination criterion.

Table 10. When all the connected DERs are ON- relay settings (*TDS*, I_p), primary and backup relay operating time in seconds.

Relay	*TDS (Sec)*	I_p *(p.u.)*	Primary Relay operating Time *(Sec)*	Backup Relay operating Time *(Sec)*
1	0.1008	0.2237	0.1241	0.5323
2	0.1590	0.4354	0.1505	
3	0.0656	0.2274		0.3507
4	0.0152	0.2162	0.1400	
5	0.0312	0.3892		0.3720
6	0.0826	0.3890	0.2240	
7	0.1590	0.4354	0.1836	0.4643
8	0.3081	0.4684	0.1299	0.4774
9	0.0656	0.2274	0.1365	0.5187
10	0.0280	0.2740	0.1317	0.4836
11	0.0548	0.5269	0.1638	0.4323
12	0.1561	0.5200	0.1799	0.5232
13	0.1590	0.4354	0.1836	0.4643
14	0.1081	0.4684	0.1908	0.4774
15	0.0548	0.5269	0.1638	0.5123
16	0.1561	0.5200	0.1799	0.4232
Objective function				8.3138
Elapsed time in seconds				0.061552

Comparison between Case I, Case II, and Case VI

Case I: No DG case is the original distribution system where DG penetrations are not considered. At this environment optimal values for *TDS* and I_p are calculated and based on the optimal values of *TDS*, I_p, T_p *and* T_b all are tabulated in **Table 6**.

Case II: When single DER is connected to the system at a time, optimal values of relay settings (*TDS* and I_p) are tabulated in **Table 7**.

Case VI: When DERs are present in all the load buses, relay parameters and operating times are calculated and tabulated in **Table 10**. Say, at any instant there was no DER in the system, *TDS* and I_p settings of R_1 are 0.1024 and

0.5814 (**Table 6**). After some time if DER at bus 3 is ON, *TDS* and I_p settings of R_1 will be 0.1908 s and 0.5272 p u. (**Table 7**) and R_1 will take 0.1148s to operate. Immediately if DER at bus 4 also becomes ON, changed settings of R_1 will be 0.0631s and 0.5432 p. u. (**Tables 8** and **9**) and it will operate taking 0.1166s. Now if DER at bus 3 becomes OFF, settings of R_1 will be changed to 0.0387s and 0.5072 p. u. and it takes 0.1214s to operate. If all the connected DGs become ON, *TDS* and I_p settings of R_1 will be 0.1008 s and 0.2237 p u. (**Table 10**) and R_1 will take 0.1241s to operate. When the system shifted from Case I to Case II minimum changes are observed as only one DER is delivering power to the system, whereas when shifted to Case VI, as maximum amount of DG penetration occurs less amount of power is received from the substation feeders.

All these changes will be taken care of properly by the proposed online adaptive algorithm. Adaptation in setting change occurs whenever there is any change in DG power injection.

The performance of Symbiotic Organism Search (SOS) algorithm in DOR coordination computation with other metaheuristic algorithms, PSO and TLBO, is compared. SOS already proved its ability to provide a better result in terms of objective function value, number of functions evaluated [Saha *et.* al 2016]. Apart from the quality of the solution, time is also an important issue for any kind of optimization technique. From Table 11 it is shown that SOS takes 0.061552 s, 0.061957s, 0.084387s, 0.083510 S, 0.087990 S, and 0.072807 S to reach the optimal solution, which is sufficient to adjust the relay settings. Initialization of ecosystem in SOS is performed using some random numbers like other stochastic optimization techniques. Due to this randomness, to judge the robustness of the algorithm, with ecosize 20, programs have been run for 25 individual trials for all the case studies. In case of Cases I to VI, it reaches a minimum objective function value 24 and 23 times out of 25 times. The success rate is 96% and 92%. From the comparative study, it is clear that the proposed algorithm with SOS has the ability to provide a quality solution in less time.

Table 11. Comparison among different test cases.

Parameters	**Case I – No DG**	**Case II –DG at bus 3**	**Case III –DG at bus 4 & 5**	**Case IV- DG at 3, 4 &5**	**Case V- DG at 3, 4, 5 &6**	**Case VI -DG at 3,4,5,6,& 7**
Objective function	7.6046	11.058	9.7696	13.1121	10.9584	8.3138
Elapsed time	0.061552	0.061957	0.084387	0.083510	0.087990	0.072807
No. of hits to the minimum solution	23	24	24	23	23	24
Robustness index	92%	96%	96%	92%	92%	96%

CONCLUSION

With the frequently changing scenario of seasonal DERs, at different topological conditions in distribution system line current varies during a fault. This paper has proposed a new adaptive protection scheme for optimal relay coordination at different topologically varying conditions. In the proposed scheme, SCADA system receives the working status of DGs and does the online calculation for finding optimal values of relay settings, identifying whether any change is required in the existing relay settings or not and accordingly communicates a signal to do the corresponding changes in the protective system.

The proposed adaptive algorithm is a unique protection scheme in terms of its reliability, accuracy, and widespread attention to all actions, which can empower the protection system.

A newly published efficient nature inspired SOS optimization technique is applied for finding optimum values of *TDS* and I_p settings of DORs, which is till now new to protection engineering. Optimum protection coordination is tested in IEEE 14-bus distribution system incorporating renewable energy based distribution generators. Simulation results validate the effectiveness of the proposed algorithm.

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خطة حماية تكيفية عبر الانترنت لشبكة التوزيع الكهربائية ذات الاختراق العالي لمصادر الطاقة المتجددة

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الخلاصة

إن دمج مصادر الطاقة الموزعة (DERs) في شبكات توزيع الطاقة يجعل النظام مترابطاً وحيوياً. وجود DER مع قدرة توليد متغيرة في مواقع مختلفة يحول مشكلة تنسيق الحماية (PCP) إلى مشكلة صعبة للغاية.

في هذا البحث، يقترح الباحثون خطة حماية تكيفية عبر الإنترنت تعتمد على تنسيق الترحيل لمعالجة PCP، عندما تخترق المولدات الموزعة المعتمدة على الطاقة المتجددة القدرة في النظام باستخدام المولدات التقليدية. تعتبر المرحلات الاتجاهية للتيار الزائد (DORs) أحد العناصر الرئيسية لمخططات الحماية في أنظمة الطاقة. تمت صياغة PCP كمشكلة برمجة غير خطية مع DORs لمجموعات التشغيل المختلفة. تستخدم الخوارزمية التكييفية تقنية تحسين منشورة جديدة وهي "البحث عن الكائنات الحية المترابطة" (SOS) المثبتة في أجهزة الكمبيوتر SCADA. تم ترميز البرنامج في MATLAB للعثور على الإعدادات المثلى لمعلمات الترحيل، وإعدادات وقت الطلب (TDS) وإعدادات التوصيل (I_p) الحالية، والتي توفر الحد الأدنى من وقت التشغيل أثناء أي خطأ. تم التحقق من القدرة التشغيلية للخوارزمية على 14 حافلة بنظام توزيع IEEE من خلال تغيير ترتيبات توليد DER في تركيبات مختلفة.

وفي كل مرة يحدث فيها تباين طفيف في مستوى فشل التيار في النظام، قد يكون ناتجاً عن التباين في معلمات خطية أو دمج بيانات DER الجديدة، يتم إرسال إعدادات الترحيل الجديدة إلى المرحلات المقابلة. مخطط الحماية المقترح مرن للغاية للحفاظ على تنسيق الحماية بين DORs، مع الحفاظ على هامش تنسيق موثوق لكل زوج من التتابع الأساسي / الاحتياطي لكل مجموعة.