

RESEARCH ARTICLE

An Adaptive Overcurrent Coordination Scheme Withstanding Active Network Operations

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ABSTRACT This paper aims to present a centralized adaptive protection scheme (APS) for the directional overcurrent relays (DOCRs) considering system dynamics such as load demand variations, topology changes and DGs to mitigate the above-mentioned effects. The scheme is suitable for different types of networks whether its radial or meshed. Afterall, it can determine the actual topology with the micro-PMUs and breaker status, automatically generate relay names accordingly with the topology bus locations, establish protection coordination pairs, coordinate DOCRs for parallel lines, identify transformers to offer backup operation for differential protection, perform load flow and fault studies, execute contingency and sensitivity analysis, and lastly, coordinate the DOCRs using differential evolution algorithm so that they always have the proper settings to operate in appropriate time providing selectivity. The performance of the proposed centralized adaptive overcurrent protection scheme is tested on the highly meshed IEEE 14 bus system. The proposed scheme has shown that it can adequately consider impacts of system dynamics and DG.

INDEX TERMS Adaptive protection, differential evolution algorithm, directional overcurrent relay, distributed generation, protection coordination.

I. INTRODUCTION

Power-hungry cities have widely spread out worldwide for the past century. Combating global warming and reducing fossil tracks have become meaningful for first-class nations and climate activists in seek of sustainable future. Ever growing power hunger habit of societies for achieving greater economic growth and quality of life, have driven researchers and governments to explore natural and renewable energy resource generations. Hence, development and integration of renewable energy distributed generations (DGs) in the sub-transmission and distribution networks has become priority target for many countries in the past decades.

A. LITERATURE REVIEW

DGs offer multiple benefits for power network such as: voltage profile support, line and transformer congestion relief, power loss reduction [1]. However, DGs also brought challenges to network protection units, such as possible upper

voltage profile violation [2], fault current variation, bidirectional load flow in radial lines [3], [4], [5], [6], [7], increase of load flow variations due to maximum/minimum load conditions and maximum/minimum renewable energy generation intermittency. These challenges cause new problems for the overcurrent relay (OCR) protection, which may eventually malfunction for the numerous power operating conditions [3], [4], [5], [6], [7], [8], [9], [10], [11], [12].

Apart from the different challenges brought by the virtuous DGs which alters the system operation and topology, modern system's dynamic operating conditions are always changing. Some conditions are network reconfiguration [10], [11], [12], optimal dispatch and consumption [13], optimal dispatch and reserve scheduling [14], dispatch for islanded microgrid [15], optimal reactive power dispatch [16], demand response [17], optimal dispatch of large-scale electric vehicles [18], maintenance and contingency.

The typical routine procedure for coordinating the overcurrent protection is executed on the main topology via offline. However, the routine procedure is to consider boarder or worst conditions that all electrical elements are active such as

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generators, lines and transformers. Which is not appropriate since topology changes due to contingency or planned dispatch scenarios as previously mentioned [10], [11], [12], [13], [14], [15], [16], [17], [18].

Consequently, fault current magnitudes fluctuate as the electrical elements varies. Hence, possible prolonged fault clearance time and shrunk equipment lifespan for smaller fault currents. On the contrary, possible miscoordination may appear if fault currents increase. Hence, distinct literatures have proposed to include multiple topologies when performing protection coordination [19], [20]. The prejudice of considering multiple topologies for coordination is the increased computation time to optimize all constraints (that is, if constraints can all be fulfilled since not all constraints can be fulfilled simultaneously), elevated protection coordination complexity, and handling bigger dial to fulfill selectivity constraints (which prolong fault clearance time). Therefore, pre-processing and reduction of coordination constraints have been proposed [21], [22].

Therefore, according to all the above-mentioned (offline conventional protection coordination, challenges due to DGs), the overcurrent protection needs to be shield against numerous operating conditions to avoid inappropriate relaying function. One of the many strategies to overcome the above-mentioned impacts is the proposal of adaptive protection scheme (APS), which may further enhance dependability or security requirements. Hence, several overcurrent APS have arisen aiming to solve this issue.

In [23], a proposal to adapt for prolonged service continuity in radial lines for overloading conditions based on adjusting technical and climate circumstance has surfaced. This proposal aims to collect and handle solar absorption, conductor temperature, emissivity and wind speed using a microprocessor that is hooked up with a relay. Since this focus on radial network, the literature commented that it does not need a central computer to perform the functions.

In [24], a proposal to obtain optimal coordination employing linear programming under the adaptive overcurrent protection principle has surfaced. The proposal will execute load flow study, optimize, send the new settings to relays. It employs Supervisory Control and Data Acquisition to monitor the network.

An adaptive overcurrent protection scheme is reported in [25] where it intends to partially overcome the effects due to DG penetration. This consists of verifying the CTI for the relays when DGs increase the fault current magnitudes. And only the relays what fail to comply CTI will be optimized again, avoiding the alteration of relays complying CTI. However, this proposal has reported that it is limited to low DG penetration for small increase of fault currents, that leads to small number of relays to mis-coordinate. Since relay coordination should be done including all relays simultaneously. Hence, it is difficult to coordinate a significant portion of relays not fulfilling coordination without alternating or losing coordination with the relays that fulfilled coordination.

These two groups may mis-coordinate among them if the increased DG fault currents are significant.

In [26], a proposal of grid connected and islanded mode operation employing adaptive overcurrent protection scheme is reported. Relays may not operate as fast as they were in grid connected mode due to the reduced fault currents if certain part of the network has to work in island mode. Hence, this proposal takes advantage of the storage capacity of the modern relays to store several setting groups and activate the appropriate setting group for islanded or grid connected mode using a state estimation algorithm. Therefore, the proposal is reported to get around this challenge of DG penetration for overcurrent relay devices in radial distribution lines.

Another proposal is reported in [27] which is an adaptive overcurrent protection that adjust the relay settings for peak and off-peak network conditions. In this proposal, Genetic Algorithm (GA) is used to previously coordinate the relays for peak and off-peak network conditions and save the different relay settings. Afterwards, SCADA is used to access existent load flow currents and analyze if the network is working on peak or off-peak status so that the adequate relay settings will be selected and shifted.

Proposals in [28], [29], [30], and [31] concentrates primarily on identifying islanding or grid connected operations including DG in radial network and perform overcurrent relay coordination employing Particle Swarm Optimization (PSO).

The authors in [31], [32], [33], [34], and [35] concentrates primarily on switching setting groups for the overcurrent relays on the present radial or meshed network considering DG. Hybrid Genetic Algorithm and Linear Programming (GA-LP), Clustering and LP are used to resolve and obtain setting groups. However, considering the different network topology and more constraints may lead to delayed protection speed. Moreover, countable setting groups may not optimally appease all network topology operating conditions.

Other adaptive overcurrent schemes without using optimization algorithms are presented in [36], [37], [38], [39], and [40] where the protective devices are reset based on look up table, multiagent systems and fundamental electrical circuit calculations. These proposals consider DG penetration but are employed for lower degree network complexity because of its original problem formation

Lastly, [41], [42], [43], [44] propose the adaptive overcurrent coordination with DG for meshed network employing Fuzzy Logic GA, Neural Network (NN), Ant Colony Optimization (ACO), Interior Point Method (IPM) and Differential Evolution (DE).

It is worth mentioning that there is a common opposition to the application of meta-heuristic and evolutionary optimization mainly in real-time systems or very short update time span (milliseconds or seconds). However, in the specific case of protection systems, the update time is during the stable state of the electrical system. For example, load variations can be updated in demand periods every 15 minutes. In case of a topology change, the update can take several minutes

TABLE 1. Comparative table of the existing and proposed APS.

	[24]	[27]	[34]	[26, 37]	[28]	[29, 31]	[32]	[33]	[38]	[25, 41-44]	Proposed
DG	--	--	--	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Radial (Grid or Island detection)	--	--	--	Yes	--	Yes	Yes	--	Yes	--	--
Interconnected	Yes	Yes	Yes	--	Yes	--	--	Yes	--	Yes	Yes
Use setting groups	--	Yes	Yes	Yes	--	Yes	Yes	--	--	--	--
Update load flow	Yes	Yes	--	Yes	Yes	--	Yes	Yes	--	Yes	Yes
Update fault magnitude	--	--	--	Yes	Yes	Yes	Yes	Yes	--	Yes	Yes
Communication Link	Yes	Yes	Yes	--	Yes	--	Yes	Yes	Yes	Yes	Yes
Identify transformers to offer backup operation	--	--	--	--	--	--	--	--	--	--	Yes
Parallel lines coordination	--	--	--	--	--	--	--	--	--	--	Yes
Forming relay names automatically	--	--	--	--	--	--	--	--	--	--	Yes
Establish coordination pairs automatically	--	--	--	--	--	--	--	--	--	--	Yes
N-1 contingency analysis	--	--	--	--	--	--	--	--	--	--	Yes
Sensitivity analysis	--	--	--	--	--	--	--	--	--	--	Yes

since no adjustment change is being made in the event of a fault where the relay must operate immediately. The protective relays allow the execution and verification times to be adequate for the application of electrical power system protection. A topology change will not cause mal operation of relays since N-1 contingency analysis has been included in the protection coordination stage. In [45], an algorithmic evaluation is presented where both the quality of the results and their impact on the protection scheme, as well as the statistical indicators of central tendency, have been verified. Hence, meta-heuristic and evolutionary algorithms are concluded to be reliable and capable for the protection coordination problem.

B. CONTRIBUTIONS

In this work, a centralized all-around adaptive protection scheme (APS) for the protective directional overcurrent relays (DOCRs) to confront active network operations (power flow, fault, topology changes and DGs) is proposed.

- The originality of the proposed APS regarding other proposals reported in the literatures is that it is suitable for different types of networks whether its radial or meshed.
- Afterall, it can determine the actual topology with the micro-PMUs and breaker status, automatically generate relay names accordingly with the topology bus locations, establish protection coordination pairs, coordinate DOCRs for parallel lines, transformers to offer backup operation for differential protection.
- The proposal also performs load flow and fault studies, execute contingency and sensitivity analysis, and lastly, coordinate the DOCRs using enhanced self-adaptive differential evolution algorithm so that they always have the proper settings to operate in appropriate time providing selectivity.

- This paper presents the computational structure that allows the APS to incorporate different relay adaptation alternatives. Updating the operating conditions of the electrical network allows the application of criteria such as dynamic restrictions that can be activated or deactivated, the incorporation of equipment protection schemes, such as transformer protection as part of the relay coordination solution.

A comparative table of the existing and proposed APS is presented in Table 1. The advantage of the proposal can be easily identified. With the proposal been able to a perform additional features such as, identifying transformers to offer backup operation, coordination of DOCRs on parallel lines, formation of relay names automatically, establishment of coordination pairs automatically, performing contingency and sensitivity analysis before optimizing and coordinating the protective DOCRs. These additional advantages make the proposal more attractive and unique compared to previously proposed schemes. Since the other proposals have not reported to perform these features.

II. COORDINATION PROBLEM FORMULATION AND OPTIMIZATION

A. COORDINATION PROBLEM FORMULATION

1) OBJECTIVE FUNCTION

$$\text{multi - objective functions} \begin{cases} OF_1 = \left(\sum_{i=1}^{NCP} t_{p,i} \right) \\ OF_2 = \left(\sum_{i=1}^{NCP} t_{b,i} \right) \\ OF_3 = \left(\sum_{L=1}^{NCP} E_{CTL} \right) \end{cases} \quad (1)$$

The objective function is established to minimize primary and backup operation times while maintaining coordination among protective relays. Hence, these parameters are all introduced in the multi-objective function and presented in (1).

where NCP represents the number of coordination pairs, $t_{p,i}$ represents the i -th primary relay tripping time, $t_{b,i}$ represents the i -th backup relay tripping time, and E_{CTI_L} represents the L -th CTI error. The Coordination Time Interval (CTI) error will help in searching for results complying the coordination restriction and optimizing the protective unit operation times to as close as the pre-specified CTI.

2) IEEE PROTECTION STANDARD EQUATION

The inverse time curve according to IEEE standard C37.112-1996 [46] is considered for protection coordination. This standard characteristic is presented in (2):

$$t_i = \left[\frac{A}{\left(\frac{I_{sc}^{3\phi}}{I_{pickup_i}} \right)^p - 1} + B \right] * dial_i \quad (2)$$

where $I_{sc}^{3\phi}$ is the three-phase fault current, A, B, p are the IEEE standard constants, t is the relay operation time, $dial$ is the time multiplier setting, and I_{pickup} is the pickup current setting. The index i indicates that the settings are for each relay.

3) CONSTRAINTS OF PICKUP AND TIME DIAL

Both settings pickup and time dial need to be controlled inside its respective superior and inferior limits. These constraints will warrant the optimized relay operations be feasible and correct for the protective devices and protected elements. Equations (3) and (4) present the inequality constraints:

$$dial_i^{min} \leq dial_i \leq dial_i^{max}; \quad i = 1 \dots NR \quad (3)$$

$$I_{pickup_i}^{min} \leq I_{pickup_i} \leq I_{pickup_i}^{max}; \quad i = 1 \dots NR \quad (4)$$

where NR is the number of relays, $dial$ is a physical tap changer of the electromechanical relay normally found between [0.5-10] but numerical relays will be considered in the study using continuous parameters settings which are the modern protective devices to be found in smart grid. I_{pickup} is calculated to give safety to the relay operation, its value must be higher than the maximum load current a factor of 1.5 to 2.0 is suggested in [47]. This setting will need to be set contemplating the temporal overloading scenarios.

4) COORDINATION CONSTRAINT

For correct tripping sequence among overcurrent protective units, either radial or meshed networks, a CTI is designated for all coordination pairs of relays. CTI is the intentional delay set for the backup relays to give primary relays a chance to extinct the fault. This is a necessary waiting time because several relays (primary and backup) may sense fault currents from different paths toward the same fault location which may cause possible simultaneous trips and

de-energize healthy lines and buses. Hence, a pre-specified time margin is designed to intentionally delay backup operations and consequently obtain tripping sequences among the different primary and backup relays for any possible fault. CTI is normally considered as 0.2 or 0.3 seconds which contemplates electro-mechanic relay disk over journey, circuit breaker opening time, and security margin. A 0.3 second CTI is set in this work according [47]. Therefore, when satisfying the CTI constraint for a coordination pair, the corresponding backup relay will trip when the corresponding primary relay for a certain fault fails to trip. The inequality constraint is given in (5):

$$CTI_L \leq t_{b,i} - t_{p,j} \quad \begin{cases} i = 1 \dots NR \\ j = 1 \dots NR \\ L = 1 \dots NCP \end{cases} \quad (5)$$

where CTI_L is the L -th coordination pair, $t_{b,i}$ and $t_{p,j}$ are the backup and primary operation time of the corresponding relays i and j , NR is the number of relays and NCP is the number of coordination pairs.

5) PROTECTION SENSITIVITY

Sensitivity, presented in (6), should be examined for each coordination pair. The overcurrent protection sensitivity can be evaluated to ensure that the backup relay will trip for two-phase short circuit situated on the remote line of the primary relay protection zone in acceptable time [47], [48].

$$sensitivity = \frac{I_{sc}^{2\phi}}{k * I_{load_{max}}} \quad (6)$$

where $I_{sc}^{2\phi}$ represents the two-phase short circuit of the backup unit, the product of k and $I_{load_{max}}$ determine the pickup current setting. Hence, constraint of sensitivity [49], is presented in (7):

$$sensitivity \geq 1.5 \quad (7)$$

where greater or equal to 1.5 is acceptable, and smaller than 1.5 would result in delayed tripping time or simply not trip at all. Therefore, whenever a coordination pair does not have enough sensitivity, alternative protection principle should be employed as complement [47].

An important idea is that as $I_{load_{max}}$ decreases and/or $I_{sc}^{2\phi}$ increases, the sensitivity may be enhanced. However, this is true only if APS is employed. The effect of DGs may generate the above-mentioned scenario, hence, obtaining possible sensitivity enhancement.

B. OPTIMIZATION PROBLEM FORMULATION

The population-based evolutionary Differential Evolution (DE) algorithm has been chosen to perform protection optimization in this paper. Its core philosophy is based on the natural selection of genes, which unlike Genetic Algorithm (GA), requires lesser numerical effort since probabilistic distribution is not required to generate descendant [50], [51], [52].

The Enhanced Self-Adaptive Differential Evolution Multi-Objective Algorithm (ESA-DEMO) [51], is a blend of handful DE variants which handles multi-objective process [53], [54], [55], [56], [57], self-adaptive role [58], [59], [60], and enhanced performance [49], [61] for protection coordination. Binomial crossover and trigonometric mutation strategy are employed for the coordination study because these strategies have demonstrated superior performance [61].

1) ENHANCED DIFFERENTIAL EVOLUTION ALGORITHM

Figure 1 presents the general layout of the enhanced DE (eDE) which is proposed precisely for the protection optimization. These four enhancements are listed:

1. Dial Reduction Strategy, shown in (8), narrow down possible searching territory to relax algorithm burden and accelerate convergence.

$$dial_{upper,G+1} = \begin{cases} \max(dial(B_{ind})_G) & \text{if } (f(B_{ind})_G \leq f(B_{ind})_{G-1}) \\ & \text{and } NV = 0 \\ dial_{upper,G-1} & \text{otherwise} \end{cases} \quad (8)$$

where $dial_{upper,G+1}$ and $dial_{upper,G-1}$ represents future and past generation upper $dial$ bounds, B_{ind} represents the best individual, $\max(dial(B_{ind})_G)$ refers to the maximum employed $dial$ in the best individual of the present generation, $f(B_{ind})_G$ and $f(B_{ind})_{G-1}$ are the fitness of the best individual of present and past generation.

2. Elitism and Mediocrity Strategy, which is presented in (9), upgrades both exploitation and exploration of the DE algorithm and evade algorithm stagnation by maintaining varied genes.

$$\begin{cases} P_{G+1}(M\%) = (B_{ind})_G \\ P_{G+1}(N\%) = rand(P(lower, upper)) \\ P_{G+1}(O\%) = P_G(O\%) \end{cases} \quad (9)$$

where P is the population, $P_{G+1}(M\%)$, $P_{G+1}(N\%)$ and $P_{G+1}(O\%)$ represents the different percentage of population individuals of the following generation.

3. Mutation Index Renew Strategy, which is presented in (10), randomly renews all three trigonometric mutation indices r_1 , r_2 and r_3 to further lift program exploration efficiency for all iterations for forthcoming generation forming varied mutant vectors.

$$\begin{cases} r_{1,G+1} = rand(P(lower, upper)) \\ r_{2,G+1} = rand(P(lower, upper)) \\ r_{3,G+1} = rand(P(lower, upper)) \end{cases} \quad (10)$$

4. Population Reduction Strategy, which is presented in (11), cut down total population individuals in exchange of quicker performance. This technique is

applied only once from the beginning to the end of algorithm generations.

$$NP_{G+1} = \begin{cases} NP_{new} & \text{if } (NV = 0) \\ NP_G & \text{otherwise} \end{cases} \quad (11)$$

where NP_{G+1} represent future dimension of the population, NP_{new} represents the newly shrunk dimension of population, NP_G is the present population dimension.

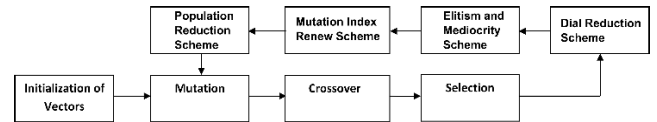


FIGURE 1. Layout of the enhanced DE [61].

2) SELF-ADAPTIVE ROLE

The DE algorithm is a dependable, meticulous, rigorous, and quick optimization method. However, similar to many evolutionary routines, crossover and mutations parameters need to be tuned in order to balance exploration and exploitation of the algorithm. This may be a very tedious and difficult task for people unfamiliar with the process. Hence, bypassing parameter tuning may be very advantageous. In references [56], [57], [58], several self-adaptive DEs have been proposed bypassing the need of parameter tuning.

For self-adapting the DE mutation parameter, a vector filled with scalar quantities is generated so that there is a scalar quantity of F_i for each parameter vector. Subsequently, a donor vector $\tilde{V}_{i,G}$ is generated for each target vector $\tilde{X}_{i,G}$ according to the trigonometric mutation scheme. The self-adaptive mutation strategy is presented in (12):

$$F_i = F_{r_1} + N(0, 0.5) * (F_{r_2} - F_{r_3}) \quad (12)$$

where N indicates the normal distribution and has been set to a mean of 0 and a standard deviation of 0.5. Studies have reported that self-adaptive mutation strategy improves DE performance.

For self-adapting the DE crossover parameter, a vector filled with scalar quantities is also generated so that there is a scalar quantity of Cr_i for each parameter vector. Subsequently, each trial vector $\tilde{U}_{i,G}$ is generated from the corresponding target vector $\tilde{X}_{i,G}$ and donor vector $\tilde{V}_{i,G}$ according to the binomial crossover scheme. The self-adaptive crossover strategy is presented in (13):

$$Cr_i = N(0.5, 0.15) \quad (13)$$

where N indicates the normal distribution and has been set to a mean of 0.5 and standard deviation of 0.15. The mean has been set to 0.5 to obtain a relatively balanced crossover for the trial vectors from the target and donor vectors.

Therefore, the self-adaptive role of mutation parameter F_i will help algorithm exploitation and exploration when

fluctuating between 0 and 1. And the crossover parameter Cr_i will help determining the number of elements to be altered for obtaining prominent achievement.

3) FLOW DIAGRAM OF THE ENHANCED SELF-ADAPTIVE DIFFERENTIAL EVOLUTION MULTI-OBJECTIVE ALGORITHM

The Multi-Objective Evolutionary Algorithms (MOEAs) are all designed to find optimal solution sets, namely the Pareto Front. Authors in [57] proposed the Differential Evolution Multi-Objective (DEMO) algorithm which evade the need of tuning the single-objective weighting parameters of the objective function. The three DEMO versions DEMO/parent, DEMO/closet/obj and DEMO/closet/dec have been expressed in [55]. It was reported that the DEMO/parent has lesser computational burden than the others. Therefore, the DEMO/parent variant is employed for the coordination study.

By employing multi-objective search, dominance concept is used to determining the better solution candidates. This can be summarized as follows:

- x_1 dominates x_2 or x_2 is dominated by x_1 , if
- Result x_1 is at least not worse than x_2 for all objectives
- Result x_1 is strictly better than x_2 in at least one objective

Fig. 2 a) precisely manifests the dominance concept. Using dot “W” as reference and examine all other dots. It can be easily recognized that “W” dominates “X”; “W” dominates “Y” and that neither “W” nor “Z” dominates each other. Fig. 2 b) displays the viable objective search area and different sets of non-dominated solutions. The sets of non-dominated solutions are the optimum results to the dispute because no other solution set dominates them. Hence, sets A, B, C and D in Fig. 2 b) is further known as Pareto-Optimal set. The Pareto-Optimal Front is then formed by mapping together the optimum solution sets.

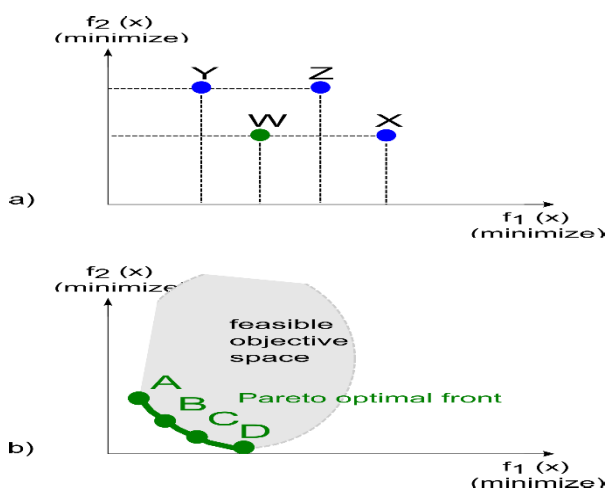


FIGURE 2. a) The concept of dominance. b) Pareto-optimal front.

Solution vectors with larger constraint violations are penalized more. Hence, if a vector has fewer or zero penalization and faster tripping times, it is more probable that this vector dominates another vector. The process of penalization will

first orientate the algorithm seeking to satisfy all coordination constraints before optimizing tripping times.

Flow diagram of the ESA-DEMO is presented in Fig. 3.

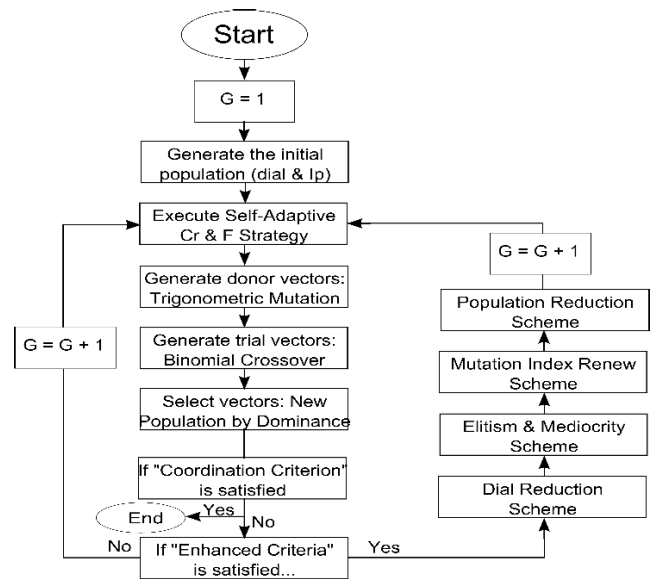


FIGURE 3. Flow diagram of ESA-DEMO.

III. ADAPTIVE OVERCURRENT COORDINATION SCHEME

The protection coordination and optimization problem formulation presented in section II deals with numerical soft computing. However, several system data and parameters need to be measured, calculated, and processed before performing protection coordination optimization. First, the initial steps include converting the network data on a common system base. These data are the number of generators, number of buses, type of buses, voltage of buses, shunt and line impedances, generation, and load powers. Then, steady and fault state power network topology can be expressed using Y_{bus} and Z_{bus} matrix respectively. These algebraic expressions are latterly used for power flow and fault calculation. The formulation of the network algebraic expressions needs to be computationally efficient to consider operational and topological changes in real-time operation. Moreover, input and output of generators, lines and loads need to be considered. Renewable DGs may be considered as power injection for steady state analysis and its transient reactance for fault analysis.

A. POWER NETWORK TOPOLOGY IDENTIFICATION

The Y_{bus} and Z_{bus} matrix are the fundamental components for any power system analysis. Y_{bus} , which directly reveal the network elements’ connectivity, can be obtained through the computationally efficient incidence method on the dominant network topology via incidence matrix [62] and can easily consider parallel lines and mutual couplings. This is shown in Fig. 4, where Z_{bus} can be obtained through direct construction or inverting the Y_{bus} [62], [63] on the dominant

network topology and also consider parallel lines and mutual couplings.

The matrix A presented in Fig. 4 a) is a topological matrix where the network connections are detailed using “1” and “-1” according to the oriented graph shown in Fig. 4 b). Then, the primitive admittances are declared in the matrix shown in Fig. 4 c). Hence, the Ybus matrix is formed by multiplying these matrices. In case when topological scenario is presented such as input or output of lines, or generation variations, these can be reflected through updating the matrix. Similarly, Zbus can be updated through partial inversion lemma of the line element according to its respective location.

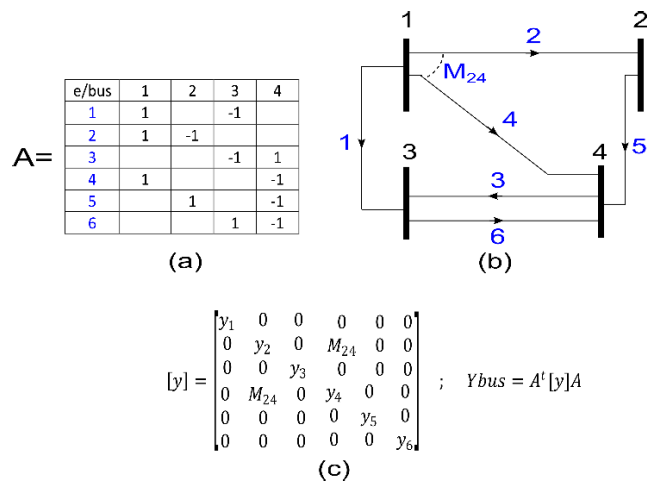


FIGURE 4. Ybus Admittance matrix. a) Bus incidence matrix b) Oriented network c) Primitive admittance matrix.

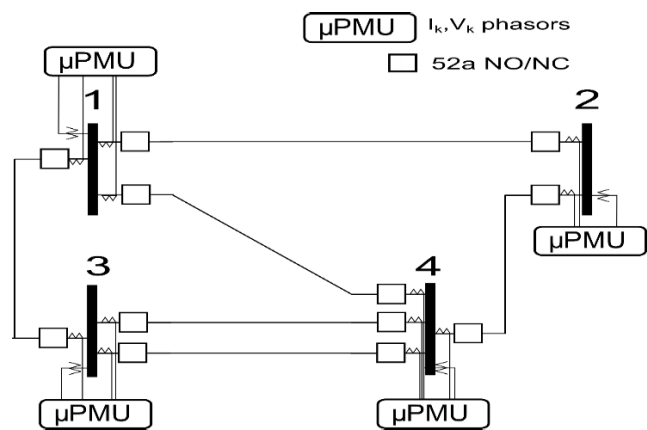


FIGURE 5. Power network topology detection.

Power network topology detection will use both the measured current in the branch using μ -PMUs and the open/close status of the breaker auxiliary contact (52a) as presented in Fig. 5. These measurements and status will be used to verify and confirm the actual network topology. Then, if there were any changes, the changes will be considered and respective Ybus and Zbus will be modified and updated for the latest operating condition. Voltage phasor and sample time will permit defining directionality of the measured current.

B. POWER FLOW AND FAULT ANALYSIS

Bus voltages and branch currents are calculated performing power flow analysis which solves the non-linear power flow equations. Line branch currents reveals the load currents that each DOCR senses on steady state operation which are used to set the respective pickup current settings. The pickup current would need to be set above the possible maximum line load current to avoid false tripping during overloading, transformer magnetizing Inrush current, motor starting current, power transfer due to outage of certain line, etc., a N-1 contingency analysis is required. Even though handy μ -PMUs in modern smart grids offer many measurements and information, performing contingency analysis is still unavoidable to obtain the possible maximum line load currents for setting the DOCR pickup current appropriately.

DOCRs normally sense different fault currents in a meshed network topology which makes them hard to coordinate. In addition, a DOCR may sometimes have to coordinate with more than one relay offering both primary and backup functions simultaneously for faults at different locations using the same settings. Hence, an exhaustive fault analysis is prerequisite to know the possible fault magnitudes that each primary and backup relays will sense on different locations. Both maximum and minimum faults are mandatory data for coordination. Maximum fault is considered as the three-phase bolt fault ($Z_f=0$) located on the closest bus of the primary relay. This is done under the assumption that the fault magnitude on the closest bus will be the same fault magnitude appearing directly in front of the primary relay. Also, the fault currents are calculated assuming that the far end breaker is opened. This assumption is made to obtain the maximum fault current which each relay may sense and the poor chance for the far end relay failing to operate. On the other hand, minimum fault is considered as the two-phase fault located on the far end of the line where primary relay is located. This is to analyze the sensitivity of backup relay for a far end primary fault. Fault analysis is carried out using the diagonal elements of Zbus, which represent the Thevenin’s impedance seen at the fault bus.

C. PROTECTION COORDINATION CONSIDERATIONS

The inverse time DOCR protection principle is simple and straight forward which lead to extensive use of this protection in sub-transmission and distribution lines, especially in looped or meshed topologies. This relay principle will trip only if both the direction unit and the overcurrent unit satisfy their tripping condition. This can be illustrated in Fig. 6.

However, special considerations may be considered for certain scenarios in the coordination formulation such as transformer, reactor and/or capacitor bank. Parallel lines also need to be contemplated separately to avoid modeling them as an equivalent line in the Ybus and, hence losing information.

DOCRs for transformer protection are normally neglected because of the transformer’s own differential protection. Afterall, backup protection operation for transformers and

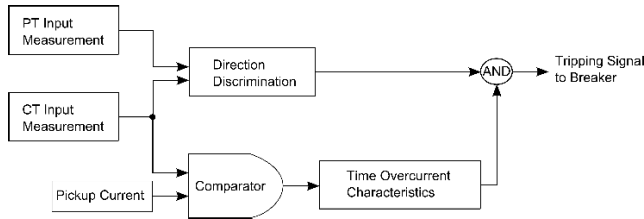


FIGURE 6. Directional overcurrent relay tripping logic.

shunt elements, such as capacitors and reactors may be contemplated in the coordination formulation as additional restrictions. Hence, if certain branch corresponds to a transformer or parallel line circuit, they should be clearly declared in the input data. Then the algorithm will proceed to set the corresponding relays as backup of the transformer differential protection or as the respective primary and backup functions for the parallel lines.

1) RELAY NAMES ASSIGNMENT AND COORDINATION PAIRS IDENTIFICATION

All relay names are generated automatically by a subroutine. These relay names which are a string of numbers, are expressed by 3 digits. The first digit is assigned according to the close end bus, the second digit is assigned according to the far end bus and the third digit is assigned according to the enumeration of parallel lines located between two buses. For example, on Fig. 5, the relays between buses 3 and 4 that are on the parallel lines and close to bus 3 looking toward bus 4 are assigned as [3 4 1] and [3 4 2]. Similarly, the relays on the parallel lines that are close to bus 4 looking toward bus 3 are assigned as [4 3 1] and [4 3 2] respectively.

Coordination pairs will then be identified and generated automatically in another subroutine. This is achieved by programming a logic that detects the backups of each primary relay based on the relay names. The logic consists of identifying the first digit of the primary relay, then compare it to all other relays and find its backup relays by identifying the relays that have this value on its second digit. For example, on Fig 5, for primary relay [4 3 1], the backup relays will all be identified when employing the previous logic, which are the relays [1 4 1], [2 4 1], and [3 4 2].

2) PARALLEL LINES

The corresponding overcurrent protection relays are assigned and modelled for protection coordination for each line branch. Setting these relays will be done according to the corresponding fault and load currents passing through each line considering its respective impedance. Normally, parallel lines may be designed and constructed with the same line impedance. Hence, obtaining the necessary data, pickup currents and the respective coordination pairs can be computed and generated. Relaying on parallel lines is presented in Fig. 7 and their respective pickup currents are

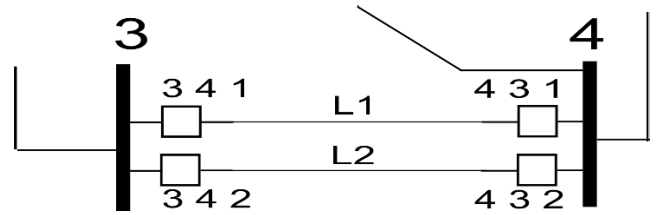


FIGURE 7. Overcurrent protection relaying for parallel lines.

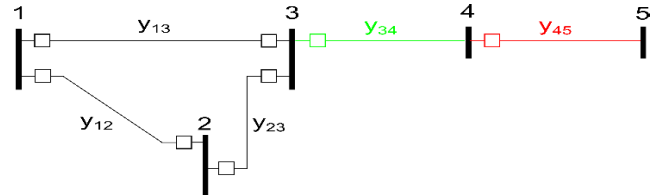


FIGURE 8. Radial line configuration and relay names generation.

computed in (14).

$$\begin{cases} I_{pickup}^{L1} = I_{loadL1} * k \\ I_{pickup}^{L2} = I_{loadL2} * k \end{cases} \quad (14)$$

Then, coordination among relays [3 4 1], [3 4 2], [4 3 1] and [4 3 2] on the parallel lines accomplished via conventional coordination criterion presented in (15).

$$\begin{cases} t_{341}^{L1} = t_{432}^{L2} + CTI; L2 \text{ end opened} \\ t_{342}^{L2} = t_{431}^{L1} + CTI; L1 \text{ end opened} \\ t_{431}^{L1} = t_{342}^{L2} + CTI; L2 \text{ end opened} \\ t_{432}^{L2} = t_{341}^{L1} + CTI; L1 \text{ end opened} \end{cases} \quad (15)$$

These relays on parallel lines will need to be coordinated with the other relays in the network as well. Following this coordination criterion, the relays on the parallel lines will maintain selectivity as long as these constraints are satisfied with sufficient relay sensitivity.

Fault analysis is carried out considering remote line opened, hence, fault contribution come from only one end. This is a common criterion considering that there is a minimal probability for relays located at distinct substation buses to fail simultaneously. In the case of faults on parallel lines, the contribution from the remote end is given by the non-fault line. For this reason, impedance of single line will need to be considered by updating the Ybus due to outage of a branch line or by updating the Zbus using the partial inversion lemma.

3) RADIAL LINE IDENTIFICATION

Radial line configuration may normally appear at the end of the network. This scenario should be identified by the algorithm to perform adequate problem formulation. When performing Ybus construction, the last radial line should be modelled and included to the matrix diagonal element and

single mutual element between buses on the matrix off diagonal elements. This should be carried out for all radial lines in the network regardless of the number of radial lines. Finally, the relay names subroutine will identify inactive radial line configurations and generates only the relays the will sense fault contribution from the source, omitting the opposite side relays. This is presented in Fig. 8 and in (16).

$$Y_{bus} = \begin{bmatrix} y_{11} & -y_{12} & -y_{13} & 0 & 0 \\ -y_{12} & y_{22} & -y_{23} & 0 & 0 \\ -y_{13} & -y_{23} & y_{33} & -y_{34} & 0 \\ 0 & 0 & -y_{34} & (y_{34} + y_{45}) & -y_{45} \\ 0 & 0 & 0 & -y_{45} & (y_{45}) \end{bmatrix} \quad (16)$$

where $y_{11} = (y_{13} + y_{12})$, $y_{22} = (y_{23} + y_{12})$ and $y_{33} = (y_{13} + y_{23} + y_{34})$.

D. ADAPTIVE OVERCURRENT COORDINATION SCHEME DIAGRAM

The adaptive overcurrent coordination scheme, presented in Fig. 9, consists of a centralized approach where continuous real-time network electrical parameters and topology are measured and monitored. The detailed flow diagram of the generic adaptive overcurrent coordination scheme is presented in Fig. 10.

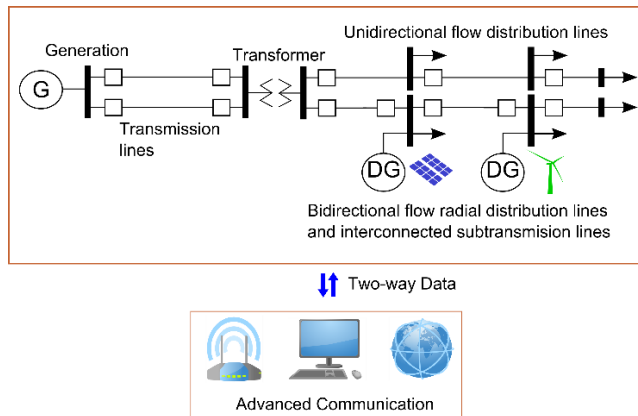


FIGURE 9. Outline of the adaptive overcurrent coordination scheme.

Topological changes need to be detected and the respective network modelling as well as load and fault analysis need to be updated as entry data for the overcurrent coordination optimization algorithm. On the other hand, steady state load demand variation may be measured and updated in every 15 minutes timespan similar to energy invoicing calculation. Advanced smart grid communication infrastructures are needed for reliable and fast point to point information exchange. The pickup current setting is updated using information of both the measured load current or contingency analysis power flow solution in every 15 mins timespan. And the fault current is updated for every topological change and/or interconnection-disconnection of renewable energy distributed generations (DGs).

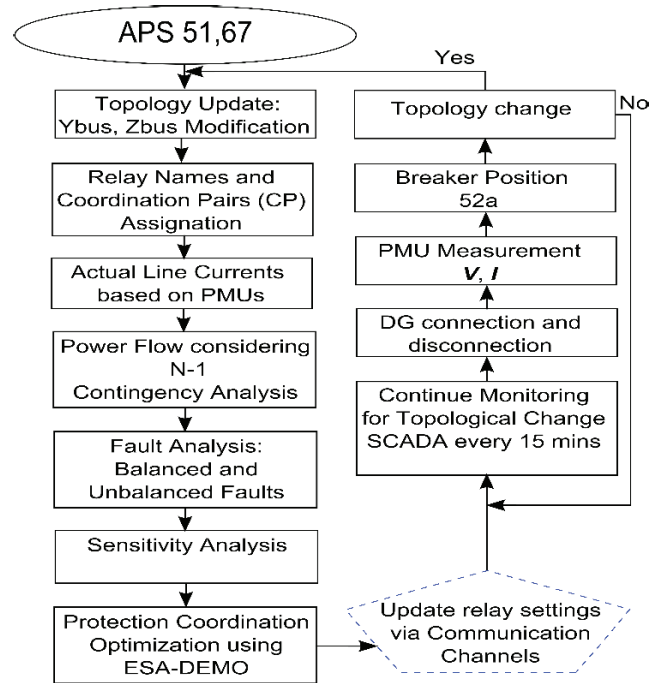


FIGURE 10. Adaptive overcurrent coordination scheme flow diagram.

IV. TEST SYSTEM AND RESULTS

The modified IEEE interconnected 14 bus system presented in Fig. 11, is tested to show that the generic overcurrent APS is capable of assigning relay names, coordination pairs automatically considering parallel lines and offering protection for power transformers.

CTI has been considered as 0.3 seconds. The time dial range is between [0.1-10]. The pickup current security factor range is between [1.4-1.6]. The algorithm convergence criterion is set to be 1,000 iterations.

The IEEE 14 bus system possesses 31 phase overcurrent relays and a total of 45 coordination pairs including parallel lines after the sensitivity analysis. Several studies have been carried out to demonstrate the capability of the proposed generic overcurrent APS:

- A. The base case where the DOCRs are considered only for line protection. All DOCRs have been coordinated successfully.
- B. Then integration of DG10 MW cases on bus 11 and 14 independently and simultaneously are presented to show that miscoordination may appear if DOCR settings are not updated. For these three scenarios, numerous miscoordination appeared.
- C. Then proposed generic APS has been employed to show that all the three previously presented scenarios of miscoordination are corrected. Moreover, sensitivity improved, and more coordination pairs became active.
- D. Lastly, DOCRs have been considered for power transformer backup protection.

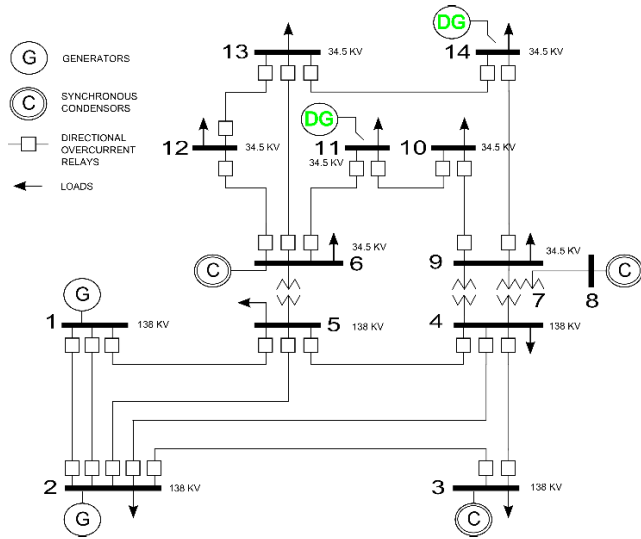


FIGURE 11. The modified IEEE interconnected 14 bus system.

It is observed from Table 2 base case optimized results that all DOCRs have been effectively coordinated. This can be seen from the respective primary, backup and CTI operation times of 0.33, 0.73 and 0.40 seconds. Table 2 presents all the active coordination pairs of base case, primary time, backup time, CTI, and primary, backup three phase fault currents. The DOCRs that are highlighted in bold represent the parallel line protective relays. Hence, it is observed that the proposed generic APS can adequately assign relay names, and coordination pairs considering parallel lines. Considering parallel lines increased numerous coordination pairs and optimization complexity.

Table 3 shows the detailed DOCR settings of the optimized base case, including the dial, pickup current, the load current considering a N-1 contingency and the optimized security factor k. The DOCRs that are highlighted in bold also represent the parallel line protective relays.

Fig. 12 shows a graphical view of the base case relay operation times. It is observed that all the active 45 coordination pairs are well coordinated, since all CTI (dashed line in red) satisfy the threshold (line in light blue). Likewise, it has been noted that DOCR protection operating times are faster for the first 26th coordination pairs that correspond to DOCRs on the high voltage side of the system. This is because they are closer to generation sources. On the other hand, the coordination pairs from the 27th and beyond tends to have slower operation because they are located further from the sources.

Fig. 13 a) and b) presents the number of miscoordinations (NV) for the four cases: base case, DG 10MW on bus 11 case, DG 10MW on bus 14 case, DG 10MW on buses 11 and 14 case. NV1 represents miscoordinations when CTI becomes lower than 0.3 seconds and NV2 represents miscoordinations when CTI becomes negative (that the backup relay will operate before the primary relay). It is observed that there were no miscoordination issue on the base case in Fig. 13 a). But NV1

TABLE 2. Detailed relay operation time and CTI of IEEE 14 bus on one simulation of base case employing the proposed generic APS in fig. 10.

P	B	tp	tb	CTI	Isc P	Isc B
2_1_2	1_2_1	0.19	0.54	0.35	18198	3036
2_3_1	1_2_1	0.16	0.59	0.43	20672	2842
2_4_1	1_2_1	0.22	0.59	0.37	20602	2847
2_5_1	1_2_1	0.27	0.58	0.31	20514	2854
1_2_2	2_1_1	0.23	0.54	0.31	45258	2544
1_5_1	2_1_1	0.17	0.63	0.46	46278	2296
2_1_1	1_2_2	0.18	0.54	0.36	18198	3036
2_3_1	1_2_2	0.16	0.58	0.42	20672	2842
2_4_1	1_2_2	0.22	0.58	0.37	20602	2847
2_5_1	1_2_2	0.27	0.58	0.31	20514	2854
1_2_1	2_1_2	0.23	0.54	0.31	45258	2544
1_5_1	2_1_2	0.17	0.63	0.46	46278	2296
5_2_1	1_5_1	0.06	0.56	0.50	4108	1731
5_4_1	1_5_1	0.26	0.56	0.30	4184	1729
3_4_1	2_3_1	0.16	0.47	0.31	2002	1871
4_3_1	2_4_1	0.07	0.58	0.51	4631	1878
4_5_1	2_4_1	0.23	0.56	0.33	3426	1920
5_1_1	2_5_1	0.07	0.62	0.54	4056	1849
5_4_1	2_5_1	0.26	0.57	0.31	4184	1993
2_1_1	5_2_1	0.18	0.71	0.53	18198	635
2_1_2	5_2_1	0.19	0.71	0.52	18198	635
2_3_1	5_2_1	0.16	0.59	0.43	20672	686
4_5_1	3_4_1	0.23	0.55	0.33	3426	959
5_1_1	4_5_1	0.07	0.39	0.31	4056	2023
4_2_1	5_4_1	0.08	0.39	0.31	3819	2558
4_3_1	5_4_1	0.07	0.40	0.34	4631	2485
11_10_1	6_11_1	0.62	0.95	0.33	3559	3522
6_12_1	11_6_1	0.51	1.13	0.61	7448	1564
6_13_1	11_6_1	0.74	1.05	0.32	7239	1667
12_13_1	6_12_1	0.35	0.67	0.32	3354	3309
6_13_1	12_6_1	0.74	1.09	0.35	7239	794
13_12_1	6_13_1	0.06	0.94	0.88	5497	3936
13_14_1	6_13_1	0.65	0.97	0.32	4803	3726
6_11_1	13_6_1	0.82	1.14	0.32	6473	1204
6_12_1	13_6_1	0.51	1.28	0.77	7448	1134
10_11_1	9_10_1	0.80	1.10	0.30	5347	5238
9_14_1	10_9_1	0.47	0.79	0.32	7668	1791
14_13_1	9_14_1	0.38	0.71	0.33	3386	3256
9_10_1	14_9_1	0.96	1.31	0.35	7290	1340
11_6_1	10_11_1	0.64	0.98	0.33	3252	3215
10_9_1	11_10_1	0.48	0.80	0.32	2581	2465
13_14_1	12_13_1	0.65	0.97	0.31	4803	968
14_9_1	13_14_1	0.57	0.88	0.32	2414	2278
13_6_1	14_13_1	0.27	0.59	0.31	3720	1690
13_12_1	14_13_1	0.06	0.69	0.64	5497	1440
Average		0.33	0.73	0.40		

and NV2 started to appear as the 10 MW DG is integrated on bus 11, 14 and simultaneously on both. Miscoordination increases as both DGs are integrated simultaneously on buses 11 and 14.

NV1 may be considered less severe than NV2, since many CTI became lower than 0.3s but are close to 0.3s. For instance, 0.29s or 0.28s. However, these still need to be accounted since the prespecified 0.3s is no longer fulfilled. Also, certain coordination pairs are left with only 0.061s, 0.035s or 0.015s CTI. Although only a few, but this may lead to simultaneous trips of primary and backup DOCRs.

On the other hand, NV2 may be said to be more severe than NV1, because negative CTI appears. Which means that

TABLE 3. Detailed relay settings of IEEE 14 bus on one simulation of base case employing the proposed generic APS in fig. 10.

Relays	Dial	Ipickup	k	Iload
1_2_1	0.47	547	1.40	226
2_1_1	0.35	572	1.47	226
1_2_2	0.46	552	1.42	226
2_1_2	0.37	553	1.42	226
1_5_1	0.35	402	1.43	218
5_1_1	0.10	444	1.58	218
2_3_1	0.32	408	1.45	214
2_4_1	0.43	381	1.46	165
4_2_1	0.11	396	1.52	165
2_5_1	0.55	326	1.44	123
5_2_1	0.10	318	1.40	123
3_4_1	0.12	401	1.42	71
4_3_1	0.11	397	1.40	71
4_5_1	0.29	406	1.41	178
5_4_1	0.38	417	1.45	178
6_11_1	1.56	274	1.41	123
11_6_1	1.02	272	1.40	123
6_12_1	0.97	335	1.45	103
12_6_1	0.24	325	1.41	103
6_13_1	1.33	411	1.41	247
13_6_1	0.37	410	1.40	247
9_10_1	1.67	485	1.46	73
10_9_1	0.42	465	1.40	73
9_14_1	0.86	424	1.48	114
14_9_1	0.54	403	1.40	114
10_11_1	1.42	323	1.43	71
11_10_1	0.93	336	1.49	71
12_13_1	0.60	225	1.42	26
13_12_1	0.10	246	1.55	26
13_14_1	1.20	254	1.44	83
14_13_1	0.64	247	1.40	83

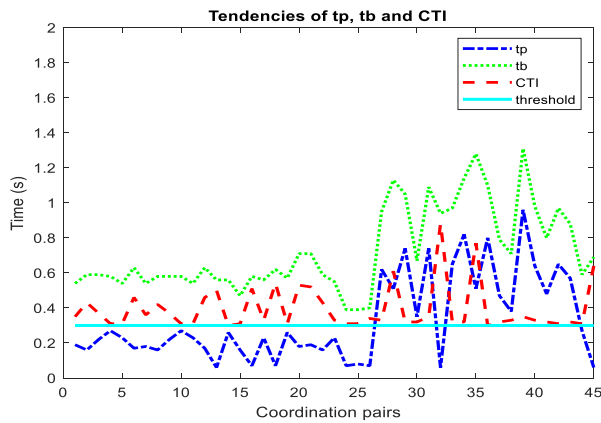


FIGURE 12. Base case operation times of relays for all 45 active coordination pairs of the modified IEEE 14 bus system.

the backup relay will definitely trip before the primary relay when a fault occurs on that line. Hence, the protection operation sequence is definitely not guaranteed and unnecessary upstream tripping will occur. The last and most important observation is that NV1 and NV2 are both avoided when the proposed Generic APS is employed as presented in Fig. 13 b).

It is important to mention that DG does not only bring negative impacts for the DOCR coordination as shown

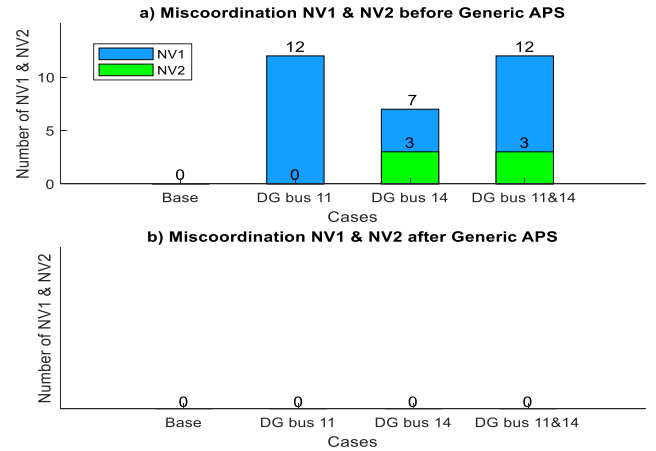


FIGURE 13. Number of miscoordination for the different cases before and after employing the proposed Generic APS on the modified IEEE 14 bus system.

in Fig. 13. Fig. 14 presents the increase of active coordination pairs (NCP) and Sensitivity as DG integrates to the network when employing APS. It is observed from Fig. 14 a) and b) that both NCP and Sensitivity increased. This is because DGs may enhance nearby bus voltage quality, power loss, and reduce power flow traveling from the main generation sources and increase contribution of fault magnitude at point of fault. Increasing network robustness. Therefore, more DOCR coordination pairs may gain enough sensitivity and become active. But this can only be achieved if the Generic APS is employed. If the proposal is not employed, then no substantial advantage may be obtained, and the disadvantages presented in Fig. 13 a) will not be avoided.

Fig. 15 presents the three phase backup fault currents of different cases for all coordination pairs. It can be observed that from the 20th coordination pair (which corresponds to DOCRs closer to the low voltage side of the system where DG is integrated) backup fault currents gradually increased their magnitudes. Many fault variations are very small in the range of 5 to 10 A, but a few others may have greater variation in the range of 200 to 900 A. Comparing the base case to the DG simultaneously on bus 11 and 14. This is the reason why there are miscoordinations (NV1, NV2) reported in Fig. 13 a).

The CTI behavior of the base case is presented in Fig. 12. However, it is presented in Fig. 16 a) for comparing the CTI among the different cases of DG integration. It can be observed that when DG is integrated to the system, several miscoordination appeared. In Fig. 16 c) and d), negative CTI appeared as well. Which means that backup DOCR will trip before the corresponding primary relay.

On the other hand, Fig. 17 a) presents zero miscoordination when employing the Generic APS in presence of DG on both bus 11 and 14. Fig. 17 b) and c) present the primary and backup DOCR time. It is worth mentioning that in this case, there a total of 51 active NCP compared to 45 in the base case. And all 51 have been coordinated successfully.

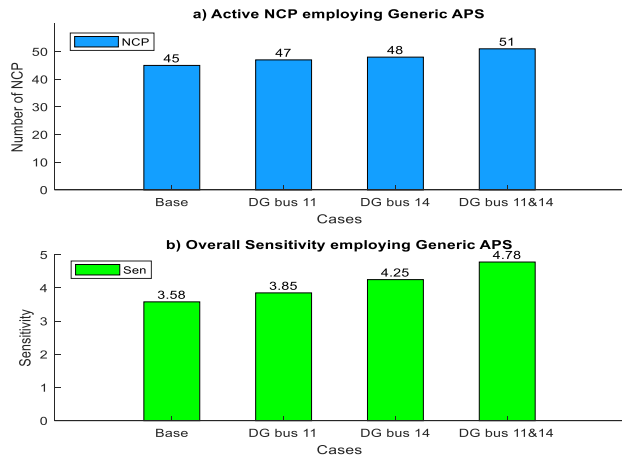


FIGURE 14. Number of active NCP and sensitivity for the different cases before and after employing the proposed Generic APS on the modified IEEE 14 bus system.

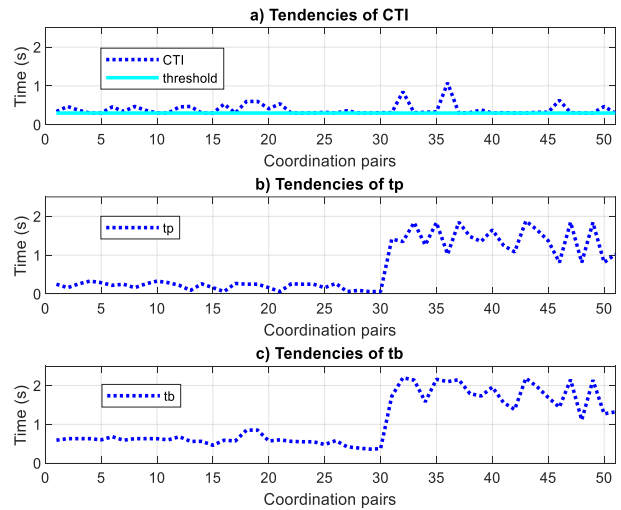


FIGURE 17. Operation times of the Generic APS including DG integration on bus 11 and 14 of all the 51 active coordination pairs on the modified IEEE 14 bus system.

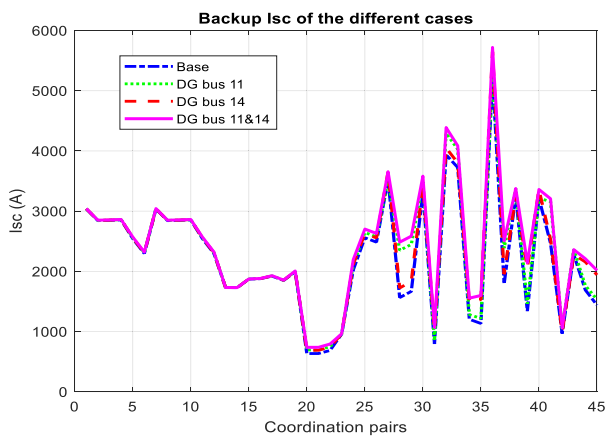


FIGURE 15. Backup fault currents for the different cases on the modified IEEE 14 bus system.

and algorithm coordination constraints. However, the ESA-DEMO still managed to converge at good results as presented in Fig. 18. It is observed from Fig. 18 a) that all 67 coordination pairs fulfilled selectivity. And from Fig. 18 b) and c) that the primary and backup time are in acceptable overcurrent operation range.

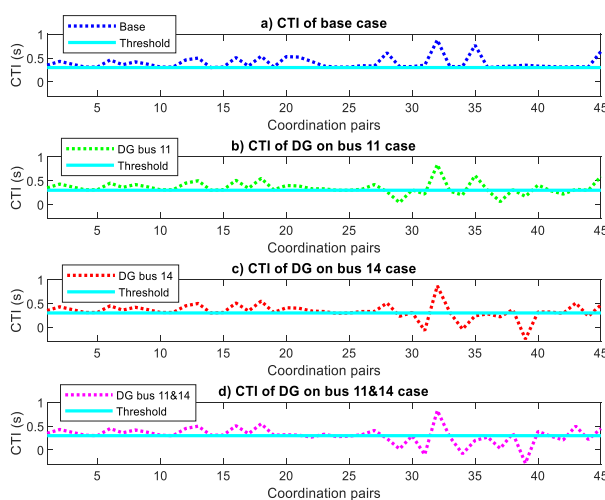


FIGURE 16. CTI for the different cases on the modified IEEE 14 bus system.

When DOCRs are considered for power transformer protection, the total active number of coordination pairs increased to 67. This increased the problem complexity

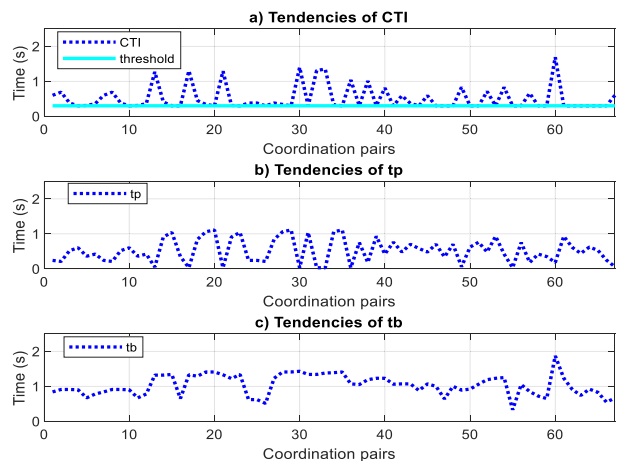


FIGURE 18. Operation times of the Generic APS considering DOCRs as backup transformer protection of all the 67 active coordination pairs on the modified IEEE 14 bus system.

Moreover, Fig. 19 a) and b) present the operation of DOCRs 5_6_1 and 4_9_1 that offer backup overcurrent protection for the category IV power transformers. Even though that the first point of the transformer damage curve is very close to the overcurrent relay operation curve, they are enough time difference between them. The first point of the damage curve of both transformers are located on 2 seconds at 2,092 A. The DOCR 5_6_1 presented in Fig. 19 a) operates in 1.24 seconds for the same current. Hence there is

a 0.76 second time difference between them. Additionally, the DOCR 4_9_1 presented in Fig. 19 b) operates in 1.22 seconds for the same current. Hence there is a 0.78 second time difference between them. Therefore, it is shown that the proposed Generic APS is also capable of coordinating the DOCRs considering transformer damage curve.

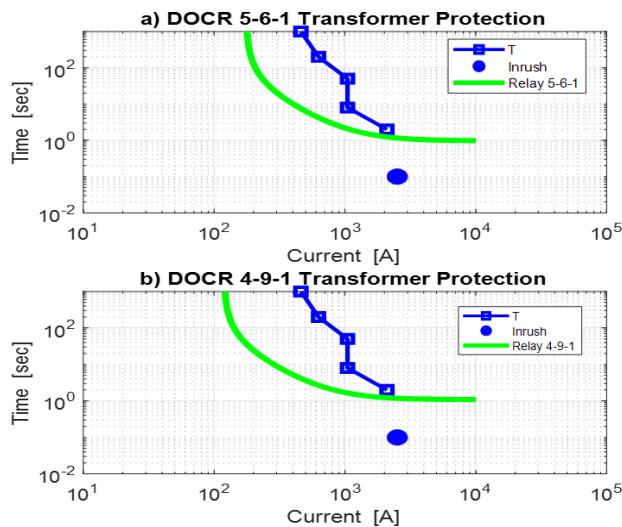


FIGURE 19. Operation times of relays 5_6_1 and 4_9_1 employing the Generic APS considering backup overcurrent protection for power transformers.

TABLE 4. A 100 independent run results employing the proposed generic APS for the different cases on the modified IEEE 14 bus.

Case employing proposedAPS	t(s)	t-SD	f(x)	f(x)-SD	NV
Base	48	3.29	1.40	0.01	0
DG Bus 11	47	1.60	1.66	0.02	0
DG Bus 14	46	1.76	2.21	0.03	0
DG Bus 11&14	45	3.58	3.88	3.51	0.09
Transformer	50	1.14	2.50	0.04	0

Table 4 presents the results of 100 independent runs for the different cases employing the proposed APS. It can be observed from Table 4 that for the different cases, the proposed approach has always converged with zero violation of coordination constraints (zero miscoordination). Also, observing the very small standard deviation (SD) of algorithm’s execution time (t) and fitness value f(x), and a average of approximately 50 seconds of execution time, one can conclude that the proposed approach is effective, robust and dependable.

V. CONCLUSION

DOCRs may be one of the most widely implemented and economic protection principle throughout the electrical network. However, due to constant network evolution toward sustainable and renewable energy, fault currents may arise and impact relay performance. A coordination loss or miscoordination scenario is the most unwanted. On top of that,

when backup relay operates before the primary relay, selectivity is no longer maintained. Hence, the centralized Adaptive Protection Scheme (APS) is proposed.

The proposed approach is illustrated in Fig. 10, which considers the network topology changes and also integration of DGs. The APS is capable of forming automatically relay names, coordination pairs, detection of parallel lines, providing protection for transformers and optimize relay settings to obtain coordination.

Miscoordination when DG integrates on the system is shown in Fig. 13 and 16. On the other hand, Fig. 17 shows the operation of relays with zero miscoordination when DGs are integrated in the system employing the proposed approach. Moreover, Fig. 18 shows the relay operations when considering overcurrent protection for the transformers. Even though more coordination pairs need to be optimized, the proposal satisfied all constraints. Fig. 19 shows the closer view of overcurrent protection for the two power transformers on the log-log page, where the transformers’ damage curves are adequately protected.

It is worth emphasizing that Fig. 14 shown the active number of coordination pairs and overall sensitivity improvement when employing the proposal with DG integration. By doing so, DG advantages of voltage and power support can be obtained without compromising selectivity.

Lastly, algorithm performance is examined for the different studied cases including DGs and transformers. Each case is simulated on 100 independent runs. It is observed that the algorithm is dependable with zero miscoordination settings and very low result standard deviation.

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