A Novel Solution Method for the Distribution Network Reconfiguration Problem based on an Objective Function and considering the Cost of Electricity Transmission

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ABSTRACT

The problem of distribution reconfiguration is an important issue in the optimal operation of distribution networks. Nowadays, with the diverse development of renewable energy sources, the uncertainty of the load becomes more complex, and the need for competitive retail electricity markets is more evident. This paper presents an optimal solution to this problem, utilizing the global advantage of the simulated annealing algorithm, improving the time parameter, and combining it with the rapid mutation ability of the genetic algorithm. Simultaneously, the Zbus, EBE, and PS models were integrated to optimize the costs, considering transmission costs under constraints related to taxes and economic indicators when connected to the distribution grid. The proposed method was simulated and tested on the IEEE 33-node standard power grid with three different scenarios. The simulation results showed that the proposed method provides optimal results, which can be applied to calculate the optimal operation of the distribution grid when participating in retail electricity markets.

Keywords-simulation annealing algorithm; genetic algorithms; distribution network reconfiguration; transmission system usage; transmission cost allocation

I. INTRODUCTION

The problem of Power Distribution Network Reconfiguration (PDNR) is a classic issue in the planning and operation research of distribution networks [1-2]. PDNR is an optimization problem that aims to alter the connection methods of the electrical network, which is a non-convex optimization challenge within a large solution space. Various approaches have been proposed to address this problem, including analytical methods, metaheuristic (empirical) methods, and artificial intelligence algorithms, with the latter gaining more popularity [3]. The objective functions in different studies vary and correspond to the diverse issues within PDNR, especially those aiming to minimize power losses and improve power quality. In recent years, the growing strength of Renewable Energy (RE) as Distributed Generation (DG) has led to an increased interest in studying PDNR issues in conjunction with the evaluation of the impact of DG [4]. These studies often consider an objective function that not only aims to minimize power losses but also contemplates the connectivity characteristics of DG, voltage quality (stability) conditions, loadability of the network (Icp), and the necessity of maintaining the network's radial structure. The problem of network reconfiguration consists of minimizing losses while considering the reliability of the power supply. The supply validity is modeled as the cost of power outages, thus leading to an evaluation of the supply reliability impact on the objective function in the network reconfiguration [5]. During the past decade, the proliferation of Distributed Energy Resources (DER) has sparked increasing interest in research on network reconfiguration for power distribution geared towards distributed generation (DG) [6-9]. In [10], the string utilized in the Genetic Algorithm (GA) delineated all the switch positions along with their "on/off" statuses. The length of this string tends to increase in tandem with the number of switches. For extensive distribution systems, managing such elongated strings becomes unfeasible for GA. In the context of this study, efforts were made to truncate the string. In [11-12], the restructuring of the electrical distribution system examining the fees for using the energy transmission system was discussed. In [11], an overview of formulas, algorithms, and current trends in research on restructuring the electrical distribution system was presented. This overview was conducted with increasing interest in the use of sustainable energy sources and factors related to electric vehicles as well as other renewable energy sources. Furthermore, it was pointed out that despite research carried out in the past decade, some aspects are still less explored, especially location costs and allocation of transmission expenses. In [13-14], the electrical distribution system expansion plan was considered from the perspective of fees associated with the energy transmission system usage. A distribution reconfiguration model was proposed to minimize these fees and analyze their effect on the restructuring of the electrical distribution system. Computational methods and simulations to evaluate the fees and their impact on using the energy transmission system in the expansion plan of the electrical distribution system were provided.

The application of transmission system usage tariffs in the evolving electricity market leads to the optimization of the transmission grid use and becomes a significant factor for guiding decisions related to the electrical distribution system operation [15]. This study aims to explore the impact of location-based transmission system usage tariffs on the reconfiguration of the electrical distribution network. The new proposals include the development of an objective function to reconfigure the electrical grid considering transmission costs. In order for this reconfiguration to be achieved, an algorithm using the Simulation Annealing (SA) algorithm and the Genetic Algorithm (GA) to solve the optimization problem with the constraints of the grid reconfiguration problem is proposed. Also, the impact of the costs resulting from using transmission lines on the problem of reconfiguring the distribution network is analyzed.

II. MODEL AND CONSTRAINT CONDITIONS

Considering the electrical supply diagram which includes the transmission line system and distribution network shown in Figure 1. The distribution network diagram consists of 50 nodes, with two supply sources from two transformer stations, and each station has two output lines corresponding to SE101, SE102, SE103, and SE104. The cost of electricity supply from the source to the electric load consumption is determined through three costs: (1) transmission cost on the transmission lines, (2) electrical energy loss cost, and (3) operation and maintenance costs of the system [15] as:

$$P = C_{CostT} + C_{Plosse} + C_{OM}$$

where C_{CostT}, C_{Plosse}, and C_{OM} represent the costs of electric energy transmission, electric energy loss, and operation and maintenance, respectively. The objective function is:

$$Min(F) = Min(C_{CostT} + C_{Plosse} + C_{OM}) \quad (1)$$

and the constraints of the problem are:

$$P_{Gi} - P_{Si} - P_{di} = 0 \quad \forall\, i \in \Omega_b \quad (2)$$

$$Q_{Gi} - Q_{si} - Q_{di} = 0 \quad \forall\, i \in \Omega_b \quad (3)$$

$$v_{min} \leq v_i \leq v_{max} \quad \forall\, i \in \Omega_b \quad (4)$$

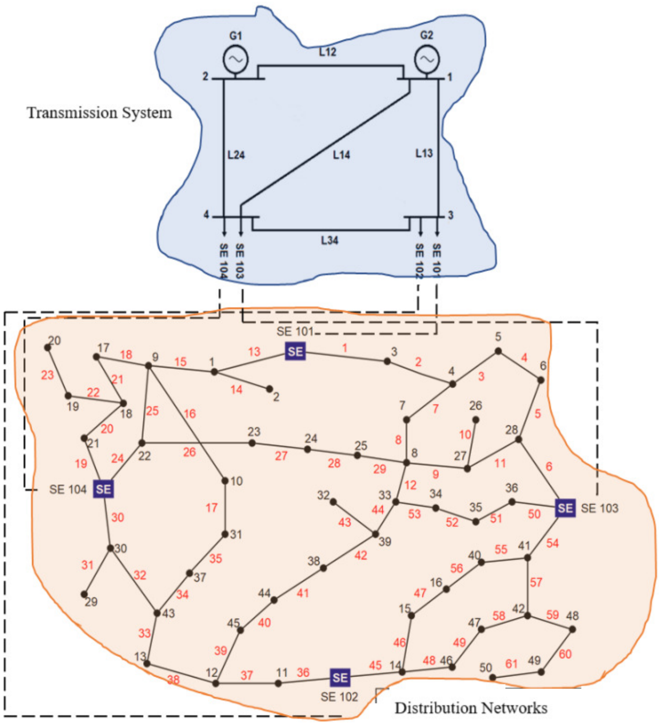

Fig. 1. A distribution network connected to two supply sources from the transmission grid.

$$n_{ij}.(P_{ij}^2 + Q_{ij}^2) \leq S_{max(ij)}^2 \quad \forall\, i \in \Omega_{ld} \quad (5)$$

$$P_{ij}^2 + Q_{ij}^2 \leq S_{max(ij)}^2 + \xi_{ij}^2 \quad \forall\, i \in \Omega_{lt} \quad (6)$$

$$P_{Si}^2 + Q_{Si}^2 \leq S_{max(i)}^2 \quad \forall\, i \in \Omega_s \quad (7)$$

$$\sum_{ij \in \Omega_{ld}} n_{ij} = n_{bd} - n_{bs} \quad (8)$$

$$n_{ij} \in \{0,1\} \quad (9)$$

$$\xi_{ij} \geq 0 \quad (10)$$

where C_{CostT} is transmission system usage charges assigned to distribution (\$), C_{Plosse} is the cost of electrical energy losses (\$), C_{OM} is the cost of operation and maintenance of substations (\$), P_{Gi} is the active power generated at bus i (pu), Q_{Gi} is the reactive power generated at bus i (pu), and P_{Si} is the total active power demanded at substation i (pu). Q_{Si} is the total reactive power demanded at substation i (pu), P_{di} is the total active power demanded at bus i (pu), Q_{di} is the total reactive power demanded at bus i (pu), Q_{Gi} is the reactive power generated at bus i (pu), v_{min} is the minimum admissible limit of voltage (pu), v_{max} is the maximum admissible limit of voltage (pu), and v_i is the voltage at bus i (pu). $S_{max(i)}$ is the maximum loading limit of substation i (pu), n_{ij} is a binary decision variable determining whether the circuit bus ij is open (0) or closed (1), P_{ij} is the active power flow in the circuit bus ij (MW), Q_{ij} is the reactive power flow in the circuit bus ij (MVAr), and S_{maxij} is the maximum loading limit of the circuit bus ij (MVA). n_{bd} is the number of bars in the distribution system, n_{bs} is the number of boundary substations in the transmission and distribution system, ξ_{ij} is the incremental variable of deficits of existing transmission line capacity ij, Ω_b

is the set of buses of the transmission and distribution system, Ω_s is the set of substations, Ω_{ld} is the set of the distribution system branches, and Ω_{lt} is the set of transmission system branches i between the transmission and distribution system($/MW).

The cost function C_{CostT} of the objective function representing the cost of using the electrical transmission system is described by:

$$C_{CostT} = \sum_{i\in\Omega_s} P_{Si} \times TUST_i^D \tag{11}$$

where $TUST_i^D$ is the transmission usage fee at boundary i between the transmission and distribution systems ($/MW). The cost function C_{Plosse} refers to the cost of electrical energy loss in the transmission and distribution network:

$$C_{Plosse} = \delta_l \sum_{i,j\in\Omega_l} R_{ij} \times I_{ij}^2 \tag{12}$$

where R_{ij} is the electrical resistance of line ij (Ω), I_{ij} is the current in the line section buses i and j (A), δ_l is the variable for electrical energy loss converted to energy. When converted to present value, the annual loss cost is described as:

$$\delta_l = 8760 \times \emptyset_l \times c_l \times \delta_{vp} \tag{13}$$

where ϕ_l is the typical annual loss coefficient, c_l is the cost for one unit of loss ($/kWh), and δ_{vp} is the coefficient for converting to the present value of annual costs, defined as:

$$\delta_{vp} = \frac{1}{\sum_{j=1}^{h}\left(1+\frac{\tau}{100}\right)^j} \tag{14}$$

where τ is the discount rate (%) and h is the number of years in the project life cycle. The operation and maintenance cost of the transformer stations C_{OM} is given by:

$$\mathrm{C_{OM}} = \delta_0 \sum_{i,j\in\Omega_l} (P_{Si}^2 + Q_{Si}^2) \tag{15}$$

The coefficient δo is used to convert the annual operation and maintenance cost to present value:

$$\delta_0 = 8760 \times \emptyset_l \times c_{vi} \times \delta_{vp} \tag{16}$$

where c_{vi} is the unit cost for operating and maintaining the transformer station ($/kVA²). Values 0 or 1 are used to represent the open/closed state of the branches n_{ij} of the switches in (9). In this case, n_{ij} refers to the status (open or closed) of the switch installed in segment *ij*.

The constraints of the mathematical model include power balance at the nodes, described by (2) and (3), radial nature of the feeder circuits ensured when simultaneously satisfying (2), (3), and (8) [6, 16], voltage magnitude limits (4), loading capacity of transmission lines and distribution networks (6), as well as loading limits of substations (7). The expansion of the loading capacity of transmission lines is modeled by the variable ξ_{ij}, reflecting the incremental deficits in the loading capacity of the existing transmission line ij. The Total Annual Revenue (TAR) is the amount paid to transmission companies by generation and distribution agents to access the system. The sum of TAR is ensured by the revenue collected from the Transmission System Usage Fee (TUSF), derived from a method of allocating transmission costs. In particular, the expansion of transmission significantly affects the price levels for end consumers. Assessing the effects of transmission expansion on the development of TAR is a complex task, considering that the actual expansion of the transmission system occurs discontinuously with the acceptance of new projects. Given that the focus of this study is the reconfiguration of the distribution system, a simplified modeling of TAR development was applied, assuming that expansion can be performed through marginal increases in the transmission capacity of existing routes, as described by

$$TAR = \sum_{i\in\Omega_{lt}} C_{ij} + (\xi_{ij}.\pi_{ij}) \tag{17}$$

where C_{ij} is the annual cost of the transmission line section ij ($), and π_{ij} is the marginal cost of the transmission line section expansion ij ($).

III. METHODOLOGY

The solution to this problem consists of two steps, as shown in Figure 2. Step 1 involves using a combination of the SA with GA to reconfigure the distribution power grid to reduce power loss. Step 2 involves utilizing the Zbus, EBE, and PS/SINCAL models for the optimization of transmission costs. Figure 3 shows Step 1.

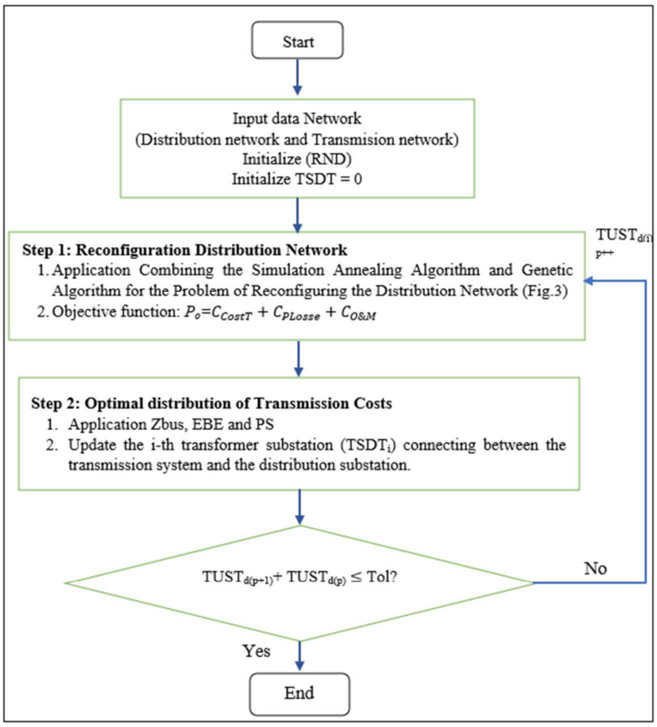

Fig. 2. Method for the reconfiguration of the distribution network based on an objective function considering the cost of electricity transmission.

A. *Step 1: Combining SA and GA to Reconfigure the Distribution Network*

SA and GA were amalgamated to form a hybrid algorithm termed GSA to reconfigure the distribution network. Within this hybrid framework, SA takes the lead in scouting for an optimal solution, while in every iteration of SA, GA steps in to offer a fresh configuration using genetic operations such as mutation or cross-over [17-19].

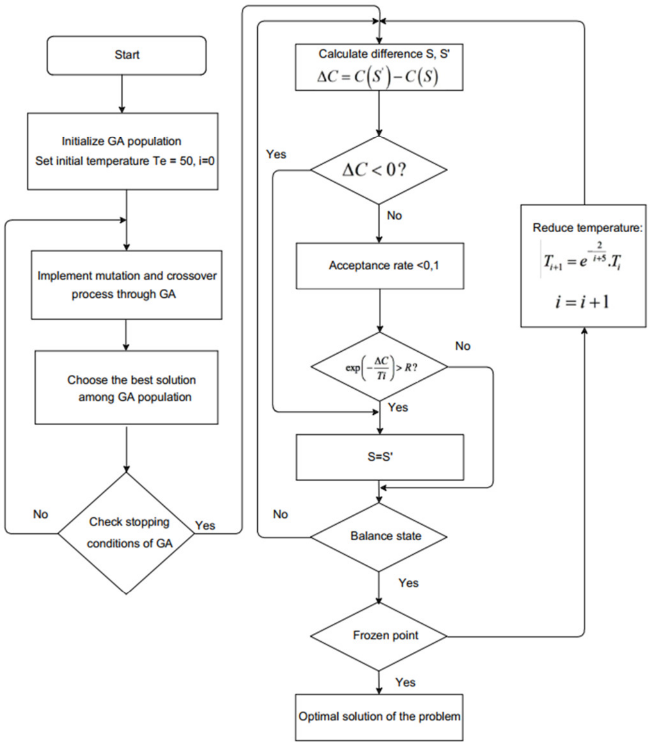

Fig. 3. Combining SA and GA to reconfigure the distribution network.

Figure 3 presents the main reconfiguration of the GSA process. The network N_0 is generated by the GA subfunction called *initialization* and the E_0 value of its objective function is calculated. The maximum temperature (T) is set to 50. Parameter I is employed to control the iterations of the GA process. The maximum number of iterations was set at 20. A new configuration N_1 is produced from the GA process and then evaluated to have E_1 [20]. If the new solution is better than the old one (which means $C_1 < C_0$), it is accepted and S_1 replaces S_0. Even if the new solution is worse than N_0, which means that $C_1 - C_0 > 0$, it can still be randomly accepted. In that case, the acceptance probability will be a function of the two values of the objective function and the temperature reduction function [21]. The cost functions are calculated using:

$$C(x) = \begin{cases} P_o + \alpha A(x) + \beta . B(x) & n \leq L_s \\ 1 + \theta(n - L_s) . P_o + \alpha A(x) + \beta . B(x) & n > L_s \end{cases} \quad (18)$$

In the SA algorithm, the following equation was applied to improve the temperature change process. With this improvement, the temperature change values in each step make it easier to find the optimal solution and the convergence time of the algorithm is faster.

$$T_{i+1} = e^{-\frac{2}{(i+5)}} . T_i \quad (19)$$

where i is the number of decreasing temperatures. GA is used to generate new potential solutions, in which the solution with the most appropriate value is selected and then put through the SA process for further selection [21].

B. Step 2: Optimal Distribution of Transmission Costs

This step focuses on the allocation of transmission system costs, conducted through three validated and widely applied methods that ensure robust and reliable results. The methods used to determine TUSFs include Zbus [22-23], PS [24], and EBE [23- 25].

IV. RESULTS AND DISCUSSION

The proposed method was simulated in Matlab R2019 [26] for the problem of electrical grid reconfiguration and transmission cost optimization (TRA) while simultaneously integrating with PSS SINCAL [27]. The simulation was run on a PC with an Intel® Core™ i7, 8GB RAM, and Windows 10. Figure 4 shows the implementation steps.

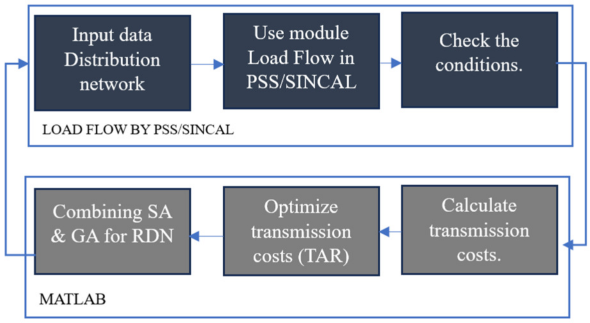

Fig. 4. Diagram implementation simulation.

Figure 1 shows the integration of transmission and distribution systems. The reconfiguration of the distribution network considering the economic signals of transmission tariffs was assessed based on the integrated modeling of the 4-bar transmission test system presented in [28-29] and the 54-node test system of [22].

A. Reconfiguration of the Distribution Network by GSA

The electricity grid considered is a distribution network including 33 nodes [6].

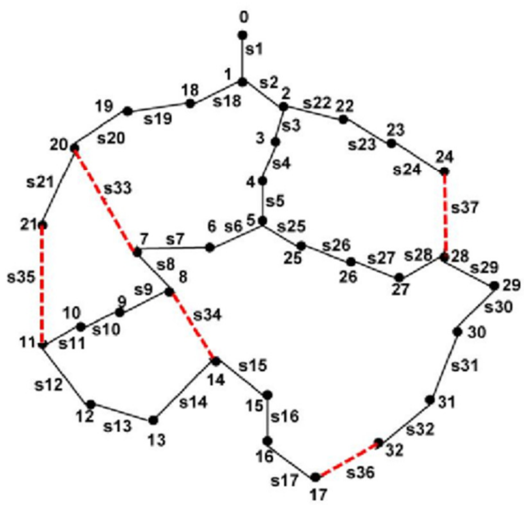

Fig. 5. Before reconfiguring the distribution network of 33 nodes.

TABLE I. COMPARISON OF GSA WITH OTHER METHODS

Parameter	Value	Parameter	Value
Intialization (before)		**GSA (proposed) (after)**	
Open switches are usually: s33, s34, s35, s36, s37 Switching usually closes: s1 to s32		Switches open: s7, s9, s14, s32, s37 Choose parameters $\alpha = 1000$, $\beta = 1000$, $\varepsilon = 0.1$, $\delta = 1$	
Voltage	12.66 kV	Voltage	12.66 kV
U_{max} U_{min}	0.913 pu 0.996 pu	U_{max} U_{min}	0.932 pu 0.995 pu
Active Capacity	5058.25 kW	Active Capacity	5058.25 kW
Reactive power	2547.32 kVAR	Reactive power	2547.32 kVAR
Total loss(P_{loss})	202.68 kW	Total loss(P_{loss})	136.89 kW

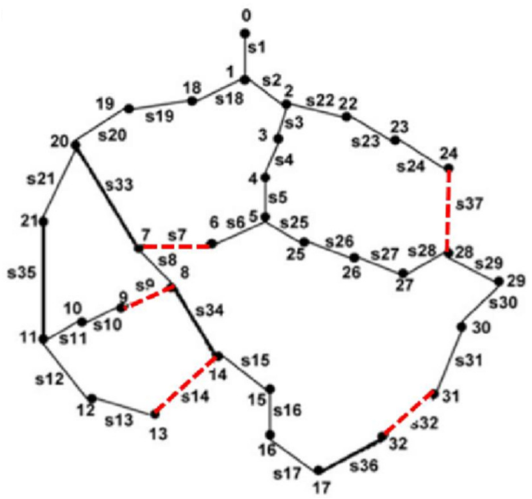

Fig. 6. After reconfiguring the distribution network.

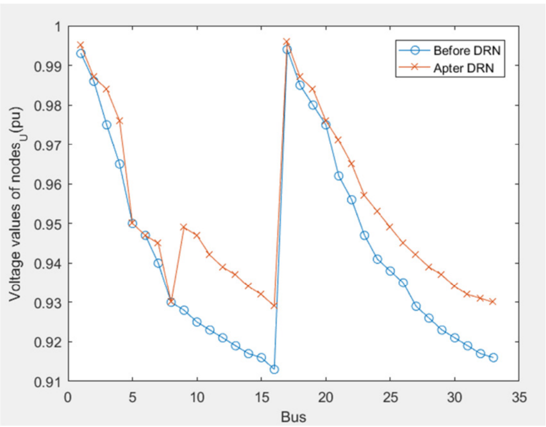

Fig. 7. Voltage before and after reconfiguring the distribution network.

TABLE II. COMPARISON OF GSA WITH OTHER METHODS

Method	P_{loss} (kW)	U_{min} (pu)	Open switches	Iteration
Initialization	202.68	0.913	s33,s34,s35,s36,s37	
SA [21]	137.57	0.932	s7,s9,s14,s32,s37	18
GSA (proposed)	**136.89**	**0.932**	**s7,s9,s14,s32,s37**	**11**
Gome [7]	138.57	0.928	s7,s9,s14,s32,s37	15
HSA[9]	139.55	0.928	s7,S9,S14,S32,s37	16
CE [5]	139.55	0.921	s7,s14,s28,s33,s36	-
Shirmoham[30]	138.87	0.932	s7,s10,s14,s32,s37	-

The results of the SA algorithm were compared with algorithms from [7, 9, 21, 30], and CE [5], as shown in Table II. The proposed method combined SA with GA to yield outcomes similar to those of other methods for the reconfiguration problem. However, it uniquely leverages the global optimization strengths of the SA algorithm and the local search capabilities of the GA during the initialization of values, thus significantly improves the processing speed. The number of iterations in the proposed method was lower than in the other methods.

B. Reconfiguration of the Distribution Network Considering Power Transmission Costs

The distribution system was connected to bus number 4 of the transmission system through substations SE-103 and SE-104, and to bus 3 through substations SE-101 and SE-102. Table III presents the technical and economic data used in the simulations.

TABLE III. TECHNICAL AND ECONOMIC DATA

No	Table column subhead	Value	Unit
1	Minimum voltage deviation	0.93	pu
2	Maximum voltage deviation	1.05	pu
3	O&M cost of the transformer substation	0.004	$\$/kVA^2$
4	Load factor	0.50	
5	Loss factor	0.50	
6	Loss cost	0.01	$/kW
7	Discount rate	10%	per year
8	Conductor impedance:	z=0.6115 +j 0.4133	Ω/km

To assess the impact of reconfiguring the distribution network considering the cost of the transmission system, the simulation study examined three scenarios regarding the load capacity of the lines:

- Scenario I: Capacity of Line LT-13: 25 MVA, other lines' capacity: 100 MVA.
- Scenario 2: Capacity of Line LT-24: 25 MVA, other lines' capacity: 100 MVA.
- Scenario 3: Capacity of Line LT-14: 25 MVA, other lines' capacity: 100 MVA.

In scenarios 1, 2, and 3, the power flowing in the transmission lines does not exceed their capacities when the reconfiguration of the distribution system aims at optimizing the charges for using the transmission system. On the contrary, in the three cases where the transmission tariffs are not considered, a need for transmission expansion arises. Table IV shows the impact of TUSFs on PDNR and the loading of distribution substations.

Table V shows a summary of the overhead costs resulting from reconfiguring the distribution grid. It was found that the outcomes of the distribution grid configuration remain the same, regardless of the transmission cost allocation method applied.

In scenarios 1, 2, and 3, the total cost decreases when considering the application of TUSF values. In this case, the proposed PDNR led to a reduction of 51.34%, 28.03%, and

30.17% in scenarios 1, 2, and 3, respectively, compared to the classical PDNR. These results underscore the importance of considering transmission fees in PDRN. The proposed method is highly reliable in these scenarios, minimizing cases of overload on transmission grid lines, and optimizing cost allocation when restructuring the problem. Moreover, the proposed method takes the cost of power supply into account, and so the need to invest in expanding the power transmission grid is reduced.

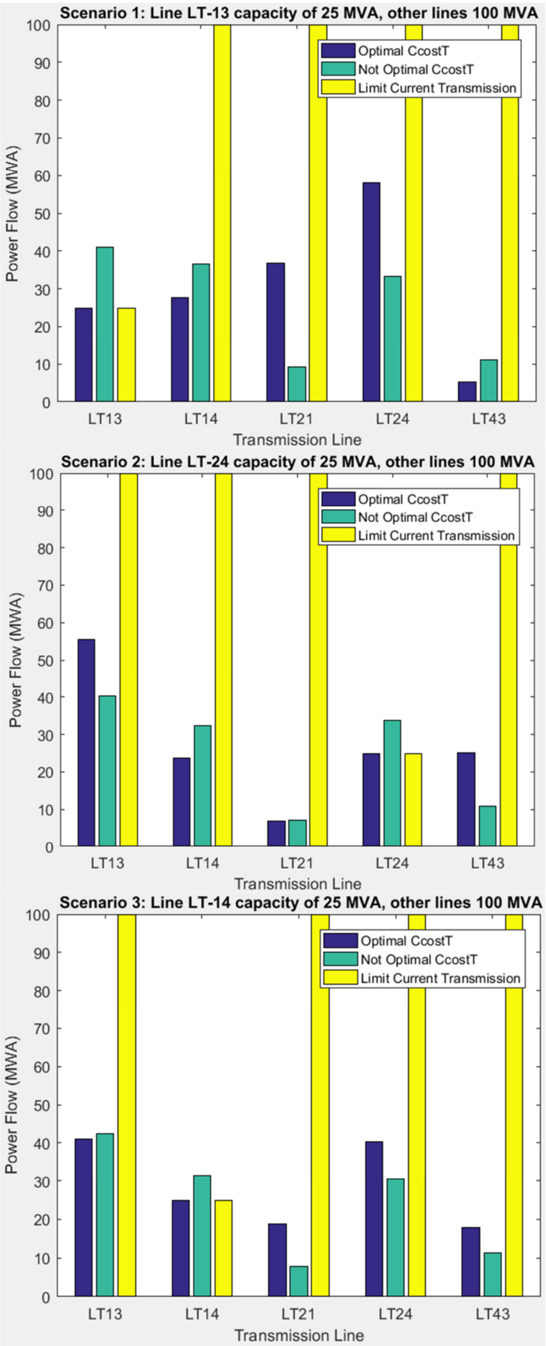

Fig. 8. Impact of DRN on power flow on transmission branches.

TABLE IV. CAPACITY TRANSFORMER STATION AND TUSF

	ATC	Capacity Transformer Station (MW)				TUSF ($/MW)	
		101	**102**	**103**	**104**	**101-102**	**103-104**
Scenario 1	EBE					0.0090	0.0064
	PS	4.77	20.53	35.48	37.33	0.0072	0.0067
	ZBUS					0.0071	0.0051
Scenario 2	EBE					0.0068	0.0076
	PS	30.26	45.11	10.27	13.48	0.0075	0.0110
	ZBUS					0.0042	0.0065
Scenario 3	EBE					0.0071	0.0066
	PS	19.73	31.22	20.92	26.39	0.0058	0.0078
	ZBUS					0.0045	0.0055

TABLE V. THE COSTS OPTIMATION

No	**Open Switch**	**PRDN (proposed)**	**PRDN (classic)**	**%**
		Global Cost ($)		
Scenario 1	2, 7, 12, 15, 18, 28, 35, 37, 39, 55, 57	1.872	3.847	51.34
Scenario 2	5, 8, 12, 20, 25, 28, 32, 34, 51, 55, 57	1.918	2.665	28.03
Scenario 3	4, 8, 12, 21, 25, 27, 35, 38, 44, 56, 57	1.768	2.532	30.17

V. CONCLUSION AND RECOMMENDATIONS

The proposed method addressed the problem of reconfiguring the distribution power grid considering transmission costs. The reconfiguration problem was approached by combining the strengths of SA and GA and improving the parameters within the SA algorithm (19), leading to faster convergence. When considering transmission cost factors, the optimized method incorporates economic indicators, taxes, voltage constraints, transmission limits, and the capacity of the distribution substations. The optimal outcome is to find the best configuration that connects substations with the most favorable TUSF values, ensuring reduced electricity supply costs for consumers. The future direction of this research will continue to explore additional constraints or include other optimization goals, such as the location, capacity of substations, transmission capacity, and power flow control in the distribution grid using Soft Open Points (SOP) and considering renewable energy sources.

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