Multi-objective Dynamic Expansion Planning of Active Meshed Distribution Network: Sizing, Siting, and Timing of Hub and Voltage Regulators

Mohammad Reza Jannati Oskuee[1],
Shahram Mojtahedzadeh[2†], and **Masoumeh Karimi**[3], Non-members

ABSTRACT

Distribution network expansion planning is a technique for managing the system effectively in the face of future challenges. This work investigates the design of a mesh distribution network to allocate substations, DGs, voltage regulators, feeder routing, switch placement, and the integration of multiple energy carrier systems. Dynamic modeling for multi-objective system expansion planning is proposed in this study to identify the optimal plan and operational strategy. The uncertainties related to DGs, electricity, heat load, and their prices are considered in the planning process. A 54-Bus distribution network is applied to evaluate the methodology and discuss the results.

Keywords: Distribution System, Expansion Planning, Hub, Voltage Regulator

LIST OF SYMBOLS

cb	Circuit breaker
DG	Distributed generation
ds	Disconnect switch
$e\alpha$	Expansion cost
f	Feeder
$I_{(f,yr,ts)}$	Current flow in f-th feeder at ts-th hour of yr-th year
$InfR$	Inflation rate
$IntR$	Interest rate
$i\alpha$	Installation cost
$l_{(f)}$	Length
lb	Load buses of the network
$MaxAE$	Max annual expansion
$MaxE$	Max expansion
$MaxG_{DG}$	Max generation of DG
$MaxI$	Max MVA of the s-th HV substation can be installed in b-th bus
$MaxL$	Max loading of a facility
$MaxNumber_{DG}$	Max number of DGs can be installed in the network in each year
$MaxP_{DG}$	Max generated power of DG
$NetV^{yr}$	Net present value
Num_{Day}	Number of days
$om\alpha$	Operation and maintenance cost
PF	Power factor
$P_{R_{(DG,lb,yr)}}$	Nominal active power at yr-th year of the dg-th DG installed in lb-th bus
$P_{Purchase}$	Purchased power
$P_{L_{(lb,yr,ts)}} + jQ_{L_{(lb,yr,ts)}}$	Scheduled active power of lb-th bus at ts-th hour of yr-th year
$R_f + jX_f$	Impedance of the f-th feeder
$S_{Loss} = P_{Loss_{(yr,ts)}} + jQ_{Loss_{(yr,ts)}}$	Power losses at ts-th hour of yr-th year
sb	HV/MV substation
ts	Time segments of a day
$V_{(lb,yr,ts)}$	Voltage amplitude of lb-th bus at ts-th hour of the yr-th year
V_R	Rated voltage
V^{min}_{Critic} & V^{max}_{Critic}	Min and max critic voltage
V^{min}_{Safe} & V^{max}_{Safe}	Min and max safe voltage
$Year$	Planning horizon
yr	Year
α	Cost
α_{HVSub}	High voltage substation cost
α_{feeder}	Feeder cost
α_{DG}	DG cost
α_{ENS}	Energy not supplied cost
α_{Loss}	Loss cost
$\alpha_{Penalty}$	Penalty cost
α_{Pur}	Cost of purchased power
α_{Switch}	Switch cost
η_{Trans}	Efficiency of transformer
$\eta_{e_{CHP}}$	Efficiency of CHP electric generation
$\eta_{h_{CHP}}$	Efficiency of CHP heat generation
η_{Boiler}	Efficiency of boiler

Manuscript received on November 3, 2021; revised on December 30, 2021; accepted on January 7, 2022. This paper was recommended by Associate Editor Kaan Kerdchuen.

[1]The author is with the Azarbaijan Power Engineering Consultants Co. (MONA), Tabriz, Iran.
[2]The author is with the Department of Electrical Engineering, Azarshahr Branch, Islamic Azad University, Azarshahr, Iran.
[3]The author is with the Shibrah Consultants Co., Tabriz, Iran.
[†]Corresponding author: mojtahedzadeh@azaruniv.ac.ir

Digital Object Identifier: 10.37936/ecti-eec.2022202.246908

1. INTRODUCTION

Distribution network expansion planners try to determine the timetable for replacing or reinforcing the operating facilities of the system or obtain the optimal capacity, site, and installation schedule of new equipment in such a way so as to meet the yearly increasing demand in an effective manner. Around the world, operating distribution networks are becoming antiquated, having been designed many years ago and unable to meet the technical challenges and the increasing distribution of generated unit penetration. Accordingly, periodic network expansion is an important challenge for system owners. Moreover, societies with a high level of digitalization need better power quality. Recent research and development tends to focus on the design and operation of distribution networks that are more reliable and secure in normal and extreme conditions.

In [1], the authors present a mixed-integer programming method to design a new network configuration by integrating two distribution networks to improve reliability and flexibility, while considering constraints such as the thermal limits of transformers and lines. In [2], an approach is proposed for reducing losses in large distribution network feeders, especially LV grids, by designing a methodology to minimize costs. The authors in [3] proposed a mixed-integer linear programming method to plan an optimal network based on feeder corridors rather than a set of candidate routes. In the proposed approach, the investment cost is minimized while meeting specific technical constraints such as reliability and load restoration strategies between feeders. A stochastic multistage method is suggested in [4, 5] for mid and long-term feeder routing. These authors considered geographical constraints, load uncertainties, and network parameter behavior in the proposed model.

A multistage planning approach is proposed in [6] for active distribution systems. The authors considered feeder and substation reinforcement, capacitor, and voltage regulator location, in conjunction with active power management of the distributed generators. To address this problem, they first solve the location and sizing of the decision variables and then the time horizon of the investment problem. In [7], the authors provide an approach for resilient distribution system planning. They attempted to solve this problem with simultaneous feeder routing, identifying types of conductors and substation siting to achieve resilient distribution system configuration. The proposed model in [8] was designed to address the expansion planning issue. The authors allocated distribution substations using artificial immunological systems. They also performed feeder routing and conductor selection in the planning process by considering economic and technical constraints. The authors in [9] suggested a method for optimizing locations, size, and substation loading while minimizing fixed and variable costs. In [10], a multistage distribution network was proposed to address the expansion planning problem by investigating asset location, and the time horizon of their installation while considering costs and reliability aspects. The researchers in [11–13] present methodologies for the optimal sizing and siting of different types of DGs in a distribution system to minimize power loss, maintaining the fault level and voltage variation within the acceptable limits.

Another requirement for network expansion planning is to consider the energy hub. In [14, 15] a decision-making approach and a stochastic method are suggested for the expansion planning of gas and power systems by considering the uncertainties in relation to DGs. In [16], a co-optimization planning approach is suggested for the optimal investment planning of power systems, by considering the interdependency of gas-power infrastructures. The researchers in [17] designed a model by considering DGs for distribution and gas networks. They presented a model based on a smart energy hub. The researchers in [18] proposed a mixed-integer linear stochastic model for electricity distribution networks and DG expansion planning. They aggregated and modeled the distributed generators using the energy hub concept. The authors in [19] propose a technique for the optimal operation and configuration of multiple energy hubs. The proposed hub contains different types of energy sources and energy storage devices to feed demand. A method for optimally obtain the size, site, and number of DGs is proposed in [20] to maintain security of the power supply during the occurrence of faults in the distribution system.

In distribution network planning, installing different types of voltage regulators (VR) and capacitors (CB) can facilitate an economic and reliable service to consumers. One of the most effective and common measures for enhancing the eco-technical specifications of a distribution network such as power loss diminishing, voltage profile enhancement, and reliability improvement is CB/VR allocation [21]. The authors in [22] aim to reduce power loss and improve the voltage profile with the optimal allocation of DGs and CBs. In [23], the optimal allocation of battery energy storage systems (BESS) and CB in the microgrid to reduce costs and loss while enhancing power quality is investigated by considering the uncertainties of renewable DGs. In [24], VRs are optimally planned to maximize photovoltaic (PV) energy integration in DNs. In [25], simultaneous optimal siting and sizing of the parking lots (PLs) and CBs is proposed to manage congestion and reactive power. In [26], an optimization approach is proposed to allocate the VRs in traditional DNs at the lowest possible cost, with the aim of preserving the voltage at allowed limits and reducing the cost of power loss. The authors in [27] proposed the optimal configuration and allocation of CBs, BESS, VRs, and DGs by integrating them into the distribution system. A method for DG allocation in distribution systems is proposed in [28] in coordination with voltage regulators and capacitors to improve performance.

In [29, 30], the simultaneous siting of dispatchable and non-dispatchable DGs and capacitors is proposed to improve system performance and minimize costs. In [31–33], the authors suggest an approach for the simultaneous allocation of capacitors, DGs, and network reconfiguration by considering related uncertainties to improve power quality and mitigate loss reduction. The authors in [34] solved the switch location optimization problem in the distribution network by considering the minimization of interruption costs. In [35], the optimal switch allocation in distribution networks is proposed, with the aim of minimizing the number of switches on feeders. The authors in [36, 37] integrated switch failure into switch allocation by considering minimizing the energy not supplied and switch costs. In [38], a multi-objective reliability-oriented model for optimal switch placement was proposed. The authors in [39] propose a multi-objective framework for distribution system planning to assess the risk imposed by probabilistic customer choices on reliability, which is a buy and sell price strategy for electricity, depending on the reliability level provided by the utility. The authors in [40, 41] solved the optimal placement problem using a sectionalizer, recloser, and fuse with the aim of minimizing the SAIDI and SAIFI. While a model was presented in [42] to optimally locate switches and tie lines to improve reliability. In [43], the authors suggest a model for optimal fault detecting and switch location in the distribution system. The model was used for fault location, isolation, and restoration under the threat of faults like cyber-attacks.

An MILP model was studied in [44] to solve the switch location problem in lateral branches as well as main feeders and evaluated the impact of this method on a number of switch locations. The authors in [45] optimized the objective functions of reliability and power quality with the installation of a timetable, modifying the location of capacitors and switches, size of existing capacitors, and type of installed switches obtained using MOPSO.

A review of the literature on distribution network planning reveals that almost all studies focus on radial DNs and the authors rarely investigate expansion planning for meshed DNs. Another notable point is that previous studies tend to focus separately on DEP issues while failing to consider expansion problem-solving in its entirety. In optimal distribution network planning, it is essential to consider the impact of all the previously mentioned topics simultaneously. This work aims to bridge some of the gaps in the distribution expansion planning process. Existing research in this field employs static models to address the issue of distribution expansion planning. Most studies focus on the last year of the planning horizon, while no decisions are made on the middle years. However, the budget constraints of distribution companies do not allow for a one-year investment in the planning period when using dynamic modeling. Moreover, an appropriate method for providing a reliable power supply requires a decrease in the energy not supplied by considering the different priorities of customers. Besides these issues, load representation, uncertainties involved with renewable generation, load and heat and the related energy prices, the power quality indices are also crucial factors in system planning. The main contributions of this paper are summarized as follows:

- Optimal sizing and placement of network facilities, such as a high voltage substation, multi-type DGs, hubs, voltage regulators, and the provision of an installation or annual expansion timetable;
- Multi-type switch placement and the provising of an installation schedule;
- Yearly feeder routing and conductor sizing;
- Solving the problem from the eco-reliability and power quality perspectives;
- Optimal annual hub and DG dispatch;
- Considering load priority in supply and voltage-sensitive loads;
- Considering DG generation, load, and heat load demand and price uncertainty;
- Using fuzzy set theory to model the soft constraints and find the best compromise solution.

2. PROPOSED PLANNING METHODOLOGY

The distribution network is a structured mesh system with open/close switches which operate radially. This feeder arrangement consists of a connected graph without any loops and feeds load buses from an HV substation. The switches placed on some of the links are used to connect nearby feeders to provide supply continuity during a fault and also reconfigure the distribution network to maintain power flow, reliability, and power quality.

In this work, the proposed approach aims to address adequacy and security issues. Supplying sufficient electricity to meet demand requires replacement or reinforcement of the operating facilities or additional investment. In addition, the distribution network is capital-intensive and must therefore be designed in a cost-effective way, while also allowing for the operational, technical, reliability, quality, and environmental constraints. Moreover, the proposed dynamic method requires decisions to be made at yearly time intervals to determine the optimal site, size, and appropriate time for installing new assets or expanding existing assets in the distribution network and operating them together over the planning period.

2.1 Main Issue

Mathematical modeling of the problem and simulation process is directly dependent on the possibilities and probabilities. Consequently, the uncertainties and impact of the network parameters on load demand are important factors and presented in the following section.

2.2 Uncertainty Modeling

The demand for electricity and heat varies over time in accordance with the price of energy carriers. The generation of renewable DGs depends on the weather conditions during a year. Therefore, uncertainties relating to demand, generation, and market price must be considered in the decision-making process for distribution network planning or operation. To achieve this aim, scenario-based modeling is proposed in this work with a specific scenario involving the generation and reduction technique [46]. Eq. (1) shows the amount of load (L^{e}_{sen}), market price (P^e_{sen}), wind speed (V^w_{sen}), and irradiation (I^s_{sen}) are presented as a percentage of their peak value. Also, π_{sen} is used to present the probability of scenarios, obtained using Eq. (2):

$$Scenario_{sen} = [L^e_{sen}\ P^e_{sen}\ V^w_{sen}\ I^s_{sen}] \tag{1}$$

$$\pi_{sen} = \pi_{L^e} \times \pi_{P^e} \times \pi_{V^w} \times \pi_{I^s} \tag{2}$$

2.3 Load Modeling

In practice, the distribution network supplies different types of load. Therefore, appropriate load modeling is a crucial factor in power system planning. In this paper, voltage-dependent load models are expressed as in [45]:

$$P = p_0 \left|\overline{V}\right|^{\zeta} \tag{3}$$

$$Q = q_0 \left|\overline{V}\right|^{\xi} \tag{4}$$

where ζ is 0.18, 0.92, and 1.51, ξ is 6, 4.4, and 3.4 for industrial, residential, and commercial loads, respectively.

3. PROBLEM FORMULATION

The proposed approach attempts to attain an optimal scheme for the distribution network which meets all economic, technical, operational, and reliability constraints. The objective function involves operational and maintenance costs, installation and expansion of facilities, operational cost of the distribution system, and penalty costs. It should be noted that distribution companies have a responsibility to provide the contracted power quality. In this regard, they must adjust the value of operational indices. Voltage stability is the most common indicator of power quality since it refers to the capability of DN to fix the voltage level of all DN buses under standard operating conditions. Therefore, the proposed objective function is shown in the following equations:

$$\alpha = \alpha_{HVSub} + \alpha_{feeder} + \alpha_{SD} + \alpha_{DG} + \alpha_{CB} + \alpha_{Hub} + \alpha_{VR} + \alpha_{Loss} + \alpha_{Pur} + \alpha_{ENS} + \alpha_{Penalty} \tag{5}$$

$$\text{Voltage Stability Function} = \frac{\sum\limits_{lb\in Bus}\sum\limits_{yr\in Year}\sum\limits_{sen\in Scenario} \pi_{sen}\times\left(2\times V_{(lb+1,yr,sen)} - V_{(lb,yr,sen)}\right)}{Num_{Year}\times Num_{Scen}\times(Num_{Bus}-1)} \tag{6}$$

Since this approach determines the annual investment cost, the "Net Present Value, β" of the annual cost can be calculated as:

$$\beta^{yr} = \left(\frac{1+InfR}{1+IntR}\right)^{yr} \tag{7}$$

All related factors and constraints are described in the following section.

3.1 High Voltage Substation Costs

In a power system, the various types of substations should be allocated in such a way so as to supply all customers. New HV substations may be installed in predefined candidate sites. These substations and those with operating capacity will be optimally specified annually. The net present value of substation cost is obtained using Eq. (8), while Eq. (9) presents the fixed costs relating to substations. Eq. (10) refers to the expansion cost. Constraints in relation to substation allocation are demonstrated using Eqs. (11)–(14). Eq. (11) is used to define the safety margin, while Eq. (13) defines the technical constraints and Eq. (14) is used to obtain the maximum capacity of a substation that can be installed in a certain bus.

$$\alpha_{HVSub} = \sum_{yr\in Year}\beta^{yr}\times\sum_{lb\in Bus}\left(i\alpha_{(sb,lb,yr)} + e\alpha_{(sb,lb,yr)} + om\alpha_{(sb,lb,yr)}\right) \tag{8}$$

$$i\alpha_{(sb,lb,yr)} = \alpha_{Ground_{(sb)}}\times\alpha_{Ground_{(lb)}} + \alpha_{Equipment_{(sb,lb)}} + \alpha_{Construction_{(sb,lb)}} + \alpha_{Connection_{(sb,lb)}} \tag{9}$$

$$e\alpha_{(sb,lb,yr)} = i\alpha_{(sb,lb,yr)} - i\alpha_{Sub_{(sb,lb,yr-1)}} \tag{10}$$

$$om\alpha_{(sb,lb,yr)} = S_{R_{(sb,lb,yr)}} \times \alpha_{om_{HVSub}} \tag{11}$$

$$S_{L_{(sb,yr)}} \le MaxL_{HVSub}\times S_{R_{(sb,yr)}} \tag{12}$$

$$S_{R_{(sb,lb,yr)}} \le S_{R_{(sb,lb,yr-1)}} + MaxAE_{(sb,lb)} \tag{13}$$

$$S_{R_{(sb,lb)}} \le MaxI_{(sb,lb)} \tag{14}$$

3.2 Distribution System Feeder Costs

This work also aims to optimize the feeder route and conductor size. The cost of installing feeders with a known conductor depends on its length.

$$\alpha_{Feeder} = \sum_{yr\in Year}\beta^{yr}\times\sum_{yr\in Year}\left(I\alpha_{(f,yr)} + E\alpha_{(f,yr)}\right) \tag{15}$$

$$I\alpha_{(f,yr)} = l_{(f)}\times\alpha_{f_{(Overhead)}} \tag{16}$$

$$E\alpha_{(f,yr)} = I\alpha_{(f,yr)} - I\alpha_{(f,yr-1)} \tag{17}$$

$$S_{L_{(f,yr)}} \le MaxL_f \times S_{R_{(f,yr)}} \tag{18}$$

3.3 Switch Placement Cost

The radial operation of mesh distribution network requires the allocation of open/close switches on the grid. Here, circuit breakers are used to immediately isolate the feeder section from other sections with sectionalizing switches used in the reconfiguration process of all operational conditions. Although these devices may improve reliability they require significant investment. The switch placement cost and related constraints are represented by Eqs. (20) and (21).

$$\alpha_{Switch} = \sum_{yr\in Year} \beta^{yr} \times \sum_{f\in feeder} \left(I\alpha_{(cb,f,yr)} + I\alpha_{(ds,f,yr)}\right) \tag{19}$$

$$InstalledNumber_{(cb)} \le MaxNumber_{CircuitBreaker} \tag{20}$$

$$InstalledNumber_{(ds)} \le MaxNumber_{DisconnectSwitch} \tag{21}$$

3.4 Distributed Generation Costs

The method proposed in this paper determines the different types of DGs including dispatchable wind and solar for optimal location, capacity, installation timetable, and simultaneous hourly power generation. The related cost functions and constraints are shown in the following section. The reactive power has a significant effect on the load flow results, and DGs can generate reactive power (Eq. (30)). The generation of DGs is limited by the ramp up and down rate (Eq. (31)). Moreover, according to the cost and time-consuming start-up of dispatchable DGs (DDG), it is assumed that these units will not be down. Their generated power is defined by Eq. (29). P_G and Q_G represent the active and reactive power of DGs, respectively.

$$\alpha_{DG} = \sum_{yr\in Year} \beta^{yr} \times \sum_{lb\in Bus} \Bigg[I\alpha_{(DG,lb,yr)} + E\alpha_{(DG,lb,yr)} + \left(Num_{Day} \times \sum_{ts\in Hour} \pi_{sen} \times om\alpha_{(DG,lb,yr)} \right) \Bigg] \tag{22}$$

$$I\alpha_{(DG,lb,yr)} = \alpha_{Ground_{(DG)}} \times \alpha_{Ground_{(lb)}} + \alpha_{Equipment_{(DG,lb)}} + \alpha_{Construction_{(DG,lb)}} + \alpha_{Connection_{(DG,lb)}} \tag{23}$$

$$E\alpha_{(DG,lb,yr)} = I\alpha_{(DG,lb,yr)} - I\alpha_{(DG,lb,yr-1)} \tag{24}$$

$$om\alpha_{(DG,lb,yr)} = P_{G_{(DG,lb,yr)}} \times \alpha_{om_{DG}} \tag{25}$$

$$\sum_{lb\in Bus} P_{R_{(DG,lb)}} \le MaxP_{DG} \tag{26}$$

$$\sum_{lb\in Bus} \frac{P_{R_{(DG,lb)}}}{\max\left(1, P_{R_{(DG,lb)}}\right)} \le MaxNumber_{DG} \tag{27}$$

$$P_{R_{(DG,lb,yr)}} \le P_{R_{(DG,lb,yr-1)}} + MaxAE_{(DG,lb)} \tag{28}$$

$$P_{R_{(DG,lb)}} \le Max_{E_{(DG,lb)}} \tag{29}$$

$$PF_{DG} = cte \tag{30}$$

$$P_{G_{(DG,lb,yr,sb)}} \ge MaxG_{DDG} \tag{31}$$

3.5 Voltage Regulator Cost

The step-voltage regulator is used to stabilize its terminal while enhancing the voltage profile and mitigating loss.

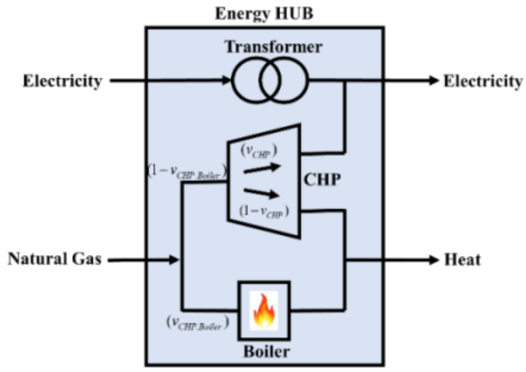

***Fig. 1**: The implemented hub model.*

$$\alpha_{VR} = \sum_{yr\in Year} \beta^{yr} \times \sum_{lb\in Bus} \left(i\alpha_{(vr,lb,yr)} + om\alpha_{(vr,lb,yr)} \right) \tag{32}$$

$$i\alpha_{(vr,lb,yr)} = S_{R(vr,lb,yr)} \times \alpha_{VR} + \alpha_{FixedVR} \tag{33}$$

$$om\alpha_{(vr,lb,yr)} = S_{R(vr,lb,yr)} \times \alpha_{om_{VR}} \tag{34}$$

$$S_{R(vr,lb,yr)} \le MaxAE_{(vr,lb)} \tag{35}$$

$$\sum_{lb\in Bus} \frac{S_{R(vr,lb)}}{\max(1, S_{R(vr,lb)})} \le MaxNumber_{VR} \tag{36}$$

3.6 Hub Cost

An energy hub is depicted in Fig. 1. The hub is a super node which receives gas and its outputs are electricity and heat. This system economically schedules the desired technology and indicates when it should be operated to meet the hub's demand. Cost reduction, reliability, resilience, and voltage profile improvements result from the optimal siting and sizing of hubs in a distribution network. In this work, it is assumed that hubs can be installed in any candidate node among network buses near gas pipelines. Electricity and heat are supplied by the distribution network and boilers, respectively, before installing the hub. They may also be supplied with CHPs in some of the nodes after hub installation. The mathematical formulation of the hub model according to the details presented in Fig. 1 is illustrated in the following equations. $P_{HUBPurGas_{(lb,yr,sen)}}$ is the purchased gas from gas distribution system and $P_{HUBPurElec_{(lb,yr,sen)}}$ is the purchased electricity from the electrical distribution network, at *sen*-th scenario of *yr*-th year by the *hb*-th hub installed in *lb*-th bus. $P_{HUBSoldHeat_{(lb,yr,ts)}}$ and $P_{HUBSoldElectricity_{(lb,yr,ts)}}$ are the sold heat and electricity, respectively. The operation and maintenance cost of the hub is obtained from Eq. (39). The power conversion process and amount of consumed or generated energy carriers are defined in Eqs. (40) and (41). For maximum gas flow in the gas distribution network, the CHP boiler is limited by Eq. (42) and the maximum electrical power flow in the electrical distribution network and CHP transformer is limited using Eq. (43).

$$\alpha_{HUB} = \sum_{yr\in Year} \beta^{yr} \times \sum_{lb\in Bus} \Bigg(i\alpha_{(hb,lb,yr)} + \Big(N_{Day} \times \sum_{sen\in Scenario} \pi_{sen} \times om\alpha_{(hb,lb,yr,sen)} \Big) \Bigg) \quad (37)$$

$$\alpha_{(hb,lb,yr)} = \alpha_{Ground_{(hb)}} \times \alpha_{Ground_{(lb)}} + \alpha_{Equipment_{(hb,lb)}} + \alpha_{Construction_{(hb,lb)}} + \alpha_{ConnectionToElecNetwork_{(hb,lb)}} + \alpha_{ConnectionToGasNetwork_{(hb,lb)}} \quad (38)$$

$$om\alpha_{(hb,lb,yr,sen)} = \alpha_{Gas_{(sen)}} \times P_{HUBPurGas(lb,yr,sen)} + P^{elec}_{sen} \times \alpha_{Electricity_{(sen)}} \times P_{HUBPurElec(lb,yr,sen)} - P^{heat}_{sen} \times \alpha_{Heat(sen)} \times P_{HUBSoldHeat(lb,yr,sen)} - \alpha_{Electricity(sen)} \times P_{HUBSoldElectricity(lb,yr,sen)} \quad (39)$$

$$P_{HUBSoldElectricity(lb,yr,sen)} = \eta_{Trans} \times P_{HUBPurElec(lb,yr,sen)} + \eta_{eCHP} \times v_{CHP\cdot Boiler} \times v_{CHP} \times P_{HUBPurGas(lb,yr,sen)} \quad (40)$$

$$P_{HUBSoldHeat(lb,yr,sen)} = \eta_{h_{CHP}} \times v_{CHP\cdot Boiler} \times (1 - v_{CHP}) \times P_{HUBPurGas(lb,yr,sen)} + \eta_{Boiler} \times (1 - v_{CHP\cdot Boiler}) \times P_{HUBPurGas(lb,yr,sen)} \quad (41)$$

$$MF_{Gas_{(GasNetwork,CHP,Boiler)}} \leq MPG_{(GasNetwork,CHP,Boiler)} \quad (42)$$

$$MF_{Electricity_{(ElectricNetwork,CHP,Transformer)}} \leq MPE_{(ElectricNetwork,CHP,Transformer)} \quad (43)$$

3.7 Power Loss Cost

The distribution subsystem is the main source of loss in the power system. The following equations are used to obtain the related costs:

$$S_{Loss_{(yr,sen)}} = \sum_{f\in feeder} \sum_{yr\in Year} \sum_{sen\in Scenario} I^2_{(f,yr,sen)} \times (R_f + jX_f) \quad (44)$$

$$\alpha_{Loss} = \sum_{yr\in Year} \beta^{yr} \times Num_{Day} \times \left[\sum_{sen\in Scenario} \pi_{sen} \times \Big(\alpha_{P_{Loss_{sen}}} \times P_{Loss(yr,sen)} + \alpha_{Q_{Loss_{sen}}} \times Q_{Loss(yr,sen)} \Big) \right] \quad (45)$$

3.8 Cost of Purchased Power

The amount of power purchased by the distribution company to supply customers and the related costs are calculated by Eqs. (46) and (47).

$$P_{Purchase(yr,sen)} = \sum_{lb\in Bus} \sum_{yr\in Year} \sum_{sen\in Scenario} \Big(\overline{P}_{Load_{(lb,yr,sen)}} - P_{Gen_{(dg,lb,yr,sen)}} + P_{HUBPurElec(hb,lb,yr,sen)} - P_{HUBSoldElectricity(hb,lb,yr,sen)} \Big) + \sum_{yr\in Year} \sum_{sen\in Scenario} P_{Loss(yr,sen)} \quad (46)$$

$$\alpha_{Loss} = \sum_{yr\in Year} \beta^{yr} \times Num_{Day} \times \sum_{sen\in Scenario} \pi_{sen} \times \Big(\alpha_{P_{Loss(sen)}} \times P_{Loss_{(yr,sen)}} + \alpha_{Q_{Loss_{(sen)}}} \times Q_{Loss_{(yr,sen)}} \Big) \quad (47)$$

3.9 Cost of Energy Not Supplied (ENS)

When evaluating reliability, it is evident that the ENS is an essential component for optimizing system reliability, while improving it will affect other reliability indices. To calculate the ENS, the failure duration of f-th feeder (fd_f), its failure rate (λ_f) and load supply priority ($sp_{(lb)}$) are required. Here, critical buses are more important.

$$ENS_{(yr)} = \sum_{f\in feeder} fd_f \times \lambda_f \times \Bigg(\sum_{\substack{lb\in Bus \\ Bus\in Damaged Area}} sp_{(lb)} \times ave(\overline{P}_{Load_{(lb,yr)}}) \Bigg) \quad (48)$$

$$\alpha_{ENS} = \sum_{yr\in Year} \beta^{yr} \times Num_{Day} \times ENS_{(yr)} \quad (49)$$

3.10 Penalty Cost

Load flow analysis is executed to obtain the bus voltage and feeder currents and check whether or not they are in the predefined limits. The penalty function (*PC*) is used to satisfy voltage and thermal limit constraints:

$$\alpha_{Penalty} = \alpha' \times \max\{(1 - \psi^V), (1 - \psi^I)\} \quad (50)$$

The load flow analysis is presented by Eqs. (51) and (52). The voltage constraint for *lb*-th bus, *sen*-th scenario, and *yr*-th year is defined by Eq. (53). The index for the entire network is calculated as Eq. (54). The same process is used for evaluating the feeder thermal limit.

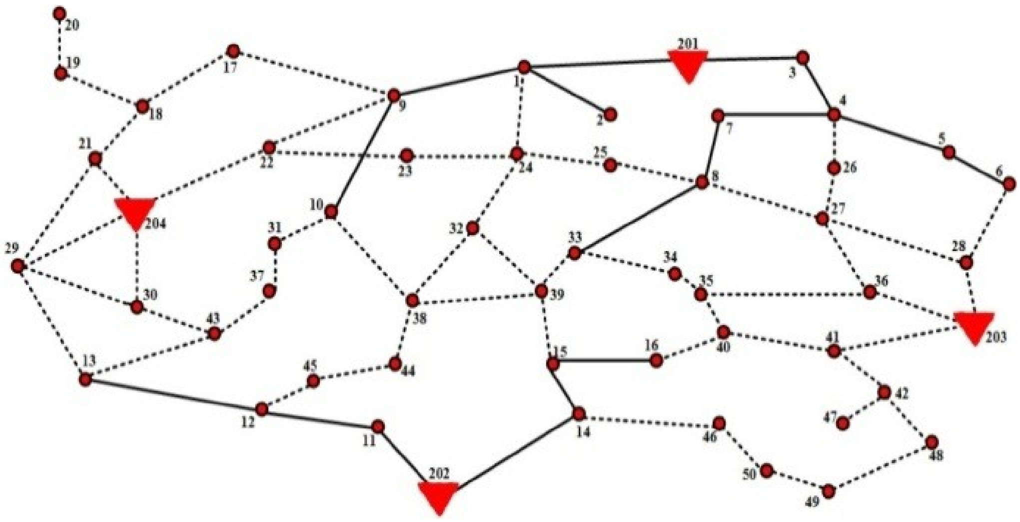

***Fig. 2**: 54-bus distribution test network.*

$$P_{L_{(lb_0,yr,sen)}} - P_{G_{(dg,lb_0,yr,sen)}} + P_{HUBPurElec(lb_0,yr,sen)} - P_{HUBSoldElectricity_{(lb_0,yr,sen)}} = V_{(lb_0,yr,sen)} \times \sum_{lb\in Bus} \left(V_{(lb,yr,sen)} \times Y_{(lb,lb_0)} \times \cos\left(\delta_{(lb,yr,sen)} - \delta_{(lb_0,yr,sen)} - \theta_{(lb,lb_0)}\right)\right) \tag{51}$$

$$Q_{L_{(lb_0,yr,sen)}} - Q_{G_{(dg,lb_0,yr,sen)}} + Q_{HUBPurElec(lb_0,yr,sen)} - Q_{HUBSoldElectricity_{(lb_0,yr,sen)}} = -V_{(lb_0,yr,sen)} \times \sum_{lb\in Bus} \left(V_{(lb,yr,sen)} \times Y_{(lb,lb_0)} \times \sin\left(\delta_{(lb,yr,sen)} - \delta_{(lb_0,yr,sen)} - \theta_{(lb,lb_0)}\right)\right) \tag{52}$$

$$\psi^V_{(lb,yr,sen)} = \begin{cases} \dfrac{V_{(lb,yr,sen)} - V^{min}_{Critic}}{V^{min}_{Safe} - V^{min}_{Critic}}; & V^{min}_{Critic} \le V_{(lb,yr,sen)} \le V^{min}_{Safe} \\ 1; & V^{min}_{Safe} \le V_{(lb,yr,sen)} \le V^{max}_{Safe} \\ \dfrac{V_{(lb,yr,ts)} - V^{max}_{Critic}}{V^{max}_{Safe} - V^{max}_{Critic}}; & V^{max}_{Safe} \le V_{(lb,yr,sen)} \le V^{max}_{Critic} \\ 0; & \text{else} \end{cases} \tag{53}$$

$$\psi^V = \frac{1}{N_{Year} \times N_{Hour} \times N_{Bus}} \sum_{lb\in Bus} \sum_{y\in Year} \sum_{sen\in Scenario} \pi_{sen} \times \psi^V_{(lb,yt,sen)} \tag{54}$$

4. CASE STUDY

To evaluate the proposed methodology, a large-scale 54-bus test case (distribution network) is selected. This test case is presented in Fig. 2. In nodes 201 and 202, HV/MV substations have already been installed and in operation. Nodes 203 and 204 are also the candidate sites for installing new ones. In other buses or nodes, different types of DGs may be installed. Bold and dashed lines represent the existing and candidate feeder routes, respectively. The tested network is a modified form of the sample network used in [47, 48].

The test case is simulated using previously developed software (Distribution Planning and Operation Software; DisPOS) in the MATLAB programming platform. This software has been tested on different test cases and its efficiency validated in various projects and papers.

4.1 Results and Discussion

A multi-objective genetic algorithm is applied when optimal decisions are made in the presence of trade-offs between conflicting objectives. In such cases, solutions exist to simultaneously optimize the objectives. Consequently, there may be a number of Pareto solutions. As can be observed from Fig. 3, six in Pareto-front solutions represent the values of different objective functions.

4.2 Finding the Best Compromise Solution

In practice, only one solution is required to address a problem. However, Pareto-front analysis is not always helpful. Therefore, the fuzzy set theory can be useful when deciding on the selection of the best compromise solution from the set of Pareto fronts [45]. Consequently, the fuzzy membership function should correspond to

***Table 1**: Substation capacities.*

Substation ID	Substation Size (MVA) in Each Year of Planning				
	1st year	2nd year	3rd year	4th year	5th year
201	30	30	37.5	45	52.2
202	15	15	15	22.5	30
203	0	0	0	0	0
204	7.5	7.5	15	15	15

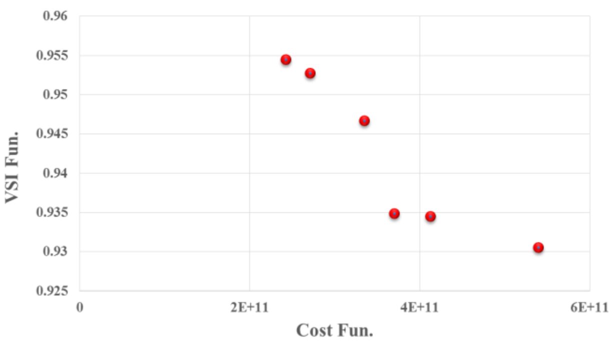

***Fig. 3**: Pareto fronts.*

the degree of satisfaction in each objective function according to the following equations:

$$h_i = \begin{cases} 1; & obj_i \leq obj_i^{min} \\ \dfrac{obj_i^{max} - obj_i}{obj_i^{max} - obj_i^{min}}; & obj_i^{min} \leq obj_i \leq obj_i^{max} \\ 0; & obj_i \geq obj_i^{max} \end{cases} \tag{55}$$

$$h = \frac{1}{N_{obj}} \sum_{i=1}^{N_{obj}} h_i \tag{56}$$

In Eq. (55), h_i varies from 0 to 1, indicating the satisfaction degrees of the i-th objective function value. The best compromise solution is the one with the greatest value of h. The following results are obtained using the fuzzy set theory applied to non-dominated solutions obtained by NSGA II to find the best solution, as described in the remainder of this section. The proposed distribution network expansion approach presented in the previous sections and the results obtained from the developed software are discussed here.

In this study, the planning horizon is set to five years, and the test case then evaluated using the proposed planning methodology in previous sections by considering the technical and operational constraints to obtain the optimal expansion planning strategy and network configuration for each year of the planning horizon. In this case, Figs. 4–6 represent the optimal configuration of the network and other related assets at different time segments of the planning horizon. These figures depict the proposed distribution network expansion during the planning period. Assume there is no maneuver switch

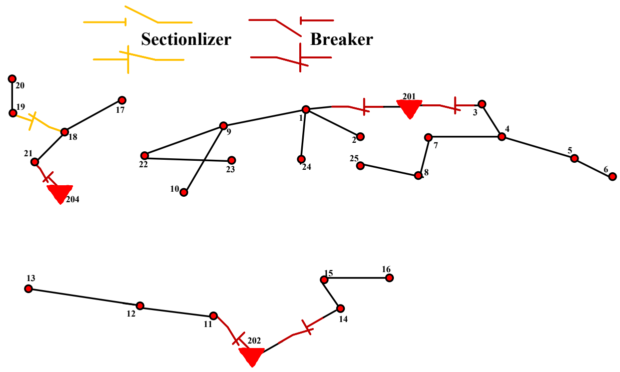

***Fig. 4**: Distribution network optimal configuration in the first year.*

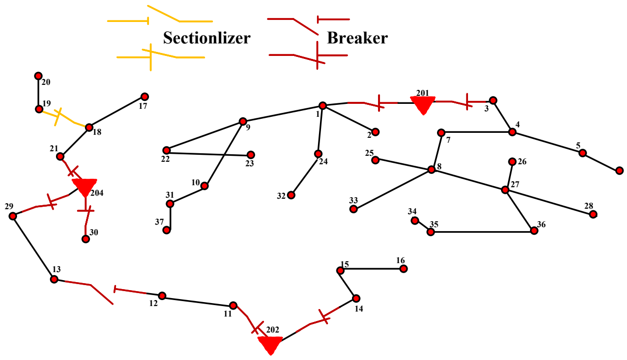

***Fig. 5**: Distribution network optimal configuration in the second year.*

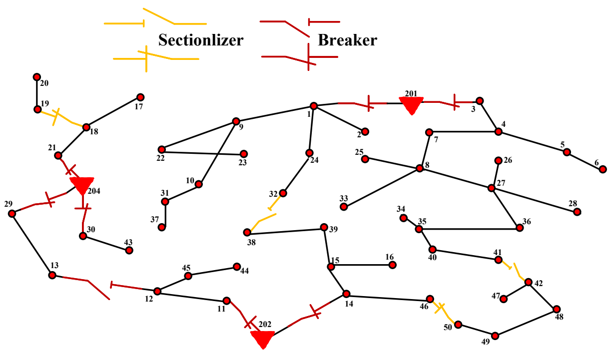

***Fig. 6**: Optimal configuration of the distribution network in years 3–5.*

(breakers between two feeders), each HV substation will supply the load radially. However, the existence of these switches makes the configuration a mesh topology. The status of the switching devices is for normal operating conditions and can be changed when necessary. The proposed methodology specifies the size, location, and installation time of substations and other assets in the network during the planning horizon. Table 1 shows the technical data and expansion plan for the HV/MV substations. Table 2 presents the specifications of the DG units, installed hubs, and voltage regulators.

***Table 2**: Specifications.*

Bus	DG	Installation Size (kW) in Each Year of the Planning Period				
		1st	2nd	3rd	4th	5th
6	Disp.	400				
14	Disp.	400				
17	Disp.		150			
20	Disp.	300				
29	Disp.		50			
49	Disp.				350	
3	Wind	100				
12	Wind	50				
13	Wind	100				
34	Wind		50			
46	Wind			300		
4	Solar	100				
16	Solar	100				
24	Solar	50	50			
33	Solar		100			
38	Solar			250		
50	Solar			50	150	
4	Hub	100	100	300		
17	VR					1.06
23	VR		0.85	1	0.88	1.12
33	VR		1.12	1.03	1.09	1.09
36	VR		1.06	0.88	1.15	0.97

***Table 3**: Costs of the network.*

Sub	8434915.708
Feeder	1.85835E+11
Switch	228662.8011
DG	4435271.048
Hub	1146441276
VR	63065.37261
Loss	30032826.21
Trans	16720615.93
ENS	9984515233
VSI Function	0.002898285

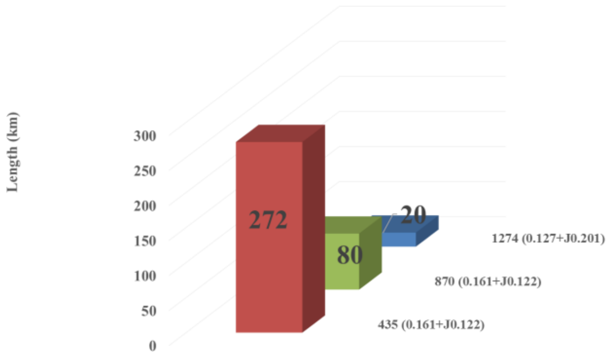

***Fig. 7**: Conductor type, current, impedance, and length in the fifth year.*

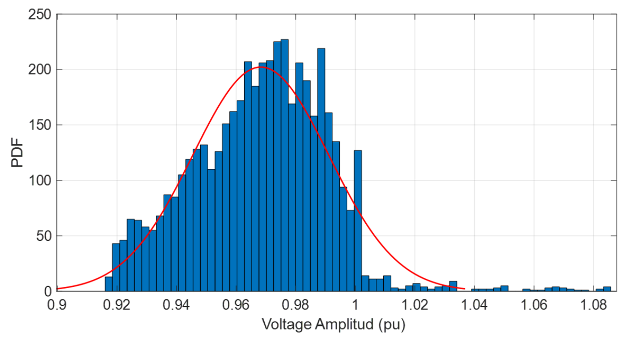

***Fig. 8**: Voltage amplitude considering all scenarios in the planning period.*

In Table 3, the costs related to the planned distribution network are presented. Fig. 7 shows the feeder conductor data, such as the maximum current limit, length, and conductor impedances for the fifth year. As can be observed, the configured grid has three types of conductors, measuring 132, 40, and 180 km, respectively.

Voltage amplitude is an important constraint and must be preserved in all scenarios of the planning period. The blue bars in Fig. 8 show the voltage amplitude of the optimum DN in all scenarios of the planning period. To clearly show the behavior of the voltage, the PDF voltage curve is fitted to the normal distribution function (red-curve). Its peak represents the mean value of the data. As can be observed, the peak is close enough to 1 pu which is the desirable voltage amplitude.

As previously mentioned, the proposed approach determines the optimal electrical power generation for DDGs, WDGs, and SDGs in all scenarios of the planning period. The amount of power generation in each unit depends on the total load demand in the network, price, and technical parameters. Figs. 9–11 show the different DG units in all scenarios of the planning horizon. Renewable DGs generate less power due to their lower capacity. It should be noted that the continuity of power supply and DDG controllability are the main reasons for the higher level of power generation.

Due to the presence of heat loads in the DN, the installation of a hub seems to be economical. Therefore, the proposed approach attempts to find the most appropriate and cost-effective hub in the DN to achieve the best results. The expansion plan of the installed hub is presented in Table 2. As can be observed from Fig. 1, the executed hub contains a transformer, CHP, and boiler to supply both heat and electricity. The heat/electricity generation of the CHP, electricity transfer amount from the transformer or heat generation by the boiler are all dependent on the price and technical parameters of the network. The optimum values for the above-mentioned terms are illustrated in Figs. 12–14.

A voltage regulator (VR) is also installed in the distribution network under study. As can be observed in Table 2, four VRs are installed and operating. The VR

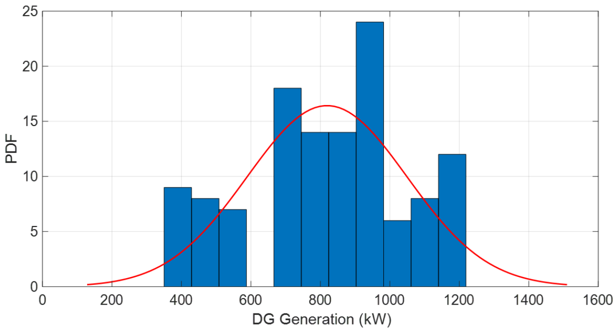

Fig. 9: *Dispatchable DG generation for all scenarios in the planning period.*

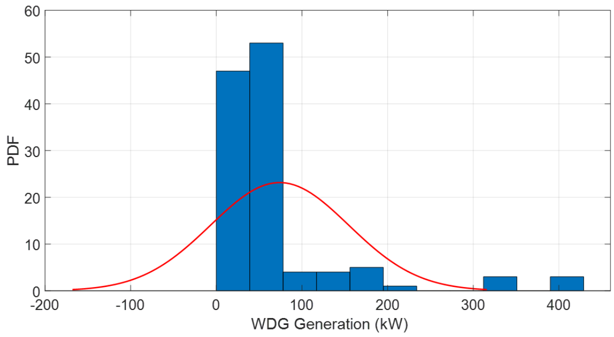

Fig. 10: *Wind DG generation considering all scenarios in planning period.*

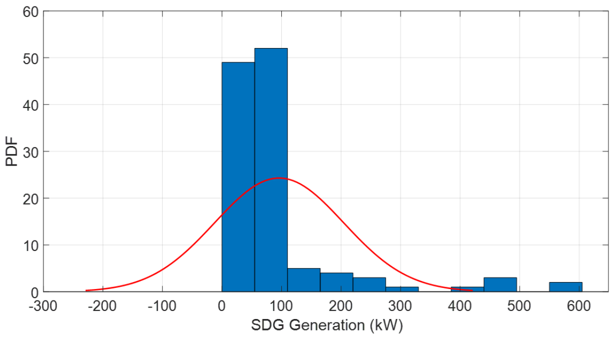

Fig. 11: *Solar DG generation considering all scenarios in planning period.*

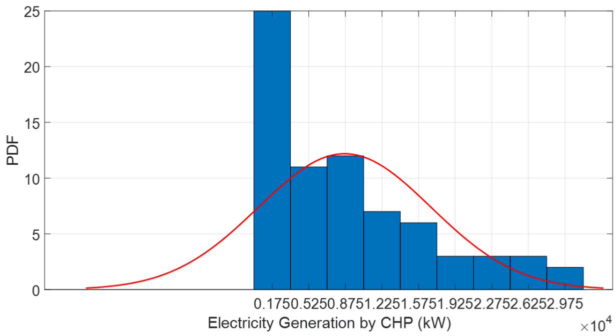

Fig. 12: *CHP electricity generation considering all scenarios in the planning period.*

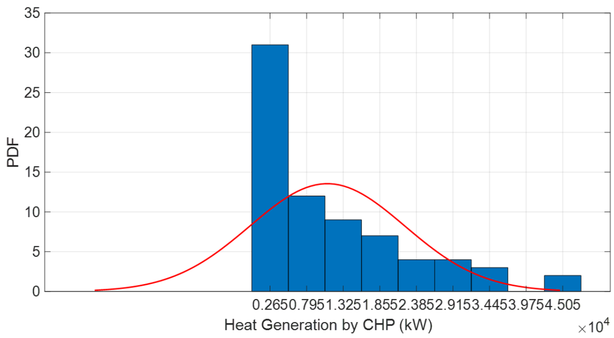

Fig. 13: *CHP heat generation considering all scenarios in the planning period.*

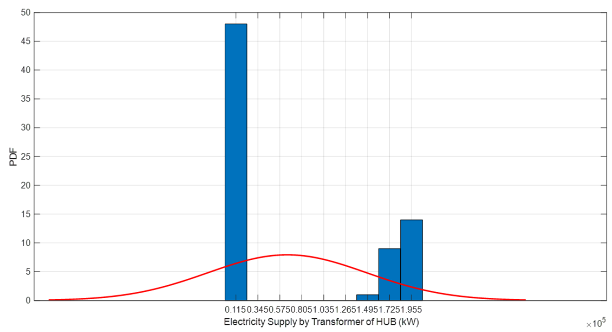

Fig. 14: *Power supply to the hub considering all scenarios in the planning period.*

steps are set in each year of the planning period according to all defined scenarios.

As detailed, the proposed approach can effectively suggest a roadmap for expansion planning in a large-scale distribution network. The optimum network can supply the required load demand in a reliable manner with high power quality.

5. CONCLUSION

Traditional distribution networks are not able to meet upcoming challenges such as improved reliability, power quality standards, new load characteristics, demand increment, and high DG penetration level. Considering these issues, network expansion is an important challenge for system owners. Therefore, it is essential that an efficient mesh distribution system be designed for optimal and effective network expansion planning by deploying switches, DGs, hubs, and VR to ensure continuity of the power supply.

In this regard, the proposed approach provides an optimal and efficient layout of a reliable distribution network while improving power quality. As detailed in this paper, the solution provides a roadmap for the distribution company until the end of the planning horizon. The solutions include a plan for installing new equipment and instructions for replacing or reinforcing existing assets. An operational plan is also provided for different facilities during normal and potential fault conditions.

REFERENCES

[1] A. Bosisio, A. Berizzi, E. Amaldi, C. Bovo, and X. A. Sun, "Optimal feeder routing in urban distribution networks planning with layout constraints and losses," *Journal of Modern Power Systems and Clean Energy*, vol. 8, no. 5, pp. 1005–1013, Sep. 2020.

[2] F. Z. Razavi, M. H. Nazari, S. M. S. Ghiasi, M. B. Sanjareh, and P. S. Bandaghiri, "Refining the conventional approach toward distribution networks expansion planning in metropolises by using self-adaptive particle swarm optimization," in *2019 International Power System Conference (PSC)*, 2019, pp. 300–305.

[3] Z. Li, W. Wu, B. Zhang, and X. Tai, "Feeder-corridor-based distribution network planning model with explicit reliability constraints," *IET Generation, Transmission & Distribution*, vol. 14, no. 22, pp. 5310–5318, Nov. 2020.

[4] N. Taghizadegan, S. N. Ravadanegh, M. Karimi, and M. R. J. Oskuee, "A solution compatible with cost-reliability for multi-stage feeder routing problem with considering uncertainties," *IETE Journal of Research*, vol. 65, no. 4, pp. 435–445, 2019.

[5] N. Taghizadegan, M. R. J. Oskuee, and T. Farhoudi, "Multi-objective modeling of robust multi-stage feeder routing problem with considering uncertainties," *UPB Scientific Bulletin, Series C: Electrical Engineering and Computer Science*, vol. 80, no. 2, pp. 69–84, 2018.

[6] N. C. Koutsoukis, P. S. Georgilakis, and N. D. Hatziargyriou, "Multistage coordinated planning of active distribution networks," *IEEE Transactions on Power Systems*, vol. 33, no. 1, pp. 32–44, Jan. 2018.

[7] R. Ghaffarpour, M. R. J. Oskuee, and A. M. Ranjbar, "Resilience-oriented distribution network optimal planning to improve the continuity of power supply," *International Journal of Ambient Energy*, vol. 41, no. 4, pp. 466–474, Apr. 2018.

[8] F. T. S. Silva, L. R. Araujo, and D. R. R. Penido, "Optimal substation placement in distribution systems using artificial immune systems," *IEEE Latin America Transactions*, vol. 16, no. 2, pp. 505–513, Feb. 2018.

[9] L. Yu *et al.*, "An efficient substation placement and sizing strategy based on GIS using semi-supervised learning," *CSEE Journal of Power and Energy Systems*, vol. 4, no. 3, pp. 371–379, Sep. 2018.

[10] G. M. noz Delgado, J. Contreras, and J. M. Arroyo, "Distribution network expansion planning with an explicit formulation for reliability assessment," *IEEE Transactions on Power Systems*, vol. 33, no. 3, pp. 2583–2596, May 2018.

[11] W. Buaklee and K. Hongesombut, "Optimal DG allocation in a smart distribution grid using cuckoo search algorithm," *ECTI Transactions on Electrical Engineering, Electronics, and Communications*, vol. 11, no. 2, pp. 16–22, Aug. 2013.

[12] Y. Kongjeen, K. Bhumkittipich, and N. Mithulananthan, "Optimal DG sizing and location in modern power grids using PEVs load demand probability," *ECTI Transactions on Electrical Engineering, Electronics, and Communications*, vol. 17, no. 1, pp. 51–59, Feb. 2019.

[13] M. Treekijjanon, B. Marungsri, T. Kulworawanichpong, and U. Leeton, "Reactive power adjustment in MV distribution systems integrating with wind-turbine power plants," *ECTI Transactions on Electrical Engineering, Electronics, and Communications*, vol. 15, no. 2, pp. 57–65, Aug. 2017.

[14] V. Khaligh, M. O. Buygi, A. Anvari-Moghaddam, and J. M. Guerrero, "A multi-attribute expansion planning model for integrated gas–electricity system," *Energies*, vol. 11, no. 10, 2018, Art. no. 2573.

[15] V. Khaligh and A. Anvari-Moghaddam, "Stochastic expansion planning of gas and electricity networks: A decentralized-based approach," *Energy*, vol. 186, Nov. 2019, Art. no. 115889.

[16] C. He, L. Wu, T. Liu, and Z. Bie, "Robust co-optimization planning of interdependent electricity and natural gas systems with a joint n-1 and probabilistic reliability criterion," *IEEE Transactions on Power Systems*, vol. 33, no. 2, pp. 2140–2154, Mar. 2018.

[17] H. Ghasemi, J. Aghaei, G. B. Gharehpetian, and H. Haeri, "Effect of smart multiple hub planning on distribution networks integrated expansion," in *2019 International Conference on Smart Energy Systems and Technologies (SEST)*, 2019.

[18] M. Jooshaki, H. Farzin, A. Abbaspour, M. Fotuhi-Firuzabad, and M. Lehtonen, "A model for stochastic planning of distribution network and autonomous DG units," *IEEE Transactions on Industrial Informatics*, vol. 16, no. 6, pp. 3685–3696, Jun. 2020.

[19] A. A. Eladl, M. I. El-Afifi, M. A. Saeed, and M. M. El-Saadawi, "Optimal operation of energy hubs integrated with renewable energy sources and storage devices considering CO_2 emissions," *International Journal of Electrical Power & Energy Systems*, vol. 117, May 2020, Art. no. 105719.

[20] H. Sekhavatmanesh and R. Cherkaoui, "Optimal infrastructure planning of active distribution networks complying with service restoration requirements," *IEEE Transactions on Smart Grid*, vol. 9, no. 6, pp. 6566–6577, Nov. 2018.

[21] A. A. Abdelsalam and H. S. E. Mansour, "Optimal allocation and hourly scheduling of capacitor banks using sine cosine algorithm for maximizing technical and economic benefits," *Electric Power Components and Systems*, vol. 47, no. 11–12, pp. 1025–1039, Jul. 2019.

[22] S. K. Sudabattula, K. Muniswamy, and V. Suresh, "Simultaneous allocation of distributed generators and shunt capacitors in a distribution system," *ECTI Transactions on Electrical Engineering, Electronics, and Communications*, vol. 17, no. 1, pp. 35–50, Feb. 2019.

[23] S. Rajamand, "Loss cost reduction and power quality improvement with applying robust optimization algorithm for optimum energy storage system placement and capacitor bank allocation," *International Journal of Energy Research*, vol. 44, no. 14, pp. 11 973–11 984, Nov. 2020.

[24] X. Xu, Y. Jia, C. S. Lai, M. H. Wang, and Z. Xu, "Bi-level optimal planning of voltage regulator in distribution system considering maximization of incentive-based photovoltaic energy integration," *CSEE Journal of Power and Energy Systems*, to be published.

[25] S. Sachan and M. H. Amini, "Optimal allocation of EV charging spots along with capacitors in smart distribution network for congestion management," *International Transactions on Electrical Energy Systems*, vol. 30, no. 9, Sep. 2020, Art. no. e12507.

[26] M. Attar, O. Homaee, H. Falaghi, and P. Siano, "A novel strategy for optimal placement of locally controlled voltage regulators in traditional distribution systems," *International Journal of Electrical Power & Energy Systems*, vol. 96, pp. 11–22, Mar. 2018.

[27] M. Ahmadi, M. E. Lotfy, M. S. S. Danish, S. Ryuto, A. Yona, and T. Senjyu, "Optimal multi-configuration and allocation of SVR, capacitor, centralised wind farm, and energy storage system: a multi-objective approach in a real distribution network," *IET Renewable Power Generation*, vol. 13, no. 5, pp. 762–773, Apr. 2019.

[28] A. M. Shaheen and R. A. El-Sehiemy, "Optimal coordinated allocation of distributed generation units/ capacitor banks/ voltage regulators by EGWA," *IEEE Systems Journal*, vol. 15, no. 1, pp. 257–264, Mar. 2021.

[29] M. R. J. Oskuee, E. Babazadeh, S. Najafi-Ravadanegh, and J. Pourmahmoud, "Multi-stage planning of distribution networks with application of multi-objective algorithm accompanied by DEA considering economical, environmental and technical improvements," *Journal of Circuits, Systems and Computers*, vol. 25, no. 04, 2016, Art. no. 1650025.

[30] S. N. Ravadanegh, M. R. J. Oskuee, and M. Karimi, "Multi-objective planning model for simultaneous reconfiguration of power distribution network and allocation of renewable energy resources and capacitors with considering uncertainties," *Journal of Central South University*, vol. 24, no. 8, pp. 1837–1849, Aug. 2017.

[31] J. Salehi, M. R. J. Oskuee, and A. Amini, "Stochastics multi-objective modelling of simultaneous reconfiguration of power distribution network and allocation of DGs and capacitors," *International Journal of Ambient Energy*, vol. 39, no. 2, pp. 176–187, 2018.

[32] M. J. A. Boushehry, M. R. J. Oskuee, and M. Karimi, "Determinations of annual investments of DisCo and private sector in expansion planning of distribution network," *International Journal on Electrical Engineering and Informatics*, vol. 12, no. 4, pp. 786–806, Dec. 2020.

[33] E. Babazadeh, M. R. J. Oskuee, J. Pourmahmoud, and S. N. Ravadanegh, "Optimal planning of smart distribution network based on efficiency evaluation using data envelopment analysis," *International Journal on Electrical Engineering and Informatics*, vol. 8, no. 1, pp. 45–61, Mar. 2016.

[34] J.-H. Teng and C.-N. Lu, "Feeder-switch relocation for customer interruption cost minimization," *IEEE Transactions on Power Delivery*, vol. 17, no. 1, pp. 254–259, Jan. 2002.

[35] Y. Xu, C.-C. Liu, K. P. Schneider, and D. T. Ton, "Placement of remote-controlled switches to enhance distribution system restoration capability," *IEEE Transactions on Power Systems*, vol. 31, no. 2, pp. 1139–1150, Mar. 2016.

[36] M. Farajollahi, M. F. Firuzabad, and A. Safdarian, "Sectionalizing switch placement in distribution networks considering switch failure," *IEEE Transactions on Smart Grid*, vol. 10, no. 1, pp. 1080–1082, Jan. 2019.

[37] M. Farajollahi, M. F. Firuzabad, and A. Safdarian, "Optimal placement of sectionalizing switch considering switch malfunction probability," *IEEE Transactions on Smart Grid*, vol. 10, no. 1, pp. 403–413, Jan. 2019.

[38] M. Amohadi and M. F. Firuzabad, "Optimal placement of switching and protection devices in radial distribution networks to enhance system reliability using the AHP-PSO method," *Turkish Journal of Electrical Engineering and Computer Sciences*, vol. 27, no. 1, pp. 181–196, 2019.

[39] S. M. Mazhari, H. Monsef, and R. Romero, "A multi-objective distribution system expansion planning incorporating customer choices on reliability," *IEEE Transactions on Power Systems*, vol. 31, no. 2, pp. 1330–1340, Mar. 2016.

[40] A. V. Pombo, J. Murta-Pina, and V. F. Pires, "Multiobjective planning of distribution networks incorporating switches and protective devices using a memetic optimization," *Reliability Engineering & System Safety*, vol. 136, pp. 101–108, Apr. 2015.

[41] A. Banerjee, S. Chattopadhyay, G. Gheorghe, and M. Gavrilas, "Minimization of reliability indices and cost of power distribution systems in urban areas using an efficient hybrid meta-heuristic algorithm," *Soft Computing*, vol. 23, pp. 1257–1281, Feb. 2019.

[42] W. Tippachon and D. Rerkpreedapong, "Multiobjective optimal placement of switches and protective devices in electric power distribution systems using ant colony optimization," *Electric Power Systems Research*, vol. 79, no. 7, pp. 1171–1178, Jul. 2009.

[43] M. Jooshaki, S. Karimi-Arpanahi, M. Lehtonen, R. J. Millar, and M. Fotuhi-Firuzabad, "Reliability-oriented electricity distribution system switch and tie line optimization," *IEEE Access*, vol. 8, pp. 130 967–130 978, 2020.

[44] M. H. Kapourchali, M. Sepehry, and V. Aravinthan, "Fault detector and switch placement in cyber-enabled power distribution network," *IEEE Transactions on Smart Grid*, vol. 9, no. 2, pp. 980–992, Mar. 2018.

[45] M. Karimi and M. R. J. Oskuee, "Risk-based dynamic expansion planning of distribution network's reliability and power quality," *International Journal of Ambient Energy*, to be published.

[46] M. R. J. Oskuee, S. N. Ravadanegh, and G. B. Gharehpetian, "Resiliency-oriented dynamic expansion planning of MG-based distribution networks," *Journal of Energy Management and Technology*, vol. 6, no. 1, pp. 44–53, Mar. 2022.

[47] M. Karimi and M. R. Haghifam, "Risk based multi-objective dynamic expansion planning of sub-transmission network in order to have eco-reliability, environmental friendly network with higher power quality," *IET Generation, Transmission & Distribution*, vol. 11, no. 1, pp. 261–271, Jan. 2017.

[48] Azarbaijan Shahid Madani University. "Resilient Smart Grids Research Lab." http://resilientsmartgrids.com/

Mohammad Reza Jannati Oskuee has been awarded as the "Iranian Distinguished Ph.D. Student" by the Iran's Ministry of Science, Research and Technology in 2019. Mr. Oskuee has been appointed as adjunct lecturer with Azarbaijan Shahid Madani University and Islamic Azad University, Iran since June 2015. Dr. Jannati has been joined MONA Consultants Company as a Senior Consultant of Distribution Networks in February 2018. His major fields of interest include Distribution Networks and Resilience.

Shahram Mojtahedzadeh received his B.Sc. degree in Electronics Engineering in 2003, M.Sc. degree in Electrical Engineering in 2006 and Ph.D. in 2017. He has joined Islamic Azad University, Iran in 2008. His main areas of interest are Power System Operation, Smart-Grids, Micro-Grids and Distribution System planning.

Masoumeh Karimi received the Ph.D. degree in electrical engineering in 2020. She has been awarded "National Alborz Foundation Prize" by the Iran's Ministry of Science, Research and Technology in 2020. She has been appointed as adjunct lecturer with Azarbaijan Shahid Madani University and Islamic Azad University, Iran since June 2017. Dr. Karimi has been joined Shibrah Consultants Company as a Senior Consultant of Distribution Networks in June 2021. Her current research interests include smart distribution networks operation and planning, Resilience and application of optimization algorithm in power system. She has been authored/co-authored of over than 40 technical papers.