Electrical Power and Energy Systems 73 (2015) 56–70

Contents lists available at ScienceDirect

Electrical Power and Energy Systems

journal homepage: www.elsevier.com/locate/ijepes

Integrated distribution network expansion planning incorporating distributed generation considering uncertainties, reliability, and operational conditions

A. Bagheri, H. Monsef *, H. Lesani

School of Electrical and Computer Engineering, University of Tehran, Tehran, Iran

ARTICLE INFO

Article history:
Received 10 June 2014
Received in revised form 9 February 2015
Accepted 17 March 2015
Available online 30 April 2015

Keywords:
Distribution network
Integrated expansion planning
Distributed generation
Uncertainty
Reliability
Operational conditions

ABSTRACT

In this paper, an integrated methodology is proposed for distribution network expansion planning which considers most of the planning alternatives. The planning aims to determine the optimal reinforcement of existing medium voltage lines and high voltage/medium voltage substations, or installation of new ones to meet the load growth in the planning horizon subject to the technical and operational constraints. Also, to take the advantages of new technologies, the renewable and non-renewable distributed generations have been included in the problem as another alternative. The uncertainties related to renewable DGs, load demand, and energy price have been considered in the calculation of cost components. The load duration curve has been utilized for loads such that the results be more precise. The possibility of islanding and load transferring through the reserve feeders have been regarded in the problem to improve the reliability of the network. Also, the required condition for successful and safe operation of island considering all of uncertainty states have been checked out to accurately calculate the reliability. The genetic algorithm is employed to solve this integrated problem. Finally, the proposed method is applied to the 54-bus system and also a real large-scale distribution network, and the results are discussed. The results verify the effectiveness of the presented method.

Introduction

Expansion planning of power distribution systems is one of the major activities of distribution utilities to deal with electric power demand growth.

The main objective of the distribution network expansion planning (DNEP) problem is to provide a reliable and cost effective service to consumers while ensuring that voltages and power quality are within standard ranges [1]. Traditionally, this aim is attained through the reinforcement of existing lines and substations, or by installation of new ones regarding to the technical and operational constraints [2–7].

Today, power system economic and operation environment has changed as new capacity options have emerged. Distributed Generation (DG) is one of these new options. The introduction of DG in power system changes the operating features, and has significant technical and economic advantages. Adding DG sources to the planning options is resulting in challenges in the distribution network operation, structure, design and upgrade issues. At present, there are several technologies ranging from traditional to non-traditional used in DG application. The former is non-renewable technologies such as internal combustion engines, combined cycles, gas turbines, and micro-turbines. The latter includes renewable-energy-based technologies such as wind, photovoltaic, biomass, geothermal, etc. Due to the availability of such a flexible option of DG as an energy source at the distribution voltage level, the distribution network is being transformed from a passive network to an active one. In this regard, DG brings about various benefits such as distribution capacity deferral, losses reduction, flattering of peak, improving of voltage profile, and reliability improvement [8–13].

Several researches have been implemented to illuminate the advantages of utilizing DG units in the distribution network. Optimal allocation and sizing of DGs is solved in [14] using an analytical-based method to minimize the line losses. The same problem is solved using an ordinal optimization method in [15]. In addition to line losses, the system's reliability is included in the DG planning problem as a constraint in [16] which tries to improve the system reliability, line losses, and voltage profile using the genetic algorithm (GA). To further improve the system reliability,

* Corresponding author at: School of ECE, North Kargar Ave., University of Tehran, Tehran, Iran. Tel.: +98 21 61114913.

E-mail address: hmonsef@ut.ac.ir (H. Monsef).

http://dx.doi.org/10.1016/j.ijepes.2015.03.010
0142-0615/© 2015 Published by Elsevier Ltd.

Nomenclature

Constants

n_f	number of network's feeders
n_s	number of HV/MV substations
n_l	number of load buses (MV/LV substations)
n_n	total number of network substations
n_{es}	number of existing HV/MV substations
n_{cs}	number of candidate HV/MV substations for installation
n_{ef}	number of existing feeders
n_{cf}	number of candidate feeders for installation
n_{LL}	number of load levels
ns	number of states
n_y	planning horizon
λ_k	failure rate of feeder k (fail/km/year)
PW	present worth factor
Infr	inflation rate (%)
Intr	interest rate (%)
Y_{ij}	magnitude of admittance between buses i and j
θ_{ij}	angle of admittance between buses i and j
r_k	repair time of feeder k (h)
T_{LL}	duration of load level LL (h)
$S^L_{i,LL,s}$	apparent power of load demand in bus i, in load level LL and state s
$S^L_{i,peak}$	apparent power of load demand in bus i, in peak condition
$\mathrm{LLF}_{LL,s}$	load level factor for load level LL and state s
$\mathrm{EP}_{LL,s}$	energy price in load level LL and state s
EP_{peak}	energy price in peak condition
$\mathrm{PLF}_{LL,s}$	price level factor for load level LL and state s
$P^L_{i,LL,s}$	active load demand in bus i, in load level LL and state s
$Q^L_{i,LL,S}$	reactive load demand in bus i, in load level LL and state s
$P^L_{i,peak}$	active load demand in bus i in peak condition
$S^{DG}_{i,LL,S}$	apparent power of DG installed in bus i, in load level LL and state s
$S^{DG}_{i,max}$	capacity of DG installed in bus i
$\mathrm{LC}_{LL,s}$	loss cost in load level LL and sate s (\$/kWh)
RC_{LL}	reliability cost of unsupplied energy in load level LL (\$/kWh)
$\mathrm{oc}_{LL,s}$	operation cost of DG in load level LL and sate s (\$/kWh)
dc	dissatisfaction cost (\$)
Load(s)	states of load demand
Price(s)	states of energy price
Wind(s)	states of wind speed
States^{comb}_s	combination of all states
V^{min}_{safe}	lower limit of buses voltages for safe operating condition
V^{max}_{safe}	upper limit of buses voltages for safe operating condition
V^{min}_{crit}	lower limit of buses voltages for critical operating condition
V^{max}_{crit}	upper limit of buses voltages for critical operating condition

Functions

$\mathrm{sec}_i(S)$	expansion cost of ith existing HV/MV substation with the capacity of S (\$/kVA)
$\mathrm{IC}_i(S)$	installation cost of ith new HV/MV substation with the capacity of S (\$/kVA)
$\mathrm{FC}_{ij}(k)$	cost of installing a feeder with the type of k between buses i, j (\$/km)
$\mathrm{MFC}_{ij}(k)$	cost of installing main feeder with the type of k between buses i, j (\$/km)
$\mathrm{RFC}_{ij}(k)$	cost of installing reserve feeder with the type of k between buses i,j (\$/km)
$\mathrm{DDGIC}_i(S)$	installation cost of dispatchable DG with the capacity of S in bus i (\$/kVA)
$\mathrm{WDGIC}_i(S)$	installation cost of wind DG with the capacity of S in bus i (\$/kVA)

Variables

$\mu^V_{i,LL,S}$	degree of voltage constraint satisfaction for bus i, in load level LL and state s
μ^V_i	degree of voltage constraint satisfaction for bus i
μ^V	degree of voltage constraint satisfaction for the whole network
μ^I	degree of current constraint satisfaction for the whole network
μ^S	degree of substation capacity constraint satisfaction for the whole network
$V_{i,LL,s}$	voltage magnitude of bus i, in load level LL and state s
$\delta_{i,LL,s}$	voltage angle of bus i, in load level LL and state s
$P^{WDG/DDG}_{i,LL,s}$	Active power generated by WDG/DDG installed in bus i, in load level LL and state s
$Q^{WDG/DDG}_{i,LL,S}$	reactive power generated by WDG/DDG installed in bus i, in load level LL and state s
PDG_{ijs}	generated power of DG installed in bus i, in load level j and state s
$P^{Trans}_{i,LL,s}$	The power imported from transmission system to distribution network through the ith HV/MV substation in load level j and state s
$\mathrm{LNS}_{k,LL,s}$	the load not supplied in load level LL and state s due to the outage of feeder k

switches, such as reclosers and cross-connections (CCs), are incorporated in the DG-based planning problem. An ant colony system algorithm is employed in [17] for finding the optimal placement of reclosers and DGs. This method minimizes an objective function composed of two reliability indices: system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI). [18] proposes an integrated methodology for distribution network planning in which the operation of DGs and CCs is optimally planned. Distribution lines and HV/MV transformers are also optimally upgraded in order to improve system reliability and to minimize the line losses under load growth; the objective function is composed of the investment cost, losses cost, and reliability cost; the energy savings resulted from installation of DGs is also included in this function. The constraints are the buses' voltages and lines' currents; the modified discrete particle swarm optimization (PSO) method is employed to optimize the problem is different scenarios.

In the abovementioned works, the considered DG technology is non-renewable and controllable (Dispatchable DG (DDG)). On the other side, the development in technology and the importance of using clean energy resources have made the renewable energies more attractive for distribution network operators, specifically because of their inexhaustible and non-polluting features. Among these renewable energies, wind-based distributed generation (WDG) has emerged very rapidly in recent years. Reduction of capital costs, improvement of reliability, and efficiency have made the wind power able to compete with the conventional power generation [19]. The renewable DG technologies like wind have special

characteristics due to their main source of energy. Since the wind speed is not a constant quantity during the operation of wind turbine, and it is highly dependent on the climate condition, therefore there is an uncertainty and variability in the output power of wind turbine. In other words, the WDG has intermittent output power [20].

In the literature, some methods have been proposed to model the impact of these uncertainties on distribution network performance. In [21], different scenarios are constructed based on the probability distribution function (PDF) of uncertain values and then a method is proposed to determine the optimal combination of different renewable technologies for minimizing the active losses. In [22], an effective tool was proposed based on Monte Carlo Simulation (MCS) for modeling the uncertainties in location, exported energy, penetration level, and the states (on/off) of the DG units. In [21,23], a powerful probabilistic method is proposed to handle the uncertainties of electric load and intermittent generation of renewable energy resources. In [21], the optimal location of a predetermined number of wind turbines is determined in order to minimize the active losses. In [23], a methodology is proposed for optimally allocating different types of renewable DG units including wind power, photovoltaic, solar thermal systems, biomass, and various forms of hydraulic power for loss minimization. Authors in [24] presented a hybrid possibilistic–probabilistic tool to assess the impact of DG units on technical performance of distribution network. The uncertainty of electric loads, DG operation and investments are taken into account. The objective function is active losses and technical risk, including the possibility of under/over voltage in load nodes. The proposed problem was formulated under GAMS environment and applied to a test network in different scenarios to evaluate the effectiveness of the method.

In [25], a possibilistic method was proposed to handle the uncertainties of electrical loads and energy prices considering different objective functions like cost and technical and economic risks. The study in [26], presents a stochastic dynamic multi-objective model for integration of distributed generations in distribution networks. The proposed model optimizes three objectives, namely technical constraint dissatisfaction, costs and environmental emissions, and simultaneously determines the optimal sitting, sizing and timing of investment for both DG units and network components. The uncertainties of electric loads, electricity price and wind power generations are taken into account using scenario modeling.

The above survey of papers indicates that there are the following major aspects in DNEP problem:

1. Formulization of DNEP with different objective functions and solving it by using efficient methods,
2. Using renewable and non-renewable DGs as an alternative for DNEP,
3. Considering uncertainties related to renewable DGs, load demand, etc. in the planning,
4. The way that the reliability of network is modeled and the effect of renewable and non-renewable DGs on reliability.

In the following, the most recent papers in DNEP are investigated in details from these four viewpoints. Ref. [18] is the most comprehensive one which has considered almost all the planning options. However, the possibility to consider new substations installation has not been regarded. Also the utilized DGs are of non-renewable type. In [27], a multi-objective technique was developed for optimal allocation of DG considering system reliability. An algorithm to determine the optimum operating strategy for DG was presented in [27,28] incorporating reliability worth evaluation of distribution system to minimize the cost of customer interruption. However, these works assumed conventional dispatchable DG units. An approach to evaluate the economic benefits of renewable DG was proposed in [5] in which a GA based method is implemented for optimal DG allocation to maximize the deferral of system upgrade investments, reduction of the energy losses cost, and reduction of the interruption cost. The proposed methodology takes into account:

- Uncertainty and variability associated with renewable DGs' output,
- Load variability,
- The possibility of islanding to improve the reliability of the system.

In the mentioned work, it is assumed that the substations are redundant, and there are neither new load points, nor new substations for installation. The lines are reinforced, and there is no reserve feeder to improve the reliability. For considering of islanding after occurring a fault on a feeder, it is checked that if there is a sufficient capacity of dispatchable and renewable DGs in the isolated part or not. In other words, the adequacy of generation in the island is checked. However, the load flow constraints are not checked to see if the island can operate successfully from the viewpoint of voltage and current constraints or not. In addition, the possibility of load shedding to reduce the interruption cost has not been regarded. Refs. [29–31] presented a framework to solve the problem of multistage distribution system expansion planning in which installation and/or reinforcement of substations, feeders, and DG units are taken into account as possible solutions for the system capacity expansion. The proposed formulation considers investment, operation, and outage costs of the system. The results show the positive effect of DG on the reliability improvement and reduction of outage costs. These two papers have not considered the renewable DGs.

In this paper, an integrated distribution network expansion planning is presented which modifies the shortcomings of the previous works. The MV feeders and HV/MV substations are reinforced to meet the load growth in the planning horizon. In addition, since there will be some new load points in the horizon year, there is a need to install some new feeders and possibly new substations. For improving the reliability of the network, the reserve feeders have been considered to be installed if economical. As an alternative, the renewable and non-renewable DGs are regarded in the proposed DNEP. The operation cost of DGs and the cost of energy purchased from the upward grid (transmission system) is calculated considering the load-duration curve (LDC) of load points. The uncertainty in the output power of renewable DGs, and that of load demand have been regarded in the calculation of the reliability, energy losses, and energy purchased from the upward grid. For further improvement of reliability, the islanding operation of DG units has been considered, and the required conditions for successful and safe operation of island considering all the uncertainty states have been checked out. The GA as a promising solution method is employed for optimization of the proposed DNEP. Finally, the proposed method is applied to the 54-bus test system and a real large-scale distribution network in different scenarios, and the results are discussed. The obtained results demonstrate the effectiveness of the presented method.

The main contributions of this paper can be listed as follows:

- An integrated DNEP has been proposed which considers the expansion of substations and feeders, along with the utilization of renewable and non-renewable distributed generation;
- Reliability and operational considerations are regarded;
- Uncertainties related to the wind energy, load demand, and energy price have been considered;
- Possibility of islanding has been regarded in reliability evaluation.

Problem formulation

The objective of the distribution network expansion planning is to provide a reliable and cost effective service to consumers while ensuring that voltages and power quality are within standard ranges [6,7]. The solution of DNEP will determine the following decision variables:

- Expansion capacity of existing high voltage/medium voltage (HV/MV) substations;
- Location and capacity of new HV/MV substations to be installed;
- Upgrade of existing medium voltage (MV) feeders;
- Routing and type of new MV feeders to be installed;
- Location and type of reserve feeders;
- Sitting and sizing of non-renewable DGs (DDG);
- Sitting and sizing of renewable DGs (here WDG);
- Determining the optimal power generation of DDG units in each load level.

Load and price model

To consider the variation of load and price during the year, and to calculate the operational costs accurately, the load duration curve (LDC) is used for the load points. In the planning studies, the continuous LDC is approximated by the discrete one. The price of purchasing energy from the transmission network is assumed to follow the same manner, which means that for each level of LDC there is a related energy price [7,29,32] as shown in Fig. 1. In this figure, the vertical axis shows the load/price level factors (the ratio of load/price to the peak value of load/price in the horizon year), and the duration of each load level (LL) is denoted by T_{LL} in horizontal axis.

Uncertainty of load and energy price

The load demand and energy price are usually uncertain parameters in the planning problems; they are dependent on each other, so that an increase/decrease in electric load will lead to increase/decrease in electricity price. To model these two uncertainties, it is assumed that they follow a normal distribution around their expected values as shown in Fig. 1. For simplicity, the distribution curves are divided into some states (seven states in Fig. 1) with the related probabilities. In this regard, the load and energy price models, considering the uncertainty are as Eqs. (1) and (2).

$$S^L_{i,LL,s} = S^L_{i,peak}\mathrm{LLF}_{LL,s} \tag{1}$$

$$\mathrm{EP}_{LL,s} = \mathrm{EP}_{peak}\mathrm{PLF}_{LL,s} \tag{2}$$

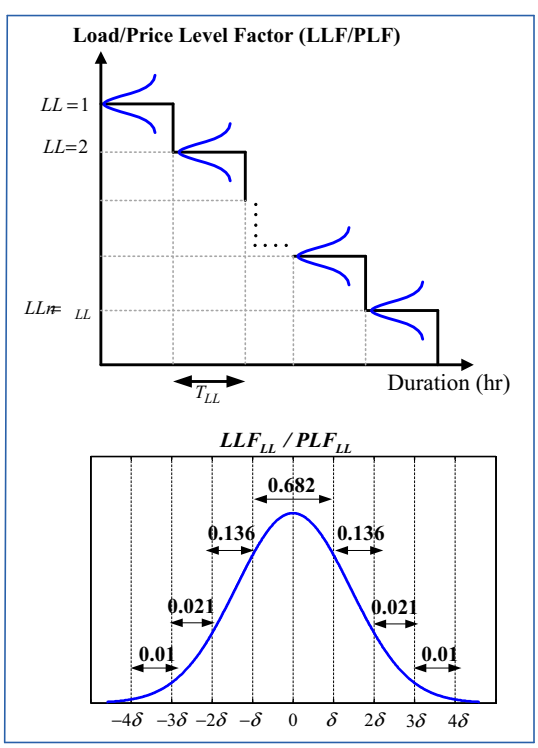

Fig. 1. Load/price duration curve and the related uncertainty model.

Wind power generation

Since the wind speed has intermittent nature, therefore, the power generated by the wind turbine is stochastic and intermittent. Several models have been proposed for the stochastic behavior of the wind speed. The most common expression is the Rayleigh probability distribution function as Eq. (3) [23]; where, v is the wind speed and c is the scale factor of the Rayleigh PDF of wind speed in the zone under study.

$$\mathrm{PDF}(v) = \left(\frac{2v}{c^2}\right)\exp\left[-\left(\frac{v}{c}\right)^2\right] \tag{3}$$

The output power of the wind turbine is calculated using the wind turbine power-speed characteristic as (4), where, P^{WDG} and P_{rated} are the output and rated power of wind turbine. Also, v_{ci}, v_{co}, and v_{rated} respectively are the cut-in, cut-off, and rated speed of wind turbine.

$$P^{WDG} = \begin{cases} 0, & \text{if } v_{ci} \leqslant v \\ P_{rated} \times \frac{v - v_{ci}}{v_{rated} - v_{ci}}, & \text{if } v_{ci} \leqslant v \leqslant v_{rated} \\ P_{rated}, & \text{if } v_{rated} \leqslant v \leqslant v_{co} \\ 0, & \text{if } v_{co} \leqslant v \end{cases} \tag{4}$$

For expansion planning studies, it is appropriate to use the behavior of wind during the whole year [23]. In this paper, the data of Table 1 have been used for modeling the wind behavior. Regarding to Table 1 and Eq. (4), the output power and the related probabilities are obtained as Table 2.

Combined state model

In each load level, the states of load, price, and wind speed are combined to construct the whole set of uncertainty states as follows:

$$\mathrm{States}^{comb}_s = [\mathrm{Load}(s) \quad \mathrm{Price}(s) \quad \mathrm{Wind}(s)] \tag{5}$$

$$\mathrm{Prob}^{comb}_s = \mathrm{Prob}^L_s \times \mathrm{Prob}^P_s \times \mathrm{Prob}^w_s \tag{6}$$

Table 1
Probabilities of wind speed

Wind speed limits (m/s)	Hours/year	Probability
0–4	1804	0.2059
4–5	579	0.0661
5–6	984	0.1123
6–7	908	0.1037
7–8	983	0.1122
8–9	799	0.0912
9–10	677	0.0773
10–11	439	0.0501
11–12	395	0.0451
12–13	286	0.0326
13–14	219	0.0250
14–25	687	0.0784

Table 2
Probabilities of wind power.

State No.	Output power as percent of rated capacity (%)	Probability
1	100.00	0.0784
2	94.97	0.0250
3	84.97	0.0326
4	74.98	0.0451
5	64.98	0.0501
6	54.98	0.0773
7	44.99	0.0912
8	34.99	0.1122
9	19.99	0.1037
10	15.00	0.1123
11	5.00	0.0661
12	0.00	0.2059

In (6), Prob_s^L, Prob_s^P, and Prob_s^w are the probabilities of load, electricity price, and wind speed states, respectively. Prob_s^{comb} is the probability of each combined state s.

Constraints

There are two types of constraints in DNEP, hard and soft ones. The satisfaction of the former one is mandatory. However the latter one can be violated, but this violation must be calculated and minimized.

Hard constraints

Network radiality constraint. Most of the distribution systems are operated in radial topology [6,7,33]. Thus, the radiality constraint is regarded in almost all of the distribution network expansion and operation planning problems. The most well-known problems are the distribution network reconfiguration (DNR) and the distribution network expansion planning (DNEP). Distribution network topology can be considered as a graph consisting of n arcs and m nodes. According to the graph theory, a tree is defined as a graph without any loops. Thus, it is possible to compare the radial topology of a distribution network with a tree. When there is only one supply point (HV/MV substation) for the distribution network, the following conditions must be satisfied to ensure the network is radial (i.e. to ensure the graph is a tree):

- **Condition 1:** the number of network feeders must be equal to the total number of network substations (including HV/MV and MV/LV buses) minus 1 as (7) [33]:

$$n_f = n_n - 1 \tag{7}$$

- **Condition 2:** the network must be connected.

where n_f is the number of network feeders, and n_n is the total number of network substations.

These two conditions must be satisfied simultaneously, i.e. satisfaction of each of them solely does not ensure the radial structure of the network. Different methods have been proposed for the sake of constructing a distribution network having radial topology in DNEP and DNR problems, such as: branch exchange [34], Evolutionary algorithm [35], specialized genetic algorithm [36], algebraic relations [37], *prufer-number* based GA [38]. In these methods, the network has only one feeding point (HV/MV substation), and the mentioned two conditions are adequate for satisfaction of the radiality. However, in the case the network has more than one HV/MV substation, or when there are a forest of trees instead of one tree, the condition 1 must be modified to expression (8) [33]:

$$n_f = n_n - n_s \tag{8}$$

where n_s is the number of HV/MV substations.

In this paper, a new criterion is introduced for checking the radiality of networks with a desired number of HV/MV substations. Satisfaction of criterion (9) ensures that the distribution network is in the structure of a forest containing several trees (satisfying the radiality constraint).

The network must be connected (9.1)

$$n_f = n_l \tag{9.2}$$

$$\text{rank}(A) = n_n - n_s \tag{9.3}$$

where:

n_l is the number of load buses (MV/LV substation),
A is the incidence matrix of distribution network,
rank(A) is the number of linearly independent rows or columns of matrix A.

Power flow equations. The following power flow equations must be satisfied for each state in each load level [6,7]:

$$P_{i,LL,s}^{net} = -P_{i,LL,s}^{L} + P_{i,LL,s}^{WDG/DDG} \tag{10.1}$$

$$Q_{i,LL,s}^{net} = -Q_{i,LL,s}^{L} + Q_{i,LL,s}^{WDG/DDG} \tag{10.2}$$

$$P_{i,LL,s}^{net} = V_{i,LL,s}\sum_{j=1}^{n_n} Y_{ij}V_{j,LL,s}cos(\delta_{i,LL,s} - \delta_{j,LL,s} - \theta_{ij}) \tag{10.3}$$

$$Q_{i,LL,s}^{net} = V_{i,LL,s}\sum_{j=1}^{n_n} Y_{ij}V_{j,LL,s}sin(\delta_{i,LL,s} - \delta_{j,LL,s} - \theta_{ij}) \tag{10.4}$$

DG units' operating constraint. The DG units' power generation must be under their capacity limit.

$$S_{i,LL,s}^{DG} \leqslant S_{i,max}^{DG} \tag{11}$$

DG units' maximum penetration. A maximum penetration level (here 35%) is usually used for DG units in the system as (12) to prevent the reverse power flow from the distribution network to the upward grid [5,23,32].

$$\sum_{i=1}^{n_l} P_i^{DDG} + \sum_{i=1}^{n_l} P_{i,rated}^{WDG} \leqslant 0.35 \times \sum_{i=1}^{n_l} P_{i,peak}^{L} \tag{12}$$

Soft constraints

The fuzzy modeling can be used to quantify the value of satisfaction of technical constraints, including bus voltages and thermal limits of feeders and substations.

Voltage limitation. When the voltage magnitude of a bus is in the safe operation interval, then there is no violation. However, the planner may tolerate the violation of these limits to some extent to improve other objectives. The voltage limitation is represented by a penalization function [26,39]. For his aim, the voltage constraint satisfaction can be mathematically represented as (13). In this way, The safe operating interval is defined as $\left[V_{safe}^{min} \quad V_{safe}^{max}\right]$, in which the satisfactory value is 1. As the voltage magnitude exceeds these limits, the value of satisfaction decreases until it becomes zero beyond the critical voltage values (V_{crit}^{min}, V_{crit}^{max}).

$$\mu_{i,LL,s}^{V} = \begin{cases} \frac{V_{i,LL,s} - V_{crit}^{min}}{V_{safe}^{min} - V_{crit}^{min}}, & V_{crit}^{min} \leqslant V_{i,LL,s} \leqslant V_{safe}^{min} \\ 1, & V_{safe}^{min} \leqslant V_{i,LL,s} \leqslant V_{safe}^{max} \\ \frac{V_{i,LL,s} - V_{crit}^{max}}{V_{safe}^{max} - V_{crit}^{max}}, & V_{safe}^{max} \leqslant V_{i,LL,s} \leqslant V_{crit}^{max} \\ 0, & else \end{cases} \tag{13}$$

The values obtained from (13) show the condition of voltage constraint satisfaction for bus i in state s. Since there are more than one state in a real system, the planner has different satisfaction levels of voltage constraint for a given bus. To obtain an index representing the voltage condition of ith bus, the weighted average of voltage satisfaction over the whole states is used as follows:

$$\mu_i^V = \frac{1}{8760}\sum_{LL=1}^{nLL}\sum_{s=1}^{ns}\mathrm{Prob}_s^{comb}T_{LL}\mu_{i,LL,s}^V \tag{14}$$

According to (14), the voltage satisfaction value of bus i is dependent on the satisfaction value of each state and also, on its probability. The average value of μ_i^V over all buses of the network provides an information about voltage condition of the whole network as (15).

$$\mu^V = \frac{\sum_{i=1}^{n_L}\mu_i^V}{n_L} \tag{15}$$

Thermal limits of feeders and substations. The satisfaction value of feeders currents (μ^l) and substations capacities (μ^S) are calculated in the similar way as the voltage. The difference is that there is only an upper limit for the feeders currents and substations capacities instead of upper and lower limits.

Objective function

The objective function of the proposed DNEP is minimization of the total cost represented in (16).

$$\begin{aligned}\text{Cost Function} = {} & \mathrm{SEC} + \mathrm{SIC} + \mathrm{FRC} + \mathrm{FIC} + \mathrm{DGIC} + \mathrm{DGOC} \\ & + \mathrm{EEC} + \mathrm{EELC} + \mathrm{EENSC} + \mathrm{EMC} + \mathrm{TDC}\end{aligned} \tag{16}$$

where:

SEC is the substations expansion cost as (17):

$$\mathrm{SEC} = \sum_{i=1}^{n_{es}}\mathrm{sec}_i(S) \tag{17}$$

SIC is the substations installation cost as (18):

$$\mathrm{SIC} = \sum_{i=1}^{n_{cs}}\mathrm{IC}_i(S) \tag{18}$$

FRC is the cost of feeders' replacement as (19):

$$\mathrm{FRC} = \sum_{i,j=1,i\neq j}^{n_{ef}}[\mathrm{FC}_{ij}(k_1) - \mathrm{FC}_{ij}(k_2)] \tag{19}$$

FIC is feeders installation cost as (20):

$$\mathrm{FIC} = \sum_{i,j=1,i\neq j}^{n_{cf}}[\mathrm{MFC}_{ij}(k) + \mathrm{RFC}_{ij}(k)] \tag{20}$$

DGIC is installation cost of DG units as (21):

$$\mathrm{DGIC} = \sum_{i,j=1,i\neq j}^{n_L}[\mathrm{DDGIC}_i(S) + \mathrm{WDGIC}_i(S)] \tag{21}$$

DGOC is DG units' operation cost as (22):

$$\mathrm{DGOC} = \sum_{t=1}^{n_y}\mathrm{PW}^t\sum_{i=1}^{n_l}\sum_{LL=1}^{n_{LL}}\sum_{s=1}^{ns}P_{i,LL,s}^{DDG/WDG}\times T_{LL}\times oc_{LL,s}\times \mathrm{Prob}_s^{comb} \tag{22}$$

$$\mathrm{PW} = \frac{1+\mathrm{Infr}}{1+\mathrm{Intr}} \tag{23}$$

EEC is the expected cost of purchased energy from the transmission network as (24):

$$\mathrm{EEC} = \sum_{t=1}^{n_y}\mathrm{PW}^t\sum_{i=1}^{n_s}\sum_{LL=1}^{n_{LL}}\sum_{s=1}^{ns}P_{i,LL,s}^{Trans}\times T_{LL}\times \mathrm{EP}_{LL,s}\times \mathrm{Prob}_s^{comb} \tag{24}$$

EELC is the expected energy loss cost as (25):

$$\mathrm{EELC} = \sum_{t=1}^{n_y}\mathrm{PW}^t\sum_{i=1}^{n_f}\sum_{LL=1}^{n_{LL}}\sum_{s=1}^{ns}\mathrm{Loss}_{i,LL,s}\times T_{LL}\times \mathrm{LC}_{LL,s}\times \mathrm{Prob}_s^{comb} \tag{25}$$

EENSC is the expected energy not supplied cost as (26):

$$\begin{aligned}\mathrm{EENSC} = {} & \sum_{t=1}^{n_y}\mathrm{PW}^t\sum_{k=1}^{n_f}\lambda_k\times r_k\sum_{LL=1}^{n_{LL}}\mathrm{RC}_{LL}\times T_{LL}\sum_{s=1}^{ns}\mathrm{LNS}_{k,LL,s} \\ & \times \mathrm{Prob}_s^{comb}\end{aligned} \tag{26}$$

EMC is the cost of emission as (27):

$$\begin{aligned}\mathrm{EMC} = {} & \sum_{t=1}^{n_y}\mathrm{PW}^t\times \mathrm{emc}\times\Bigg[\sum_{i=1}^{n_s}\sum_{LL=1}^{n_{LL}}\sum_{s=1}^{ns}(P_{i,LL,s}^{Trans}\times T_{LL}\times \mathrm{GE}_{LL,s})\times \mathrm{Prob}_s^{comb} \\ & + \sum_{i=1}^{n_l}\sum_{LL=1}^{n_{LL}}\sum_{s=1}^{ns}(P_{i,LL,s}^{DDG}\times T_{LL}\times \mathrm{DGE}_{LL,s})\times \mathrm{Prob}_s^{comb}\Bigg]\end{aligned} \tag{27}$$

where

EMC is the emission cost due to pollutant CO_2.

emc is the cost of emission in ($/ton).

$P_{i,LL,s}^{Trans}$ is the power received from the ith transmission substation in load level LL and state s.

$\mathrm{GE}_{LL,s}$ is the emission related to the power received from transmission grid in load level LL and state s (ton/kWh).

$\mathrm{DGE}_{LL,s}$ is the emission related to the power generated by DG units in load level LL and state s (ton/kWh).

TDC is the technical dissatisfaction cost as (28):

$$\mathrm{TDC} = \mathrm{dc}\times\max\{(1-\mu^V),(1-\mu^l),(1-\mu^S)\} \tag{28}$$

where, dc is the dissatisfaction cost.

Calculation of EENSC

In this section, the procedure for calculating the reliability index is described in details. Most of the researches have not considered the following items in reliability calculation:

- Possibility of islanding after a fault;
- Uncertainty of load and wind power;
- Load duration curve;
- Checking the power flow and other constraints in the island.

To clarify the discussion, suppose that a fault occurs on feeder k. To reduce the outage cost, at first, the circuit breaker (CB), located at outgoing of the substation, disconnects all the branches (including the faulted and un-faulted sections), then the faulted section is isolated from the rest of the network using the switches and goes to repair state. Then, the circuit breaker is again closed. Here, there may be some isolated parts with some loads. If there are some DDGs with enough generation in the isolated part, and the constraints are satisfied, this part can be operated successfully as an island to supply the disconnected loads until the faulted section is repaired. Otherwise, all or a part of the loads of the island must be shed. In some cases, there may be reserve feeders that can connect the islanded part to the neighboring feeders or substations to supply the island's loads without the voltage and current violations.

Now, it is important to see in the time that the fault occurs, and feeder goes out of service, what are the amounts of load and generated power of WDGs (as uncertain and stochastic parameters).

In each outage, depending on the network condition, the result of reliability calculation would be different. In this paper, all the possibilities of network states are simulated to precisely calculate the reliability index (EENSC).

Regarding to the above explanation, the following stages are required to calculate the EENSC:

1. It is assumed that each feeder is equipped with two switches at its endings, and there is a circuit breaker at each outgoing of HV/MV substation that can disconnect the main feeder and its downstream load points (MV/LV buses) from the substation.
2. After that a fault occurs on feeder k, at first, the circuit breaker immediately operates and disconnects all the loads fed from the substation. Then, to reduce the outage cost, the faulted section is located and isolated from the rest of the network; finally, the

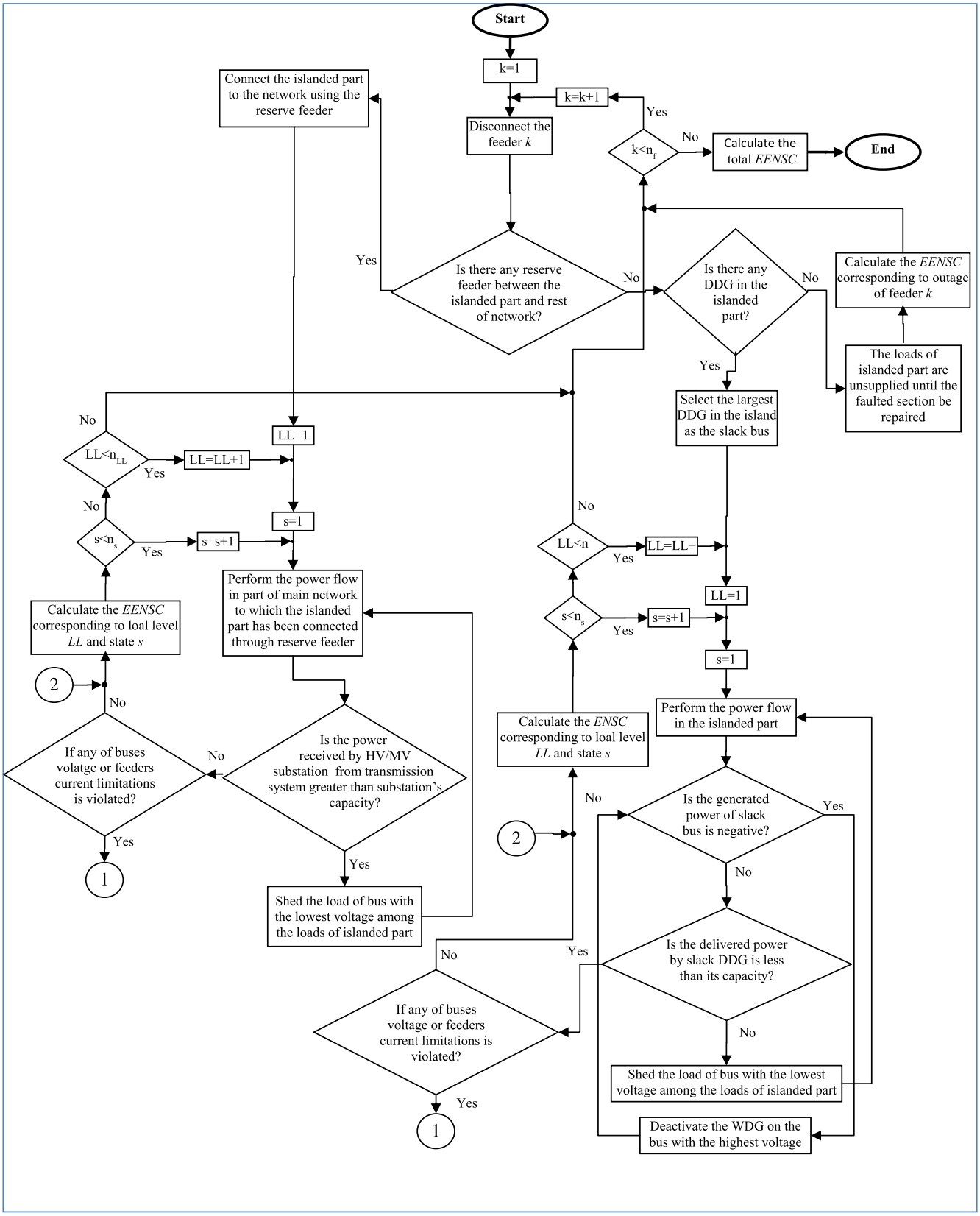

Fig. 2. Flowchart for calculation of the EENSC.

circuit breaker is again closed. By reclosing the circuit breaker, the loads of un-faulted sections are fed as before. However, there may be some isolated parts with some loads. In these parts, there may be some DG units, or there may be some reserve feeders that can connect the isolated part to a neighboring HV/MV substation, or an energized feeder. On this basis, three situations can be arisen:

Case 1: There is no DDG in the isolated part, and no reserve feeder to connect this part to the rest of the network; in this case, all the loads of isolated part will be unsupplied until the faulted section is repaired;

Case 2: There is reserve feeder between the isolated part and the rest of network;

Case 3: There is no reserve feeder between the isolated part and the rest of the network, but there is DDG in the isolated part.

In case 2, the reserve feeder connects the isolated part to the rest of the network; then the backward-forward power flow is performed [40]. If none of the constraints related to the voltage, current, and substations capacity is violated, then the loads of isolated part will be supplied. If the thermal capacities of substation or buses voltages are violated, then the loads of isolated part are shed step by step until the violation is resolved. In each step, the load of bus with the minimum voltage will be shed. If the current limitation of any feeder is violated, then the loads influencing the current of this feeder are determined, and the loads of buses which have the minimum voltage is shed step by step until the current violation is removed.

In case 3, the largest DDG is selected as the slack bus of island; then the power flow in the island is performed; if the output power of slack bus is negative (which means that the generation in the island is more than the load plus losses), the WDG and if necessary, the DDG on the bus with the highest voltage will be disconnected; then, the power flow is re-performed. This process is continued until the output power of slack bus becomes positive.

If the output power of slack bus is positive, but it exceeds the capacity of DDG, the loads of island are shed based on the lowest voltage until the output power of DDG falls under its capacity.

The flowchart of Fig. 2 shows the procedure of calculating the EENSC in details.

Proposed solution method

To solve the DNEP problem formulated in part 2, the genetic algorithm has been employed as the following.

Genetic algorithm

In the field of artificial intelligence, a genetic algorithm (GA) is a search heuristic that mimics the process of natural selection. This heuristic (also sometimes called a metaheuristic) is routinely used to generate useful solutions to optimization and search problems [41,42]. Genetic algorithm belongs to the larger class of evolutionary algorithms (EA), which generate solutions to optimization problems using techniques inspired by natural evolution, such as selection, crossover, and mutation. In genetic algorithm, a population of candidate solutions (called individuals) to an optimization problem is evolved toward better solutions. Each candidate solution has a set of properties (its chromosomes or genotype) which can be mutated and altered; traditionally, solutions are represented in binary as strings of 0s and 1s, but other encodings like real and decimal codifications are also possible [32,43].

The evolution usually starts from a population of randomly generated individuals, and is an iterative process, with the population in each iteration called a generation. In each generation, the fitness of every individual in the population is evaluated; the fitness is usually the value of the objective function in the optimization problem being solved. The more fit individuals are stochastically selected from the current population, and each individual's genome is modified (crossed over and possibly randomly mutated) to form a new generation. The new generation of candidate solutions is then used in the next iteration of the algorithm. Commonly, the algorithm terminates when either a maximum number of generations has been produced, or a satisfactory fitness level has been reached for the population.

The GA has been used for solving many of planning problems [27,29,32,43]. Since the decision variables used in this study are of real, binary and decimal type, thus a combination of all the three methods has been employed.

Proposed chromosome structure

To optimize the proposed DNEP problem, the information showing the configuration of distribution network should be encoded in the genes of chromosome. The structure of the proposed chromosome is illustrated in Fig. 3. As shown in this figure, the chromosome is composed of seven parts. In the first part, the *i*th gene gets binary values as 0 or 1, and indicates that the feeder *i* has been installed or not. The number of genes in this part is equal

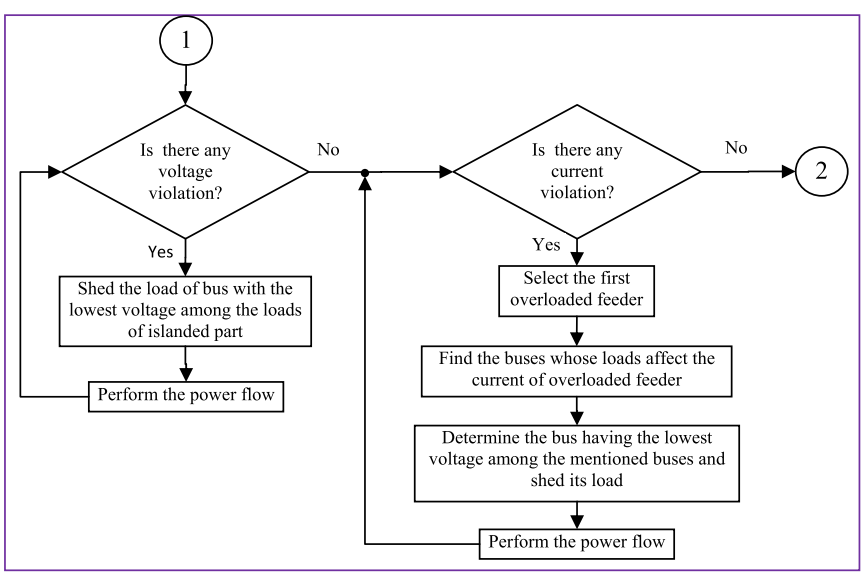

Fig. 2 (*continued*)

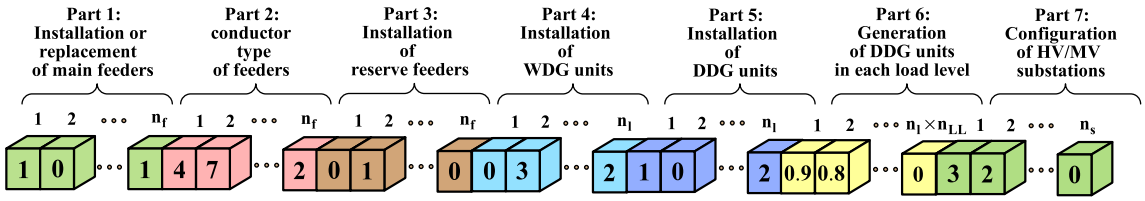

Fig. 3. Structure of the proposed chromosome.

to the number of existing feeders plus candidate ones. The *i*th gene of second part shows the type of *i*th feeder and can get the discrete values between 1 and the number of conductor types. The reserve feeders which should be installed are expressed by the values 1 or 0 of the genes of the third part. Here, 1 means that the related reserve feeder is installed, and 0 means that it is not installed. The genes of 4th and 5th parts determine the installation of WDGs and DDGs on MV/LV buses. The integer values of the genes in this part are between 0 and the maximum installable DG units on the buses. The 6th part of the proposed chromosome indicates the power generation of DDG units in each load level, and its genes have real values between 0 and the related DDG's capacity. Finally, the 7th part shows the layout of the HV/MV substations including the existing and candidate ones.

Procedure of problem optimization

According to the proposed chromosome structure, when the genes of chromosome are initialized, the network configuration such as substations site and capacities, main and reserve feeders routing and their conductor type, the DGs' site, capacities and their generated power in each load level will be known. This data is sufficient for performing the backward-forward load flow to obtain the power flowing through the feeders and substations, and the voltages of buses for all the states. In this stage, the installation and operation costs of equipment, cost of losses, and the violation of constraints are determined. In the next stage, the interruption cost is calculated according to the procedure proposed in flowchart of Fig. 2. Finally, all the cost components are summed to compose the cost or objective function. The complete procedure of the proposed optimization is illustrated in flowchart of Fig. 4.

Numerical study

The proposed DNEP is programmed and executed in MATLAB programming environment and applied to the 54-bus test system and also on a real 104-bus distribution network. The data of these

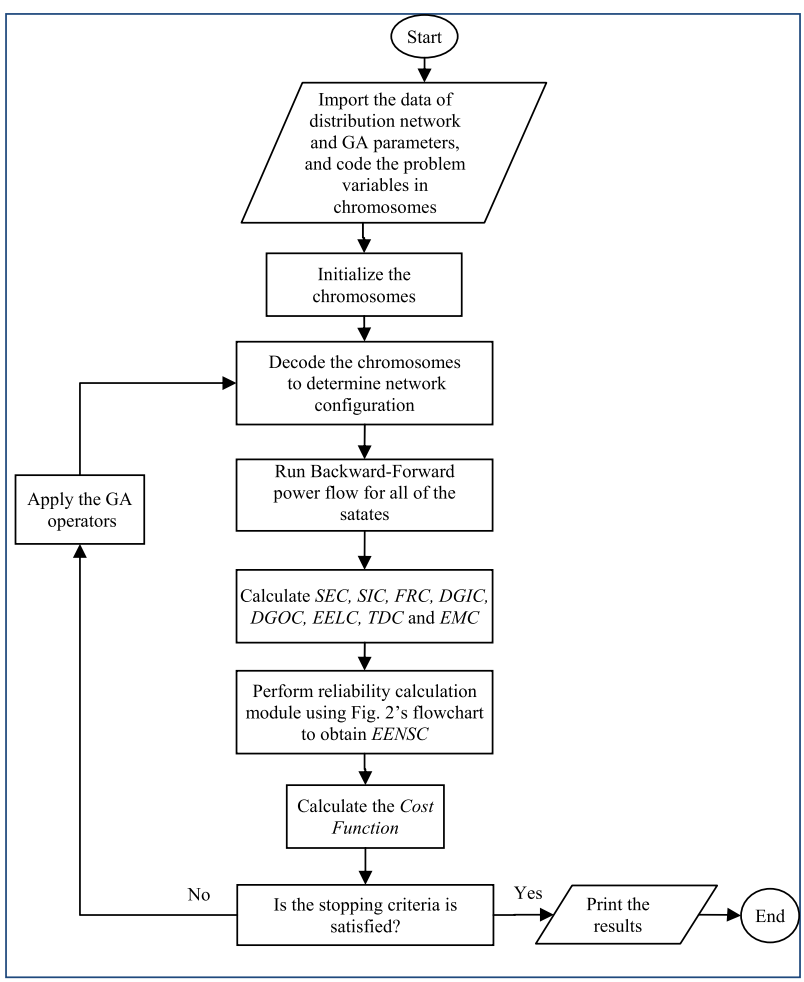

Fig. 4. Flowchart of the problem optimization.

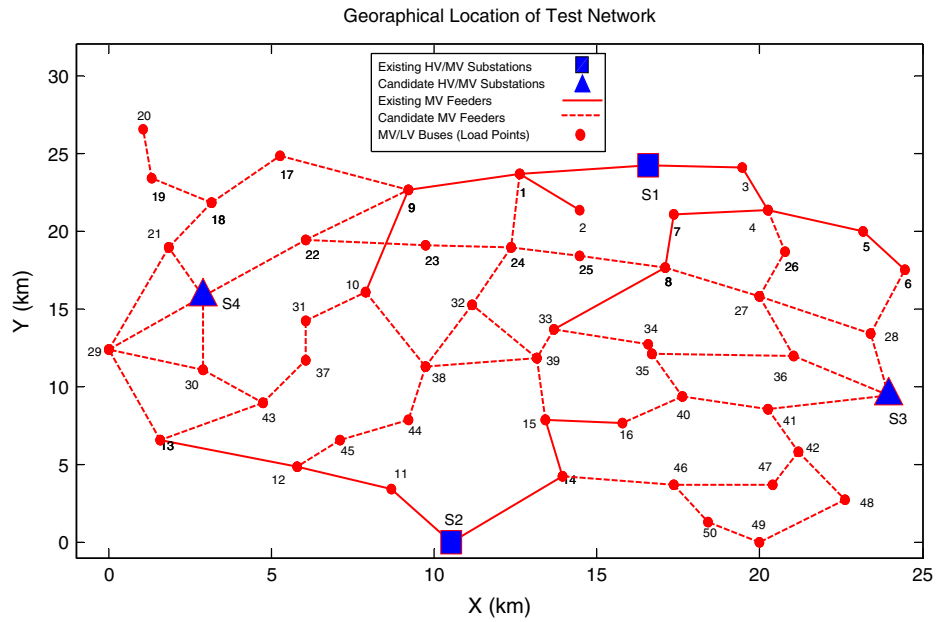

Fig. 5. The 54-node test system.

systems are introduced in the next parts. By several executions of the algorithm for different values of GA parameters, it was observed that assigning the values 100, 0.75 and 0.05 respectively for the number of chromosomes, crossover rate, and mutation rate, yields the best results. In addition, the roulette wheel is used for the reproduction process [42].

Improving the GA performance

To maintain the fittest chromosomes during the optimization procedure, and to improve the performance of the GA, the "Elite Selection" (ES) process has been employed. For this purpose, the worst 10% of present generation (population) are replaced with the best 10% of previous generation. Of course, this substitution is fulfilled if the mentioned 10% of previous generation is more qualified than that of the present one from the objective function viewpoint.

54-node distribution system

The first test system, as shown in Fig. 5, is a 54-node, 33 kV network consisted of 50 load points (MV/LV buses) with the specifications of Table 3 [7,33]. The total load of the system in the horizon year is 73.22 MVA, and the power factor of loads is 0.8. There are two existing and two candidate HV/MV substations to feed the distribution network. The data related to HV/MV substations are given in Table 4. The number of existing feeders is 17, and there are 56 new feeders as candidates for installation. There are twelve types of conductors used in the feeders; their characteristics are presented in Table 5. Two DG technologies, including gas turbine and wind turbine are considered in the simulation; their characteristics are given in Table 6. The wind turbine's cut-in, rated, and cut-off speeds are 4, 14, and 25 m/s, respectively. The data of the chosen wind turbine are used to generate the probabilistic wind output power model as Tables 1and 2. All the MV/LV buses are candidates for DG installation. Other parameters used in the simulations are presented in Table 7.

Table 3
Specification of load points of Fig. 5.

No.	Load (kW)	No.	Load (kW)	No.	Load (kW)	No.	Load (kW)	No.	Load (kW)
1	4200	11	300	21	1800	31	700	41	900
2	1500	12	1800	22	1100	32	1700	42	1200
3	700	13	1100	23	1000	33	2900	43	1300
4	1100	14	1000	24	500	34	1200	44	1400
5	2600	15	1400	25	900	35	900	45	800
6	700	16	1900	26	1200	36	300	46	1800
7	1000	17	700	27	1500	37	2100	47	1000
8	1900	18	1200	28	700	38	1100	48	800
9	1200	19	1400	29	1400	39	1000	49	500
10	2900	20	800	30	2600	40	1400	50	800

Table 4
Specification of HV/MV substations.

Substation	Geographical position		Existing capacity (MVA)	Expandable capacity (MVA)
	X (km)	Y (km)		
S_1	16.6	24.2	2 × 15	4 × 15
S_2	10.5	0	1 × 15	4 × 15
S_3	23.9	9.5	0	4 × 7.5
S_4	2.9	15.8	0	4 × 7.5

Table 5
Specification of conductors used in feeders.

Conductor type	Resistance (ohm/km)	Reactance (ohm/km)	Current capacity (A)	Cost (k$/km)
1	0.7500	0.1746	61	17
2	0.4794	0.1673	84	22
3	0.3080	0.1596	114	30
4	0.1972	0.1496	156	42
5	0.1208	0.1442	208	54
6	0.0723	0.1262	303	85
7	0.0487	0.1217	400	125
8	0.0405	0.1196	453	140
9	0.0350	0.1180	500	165
10	0.0247	0.1140	645	220
11	0.019	0.11	700	270
12	0.017	0.09	850	310

Table 6
Characteristics of DG units used in the problem.

DG technology	Size (MVA)	Installation cost (k$/MVA)	Operation cost ($/MW h)
Gas turbine (GT)	1	400	46
Wind turbine (WT)	1	800	10

Table 7
The value of parameters used in the simulation.

Parameter	Value
ρ($/MWh)	60
Infr (%)	10
Intr (%)	12
V_{safe}^{min} (pu)	0.95
V_{safe}^{max} (pu)	1.05
V_{crit}^{min} (pu)	$0.95 \times V_{safe}^{min}$
V_{crit}^{max} (pu)	$1.05 \times V_{safe}^{max}$
$I_{crit,i}^{max}$ (A)	1.1 × Current capacity of feeder i
Failure rate of feeders (fail/km/year)	0.2
Repair time (h)	2
Emission of CO_2 related to the received power from the transmission grid (ton/MWh)	0.632
Emission of CO_2 related to the generated power by DDGs (ton/MWh)	0.365
Maximum number of installable DGs on each bus	4

Scenario 1

In this scenario, the distribution network expansion planning is implemented without the presence of distributed generation. Thus, the DNEP is fulfilled through the upgrading or installation of feeders and substations. In this case, the improvement of reliability would be gained by means of reserve feeders installation, and by the load transferring between the substations during he fault on the feeders. The results of this scenario are illustrated in Fig. 6 and Tables 8 and 9. Fig. 6 shows the configuration of expanded network. In this Figure, the conductors with higher current capacity are depicted by the thicker lines. Also, the dashed lines are the installed feeders as the reserve ones. Tables 8 and 9 show the results of expanded substations and cost components, respectively.

Table 8
Results of substation expansion for 54-bus network.

Substation	Existing capacity (MVA)	Expanded capacity (MVA)	
		Scenario 1	Scenario 2
S_1	2 × 15	3 × 15	3 × 15
S_2	1 × 15	3 × 15	2 × 15
S_3	0	3 × 7.5	2 × 7.5
S_4	0	4 × 7.5	4 × 7.5

Table 9
Cost components for 54-bus network.

Component	Value (M$)	
	Scenario 1	Scenario 2
Substation expansion cost	2.40	2.00
Substation installation cost	11.40	11.20
Feeders cost	9.89	5.30
DG installation cost	0	14.40
DG operation cost	0	23.03
Energy purchase cost	94.39	66.42
Energy not supplied cost	26.71	11.95
Energy loss cost	3.17	2.09
Emission cost	56.76	44.41
Total cost	204.72	180.80

Scenario 2

In this scenario, the DNEP is solved considering the presence of DG. The results of this scenario are shown in Fig. 7 and Tables 8 and 9. Also the type and number of installed DGs on the buses are illustrated in Table 10.

Comparing the results of the two scenarios indicates the benefits of using DG in DNEP. As the results show, the installation and upgrading costs of substations and feeders have been decreased, and the energy loss and reliability costs have been diminished significantly. Also, the energy cost is lower than that without DG. As an important advantage, the emission cost in the presence of DG

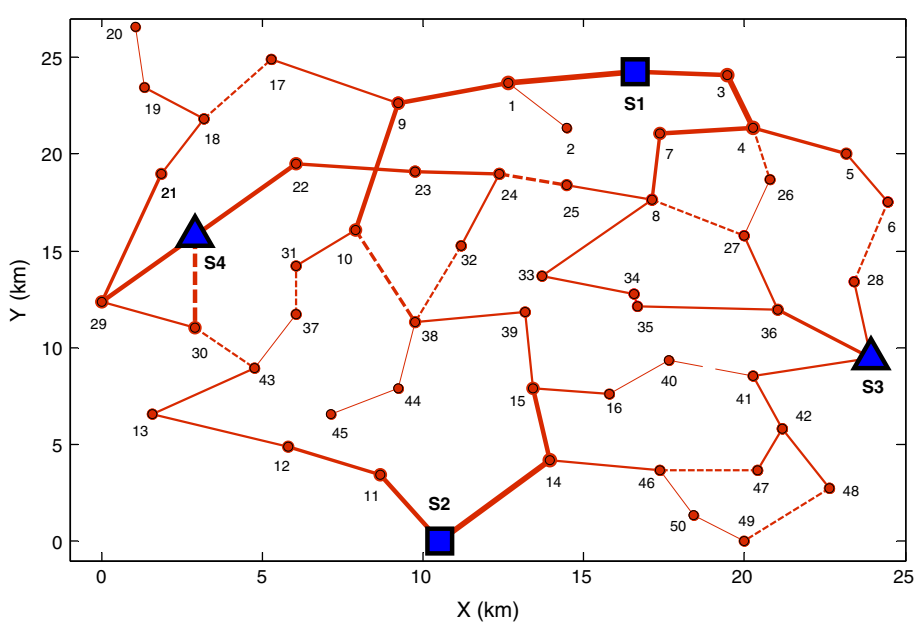

Fig. 6. Configuration of 54-bus network after expansion in scenario 1.

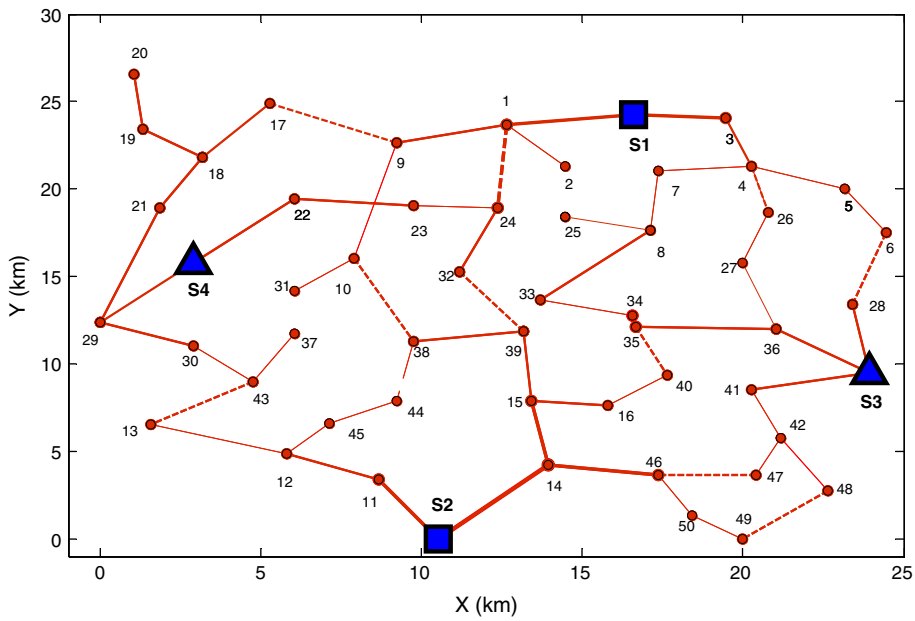

Fig. 7. Configuration of 54-bus network after expansion in scenario 2.

is lower, and this can be very valuable from the environmental concerns viewpoint. The decrease of cost components leads to a 10% decrease in the total cost. Fig. 8 compares the cost components in the two scenarios.

Table 10
Number and type of installed DGs on 54-bus network in scenario 2.

Bus number	Type of installed DG	Number of installed DG
6	WDG	3
8	DDG	2
13	WDG	3
17	DDG	1
18	DDG	1
20	WDG	2
21	DDG	2
28	DDG	1
33	DDG	3
35	DDG	1
36	DDG	1
43	DDG	1
49	WDG	3

The convergence trend of GA with and without elite selection process has been depicted in Fig. 9 for the second scenario. As

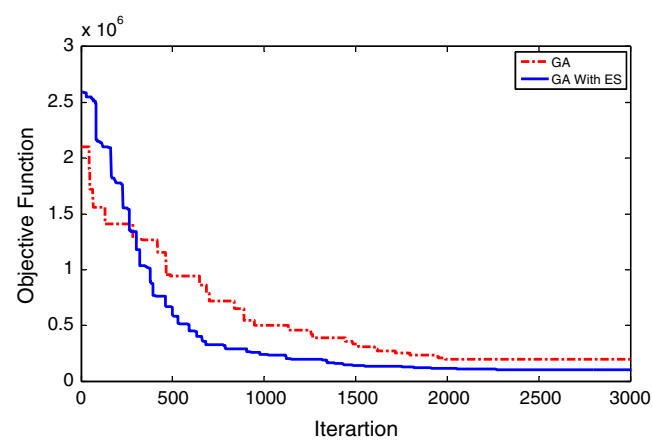

Fig. 9. Convergence trend of GA with and without elite selection.

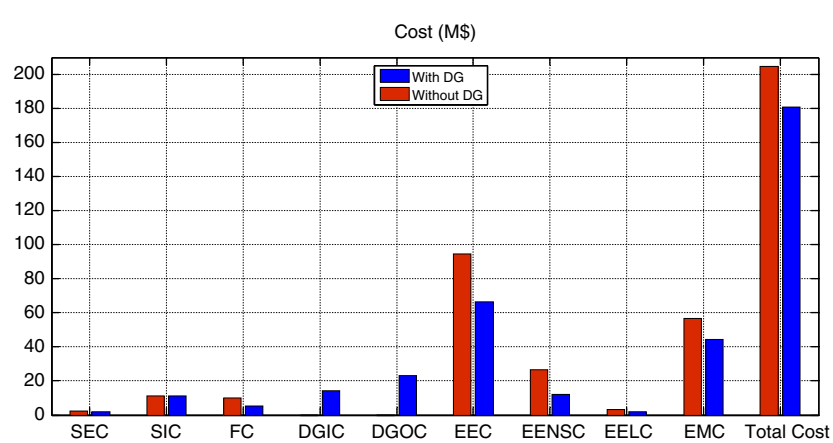

Fig. 8. Comparison of the cost components in the two scenarios.

shown, when the GA is equipped with ES, more optimal result is obtained.

Real distribution network

The second test system is a real distribution network [44]. It is a 13.5 kV network consisted of 101 load buses, with the characteristics given in [44] and shown in Fig. 10. The total load of the system in the horizon year is 58.23 MW and 43.67 MVAr. Three HV/MV substations named as HV1, HV2 and HV3 are candidate to feed the distribution network. There are 184 candidate feeders as shown in Fig. 10. The utilized conductors are the ones reported in Table 5. The ratings of gas and wind turbines are 500 kW. All the MV/LV buses are candidates for DDG installation. In addition, the potential buses for WDG installation are the nodes: 10, 19, 21, 22, 27, 32, 35, 36, 37, 43, 59, 64, 89, 97, 98, 99, 102, and 103. The same scenarios defined for the 54-bus network (i.e. the scenarios without and with DG) are also implemented on this network. The simulation results are provided in Figs. 11 and 12 and Tables 11–13. As shown, when the DG units are not utilized, all the candidate substations have been expanded, while when the DGs are incorporated, there is no need to install substation HV2. The

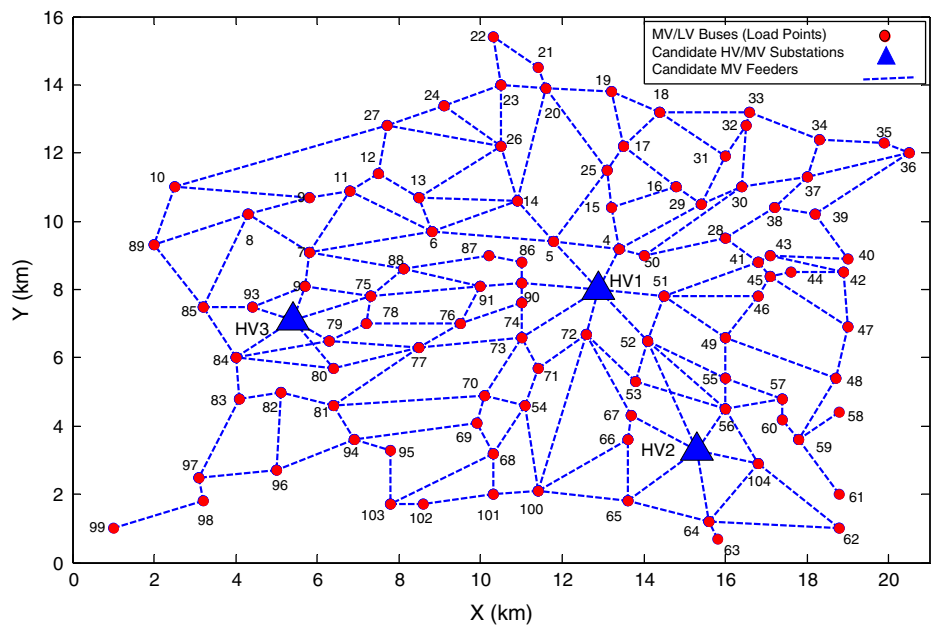

Fig. 10. Initial configuration of real 104-bus distribution network.

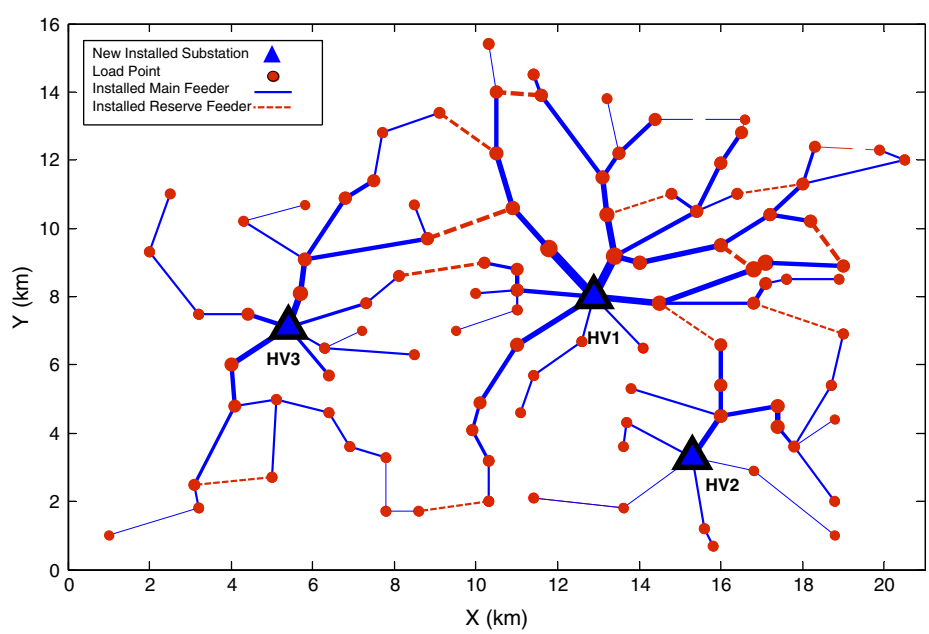

Fig. 11. Configuration of 104-bus network after expansion in scenario 1.

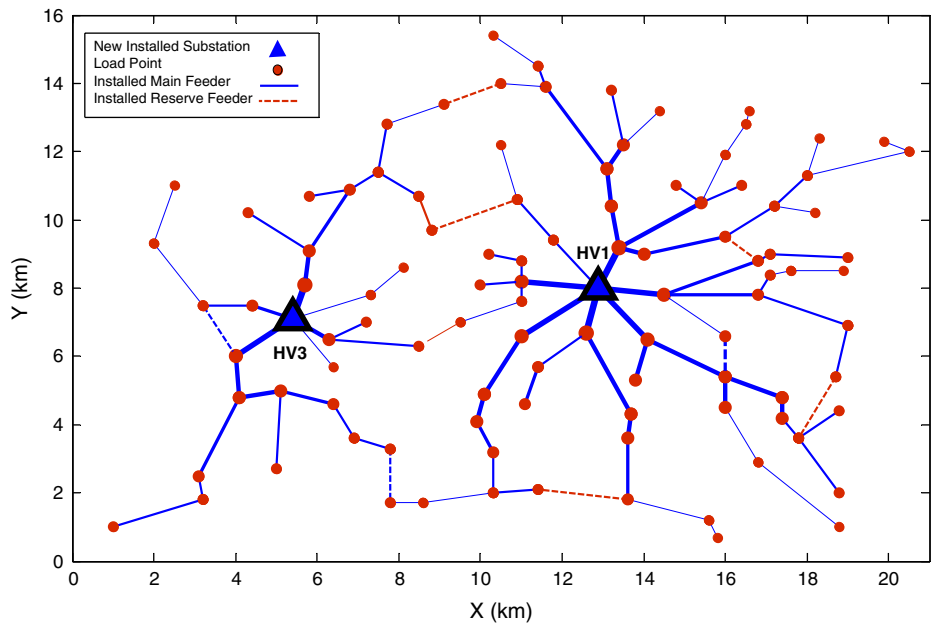

Fig. 12. Configuration of 104-bus network after expansion in scenario 2.

Table 11
Results of substation expansion for 104-bus network.

Substation	Existing capacity (MVA)	Installable capacity (MVA)	Expanded capacity (MVA)	
			Scenario 1	Scenario 2
HV1	0	4 × 15	4 × 15	3 × 15
HV2	0	4 × 15	2 × 15	0
HV3	0	4 × 15	3 × 15	2 × 15

Table 12
Cost components for 104-bus network.

Component	Value (M$)	
	Scenario 1	Scenario 2
Substation expansion cost	0	0
Substation installation cost	27.60	18
Feeders cost	12.51	9.29
DG installation cost	0	15.8
DG operation cost	0	2.12
Energy purchase cost	83.46	54.78
Energy not supplied cost	17.62	9.35
Energy loss cost	2.78	1.73
Emission cost	50.18	32.81
Total cost	194.15	143.88

feeders installation cost, the purchased energy cost are also decreased. Moreover, the energy not supplied cost, the emission cost, and the energy losses cost have been diminished significantly. As a whole, the total expansion cost is reduced from 194.15 M$ to 143.88 M$.

Conclusion

In this paper, an integrated distribution network expansion planning in the presence of renewable and non-renewable distributed generation is proposed. The reinforcement of existing feeders and substations, the installation of new feeders and substations, and also the installation of renewable and non-renewable DGs have been considered as the expansion planning options. The objective function includes all the installation and operation costs. Moreover, the reliability and environmental concerns have been regarded in the problem. The annual load variation, and also, the uncertainties of renewable DGs' output power, load demand and energy price have been taken into account in the calculation of reliability and other cost components. To enhance the reliability and lower the interruption costs, the reserve feeders and also, the possibility of islanding operation of DG units are considered. Likewise, the required condition for successful and safe operation of island has been evaluated for all the uncertainty states. The proposed DNEP along with its constraints has been formulated as an optimization problem where the genetic algorithm is employed to solve this integrated problem. To evaluate the effectiveness of the presented DNEP problem, it has been applied to the 54-bus network and also a real large-scale distribution network. The simulation results verify the efficiency of the proposed method in the improvement of the network's technical characteristics, the decrease of total cost and the decrease in environmental pollution.

Table 13
Number and type of installed DGs on 104-bus network in scenario 2.

Bus number	Type of installed DG	Number of installed DG
12	DDG	1
19	WDG	4
21	WDG	2
27	WDG	4
32	WDG	4
36	DDG	1
37	WDG	4
38	DDG	4
43	WDG	4
44	DDG	2
64	WDG	4
68	DDG	3
89	WDG	3
98	WDG	4
103	DDG	2

References

[1] El-Khattam W, Hegazy YG, Salama MMA. An integrated distributed generation optimization model for distribution system planning. IEEE Trans Power Syst 2005;20(2):1158–65.
[2] Farrag MA, El-Metwally MM, El-Bages MS. A new model for distribution system planning. Electr Power Energy Syst 1999;21(7):523–31.
[3] Willis HL. Power distribution planning reference book. 2nd ed. New York: Marcel Dekker; 2004. p. 1217.
[4] Ault GW, Foote CET, McDonald JR. Distribution system planning in focus. IEEE Power Eng Rev 2002;22(1):60–2.
[5] Shaaban MF, Attwa YM, El-Saadnay EF. DG allocation for benefit maximization in distribution networks. IEEE Trans Power Syst 2013;28(2):639–49.
[6] Jabr RA. Polyhedral formulations and loop elimination constraints for distribution network expansion planning. IEEE Trans Power Syst 2013;28(2):1888–97.
[7] Franco JF, Rider MJ, Romero R. A mixed-integer quadratically-constrained programming model for the distribution system expansion planning. Electr Power Energy Syst 2014;62:265–72.
[8] El-Khattam W, Bhattacharya K, Hegazy YG, Salama MMA. Optimal investment planning for distributed generation in a competitive electricity market. IEEE Trans Power Syst 2004;19(3):1674–84.
[9] Greatbanks JA, Popovic DH, Begovic M, Pregelj A, Green TC. On optimization for security and reliability of power systems with distributed generation. In: Proc. 2003 IEEE power tech conf., vol. 1.
[10] Pregelj A, Begovic M, Rohatgi A. Recloser allocation for improved reliability of DG-enhanced distribution networks. IEEE Trans Power Syst 2006;21(3):1442–9.
[11] Gil HA, Joos G. On the quantification of the network capacity deferral value of distributed generation. IEEE Trans Power Syst 2006;21(4):1592–9.
[12] Mendez VH, Rivier J, de la Fuente JI, Gomez T, Arceluz J, Marin J, et al. Impact of distributed generation on distribution investment deferral. Electr Power Energy Syst 2006;28(4):244–52.
[13] Ziari I, Ledvich G, Ghosh A, Platt G. Optimal distribution network reinforcement considering load growth, line loss, and reliability. IEEE Trans Power Syst 2013;28(2):587–97.
[14] Gozel T, Hocaoglu MH. An analytical method for the sizing and sitting of distributed generators in radial systems. Electr Power Syst Res 2009;79(6):912–8.
[15] Jabr RA, Pal BC. Ordinal optimization approach for locating and sizing of distributed generation. IET Gener Transm Distrib 2009;3(8):713–23.
[16] Borges CLT, Falcao DM. Optimal distributed generation allocation for reliability, losses, and voltage improvement. Electr Power Energy Syst 2006;28(6):413–20.
[17] Wang L, Singh C. Reliability-constrained optimum placement of reclosers and distributed generators in distribution networks using an ant colony system algorithm. IEEE Trans Syst Man Cybern C Appl Rev 2008;38(6):757–64.
[18] Ziari I, Ledwich G, Ghosh A, Platt G. Integrated distribution system planning to improve reliability under load growth. IEEE Trans Power Syst 2012;27(2):757–65.
[19] Thresher R, Robinson M, Veers P. To capture the wind. IEEE Power Energy Mag 2007;5(6):34–46.
[20] Smith J, Thresher R, Zavadil R, DeMeo E, Piwko R, Ernst B, et al. A mighty wind. IEEE Power Energy Mag 2009;7(2):41–51.
[21] Atwa YM, El-Saadany EF, Salama MMA, Seethapathy R. Optimal renewable resources mix for distribution system energy loss minimization. IEEE Trans Power Syst 2010;25(1):360–70.
[22] El-Khattam W, Hegazy Y, Salama M. Investigating distributed generation systems performance using Monte Carlo simulation. IEEE Trans Power Syst 2006;25(2):524–32.
[23] Attwa Y, El-Saadany E. Probabilistic approach for optimal allocation of wind-based distributed generation in distribution systems. IET Renew Power Gener 2011;5(1):79–88.
[24] Sorudi A. Possibilistic-scenario model for DG impact assessment on distribution networks in an uncertain environment. IEEE Trans Power Syst 2012;27(3):1283–93.
[25] Soroudi A, Caire R, Hadjsaid N, Ehsan M. Probabilistic dynamic multi-objective model for renewable and non-renewable distributed generation planning. IET Gener Transm Distrib 2011;5(11):1173–82.
[26] Soroudi A, Afrasiab M. Binary PSO-based dynamic multi-objective model for distributed generation planning under uncertainty. IET Renew Power Gener 2012;6(2):67–78.
[27] Celli G, Ghiani E, Mocci S, Pilo F. A multiobjective evolutionary algorithm for the sizing and sitting of distributed generation. IEEE Trans Power Syst 2005;20(2):750–7.
[28] Bae IS, Kim JO, Kim JC, Singh C. Optimal operating strategy for distributed generation considering hourly reliability worth. IEEE Trans Power Syst 2004;19(1):287–92.
[29] Falaghi H, Singh C, Haghifam MR, Ramezani M. DG integrated multistage distribution system expansion planning. Electr Power Energy Syst 2011;33(8):1489–97.
[30] Gitizadeh M, Vahed AA, Aghaei J. Multistage distribution system expansion planning considering distributed generation using hybrid evolutionary algorithms. Appl Energy 2013;101:655–66.
[31] Sedghi M, Golkar MA, Haghifam MR. Distribution network expansion considering distributed generation and storage units using modified PSO algorithm. Electr Power Energy Syst 2013;52(4):221–30.
[32] Shayeghi H, Bagheri A. Dynamic sub-transmission system expansion planning incorporating distributed generation using hybrid DCGA and LP technique. Electr Power Energy Syst 2013;48:111–22.
[33] Lavorato M, Franco JF, Rider MJ, Romero R. Imposing radiality constraints in distribution system optimization problems. IEEE Trans Power Syst 2012;27(1):172–80.
[34] Miguez E, Cidras J, Diaz-Dorado E, Garcia-Dornelas JL. An improved branch-exchange algorithm for large-scale distribution network planning. IEEE Trans Power Syst 2002;17(4):931–6.
[35] Delbem CB, de Carvalho AC, Bretas NG. Main chain representation for evolutionary algorithms applied to distribution system reconfiguration. IEEE Trans Power Syst 2005;20(1):425–36.
[36] Carreño EM, Romero R, Padilha-Feltrin A. An efficient codification to solve distribution network reconfiguration for loss reduction problem. IEEE Trans Power Syst 2008;23(4):1542–51.
[37] Ramos ER, Exposito AG, Santos JR, Iborra FL. Path-based distribution network modeling: application to reconfiguration for loss reduction. IEEE Trans Power Syst 2005;20(2):556–64.
[38] Hong YY, Ho SY. Determination of network configuration considering multiobjective in distribution systems using genetic algorithms. IEEE Trans Power Syst 2005;20(2):1062–9.
[39] Haghifam MR, Falaghi H, Malik O. Risk-based distributed generation placement. IET Gener Transm Distrib 2008;2(2):252–60.
[40] Shirmohammadi D, Hong H, Semlyen A, Luo G. A compensation-based power flow method for weakly meshed distribution and transmission networks. IEEE Trans Power Syst 1988;3(2):753–62.
[41] Gen M, Cheng R. Genetic algorithms and engineering design. New York: Wiley; 1997.
[42] Arora JS. Introduction to optimum design. In: Chapter 16: Genetic algorithms for optimum design. Iowa City, Iowa: The University of Iowa, College of Engineering; 2012. p. 643–55.
[43] Shayeghi H, Mahdavi M, Kazemi A, Shayanfar HA. Studying effect of bundle lines on TNEP considering network losses using decimal codification genetic algorithm. Energy Convers Manage 2010;51(12):2685–91.
[44] Najafi Ravandagh S. On optimal design and expansion of electrical power distribution systems. J Circ Syst Comput 2010;19(1):45–58.