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OPTIMAL NETWORK EXPANSION PLANNING USING COMBINED DG AND CAPACITOR

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ABSTRACT

This paper presents a multi-stage distribution network expansion planning model with the view point of Distribution Company (DisCo), considering combined Distributed Generation (DG) and capacitor option together with traditional planning method. The objective function comprises: installation and operating costs of DGs, installation cost of capacitors, cost of energy loss, cost of power purchased from grid and costs of substation and feeder upgradation. For solving the proposed problem, a Genetic Algorithm (GA) based approach is used. To evaluate and illustrate the feasibility of the proposed approach, a 9-bus primary distribution system is used. The results obtained on the test system reveals that lowest planning cost along with the technical performance improvement can be achieved by implementing DG and capacitor option together with traditional planning.

Key words: Power Distribution Network, Expansion Planning, Distributed Generation, Capacitor, Genetic Algorithm

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1. INTRODUCTION

Distribution network planners are continuously exercising to obtain optimal expansion planning strategies to meet the increasing customer's load at affordable prices with maximum profit to the DisCo's and low system investment cost. These strategies includes: expansion of existing substations, building new substations and adding new feeders but are constrained by system operation and performance as well as the economic limits [1]. Also, these expansion methods require considerable time and money to increase the grid capacity. Due to the low investment risk and flexibility, DG can be used as a possible solution to distribution system expansion planning [1, 2] to provide more diversity of expansion solutions for distribution utilities. The installation of DG to the existing distribution network offers several economical benefits like deferred network upgrade cost and reduced costs to supply the peak hour energy demand [3, 4].

There are a number of approaches available in literature for expansion planning of the distribution systems by optimal allocation of either DG alone or together with the traditional options [5, 6, 7, 8, 9, 10, 2, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24]. The researchers have presented either single stage [5, 9, 11, 15, 19, 21] or multi stage [2, 18, 20, 23, 24] problem formulation with either single objective [8, 11, 17, 19, 23, 24] or multi-objective [9, 10, 2, 15, 16, 20, 21]. The various objectives considered are cost of network upgradation [5, 6, 7, 8, 10, 2, 11, 17, 18, 23], installation and operating costs of DG [7, 9, 10, 2, 12, 14, 15, 16, 19, 21, 23, 24], cost of energy loss [6, 7, 9, 10, 16, 20, 21], and cost of power purchased from the grid [7, 9, 10, 2, 15, 19, 21, 24], reduction of customer bill [9, 10, 16, 20, 21], improvement in reliability [8, 12, 15, 24], reduction in emission [7] etc. The developed formulations have been solved by different optimization techniques like classical optimization techniques [5, 6, 8, 9, 10, 11, 16, 20, 21, 23] and Artificial Intelligence (AI) based methods [7, 2, 12, 14, 15, 17, 18, 19, 24]. In the literature, only few works [5, 6, 51, 2, 18] are available on optimal planning of DG with perspective of DisCo considering load and electricity price variation over the planning horizon. Moreover, the combined DG and capacitor as possible option for network expansion planning is rarely used. Being a less expensive device as compared to DGs, capacitors can also be used in distribution system planning process to postpone the need of network upgrade due to load growth [25, 26, 27]. Consequently, the modeling of network expansion planning should consider not only the substations and feeders, but also DG and capacitor sources as expansion planning alternatives.

In this paper, a comprehensive expansion planning model is proposed considering installation of DGs and capacitors along with reinforcement of distribution lines and substation transformer as alternatives to meet the load growth. This paper is organized as follows: Section 2 discusses the problem formulation, Section 3 presents the solution methodology, and Section 4 presents the results and discussion of the proposed work. Finally, in Section 5, conclusions are summarized.

2. PROBLEM FORMULATION

This section presents the problem formulation of proposed distribution network expansion planning model with perspective of Distribution Company (DisCo). The main functions of DisCo is to operate, maintain and develop the network from a technical view point, to respond for the distribution network outages and power quality concerns, and maintain the voltage support as well as ancillary services [26, 28]. The following assumptions are made in the problem formulation:

- The DisCo is the owner and operator of a distribution system. It is responsible to purchase the energy from the main grid and is authorized to invest in DG units, capacitors and network components to meet the growing load demand.
- No DG and capacitor is connected to sub-station bus.
- The connection of a DG unit to the bus is modeled as a negative load with a fixed and pre-specified power factor.
- All DGs and capacitors of a given type at a bus will have same output/level.

2.1. Objective Function

The objective of the proposed work is to minimize the installation and operating costs of DGs, installation costs of fixed and variable capacitors, costs associated with reinforcement/addition of transformers and feeders, cost of power purchased from the grid and cost of energy losses.

Cost of DG Installation

The Net Present Value (NPV) of total cost of installation (in \$) of DG units over the planning horizon year can be given as:

$$ICDG = \sum_{t=1}^{T} \sum_{i=1}^{N_{Bus}} \sum_{j=1}^{N_{DG}} x_{j,i,t}^{DG} \times IC_j^{DG} \times (1+r)^{-t} \tag{1}$$

where,

ICDG = Total installation cost of DG over the planning horizon (in \$),

T = No. of years involved in the planning horizon (in year),

NBus = No. of buses in the system,

NDG = No. of different types of DG employed for planning,

$x_{j,i,t}^{DG}$ = Integer variable representing the installation of DG type j at bus i during planning year t,

IC_j^{DG} = Installation cost of DG type j (in \$),

r = Discount rate.

Cost of DG Operation

The NPV of total operating cost (in \$) of DG units over the planning horizon year can be given as:

$$OCDG = \sum_{t=1}^{T} \sum_{i=1}^{N_{Bus}} \sum_{j=1}^{N_{DG}} \sum_{d=1}^{N_{dl}} \left(\sum_{k=1}^{t} x_{j,i,k}^{DG} \right) \times P_{d,j,i,t}^{DG} \times OC_j^{DG} \times TD_d \times (1+r)^{-t} \tag{2}$$

where,

OCDG = Total operating cost of DG over the planning horizon (in \$),

N_{dl} = No of load levels,

$P_{d,j,i,t}^{DG}$ = Power generated by a single DG of type j at bus i during planning year t corresponding to demand level d (in kW),

OC_j^{DG} = Operating cost of DG type j (in \$/kWh),

TD_d = Duration of load level d (in h).

Cost of Capacitor Installation

Over the planning horizon year, the NPV of total cost of installation (in \$) of both fixed and switching capacitors can be given as:

$$ICCR = \sum_{t=1}^{T} \sum_{i=1}^{N_{Bus}} \left(\sum_{j=1}^{N_{CF}} x_{j,i,t}^{CF} \times IC_j^{CF} + \sum_{j=1}^{N_{CS}} x_{j,i,t}^{CS} \times IC_j^{CS} \right) \times (1+r)^{-t} \tag{3}$$

where,

ICCR = Total installation cost of capacitor over the planning horizon (in \$),

N_{CF} = No. of different types of fixed capacitors employed for planning,

$x_{j,i,t}^{CF}$ = Integer variable representing the installation of fixed capacitor type j at bus i during planning year t,

IC_j^{CF} = Installation cost of fixed capacitor type j (in \$),
N_{CS} = No. of different types of switching capacitors employed for planning,
$x_{j,i,t}^{CS}$ = Integer variable representing the installation of switching capacitor type j at bus i during planning year t,
IC_j^{CS} = Installation cost of switching capacitor type j (in \$).

Cost of Reinforcement of Feeders/Lines

The reinforcement cost of feeder/lines is the total cost paid for installation of new feeder/lines over the planning horizon year and its NPV value can be given as:

$$ICLU = \sum_{t=1}^{T} \sum_{i=1}^{N_{Bus}-1} x_{i,t}^{LU} \times LL_i \times IC^{LU} \times (1+r)^{-t} \qquad (4)$$

where,
ICLU = Total cost associated with line reinforcement over the planning horizon (in \$),
$x_{i,t}^{LU}$ = Binary variable representing the reinforcement of line i during planning year t,
LL_i = Length of line i (in km),
IC^{LU} = Cost of the upgradation of line (in \$/km).

Cost of Reinforcement of Transformer

The NPV of total costs paid for installation of new transformers during planning horizon year can be given as:

$$ICTR = \sum_{t=1}^{T} x_t^{TR} \times IC^{TR} \times (1+r)^{-t} \qquad (5)$$

where,
ICTR = Total cost associated with reinforcement of transformer over the planning horizon (in \$),
x_t^{TR} = Binary variable representing the reinforcement of transformer during planning year t,
IC^{TR} = Cost of the reinforcement of transformer (in \$).

Cost of Electricity Purchased from Grid

The NPV of total cost of electricity that purchased from grid by DisCo over the planning horizon year can be given as:

$$CEGD = \sum_{t=1}^{T} \sum_{d=1}^{N_{dl}} P_{d,t}^{GD} \times CE_d^{GD} \times TD_d \times (1+r)^{-t} \qquad (6)$$

where,
CEGD = Total cost of electricity purchased from grid over the planning horizon (in \$),
$P_{d,t}^{GD}$ = Power purchased from grid during the planning year t corresponding to demand level d (in kW),
CE_d^{GD} = Price of electricity purchased from the grid corresponding to demand level d (in \$/kWh).

Cost of Energy Losses

The NPV of total cost of energy lost on distribution network over the planning horizon year can be given as:

$$CEL = \sum_{t=1}^{T} \sum_{d=1}^{N_{dl}} P_{d,t}^{L} \times CL_d \times TD_d \times (1+r)^{-t} \tag{7}$$

where,

CEL = Total cost of losses over the planning horizon (in $),

$P_{d,t}^{L}$ = Power loss during planning year t corresponding to demand level d (in kW),

CL_d = Price of energy loss corresponding to demand level d (in $/kWh).

Now, eqs. (7.1) to (7.7) can be added to get the NPV of total costs associated with distribution system expansion planning problem, and consequently, the objective function, *C* can be obtained as:

$$\text{Minimize } C \tag{8}$$

where,

$$C = ICDG + OCDG + ICCR + ICLU + ICTR + CEGD + CEL$$

$$= \sum_{t=1}^{T} \sum_{i=1}^{N_{Bus}} \sum_{j=1}^{N_{DG}} \left(x_{j,i,t}^{DG} \times IC_j^{DG} \right) \sum_{d=1}^{N_{dl}} \left(\sum_{k=1}^{t} x_{j,i,k}^{DG} \right) \times P_{d,j,i,t}^{DG} \times OC_j^{DG} \times TD_d \times (1+r)^{-t} +$$

$$\sum_{t=1}^{T} \sum_{i=1}^{N_{Bus}} \left(\sum_{j=1}^{N_{CF}} x_{j,i,t}^{CF} \times IC_j^{CF} + \sum_{j=1}^{N_{CS}} x_{j,i,t}^{CS} \times IC_j^{CS} \right) \times (1+r)^{-t} + \sum_{t=1}^{T} \sum_{i=1}^{N_{Bus}-1} x_{i,t}^{LU} \times LL_i \times IC^{LU} \times (1+r)^{-t} +$$

$$\sum_{t=1}^{T} x_t^{TR} \times IC^{TR} \times (1+r)^{-t} + \sum_{t=1}^{T} \sum_{d=1}^{N_{dl}} \left(P_{d,t}^{GD} \times CE_d^{GD} + P_{d,t}^{L} \times CL_d \right) \times TD_d \times (1+r)^{-t}$$

2.2. Constraints

In the presented planning problem formulation, the following constraints have been considered:

Total Capacity of Feeder

The power flow through any distribution feeder must be within the permissible capacity limits for each demand level as:

$$S_{d,i,t} \le LC_{i,0} + \sum_{k=1}^{t} x_{i,k}^{LU} \times LC \tag{9}$$

where,

$S_{d,i,t}$ = Apparent power flow through line i during planning year t corresponding to demand level d (in kVA),

$LC_{i,0}$ = Initial capacity of line i (in kVA),

LC = Capacity of feeder/line considered for planning (in kVA).

Total Capacity of Substation Transformer

The total power delivered by the substation transformer over the outgoing distribution feeders must be within the substation capacity limit for each demand level as:

$$S_{d,t}^{GD} \le SC_0 + \sum_{k=1}^{t} x_t^{TR} \times SC \tag{10}$$

where,

$S_{d,t}^{GD}$ = Apparent power from grid during planning year t corresponding to demand level d (in kVA),

$SC_{i,0}$ = Initial capacity of sub-station transformer (in kVA),

SC = Capacity of sub-station transformer considered for planning (in kVA).

Active and Reactive Power Flow Balance

For each demand level, the summation of all incoming and outgoing power over the DisCo's feeders, taking into consideration the DisCo's feeders losses and the power supplied by DG and capacitor, if they exists, should be equal to the total demand at that bus as:

$$\sum_{i=1}^{N_{Bus}}\sum_{j=1}^{N_{DG}}\left(\sum_{k=1}^{t}x_{j,i,k}^{DG}\right)\times P_{d,j,i,t}^{DG}+P_{d,t}^{GD}=\sum_{i=1}^{N_{Bus}}P_{i,d,t}+P_{d,t}^{L} \tag{11}$$

$$\sum_{i=1}^{N_{Bus}}\sum_{j=1}^{N_{DG}}\left(\sum_{k=1}^{t}x_{j,i,k}^{DG}\right)\times P_{d,j,i,t}^{DG}\times\tan\left(\cos^{-1}PF_{j}^{DG}\right)+Q_{d,t}^{GD}$$
$$+\sum_{i=1}^{N_{Bus}}\left\{\sum_{j=1}^{N_{CF}}\left(\sum_{k=1}^{t}x_{j,i,k}^{CF}\right)\times Q_{j\max}^{CF}+\sum_{j=1}^{N_{CS}}\left(\sum_{k=1}^{t}x_{j,i,k}^{CS}\right)Q_{d,j,i,t}^{CS}\right\}=\sum_{i=1}^{N_{Bus}}Q_{i,d,t}+Q_{d,t}^{L} \tag{12}$$

where,

$P_{i,d,t}$ = Real power demand at bus *i* corresponding to demand level *d* during year *t* (in kW).

PF_{j}^{DG} = Power factor of DG of type *j*,

$Q_{d,t}^{GD}$ = Reactive power from grid during planning year *t* corresponding to demand level *d* (in kVAr),

$Q_{j\max}^{CF}$ = Capacity of fixed capacitor of type *j* (in kVAr),

$Q_{d,j,i,t}^{CS}$ = Reactive power supplied by a switching capacitor of type *j* at bus *i* during planning year *t* corresponding to demand level *d* (in kVAr),

$Q_{i,d,t}$ = Reactive power demand at bus *i* corresponding to demand level *d* during year *t* (in kVAr).

System Voltage Profile

The voltage magnitudes at different buses in the system are restricted by lower and upper bounds for each demand level. These constraints can be mathematically given as:

$$V_{\min}\le V_{d,i,t}\le V_{\max} \tag{13}$$

where,

$V_{d,i,t}$ = Voltage magnitude at bus i corresponding to demand level d during year t (in kV),

V_{min} = Minimum limit on voltage magnitude (in kV),

V_{max} = Maximum limit on voltage magnitude (in kV).

Load growth

Given the base load demand at each bus, the load growth with annual load growth rate can be expressed as:

$$S_{i,d,t}=P_{i,d,t}+jQ_{i,d,t}=S_{i}^{D}\times DL_{d}\times\left(1+\alpha\right)^{t} \tag{14}$$

where,

$S_{i,d,t}$ = Demand at bus i corresponding to demand level d during year t (in kVA),

S_i^D = Peak demand at bus i during the beginning of planning horizon (in kVA),

DL_d = Fraction of base case peak demand corresponding to demand level d,

α = Annual load growth rate.

Number of DG and Capacitor to be placed

The maximum numbers of DG unit and capacitor of type *j* to be allocated at bus *i* during planning year *t* must be equal to their specified/considered number as:

$$\left.\begin{aligned} x_{j,i,t}^{DG} &\le x_{j,\max}^{DG}, \forall j \in N_{DG} \\ x_{j,i,t}^{CF} &\le x_{j,\max}^{CF}, \forall j \in N_{CF} \\ x_{j,i,t}^{CS} &\le x_{j,\max}^{CS}, \forall j \in N_{CS} \end{aligned}\right\} \tag{15}$$

where,

$x_{j,\max}^{DG}$ = Maximum number of DG of type j

$x_{j,\max}^{CF}$ = Maximum number of fixed capacitor of type j

$x_{j,\max}^{CS}$ = Maximum number of switching capacitor of type j

Operating Limits on DG units

For each demand level, the power output from a DG unit should be below its maximum limit. This can be written mathematically as:

$$0 \le P_{d,j,i,t}^{DG} \le S_{j\max}^{DG} \times PF_j^{DG}, \forall j \in N_{DG} \tag{16}$$

where,

$S_{j,\max}^{DG}$ = Capacity of DG of type j (in kVA)

Operating Limits on Switching Capacitors

The reactive power output from a switching capacitor should correspond to its switching state for each demand level. This can be written mathematically as:

$$Q_{d,j,i,t}^{CS} = y_{j,k}^{CS} Q_{j\max}^{CS}, \forall j \in N_{CS} \tag{17}$$

$$\text{with} \quad y_{j,k}^{CS} = \frac{k}{\left(n_j^{CS} - 1\right)}, k \in \left[0, 1, \cdots, n_j^{CS} - 1\right]$$

where,

$Q_{j\max}^{CS}$ = Capacity of switching capacitor of type j (in kVAr)

$y_{j,k}^{CS}$ = k^{th} switching state of switching capacitor of type j in fraction of its capacity

n_j^{CS} = Number of switching states of switching capacitor of type j

Reverser Power Flow

For each demand level, there should not be any reverse power flow from network to substation as:

$$\sum_{i=1}^{N_{Bus}} \sum_{j=1}^{N_{DG}} \left(\sum_{k=1}^{t} x_{j,i,k}^{DG} \right) \times P_{d,j,i,t}^{DG} \le \sum_{i=1}^{N_{Bus}} P_{i,d,t} \tag{18}$$

$$\sum_{i=1}^{N_{Bus}} \left\{ \sum_{j=1}^{N_{DG}} \left(\sum_{k=1}^{t} x_{j,i,k}^{DG} \right) \times P_{d,j,i,t}^{DG} \times \tan\left(\cos^{-1} PF_{j}^{DG} \right) + \sum_{j=1}^{N_{CF}} \left(\sum_{k=1}^{t} x_{j,i,k}^{CF} \right) \times Q_{j\max}^{CF} + \sum_{j=1}^{N_{CS}} \left(\sum_{k=1}^{t} x_{j,i,k}^{CS} \right) Q_{d,j,i,t}^{CS} \right\} \le \sum_{i=1}^{N_{Bus}} Q_{i,d,t} \tag{19}$$

The statement of the problem for distribution system expansion planning can be given by the objective function, defined by eq. (8), along with various constraints, represented by eqs. (9) - (19).

3. SOLUTION METHODOLOGY

Once the above objective function defined by eq. (8), is minimized subject to various constraints represented by eqs. (9) - (19), the following are determined:

- The location, installation year, and capacity of DG and capacitor units.
- The installation year of new substation (SS) transformer as well as its capacity.
- The feeder line upgradation required with their time schedule.

The developed formulation for optimal expansion planning of the distribution system is a mixed integer nonlinear programming problem. Due to its powerful capability in handling with such problems, Genetic Algorithm (GA) optimization technique is used here to obtain the solution. GA based algorithms are emerging as the efficient approaches for various search, classification, and optimization problems. These algorithms efficiently find global optima at a rapid and robust convergence rate, regardless of nature/complexity level of the problem. The computational steps involved in solving the proposed formulation using GA are given as follows:

3.1. Chromosome Codification

The developed formulation contains two types of variables, namely, planning variables and operation variables. The planning variables are to be defined for each planning year, whereas the operation variables are to be defined for each demand level of each planning year. The structure of a typical chromosome is shown in Fig. 1. For each combination of decision variables, the load flow is used to determine the power purchased from grid and power loss in the network.

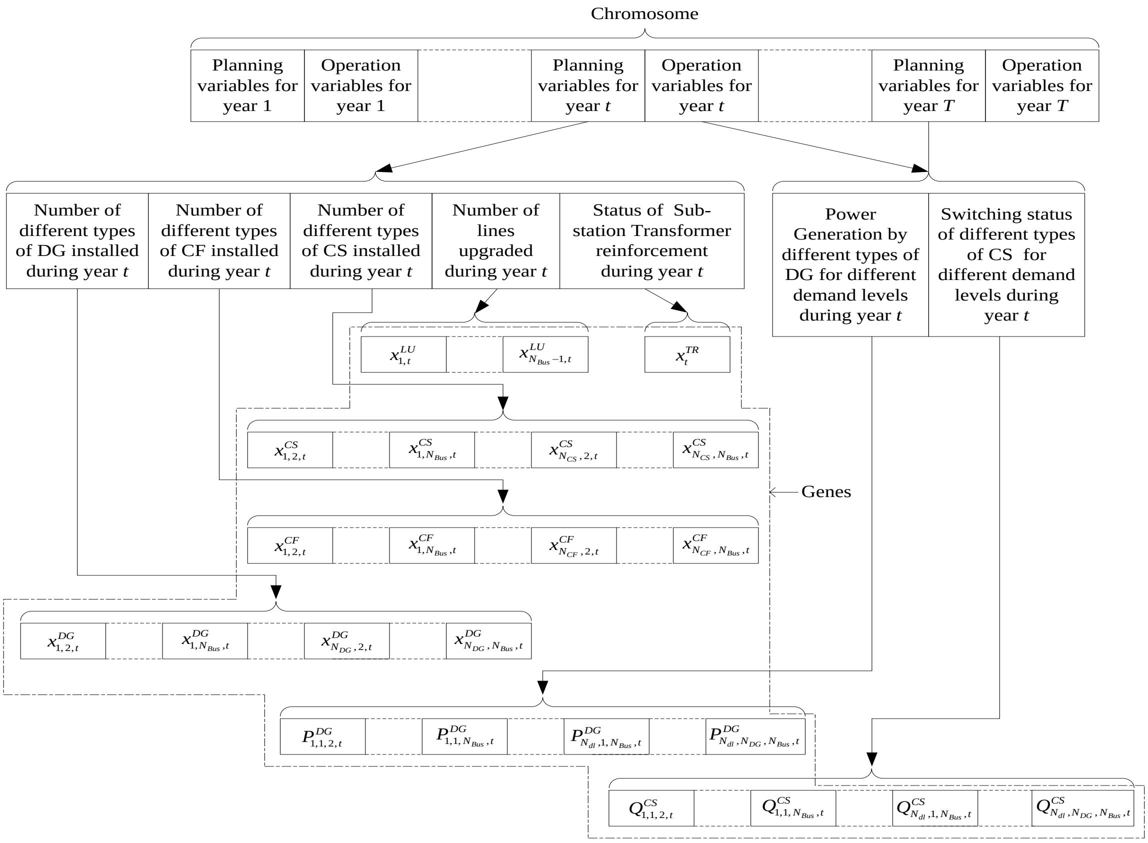

Figure 1 Structure of a typical chromosome in the proposed planning problem

As seen from Fig. 1, each chromosome contains information about all planning variables, power generated by DGs and states of switching capacitors over the planning horizon. First genes are arranged year-wise, then for each planning year, these are divided into two major groups, first group contains the genes representing the planning variables, while second group contains the genes representing the operation variables.

The first minor group contains a total N_{DG} x (N_{Bus} - 1) genes, each representing the number of a given type of DG placed at a given bus. Similarly, the second minor group contains a total N_{CF} x (N_{Bus} - 1) genes, each representing the number of a given type of CF placed at a given bus. The third minor group contains a total N_{CS} x (N_{Bus} - 1) genes, each representing the number of a given type of CS placed at a given bus. The fourth minor group contains a total (N_{Bus} - 1) genes, each representing the status of upgradation of a given line. Finally, the fifth minor group contains a single gene representing the status of upgradation of sub-station transformer. The second major group is sub-divided into two minor groups representing power generated by different types of DG for different demand levels and states of different types of CS for different demand levels, respectively, during the planning year under consideration. The first minor group contains a total N_{dl} x N_{DG} x (N_{Bus} - 1) genes, each representing the active power generated by a given type of DG placed at a given bus corresponding to a given demand level. The second minor group contains a total N_{dl} x N_{CS} x (N_{Bus} - 1) genes, each representing the reactive power generated by a given type of CS placed at a given bus corresponding to a given demand level.

For the sake of explanation, consider a 3-bus radial distribution network, having bus 1 as root bus, for expansion planning. Further consider that there are two DG types (DG1 and DG2), two CF types (CF1 and CF2) and two CS types (CS1 and CS2) available for expansion planning along with reinforcement of lines and sub-station transformer. If no DG and capacitor is connected to root bus and assuming two load levels (dl1 and dl2) in the system, a set of genes representing the solution vector for a planning year under consideration is shown in Fig. 2. Over the planning horizon, there will be several such sets equal to the planning period to represent a chromosome of the proposed GA based method.

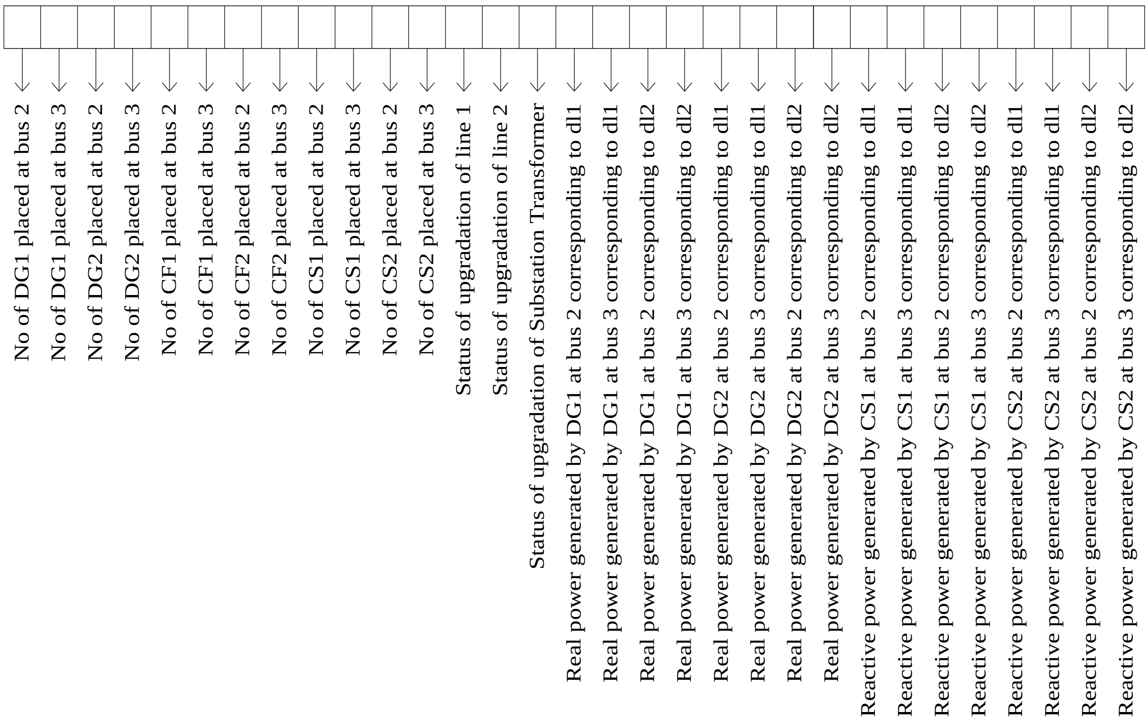

Figure 2 A typical set of genes

3.2. Generation of Parent Population

During population generation, the planning decision variables corresponding to DG units and capacitors should satisfy eq. (15) and the planning decision variables corresponding to reinforcement of lines and sub-station transformer should be either 0 or 1. The operation decision variables corresponding to power generated by DGs and switching states of CSs should satisfy eqs. (16) and (17), respectively, for each load level.

3.3. Fitness Evaluation

After generating initial population, fitness of each chromosome/individual in the current population is computed using the following steps:

Step 1: Update the network by connecting DG and capacitor and reinforcing the line and sub-station transformer as per the chromosome information and determine the total investment cost by adding different costs obtained from eqs. (1), (3)-(5).

Step 2: For each load level, perform the load flow using the information about power generated by DGs and switching states of CSs contained by chromosomes to compute active power purchased from grid and power loss. Determine the total operating cost by adding different costs obtained from eqs. (2), (6) and (7) and then the total cost by adding investment cost and operating cost. Also check the constraints given by eqs. (9), (10), (13), (18) and (19). If any of the constraints is not satisfied, a large number (10^6) is assigned as penalty to the fitness value of corresponding individual.

3.4. Generation of New Population

In this step, fittest chromosomes from the current population are selected to form the mating pool. In the proposed approach, first, the elitist strategy is used to select a portion (5%) of the chromosomes with the best fitness values and then the the roulette wheel approach is employed to select the remaining portion of the chromosomes so that the number of chromosomes in the mating pool is the same as the population size.

The proposed approach uses the mating pool to create the children that make for the next generation using crossover and mutation operator in each iteration. Through the crossover, the two chromosomes which are selected randomly from the mating pool are combined to produce two or more chromosomes. The crossover operator is applied separately for different minor groups of chromosomes. In this work, single-point crossover operator is used. In a single-point crossover, a crossover site is selected at random along the length of a minor group of chromosome, and the information lying on the right side of the crossover site are swapped between the two minor groups.

In the mutation mechanism, for each gene, a uniformly distributed random number between 0-1 is generated. If this number is less than the mutation rate, the respective value of the gene under consideration is replaced by another random value within its range specified.

3.5. Termination

At the end of each generation, the new population is tested for the convergence. In this work, the maximum number of generations is fixed at a constant value known as generation limit. The maximum number of successive generations without producing better results is also fixed at a constant value known as stall generation limit. For convergence, both the limits are compared with current generation counter. If any of the two is satisfied, the process is terminated; otherwise the new population is evaluated for the fitness value. The procedure is continued through several generations until the convergence criterion is satisfied.

4. RESULTS AND DISCUSSION

The proposed GA based methodology is implemented using Optimization Toolbox of MATLAB and is applied to a 33 kV, 9-bus test system. The technical data of this network is obtained from [29]. The power factor of the system is 0.9 lagging. This network has a 132/33 kV, 40 MVA substation. The thermal loading limit of each conductor is 12 MVA (or 210 A) [29].

Three demand levels, i.e. low, medium and high are considered [22]. The corresponding data of electricity market prices and the time duration for selected demand levels are obtained from [2] and given in Table 1. For each loading level load flow has been performed and system performance in terms of energy losses, energy from sub-station and voltage profile of the network has been recorded. Three different DG types are considered for distribution network expansion planning to meet future load growth. Table 2 gives the particulars of different DG types employed in the study [29]. The maximum number of each DG type to be allocated at a bus during a planning year is taken as 5. Two different types of fixed and switching capacitors are considered in this problem. Table 3 gives the particulars of different capacitors employed in the study [30]. The maximum number of each capacitor type to be allocated at a bus during a planning year is taken as 3. The cost associated with line reinforcement is 0.15 M$/km [10] with a capacity of 210 A (12 MVA). The cost of the reinforcement of sub-station transformer with a capacity equal to 20 MVA is taken as 0.4 M$

[10]. Some other planning related data and GA parameters used in the study are given in Table 4.

Using the proposed GA based approach, following scenarios are considered to determine the distribution system expansion plan:

Scenario-1: Traditional expansion planning,

Scenario-2: Traditional expansion planning including DG and capacitor options.

Table 1 Different loading levels and corresponding electricity market prices

Load Level	Percentage of peak load (in %)	Time Duration (in h)	Market Price (in $/MWh)
Low	0.887	2260	35
Medium	1.0	5000	49
High	1.334	1500	70

Table 2 Particulars of different candidate DG types

DG Type	Size (in MVA)	Installation Cost (in M$)	Operating Cost (in $/MWh)	Power Factor
DG1: Micro Turbine	0.5	0.7425	90	0.9
DG2: Gas Turbine	1.0	1.03	85	0.9
DG3: Fuel Cell	2.0	7.348	39	1.0

Table 3 Particulars of different capacitor types

<table>
<tr><th colspan="2">Capacitor Type</th><th>Size (in MVAr)</th><th>Installation Cost (in $)</th><th>Switching States</th></tr>
<tr><td rowspan="2">Fixed Capacitor</td><td>CF1</td><td>0.5</td><td>1700</td><td>-</td></tr>
<tr><td>CF2</td><td>1.0</td><td>2800</td><td>-</td></tr>
<tr><td rowspan="2">Switching Capacitor</td><td>CS1</td><td>0.5</td><td>3400</td><td>5</td></tr>
<tr><td>CS2</td><td>1.0</td><td>5500</td><td>10</td></tr>
</table>

Table 4 Other data used in the study

Parameter	scenario-1	scenario-2
Planning Horizon, T	10 years	-
Annual Load Growth Rate, α	5%	-
Discount Rate, r	12%	-
Length of Chromosome	90	1850
Population Size	50	500
Generation Limit	500	500
Stall Generation limit	50	50

4.1. Scenario-1: Traditional expansion planning

Under this scenario, the optimal expansion plan of distribution network under consideration is determined by upgrading the lines and sub-station transformer only. Various cost terms involved in distribution network expansion planning under scenario-1 are presented in Table 5. The net present value of the total planning cost incurred in this scenario at the end of planning horizon is 133.35 M$.

Table 5 Costs involved in distribution network expansion planning under scenario-1

Cost	Value (in M$)
NPV of line reinforcement cost	19.52
NPV of transformer reinforcement cost	1.00
NPV of purchased energy cost	111.20
NPV of energy loss cost	1.63
NPV of total expansion cost	133.35

The convergence characteristic of the proposed GA based approach for the expansion planning of distribution system by upgrading the lines and sub-station transformer under scenario-1 is shown in Fig. 3.

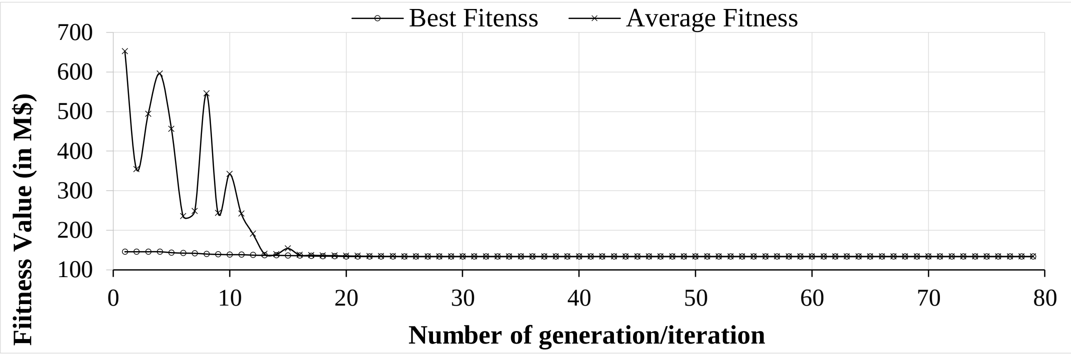

Figure 3 Convergence characteristic of proposed GA based approach in scenario-1

4.2. Scenario-2: Traditional expansion planning including DG and capacitor options

Under this scenario, the optimal expansion plan of distribution network under consideration is determined by upgrading the lines and sub-station transformer along with DGs and capacitors as the possible alternatives. Various cost terms involved in distribution network expansion planning under scenario-2 are presented in Table 6. The net present value of the total planning cost incurred in this scenario at the end of planning horizon is 123.78 M$.

Table 6 Costs involved in distribution network expansion planning under scenario-2

Cost	Value (in M$)
NPV of DG installation cost	1.43
NPV of DG operation cost	0.33
NPV of fixed capacitor installation cost	0.37
NPV of switching capacitor installation cost	0.07
NPV of line reinforcement cost	9.69

NPV of transformer reinforcement cost	0.64
NPV of purchased energy cost	109.82
NPV of energy loss cost	1.77
NPV of total expansion cost	123.78

The performance of considered test network at the end of planning horizon under scenario-1 & 2 in terms of energy losses, energy from sub-station and voltage profile of the network is presented in Table 7.

Table 7 Performance of test system at the end of planning horizon under scenario-1&2 Scenario-1

Load Level	Energy Losses		Energy from Sub-station		Voltage (pu)	
	Active (MWh)	Reactive (MVARh)	Active (MWh)	Reactive (MVARh)	Minimum	Maximum
Low	13084.42	21169.24	906449.33	453845.61	0.9660	1.0000
Medium	37031.08	59912.53	2265296.06	1139110.50	0.9615	1.0000
High	19718.63	31903.62	902020.28	459221.80	0.9505	1.0000
Total	69834.14	112985.39	4073765.67	2052177.90	-	-

Scenario-2

Load Level	Energy Losses		Energy from Sub-station		Voltage (pu)	
	Active (MWh)	Reactive (MVARh)	Active (MWh)	Reactive (MVARh)	Minimum	Maximum
Low	9746.00	15762.98	903110.91	117349.34	0.9844	1.0000
Medium	27413.13	44337.64	2255678.10	284035.60	0.9847	1.0000
High	15132.49	24474.23	906884.13	202869.26	0.9711	1.0000
Total	52291.62	84574.85	4065673.15	604254.20	-	-

The convergence characteristic of the proposed GA based approach for the expansion planning of distribution system by upgrading the lines and sub-station transformer along with DG and capacitors as the possible alternatives under scenario-2 is shown in Fig. 4.

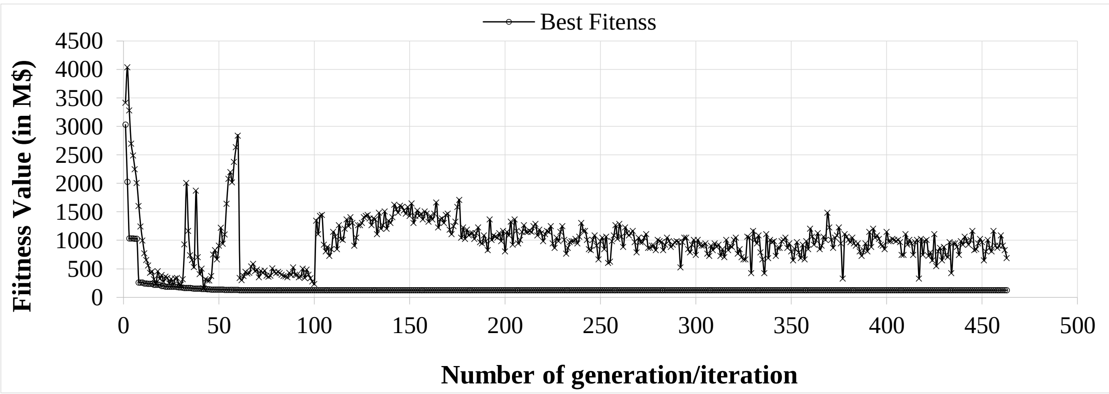

Figure 4 Convergence characteristic of proposed GA based approach in scenario-2

Table 8 Comparison of results with different considered scenarios

Scenario	Energy Losses		Energy from Sub-station		Minimum Voltage (pu)	Total cost of expansion (M$)
	Active (GWh)	Reactive (GVARh)	Active (GWh)	Reactive (GVARh)		
Scenario-1	69.83	112.99	4073.77	2052.18	0.9505	133.35
Scenario-2	52.29	84.57	4065.67	604.25	0.9711	123.78

Summarizing different scenarios considered, a comparison between different scenarios considered for the network expansion planning in terms of energy losses, energy from sub-station and voltage profile of the network is given in Table 8. Different values in this table are computed over the entire planning horizon. By comparing the total expansion planning cost incurred over the complete horizon of 10 years for different scenarios considered, it is observed that expansion plan by employing scenario-2 results the cheapest among other scenario. Further, in terms of the performance of the system by the end of planning horizon, the expansion plan with scenario-2 is better in comparison to scenario-1. Therefore, it can be concluded that application of combined DG and capacitor options for the network expansion planning results into lowest planning cost by deferring the network upgradation requirement in order to supply the increased load demand over the planning year.

5. CONCLUSIONS

In this paper, a multistage distribution network expansion planning model considering DGs and capacitors as the possible alternatives along with traditional planning has been presented from the distribution utilities point of view. The capability and the performance of the proposed model have been demonstrated and analyzed by applying it to a typical primary 9-bus distribution test system. Two different scenarios, one using without DG and capacitor option and the other using DG and capacitor options, of distribution system expansion planning have been considered. The comparison of results by different scenarios considered shows that integration of combined DG and capacitor options in the power distribution system during its expansion, to meet load growth over the planning horizon, results into a lower planning cost and better performance of the system.

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