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Optimal Expansion Planning of Distribution System and DG Placement Using BPSO

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ABSTRACT

A new method to solve the single and multi-objective distribution expansion planning problems including DG is investigated in this paper. The sizing and placement of DG as well as the required power of the main grid would be optimized using proposed method to meet the demand. Binary Particle Swarm Optimization (BPSO) algorithm is used to solve the optimization problem for three objective functions: total expansion cost, total voltage deviation, and total system loss. The goal of presented model is to satisfy operational and economic requirements by using DG as an alternative candidate for distribution system planning to avoid or at least reduce the expanding existing substations and upgrading existing feeders. The 30-bus distribution system is used in this work to evaluate the proposed algorithm. The conventional Weighted Aggregation Method is used to solve the multi-objective optimization problem so that further objective functions and constraints can be easily added to the proposed algorithm. Optimization results show that the DG has economical and electrical advantages in comparison with the traditional method.

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NOMENCLATURE

J_{MO}	Multi-objective function
J_{TEC}	Objective function of the total expansion cost
J_{TVD}	Objective function of the total voltage deviation
J_{TSL}	Objective function of the total system losses
C^{EM}	Electricity market price ($/ MWh)
$C_{i,j}^{Tr,F}$	Fixed cost of the transformer j in the substation i ($/unit)
$C_{i,j}^{DG,F}$	Fixed cost of the DG unit j in the load bus i ($/unit)
$C_{i,j}^{DG,O}$	Operation cost of the DG unit j in the load bus i ($/MW)
$\sigma_{i,j}^{DG}$	Binary decision variable of the DG unit j in the load bus i
$\sigma_{i,j}^{Tr}$	Binary decision variable of the transformer j in the substation i
σ_l	Binary decision variable of the feeder l
$S_{i,j}^{DG}$	Power generated from the DG unit j in the load bus i (MVA)
S_i^{DG}	Total power generated from distributed generation in the load bus i (MVA)
$S_i^{DG,MAX}$	Distributed generation capacity limit in the load bus i (MVA)
S_i^{Tr}	Total power transferred from electricity market in the substation i (MVA)
$S_i^{Tr,MAX}$	Maximum substation capacity limit in the substation i (MVA)
P_i^{Tr}	Total active power transferred from electricity market in the substation i (MW)

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Q_i^{Tr}	Total reactive power transferred from electricity market in the substation ***i*** (MVAR)
P_i^D	Total active power consumption in the bus ***i*** (MW)
Q_i^D	Total reactive power consumption in the bus ***i*** (MVAR)
$pf_{i,j}^{DG}$	Power factor of the DG unit ***j*** in the load bus ***i***
L	Feeders' set
C_l	upgrade cost of the feeder ***l*** ($)
R_l	Resistance of the feeder ***l***
X_l	Reactance of the feeder ***l***
I_l	Current of the feeder ***l***
S_l	Power transferred from the feeder ***l*** (MVA)
S_l^{MAX}	Thermal capacity limit of the feeder ***l*** (MVA)
V_i	Voltage of the bus ***i*** (per unit)
β	Present worth factor
d	Discount factor
TN	Total number of system buses
N	Set of buses capable for substation expansion
N_{tr}	Maximum number of transformers at each bus
M	Set of buses capable for installing DG units (load buses)
M_{dg}	Maximum number of DG considered at each bus
BK_i	Back-up protection DG unit in the load bus ***i***
w	Weighting factor
t	Incremental time intervals (in years)
T	Horizon planning year (in years)

INTRODUCTION

Electric utilities have historically satisfied customer demands by generating electricity centrally and distributing it through an extensive transmission and distribution system. As demand increases, the utility generates more electricity. Once demand exceeds a certain level, the capacity of the generation, transmission, and distribution systems may become diminished. This situation has led to power shortages, and power quality issues. Distribution planners must ensure that there are enough substation and feeder capacities to meet the load forecasts within the planning horizon. In general, the primary goal in any expansion planning is to satisfy the growth of demand as economical, reliable, and safe as possible.

Traditional distribution planning strategies are based on an established rule-based experience. The load growth value is forecasted until it reaches a predetermined threshold; then, a new capacity must be added to the electric system. This new capacity is obtained by adding new substations or expanding existing substation's capacities and their new feeders or both of them (Khator, S.K and L.C. Leung, 1997). The options for this rule-based strategy are limited and valid only if the economic aspects do not vary rapidly. If the economic variations are significant, this rule-based strategy must be readjusted to include nontraditional alternative capacity's investment options to address the varying economic environments (Quintana, V.H., *et al*., 1993). Distributed generation (DG) is one of the new alternative options for distribution system planners. Despite the great variety of methods for traditional distribution system planning, there are few studies available in the literature for the problem considering DG sources. The possibility of considering DG as a feasible alternative to traditional distribution system planning is discussed in (Dugan, R.C., *et al*., 1999). In (Brown, R.E. and L.A.A. Freeman, 2001), the authors present a network capacity single stage expansion algorithm based on successive elimination capable of deferring network expansion by optimally using DG sources in new or existing substations. In (Ouyang, W., *et al*., 2010) a distribution system planning method considering DG for cutting peak time is proposed to minimize the costs of feeder investments, DG investments, energy loss and the additional cost of DG sources. Effects of DG on substations expansion is not considered in this work. In (El-Khattam, W., *et al*., 2005), the authors developed a model for static distribution system planning, considering DG sources. The proposed model integrates a comprehensive optimization model and planner's experience to achieve optimum sizing and placement of distributed generation. In this model minimization of DG's investment, operating costs, total payments toward compensating for system losses along the planning period and different costs according to the available alternative scenarios is investigated. In (Haffner, S., *et al.*, 2008), a multistage model for distribution system planning considering DG option is presented. The objective function which is minimized in this model is the present value of total installation costs (feeders and substations) of operating and maintaining the network and cost of distributed generation. In (Ault, G.W. and J.R. Mcdonald, 2000), importance of DG consideration in distribution system planning has been discussed.

The aim of the model which is proposed in this paper is to satisfy the operational and economic requirements by using DG as an alternative candidate for distribution system planning and avoiding or at least reducing expanding existing substations and upgrading the existing feeders. The proposed method will determine new sizing and placement of DG as well as the required power to be imported from the main grid to meet the demand in an optimum way. This optimization problem is solved by Binary Particle Swarm Optimization (BPSO) algorithm for three objective functions: total expansion cost, total voltage deviation, and total system losses. In comparison with the old methods, the proposed approach not only considers the system planning economic cost but also considers other aspects in the optimization process by assigning and evaluating the different weights for different objective functions depend on their importance for planner in the system planning. The salient feature of the proposed optimization model which makes this method different from previous methods is using binary decision variables. This provides the optimum decisions without any need for rounding the solution.

The problem formulations, constraints, objective functions, briefly description about binary particle swarm optimization algorithm, single and multi-objective, and proposed method for expansion planning problem are presented in following sections. Then the results of proposed methods on IEEE 30-Bus system for single and multi-objective expansion planning will be presented. Finally, conclusions are given in the last section.

MATERIALS AND METHODS

Objective Functions:

Total Expansion Cost (TEC):

The expansion cost function consists of four terms: the cost of the new transformers in the substation, cost of the distributed generation, cost of the new feeders upgrade, and the cost of the active power losses. New transformers and DGs have fixed and variable parts. The cost of new feeders upgrade and active power losses are respectively fixed and variable. The fixed cost is spent during the installation phase and includes the cost of the construction, equipment, etc. The variable cost is the cost of the operation and depends mainly on the loading of the equipment during the operation period. An existing substation is represented as a power source which can supply power at a given unit variable cost up to a prescribed upper bound (El-Khattam, W., *et al.*, 2005).

$$J_{TEC} = C_U + C_{DG} + C_F + C_L \tag{1}$$

Whereas

C_U : Fixed and variable cost for substation expansion

$$C_U = \sum_{i\in N}\sum_{j=1}^{Ntr} C_{i,j}^{Tr,F}\cdot\sigma_{i,j}^{Tr} + 8760\cdot C^{EM}\cdot\sum_{t=1}^{T}\left(\beta^t\cdot\sum_{i\in N}P_i^{Tr}\right) \tag{2}$$

C_{DG} : Fixed and variable cost for DG

$$C_{DG} = \sum_{i\in M}\sum_{j=1}^{Mdg}\left(C_{i,j}^{DG,F}\cdot S_{i,j}^{DG}\cdot\left(BK_i+\sigma_{i,j}^{DG}\right)\right) + 8760\cdot\sum_{t=1}^{T}\left(\beta^t\cdot\sum_{i\in M}\sum_{j=1}^{Mdg}C_{i,j}^{DG,O}\cdot S_{i,j}^{DG}\cdot pf_{i,j}^{DG}.\sigma_{i,j}^{DG}\right) \tag{3}$$

C_F : Fixed cost of upgrading the feeders

$$C_F = \sum_{l=1}^{L} C_l\cdot\sigma_l \tag{4}$$

C_L : Variable cost for total system losses

$$C_L = 8760\cdot C^{EM}\cdot\sum_{t=1}^{T}\beta^t\left(\sum_{l=1}^{L}R_l\cdot\left|I_l\right|^2\right) \tag{5}$$

Whereas β is the present worth factor which equals $\beta = 1/(1+d)$ (Willis, H.L., 2004).

Total Voltage Deviation (TVD):

The expression of total voltage deviation in the system is:

$$J_{TVD} = \sum_{i=1}^{TN}\left|1-V_i\right| \tag{6}$$

Where V_i is the voltage in per unit at the system bus ***i***.

Total System Losses (TSL):

Total system losses can be expressed as:

$$J_{TSL} = \sum_{l=1}^{L} R_l \cdot \left|I_l\right|^2 \tag{7}$$

Problem Constraints:

Network power balance:

Total power consumption should be equal to the total generation. This constraint is met in load flow calculation (Dondi, P., *et al*., 2002), considering the cost of available power sources and dispatching them. In this approach, DG units are assumed as negative loads.

$$\sum_{i\in N} P_i^{Tr} + \sum_{i\in N}\sum_{j=1}^{Mdg} S_{i,j}^{DG} \cdot pf_{i,j}^{DG} \cdot \sigma_{i,j}^{DG} - \sum_{l=1}^{L} R_l \cdot \left|I_l\right|^2 = \sum_{i\in M} P_i^D \tag{8}$$

$$\sum_{i\in N} Q_i^{Tr} + \sum_{i\in N}\sum_{j=1}^{Mdg} S_{i,j}^{DG} \cdot \sqrt{1-(pf_{i,j}^{DG})^2} \cdot \sigma_{i,j}^{DG} - \sum_{l=1}^{L} X_l \cdot \left|I_l\right|^2 = \sum_{i\in M} Q_i^D \tag{9}$$

Distribution feeder's thermal limit:

When the load grows the feeder's thermal capacity may exceed their nominal values. If this problem occurs, additional investment will be required for reinforcement of these feeders:

$$S_l \le S_l^{MAX} \qquad l = 1,2,3,...,L \tag{10}$$

Transformer and DG unit maximum capacity:

Power delivered by each transformer and DG unit must be within the upper limit of their capacities.

$$S_i^{Tr} \le S_i^{Tr,MAX} \qquad \forall i \in N \tag{11}$$

$$S_i^{DG} \le S_i^{DG,MAX} \qquad \forall i \in M \tag{12}$$

Voltage deviation:

Voltage value of each bus should remain within acceptable limits as following:

$$V_i^{MIN} \le V_i \le V_i^{MAX} \qquad i = 1,2,3,...,TN \tag{13}$$

Maximum DG penetration:

Summation of total DG capacity in the grid should be less than some percentage (say, 30%) of the total load.

Binary Particle Swarm Optimization (BPSO):

The Particle Swarm Optimization (PSO) algorithm was introduced by James Kennedy and Russell Eberhart in 1995 (Kennedy, J. and R.C. Eberhart, 1995). PSO is a population based heuristic search technique in which each particle represents a potential solution within the search space and is characterized by a position, a velocity and a record of its past performance. At each flight cycle, the objective function for each particle with respect to its current position is evaluated. The obtained value measures the quality of the particle (Eberhart, R. and Y. Shi, 2001). The (original) process for implementing the global version of PSO is as following (Kennedy, J. and R.C. Eberhart, 1995; Eberhart, R. and Y. Shi, 2001):

1.1.1. Initializing a population (array) of particles with random positions and velocities on d-dimensions in the problem space.

1.1.2. For each particle, the desired optimization fitness function in d variables is evaluated.

1.1.3. Comparing particles' fitness evaluation with particles' P_{best}. If current value is better than P_{best}, then P_{best} value will be equal to the current value.

1.1.4. Comparing fitness evaluation with the population's overall previous best. If current value is better than G_{best}, then G_{best} will be updated.

1.1.5. Changing the velocity and position of the particle according to equations (14) and (15), respectively:

$$V_{id} = w \cdot V_{id} + C_1 \cdot rand(1) \cdot \left(X_{P_{best}} - X_{id}\right) + C_2 \cdot rand(1) \cdot \left(X_{G_{best}} - X_{id}\right) \tag{14}$$

$$X_{id} = X_{id} + V_{id} \tag{15}$$

1.1.6. Going to step 2 until a criterion that is usually a maximum number of iterations is met.

The Binary PSO algorithm (BPSO) was introduced by Kennedy and Eberhart (1997) to allow the PSO algorithm to operate in binary problem spaces. The BPSO has a structure similar to the standard PSO, but, the velocity vector is still continuous which is used to define the probability of a bit to be 0 or 1. The only difference between standard PSO and Binary PSO algorithm is the position vector of the particle. In BPSO this vector is a vector of binary digits, rather than a vector of continuous values, and the position update equation changes to (Kennedy and Eberhart (1997):

$$X_{id} = \begin{cases} 1 & rand(1) < S(V_{id}) \\ 0 & otherwise \end{cases} \tag{16}$$

Where S(x) is the sigmoid function:

$$S(x) = \frac{1}{1+e^{-x}} \tag{17}$$

The BPSO is sensitive to sigmoid function saturation, which occurs when velocity values are either too large or too small. In such cases the probability of a change in bit value approaches to zero, so limits exploration. For 0 velocity, the sigmoid function returns a probability of 0.5, implying that there is a 50% chance for the bit to change (Clerc, M., 2004; Ngatchou, P., *et al*., 2005). Fig. 1 shows the flowchart of BPSO.

The Proposed Algorithm for Single-Objective Optimization:

The binary string of particle position is shown in Fig. 2. This string consists of two main parts. One of them is related to the set of buses that are capable of substation expansion. This part includes n(N) bytes which has N_{tr} bits. Each byte indicates a bus which is capable of substation expansion. The summation of bits in this byte shows the number of transformers installed in this bus. The other part shows the set of load buses and DG units can be installed on it. This part includes n(M) bytes which has M_{dg} bits. Each byte indicates a bus and DG units can be installed on it. The summation of bits in this byte shows the number of DG units. So the binary string of particle position has *m* bits which equals to the total possible locations of the DGs. The total number of transformers which can be installed on substation expansion buses is mentioned as below:

$$m = n(N) \cdot N_{tr} + n(M) \cdot M_{dg} \tag{18}$$

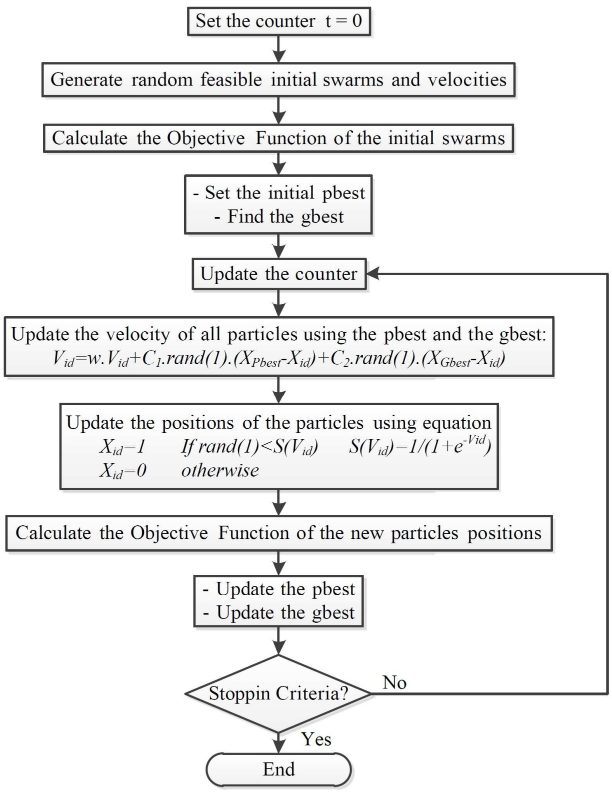

Fig. 1: Flow chart of binary particle swarm

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All transformers and DG units are in binary representation which is illustrated in Fig. 2. In the binary string of particle position $\sigma_{i,j}^{Tr}$ and $\sigma_{i,j}^{DG}$ are binary decision variables. These variables are generated by selecting a random binary value with uniform probability over the optimized parameter search space (0 or 1).

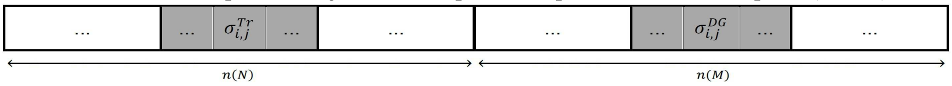

Fig. 2: Binary String of Particle Position

After generating binary string of particle position, this string is decoded and summation of DG units or transformers in each byte is installed on the corresponding bus. Then the power flow is run. After running power flow, the feeders' thermal capacity is evaluated and the exceeded feeders are upgraded and the power flow is run again until all exceeded feeders are replaced. Then the objective function is evaluated. In the next stage the saturation values evaluated in the previous stage are calculated and added to the objective function if summation of total substations capacity and total power generated from distributed generation is less than total load demand or the voltage of each bus is not in the predetermined voltage range. Once these stages are accomplished for all particles, the global best fitness with its corresponding binary string is determined according to the BPSO algorithm. Then velocities and positions are updated according to the BPSO algorithm until iteration reaches its maximum value. The proposed algorithm for Single-Objective optimization is shown in the Fig 3.

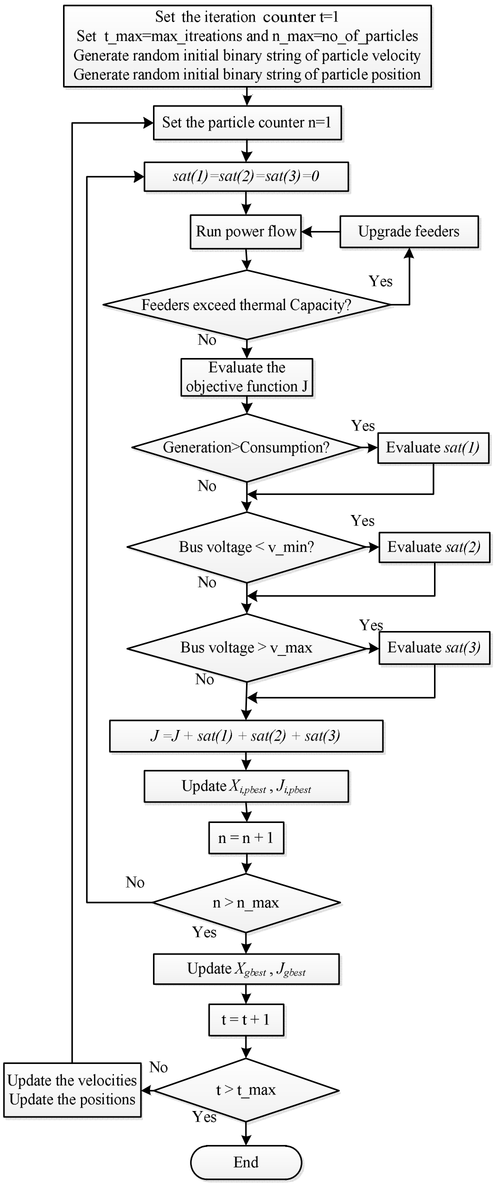

Fig. 3: Flow chart of proposed method for single-objective optimization

Multi-Objective Optimization with Weighting Sum Method:

Many real-world problems involve simultaneous optimization of several objective functions. Multi-objective optimization with such objective functions gives rise to a set of optimal solutions, instead of one optimal solution. The reason for the optimality of many solutions is that no one is considered to be better than any others with respect to all objective functions. These optimum solutions are known as Pareto-optimal solutions (Ngatchou, P., *et al*., 2005).

This is particularly important in optimal placement and sizing of DG, where the distinctiveness of the planning objectives, which may conflict each other (e.g., investments cost .vs. the total voltage deviation or system losses), has a significant impact on the search for a feasible configuration. The multi-objective optimization gives a better simulation of the real world. Often characterized by contrasting goals, it gives the planner the capability of making the final decision by selecting some individual point of view and a trade-off between a wide range of suitable solutions.

There are various techniques to optimize multi objective functions simultaneously. The most important technique is the Weights Sum Method (WSM) (Carpinelli, G., *et al*., 2005).

The Weighted Sum Method is used to combine the objective functions as a single objective optimization problem. This single objective function is constructed as a sum of objective functions multiplied by weighting factors .By changing the value of the weights the Pareto optimal solution set can be easily obtained (Ngatchou, P., *et al*., 2005; Ding, Y., *et al*., 2006):

$$\min f(x) = \min \sum_{i=1}^{N} w_i f_i(x) \tag{19}$$

$$w_i \geq 0, \quad i = 1,...,k \ \& \sum_{i=1}^{k} w_i = 1 \tag{20}$$

By changing the weights all Pareto optimal solution can be generated. In a variant of this method called Conventional Weighted Aggregation (CWA), the weights are incrementally changed. For each combination of weights, the problem is solved, so a new Pareto optimal solution is generated (Kim, I.Y. and O.L. de Weck, 2006; Parsopoulos, K.E. and M.N. Vrahatis, 2002).

In some cases, different objective functions have different magnitudes. So it is required to find normalization of objective functions (Ding, Y., *et al*., 2006; Parsopoulos, K.E. and M.N. Vrahatis, 2002). Each objective function is normalized as following:

$$\bar{J}_i(x) = \frac{J_i(x) - J_{i,\min}}{J_{i,\max} - J_{i,\min}} \tag{21}$$

In this paper for solving distribution system planning, three objective functions are combined as below and then the program will run based on the algorithm illustrated in Fig. 4.

$$J_{MO} = w_1 \cdot \bar{J}_{TEC} + w_2 \cdot \bar{J}_{TVD} + w_3 \cdot \bar{J}_{LOSS} \tag{22}$$

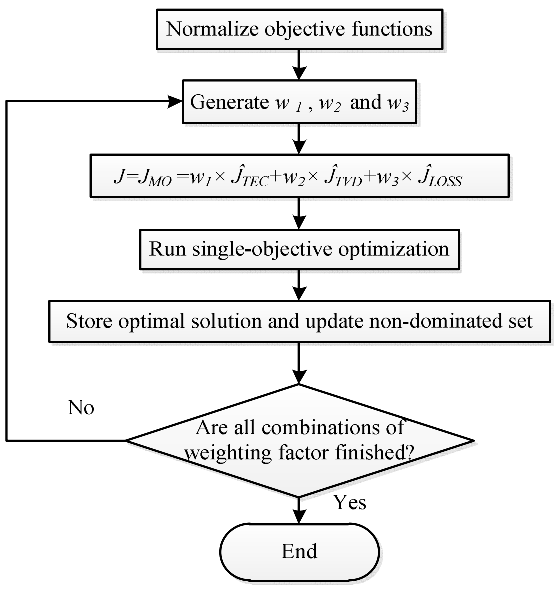

Fig. 4: Flow chart of proposed method for multi-objective optimization

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Case Study And Numerical Results:

The studied system in this paper includes 11 kV distribution system with 30 buses is shown in Fgi 4. (Eminoglu, U. and M.H. Hocaoglu, 2005; Salama, M.M.A. and A.Y. Chikhani, 1993). The system has main feeder and three laterals. The capacity of the transformers at the source bus is assumed to be 12 MVA at bus number 1 and the loads are at buses 2-30. The capacity of the system is 10.224 MVA. The thermal capacity of the feeders assumed to be 12 MVA. However, a 30% load growth is forecasted after 4 years from the base year and the power demand will be approximately 13.291 MVA. A backup DG unit should be installed in case of any DG failure or scheduled maintenance intervals. The system power factor is set to be 0.85 for the DG and the size of the DG's is multiple of 0.1 MVA. The maximum number of the DG capacity at each bus is 0.3 MVA (3 DG units) plus the backup DG. The new three phase 10 MVA transformer unit is used in the case of substation expansion. Feeders upgrade to higher capacity limit (20 MVA) with an impedance of Z_{20MVA}= 0.1469+j0.2719 Ω/Km. The voltage range is supposed to be in the [0.9, 1.1] interval.

For the cost data, the electricity market price is considered to be 70 $/MWh for purchasing power from the main grid. The price of the DG unit is 0.5 M$/MVA and the running cost of the DG is assumed to be 70 $/MWh. The fixed cost of the new 10 MVA transformer is 0.2 M$. The cost of upgrading the feeders to higher capacity (20 MVA feeders) is 0.15 M$/Km and the discount rate is considered to be 12.5% (El-Khattam, W., *et al*., 2005).

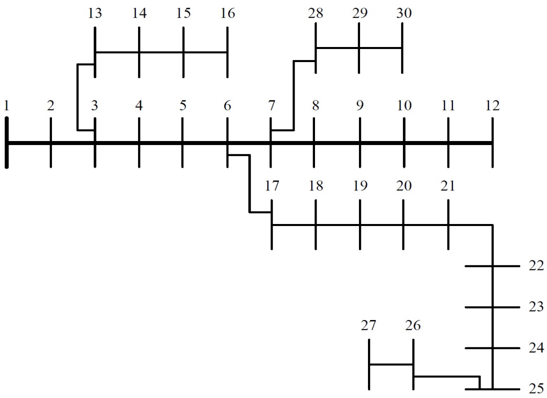

Fig. 5: 30-bus distribution system

Single-Objective Results:

The comparison of the optimal single-objective numerical is presented in Fig 5. The first column shows the substation expansion option without installing any distributed generator. One transformer is installed to meet the demand and four feeders are upgraded because their power flow is higher than thermal capacity. In the next columns the DG option and the substation expansion with different objective functions is considered. In the DG option, the feeders aren't needed to be upgraded because the DG presence in the load side reduces feeders' power flow under their thermal limits. The system voltages are improved for the DG option in the system in comparison with the system which is expanded with traditional substation expansion. When the DG units are added in the load side, the load on the system is reduced and the feeders are less loaded causing in increasing of the voltages at all nodes. The voltage deviations on the system and power losses are reduced considerably in the presence of the DG in the system.

Table 1: Single-Objective numerical results

	Without DG	Objective function		
		TEC	TVD	TSL
Max. DG Penetration Level	0%	30%	30%	30%
Number of New Transformers	1	0	0	0
Expanding Substation Fixed Cost (M$)	0.2	0	0	0
Total System Power (MVA)	14.9827	14.1033	13.8113	13.8113
Substation Purchased Power (MW)	12.5789	9.9043	8.0844	8.0844
Expanding Substation Variable Cost (M$)	20.845	16.7718	13.9519	13.9519
Expanding Substation Total Cost (M$)	21.045	16.7718	13.9519	13.9519
Number of DG	0	26	44	44
Number of Back-Up DG	0	9	15	15
DG Fixed Cost (M$)	0	1.75	2.95	2.95
DG Variable Cost (M$)	0	4.0732	6.893	6.893
DG Total Cost (M$)	0	5.8232	9.843	9.843
Number of Feeders Upgrades	4	0	0	0
Feeders Fixed Cost (M$)	0.33	0	0	0
Total Active Power Losses (MW)	1.2689	0.8043	0.51444	0.51444
Losses Cost (M$)	2.3386	1.4824	0.94815	0.94815
Total Expansion Cost (MS)	23.7136	24.0774	24.7431	24.7431
Total Voltage Deviation (Per-Unit)	2.8609	1.9279	1.5466	1.5466

Fig. 6 and Fig 7. show the bus voltage profile and feeders' power flow in all solutions. It is clear that the voltage profile in DG option solutions is better than the voltage profile in the substation expansion case and also feeders' power flow and consequently total system losses are decreased and feeder upgrading is not necessary. These improvements are advantages of using the DG in the distribution system.

Multi-Objective Results:

Initially 66 combinations of weighing factors are generated by an increment of 0.1. Then for each combination, problem is solved. After eliminating identical solutions, 5 non-dominated solutions are obtained. Each solution is shown with its corresponding total expansion cost, total voltage deviation, total system losses, the locations and the size of the DG is shown in Fig. 8. The decision maker can choose the optimal solution based on the importance of the different objectives and the budget constraints. Also Pareto front of solutions is represented in Fig. 9.

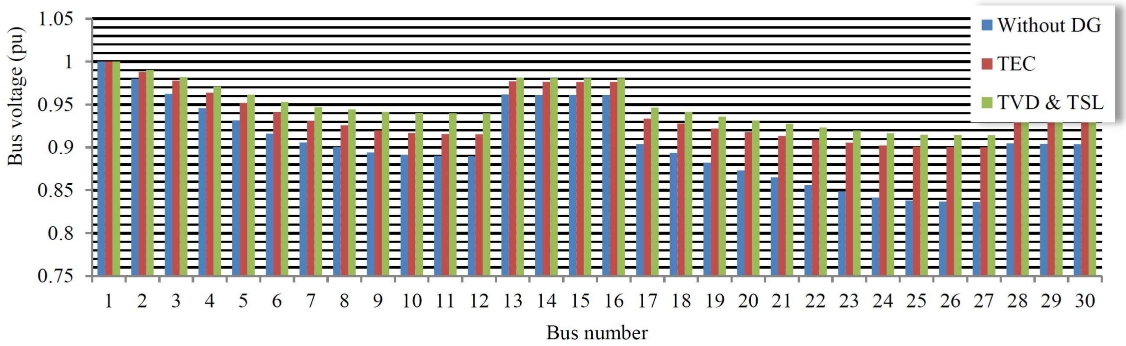

Fig. 6: Comparison of system bus voltage for TEC, TVD and TSL objective function

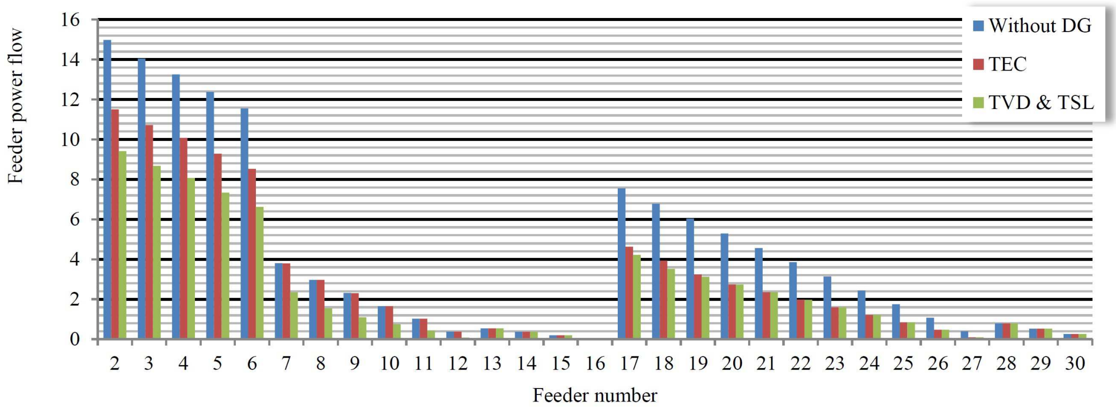

Fig. 7: Comparison of system feeder power flow for TEC, TVD and TSL objective function

Table 2: Multi-Objective numerical results

	Solution 1	Solution 2	Solution 3	Solution 4	Solution 5
w_1	1	0.7	0.5	0.4	0
w_2	0	0	0	0	1
w_3	0	0.3	0.5	0.6	0
J_{TEC}	24.077	24.094	24.399	24.64	24.743
J_{TVD}	1.9279	1.9058	1.7068	1.5854	1.5466
J_{TSL}	0.8043	0.78623	0.6259	0.53996	0.51444
Trans.	0	0	0	0	0
DG	26	27	36	42	44
B-DG	9	9	12	14	15
Bus			Number of DGs		
2-7	0	0	0	0	0
8	0	0	0	0	2
9	0	0	0	3	3
10-12	0	0	3	3	3
13-17	0	0	0	0	0
18	0	0	0	3	3
19	2	3	3	3	3
20-27	3	3	3	3	3
28-30	0	0	0	0	0

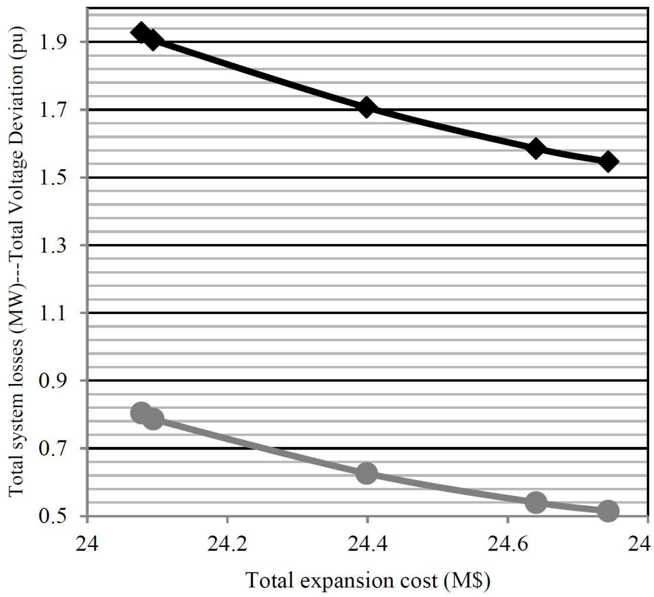

Fig. 8: Pareto solutions front

Conclusions:

This work was based on optimization of distribution system planning including DG using BPSO. The optimization model provided two options to meet the electrical load growth: Installing new transformer with upgrading the feeders and adding DG units in the load buses. This model evaluates more different situations and solutions. Although the planning problem becomes much more complex when DG placement and feeder upgrades are considered together, it provides more diverse expansion solutions for utilities. The Weighting Sum Method (WSM) has been successfully used to generate the non-dominated solutions set for the multi-objective distribution planning problem. This method offers flexibility to assign and evaluate different weights for different objective functions depending on their importance in the system planning. Optimization results analysis of 30-bus radial distribution system show that the DGs introduce electrical benefits to the system in compare with the traditional option including new transformers addition at the existing substation and upgrading the overloaded feeders while the investment of both options is almost equal. Implicitly, the model discussed in this paper assumes that new DGs may be installed by distribution company (DISCO). Although it may be practical in some cases, it is not true for some situations.

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